ENVIRONMENTAL LAW & POLICY CENTER

September 18, 2026

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-22061

Dear Ms. Felice:

Attached for paperless electronic filing, please find the **Corrected** Official Exhibits and Exhibit List of The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively the Clean Energy Organizations or "CEO"). This document is a corrected version of CEO's Official Exhibits and Exhibit List, originally filed on September 17, 2026 (docketed item U-22061-0086), which was missing pages. Proof of service is also attached.

Please note this filing contains confidential information and has been redacted. The unredacted version of Exhibit CEO-6 has been filed under seal with the Executive Secretary of the MPSC.

Thank you,

Katie Duckworth (P86670)
Environmental Law & Policy Center
35 E Wacker Dr., Ste. 1600
Chicago, IL 60601
312-673-6500
kduckworth@elpc.org

cc: Service List, Case No. U-22061

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE ELECTRIC COMPANY for approval of amendments to Rate D11 and related relief.	)))))	Case No. U-22061

EXHIBIT LIST OF

THE ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR

CEO Witness	Ex. #	Exhibit Description
Lee Shaver	CEO-1	Resumé of Lee Shaver
	CEO-2	Characteristics and Risks of Emerging Large Loads: Large Loads Task Force White Paper (July 2025)
	CEO-3	NERC, Incident Review Considering Simultaneous Voltage Sensitive Load Reductions (Jan. 2025)
	CEO-4	NERC, 2026 State of Reliability: Assessment Overview of 2025 Bulk Power System Performance (June 2026)
	CEO-5	DTE discovery responses to CEODE-2.2a; CEODE-2.3a; CEODE-2.3e; CEODE-2.4a; CEODE-2.4b; CEODE-2.4c; CEODE-2.5bi–bii; CEODE-2.7a–d; CEODE-2.7f–g; CEODE-2.7i; CEODE-2.7k; CEODE-2.10i; CEODE-2.14c; and CEODE-2.16b
	CEO-6	**Confidential** DTE discovery response to CEODE-3.1
	CEO-7	Energy Systems Integration Group, Interconnection Processes for Large Loads: Current Practices and Recommendations (June 2026)

	CEO-8	NERC, Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads White Paper (March 2026)
	CEO-9	NERC, Draft Large Load Disturbance Performance Impact Analysis and Ride-Through Recommendations (August 2026)
Hearing Exhibit	CEO-10	DTE discovery responses to CEODE-4.1–4.2

LEE SHAVER

Senior Energy Analyst | Union of Concerned Scientists

As a Senior Energy Analyst, I focus on research and analysis of state and regional energy system transformation to support increasing shares of renewable energy and distributed energy resources. My work contributes to UCS' efforts to reform wholesale electricity market designs to increasing shares of clean energy technologies. I also contribute to UCS's state-focused efforts for policies that enable clean energy technologies, including distribution grid planning and equitable energy storage. This work supports the transition toward sustainable energy systems with high shares of renewables and distributed energy resources.

PRIOR EXPERIENCE

Slipstream — Feb. 2018 - Jan. 2024

Senior Energy Engineer (Nov. 2022 - Jan. 2024)
Energy Engineer II (Feb. 2018 - Nov. 2022)

- Proposal writer, project manager, outreach lead, and subject matter expert for research studies of distributed energy resources and emerging technologies in energy efficiency and load management in commercial buildings for resilience, grid stability, and utility cost savings.
- Managed budgets and contracts up to $2M across multiple complex projects through collaboration, effective communication, attention to detail, and flexibility to ensure timelines and objectives are exceeded.
- Partnered with two machine learning startups for pilot studies on commercial refrigeration system controls, using field data and energy modeling to verify the demand and energy savings potential.
- Advised building design teams on best practices for energy efficiency measures in new buildings using energy modeling in eQuest and Sketchbox, resulting in 50+ new commercial buildings exceeding energy code baseline (IECC, ASHRAE 90.1) and receiving utility incentives.
- Promoted equity internally through co-chairing the DEI employee resource group as well as externally by creating an audit to develop recommendations for measuring and increasing the equity impact of projects.

PA Consulting Group, *Consultant Analyst, Global Energy and Utilities* — Jun. 2017 - Jan. 2018

- Advised utilities and power producers using technical, policy, financial, and market analysis to quantify risk, evaluate assets, and improve operations.
- Performed market research and policy analysis across MISO, PJM, ERCOT, and CAISO, including market and environmental regulations, infrastructure development, and economic forecasts.

University of Wisconsin-Madison, *Research Assistant* — Aug. 2014 - May 2017

- Developed, tested, and documented a solution for rural home electrification by designing hardware and software for a modular, home-scale dc microgrid.
- Partnered with the National Institute of Engineering in Mysuru, India to implement a microgrid testbed and identify locations for field testing.

Quadlogic Controls, *Sales and Specification Engineer* — Jul. 2013 - Aug. 2014

- Coordinated manufacturer's representatives in 13 states to drive sales through networking, outreach, trade shows, and technical seminars.
- Lead updates of product manuals and specifications using technical writing and editing skills to provide improved support to clients and partners.

Energy Spectrum, *Project Manager* — Oct. 2012 - Jul. 2013

- Supported successful participation in grid operator and utility demand response programs by specifying, commissioning, and managing electric submetering systems.
- Managed turn-key upgrade of 500+ electric submeters at an industrial/commercial complex in Brooklyn from quotation to daily operation, resulting in increased submetering revenue.

Quadlogic Controls — Dec. 2009 - Oct. 2012

Assistant Engineering Manager (May 2012 – Oct 2012)

- Coordinated operations of tech support, commissioning, and field service.
- Managed a new team of seven including technicians, engineers, and a service dispatcher resulting in improved customer service and faster completion of commissioning projects.

Field Engineering Supervisor (Jul 2010 – May 2012)

- Developed and facilitated training seminars to certify service providers in the US and Canada, resulting in expansion of service range to five new markets and reduction in service call response time and costs by 20%.
- Implemented a CRM system for field service, repairs, and tech support resulting in reduced response time with no increase in workforce.

Technical Support Engineer (Dec 2009 – Jul 2010)

- Conducted long term diagnostic studies on problematic issues and developed Engineering Change Orders to implement proposed solutions.

United States Peace Corps, El Salvador, *Municipal Development Volunteer* Jun. 2007 - Jul. 2009

- Cultivated a deep understanding of community strengths and needs to support several community groups in fundraising for computer labs, soccer stadiums, and community events.

EDUCATION & CERTIFICATES

- M.S. in Electrical Engineering (Energy & Power Systems), *University of Wisconsin-Madison*
- Energy Analysis & Policy Graduate Certificate, *University of Wisconsin-Madison*
- B.S. in Electrical Engineering, *LeTourneau University*

SELECTED PUBLICATIONS

- S. Clemmer, M. Chavez, S. Dotson, J. Gignac, S. Sattler, and L. Shaver. *Data Center Power Play: How Clean Energy Can Meet Rising Electricity Demand While Delivering Climate and Health Benefits*. Union of Concerned Scientists, 2026.
- S. Dotson, L. Shaver, and J. Gignac. *Storing the Future: A Modeling Analysis of Illinois Storage Needs*. Union of Concerned Scientists, 2024.
- M. Koolbeck, L. Shaver, and J. LeZaks, "Weathering the storm: Microgrid feasibility studies for municipal applications". ACEEE Summer Study on Energy Efficiency in Buildings, 2022.
- "Chapter 9: Microgrids," ASHRAE *Smart Grid Application guide: Integrating Facilities with the Electric Grid*, 2020.

SELECTED TESTIMONY

- Direct testimony on behalf of UCS, Environmental Defense Fund, ELPC, NRDC, and Vote Solar, *Ameren Illinois Company Petition for Approval of Multi-Year Integrated Grid Plan pursuant to 220 ILCS 5/16-105.17*, Illinois Commerce Commission, Case No. 26-0051, 2026.
- Direct and rebuttal testimony on behalf of UCS, the Ecology Center, ELPC, and Vote Solar, *In the matter of the application of Indiana Michigan Power Company for approval of modifications to its Large Power Tariff*, Michigan Public Service Commission, Case No. U-21986, 2026.
- Direct testimony on behalf of UCS, the Ecology Center, ELPC, and Vote Solar, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission, Case No. U-21870, 2025.
- Direct and rebuttal testimony on behalf of UCS, the Ecology Center, ELPC, and Vote Solar, *In the matter of Consumers Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023*, Michigan Public Service Commission, Case No. U-21816, 2025.
- Direct and rebuttal testimony on behalf of UCS, the Ecology Center, ELPC, and Vote Solar, *In the matter of the application of DTE Electric Company for approval of Interconnection Procedures and Waivers from Interconnection and Distributed Generation Standards R 460.901a*, Michigan Public Service Commission, Case No. U-21482, 2024.

PROFESSIONAL ASSOCIATIONS & INDUSTRY INVOLVEMENT

- Wisconsin Distributed Resources Consortium (WIDRC), *Treasurer*
- IEEE, *Member*
- SEPA Microgrid Working Group, *Member*
- Wisconsin PSC 119 interconnection rulemaking advisory committee, *Member*

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Characteristics and Risks of Emerging Large Loads

Large Loads Task Force White Paper

July 2025

RELIABILITY | RESILIENCE | SECURITY






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Table of Contents

Preface iv
Executive Summary v
A New Challenge on the Horizon v
NERC'S Response v
Next Steps vii
Chapter 1: Introduction to Large Loads 1
Intended Audience 1
NERC Large Loads Task Force 1
Large Load Definition 1
Background 2
Chapter 2: Characterization of Large Loads 3
Categories of Large Loads 3
Data Centers and Other Computational Load 3
Industrial Load 7
Hydrogen Production Facilities 8
Example Existing Large Load Programs and Constructs 9
Reliability Coordinators 9
Utility-Specific Programs 11
Future Large Load Definition Considerations 11
Single Number vs. Size Range 11
Behind-the-Meter Loads 12
Real-Time Load Behavior 13
Firm Load vs. Flexible Load 14
Chapter 3: Risks to the Bulk Power System 15
Large Load Observability and Data Risks 15
Long-Term Planning 15
Demand Forecasting 15
Resource Adequacy 16
Transmission Adequacy 17
Operations/Balancing 18
Short-Term Demand Forecasting 18
Balancing and Reserves 19
Lack of Real-Time Coordination 20

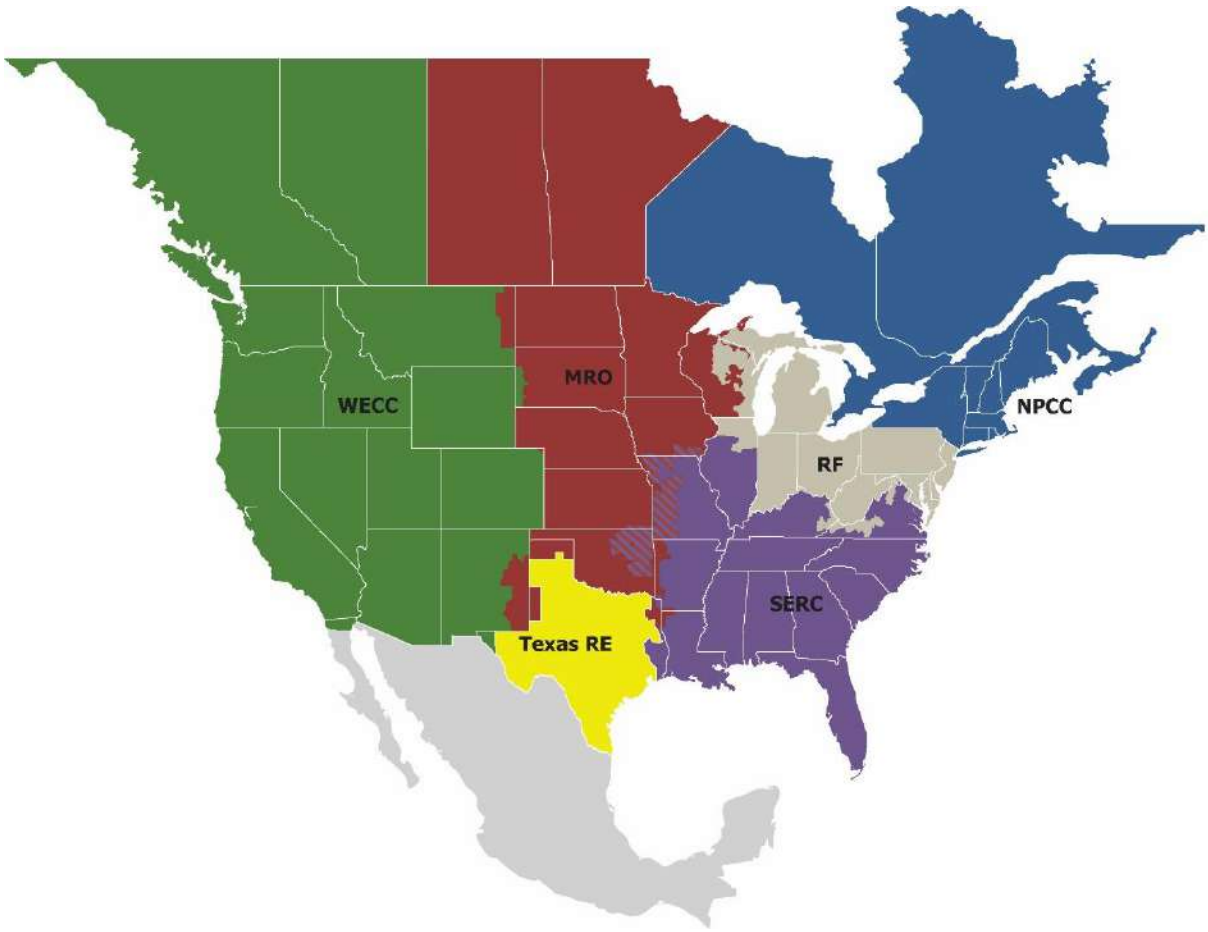
Outage Coordination in Operations Planning 21
Stability 21
Ride-Through 22
Frequency Stability 23
Rotor Angle Stability 25
Voltage Stability 27
Resonance- and Converter-Driven Stability 28
Forced Oscillations 29
Power Quality 32
Harmonics 32
Voltage Fluctuations 34
Physical and Cyber Security Risks 36
Cyber Security 36
Load-Shedding Programs and System Restoration 36
Manual Load-Shed Obligation Impacts 36
Automatic Under-Frequency Load-Shedding Programs 36
System Restoration 36
Chapter 4: Conclusion 38
Appendix A: Large Load Construct Data 40
Appendix B: Comparison of Characteristics and Risks 41
Appendix C: Acknowledgements 42

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

A New Challenge on the Horizon

As the North American power system evolves, loads such as computational, industrial, and hydrogen production facilities are seeking to connect to the bulk power system (BPS) faster than ever before and at a magnitude beyond the largest currently operating loads. There is already evidence that large loads impact BPS reliability. For example, the Eastern and Electric Reliability Council of Texas (ERCOT) Interconnections have observed load-reduction events[1] with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction. The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation and caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying size reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue.

There is already evidence that large loads impact bulk power system reliability.

NERC'S Response

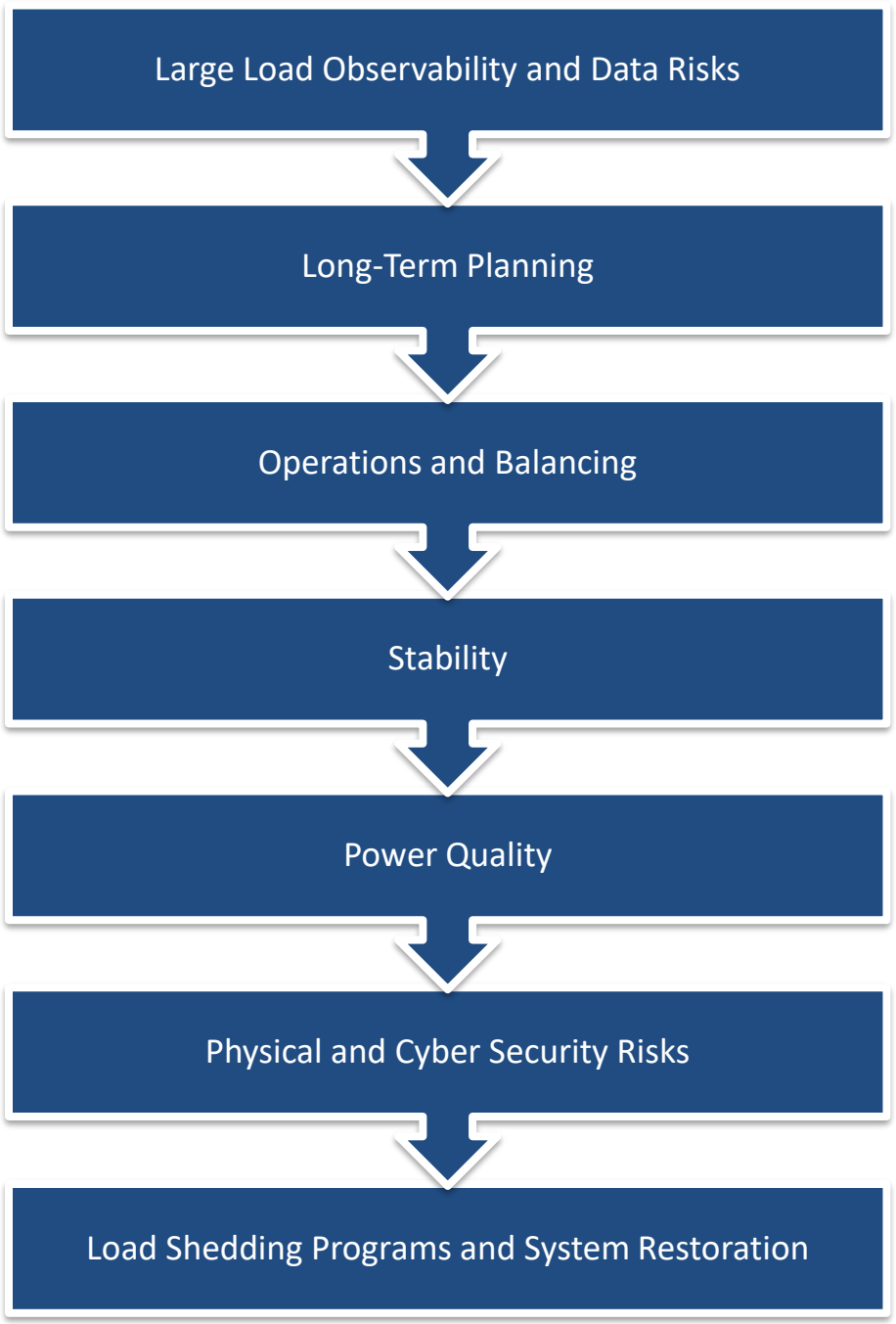
NERC's Reliability and Security Technical Committee (RSTC) established the Large Load Task Force (LLTF) to analyze the reliability impacts related to emerging large loads (e.g., data centers (including cryptocurrency mining, and artificial intelligence (AI)), industrial facilities, and hydrogen production facilities). This white paper characterizes large loads and defines the reliability risks that they may pose to the BPS. A reliability gap analysis white paper will follow, shedding more light on where the most significant risks exist.

To better understand the reliability impacts, NERC established the Large Loads Task Force.

The loads examined in this paper range in size from several megawatts to several gigawatts, posing novel challenges to the reliability and security of the BPS. Several Reliability Coordinators (RC) and utilities have existing large-load constructs based primarily on facility peak demand. However, additional characteristics should be considered in any definition of large loads, as this white paper shows that peak demand is only one of many characteristics that can impact BPS reliability.

[1] "Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions," NERC, Jan. 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf

The LLTF analyzed the following risk categories for this white paper:

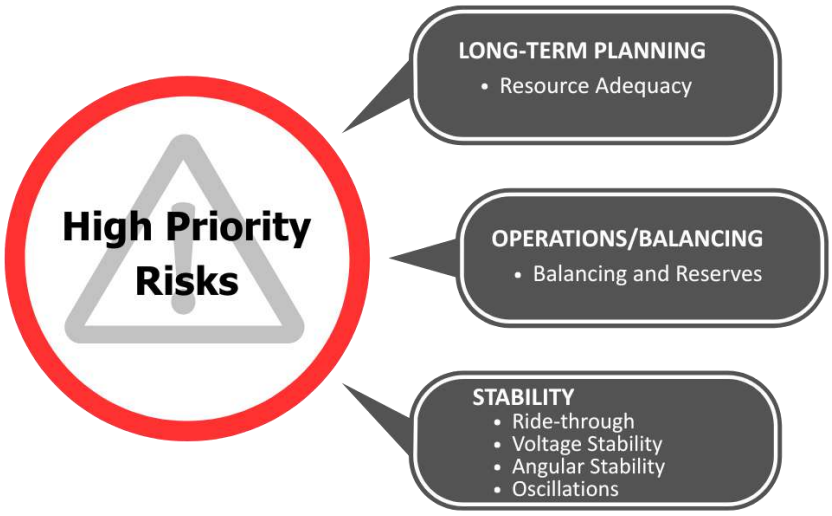


The following recommendations are offered as guidance for future work to ensure the reliability and security of the BPS:

- ✓ **Recommendation 1:** The NERC LLTF should identify existing processes and standards that do not fully address the risks of emerging large loads, as planned for the LLTF's second work item—*White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*.
- ✓ **Recommendation 2:** The LLTF should identify potential mitigations to risks posed by emerging large loads through improvements to existing planning and operation processes and interconnection procedures for large loads as planned for the LLTF's third work item—*Reliability Guideline: Risk Mitigation for Emerging Large Loads*.
- ✓ **Recommendation 3:** The LLTF should clearly define each of the identified characteristics of emerging large loads and develop a framework for classifying large loads.
- ✓ **Recommendation 4:** The NERC Load Modeling Working Group should create and approve load models that can show the characteristics and risks of each category of emerging large loads in simulations.
- ✓ **Recommendation 5:** The NERC System Protection and Control Working Group should assess possible protection system impacts to the BPS from emerging large loads.
- ✓ **Recommendation 6:** The NERC Energy Reliability Assessment Working Group and Probabilistic Assessments Working Group should investigate methods for grid operators and planners to assess the risks potentially posed by emerging large loads to resource adequacy.

Next Steps

To address the near- and long-term risks associated with large loads, NERC is identifying gaps in integrating these large loads onto the grid, enabling a coordinated approach to address this issue effectively. This white paper is expected to be published in Q4 2025.



Chapter 1: Introduction to Large Loads

Intended Audience

This white paper is intended for the following NERC registered entities, external entities, and broader groups:

- Planning Coordinators (PC)
- Transmission Planners (TP)
- Transmission Owners (TO)
- Transmission Operators (TOP)
- Distribution Providers (DP)
- Balancing Authorities (BA)
- Reliability Coordinators (RC)
- Large load developers, owners, operators, or other related companies
- Generator Owners (GO)
- Generator Operators (GOP)
- Reliability and Security Technical Committee (RSTC) subgroups

This white paper identifies, validates, and prioritizes the characteristics and risks of emerging large loads to the BPS. Entities responsible for operating and planning facilities on the BPS should be aware of these characteristics and risks to maintain reliable service. Subsequent LLTF work items, like the next white paper and reliability guideline, will need to address the risks noted in this white paper. Finally, this white paper identifies areas where potential security risks associated with emerging large loads require further assessment by related RSTC subgroups.

NERC Large Loads Task Force

The purpose of the NERC LLTF is to better understand the reliability impacts that emerging large loads, such as data centers and other computational loads, large industrial loads, and hydrogen production facilities, will have on the BPS. The LLTF has two primary phases identified in the NERC LLTF scope[2] as follows:

- Phase 1: Identify unique characteristics and risks of large loads
- Phase 2: Identify gaps and potential risk mitigation

Large Load Definition

NERC's LLTF was tasked with defining large loads. The definition was created for use in this white paper and the other work products from NERC's LLTF. This definition is expected to be modified in the future for specific applications, like the *NERC Glossary of Terms Used in NERC Reliability Standards*.[3] For the purposes of this white paper and the following white paper and reliability guideline, large loads shall be defined as the following:

"Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors. Examples include, but are not limited to, data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces."

[2] "Large Loads Task Force (LLTF)," NERC, Aug. 2024. [Online]. Available: https://www.nerc.com/comm/RSTC/LLTF/LLTF%20Scope.pdf
[3] "Glossary of Terms Used in NERC Reliability Standards," NERC, Feb. 2025. Available: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

The LLTF has not yet provided a megawatt (MW) threshold or more granular characteristics of large load as further analysis and development is forthcoming.

Background

Emerging large loads have grown substantially in recent history, and forecasts predict that data centers alone may account for as much as 12% of all U.S. electricity consumption by 2028[4] (up from 4.4% in 2023). In addition to the rapid, demonstrated, and forecasted growth of emerging large loads, the characteristics that inform their electrical behavior are not as predictable as conforming loads. The electrical behavior of emerging large loads during both normal and abnormal grid conditions represents new challenges for planners and operators. Operating experience is limited with emerging large loads. Large loads may come in different forms, although the rapid growth associated with data centers have led the authors of this white paper to focus on the characteristics and potential risks associated with integrating these types of users of the BPS. This white paper will discuss emerging large loads' characteristics and how each one informs specific risks to the BPS.

[4] A. Shehabi *et al.*, "2024 United States Data Center Energy Usage Report," Lawrence Berkeley National Laboratory, Dec. 2024. Available: https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report.pdf

Chapter 2: Characterization of Large Loads

This chapter categorizes the large loads that have emerged in recent years across North America, reviews existing large load programs and constructs in the United States and Canada and addresses certain factors that could inform a formal NERC large load definition.

Large load customers are connecting to the grid faster than ever before. These loads range widely in size: some are facilities of several MWs that can connect at the distribution level, while others are multi-gigawatt (GW) complexes that must be served by the transmission system and may require new transmission facilities or other upgrades to support the increased system demand.

In addition to their size, large loads have other characteristics that pose reliability risks to the BPS. For example, many new large loads are PELs that use software controls to manage the load behavior rather than the mechanical controls used by older motor loads. PEL control systems enable loads to rapidly change electricity consumption, creating previously unseen load behavior that can cause BPS planning and operational challenges.

Categories of Large Loads

The following large load categories are based on the function or activity of the facility in question. Each type will require tailored considerations for interconnection, BPS reliability, and grid integration.

Data Centers and Other Computational Load

A data center is a physical room, building, or facility that houses IT infrastructure for building, running, and delivering applications and services.[5] Data centers are among the fastest-growing energy consumers in North America, supporting cloud computing, AI, cryptocurrencies, and other digital services. They range from hyperscale facilities operated by tech giants, like Meta's planned 2 GW AI training facility in Louisiana,[6] to smaller data centers that serve multiple enterprises. Some data center loads are known to have pulsed and non-linear characteristics, giving them extremely quick ramping potential that can introduce power quality and stability issues. Cryptocurrency mines are generally not classified as data centers though much of their makeup is similar. Cryptocurrency mines may have different types of IT equipment compared to traditional and AI data centers, and they may not prioritize uptime as much as a traditional data center.

Data centers and other computational loads are PELs that consist of high-performance computing (HPC) systems in which large clusters of computing resources work in concert to perform complex analysis and other tasks. These loads are characterized by high energy consumption, variable operational demand, and significant cooling requirements. "Data center" is a term that encompasses many different end uses and configurations, as explained in this section's various sub-sections. The internal configuration of the load can be very complex, including internal protection and backup power systems. Data centers and other computational loads are often located in areas with access to reliable and cost-effective electricity, requiring carefully tailored grid planning and interconnection strategies.

[5] S. Susnjara and I. Smalley, "What is a data center?," IBM Think, Sep. 04, 2024. https://www.ibm.com/think/topics/data-centers (accessed May 27, 2025).
[6] "Meta's Richland Parish Data Center." Available: https://datacenters.atmeta.com/wp-content/uploads/2024/12/Metas-Richland-Parish-Data-Center.pdf

The four main components in data centers are listed as follows:

- **IT-related equipment** consists of servers, storage, and networking gear driven by power electronics. These components generally comprise at least half of the data center's energy consumption.[7,8] Data center industry experts state that IT-related equipment may make up 60–95% of a data center's total energy demand.
- **Power delivery systems** control and distribute power in the facility. They may consist of multiple sources of external power, internal power distribution systems, emergency backup systems (including uninterruptible power supply (UPS) and on-site generation), and sophisticated control systems that ensure continuity of service to their critical network equipment. Data center industry experts note that power delivery systems for HPC loads (AI data centers) commonly exclude UPS protection systems for the IT equipment. Instead, they employ a checkpoint process where checkpoints are saved at regular intervals. If there is an interruption to the IT equipment's power, the checkpoint may be restored after the power interruption ends.
- **Cooling systems** typically consist of PEL including variable speed drives, inverters, and other internal equipment that can create harmonics and increased reactive power demands.
- **Miscellaneous** lighting and security loads are necessary for operation of the load. This typically makes up the smallest portion of the total energy usage of the load.

Figure 2.1 shows how these components and other features, such as UPS and backup generation, may be arranged in a data center. Notably, the desired uptime of the facility determines what tier of backup equipment is required. This figure is more relevant to traditional data centers. For AI training loads, there may be no UPS for the IT equipment.

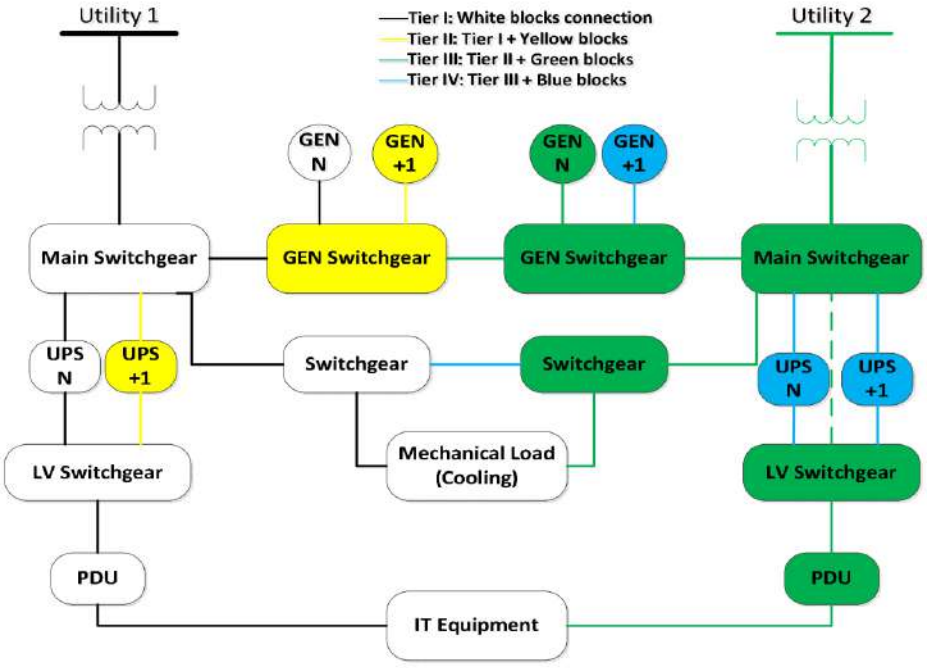


Figure 2.1: Tier I–IV Data Center One-Line[9]

[7] J. Davis, "Large data centers are mostly more efficient, analysis confirms," *Uptime Institute Blog*, Feb. 07, 2024. https://journal.uptimeinstitute.com/large-data-centers-are-mostly-more-efficient-analysis-confirms/

[8] "Technical Update on Load Modeling. EPRI, Palo Alto, CA: 2023. 3002027016"

[9] S. Chalise et al., "Data center energy systems: Current technology and future direction," 2015 IEEE Power & Energy Society General Meeting, Denver, CO, 2015, pp. 1-5, doi: 10.1109/PESGM.2015.7286420.

Traditional Data Centers

Traditional data centers power the digital services of the modern world. They enable almost every online service, including banking, healthcare, e-commerce, and social media.[10] Traditional data centers make up most of the currently operational data centers and exclude AI training and inference facilities. The exact configuration and business model can vary greatly, but most traditional data centers have similar electrical characteristics. Traditional data centers have historically been characterized by their smaller size[11] (under 30 MW in many cases) and limited variability. Traditional data centers commonly prioritize up time – the percentage of time that a data center provides uninterrupted service. These types of data centers are known for their redundancy. There are a few organizations, like the Uptime Institute,[12] that classify data centers into Tiers I-IV. Tier IV data centers have the highest redundancy, resulting in uptimes of over 99.995%.

Some companies, like utilities, use small local data centers to meet their business needs. These types of data centers are typically very small (less than 1 MW) and are not the focus of this white paper.

Larger businesses may use self-hosted data centers for their own business use cases. Social media is a prime example of this, as it takes many large data centers to host services that are used by millions of people. These data centers are owned and operated by a single company, so they will have the most information available about physical infrastructure, electrical characteristics, and demand patterns.

The last major type of traditional data center is the cloud data center, which may rent out its computing power to multiple businesses on a recurring or temporary basis. These data centers have information about the physical equipment and characteristics but may not have as much information on demand patterns as a self-hosted, self-use data center.

Artificial Intelligence Training Data Centers

Data centers powering AI technologies are among the newest types of load customers. AI is generally defined as technology that enables computers to perform complex tasks like translating spoken and written language, analyzing data, and making recommendations.[13] AI training refers to the creation and modification of an AI model and its associated model weights.

AI facilities (training and inference) include powerful, application-specific integrated circuits (ASIC) or graphics processing units (GPU). Current industry trends, especially in AI applications, show GPUs getting smaller with higher power ratings than historic GPUs. These computing components operate best in very specific conditions, requiring specific temperatures and humidity. This is often a key consideration when siting data centers. If temperature and humidity ranges are too vast, the temperature and humidity control equipment may be too burdensome. Cooling load demand can vary widely depending on the specific data center's cooling equipment and based on the intensity of the processing tasks that the IT equipment is assigned at any given time. The cooling load requirements are highly dependent on the end use. For instance, cooling load has different characteristics for AI data centers compared to traditional data centers.

The electrical demand is different for training an AI model versus using an AI model to create inferences.[14] Generally, AI training executed in large clusters has rapid fluctuations during training periods and while saving checkpoint

[10] "What is a datacenter? - Microsoft Datacenters," Microsoft Datacenters, May 05, 2025. https://datacenters.microsoft.com/whatisadatacenter/

[11] B. Srivathsan, M. Sorel, and P. Sachdeva, "AI power: Expanding data center capacity to meet growing demand," *McKinsey & Company*, Oct. 29, 2024. https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/ai-power-expanding-data-center-capacity-to-meet-growing-demand

[12] "Tier Classification System," Uptime Institute. https://uptimeinstitute.com/tiers

[13] Google Cloud, "What Is Artificial Intelligence (AI)?," *Google Cloud*, 2025. https://cloud.google.com/learn/what-is-artificial-intelligence

[14] Trends in AI inference energy consumption: Beyond the performance-vs-parameter laws of deep learning, https://doi.org/10.1016/j.suscom.2023.100857

progress. Additionally, the transition from training to saving checkpoint progress (or vice versa) may happen in under one second. See **Figure 2.2** and **Figure 2.3**, which shows the demand from a 50 MW block of a larger 200 MW AI training data center that starts a training run. The data was recorded with a high-speed recorder and was supplied by EdgeTunePower.[15] In the fastest ramping period, the demand changes at a rate of 1.9 p.u. per second for about 250 milliseconds.

While the training is active, jittery spikes up and down occur, shown between 360 and 660 seconds in **Figure 2.2**. Google explains the problem in a Google Cloud blog post,[16] stating that large power spikes are observed when transitioning between "idle and peak utilization levels" but that they also occur "when the workload is running normally, mostly attributable to alternating compute- and networking-intensive phases of the workload within a training step."

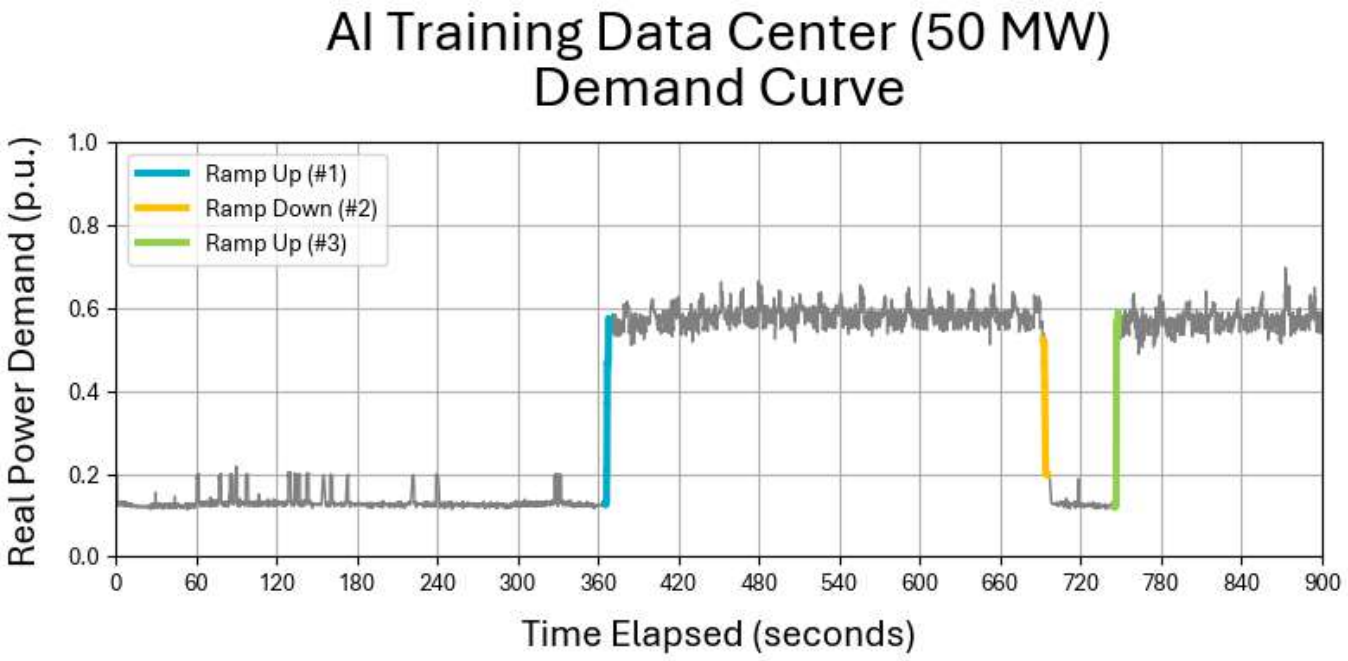


Figure 2.2: An AI Training Data Center Begins a Training Run (EdgeTunePower)

[15] "About Us | EdgeTunePower," *EdgeTunePower*. https://www.etpower.ca/about-us
[16] H. Gan and P. Ranganathan, "Balance of power: A full-stack approach to power and thermal fluctuations in ML infrastructure," *Google Cloud*, Feb. 11, 2025. https://cloud.google.com/blog/topics/systems/mitigating-power-and-thermal-fluctuations-in-ml-infrastructure (accessed May 29, 2025).

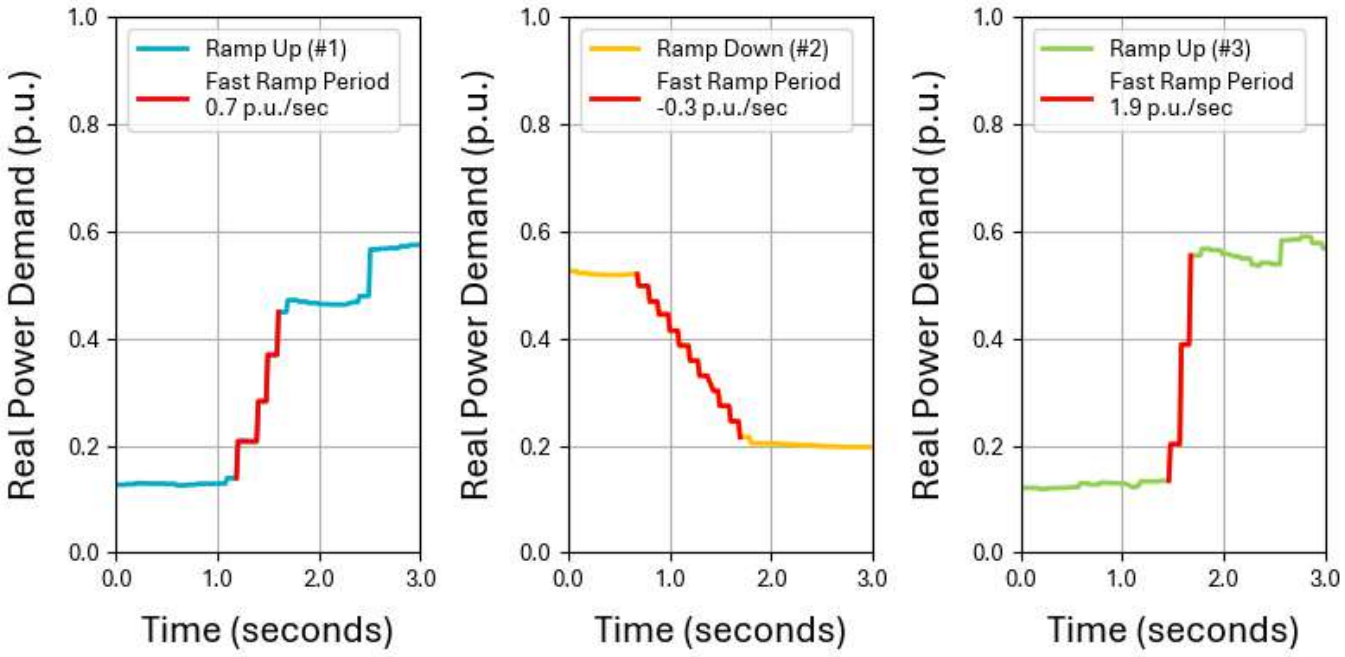


Figure 2.3: Zoomed-In Views of AI Training Data Center Ramping Up and Down Due to Transitioning Between Training and Saving Checkpoint Progress

Artificial Intelligence Inference Data Centers

AI inference is the process of using a pre-trained AI model to generate output(s) based on new input. AI inference uses similar, high-power GPUs when compared to AI training. It is common for data centers to be purpose-built for either inference or training workloads. The primary difference is in the underlying computations happening on the GPUs. The rapid ramps up and down seen in AI training/checkpoint cycles are not observed in current AI inference methods. Some companies in the AI industry, like NVIDIA, postulate that inference will be the greater electrical demand in the future when compared to training. In February 2022, Google stated that 60% of its total energy use went toward inference and 40% went toward training.[17] However, this was before some of the largest growth in large language models (LLM) and AI over the past three years.

Cryptocurrency Mining

Cryptocurrencies (e.g., Bitcoin) rely on "data mining," wherein computers solve mathematical puzzles to validate and enable various transactions. Cryptocurrency mining facilities consist of purpose-built servers and mining units—typically ASIC miners. Depending on the size of the operation and the number of units, cryptocurrency mining can consume large amounts of electricity to power the machines and cool the equipment.

Unlike data centers, which ramp up or down in response to customer demands or training cycles, the power consumption of cryptocurrency mining facilities is more stable and typically driven by internal computational needs, giving cryptocurrency miners flexibility in responding to system conditions, like reducing demand when prices are high.

Industrial Load

Industrial loads consist of facilities and equipment used for producing, processing, or assembling goods. These operations often require robust electric infrastructure and are typically more complex and energy-demanding than residential or commercial loads. Industrial loads are commonly referred to as non-conforming loads. This sector is set

[17] D. Patterson, "Good News About the Carbon Footprint of Machine Learning Training," *Google Research*, Feb. 15, 2022. https://research.google/blog/good-news-about-the-carbon-footprint-of-machine-learning-training/ (accessed May 28, 2025).

to grow as more industrial activity moves to North America and existing facilities replace oil and gas with electricity as a primary fuel source.

Mining and Mineral Processing
The mining and mineral processing industries extract and refine raw materials essential for sectors including hard rock mining, coal mining, mineral processing, and cement production.

Metals and Heavy Manufacturing
Metals and heavy manufacturing consists of industries involved in the processing of metals and large-scale manufacturing, including steel mills, smelters and metal refineries, rolling mills, foundries, and casting facilities.

These industries use electricity-intensive processes, including electric arc furnaces (EAF), induction furnaces, electro-refining, arc welding and plasma cutting, and large-scale electrolysis.

Semiconductor and Electronics Manufacturing
These industries require precision power and cleanroom environments. Examples include semiconductor fabrication, liquid-crystal display (LCD) and organic light-emitting diode (OLED) and display manufacturing, battery manufacturing, and printed circuit board (PCB) production.

Chemical and Petrochemical Processing
These industries rely on high-energy chemical reactions to facilitate their processes. Examples include ammonia and fertilizer plants, chlor-alkali and electrochemical processing, refining and petrochemicals (oil refineries, synthetic fuels, plastics), and carbon capture and utilization (CCU).

Oil and Gas Production
The production of oil and gas requires vast amounts of energy. To improve oil and gas field equipment efficiencies and reduce costs, many operators are switching equipment to run on electricity and not fossil fuels. The buildout of liquefied natural gas plants is also driving load growth in certain regions of North America.

Hydrogen Production Facilities

This white paper focuses solely on hydrogen production facilities that use electricity to perform electrolysis. Hydrogen is an emerging option in the push to decarbonize the grid. The hydrogen production process begins at a hydrogen production plant, where water is treated and purified to remove dissolved solids, organic compounds, and other contaminants, resulting in pure water (H_2O).

This purified water then undergoes electrolysis, which splits the water into hydrogen and oxygen molecules. Each electrolyzer used in this process typically consumes 5–10 MW of power, and multiple units can operate within the same facility, as shown in **Figure 2.4**. After electrolysis, the hydrogen is cooled and liquefied. Liquid hydrogen can then be stored or transported for use in various applications, including fueling vehicles (e.g., cars, trucks, airplanes), powering data centers, providing backup power, and supporting manufacturing processes.

Hydrogen electrolyzer facilities under development could reach the multi-gigawatt scale. Initial surveys have shown that over 85% of the facility load consists of power electronic converters with the remaining load being motor driven for H2 compression, water treatment and cooling, and other plant equipment.

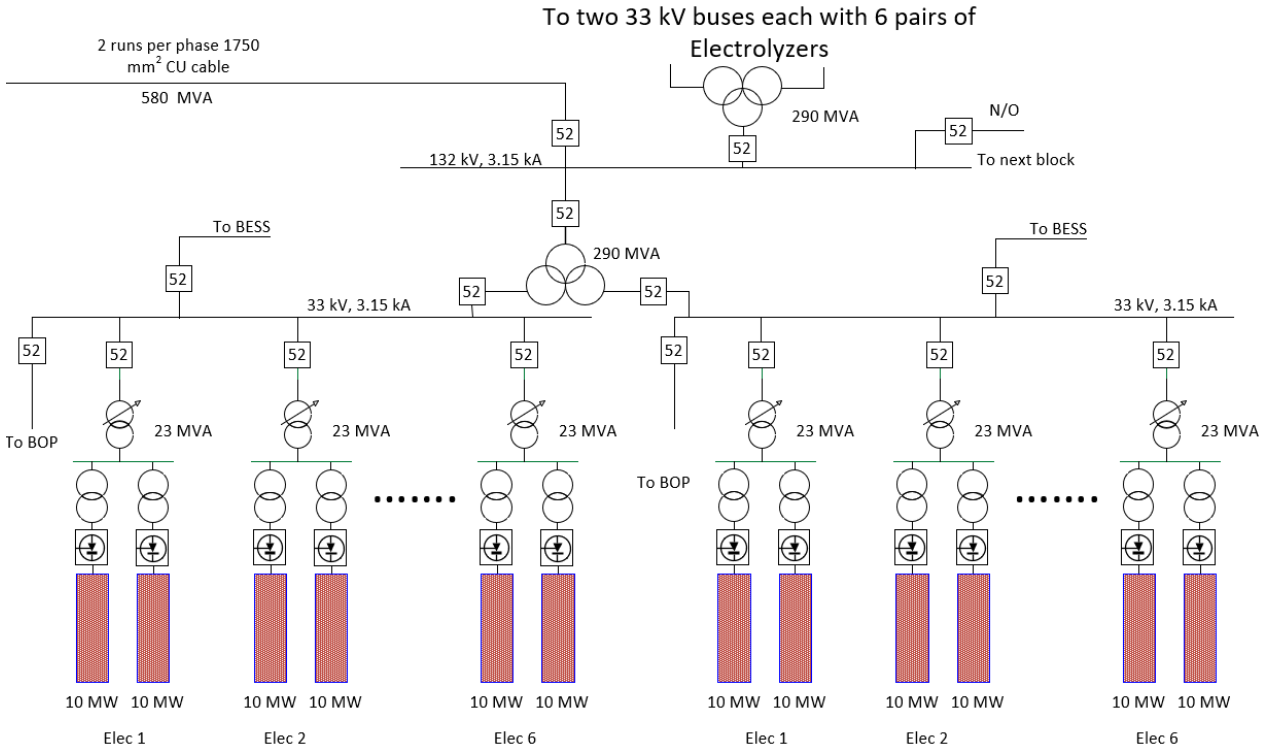


Figure 2.4: Example Hydrogen Production Facility One-Line Diagram (EPRI)

Example Existing Large Load Programs and Constructs

Several entities in North America have requirements for large load interconnection and/or preliminary definitions and programs for large loads. Notably, the only organizations included in this white paper are ones that voluntarily provided information to the writers of the white paper. Of the RCs and utilities with existing large load constructs, many of the current constructs are based on transmission facility ratings with no additional accounting for the potential impact that large loads may have on the BPS. Utility-specific programs not detailed in this section are described in **Appendix A: Large Load Construct Data**. All information about programs and constructs in this white paper reflects current practices and is subject to change.

Reliability Coordinators

ERCOT

In the ERCOT Interconnection, a large load is defined as 75 MW or larger. At this size, transmission service providers (TSP) in ERCOT typically must develop and construct transmission upgrades to support the full amount of load that is seeking interconnection.

ERCOT established an interim large load interconnection process through Market Notice W-A032522-01[18] to ensure compliance with existing NERC requirements and for the reliable interconnection of large loads to the ERCOT system. TSPs are required to submit interconnection studies that meet the requirements of NERC Reliability Standard FAC-002-2 for each applicable large load proposing to interconnect to the ERCOT system.

[18] "Market Notice - Interim Large Load Interconnection Process," *Ercot.com*, Mar. 25, 2022. https://www.ercot.com/services/comm/mkt_notices/W-A032522-01

ERCOT's interim large load program applies to projects seeking to interconnect in two years or less that meet one of the following criteria:

- For standalone loads not co-located with a generation resource:
  - A new load is requesting a total peak demand of 75 MW or more
  - An existing load is requesting an increase of its total peak demand by 75 MW or more
- For loads co-located with a generation resource:
  - A new load is requesting a total peak demand of 20 MW or more
  - An existing load is requesting an increase of its total peak demand by 20 MW or more

NYISO

To supplement the load interconnection procedures in the New York Independent System Operator (NYISO) Open Access Transmission Tariff (OATT), NYISO has defined load interconnection procedures in its *Transmission Expansion and Interconnection Manual*. These procedures specify which load interconnections are subject to NYISO's interconnection studies: those with a load of 10 MW or greater connecting at a voltage level of 115 kV or above or a load 80 MW or greater connecting at a voltage level below 115 kV. Such projects must be evaluated to determine whether they may degrade system reliability or adversely affect the operation of the New York state transmission system.

NYISO performs a single interconnection study, the System Impact Study, for load interconnections, the scope and results of which are reviewed by NYISO's operating committee. If the System Impact Study indicates the potential for an adverse reliability impact, NYISO identifies the need for potential upgrades required to reliably interconnect the load project. Should the load customer elect to proceed, required upgrades are evaluated by the applicable TO(s), and the engineering, procurement, and construction details as well as the cost responsibility for such upgrades are memorialized in Interconnection Agreements between the load customer and the applicable TO(s).

Projects that do not meet the above MW/voltage thresholds are subject entirely to the connecting TO(s) load interconnection procedures; NYISO is not involved in any interconnection studies for such projects.

Southwest Power Pool (SPP)

The Delivery Point Addition Process in SPP, defined under Attachment AQ of the SPP tariff, governs how new or modified delivery points are added to the transmission system. A delivery point is where power is transferred from the grid to a local utility or load-serving entity. When a new delivery point is proposed or an existing one is changed, the transmission customer (TC) submits a delivery point assessment (DPA) request. The transmission provider, SPP, then performs an engineering study to assess reliability impacts, and the host TO performs a load connection study (LCS) to assess load interconnection needs. SPP reviews the LCS, coordinates with stakeholders, and determines if system upgrades are needed. Costs for network upgrades are regionally funded, and interconnection facility upgrade costs are agreed upon between the TC and TO. Once approved, the delivery point and associated upgrades are added to the TC's service agreement, ensuring that the agreement is recognized in planning, operations, and billing. This process ensures reliability, coordination, transparency, and fair cost allocation across the SPP system.

ISO-NE

The Independent System Operator New England (ISO-NE) does not have an explicit "large loads program." However, ISO-NE learns of new loads seeking to interconnect through either a transmission service application for new load (regional network load or local network load) under regional network service (typically 115 kV or above) or local network service (typically below 115 kV, not including distribution facilities), depending on how the new load would be served. However, large data center loads have not yet sought interconnection in the area through application for these services, and there is no definition of "large loads."

Only applications for wholesale service are submitted to ISO-NE. Applications for retail service to serve load are submitted to the New England TOs, and ISO-NE has no visibility into those applications.

Utility-Specific Programs

In this category, Dominion Energy has the most experience with large load interconnections because Virginia (which is within Dominion's service area) is home to the world's largest concentration of data centers. Other known utility-specific programs are described in **Appendix A: Large Load Construct Data**.

Dominion

Per Section 2.13 End User Facilities (Load Interconnection) of the Electric Transmission Facility Interconnection Requirements End Users Facilities,[19] Dominion sets a 100 MW threshold for loads tapping the transmission system at a single point of interconnection. Below 100 MW, Dominion allows the load to be tapped with only isolation switches; above 100 MW, a ring bus configuration is required. As part of Dominion's planning criteria, the amount of load connected to a single substation is limited to 300 MW and requires no more than 300 MW load loss for N-1 and N-1-1 contingencies.

For any load connection to the transmission system, Dominion requires customers to submit a detailed request form with specific sections for data centers that require information about ride-through capabilities and other features. The Dominion 500 kV system is reserved for bulk power transfer, and load interconnections are not allowed to reach this voltage. Most data center load connections are on the 230 kV system, but some occur on the 115 kV and 138 kV systems.

Future Large Load Definition Considerations

Given the numerous categories and subtypes of large loads, a classification system based solely on a load's peak demand may be overly simplistic. Due to the differences highlighted above, it cannot be assumed that all loads will behave similarly. Several other factors, such as load ramp rates, real-time behavior and flexibility, protection systems, and backup power schemes, should be considered if a large load definition is developed for regulatory procedures or policies. Some of the additional factors for consideration are described below.

Single Number vs. Size Range

In November 2024, a subgroup of the NERC LLTF conducted an informal survey to gather feedback from participants on what load size should qualify as "large" under a potential NERC regulatory construct. Most of the survey respondents qualified "large" as greater than 50 MW, and the single size number most commonly suggested was 75 MW.

However, the survey also revealed that "large" may be relative to other factors, such as the voltage to which the load is interconnected. For example, a consuming site with a 20 MW peak demand would be considered "large" for distribution service, whereas 20 MW is a relatively small customer if interconnected at transmission voltage. Additionally, the relative size of the load to the local system and overall interconnection affects how it impacts BPS reliability. For instance, frequency stability looks different in the Eastern Interconnection compared to the ERCOT Interconnection.[20] Additionally, even within the ERCOT Interconnection, voltage stability considerations are different in each zone.

[19] Dominion Energy Virginia, "Electric Transmission Facility Interconnection Requirements," Apr. 01, 2025. https://www.dominionenergy.com/-/media/pdfs/virginia/parallel-generation/facility-connection-requirements.pdf?la=en&rev=07744be57e5a439988e46f630af76e6f (accessed Jun. 06, 2025).
[20] "2024 Frequency Response Annual Analysis," Nov. 2024. [Online]. Available: https://www.nerc.com/comm/OC/Documents/2024_FRAA_Report_Final_Draft.pdf

While defining a singular size could be a way to establish a clear threshold for future regulations, policies, and standards, it could also create unjust or unreasonable unintended consequences. For example, a single number may motivate regulated entities to intentionally size beneath to avoid regulation. This is not to say that size is irrelevant; it is rather that size alone would be too limited a way to examine what is a materially impactful large load.

Behind-the-Meter Loads

The increasing prevalence of behind-the-meter (BTM) large loads is an important issue in the landscape of electric markets, grid reliability, and operations. **Figure 2.5** illustrates the difference between front-of-meter (FOM) and BTM configurations. BTM large loads receive their energy directly from co-located generators without the use of the transmission or distribution grid. In certain configurations, the load is served partially through FOM and BTM configurations.

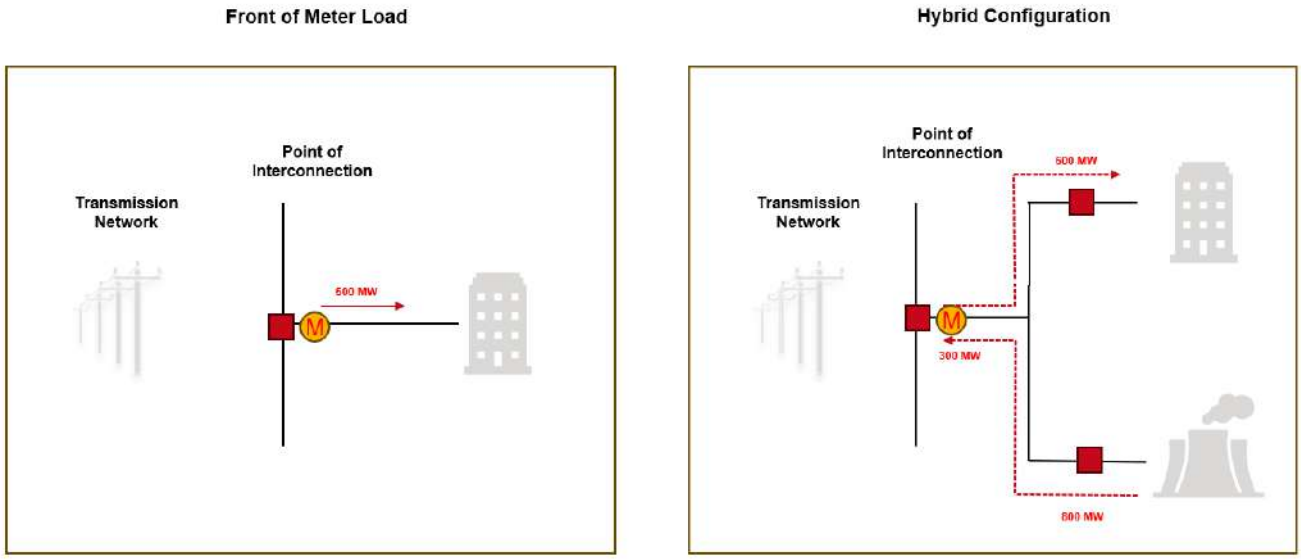


Figure 2.5: FOM vs. BTM Load Illustrations[21]

When a load is served exclusively by a co-located generator, protection mechanisms are typically installed to prevent grid energy from flowing to the load. In these instances, if the co-located generator is out of service, the load will also be disconnected unless it possesses backup generation of its own. **Figure 2.6** demonstrates the effects of a generator outage when the load is served exclusively by co-located generation.

[21] The metering configuration in the BTM configuration example is for illustration purposes only; specific metering design for BTM configurations will depend on the metering practices of the interconnecting utility or utilities.

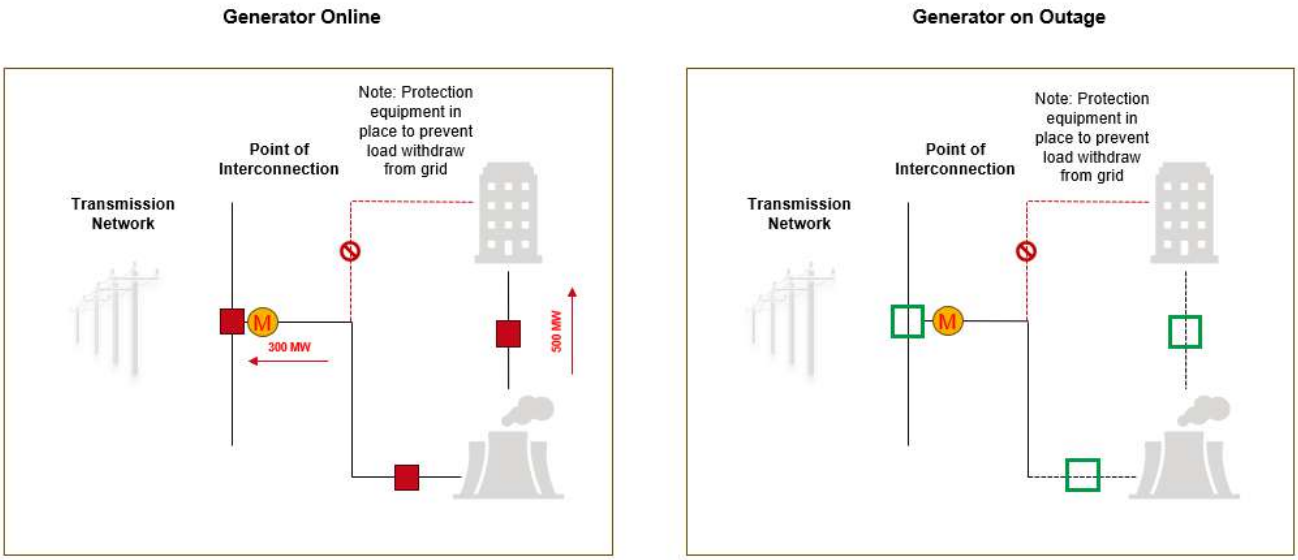


Figure 2.6: BTM Online vs. On Outage

As BTM large loads continue to develop, their impact on operational visibility, independent system operator (ISO) control, and system stability becomes increasingly influential. Below is a list of characteristics that impact the BPS:

- **Operational visibility differs between FOM and BTM loads.** FOM loads are directly integrated into the transmission or distribution system and are usually visible to the interconnecting utility and/or the system operator in the operational environment. In contrast, depending on the utility's requirements, BTM loads may not undergo the same level of impact analysis during the interconnection process. As a result, BTM resources can pose reliability risks if their generation unexpectedly trips off-line and appropriate protection or ride-through systems are not in place. The operational visibility and controllability of BTM loads are limited, making it more challenging to predict system impacts, especially during uncontrolled transitions between on-site generation and grid supply that may arise due to protection system failures.
- **Load or generator trips pose risks to system stability.** In cases where co-located generation suddenly trips off-line, the co-located load might not seamlessly transition to grid supply unless a formal interconnection agreement exists with the utility, leading to a sudden interruption of service to this load. If the load unexpectedly shifts to grid supply after the co-located generation fails, the utility supply sees a rapid demand spike, which may stress the transmission system.
- **Size and interconnection type matter.** Large BTM loads shifting to the grid during generator outages can disrupt system stability and cause capacity shortfalls or resource adequacy issues. Clear interconnection standards, monitoring, and coordination are needed to prevent unexpected demand swings and ensure reliable operations.

Real-Time Load Behavior

Each category of large load—computational, industrial, and hydrogen—displays real-time operating characteristics that differ from loads previously connected to the BPS. These loads are typically not controllable by the utility or ISO unless they voluntarily enter into a load curtailment or demand-response program. The choice to participate in such programs is usually an individual customer strategy based on an economic evaluation (i.e., customers that have flexible processes may be able to earn revenue from such programs through demand reductions during periods of

high grid stress). Certain control areas allow loads to provide ancillary services, like ERCOT's Controllable Load Resource program.[22] These programs are all voluntary.

Many large loads, such as cryptocurrency mining and AI facilities, can cycle their consumption on and off in less than a minute and can ramp from zero to hundreds of MW of power demand over very short time frames, like in the previously mentioned **Figure 2.2** and **Figure 2.3**. As a comparison, data centers that support cloud computing and digital services typically have high load factors and non-conforming behavior, so their consumption is relatively static.

Firm Load vs. Flexible Load

Large loads interconnecting to the grid typically request firm utility service during the interconnection process. This means that the utility is required to provide the transmission infrastructure capable of serving the load's peak demand request at all times.

Concepts have been explored[23] in some areas around mandatory load curtailments by the ISO or utility during stressful grid conditions, which might allow for TPs to assume a lower peak demand for the load and potentially reduce the transmission buildout exclusively needed to support the load. Utility controllability of loads is usually not accounted for at the transmission planning stage. However, many loads are still expected to obtain firm transmission service to ensure reliable electric service delivery, necessitating transmission buildouts to support the load and an increase in energy supply during both normal and emergency system operations.

[22] "Load Resource Participation in the ERCOT Markets," *ERCOT*, 2021. https://www.ercot.com/services/programs/load/laar (accessed May 30, 2025).

[23] T. Norris, T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell, "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems," Nicholas Institute of Energy, Environment, & Sustainability, 2025. Accessed: May 30, 2025. [Online]. Available: https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf

Chapter 3: Risks to the Bulk Power System

The interconnection of emerging large loads may pose reliability risks to the BPS, and the LLTF has reviewed, categorized, and prioritized these risks. Grid planners and operators need to consider large loads in both the planning and operations domains to ensure that the transmission system is properly planned considering these loads. They must also ensure that the system can be reliably operated in real time with adequate reserves. Large loads can pose numerous risks to the BPS reliability, as discussed below.

Large Load Observability and Data Risks

System operators and planners need data and models about large loads to properly characterize the load's behavior and study potential risks to the BPS. To run steady-state and dynamic simulations, for example, the operator and planner need to know the expected interconnection timelines, peak demand, load behaviors, protection and control settings, and dynamic models for the load. Without this data, operators and planners cannot properly account for the load's effect on the rest of the BPS, potentially leading to poor operating and planning decisions and poor real-time situational awareness.

Currently, developers, owners, and operators of large loads are not required to be NERC registered entities under NERC's Registry Criteria Rules of Procedure. This means that large loads are not required to adhere to Reliability Standards. Operators have already cited multiple events in the Eastern Interconnection (EI) and ERCOT systems that involved large loads in which it was difficult to obtain information from the large load customer, impeding the operator's ability to investigate loss-of-load events. While load currently does not need to register or be involved in the investigation, the magnitude of these loads poses a risk to system stability if the loads behave unexpectedly. Additionally, the control systems of these loads can interact with the grid, exacerbating oscillations and other phenomena. If there is no high-speed recording data available, diagnosing the root cause and fixing it may be difficult or impossible.

In addition to impeding proper planning, the lack of high-resolution measurement data from large loads will hinder system operators' ability to analyze events after they occur. Few loads have phasor measurement units (PMU) or other ways to monitor their behavior to validate facility performance and modeling. Some notable grid events that involve large loads are only able to be analyzed and published in reports because of high-speed recording data at or near a large load.

Many large loads—especially data centers and other computational loads—may shift their computational demand to a different physical facility. These shifts may occur in response to changes in factors such as energy pricing, emission intensity, and currency pricing. However, without knowing the exact causes for these shifts and when they will occur, system operators cannot account for the load response or create accurate forecasts, potentially leading them to use more balancing reserves than expected to handle large load power swings.

Long-Term Planning

Large loads must be accounted for in the transmission and resource adequacy planning horizons to reliably plan and operate the grid. Building a new transmission line can take up to 10 years due to permitting, planning, equipment lead times, and construction. With accurate models and studies, planners can ensure that the system is designed to serve the load and maintain resource adequacy.

Demand Forecasting

Large loads pose specific risks to both the short- and long-term demand forecasts. The risks to BPS reliability related to demand forecasting (1+ years) out include the following:

- Under-forecasting the growth of emerging large loads could pose long-term challenges to resource and transmission adequacy.

- Rapid integration of emerging large loads poses challenges to existing assumptions in resource adequacy and transmission planning processes.

Each load by itself may represent a significant portion of both annual energy consumption and peak demand. In aggregate, they comprise even more. In many jurisdictions, the types and volumes of proposed large loads are unprecedented, making them difficult to incorporate into existing forecasting models. As of April 28, 2025, ERCOT had 136 GW of large load in its interconnection queue with energization dates from 2025 through 2030, with a system that has a historic peak of approximately 85 GW. [24]

Estimating the amount of load that will make it from interconnection studies to energization is a challenge for grid planners. As stated before, the primary BPS risks to resource adequacy and transmission planning arise from under-forecasting the growth of emerging large loads.

The arrival and timing of large loads is also frequently uncertain. Some companies engage in "location shopping," exploring and submitting interconnection requests to multiple regions to determine the best location for their operations, creating uncertainty about which projects are firm enough to include in forecasts. Some proposed large loads do not materialize as planned: they may be canceled due to economic and financial challenges or other setbacks. Due to the uncertainty of these large loads materializing, forecasting load for resource adequacy and transmission planning may be much more difficult.

Resource Adequacy

Large loads may also introduce risks to BPS reliability through their effects on resource adequacy. The Virginia Joint Legislative Audit and Review Commission reported that construction of individual data center buildings usually takes 12–18 months.[25] In a 2024 report on generator interconnection timelines, Lawrence Berkeley National Laboratory showed that the median duration from interconnection request (IR) to commercial operations date (COD) is nearly 5 years, with the 25th percentile around 40 months and the 75th percentile around 70 months.[26] As these loads are magnitudes larger than most loads historically seen on the system and proliferating more quickly than most historical load growth, the need for additional generation may not have been planned for, and current system plans may not be able to meet it.

As a result, demand may outstrip generation supply in the near future. Some of this risk may be mitigated if loads are flexible and demand can be reduced during peak hours.[23,23] But, as mentioned above, most computational and other large loads are expected to request firm service. If demand leads to a shortfall of generation and all operating reserves—including controllable loads—are exhausted, manual load shed may be needed to stabilize the system.

Performing resource adequacy assessments and resource planning poses a challenge when the amount of load that may materialize is variable or uncertain, especially when compared to forecasting growth of traditional loads. Planners may model additional scenarios to account for the uncertainty of the magnitude and timing of large loads, but this can lengthen timelines and workloads. This can also cause confusion, as one scenario will ultimately need to be used for planning purposes.

If loads connect within the 10-year *Long-Term Reliability Assessment* (*LTRA*) time frame or five-year adequacy studies, their connections may be unaccounted for when undertaking coordinated planning between regions until the study is updated in the following year.

[24] "ERCOT Monthly Operational Overview (April 2025)." Accessed: May 30, 2025. [Online]. Available: https://www.ercot.com/files/docs/2025/05/15/ERCOT-Monthly-Operational-Overview-April-2025.pdf
[25] "Data Centers in Virginia," Virginia Joint Legislative Audit and Review Commission, Dec. 2024. Accessed: May 30, 2025. [Online]. Available: https://jlarc.virginia.gov/pdfs/reports/Rpt598.pdf
[26] "Queued Up: 2024 Edition," Lawrence Berkeley National Laboratory, Apr. 2024. Accessed: May 30, 2025. [Online]. Available: https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf

Transmission Adequacy

Transmission adequacy is a well-defined industry concept that is embodied in numerous NERC standards from both the planning and operating perspectives. Large loads can be of a magnitude that must be analyzed well in advance to assess the security of the transmission system and determine whether transmission upgrades are needed to reliably serve the load and meet the expectation of an "adequate level of reliability."[27] Failure to analyze the impact of the new large load can also lead to real-time transmission system restrictions in the amount of load that can be served.

Part of transmission planning is evaluating the planned system for thermal overloads, voltage criteria exceedances (high and low), and system stability performance against various performance criteria. All problematic findings must be remediated prior to energization to prevent real-time operating reliability risks. Without comprehensive pre-energization analysis and configuration planning, large loads pose potential risks to the reliable operation of the BPS. The larger the load's peak demand, the greater the risk that it will contribute to an inadequate level of reliability.

From a planning and interconnection perspective, large load interconnection designs are analyzed similarly to large generator interconnection designs. The performance of the transmission system with the inclusion of the large load and its connecting facilities can be defined in general terms as follows:

- The transmission system does not experience instability, uncontrolled separation, cascading, or voltage collapse under normal operating conditions and when subject to predefined disturbances.
  - The performance outcomes are the following:
    - Stable frequency and voltage within predefined ranges
    - No instability, uncontrolled separation, cascading, or voltage collapse
- System frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - The performance outcomes are as follows:
    - Stable frequency within predefined range
    - Facility ratings are respected
    - Frequency oscillations experience adequate damping
- Transmission voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - The performance outcomes are as follows:
    - Stable voltage within predefined range
    - Facility ratings are respected
    - Voltage oscillations experience adequate damping
- Adverse reliability impacts on the transmission system following low-probability disturbances (e.g., multiple contingences, unplanned and uncontrolled equipment outages, cyber security events, and malicious acts) are maintained at an acceptably low level and, if they occur, are mitigated.
  - The performance outcome is to manage the propagation of frequency deviations, voltage deviations, angular instability, uncontrolled separation, and cascading failures.

[27] "RE: Informational Filing on the Definition of 'Adequate Level of Reliability,'" NERC, May 2013. Available: https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/ALR%20filing%202013.pdf#search=adequate%20level%20of%20reliability

- Restoration of the transmission system after major system disturbances that result in blackouts and widespread outages of transmission elements is performed in a coordinated and controlled manner.
    - The performance outcome is to recover the transmission system and restore available resources and load to a stable interconnected operating state.

Bulk Electric System (BES) transmission capability is assessed to determine availability to meet anticipated BES demands during normal operating conditions and when subject to predefined disturbances.[28] Additionally, significant demand additions can require a high level of concurrent new transmission buildout as well as many transmission upgrades that require complex and long-term outage coordination evaluations. Delays in completing these new buildouts and projects can result in increased risks to transmission adequacy to serve loads from existing and new generation.

Operations/Balancing

Short-Term Demand Forecasting

Many emerging large loads differ technologically from past industrial loads, leading to significant uncertainty in modeling their behavior and consumption profiles. New loads serve new end uses, such as the parallel training of large language models in AI data centers. This uncertainty results in considerable forecasting errors that could cause system operators to run the risk of under- or over-scheduling, dispatching, or procuring energy and ancillary services. Even after these new loads have been in operation for an extended period, real-time forecasting can remain challenging due to their unpredictable and stochastic nature. For example, high-intensity electrical processing loads like EAFs often experience frequent on-off cycles, causing large, random fluctuations in consumption. Such behavior can lead to dispatch errors, shutting down units prematurely, committing units that are not needed, and generally causing balancing issues. Additionally, large loads are particularly difficult to forecast during extreme conditions, such as during periods of high electricity prices or adverse weather events, amplifying errors in dispatch algorithms when forecasting accuracy is most critical.

Concentrating large loads at single points increases exposure to numerous forecast risks. A single fault could trip the load, from a utility perspective, and amplify the grid disturbance. Moreover, if one of these large loads, such as a data center, is lost and does not return quickly, it can skew the overall forecast and affect transmission station-level forecasts and planning.

Currently, many large loads do not submit real-time or day-ahead operational consumption profiles or plans. This lack of visibility creates forecasting issues, especially for loads with unpredictable consumption patterns, such as data centers or EAFs. Existing short-term forecasting models typically rely on regression-based or autoregressive time series methods that assume past behavior will be replicated in a predictable manner, which fails to account for the dynamic nature of these types of loads.

Load Response to Price and Other Signals

Many large loads may change their demand based on signals like price or emission limits. If the utility is unaware of the triggers that cause the load to change its demand, the utility may not be able to accurately forecast demand. ERCOT analyzed the average percentage of each large load's curtailment when prices go above specific thresholds, and a handful of loads were highly responsive to prices. Conversely, another handful of large loads curtailed less than half of their demand when prices were high. ERCOT notes that a large portion of its large loads at the time of the analysis were cryptocurrency mining, which is known to be more price sensitive when compared to something like cloud data centers that prioritize uptimes over 99.999%. When the system operators are not aware of these triggers, the forecasting quality may be degraded, which could lead to insufficient reserves.

[28] Reference NERC's "Adequate Level of Reliability" submittal to FERC: Link

Balancing and Reserves

In real-time power system operations, there must be enough generation to meet demand while maintaining reserves. Failure to maintain this balance could lead to load shed or a system collapse if there is not enough power or if the reserves cannot handle load movement or unit trips.

Large loads, especially PELs, can shift their consumption in seconds, much quicker than conventional generators can ramp. Quick load ramps—increase or decrease—can stress the system, as generation must be rapidly loaded or unloaded in response. These quick real power demand ramps have been observed in the field during normal operations. For example, **Figure 3.1** shows a North American data center ramping down from about 450 MW to about 40 MW within 36 seconds around hour 6. The load's demand is constant (around 7 MW) for approximately 4 hours. After hour 10, the data center ramps back up to 450 MW over the course of a few minutes.

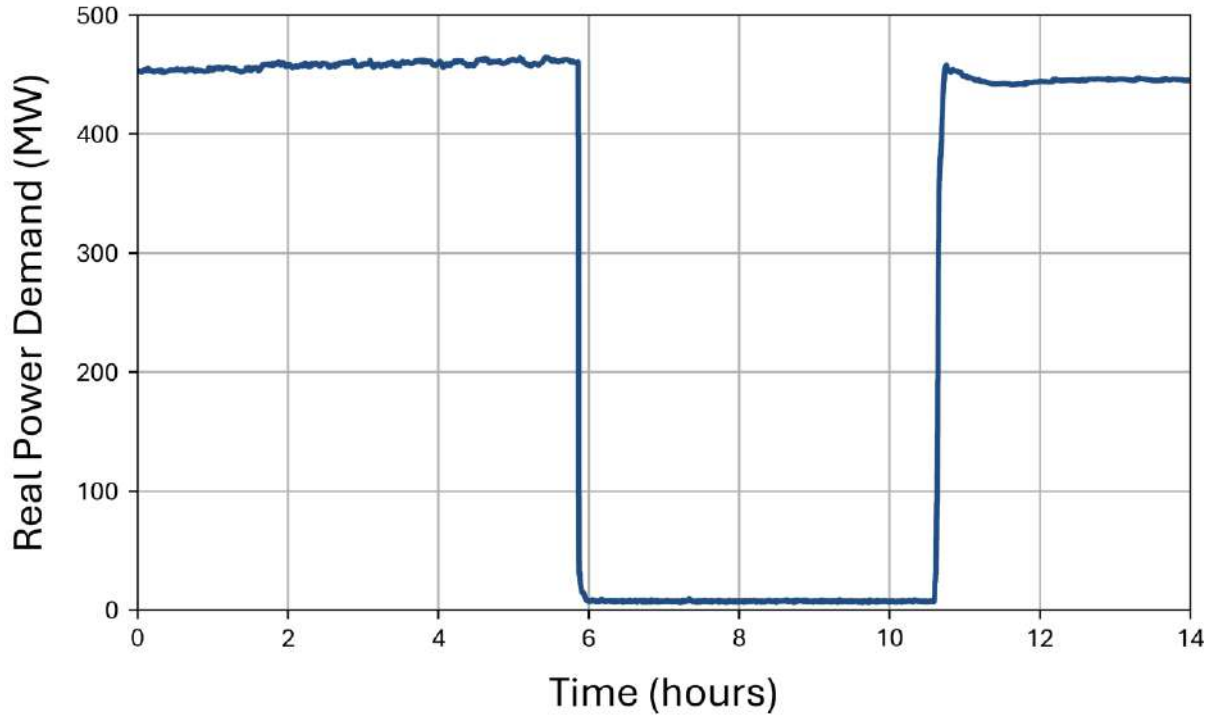


Figure 3.1: Data Center Load Ramp Down and Up

Forecasting these loads to ensure that the system operator procures the appropriate reserves is also a challenge. Without accurate real-time forecasting methods, the system operator may not procure enough energy reserves in the operating day, leading to energy shortfalls and potential load shedding. Loads in operation have already been shown to be flexible, but the signals that affect demand are not known. Without knowledge of the triggers that cause facilities to shift consumption, it will be impossible to properly account for the load behavior in forecasting.

Large load ramp rates may cause issues with frequency regulation by outstripping the reserves held to regulate frequency. These reserves are provided by on-line spinning resources with headroom to manage a decrease in frequency and units that can further lower their output to manage an increase in frequency. With larger ramp rates, more regulation services will be needed to handle larger swings.

In addition to the magnitude of the ramp rates, the timing matters as well. To handle loads that ramp within seconds or minutes and require fast-acting regulation services, system operators typically procure fast-frequency response services to maintain frequency. The case of ramping down may necessitate units that can rapidly shut down.

The system operator will need information on the large load ramp rates to assess the potential magnitude of the ramping problem. Fast ramping of large loads can cause issues with both voltage and frequency regulation.

If the system operator fails to procure adequate regulation to manage frequency, then load shed or rapid generation curtailment may take place and result in unplanned outages, reducing system security/reliability. In addition to the loss of load, the sudden restoration of a large load could exhaust available balancing reserves, ultimately leading to decreased system frequency and potential frequency instability.

Large rapid changes in demand will also rapidly alter the flow of reactive power in the system, potentially exceeding the ability of existing voltage controls to respond and lead to over- and undervoltage conditions. This could lead to the unplanned outages of generation plants initiated by voltage-ride through protection, load loss related to undervoltage load shedding, or even more widespread outages caused by voltage instability and collapse.

Figure 3.2 shows a load ramp down 298 MW within 25 seconds at a cryptocurrency mining facility in North America. The load was exhibiting real power oscillations with a peak-to-peak amplitude of around 25 MW following a load control issue due to an offsite telecommunication failure. The operator instructed the load to decrease its demand, demonstrating the potential for rapid load ramps.

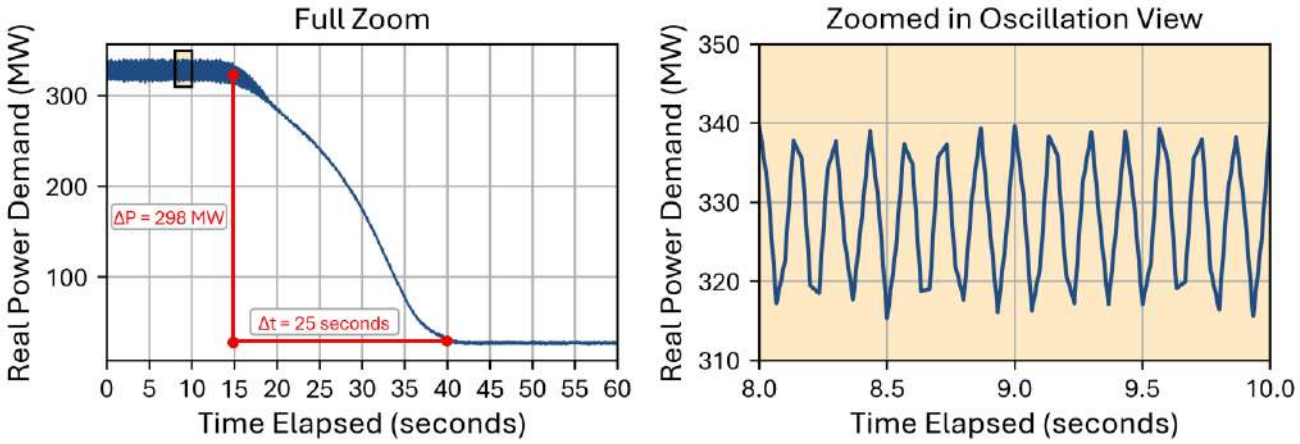


Figure 3.2: Cryptocurrency Mining Facility Load Oscillation and Ramp Down

Lack of Real-Time Coordination

The lack of coordination between grid operators and large load operators creates multiple risks, including those mentioned above, such as load-ramping coordination.

Risks like these may lead to challenges in controlling the area control error (ACE). For example, AI model training at the xAI Colossus Supercomputer in Memphis, Tennessee—currently the world's largest AI training cluster[29]—can change the loading 35–70 MW or more within a minute as the model starts and stops. That change may not be an issue for a single facility, but the aggregate effect across multiple facilities may negatively impact ACE control. These sudden ACE changes may be reflected negatively in the BA Control Performance Standard 1 (CPS1) and BA ACE Limits (BAAL) as required in NERC BAL-001.[30]

The key characteristics impacting real-time coordination for CPS1 and BAAL are: (1) ramp rate (2) peak demand and (3) load predictability. Large, fast, unpredictable ramps from large loads may cause volatility in ACE and BAAL if a BAs

[29] P. Kennedy, "Inside the 100K GPU xAI Colossus Cluster that Supermicro Helped Build for Elon Musk," *ServeTheHome*, Oct. 28, 2024. https://www.servethehome.com/inside-100000-nvidia-gpu-xai-colossus-cluster-supermicro-helped-build-for-elon-musk/
[30] Standard BAL-001-2 – Real Power Balancing Control Performance

generation fleet can't make rapid adjustments. Additionally, if a BAs generation fleet is making rapid adjustments to follow fluctuations in large loads, response reserves could end up being depleted.

There have been documented instances where grid events have unexpectedly impacted data center loads. The NERC *Considering Simultaneous Voltage-Sensitive Load Reductions* incident review[1] details how a 230 kV fault led to customer-initiated simultaneous loss of approximately 1,500 MW of voltage-sensitive load that was not anticipated by the BPS operators. There was a corresponding sudden increase in ACE for the BA when the load tripped. A similar but opposite scenario could occur if a fault at a large load facility adversely impacts nearby generation. The risk to the BPS is unnecessary relay triggering causing potential interactions between the load and generation or the sudden loss of generation and the impacts to ACE control.

Outage Coordination in Operations Planning

Large loads that want to connect within 18 months may also pose risks to outage planning by changing the planning forecast. If the load's connection is approved and there is a resulting increase in load, resource and transmission adequacy margins may be affected. Generation and transmission outages that were approved based on a previous load forecast may need to be shifted or delayed if there is now a resource or transmission adequacy issue based on this increased forecast. This could result in delayed maintenance. Maintenance outages that are taken to avoid sudden tripping (like a failing lightning arrestor) being delayed could increase risks of sudden tripping, which may take longer to repair, leaving the equipment out of service for longer than the original maintenance request. Extended outages on key equipment like generators may affect the system's ability to serve all loads with sufficient operating reserves. Additionally, significant demand additions can require a high level of concurrent generation and pipeline infrastructure development to adequately serve the demand. Delays in completing these new buildouts can result in increased risks to resource adequacy.

BAs must accurately determine their total generation capacity to meet both forecasted and real-time demand. A crucial component of this process is outage coordination. Typically, generators are required to submit their availability, including any deratings, to their BA. This critical information is provided at a minimum in real-time operations and in the near-term horizon. Inconsistent outage coordination between BAs and large load operators can result in inaccurate load forecasts, resulting in either under- or over-committing generation resources. If generation is under-committed, there may not be enough generation to serve all the load. Over-committing generation may cause a different reliability issue related to the mechanical limitations of generation. Thermal units have minimum output levels that can be challenging for them to operate below and may cause undue stress on the unit to come off-line. The risk to the BPS is the potential for inaccurate forecasts and suboptimal generation commitments due to a lack of visibility into large load outages.

Stability

The BPS is planned and operated to be stable as system conditions change and disturbances occur. Potential consequences from power system instability (i.e., a loss of stability) include widespread power outages and permanent damage to BPS equipment. Maintaining stability involves considering a broad range of mechanisms from which instability may arise—**Figure 3.3** illustrates a widely used taxonomy of power system stability problems. Large loads, owing to their high power ratings, fast controls, rapidly varying load profiles, and heavy use of active power electronics, are capable of contributing adversely to any of the stability problems shown in **Figure 3.3**.

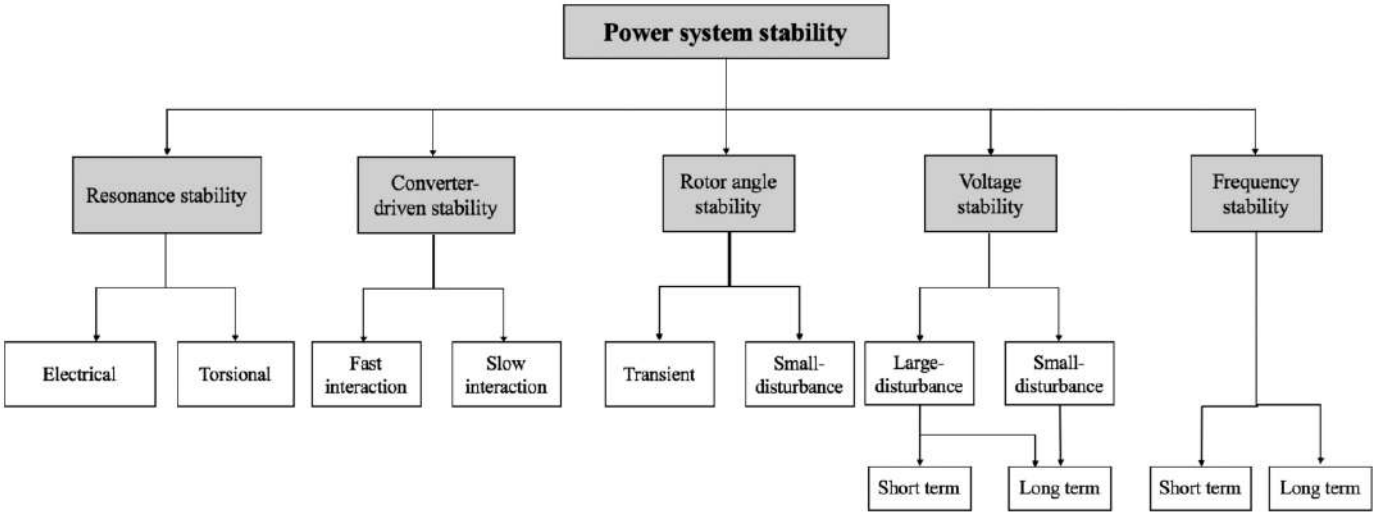


Figure 3.3: Taxonomy of Power System Stability

To keep stability problems from adversely affecting BPS reliability, it is generally necessary to identify them proactively and put mitigations in place to ensure conditions conducive to instability are avoided. Power system stability studies are the primary means by which this is accomplished. Thus, many of the stability-related risks associated with large loads arise from the concern that the loads have not been accurately represented in power system stability studies. This is one reason why the widespread tripping of large loads has attracted significant attention—this widespread tripping was not anticipated in power system studies and could indicate unforeseen (and therefore unmitigated) stability problems. In the next white paper, gaps in current practices (e.g., modeling practices) contributing to this concern will be discussed in detail. This white paper, however, is dedicated to identifying ways in which large loads might contribute adversely to stability problems.

Ride-Through

The voltage and frequency ride-through behavior of large loads during disturbances plays a significant role in how they may contribute to instability. Ride-through behavior is primarily defined in terms of how long the load remains connected during a given voltage and/or frequency disturbance. However, changes in the load's real or reactive power consumption during or after the disturbance are important as well (e.g., how much time passes before a disconnected load reconnects, and how quickly does it return to its original consumption). Currently, much attention is directed toward the tendency of many large loads to disconnect during disturbances. Some large loads have internal protection and control systems that will disconnect from the grid during disturbances. For example, some data centers may switch to backup power systems after three transient voltage disturbances within one minute as observed at certain data centers in the EI load transfer event.[1] The intent behind such systems is usually to ensure the reliability of the large load's process (e.g., serving internet traffic) or protect equipment from damage by switching to a local backup power source.

BPS equipment is designed and operated to meet certain ride-through requirements (e.g., Reliability Standard PRC-024) so that it remains on-line during disturbances and supports the system.[31] These requirements are necessary because disconnecting BPS equipment during a disturbance can worsen the disturbance's effects and, if enough equipment disconnects, lead to cascading power outages. At a sufficient scale, the disconnection of load introduces similar concerns. The tendency of some loads to disconnect during disturbances is not new. However, the scale of recent load loss events was unexpected and had measurable effects on the BPS. This called into question existing modeling practices and expectations for loads.

[31] Standard PRC-024-3

Some large loads have disconnected in large quantities during system disturbances, including the following:

- ERCOT has seen numerous unexpected reductions in consumption or loss of load during disturbances. The majority of losses were with PEL at cryptocurrency mining facilities and oil and gas facilities, which reduced their consumption in response to transmission faults. It was noted that not all facility protections were visible to ERCOT or included in dynamic models. Analysts lacked necessary single-phase high-resolution data as well.
- In the EI, a transmission fault caused the simultaneous loss of approximately 1,500 MW of voltage-sensitive load, primarily from data centers. While circuit breakers at the data center substations did not trip, multiple data centers decreased consumption, switching some of their facility power to backup systems in response to the transient voltage disturbance. **Figure 3.4** shows the loss of data center load in the EI following this fault. The third spike is the third recloser shot at 19:00:39.21 upon which the load tripped.

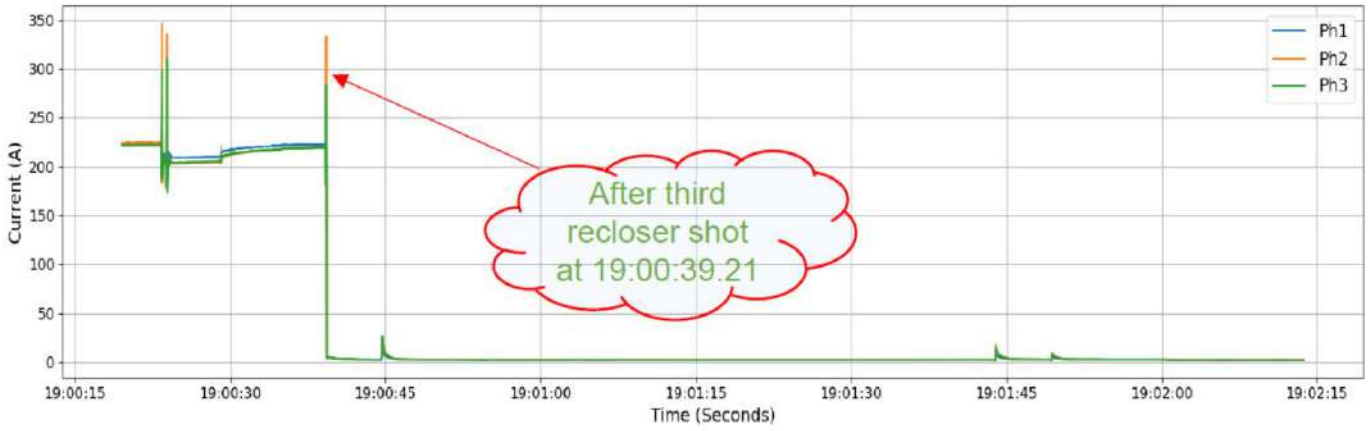


Figure 3.4: Data Center Load Trip

In subsequent sections, stability issues associated with large and sudden load loss are discussed. Ride-through-related challenges are a focal point in many discussions as they are already having an observable impact on BPS dynamics, but there are other stability risks unrelated to ride-through behavior. Power system instability events are often low-probability, high-impact events that require proactive mitigation. Therefore, it is essential to consider potential stability issues unrelated to ride-through, even if they are not yet observed in operations.

Frequency Stability

BPS frequency is maintained at a near-constant value by closely balancing the energy produced by generation resources with that demanded by the load and losses in power system equipment. This is achieved on timescales varying from seconds to years by different processes. Frequency stability risks are associated with the shortest of these timescales and are closely related to operational risks surrounding balancing and reserves. The stability concern is that very large and sudden (e.g., within seconds) changes in the demand from large loads might exceed the ability of fast-acting generation controls to respond and restore balance between generation and demand. As this capacity is exceeded, the frequency deviation will grow larger. Both loads and generation have limits to the frequency deviation that they will withstand before tripping off-line, which may cause further frequency deviations. Thus, the critical reliability concern is that operators may totally lose their ability to regulate the system frequency and large-scale power outages might follow.

When a large load trips, it causes an instantaneous imbalance in load and generation and frequency deviates from nominal. For example, according to NERC's incident review[1] on July 10, 2024, a lightning arrestor failure on a 230 kV transmission line in the EI led to multiple system faults within 82 seconds. These repeated faults resulted in voltage depressions ranging from 0.25 to 0.40 per unit in the affected area. Coinciding with this disturbance, approximately

1,500 MW of load was lost, as demonstrated in **Figure 3.5**—not due to utility disconnection but because of customer-side protection and controls. This sudden load loss caused frequency to rise to 60.053 Hz before it stabilized back to 60.0 Hz within four minutes, as seen in **Figure 3.6**. This incident demonstrates how large-scale load tripping can meaningfully affect BPS frequency. Note that the EI is the largest of the interconnections in terms of inertia and frequency responsive generation capacity—load loss events of a similar size can cause much larger frequency deviations in other interconnections (e.g., a ~235 mHz rise in the ERCOT Interconnection).

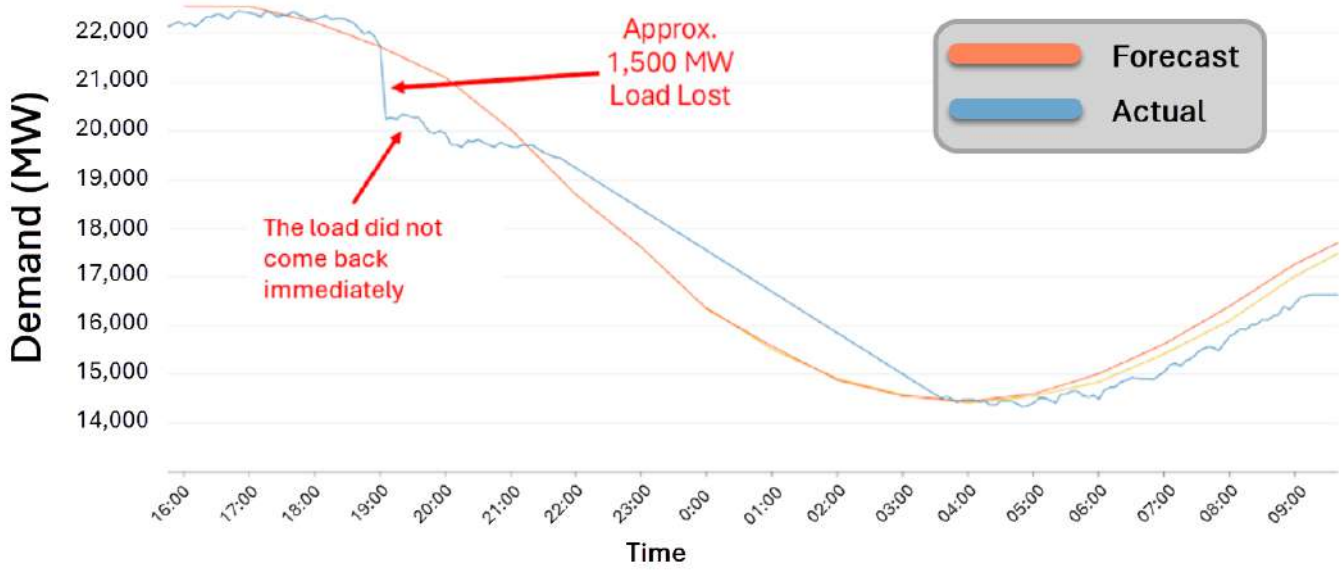


Figure 3.5: System Load Chart[1]

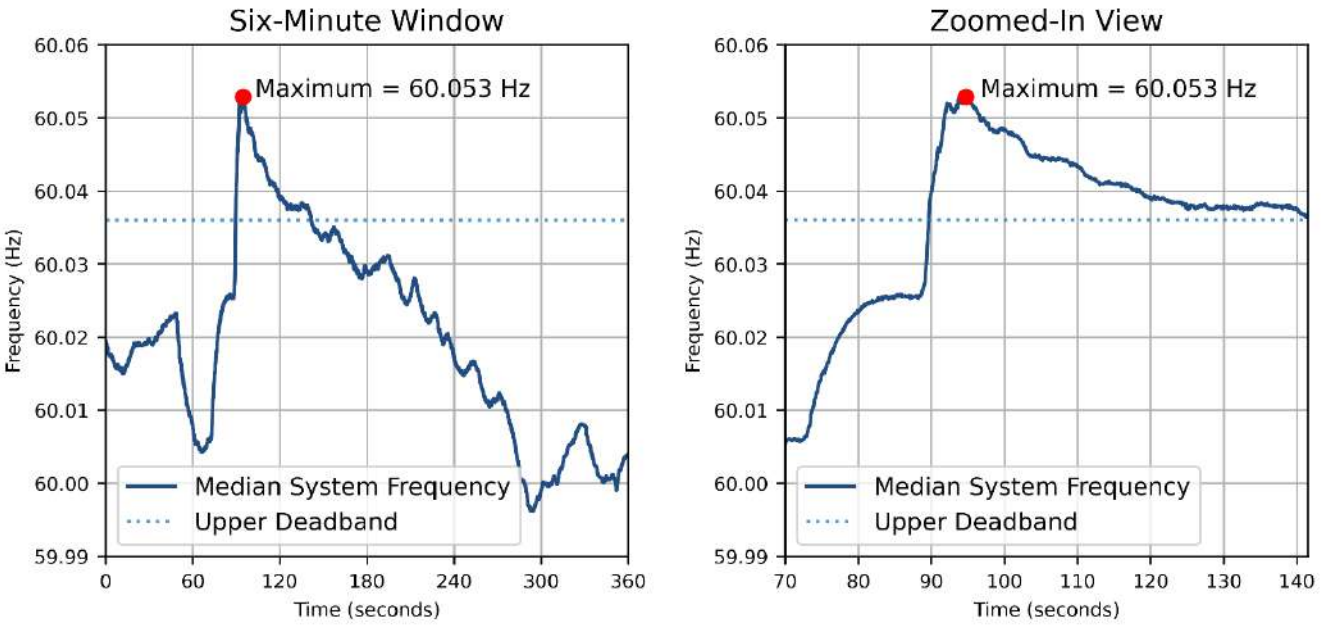


Figure 3.6: Frequency Plot for Eastern Interconnection 1,500 MW Large Load Loss/Transfer on July 10, 2024 (Provided by University of Tennessee: Knoxville)

Generators are prone to damage from overfrequency conditions as an increase in system frequency corresponds to an increase in the generator's mechanical speed as well. For this reason, BPS generators are equipped with

overfrequency protection. Large load tripping may also result in subsequent generation tripping initiated by overfrequency protection. The tripping of generation will aid frequency stability and mitigate overfrequency conditions, and so the primary concern is not necessarily that frequency would increase indefinitely. Rather, the concern is that the subsequent loss of generation could initiate other reliability issues. Generator overfrequency protection is designed to protect generators from damage during extreme disturbances—it is not designed as a method for fast frequency control or to prevent blackouts. Thus, generation overfrequency tripping that follows large load tripping may cause line overloads, voltage regulation issues, or even a subsequent underfrequency event. All these issues have the potential to cause further operation of protection systems. With each protection system operation, more BPS equipment is taken out of service, and the possibility for cascading outages grows.

The known behaviors of large loads indicate that there is the potential for many gigawatts of large load to be lost nearly simultaneously, leading to the overfrequency issues discussed previously. There are other ways in which large loads could cause frequency stability issues. If many large loads energized at the same time, they could cause significant underfrequency events. This could cause other loads to be tripped off-line via underfrequency load-shedding schemes. If enough large load energizes and is not tripped off-line, the frequency may become low enough that generators trip off-line due to underfrequency protection. If this occurs, frequency instability and widespread outages are a serious possibility as each generator that trips off-line further reduces the system's ability to halt the decline in frequency.

Rotor Angle Stability

Large loads introduce rotor angle stability risks primarily as a result of their potential to cause gigawatt-scale changes in BPS real power flows within a few electrical cycles (50 milliseconds in a 60 Hz system). Of the two forms of rotor angle stability (transient and small signal), these characteristics are more relevant in the context of transient rotor angle stability, which is the primary focus of this section. Rapid changes in real power flows cause synchronous generators to experience power swings, wherein generator power outputs oscillate for a time. The greater the change in real power flows, the greater the magnitude of the resultant power swings. If the power swings become too large, the generators become entirely unable to control their output power or frequency (i.e., they lose synchronism) and must be immediately tripped offline or they will be seriously damaged. The portion of the BPS affected by a particular loss of synchronism event can vary greatly, and consequences range from the outage of a single plant to the islanding of large sections of an interconnection.

There are several ways in which known large load behaviors can adversely affect rotor angle stability:

- **Exacerbated postfault power swings:** BPS faults often cause generators to accelerate rapidly until the fault is cleared. Postfault, the energy consumed by loads provides much of the "braking" force that eventually reverses this acceleration and prevents a loss of synchronism. Thus, if large loads trip off-line during the fault and do not resume consuming energy after the fault is cleared, generators may be unable to halt their acceleration and rotor angle instability may result. This is shown below in **Figure 3.7**, where a large load is tripped in a positive-sequence dynamic stability simulation. Note that multiple generators lose angular stability in seconds.
- **Unexpected violations of stability-related transfer limits:** If there is too much electrical distance between generators and the loads they serve, the generators may lose synchronism. In terms of system requirements, this manifests as stability-related power transfer limits on transmission lines. This becomes a problem in the context of large loads because the sudden tripping of many large loads can lead to almost instantaneous gigawatt-scale shifts in net power exchange for an area. From a stability perspective, the problem is that the nearby generators, being unable to decrease their real power output quickly enough to account for the loss of load, will begin transferring real power to loads further away. This can lead to sudden and unexpected

violations of stability-related transfer limits, in which case the generator(s) near the large loads will lose synchronism.[32]

- **Reduced stability margins due to generator reactive power absorption:** Most BPS equipment and most kinds of load consume more reactive power than they produce, and BPS generators supply a significant portion of the BPS's reactive power needs. Some large loads, in contrast with traditional loads, produce reactive power (i.e., they are capacitive loads and operate at a leading power factor). This is because the active power electronics commonly used in LEL operate at roughly unity displacement power factor and are equipped with filters[33] that, while primarily intended to attenuate switching noise and harmonics from the electronics, also produce reactive power. While this can benefit the BPS by improving voltage regulation and reducing transmission system losses, it can worsen rotor angle stability. This is because synchronous generators are more prone to rotor angle instability when absorbing significant amounts of reactive power.[34] Unless this excess reactive power production is accounted for in studies, the available stability margin may be overestimated, leading to field events where generators become unstable unexpectedly.

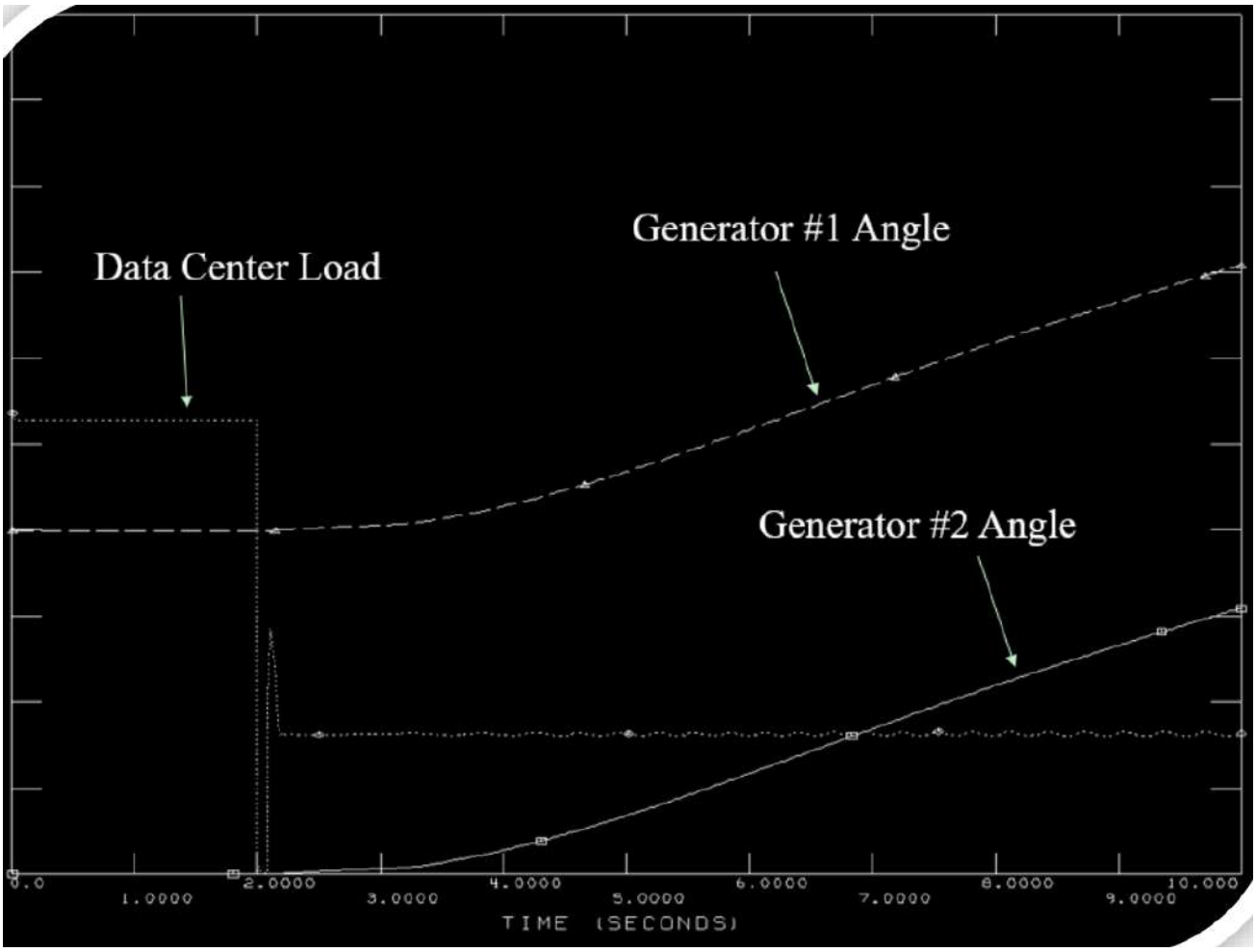


Figure 3.7: Simulation Showing Generators Losing Angular Stability Following Nearby Data Center Load Trip

[32] M. Peterson, "Data Center Interconnection Studies & Challenges," presented at the Large Loads Task Force Meeting and Workshop, Apr. 2025, pp. 53–65. Available: https://www.nerc.com/comm/RSTC/LLTF/LLTF_April_Meeting_&_Technical_Workshop_Presentations_.pdf

[33] Some of these filters are separate devices but some are built into the power electronics themselves (i.e., they would not be visible in a single-line diagram).

[34] Absorbing reactive power is achieved by reducing the generator's internal voltage. This necessitates operating at a higher power transfer angle to deliver a given quantity of real power, reducing angular stability margin.

The first two issues arise from the ride-through issues discussed previously. The third arises from the unusually high penetration of active power electronics in large loads. In all three cases, shortcomings in stability models are the primary source of risk. All three issues relate to the unique properties of large loads, which may not be captured in existing models or studies. Stability issues cannot be reliably avoided if they cannot be identified, and models and studies are an essential tool for identifying reliability issues.

Rotor angle stability risks are especially relevant for new generation plants being sited near large loads. In some cases, the siting of new generation near large loads is motivated by a need to defer or avoid transmission system upgrades. The same transmission constraints that prevented the large loads from being served by existing generation are likely to adversely affect the generation plant's ability to maintain synchronism with the rest of the BPS.

Apart from risks related to transient rotor angle stability, there does exist the possibility for large loads to affect small-signal rotor stability. Small-signal rotor angle stability problems relate to the generators' ability to successfully damp out small power swings and is the main form of stability that power system stabilizers (PSS) are designed to address. Just as active power electronics devices such as STATCOMs may be used to intentionally act as PSS and improve the damping of power swings, it is possible that the active electronics present in large loads might unintentionally lessen the damping of power swings. The risk of this depends highly on the control design of the active power electronics used in large loads. These can vary significantly by vendor and their inner workings are often protected intellectual property. The risk of small-signal rotor angle stability issues involving a large load are higher if the load is connecting at a location where power swings are more poorly damped.

Voltage Stability

Large loads can affect voltage response and stability, with possible impact on transmission and generation elements, including tripping. While low voltage is generally the focus for voltage collapse, overvoltage issues could result in instability; this has occurred on at least one system.[35]

Transient (Short-Term) Voltage Stability

Transient voltage stability refers to the ability of the BPS to support system voltages by maintaining adequate dynamic reactive power support following large disturbances. Typically, this time frame captures up to 30 seconds after the disturbance. The ramp rate, peak power consumption, and voltage sensitivity are all major factors in the transient time frame of voltage stability. The larger and faster the difference in real and reactive power consumption is during the transient time frame, the greater the risk to the BPS voltage stability. This could be brought on by a load rapidly ramping up or down. Additionally, this rapid change in power demand could be caused by a planned or unplanned instantaneous tripping of the load. Loads with more sensitivity to low or high voltages will carry increased risk of sudden trips, which can lead to voltage instability.

As demonstrated by an ERCOT voltage stability study,[36] risks to BPS voltage stability may occur if enough load trips off-line in response to faults. The primary characteristic of large loads that cause this risk is ride-through behavior. As shown in the NERC *Incident Review on Simultaneous Voltage-Sensitive Load Reductions*,[1] certain fault conditions can cause many electrically close loads to trip or reduce demand.

Mid-Term Voltage Stability

Mid-term voltage stability refers to the ability of the BPS to transition from the transient time frame (less than 30 seconds) to the multiple-minute time frame during which system load and generator response should have stabilized. During this period, numerous factors are in play. Voltage instability arises in this time frame when system reactive demands cannot be met by dynamic and static reactive resources with the applied control schemes (e.g., automatic

[35] T. Van Cutsem and R. Mailhot, "Validation of a Fast Voltage Stability Analysis Method on the Hydro-Quebec System," IEEE Trans. on Power Systems, Vol. 12, No. 1, pp. 282-292, February 1997.
[36] ERCOT, "Load Loss Threshold Analysis", presented at the ERCOT Large Load Working Group (LLWG) Meeting, May 2025. [Online]. Available: https://www.ercot.com/files/docs/2025/05/19/Large_Load_Loss_Analysis_051625_LLWG.pptx

generator controls, dynamic reactive resource control, controlled shunt devices, and on-load tap changers) and unacceptably low voltage or voltage collapse ensues. Large loads may pose a risk to the mid-term voltage stability of the BPS depending on their ramping behavior, peak load, and overall variability.

Steady State (Long-Term) Voltage Stability

Long-term voltage stability refers to the system's ability to maintain steady voltages once a new operating state is reached, typically well beyond the transient time frame. The magnitude of increase and decrease of real and reactive power informs the amount of risk to voltage stability. The larger the magnitude in change, the greater the risk of steady-state voltage instability. Large loads with the largest peaks and troughs in demand may affect the long-term voltage stability of the system more as compared to smaller loads or less variable loads.

Resonance- and Converter-Driven Stability

The risks associated with large loads and both resonance- and converter-driven stability have many facets in common, and they are discussed together here to avoid unneeded repetition. Both kinds of stability risk involve the closed-loop controls used in large load electronics interacting with other power system equipment. Any closed loop control has limitations regarding the kinds of signals to which it can respond effectively, and the deployment of power electronics in large loads may uncover limitations that were of little or no consequence when the same electronics were used in smaller quantities and for different applications.

For resonance stability, the concern is that large loads will significantly decrease the damping of resonances, or oscillatory modes, in the BPS. These resonances may be electrical (e.g., those introduced by series-compensated transmission lines), mechanical (e.g., turbine torsional modes). Whenever a disturbance occurs in the grid, some oscillation occurs at these resonant frequencies. When the system is stable, the energy associated with the oscillation is absorbed by a mix of generators, loads, and power system equipment, and the oscillation quickly decreases in amplitude. In the context of resonance stability, the concern is that the controls in the large load's electronics will respond by *supplying* energy to the oscillation, instead of absorbing it. Depending on how much energy the large load contributes, the oscillation may increase in duration or even begin to grow in amplitude over time (i.e., the system will become unstable).

The term "converter-driven stability" was introduced to categorize some stability problems that are associated with converter-interfaced generation but not with traditional synchronous generation. Many of the active power electronics devices used in large loads are capable of exhibiting the same converter-driven stability problems as converter-interfaced generation. Converter-driven stability problems can involve interactions between different power electronics and, given the large variety of power electronics designs in use, the possible behaviors and scenarios are many. One form of converter-driven stability that has significantly impacted grid reliability before is weak system stability, an issue associated with the phase-locked loops used by many active power electronics (including those used in large loads). Such controls can become unstable at low short-circuit ratios (e.g., 2 or less). In 2019, an 800 MW offshore wind plant in Great Britain experienced a weak grid instability issue and tripped offline,[37] eventually contributing to an outage affecting over 1 million customers.[38]

Regardless of whether resonance- or converter-driven stability is involved, the potential for the large loads to cause issues is primarily determined by the control algorithms used in the active power electronics. This introduces the same challenge as that associated with small signal rotor angle stability—control algorithms in power electronics vary significantly by make and model, and the control details needed to accurately model the device's potential to interact

[37] Y. Cheng *et al*., "Real-World Subsynchronous Oscillation Events in Power Grids With High Penetrations of Inverter-Based Resources," in *IEEE Transactions on Power Systems*, vol. 38, no. 1, pp. 316-330, Jan. 2023, doi: 10.1109/TPWRS.2022.3161418.

[38] Energy Emergencies Executive Committee, "GB POWER SYSTEM DISRUPTION – 9 AUGUST 2019," Department for Business, Energy, and Industrial Strategy, Sep. 2019. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/836626/20191003_E3C_Interim_Report_into_GB_Power_Disruption.pdf

with grid dynamics are usually protected intellectual property. That said, some risk factors relevant in the case of known stability issues may be relevant for large loads as well.

Some trends from known converter-driven and resonance stability issues might indicate which large loads are at a higher risk of being involved in similar problems. Broadly speaking, the resonance and converter-driven stability issues are more common when a large concentration of power electronics devices is located close to a generation plant (traditional or inverter-based), series compensated line, or other large concentration of power electronics devices (e.g., a STATCOM or HVdc line). The stability issues are usually most prominent when the components involved are more weakly coupled with the rest of the BPS (e.g., they are connected through only a single transmission line). This tends to correspond to a low short-circuit ratio (relative to the size of the large load).

Forced Oscillations

In the context of resonant stability, the concern was that the large load's power electronics cause existing oscillatory modes in the power system to become less damped and potentially unstable. In such cases, the large load is not the source of the oscillation—it is responding to an oscillation that is a natural result of the power system's dynamics. However, there are also cases where large loads can be a source of oscillations and introduce related reliability risks. In such cases, where the large load acts as a relatively fixed source of an oscillatory signal (e.g., voltage magnitude, real power), the load is producing a forced oscillation.[39]

Broadly speaking, the reliability risks associated with forced oscillations are not always well defined. In some cases, they may cause accelerated aging of BPS equipment (generators in particular) or the operation of protection systems (especially those designed to detect unstable oscillations). In such situations, the concerns generally arise because the frequency of the forced oscillation is the same as that of an existing oscillatory mode in the power system. There are some known risks in such cases, which will be the focus of this section.

If the forced oscillation does not happen to be near the frequency of any known oscillatory modes, it becomes difficult to define specific reliability risks. That said, unexpected interactions involving oscillations have been responsible for well-known reliability issues, such as the Mohave generator shaft failures of the 1970s (caused by subsynchronous resonance, a kind of resonance stability problem) or the 1996 blackouts in the Western Interconnection (which involved an unstable interarea oscillation). The BPS was not designed to operate with large and persistent subsynchronous oscillations, and their presence heightens the risk of unintended interactions that could result in power outages and/or BPS equipment damage.

Some large loads can produce forced oscillations at frequencies below 60 Hz (i.e., subsynchronous frequencies). These oscillations can occur either as a natural byproduct of the load's end use or as the result of unexpected control interactions (i.e., load equipment is not behaving as designed/intended). AI data centers can have load profiles that are periodic, repetitive, and sustained in nature (see **Figure 3.8**). More traditional large loads, such as EAFs, can also exhibit sustained subsynchronous oscillations as a natural byproduct of the arcing process.

[39] Energy Systems Integration Group's Stability Task Force, "Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems," Energy Systems Integration Group, Aug. 2024. Available: https://www.esig.energy/wp-content/uploads/2024/08/ESIG-Oscillations-Guide-2024.pdf

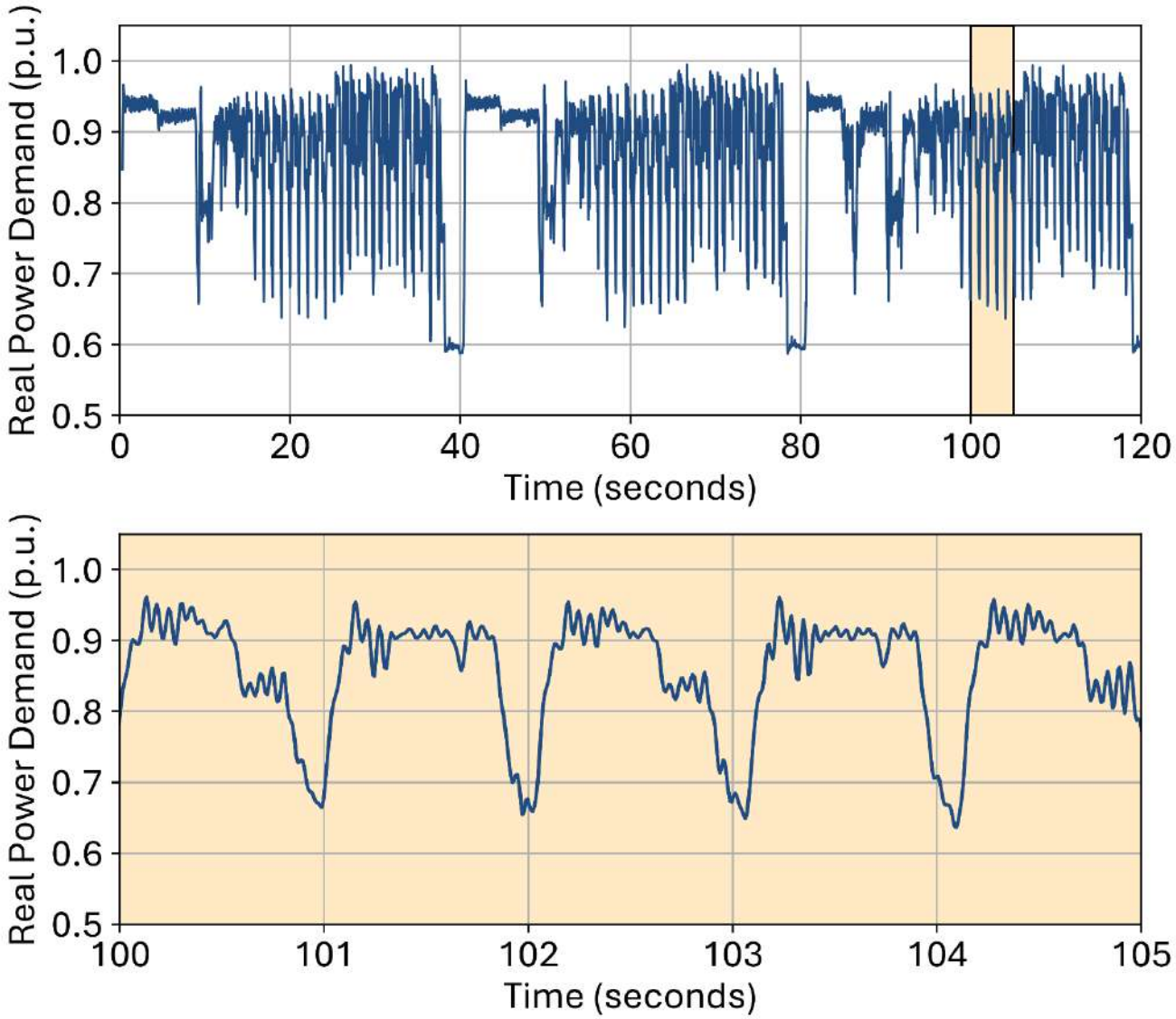


Figure 3.8: Example AI Data Center Load Profile During Training Over Two Minutes (Top) and in a Five-Second Period (Bottom)

Forced oscillations can also arise from unintended control issues involving large load equipment. In 2023, a large data center in the Midwest produced forced oscillations unexpectedly. A 1 Hz forced oscillation occurred when a natural frequency was stimulated by periodic forcing of a slower frequency (see **Figure 3.9**). The system was inadvertently perturbed at one-second intervals by active power electronics at a data center. Each perturbation resulted in a relatively well-damped 11 Hz ringdown.[40]

[40] L. Zhu, E. Farantatos, and L. Chen, "Sub-Synchronous Oscillation Detection and Analysis – Dominion Case Study," presented at the Sub-Synchronous Oscillations (SSO) Workshop, Accessed: Jun. 07, 2025. [Online]. Available: https://www.epri.com/events/539b60d7-57da-4252-9968-fb1754ee3b66

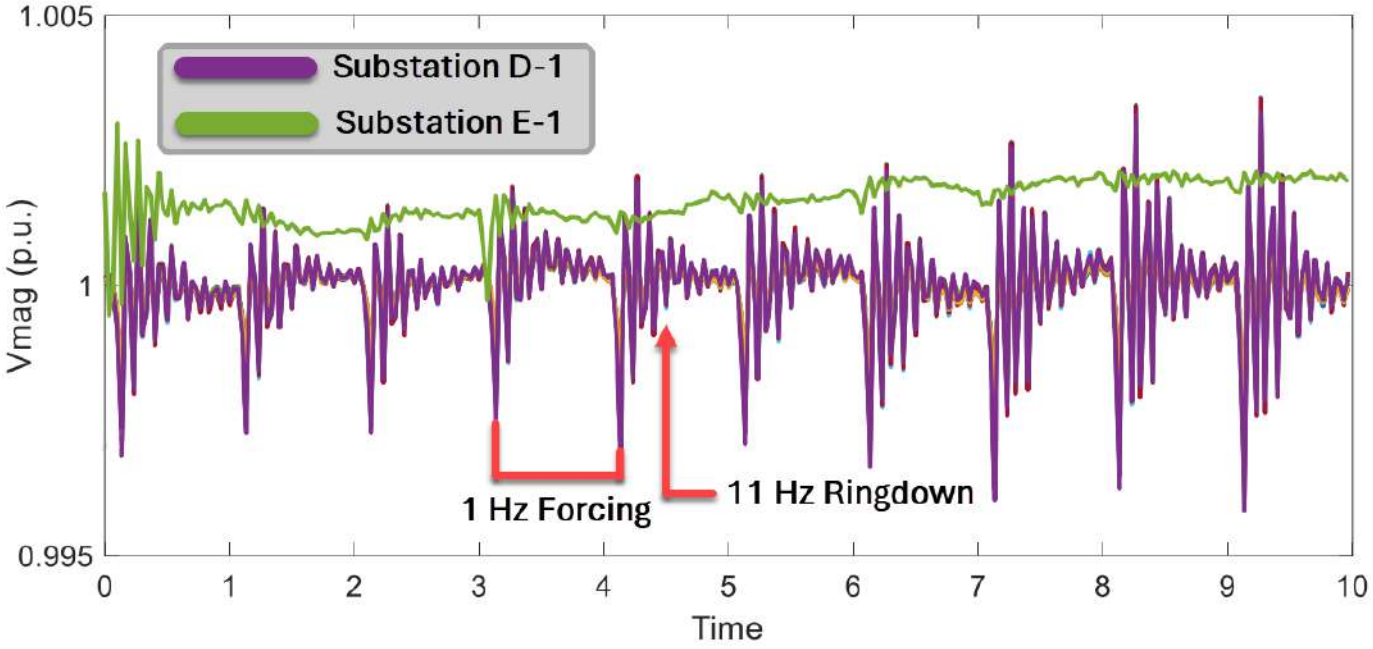


Figure 3.9: Field Measurement of Forced Oscillations Occurring at 1 Hz[40]

Forced oscillations that occur at modal frequencies present a heightened reliability risk (compared to forced oscillations at other frequencies) because they propagate more effectively—either across the BPS or into specific components such as the blades or shafts of large turbines.

Forced oscillations at interarea modal frequencies can affect an entire interconnection. In 2019, a steam turbine in Florida created a forced oscillation with an amplitude of 200 MW and a frequency of 0.25 Hz.[41] The EI has an inter-area mode with a frequency of roughly 0.25 Hz, and this mode is excitable from the Florida region.[42] Because of this mode, the oscillation spread far across the EI, and oscillations at large as 50 MW were observed in New England. The oscillation persisted for 18 minutes and no outages or damage were reported. However, if the oscillation were larger in magnitude, it may have affected a larger portion of the EI. Depending on the location where the large load is connected and frequency of oscillations it produces, forced oscillations produced by a large load could interact with interarea modes in much the same way and pose risks for a large portion of the interconnection they are connected to.

Forced oscillations at the torsional modal frequencies of a turbine-generating units (steam and gas turbines, specifically) can cause persistent, large torque pulsations (e.g., 30% peak-to-peak) and fatigue the turbine, aging it more rapidly. As an example, **Figure 3.10** illustrates the torques produced in a steam turbine by the acceptance of two different prospective EAF loads.[43] In the left-hand plot, the EAF characteristic (not shown) does contain significant oscillations, but these occur at frequencies other than the torsional frequencies of the turbine-generating units. Consequently, these oscillations do not propagate very effectively into the turbine and generate little torque ripple beyond an initial transient. In the right-hand plot, however, the EAF's oscillations correspond to one of the turbine-generator's modal frequencies and significant torque pulsations are apparent, even in steady-state.

[41] NERC, "Eastern Interconnection Oscillation Disturbance Forced Oscillation Event," NERC, Jan. 2019. Available: https://www.nerc.com/pa/rrm/ea/Documents/January_11_Oscillation_Event_Report.pdf

[42] Interarea modes are generally most excitable from locations near the edges of the interconnection and less excitable from regions near the center.

[43] Torsional Resonance Identification in Turbine-Generator Shaft Due to the Operation of Electric Arc Furnaces at Steel Mills in Bangladesh Power System

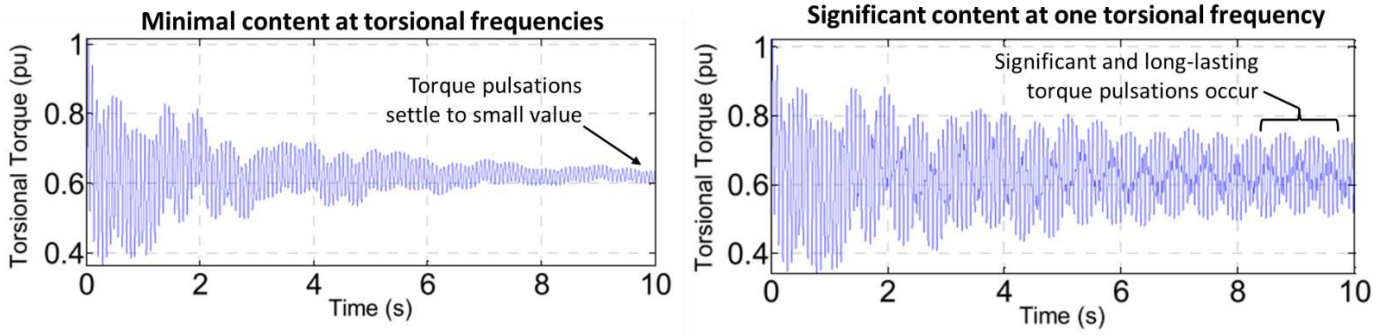


Figure 3.10: Torques Produced in a Steam Turbine for EAF Loads That Do Not (Left) and Do (Right) Contain Frequency Content at the Steam Turbine's Torsional Modal Frequency

As with resonance and converter-driven stability, the risks associated with forced oscillations from large loads are higher when the large load is located near a kind of device known to participate in stability problems, as well as when the large load's short-circuit ratio is low. The same list of devices (generators, capacitors, concentrations of power electronics) is relevant. Forced oscillations involving regional or interarea modes are a special case; studies or measurements must be used to identify the excitability of the modes at buses throughout the BPS. Risks associated with forced oscillations are higher at buses where modes are more excitable,[44] and modes with lower damping coefficients are more likely to introduce reliability issues if excited.

In the Dominion system, oscillations have been seen arising from the interaction of data centers' UPS input units.[45] These oscillations could also interact with nearby inverter-based resources and complicate system stability.

Power Quality

Depending on the operating performance, large loads can have relatively low energy consumption while idling and then have sudden demand spikes when expected to operate. The extensive use of power electronics-based devices could make data centers a significant source of harmonics, unless filtering is designed to address those harmonics. During the transition to these higher-power pulses, the system may experience even higher harmonic distortions, voltage fluctuations causing flicker (visible, frequent changes in the brightness of lights), unbalances, or general power quality issues.

Harmonics

Traditional large industrial loads are known to be a key source of harmonic current injections into utility systems. EAFs employ power-electronic-rich devices such as rectifiers and variable speed drives, which are unbalanced and variable loads. This can lead to significant harmonic current injections, as illustrated in the example harmonic spectrum for an EAF in **Table 3.1**. In addition, inter-harmonics from these loads have the potential to excite torsional modes of nearby fossil and nuclear generation, which can damage turbine shafts.

[44] Western Interconnection Modes Review Group, "Modes of Inter-Area Power Oscillations in the Western Interconnection," WECC, 2021. Accessed: Jun. 09, 2025. [Online]. Available: https://www.wecc.org/sites/default/files/documents/meeting/2024/Modes%20of%20Inter-Area%20Power%20Oscillations%20in%20the%20WI.pdf

[45] Mishra, Chetan & Vanfretti, Luigi & Jr, Jaime & Purcell, T & Jones, Kevin. (2025). Understanding the Inception of 14.7 Hz Oscillations Emerging from a Data Center. 10.13140/RG.2.2.19971.82720. Available: https://www.researchgate.net/publication/389098360_Understanding_the_Inception_of_147_Hz_Oscillations_Emerging_from_a_Data_Center

Table 3.1: Example Harmonic Spectrum of an EAF	
Harmonic Order	**Magnitude (% of Fundamental)**
2	8.9
3	5.7
4	3.0
5	3.7
7	2.1

Large loads such as data centers are a source of harmonics due to extensive usage of power electronics in both their IT (e.g., UPS, power supplies) and cooling (variable speed drives) components. **Figure 3.11** illustrates the excessive voltage harmonics distortion caused by a data center facility and the impact of a harmonic mitigation solution. As shown in the figure, voltage distortion was greatly reduced once harmonic mitigation measures were implemented for the system.

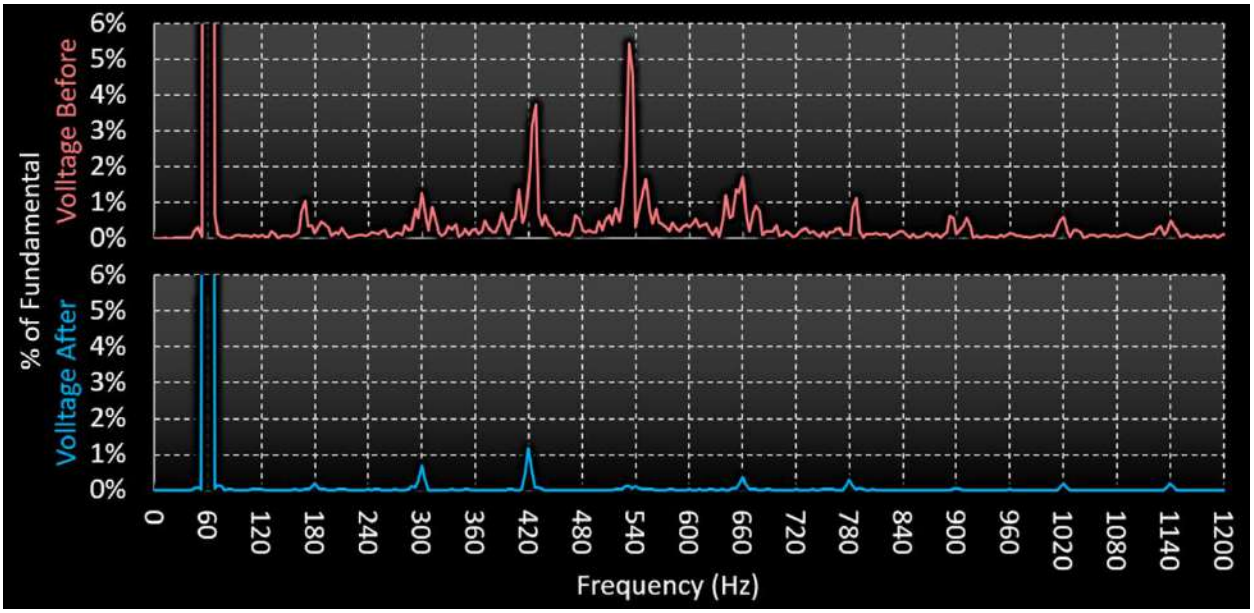


Figure 3.11: Voltage Distortion Before and After Harmonic Correction for a Data Center Facility

Some other large loads may have a variable frequency spectrum that must be accommodated for multiple operating scenarios. **Figure 3.12** provides the harmonic spectrum of a medium-frequency induction furnace (MFIF) for both starting and normal operations. Frequency spectrums will often change depending on factors including the operating mode, system configuration, and capacitor switching.

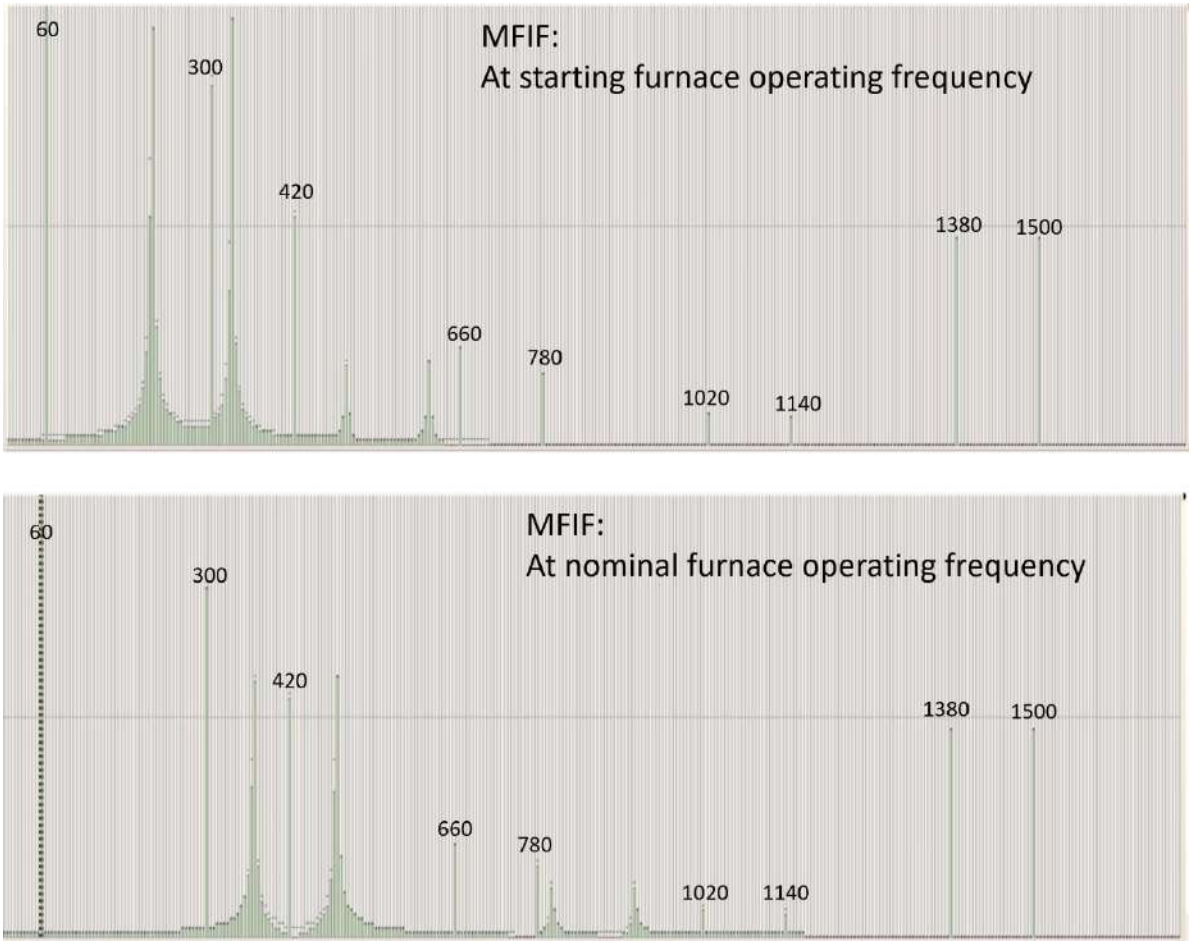


Figure 3.12: MFIF Current Spectrum for Starting and Normal Operation

Voltage Fluctuations

Traditionally, persistent voltage fluctuations resulting in excessive flicker have been a concern with large industrial loads with fluctuating power demand, such as EAFs and welders. **Figure 3.13** shows an example demand profile illustrating high variability in power demand of an EAF.

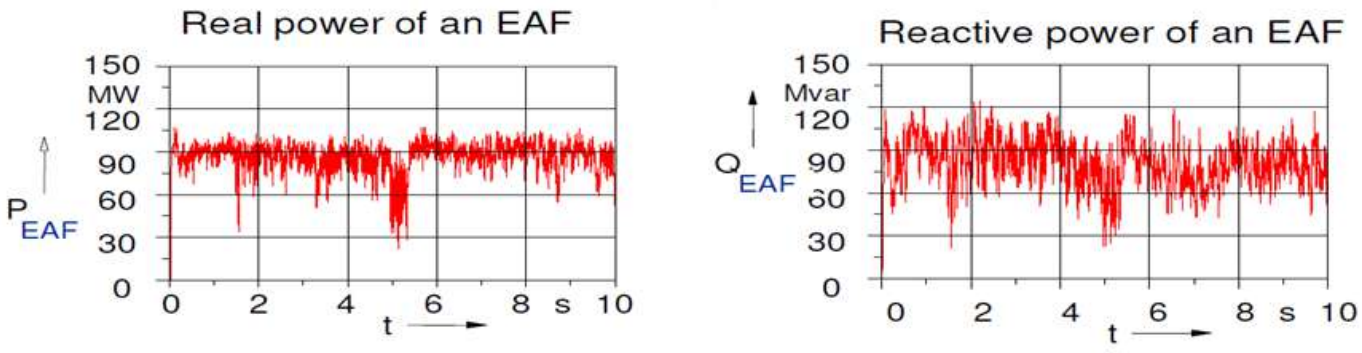


Figure 3.13: Load Profile of an Electric Arc Furnace

Some new large electric loads, such as cryptocurrency miners and AI data centers, also have the potential to introduce significant voltage fluctuations to the supply system. This can be attributed to the significant variation in the load profile of these loads. An example variable load profile of an AI data center is shown in **Figure 3.14**. This can be an issue, for example, when these loads are concentrated in regions where background flicker is already high (i.e., low

system margin) and these new loads contribute to push the overall flicker above the acceptable values. **Figure 3.15** shows an example of a data center load pulse where the doubling of the load caused voltage distortion and flicker issues for those connected to the facility.

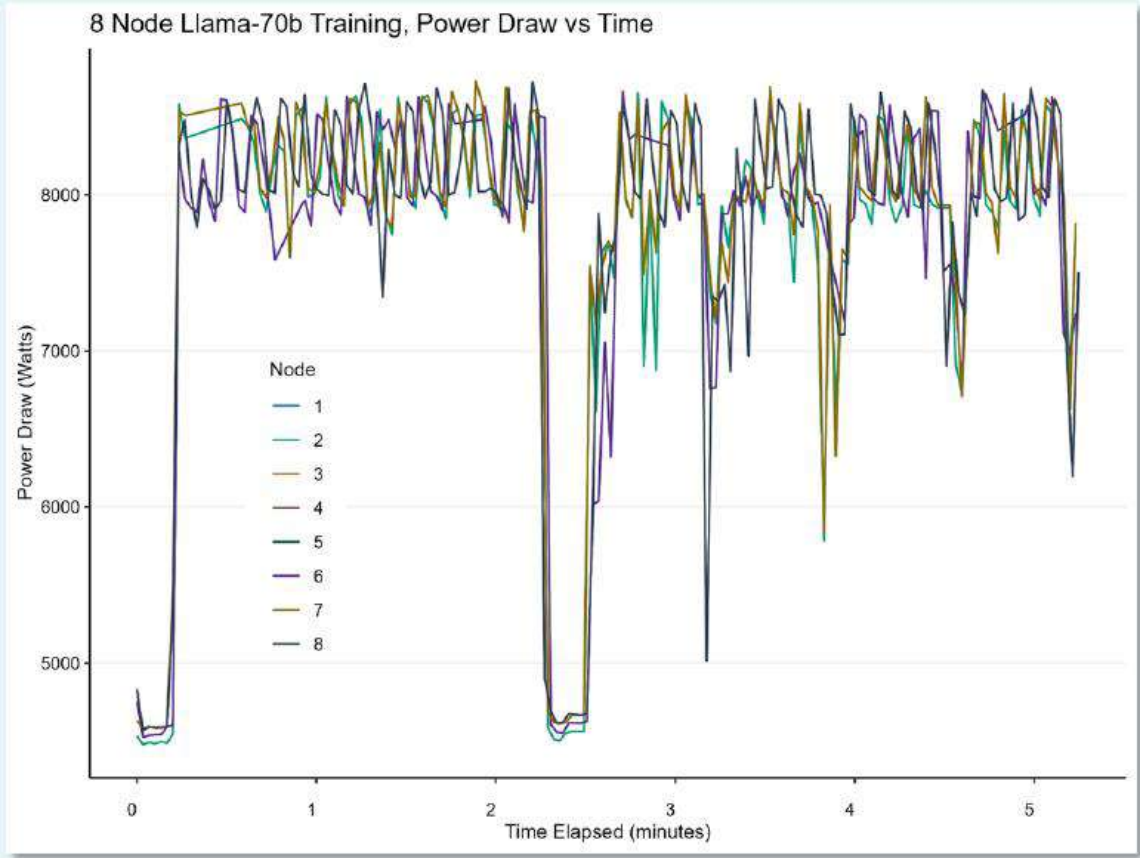


Figure 3.14: AI Training Load Profile Example

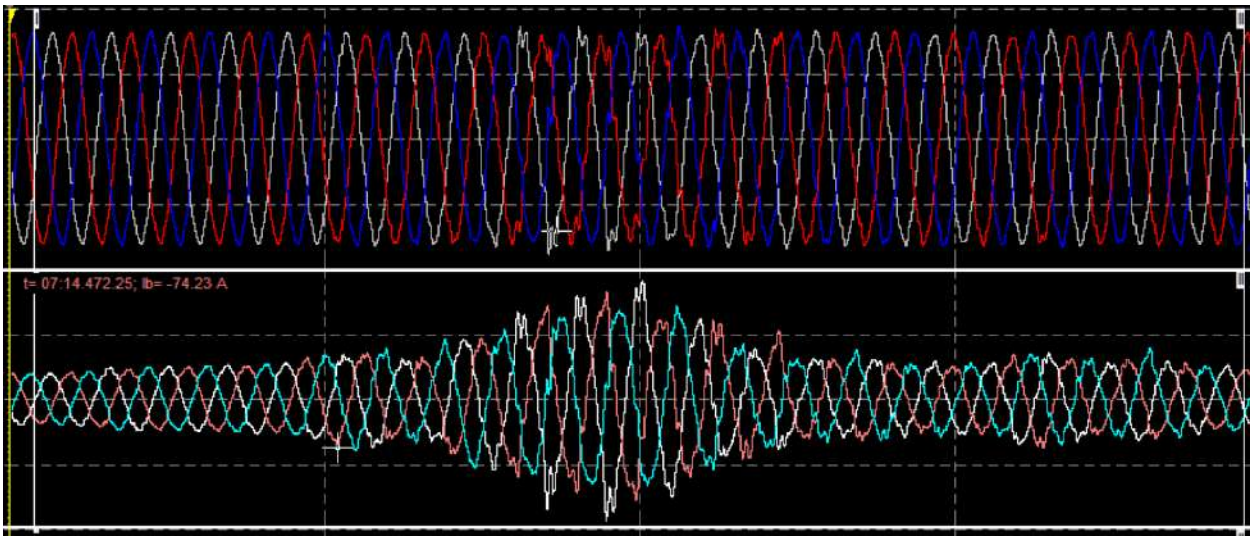


Figure 3.15: Data Center Load Pulse (Top: Voltage; Bottom: Line Current)

Voltage Sags and Transients

Voltage sags associated with normal system fault clearing have been known to result in tripping of large load facilities. In addition, transient events associated with capacitor or reactor switching in power systems have also been known to result in unnecessary tripping of large loads, resulting in significant system impact.

Physical and Cyber Security Risks

Cyber Security

This section focuses on theoretical situations and the likelihood of these sorts of attacks are not explored in this paper. The primary cyber security risks to BPS reliability from large loads are bad-actor control of large load demand (e.g. tripping or rapid ramping) and loss of critical communications between a large load and the utility.

It has been shown that some of the latest large loads may exceed 1 GW at a single site. Bad-actor control of a single site that large could affect BPS reliability. If a bad actor has control of the large load, they may be able to control the demand. The risks associated with fast ramping and sudden tripping of large loads are discussed in prior sections of the paper (e.g. Operations/Balancing and Stability).

Loss of communication between the large load and utility could cause similar issues to bad-actor control of the load. If the utility loses visibility of the large load or communications with the large load operators, it could negatively impact operations, balancing, and stability.

Load-Shedding Programs and System Restoration

Manual Load-Shed Obligation Impacts

TOs and TOPs are required to maintain load-shed and under-frequency load shed (UFLS) programs. As large loads are integrated to the system, they may add to the owner's UFLS obligation, eventually reaching a point where the owner must shed all its residential load but still cannot meet load-shed obligations. Tripping the large load could shed more load than intended, risking the stability of the system.

Automatic Under-Frequency Load-Shedding Programs

UFLS programs are the last line of defense for BPS reliability. If frequency declines below preset thresholds, and Transmission Owners have exhausted all preplanned manual load shedding options (i.e., rotating blackout), UFLS programs automatically shed load to arrest the frequency decline and stabilize the system.

Although the PRC-006-5 automatic UFLS standard calls for having a certain amount of load under automatic control to be shed, the rapid addition of large loads makes it even more important to ensure that the automatic UFLS programs are up to date and can address the presence of the new large loads on the system. The current procedure of evaluating UFLS programs every five years may not be often enough. These large loads present a risk that the local distribution system may not contain enough load to cover the UFLS requirements. TOs may need to start including load at the transmission system to meet the requirements of PRC-006.

The functionality of this "last-resort system preservation" program is assessed through studies that identify the electrical islands that may be formed under simulated conditions. The studies are used to establish the parameters of the UFLS entity automatic UFLS programs as required by the standard.

System Restoration

System restoration (blackstart) is the worst-case scenario for everyone who relies on the electric grid, especially for system operators who must restore the grid as quickly and safely as possible. Fortunately, system operators have existing procedures and train annually for this scenario.

Blackstart is an iterative process that relies on either starting a blackstart resource or building out from intact islands to re-energize transmission lines and restore load while maintaining frequency and voltage within acceptable limits. When starting from blackstart resources, transmission lines and loads are brought online iteratively, creating a small electrical island. Multiple islands are gradually connected until the entire grid is re-established. Appropriate load pickup is critical to successful restoration from a blackstart resource because small islands are more sensitive to small changes creating larger swings in voltage and frequency. It is crucial to consider the effects of cold load pickup during this process. If frequency swings too low during the load pickup, it could cause the blackstart resource or other generators to trip. The blackstart resource and other generators should be dispatched near the middle of their real power capability range to allow room to increase or decrease generation to control frequency. Additionally, high voltages could also lead to generators tripping, causing the island to collapse. A summarized example blackstart procedure is listed below.

1. First, small amounts of load (10–15 MW) are restored in a particular island.
2. As islands are stabilized (more transmission lines, more load, more units connected in the same island), the operator reviews the feasibility of connecting two islands together.
3. If connection is successful, more transmission lines, load, and units are added to the now-growing island. If not, the smaller islands must be rebuilt.
4. An island may black out even prior to connecting with another island. The most likely cause in those cases is the addition of too much load at one time—a distinct possibility in the world of new large loads.

System operators prioritize the restoration of loads based on their function, size, and location. Loads are restored in blocks that are limited by the size of the blackstart generator on isochronous control and, eventually, constant frequency control.

Two other load characteristics can affect the system restoration process as loads are restored: segmentation and demand variability. In the case of large loads, the total load of a customer may need to be portioned into smaller, manageable and predictable segments for restoration. A lack of clear, pre-determined segmentation agreed between load customer and TSP during the restoration state can cause frequency decline or voltage collapse. This can trigger UFLS and crash the island or create the need for load shed. The same is true when a restored load increases its demand without system operators' instruction.

Typically, the system operator has had finer control of load segmentation on the distribution and transmission system. However, large loads with internal segmentation raise the risk of restoring too much load too fast.

Chapter 4: Conclusion

As emerging large loads seek to swiftly interconnect to the BPS, they pose new risks to the BPS. Many current large load constructs are based on transmission facility ratings with no additional accounting for the potential impact that large loads may have on the BPS. If large loads are defined by a single number, many in the sector would choose 50 or 75 MW. However, additional characteristics should be considered in any definition of large loads. This white paper shows that in addition to peak demand, many other characteristics of emerging large loads affect their impact on BPS reliability. These characteristics include fast interconnection timelines, demand profile, load predictability, ramp rate, PELs, voltage sensitivity, and internal segmentation. In addition to the characteristics of the load, the system characteristics also affect what a "large load" means. Frequency stability depends heavily upon interconnection-wide properties like inertia and on-line generation. These interconnection-wide characteristics vary greatly in North America. Additionally, risks like voltage instability may be more dependent on local system properties, like available reactive power from nearby equipment.

Large loads pose risks in both the planning and operations horizons. Their quick interconnection timelines and large peak demands drive generation and transmission adequacy risks. The fast ramp rates and variability of the loads could exhaust reserves for balancing and contribute to voltage and frequency instability. If system planners and operators lack accurate dynamic models, they may be unable to predict ride-through and system behaviors during events. Much of the PEL load can contribute to harmonics and voltage fluctuations. Large loads like data centers can also be susceptible to cyber-attacks that could trigger load ramps. Additionally, the rapid pace of load integration with large loads' magnitude could negatively impact system resilience. Large loads must be considered in load-shed obligations, UFLS program design, and blackstart restoration.

To understand how these risks align with the unique characteristics of large loads discussed in this white paper, see **Appendix B: Comparison of Characteristics and Risks**.

Given the multitude of risks posed by large loads, it is recommended that the risks be prioritized in the order shown across the following three tables. NERC's Framework to Address Known and Emerging Reliability and Security Risks states that prioritization of risks is accomplished through analysis of their exposure, scope, and duration as well as impact and likelihood.

High-Priority Risks	
Long-Term Planning	Resource Adequacy
Operations/Balancing	Balancing and Reserves
Stability	Ride-through
	Voltage Stability
	Angular Stability
	Oscillations

Medium-Priority Risks	
Operations/Balancing	Short-Term Demand Forecasting
	Lack of Real-Time Coordination
Long-Term Planning	Demand Forecasting
	Transmission Adequacy
Stability	Frequency Stability
Security Risks	Cyber Security
Load Shedding Programs & System Restoration	Manual Load-Shed Obligations
	Automatic UFLS Programs

Low-Priority Risks	
Power Quality	Harmonics
	Voltage Fluctuations
Load Shedding Programs & System Restoration	System Restoration

Finally, NERC would like to formally thank all the industry experts, from utilities, regulators, national labs, government agencies, and data center developers/operators/owners, who contributed to this white paper. The names of individual contributors and their organizations are provided in **Appendix C: Acknowledgements**.

Appendix A: Large Load Construct Data

Table A.1: Summary of Large Load Constructs			
Region/Entity	**Threshold**	**Rationale**	**Classification**
ERCOT	75 MW	Above 75 MW, a transmission upgrade is likely needed to serve the full load.	Peak Demand
NYISO	10 MW at 115kV or above, or 80 MW below 115kV	These loads could impact the New York state transmission system and need to be evaluated to determine their responsibility for upgrades required to reliably interconnect to the NY State Transmission System.	Peak Demand and Voltage Level
Dominion	100 MW	Above 100 MW, a ring bus configuration is needed per Facility Interconnection Requirements.	Peak Demand
Grant PUD	2 MVA for large, and 40 MVA	2 MVA is the largest secondary service transformer and 40 MVA is the largest transformer size available and requires additional or new substation work. Above 40 MVA may require transmission service.	Peak Demand
Portland General Electric	1 MW, 30 MW	The primary drivers are rate and cost allocation. At 1 MW or greater, there can potentially be an impact on feeder mainline or substation vs. a simple line extension for smaller load. Load at 30 MW aligns with the typical distribution substation transformer loading criteria.	Peak Demand
PacifiCorp	1 MW	Currently driven by tariffs.	Peak Demand
SRP	10 MW, 150 MW	At 10 MW or greater a dedicated substation off of 69 kV system is required. At 150 MW or above, a 230 kV connection is needed.	Peak Demand

Appendix B: Comparison of Characteristics and Risks

Table B.1 shows a mapping of potential large load characteristics to the risk that it causes or is related to. Large loads can be categorized, as shown in Chapter 2:. It should be noted that each large load may have a unique mix of characteristics. Additionally, each characteristic may have different thresholds for causing risks depending on the system and local area it connects to.

Table B.1: Large Load Characteristics and Risks Mapping

Risks	Characteristics								
	Peak Demand	Fast Interconnection Timelines	Demand Profile	Load Predictability	Ramp Rate	Load Type (PEL)	Voltage Sensitivity (Ride-through)	Inaccurate Dynamic Models	Internal Segmentation
Inaccurate Long-Term Forecasts	X	X		X					
Steady State Thermal and Voltage Violation	X		X	X	X		X		
Insufficient Generation Adequacy	X	X		X					
Inaccurate Short-Term Forecasts			X	X	X	X	X		
Balancing Reserves Shortage		X	X	X	X	X	X		
Voltage Instability	X		X		X	X	X	X	
Frequency Instability	X				X		X	X	
Oscillations			X	X		X		X	
Harmonics			X			X			
Insufficient UFLS Procurement	X	X							X
Insufficient Load Shed Obligations	X	X		X					
Loss of Blackstart Islands				X			X		X

Appendix C: Acknowledgements

This white paper was developed by a significant number of contributors from the NERC LLTF. The LLTF would like to acknowledge and thank the following individuals for their support in drafting this white paper.

Table C.1: Contributors

Name	Company
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Incident Review

Considering Simultaneous Voltage-Sensitive Load Reductions

Primary Takeaways

Operators and planners of the Bulk Electric System (BES) should be aware of the risks and challenges associated with voltage-sensitive large loads that are rapidly being connected to the power system. Specifically, when considering data centers and cryptocurrency mining facilities, entities should be aware of the potential for large amounts of voltage-sensitive load loss during normally cleared faults on the BES. Voltage-sensitive data center-type loads have increased on the system and are predicted to continue growing rapidly. The 2024 NERC *Long-Term Reliability Assessment* (LTRA) documents and discusses this potential growth of data center-type loads. This vignette highlights this load-loss potential based on analysis of a recent event in the Eastern Interconnection and offers some considerations for BES operators, planners, and regulators concerning identifying and mitigating the potential reliability effects and risks presented by these large voltage-sensitive load losses for future operations.

Summary of Incident

A 230 kV transmission line fault led to customer-initiated simultaneous loss of approximately 1,500 MW of voltage-sensitive load that was not anticipated by the BES operators. The electric grid has not historically experienced simultaneous load losses of this magnitude in response to a fault on the system, which has historically been planned for large generation losses but not for such significant simultaneous load losses. Simultaneous large load losses have two effects on the electric system: First, frequency rises on the system as a result of the imbalance between load and generation; second, voltage rises rapidly because less power is flowing through the system. In this incident, the frequency did not rise to a level high enough to cause concern. The voltage also did not rise to levels that posed a reliability risk, but operators did have to take action to reduce the voltage to within normal operating levels. However, as the potential for this type of load loss increases, the risk for frequency and voltage issues also increases. Operators and planners should be aware of this reliability risk and ensure that these load losses do not reach intolerable levels.

Incident Details

At approximately 7:00 p.m. Eastern on July 10, 2024, a lightning arrestor failed on a 230 kV transmission line in the Eastern Interconnection, resulting in a permanent fault that eventually “locked out” the transmission line. The auto-reclosing control on the transmission line was configured for three auto-reclose attempts staggered at each end of the line. This configuration resulted in 6 successive system faults in an 82-second period. The protection system detected these faults and cleared them properly. The shortest fault duration was the initial fault at 42 milliseconds, and the longest fault duration was 66 milliseconds. The voltage magnitudes during the fault ranged from .25 to .40 per unit in the load-loss area.

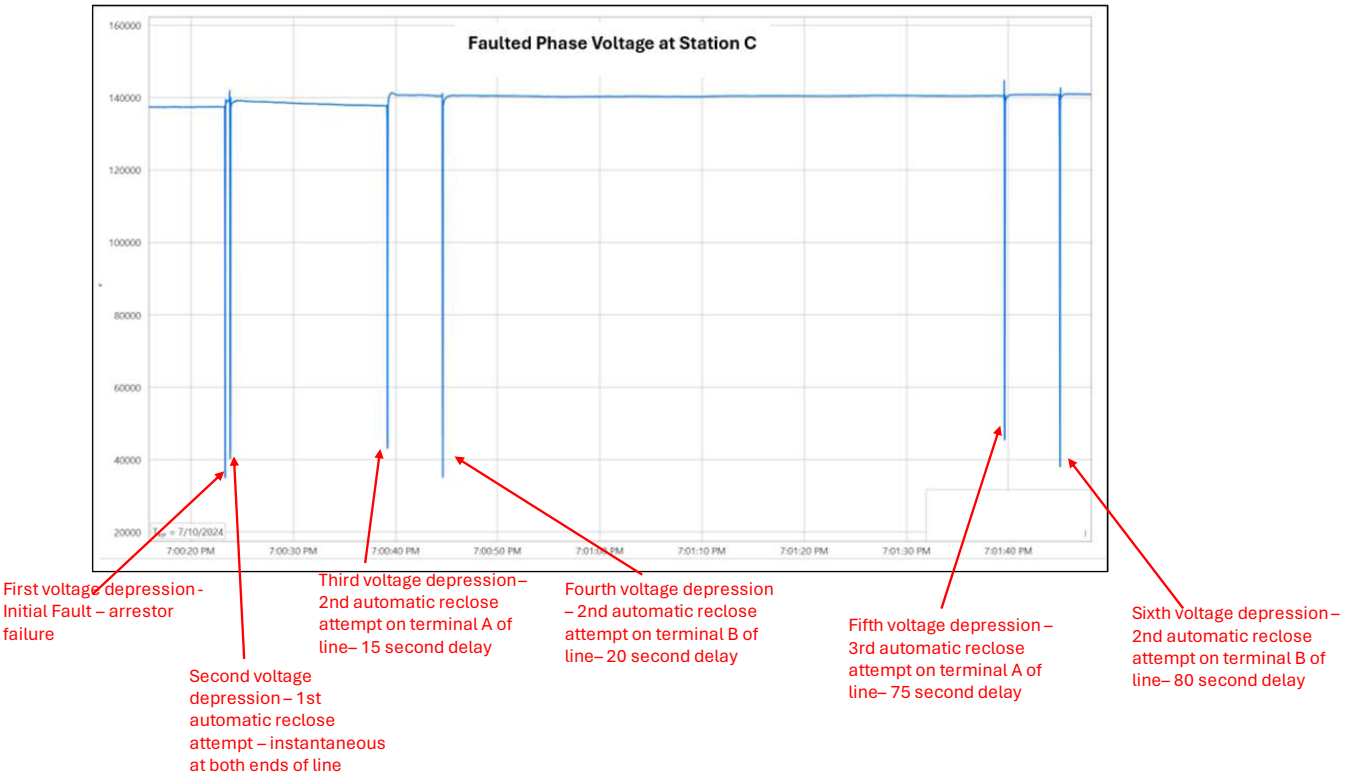


Figure 1: Faulted Phase Voltage

Table 1: Voltage Depression Times and Durations

		Voltage Depression Time (hh:mm:ss.msec)	Voltage Depression Duration (milliseconds)
Voltage Depression 1	Initial Fault (arrestor failure)	19:00:23.351	42
Voltage Depression 2	Instantaneous and simultaneous automatic reclose at both terminals	19:00:23.883	66
Voltage Depression 3	2nd Automatic reclose at terminal A	19:00:39.211	58
Voltage Depression 4	2nd automatic reclose at terminal B	19:00:44.630	50
Voltage Depression 5	3rd automatic reclose at terminal A	19:01:39.600	66
Voltage Depression 6	3rd automatic reclose at terminal B	19:01:45.016	59

Coincident with this six-fault disturbance, the same local area saw an approximate 1,500 MW of load reduction. None of this load was disconnected from the system by utility equipment; rather, the load was disconnected on the customer side by customer protection and controls. It was determined that the 1,500

MW of load reduction was exclusively data center-type load. The area where the disturbance occurred has a high concentration of data center loads.

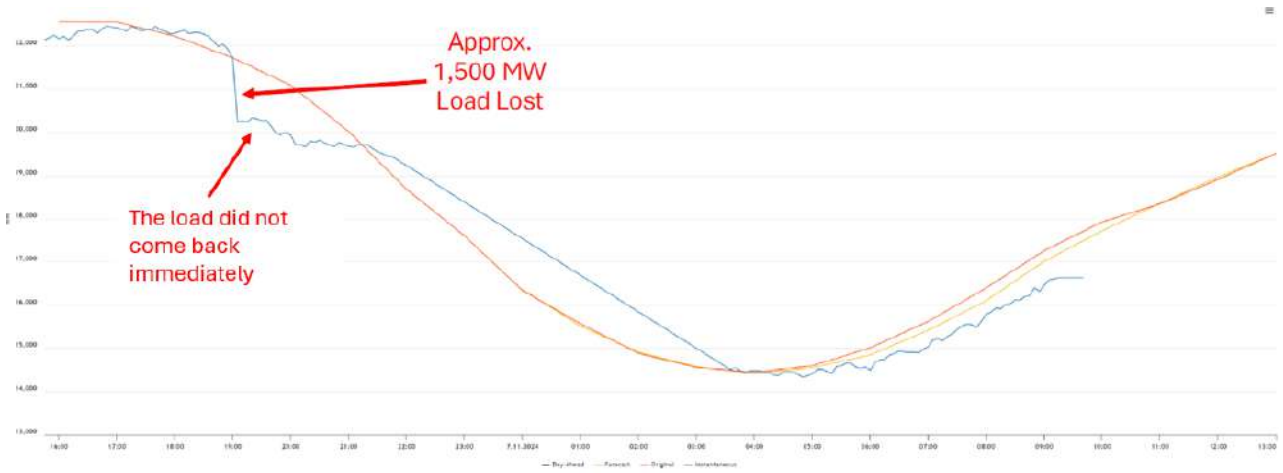


Figure 2: System Load Chart

Frequency and voltage rose due to the load loss. Frequency rose to a high of 60.047 Hz and settled back to 60.0 Hz in approximately 4 minutes. At the highest level, voltage rose to 1.07 per unit. Operators removed shunt capacitor banks in the local area to return voltages to normal operating values.

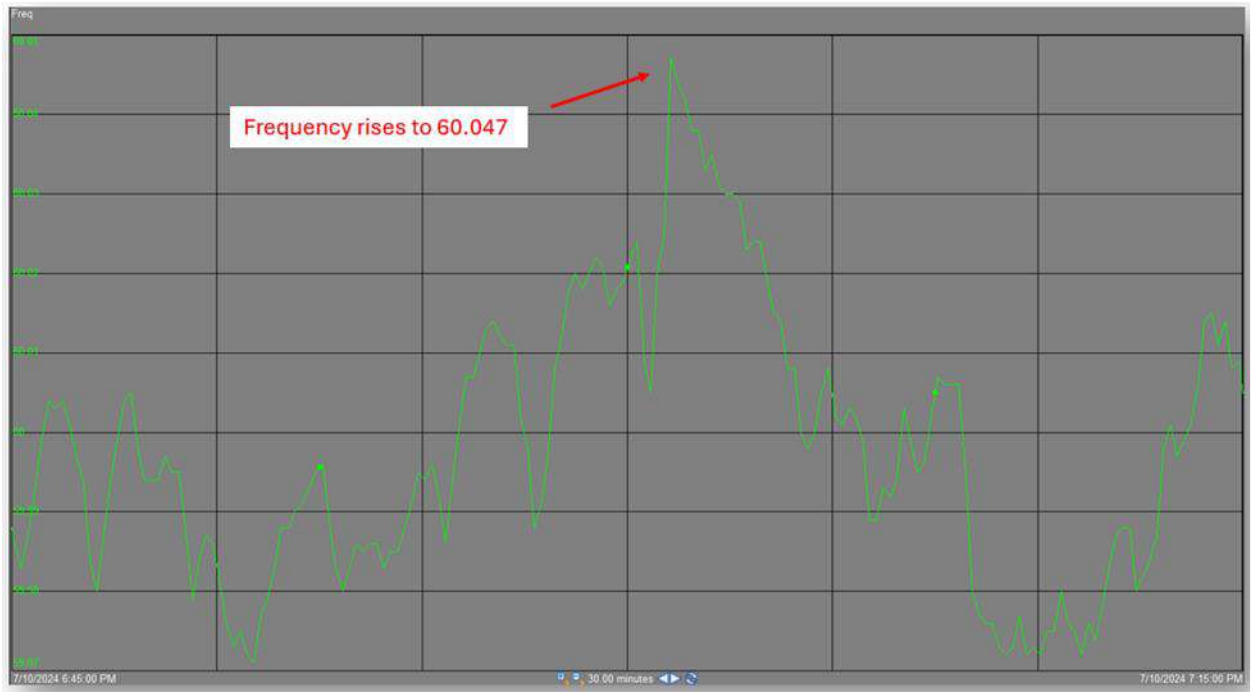


Figure 3: Frequency at Time of Load Loss

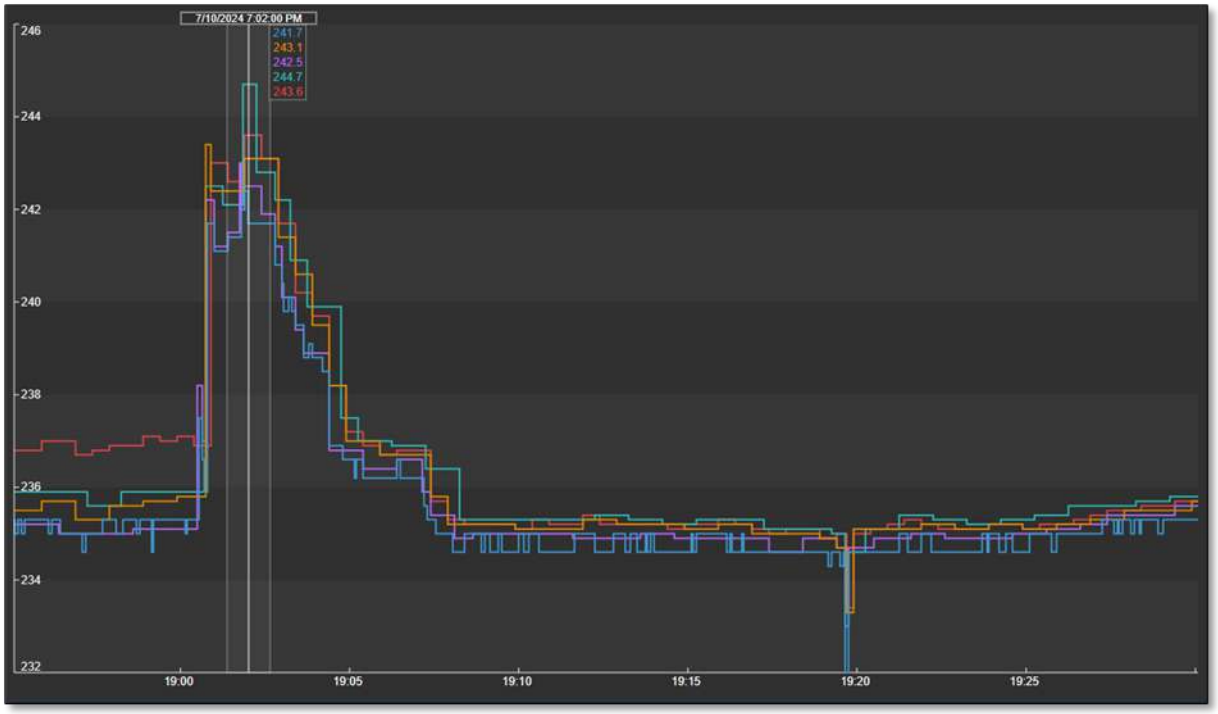


Figure 4: 230 kV Voltages

Load Details

Discussions were held with data center owners to understand the specific cause of their load reductions. It was determined that the data centers transferred their loads to their backup power systems in response to the disturbance. Data center loads are sensitive to voltage disturbances. The data center protections and controls are designed to avoid equipment outages for voltage disturbances. In addition to the computer equipment at these facilities, cooling equipment is also critical to the operation of the data center and sensitive to voltage disturbances. To ride through voltage disturbances on the electric grid, data centers employ uninterruptible power supply (UPS) systems that will instantaneously take over providing power to the data center equipment when a grid disturbance occurs. The differing types and designs of these UPS systems cause differences in the characteristics of the data center responses to a voltage disturbance. A centralized design uses UPS systems at the load-center level that are typically in the range of 2–5 MWs. The UPS uses power electronics to switch the load to a battery bank connected to the UPS. These battery banks are not designed to supply the load for long periods of time but rather to power the load for the short time periods of disturbances or—in the case of a complete electric grid outage—long enough to start a backup generator that will then provide power to the UPS. The decentralized UPS design uses many smaller UPSs at the rack level. These rack-mounted UPSs are typically in the range of 3–4 kW. The decentralized UPS systems operate similarly to the centralized UPS systems, just on a smaller scale. Another type of UPS is a dynamic/diesel rotary uninterruptible power supply (DRUPS). These systems use a flywheel to provide uninterruptible power and a clutch system to quickly start and connect a diesel engine upon a disturbance on the electric grid.

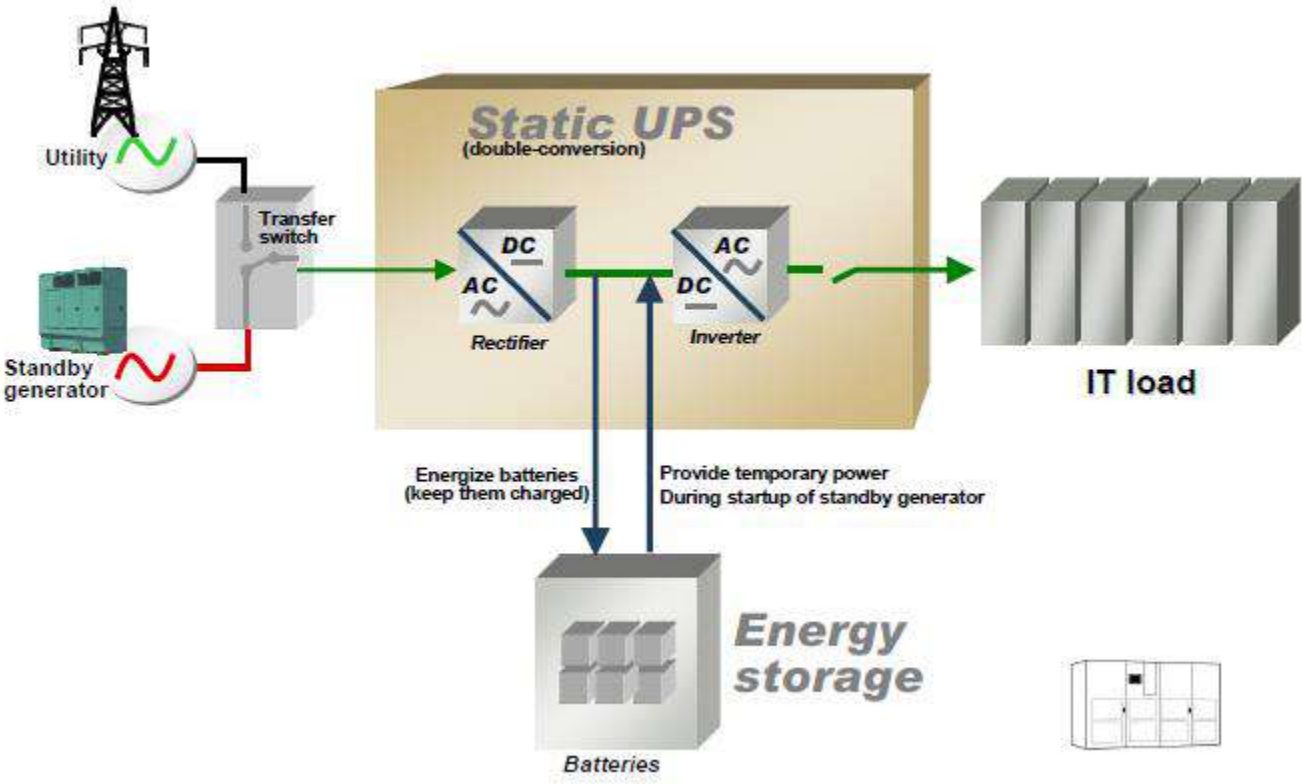


Figure 5: Static Centralized UPS
[Source: Schneider Electric White Paper 92]

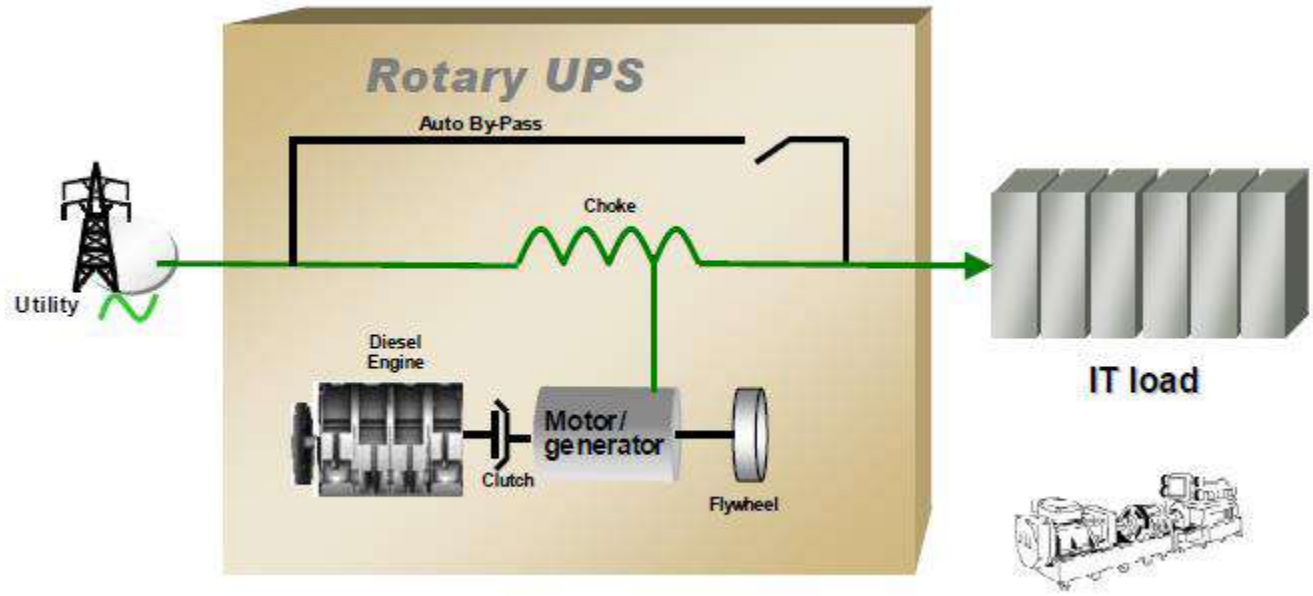


Figure 6: DRUPS
[Source: Schneider Electric White Paper 92]

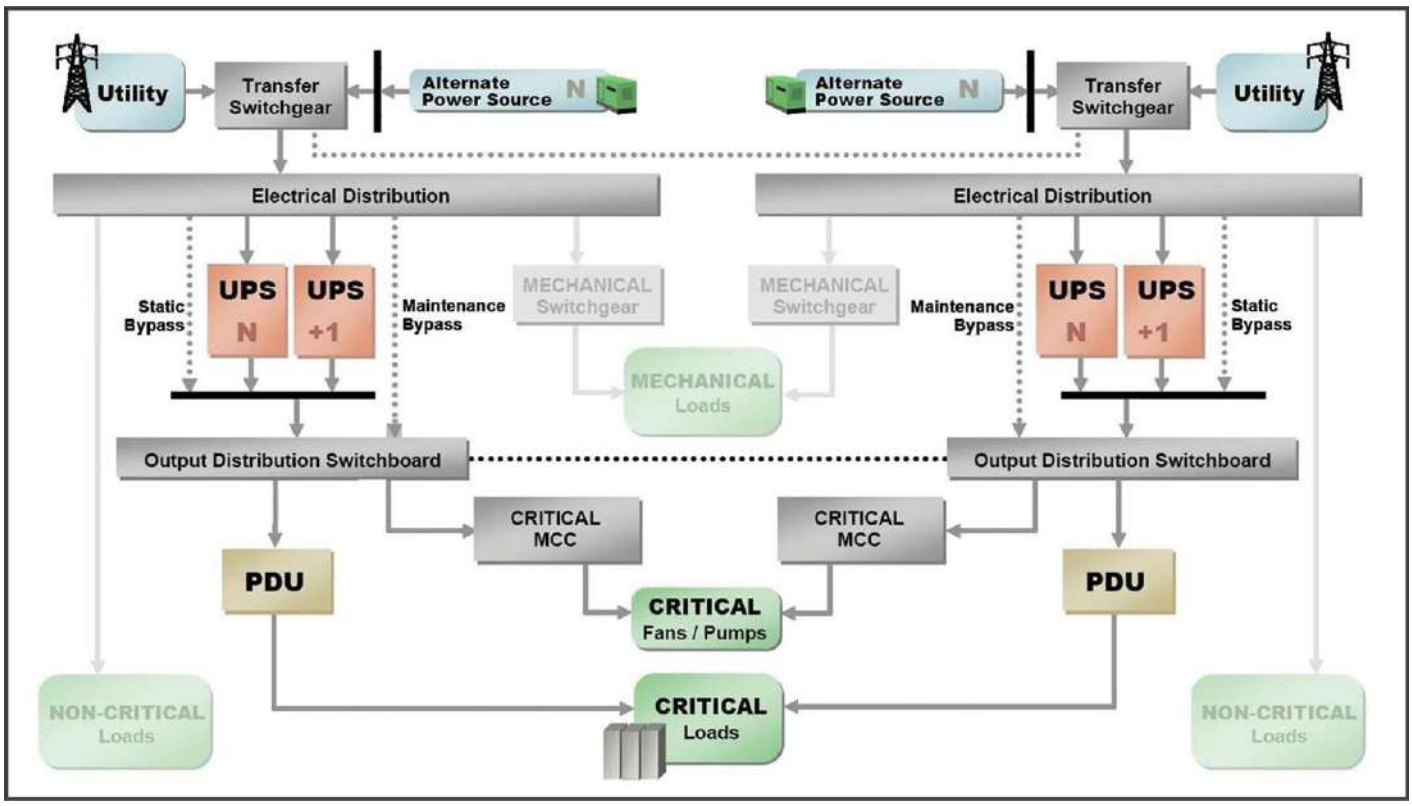


Figure 7: Typical Centralized UPS Power Distribution
[Source: Uptime Institute Journal]

The load characteristics of these types of UPS systems differ in response to a transient disturbance on the electric grid. For the static centralized and decentralized UPS systems that utilize batteries, the load will be taken over by the battery when the transient voltage disturbance occurs. Since it is a transient disturbance, such as a temporary fault on the electric grid, the grid voltage will typically return to normal in milliseconds. Once the grid voltage returns to normal, the load will then be transferred back to the grid. A typical load characteristic for these types of static UPS systems, as seen by the grid, is shown in **Figure 8**. Upon detecting the transient voltage disturbance, the DRUPS system will immediately transfer the load to the flywheel/ac generator and start the engine that will act as the prime mover for the generator before the flywheel exhausts its kinetic energy. This system will not quickly transfer the load back to the grid after the transient disturbance has cleared and the grid voltage returns to normal. Typically, transferring the load back to the grid from the DRUPS system must be done manually. A typical load characteristic for a DRUPS system, as seen by the grid, is shown in **Figure 9**. As can be seen in these figures, the typical static UPS system load characteristic, as seen by the grid, is a short-duration loss of load that returns quickly after the transient disturbance clears. The typical DRUPS system load characteristic, as seen by the grid, is a loss of load that does not return quickly after the transient disturbance clears.

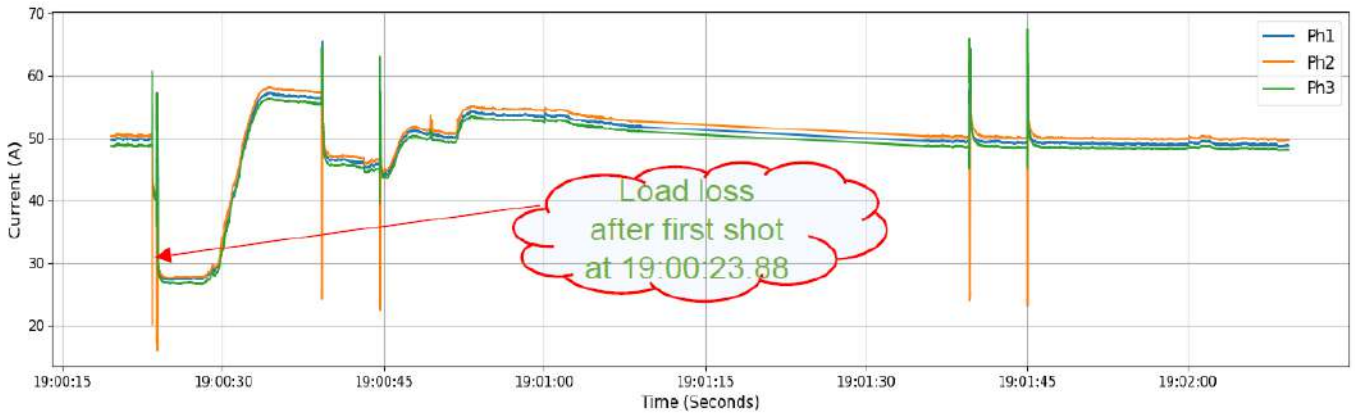


Figure 8: Static UPS Load Characteristic



Figure 9: DRUPS Load Characteristic

Discussions with the data center owners also identified another protection/control scheme that impacts the response of data center load to voltage disturbances on the grid. The scheme detects and counts voltage disturbances on the grid. If a certain number of voltage disturbances are seen within a certain time, the data center will transfer its load to the backup system, and it will remain there until it is manually reconnected to the grid. The typical number of voltage disturbances that trigger this scheme is three, and a typical time is one minute. As such, three voltage disturbances within one minute will result in data centers using this protection/control scheme transferring their load off the grid and staying off until they manually transfer back. This scheme can be deployed on both centralized and decentralized UPS designs. A load characteristic for this type of data center control scheme can be seen in **Figure 10**.

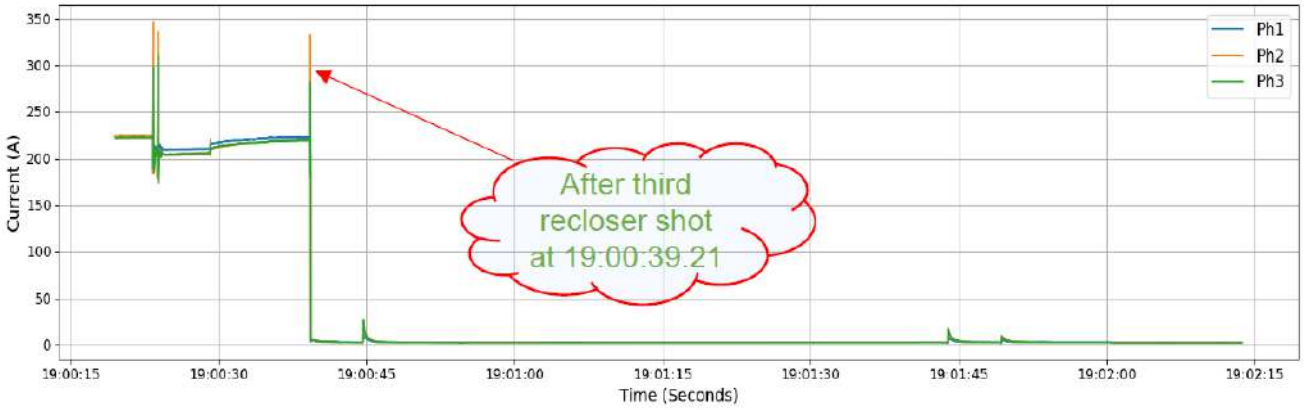


Figure 10: Voltage Disturbance Counting Scheme Load Characteristic

While these three load characteristics were predominant in this event, many load characteristic variations exist. These characteristics are determined by the numerous vendor-supplied equipment controls within the data center, including the vendor-specific UPS controls. Additionally, controls under the purview of data center owner/operators, such as a certain number of disturbances within a certain period of time, also determine the characteristic response to system disturbances.

Most of the sustained load reduction occurred simultaneously with the third voltage depression, which coincided with the third automatic reclosing attempt. At that time, approximately 1,260 MW of load dropped off the electric grid and did not return for hours. Most of the load loss in this event can be attributed to the interaction between the automatic reclosing sequence on the faulted transmission line and the data center's protection/control scheme that counts the number of voltage disturbances within a specified period of time.

While this incident did not present any significant issues with the reconnection of the large loads, the potential exists for issues in future incidents if the load is not reconnected in a controlled manner. Significant amounts of load being reconnected to the system present challenges to Balancing Authorities (BA) and Transmission Operators (TOP). Ramp rates for load connection are just as critical to system operations as generation ramping. Voltage management and maintaining balance between load and generation are considerations that need to be given for load reconnection ramp rates.

This incident has highlighted potential reliability risks to the BES with respect to the voltage ride-through characteristics of large data center loads. Similar incidents have occurred in other Interconnections with cryptocurrency mining loads as well as oil/gas loads. While these loads are different than the data center loads in this incident, they present the same challenges to the operators and planners of the BES. Understanding the changing dynamic nature of load is critical to the future operation of the BES.

Future Considerations

While this disturbance did not cause significant operating issues with the grid at this location and at this time, as data center loads continue to grow rapidly, the risk could quickly increase. Actions that TOPs and Transmission Planners (TP) should start taking to avoid significant issues in the future are listed below:

- Require dynamic response models of large loads in their facility interconnection requirements

- Perform studies to determine the potential magnitude of load loss for system disturbances (faults)
  - Study the impact that these large load losses would have on the system
- Take into consideration the potential for voltage-sensitive load loss when configuring automatic reclosing schemes
- Actively monitor to detect load losses coincident with system faults
- TOPs: Ensure that operating agreements with large loads include ramp rates when connecting/reconnecting large loads to the system
- Critical questions that must be resolved:
  - Should large loads be a NERC registered entity?
  - Should NERC Reliability Standard modifications be developed for large load interconnection requirements?
  - What studies should TOPs perform to "consider" the impacts of large load operation?
  - What is the definition of a large load?

Transmission Owners (TO), TOPs, TPs, and large-load owners will have to work collaboratively to identify and mitigate reliability risks posed by large load losses during system faults. The NERC Large Load Task Force (LLTF) is one group where this type of collaboration can take place.

For more information, please contact:
NERC – Event Analysis

Date of Publication: January 8, 2025

2026 State of Reliability

Assessment Overview of 2025 Bulk Power System Performance

June 24, 2026

2026 SOR Snapshot

2026 SOR Technical Assessment

Table of Contents

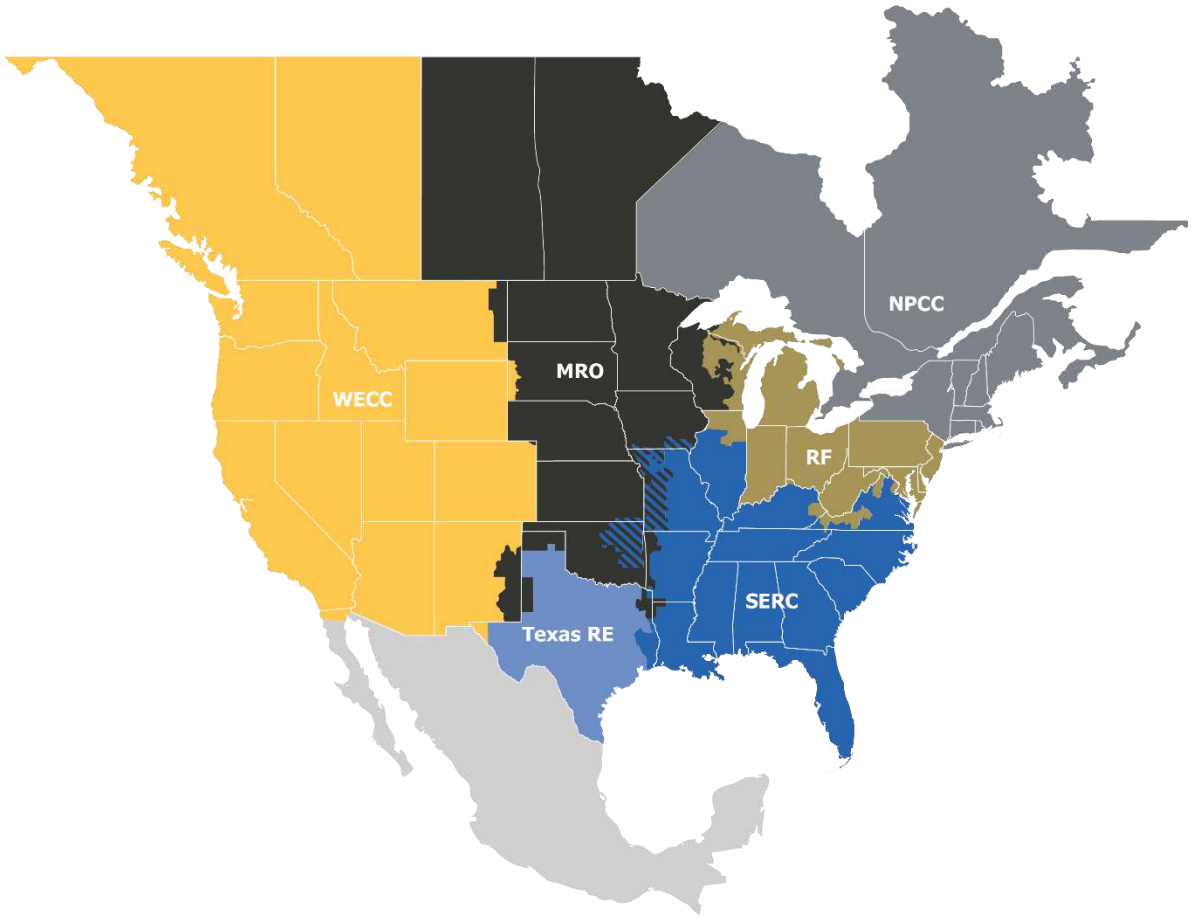
Preface iii
About This Overview iv
Development Process iv
Considerations iv
Executive Summary v
Reliability Indicators v
Emerging Trends vi
Conventional Generation Forced Outage Rates Up 1
Analysis of 2025 Weighted Equivalent Forced Outage Rate 1
Related Actions 4
Recommendations 4
Demand Growth and Large Load Integration Challenges Continue 5
Related Actions 6
Existing and Ongoing Efforts 6
Recommendations 8
Resource Mix Transformation 9
IBR Reliability Considerations 9
IBR-Related Actions 9
Existing and Ongoing Efforts 9
BESS Reliability Considerations 11
Unique Failure Event 12
Load Curve Smoothing 12
Frequency Response Impacts 13
BESS-Related Actions 13
Recommendations 13
Industry Mitigation Actions 14

Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Overview

NERC delivers the *State of Reliability* (SOR) as a two-part report that consists of the *2026 SOR Overview* and the *2026 SOR Technical Assessment*.[1] The *2026 SOR Overview* serves as a high-level summary of the most important and actionable topics impacting the BPS and how they are being addressed, while the *2026 SOR Technical Assessment* provides NERC's comprehensive annual analytical review of BPS reliability for the 2025 calendar year. The analysis within the SOR report fulfills a key role in NERC's mission by providing an unbiased, data-driven look at the BPS's reliability, identifying ongoing challenges, and informing future-looking assessments. This overview seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describes the actions that the ERO Enterprise has taken, and will take, to address them.

Development Process

ERO staff developed this overview and the corresponding *2026 SOR Technical Assessment* with support from the Performance Analysis Subcommittee (PAS). Both documents draw conclusions from an established set of reliability indicators and mandatory information reported by industry to the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), voluntary reporting into the Event Analysis Management System (TEAMS), Bulk Power System Awareness monitoring and processes, the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group, and other sources as available.

Considerations

- Data in the SOR represents the performance for the January–December 2025 operating year unless otherwise noted.
- Analysis in this report is based on data from 2021–2025 that was available in Spring 2026 and provides a basis to evaluate 2025 performance relative to performance from the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- The SOR is a review of industry-wide trends—not a review of the performance of individual entities.
- When analysis is presented by Interconnection, the Québec Interconnection is combined with the Eastern Interconnection unless specific analysis for the Québec Interconnection is shown.

[1] NERC SOR 2026 Technical Assessment

Executive Summary

The North American BPS continues to deliver reliable electric service under increasingly challenging conditions. Key performance indicators remain stable overall even as the system experiences rising demand growth, more frequent extreme weather events, and significantly higher penetrations of inverter-based resources (IBR).

At the same time, the report highlights a critical shift in the nature of reliability risk. Many of the emerging concerns facing the system are no longer driven by single contingencies or localized disturbances but by correlated and system-wide stresses, including energy limitations, operational challenges associated with maintaining reliability in lower-inertia systems, and declining availability of aging combustion generation. Although fuel supply uncertainty and extreme weather exposure were not major drivers in this year's assessment, they remain subject to ongoing monitoring given their continuing potential to affect reliability. The findings emphasize that continued reliability success will depend not only on maintaining infrastructure and resource adequacy but also on improving industry's ability to anticipate, model, and manage these evolving risks before they manifest as reliability events.

While the SOR focuses on historical occurrences in the past year, it is also important to recognize future resource adequacy concerns. NERC's forward-looking *Long-Term Reliability Assessment*[2] and related non-NERC reports[3] continue to highlight that generation development has not and is not expected to keep pace with needs as new projects face delays and cancellations due to supply chain constraints, changing economies, and increasing grid upgrade costs. Similarly, while existing transmission performance continues to improve, its development, particularly of major interstate lines, is not advancing at a pace that can adequately support future reliability needs.

Reliability Indicators

Table 1 provides an overview of key performance measures of the BPS that compares 2025 performance to the previous four years. The results show that while a majority of these measures continue to improve or remain stable, several indicators are identified for monitoring or further attention, highlighting areas that warrant industry focus. The table is intended to contextualize known and emerging trends and areas of operational focus to help stakeholders understand where reliability risks may be evolving or re-emerging as the grid continues to transform.

[2] Long-Term Reliability Assessments
[3] MISO *2026 Reliability Imperative Report*

Table 1: Reliability Indicators[4]			
Improving	**Stable**	**Monitor**	**Actionable**
Frequency Response: Eastern, Texas, and Western Interconnections	**Frequency Response:** Québec Interconnection	**Winter Reserve Margin:** NPCC Maritimes	**Inertia and Rate-of-Change-of-Frequency:** Québec Interconnection[5]
Inertia and Rate-of-Change-of-Frequency: Eastern, Texas, and Western Interconnections	**Protection System Misoperations Rate**	**Transmission-Related Events Resulting in Loss of Load:** Supported by Event Analysis Data	
Energy Emergency Alerts	**Transmission Outages Caused by Failed Protection System Equipment:** AC Circuits	**Interconnection Reliability Operating Limit (IROL) Exceedance**	
Transmission Outages Caused by Failed Protection System Equipment: Transformers	**Automatic AC Transmission Outages Caused by Failed AC Substation Equipment:** AC Circuits	**Transmission Outages Caused by Failed AC Substation Equipment:** Transformers	
Automatic Transmission Outage Events Involving Human Error: AC Circuits and Transformers	**Transmission Element Availability:** AC Circuits	**Transmission Element Availability:** Transformers	
Transmission Outages Caused by Failed AC Circuit Equipment	**Transmission Outage Severity**		
	Transmission Physical Security Metric		

Emerging Trends

While the BPS remains reliable and continues to perform well operationally, underlying reliability risk is increasing and changing in nature; the margin for error continues to decrease while dependence on operational mitigations increases.

NERC's analysis in the SOR report also identifies several important emerging trends:

1. **Conventional generation forced outage rates are up.**
   The report identifies a meaningful increase in conventional generator forced outage rates in 2025, with annual weighted equivalent forced outage rates (WEFOR) increasing to 9.2% compared to historical norms rarely exceeding 8%. Coal and combined-cycle units were the primary drivers of this increase with an increase of over 39.8 TWh and 19.1 TWh of unavailable energy year over year, respectively. In contrast to recent years' generation challenges, operational performance during the

[4] Some metrics are evaluated for multiple sub-topics. These metrics are either listed multiple times, with the different sub-topics beneath the bolded metric name (e.g. different interconnections for Frequency Response), or the criteria driving the overall status is listed (e.g. NPCC Maritimes causing Winter Reserve Margin to have the Monitor status).

[5] The Québec Interconnection has been experiencing low hydraulicity conditions since 2023. In 2025, this resulted in reduced energy exports and increased energy imports. Therefore, fewer hydro generating units were synchronized within the Interconnection, particularly under summer light-load conditions, leading to lower system inertia during this period. These conditions have been cyclical historically and are expected to improve in the coming years.

most challenging winter week of 2025[6] improved as industry winterization efforts continued. Instead, the reduction in availability was distributed throughout the year, suggesting a broader baseline degradation in much of the coal and combined-cycle fleets' performance.

2. **Demand growth and large load integration continue challenging operators.**
   Projected annual energy demand rose to nearly 4.95 million GWh in 2025, while actual summer peak demand in several areas approached or exceeded the normal forecast. Data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics. In 2025, two instances of data center customer-initiated load reduction (CILR) exceeded 1,000 MWs, with many more exceeding 100 MWs. NERC continued to work with the electric and data center industries to issue new alerts, host technical conferences, perform standards work, and offer large load guidance activities, reflecting the growing importance of load modeling, operational coordination, and frequency response impacts associated with these rapidly growing loads.

3. **Resource mix transformation is fundamentally changing system operations and reliability management.**
   Solar, wind, and battery energy storage systems (BESS), all IBRs, continued to expand rapidly in 2025, with BESS growth approximately matching solar growth. In several peak demand periods, solar and/or wind production materially exceeded planning assumptions and supported system operations during stressed conditions. Additionally, BESS continued to demonstrate the capability to provide rapid frequency response. At the same time, IBRs are increasing operational complexity associated with inertia, protection systems, dynamic performance, and disturbance response. NERC continued extensive IBR mitigation work in 2025 and early 2026, including new technical requirements related to IBR performance, ride-through capability, and model validation.

4. **Industry mitigation actions are tracking well in many foundational reliability areas.**
   The *2026 SOR Technical Assessment* also documents continued improvement in several important controllable reliability metrics, including overall transmission system outage severity, protection system misoperations, failed protection-system-related outages, and transmission-related loss-of-load events.

[6] Comparisons across winter storm events should be interpreted with caution, as outage risk remains elevated and storm impacts vary significantly by the area impacted, duration, system condition, and event severity.

Conventional Generation Forced Outage Rates Up

Forced outage performance is a foundational indicator of BPS reliability because it illustrates the ability of generating resources to perform daily as well as when they are most needed, during periods of high demand, stressed system conditions, and extreme weather. While reserve margins and accredited capacity metrics provide a static view of resource sufficiency, an analysis of year-over-year forced outage rate changes provides insights into the availability of the conventional resource fleet, revealing trends in outage behavior and emerging reliability vulnerabilities.

Analysis of 2025 Weighted Equivalent Forced Outage Rate

Our 2025 analysis of the conventional GADS[7] revealed an increase in reported units' annual WEFOR[8] to 9.2%, which is higher than the historical norms of 7–8% (see **Figure 2**). This increase was not the result of any particular event but an increase distributed across most months throughout the year, with three months' WEFORs being comparable to the months when winter storms Elliott and Uri occurred. The lack of specific major events is indicative of a more subtle baseline increase in conventional forced outage rates. This, combined with tightening reserve margins[9] in some areas that have continued into 2025 from prior years—as well as performance improvements during the most challenging winter week of the year (January 19–25), highlighted by NERC, the Federal Energy Regulatory Commission (FERC), and industry—emphasizes the overall operational improvements while underscoring the increasingly precarious position of the BPS. As WEFOR increases, planning reserve margins may also increase at a higher rate to accommodate the associated uncertainty[10] (see **Figure 1**).[11]

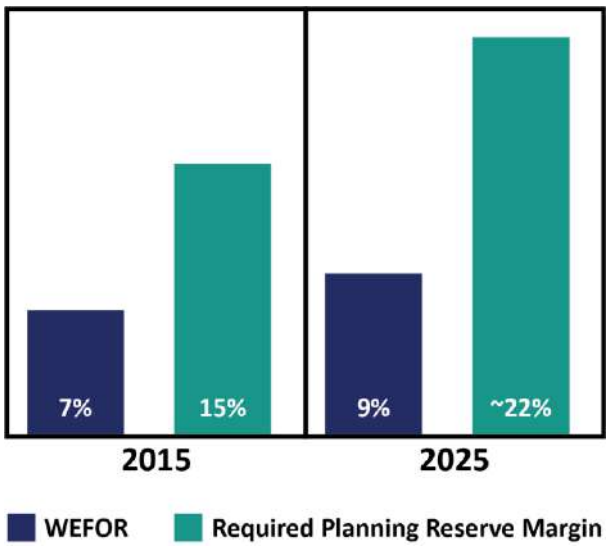


Figure 1: Conceptual Example of Forced Outage Rates Impacting Reserves

[7] GADS reporting is mandatory for units with a capacity >20 MW owned by NERC-registered Generator Owners (GO) per Section 1600 of NERC's Rules of Procedure. The conventional data set is separate from wind, solar, and hybrid energy storage data collection. Standalone energy storage is not currently collected by NERC under a Section 1600 data request.

[8] GADS Data Reporting Instructions - Appendix F Equations - WEFOR is an equation used throughout the electric industry to assess generator reliability by looking at how much units' time and generating capacity is reduced due to forced outages and derates relative to the amount of time they could be generating, weighting that value by each units' net maximum capacity.

[9] Reserve margins refer to the amount of excess generation an area is required to have available as a contingency for major system events to reduce the likelihood of cascading blackouts and load shedding. They are also key to NERC's Reliability Assessments' ability to forecast adequate generation.

[10] Many factors impact reserve margin calculations and vary from season to season throughout the year. Higher impact drivers include forced outage rates, planned maintenance rates, load forecasts, extreme weather outage adders, resource fleet composition, variable energy performance, and resource age.

[11] Figure is for demonstrative purposes. Proportions are not perfectly representative to actual value relations.

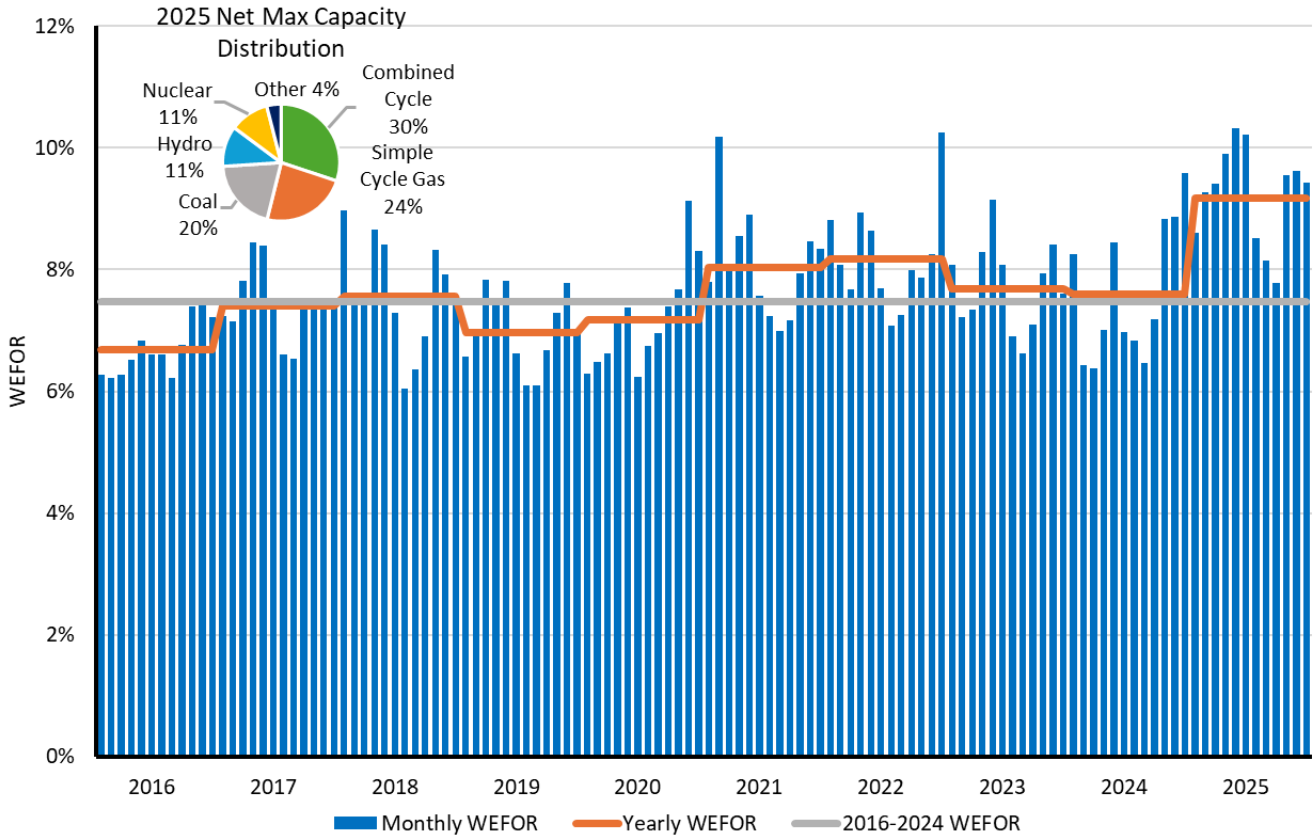


Figure 2: Monthly, Annual, and Five-Year WEFOR

Further analysis (see **Table 2**) identified that the increase in unavailability was primarily driven by a variety of combustion-based generators. The largest year-over-year increases in TWh of unavailability were observed in coal (39.8 TWh increase from 2024 to 2025) and combined-cycle units (19.1 TWh increase from 2024 to 2025). Combining this information with each type of unit's installed net maximum capacity and WEFOR identifies coal-fueled generators as being of more concern than others.

Table 2: 2024 vs. 2025 Year-Over-Year Forced Unavailability Comparison

Primary Fuel Type	Change in GWh[12]	2024 WEFOR	2025 WEFOR
Gas - Steam Turbine	8,772	19.2%	22.4%
Gas - Simple Cycle Combustion Turbine	5,938	20.7%	22.8%
Gas - Simple Cycle w/Heat Recovery Steam Generator (HRSG)	-203	7.7%	7.0%
Combined Cycle	19,154	4.2%	5.7%
Coal	39,835	11.2%	14.1%
Oil - Steam Turbine	1,857	24.6%	25.6%
Oil - Combustion Turbine	2,427	48.2%	69.4%
Hydro	-3,171	8.4%	7.7%
Nuclear	-3,862	2.7%	2.2%
Other	-2,308	11.1%	8.4%
Total/Overall	68,440	7.6%	9.2%

[12] Measured by WEFOR numerator:
$\sum(([Forced\ Outage\ Hours] + [Equivalent\ Forced\ Derate\ Hours]) * [Net\ Maximum\ Capacity])$

To identify possible commonalities, the owners of 41 generators that had a year-over-year increase of at least 1 TWh[13] of unavailability were asked to voluntarily provide additional context to their 2025 GADS data by NERC and the Regional Entities. Of those contacted, responses for 26 generators were provided, which identified several key insights to drive further investigation:

- Sixteen of the units experienced equipment destruction extensive enough to significantly prolong their 2025 outage(s).
- Eight of the units indicated that supply chain constraints significantly prolonged their 2025 outage(s).
  - Constraints were all indicated as occurring at the manufacturer; however, constraints may have occurred deeper into the supply chain unknown to the Generator Owner (GO).
  - Constraints identified included being unable to obtain materials for the repairs, challenges locating part specifications, inexperienced project management, and lack of staff to perform the work.
- Six of the units indicated complete or partial turbine blade release or vibration, which, upon further inspection, would have likely resulted in eventual release.
- Multiple units[14] leveraged the forced outage downtime to perform additional maintenance and inspections. Some indicated that these actions also extended the duration of the outage(s) but resulted in future benefits by either functionally moving up scheduled outages or identifying opportunities to prevent future outages.

After entity responses were evaluated, cause code components were also evaluated by an approximated MWh of forced capacity reduction since 2016. The largest groups were then trended to identify which ones had the largest and/or most consistent increases, with the following component groups being identified:

- **Catastrophe:** Increases over prior year in 2017, 2020, and 2024
  - Largely driven by an increase in use in 2020 because of COVID-19. NERC directed reporters to utilize this code for outages relating to the pandemic at that time prior to the addition of a more appropriate cause code.
  - 2017 and 2024 increases were higher than usual but would not have warranted inclusion on their own.
- **Turbines (High, Intermediate, and Low Pressure):** Increases over prior year in 2017, 2020, 2023, and 2025
  - All three individual turbine component groups were independently identified and represent the largest, most consistently increasing group if combined.
- **Regulatory:** Increases over prior year in 2017, 2018, 2019, 2022, 2023, and 2025
  - Most consistently increasing component group.
  - Initial analysis did not indicate any alignment with a particular policy objective, with both decreases and increases throughout various governmental phases.

[13] Year-over-year variation in MWhs of unavailable generation was used intentionally used in lieu of WEFOR or a single year's MWhs of unavailable generation. This was to focus on units that experienced issues starting in or shortly before 2025 and were most impactful to the overall annual WEFOR. A cutoff was applied to limit overall industry burden and receive a processable amount of input given the timeframe while also being a large enough group to identify common issues. The exact 1 TWh amount provided a clean cut point with a sufficient population but was ultimately arbitrary.

[14] Because this specific information was not directly requested and this is a common industry practice, an exact number of units is not available.

- **Safety:** Increases over prior year in 2018, 2020, 2022, and 2025
- **Nox Reduction Systems:** Increases over prior year in 2017, 2018, 2022, and 2025
- **Boiler Fuel Supply to Bunker:** Increases over prior year in 2017, 2020, 2022, 2024, and 2025

Further data analysis of these component groups and investigation into the underlying cause codes and submitted verbal descriptions are necessary.

The results of this analysis align with, but do not prove, industry assertions concerning coal and combined-cycle units. Most large coal units are over 40 years old and are expected to be retired in the relatively near future. These large coal and combined-cycle units were not designed for regular cycling, which has become an operational requirement in some areas and a necessity to maintain economic viability in others. These factors compound to increase the likelihood of failure over time and act to reduce the incentive to prioritize expensive restoration. Recent Federal Power Act section 202(c) emergency energy orders requested through the Department of Energy (DOE) have also received mixed reception among GOs. These mandates do improve system capacity, but that capacity may not be from reliable units.

Related Actions

Recommendations

- NERC will pursue further analysis and collaborate with the GADS user group (GADSUG) to better understand the causes driving this increase in WEFOR.
- NERC will work with industry to develop specific, measurable reliability indicators for generation performance.
- NERC and the relevant stakeholders should consider adjusting or at least be prepared to adjust reserve requirements to account for lower conventional generation availability.
- GOs should consider bolstering turbine inspection procedures at required intervals. GOs should also consider performing these inspections more frequently or when other major maintenance/outages provide the opportunity.
- Regulators should consider implementing alternative operating requirements during energy emergencies to ensure that regulations do not hinder BPS reliability during critical periods.
- GOs should ensure that manufacturers have capability and plan to replace major components in the event of failure.
- Manufacturers should consider immediately increasing the number of trained technical maintenance personnel to bolster expertise due to the increasing frequency of outages involving major equipment failure and the lack of adequate or sufficiently experienced staff, which was cited multiple times.
- Manufacturers should verify material procurement and processing capabilities.

Demand Growth and Large Load Integration Challenges Continue

Recent events involving data centers and cryptocurrency mining facilities continue to demonstrate the importance of improving industry's understanding of these loads' characteristics and risks as well as the considerations and mitigations needed to reliably integrate them into the BPS.

In a February 2025 event in the Eastern Interconnection, 1,800 MW of data center CILR occurred due to a transmission fault. An additional Eastern Interconnection event in February 2025 resulted in 428 MW of data center CILR. Similar Eastern Interconnection events were observed in March 2025 (227 MW of data center CILR), May 2025 (540 MW of data center CILR), and June 2025 (1,300 MW of data center CILR). ERCOT continues to experience cryptocurrency mining facility CILR events with nine events occurring in 2025 in which at least 100 MW of CILR occurred from computational load facilities.[15] **Figure 3** provides a summary of the Eastern Interconnection and ERCOT data center and cryptocurrency mining facility events.

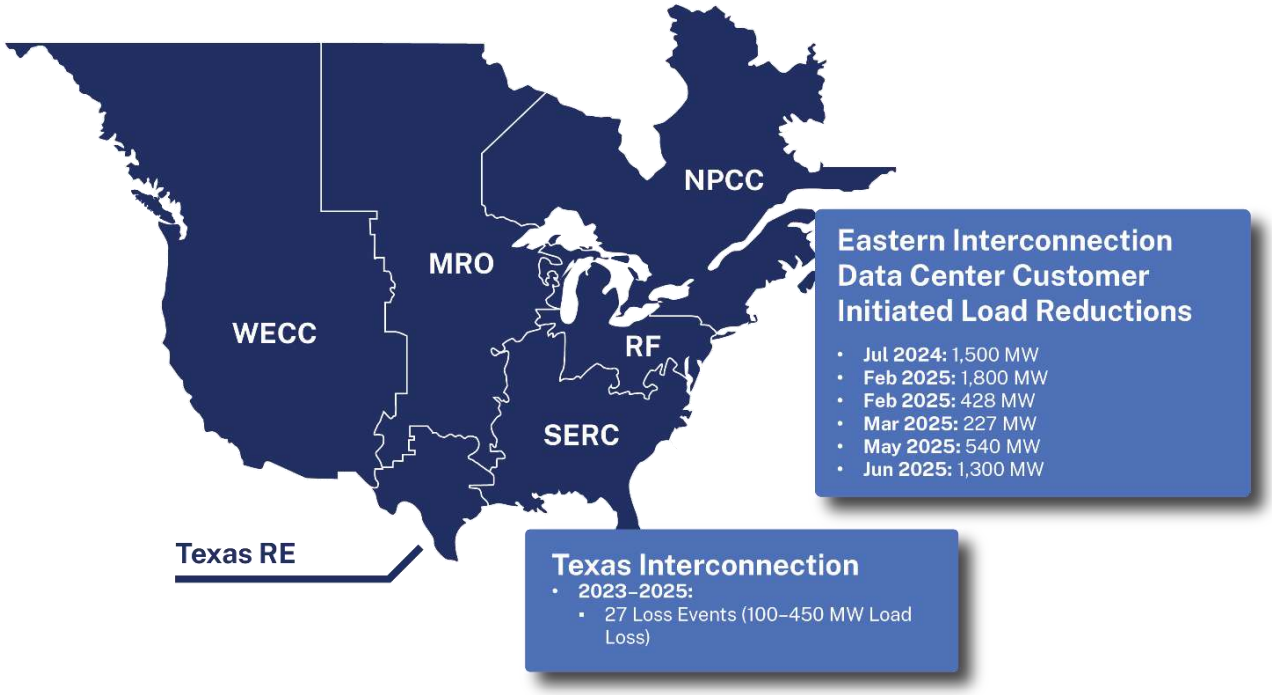


Figure 3: Customer-Initiated Load Reduction Events

Figure 4 provides a breakdown of the large CILRs tracked in ERCOT since 2023. Compared to 2023, the number of events in 2024 and 2025 increased, without indicating improvement. Most events were large computational load events; however, several non-computational load events did occur.

[15] See the Incident Review: Considering Voltage-Sensitive Crypto Load Reductions for an analysis of cryptocurrency mining facility ride-through events in ERCOT.

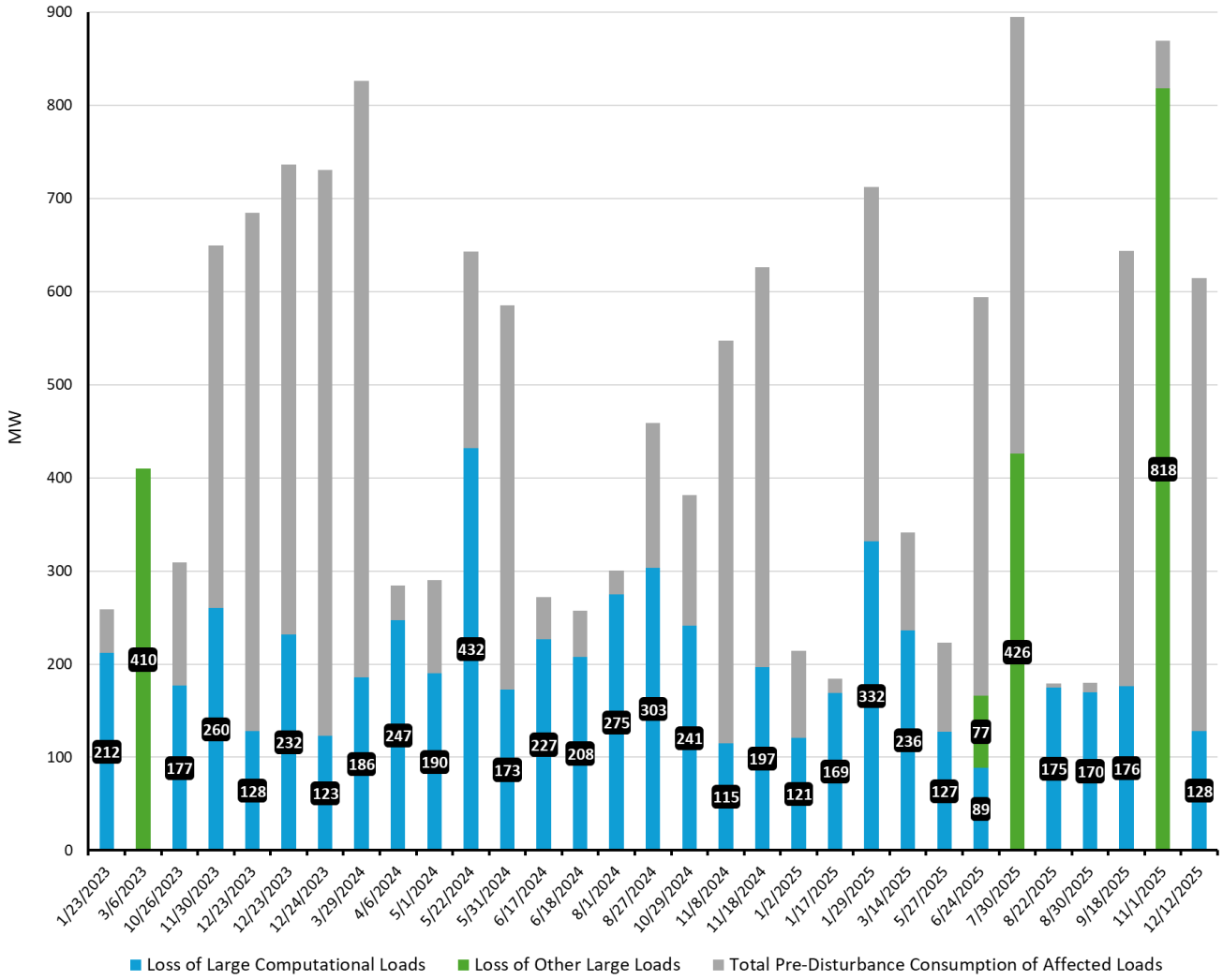


Figure 4: ERCOT Large Load Ride-Through Events

These events demonstrate that the reliability challenges from large loads will increase as these facilities become more prevalent on the grid. As the size of individual large load facilities increases and if large load facilities are located near one another, the sizes of these large load events will likely increase. This could lead to measurable frequency or voltage stability issues. It remains important for grid planners and operators to understand and study the expected performance of the large load facilities during grid disturbances. For the reliability risks to be studied and addressed, load models and study practices that reflect the behavior of the large loads and the risks to the BPS are essential. Continued collaboration between large load facility owners and operators as well as grid planners and operators is essential to ensure the reliable operation of the BPS.

Related Actions

Existing and Ongoing Efforts

- NERC developed a Large Loads Action Plan to address the BPS risks related to emerging large loads.[16]
- The Large Loads Working Group (LLWG) continues to provide technical guidance, industry collaboration, and reliability risk assessment and monitoring for the increasing integration of large loads. The LLWG has published the following white papers and reliability guideline:

[16] Large Loads Action Plan

- A white paper discussing the characteristics of emerging large loads and the risks they pose to the BPS[17]
- A white paper discussing the gaps in NERC Reliability Standards and industry practices related to emerging large loads[18]
- A reliability guideline providing industry with the best practices for mitigating BPS risks related to emerging large loads[19]

- The Load Modeling Working Group (LMWG) continues to address gaps in modeling the dynamic characteristics of the emerging large loads. The LMWG's activities include the following:
  - Developed a technical reference guide for industry on modeling data centers for transient stability studies
  - Endorsed and continues to improve a performance model called Power Electronic Reconnecting and Ceasing (PERC1) for modeling data centers in 2025
  - Continues to educate industry with workshops and by developing tools to help industry develop useful data center models, such as a data center questionnaire[20]
- NERC issued a Level 2 Industry Recommendation Alert to address risks related to large loads.[21]
- Additionally, NERC issued a Level 3 Essential Actions Alert providing specific actions deemed essential to address BPS risks posed by computational large loads,[22] including the following:
  - Transmission Planners and Planning Coordinators developing requirements for computational load modeling data, settings, and parameters
  - Transmission Planners and Planning Coordinators focusing on computational load impacts in system studies
  - Planning Coordinators updating their qualified change definition to reflect the changes that can occur to computational loads
  - Transmission Operators establishing a commissioning process that ensures operational readiness for the integration of large loads
  - Transmission Planners and Planning Coordinators implementing actions to ensure that non-consequential loss of firm computational load does not occur for typically cleared faults
  - Transmission Owners taking actions to capture and share fault recording data for computational load facilities
  - Transmission Operators, Reliability Coordinators, and Balancing Authorities establishing interpersonal communication capabilities and joint operating procedures with computational loads as well as issuing operating instructions to prevent Bulk Electric System (BES) emergencies
- NERC hosted a technical conference focused on the BPS risks posed by emerging large loads and the mitigations needed to integrate emerging large loads into the BPS.[23]

[17] Characteristics and Risks of Emerging Large Loads
[18] NERC LLWG White Paper - Assessment of Gaps
[19] Risk Mitigation for Emerging Large Loads
[20] Data Center Information Collection Questionnaire
[21] Large Load Interconnection, Study, Commissioning, and Operations
[22] Level 3 Computational Load Alert
[23] 02-24-26 Emerging Large Loads Technical Conference

- NERC posted draft updates to the NERC Rules of Procedure for establishing a new registered entity for computational load entities. Additionally, the NERC Standards Committee has launched a standards project to develop Reliability Standards that address the risks posed by computational loads.
- The frequency response metric will continue to be monitored to measure the response to frequency events during large load tripping events.

Recommendations

- The following recommendations are discussed in the LLWG white papers:[24]
  - Registered entities should coordinate with large load entities to address the risks posed by emerging large loads.
  - Relevant NERC Reliability and Security Technical Committee (RSTC) subgroups (including the LLWG, the LMWG, the Security Working Group, and the System Protection and Control Working Group) should continue to assess and address the risks posed by emerging large loads.
  - Regulators should work with utilities to address the risks posed by emerging large loads.
  - Policymakers should review interactions between interconnection requirements, existing state regulations and planning processes, and regional grid operator requirements. Additionally, policymakers should review requirements for large load customers to provide operational data and information to Transmission Owners (TO), Transmission Operators (TOP), Transmission Planners (TP), and other entities.
- NERC registered entities should implement the recommendations provided in the Level 2 Industry Recommendation Alert and the Level 3 Essential Actions Alert.[25]
- NERC will continue incident analysis and lessons learned and share findings with industry.
  - NERC will consider the necessity of mandatory data collection requirements.
- Communication and coordination with the Electric Power Research Institution (EPRI), the Energy Systems Integration Group (ESIG), large load industry groups, and the electric industry at large should be continued.

[24] Characteristics and Risks of Emerging Large Loads, NERC LLWG White Paper - Assessment of Gaps
[25] Large Load Interconnection, Study, Commissioning, and Operations, Level 3 Computational Load Alert

Resource Mix Transformation

The BPS and BES continue to experience a rapid resource mix transformation as conventional generation retirements continue to be replaced primarily by natural gas and increasing IBR penetration. This reduction in conventional resource diversity and increased reliance on variable energy resources continued to pose risks and challenge grid operations in 2025. Additionally, the magnitude of BESS helping to smooth solar generation coming on-line in the morning and going off-line in the evening has increased, with installed capacity roughly matching solar additions last year.

IBR Reliability Considerations

As detailed in NERC's *2025 SOR Overview*,[26] IBR reliability risks remain a priority as these resources continue to grow across the BPS. The primary concern is that some IBRs have unexpectedly reduced or ceased output in response to normally occurring grid disturbances, including generator faults, then rapidly resume output within minutes. These events are driven by a combination of ride-through performance limitations, inverter and plant-level controls, protection systems, and modeling quality deficiencies. Following several major IBR-driven disturbances since 2017, NERC has pursued numerous activities to mitigate related reliability concerns.[27] The *2025 SOR* identified continued unexpected IBR output reductions following normally occurring system disturbances with four events four events exceeding 500 MW reported in 2024 and 16 such events reported since 2020.

Available operational data in 2025 suggests improvements in several key areas. Industry participation in model validation and disturbance review activities increased substantially following implementation of the alert recommendations. While no major widespread disturbance events associated with previously observed common-mode IBR tripping mechanisms were identified during the assessment period, there was a loss of 1,132 MW due to sub-synchronous oscillation protection tripping generation off, a failure mode previously unobserved at this scale. Additionally, rapidly increasing IBR penetration continues to increase operational complexity, particularly in regions experiencing reduced inertia, high renewable penetration during light-load conditions, or rapidly changing power flow conditions. Throughout 2025 and the first half of 2026, several additional major efforts have been undertaken and/or completed as highlighted below.

IBR-Related Actions

Existing and Ongoing Efforts

Level 3 Alert[28]

NERC issued *Level 3 Alert: Essential Actions for Inverter-Based Resource (IBR) Performance and Modeling* to TOs, TPs, Planning Coordinators (PC), and currently registered GOs to enhance technical minimum requirements, study processes, and improve modeling to mitigate risks posed by IBR performance during system disturbances.

- **Essential Action #1**: Each TO and TP, in coordination with their PC, should enhance the existing criteria and policies in their generator interconnection and planning activities, respectively, with additional technical details and IBR-specific performance criteria. These performance-based factors help ensure uniform IBR performance both in normal and post-disturbance operations and include reactive power control, frequency response control, ride-through behavior and post-disturbance performance, and full use of reactive power capability.

[26] 2025 NERC State of Reliability - Overview
[27] Quick Reference Guide: Inverter-Based Resource Activities
[28] NERC Level 3 Alert: Essential Actions for Inverter-Based Resource (IBR) Performance and Modeling

- **Essential Action #2**: Each TP and PC should enhance their modeling and study practices to ensure that sufficient study work and model quality verification are performed and documented to reflect models that are representative of installed, or to-be installed, equipment by establishing model quality and accuracy criteria as well as model performance tests and conformity criteria and by enhancing existing criteria used throughout the generator interconnection.
- **Essential Action #3**: TOs, TPs, or PCs should perform a detailed review of currently operating IBRs on their systems to understand the extent of condition of both real-world performance and accuracy of their models.
- **Essential Action #4**: Each GO should create and implement processes to help ensure that the models used for the evaluation of their design and submitted to TPs and PCs for use in generator interconnection and planning processes are accurate and high-fidelity representations of their IBRs.

To follow up on the Level 3 Alert, the ERO has developed an outreach strategy for 2026 to gather information about why entities are not adopting essential actions or are reporting substandard performance expectations and to address legitimate challenges through clarification of essential actions or, where appropriate, through regulatory processes.

New Standards

Significant reliability gaps associated with modeling are addressed by the updated MOD standards finalized in 2025: MOD-026-2,[29] MOD-032-2,[30] and MOD-033-2.[31] Model validation and verification requirements in MOD-026-2 improve model accuracy and documentation. Enhancements in MOD-032-2 help ensure that validated and verified models are collected and used for both local reliability studies and Interconnection-wide case creation. Improvements in MOD-033-2 allow PCs to assess individual generator performance against their model behaviors as part of system model validation efforts and to remedy discrepancies through MOD-032-2 processes.

Inverter-Based Resource Subcommittee and Electromagnetic Transient Modeling Working Group

The Inverter-Based Resource Subcommittee (IRPS) and Electromagnetic Transient Modeling Working Group (EMTWG) continue to develop reliability guidelines and white papers to share best practices among industry to further reduce IBR risks associated with modeling, studies, commissioning, and testing. Many of these risks can be traced back to poor commissioning and testing of IBRs before they enter commercial operation. These gaps are addressed in the *Draft Reliability Guideline: IBR Commissioning Best Practices*[32] and an upcoming white paper, *IBR Equipment EMT Model Validation*, which aims to provide model validation acceptance criteria, thereby complementing model validation requirements in MOD-026-2 and closing risks posed by inaccurate models.

Category 2 Generator Owner Registration[33]

On May 18, 2023, FERC issued an order approving the NERC Work Plan filed on February 15, 2023, as amended on March 13, 2023, to address registration of IBRs that are connected to the BPS but not within NERC's definition of the BES (referred to hereafter as "Category 2 GO/GOP"). The ERO Enterprise has identified and communicated with 531 IBR facilities that meet the Category 2 GO/Generator Operator (GOP) registry criteria across all the Regional Entities and are, or planned to be, interconnected as of May 15, 2026.

[29] MOD-026-2
[30] MOD-032-2
[31] MOD-033-3 – Further revisions have been implemented in 2026.
[32] Draft Reliability Guideline: Commissioning Best Practices
[33] NERC Files IBR Registration Update, Marking Milestone for Grid Reliability

Beginning on May 15, 2026, entities with identified IBR facilities that meet the Category 2 GO/GOP registry criteria were registered and are now subject to compliance with applicable Reliability Standards, as required by the IBR Order. As part of the Inverter-Based Resource Registration Initiative, NERC staff developed a document identifying the finalized and pending compliance dates for the applicability and enforceability of Reliability Standards applicable to Category 2 GO and GOP registrations. As of May 15, 2026, entities registered as Category 2 GOs or Category 2 GOPs are required to comply with, as applicable, BAL-001-TRE, IRO-010-5, MOD-032-2, PRC-012-2, PRC-017-1, TOP-003-6.1, VAR-001-5, and VAR-002-4.1.

Additional technical conferences will be pursued to assist in identifying which Reliability Standards must be revised to establish applicability to Category 2 IBRs and in which order and grouping they should be developed.

The ERO Enterprise is integrating the new Category 2 GO and GOP registrants into relevant ERO Enterprise efforts, including Compliance Monitoring and Enforcement Program activities related to Reliability Standards applicable to those entities. The ERO Enterprise will continue to identify and register additional entities that meet the Category 2 GO and GOP registry criteria as additional IBR facilities are developed and connected to the BPS.

The completion of the NERC Work Plan represents the conclusion of a substantial three-year ERO Enterprise effort to address the risk to BPS reliability posed by unregistered IBR facilities.

BESS Reliability Considerations

As the BES resource mix continues to rapidly evolve, BESS penetration has rapidly increased over the past several years (see **Figure 5**) to approximately match solar growth in 2025. This growth is projected to continue, requiring observation and analysis of this resource's capabilities.

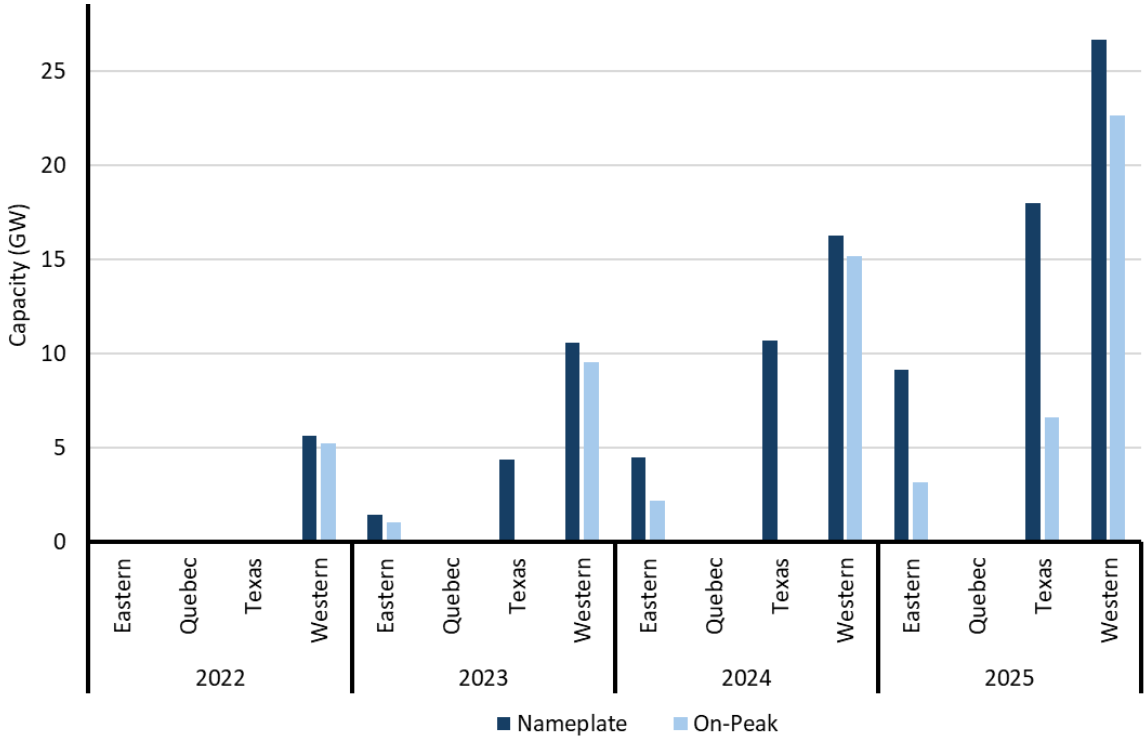


Figure 5: 2022–2025 Battery and Hybrid Capacity by Interconnection

Unique Failure Event

In January 2025, a 300 MW BESS facility experienced thermal runaway during routine testing that ultimately resulted in the functional destruction of a previous-generation warehouse-style facility.[34] While outages internal to the plant regularly occur with other generation resources of similar or greater capacities, the permanent, unplanned loss of a non-BESS facility is exceedingly rare. As such, this type of failure represents a risk consideration unique to BESS that needs to be taken into consideration as the resource continues to expand. Improvements to BESS reliability, thermal runaway mitigation, failure isolation, fire suppression, and updates to fire codes have all acted to significantly reduce the likelihood of these events occurring. NERC will continue to monitor these failure events, but they do not represent a significant concern to overall system reliability at this time.

Load Curve Smoothing

BESS is typically installed to take advantage of price differences between high-generation/low-load and low-generation/high-load conditions. As a result, it provides a smoothing effect that functionally reduces expected and unexpected variability from increasingly prevalent wind and solar generation (see **Figure 6**).

As a result, conventional generators have more time to come off-line and on-line during the most strenuous portions of the day in areas most impacted by as the period when solar resources are going off-line just before peak load conditions in the evening. Because many older, larger conventional generators were not designed to cycle on- and off-line daily, increasing the ramp period can reduce wear and tear, improving their reliability.

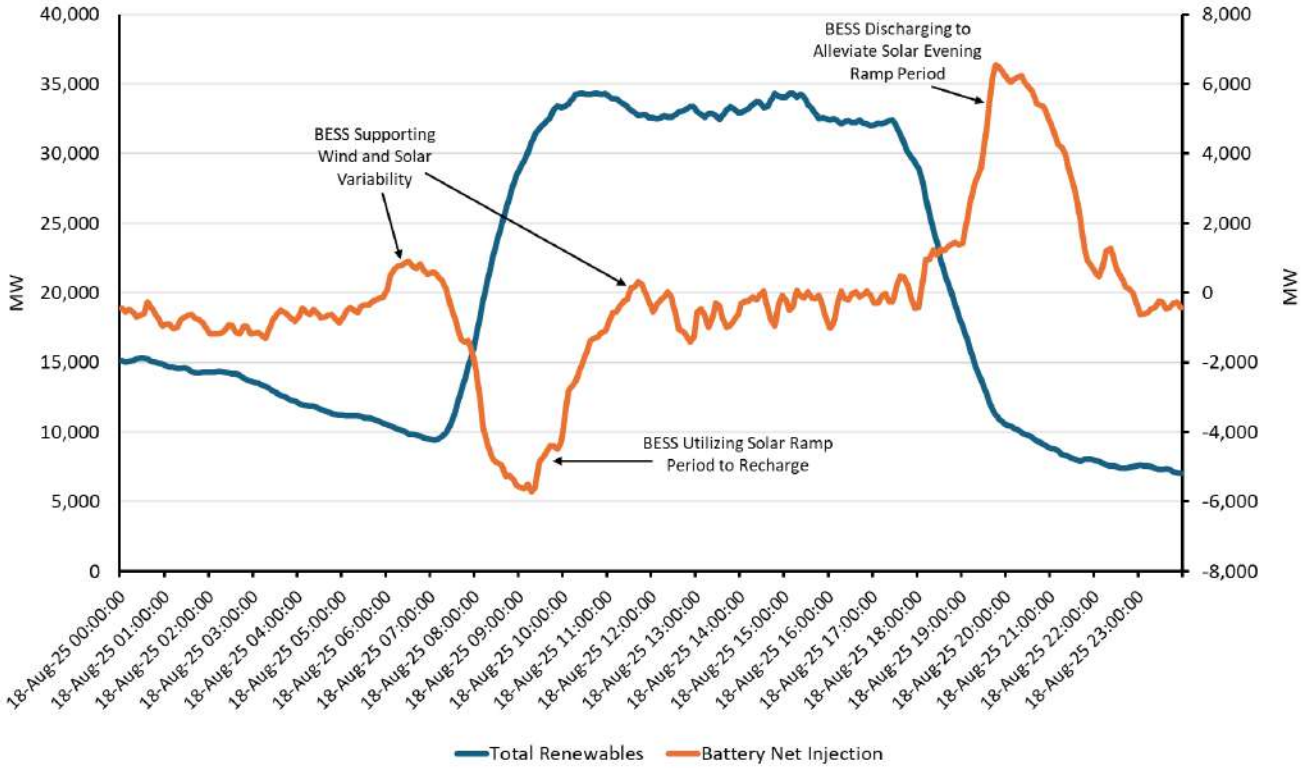


Figure 6: Total Renewables Plus Evening Solar Ramp[35]

[34] Moss Landing BESS Fire Report Final 12.22.25.pdf

[35] Secondary Y-axis has been shifted and scaled for visual clarity.

Frequency Response Impacts

As detailed earlier in the *2025 SOR Overview*,[36] BESS has demonstrated the capability to rapidly respond to frequency disturbances. In 2025, areas with sufficiently dense BESS installations and primary frequency response support initiatives continued to demonstrate the resource's ability to arrest frequency decline and restore frequency to deadband more quickly than conventional generators.

It should be noted that BESS are energy storage resources with limited capacity, typically intended to last a few hours. As a result, BESS's role in frequency disturbance events is ultimately to rapidly recover and maintain frequency until additional resources can come on-line for indefinite system support. This introduces a functional limitation during long-term widespread system degradation events, meaning that BESS is not a complete solution for events like major winter storms.

BESS-Related Actions

Recommendations

- BESS data collection and sharing value and viability are being evaluated by NERC's Performance Analysis team.
- NERC encourages BESS facilities to provide information on services that they are providing with relevant parties.
- NERC encourages policymakers to consider revisions to fire codes if they have not already.
- NERC will continue to monitor BESS performance and major events for risks.
- In November 2025, ERCOT stakeholders approved Nodal Operating Guide Revision Request 272 and Planning Guide Revision Request 121. These revisions require new BESS resources with a standard generation interconnection agreement (SGIA) date on or after April 1, 2026, to demonstrate the capability of providing advanced grid-support (grid-forming) functions as well as to provide appropriate models for these functions.

[36] 2025 NERC State of Reliability - Overview

Industry Mitigation Actions

Performance data reported to NERC enables a risk-based approach to reliability management across major emerging reliability issues prior to the creation of formal reliability indicators. Current areas of focus include severe weather, conventional generator performance, large loads, BESS, and IBRs (see **Table 3**). In response to these evolving risks, industry and the ERO Enterprise implemented a broad range of mitigation activities throughout 2025 detailed in the body of this report.

In addition to these top priorities, more cautionary mitigation activities included more conservative operating practices during stressed and cold-weather conditions, increased use of probabilistic and all-hours reliability assessments, improved model validation requirements, transmission planning resilience analysis for extreme weather events, and new planning and operational guidance associated with load-pocket reliability risks.

Table 3: Monitoring Emerging Trends and Mitigation Resolution

Monitored Reliability Challenge	Key Measures Tracked	2025 Trends	Mitigation Effectiveness Indicators	Indicators that Additional Attention is Required
Increasing Incidence of Severe Weather	Severity risk index (SRI), transmission outages, restoration duration, MVA-days lost, load loss	Worst SRI days remained within historically favorable ranges; overall weather conditions considered favorable	Reduced outage severity, faster restoration, lower cumulative SRI	Increasing high-SRI days, longer restoration times, larger correlated outages
Generator Forced Outage and Performance Trends	Annual/monthly WEFOR, fuel-specific outage rates, unavailable MWh, seasonal outage spikes	Overall WEFOR increased to 9.2%; coal 11.2% to 14.1% (39.8 TWh change), combined cycle 4.2% to 5.7% (19.1 TWh change)	Improved winter performance, reduced outage severity during extreme events	Elevated WEFOR, correlated winter outage spikes
Reliable Large Load Integration	Peak demand growth, frequency response, load forecast error, transmission constraints, CILR	Annual energy demand increased to ~4.95 million GWh; actual summer peak higher than forecast; two CILRs exceeding 1,000 MWs	Stable frequency performance, improved operational visibility	Rapid localized demand growth, frequency volatility, planning uncertainty
Reliable BESS Integration and Performance	Frequency arrest performance, recovery speed, BESS availability	BESS deployment approximately matched solar growth; improved fast frequency response performance observed when incentivized in high-BESS areas	Improved frequency recovery, successful grid-forming performance	Thermal runaway/fire events, duration limitations, unavailable BESS capacity
Reliable IBR Integration	Ride-through performance, rate-of-change-of-frequency (RoCoF), IBR trip events, model validation	Expanded IBR mitigation activities continued through 2025	Reduced disturbance-related tripping, improved model accuracy	Weak-grid instability, repeated tripping events, model-performance divergence

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.2a

Respondent: A. Willis

Page: 1 of 1

Question: 2. Refer to Exhibit A-1, page 3: “Customer-owned equipment must be operated so that voltage fluctuations on the primary distribution system of the Company shall not exceed permissible limits.”
a. Do limits on voltage fluctuations also apply to customers connected to the subtransmission and transmission systems?

Answer: Yes.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.3a

Respondent: M. Witkowski

Page: 1 of 1

Question: 3. Refer to the rebuttal testimony of DTE Witness Benyard in Case No. U-22058 at pages 34: “The Company provided a draft operating parameters document in discovery, which is included with this testimony as CONFIDENTIAL Exhibit A-21.”
a. Would all Large Load Customers seeking to interconnect to the transmission system in DTE’s territory under the large load provision of Rate D11 be subject to a similar set of operating parameters as was required for the customer in Case No. U-22058?

Answer: Yes.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.3e

Respondent: M. Witkowski

Page: 1 of 1

Question: 3. Refer to the rebuttal testimony of DTE Witness Benyard in Case No. U-22058 at pages 34: “The Company provided a draft operating parameters document in discovery, which is included with this testimony as CONFIDENTIAL Exhibit A-21.”
e. Are the finalized operating parameters filed with the MPSC, ITC, MISO, NERC, or any other relevant entities?

Answer: Operating parameters are between DTE Electric and the customer, developed in partnership with ITC and MISO’s participation/awareness as applicable. At this time, DTE Electric is not planning to file operating parameter documents applicable to large load customer service agreements with MPSC, MISO or NERC unless required by an applicable regulation, tariff, or order. ITC will have a copy of the operating parameters as they are designed in coordination between DTE and ITC.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.4a

Respondent: M. Witkowski

Page: 1 of 1

Question: 4. For transmission-connected Large Load Customers, please confirm that DTE coordinates or will coordinate with the transmission provider (ITC), to conduct, as necessary, (1) short circuit studies, (2) stability studies, and (3) electromagnetic transient (EMT) studies.
a. If confirmed, please describe the timeline of these studies in relation to the customer's application for service, completion of interconnection agreement, initial energization of the customer facility, and load ramping of the facility to the full approved load.

Answer: Confirmed in general. For transmission-connected Large Loads, DTE Electric coordinates with ITC on studies necessary to evaluate reliable interconnection/service, which may include evaluating short-circuit, steady-state/power-flow, stability/dynamic, voltage, harmonic/power-quality, electromagnetic transient/PSCAD (EMT), disconnection/reconnection, and other analyses as appropriate. Some studies may be performed by ITC; some by DTE Electric. All studies must be completed prior to initial energization of the customer facility.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.4b

Respondent: M. Witkowski

Page: 1 of 1

Question: 4. For transmission-connected Large Load Customers, please confirm that DTE coordinates or will coordinate with the transmission provider (ITC), to conduct, as necessary, (1) short circuit studies, (2) stability studies, and (3) electromagnetic transient (EMT) studies.
b. Are additional studies beyond these three also conducted as a matter of course?

Answer: Yes, additional studies can be conducted depending on the customer, project scope, system conditions, applicable reliability requirements, and observed risks. The operating parameters framework references power factor, load ramping, load block oscillations, ride-through, harmonics, UFLS, MLS, and other operating parameters; the technical study scope will align with these categories.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.4c

Respondent: M. Witkowski

Page: 1 of 1

Question: 4. For transmission-connected Large Load Customers, please confirm that DTE coordinates or will coordinate with the transmission provider (ITC), to conduct, as necessary, (1) short circuit studies, (2) stability studies, and (3) electromagnetic transient (EMT) studies.
c. After these studies are completed, who receives a copy of the results?

Answer: Study results are shared between DTE and ITC, and other entities who may need the results to evaluate, design, operate, or approve the interconnection/service, subject to confidentiality and CEII/security requirements (e.g. MISO or the customer). The studies are not available upon request.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.5bi

Respondent: M. Witkowski

Page: 1 of 2

Question: 5. Refer to June 2026 MISO whitepaper, “Interconnection Reliability Requirements for Large Loads,” available at: https://cdn.misoenergy.org/20260629%20LLWG%20Item%2007%20Draft_MISO_La
rge_Load_Interconnection_Requirement_Technical%20Compendium765704.pdf .
b. The whitepaper describes “four categories of reliability requirements” at page 4: “Data, Modeling, Telemetry, Forecasting, and Outage Coordination Requirements,” “Ramp Requirements,” “Ride-through Requirements,” and “Stability Assessment Requirements.” For each category of requirement:
i. Will Large Load Customers seeking service under Rate D11 be subject to existing requirements of this category?

Answer: The Company objects to the question on the basis that the MISO whitepaper referenced in the request is not relevant to the Large Load Provision tariff changes presented in the Company’s Application and is beyond the scope of the current proceeding. The MISO whitepaper document carries no regulatory authority, imposes no obligations on DTE Electric, and does not constitute a standard, requirement, or directive applicable to DTE Electric’s Application in this case. The MISO whitepaper document has no bearing on the Application or any determinations the Commission is asked to make in this case. This proceeding is limited to approval of the proposed Large Load Provision and concerns tariff terms and conditions, whereas the referenced document pertains to proposed revisions to MISO operating procedures and business practices for large load interconnections that are not at issue in this case.

The Company further objects to the extent the request seeks information regarding internal deliberations, regulatory advocacy, or participation in external stakeholder processes, which are not relevant to this proceeding and may implicate commercially sensitive or deliberative communications.

Subject to and without waiving the foregoing objection, the Company states that the Company intends to comply with applicable MISO requirements once

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.5bi

Respondent: M. Witkowski

Page: 2 of 2

effective, and thus large load customers will be subject to final MISO requirements.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.5bii

Respondent: M. Witkowski

Page: 1 of 2

Question: 5. Refer to June 2026 MISO whitepaper, “Interconnection Reliability Requirements for Large Loads,” available at: https://cdn.misoenergy.org/20260629%20LLWG%20Item%2007%20Draft_MISO_Large_Load_Interconnection_Requirement_Technical%20Compendium765704.pdf .
b. The whitepaper describes “four categories of reliability requirements” at page 4: “Data, Modeling, Telemetry, Forecasting, and Outage Coordination Requirements,” “Ramp Requirements,” “Ride-through Requirements,” and “Stability Assessment Requirements.” For each category of requirement:
ii. How do these existing requirements compare to MISO’s proposed requirements?

Answer: The Company objects to the question on the basis that the MISO whitepaper referenced in the request and the related request to compare “existing requirements” to “MISO’s proposed requirements” is not relevant to the Large Load Provision tariff changes presented in the Company’s Application and is beyond the scope of the current proceeding. The MISO whitepaper document carries no regulatory authority, imposes no obligations on DTE Electric, and does not constitute a standard, requirement, or directive applicable to DTE Electric’s Application in this case. The MISO whitepaper document has no bearing on the Application or any determinations the Commission is asked to make in this case. This proceeding is limited to approval of the proposed Large Load Provision and concerns tariff terms and conditions, whereas the referenced document pertains to proposed revisions to MISO operating procedures and business practices for large load interconnections that are not at issue in this case.

The Company further objects to the extent the request seeks information regarding internal deliberations, regulatory advocacy, or participation in external stakeholder processes, which are not relevant to this proceeding and may implicate commercially sensitive or deliberative communications. Subject to and without waiving the foregoing objection, the Company states that the proposed MISO requirement categories closely align with DTE’s operating parameter framework: data/modeling/telemetry/forecasting/outage coordination; ramp

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.5bii

Respondent: M. Witkowski

Page: 2 of 2

limits; ride-through; and stability assessment. DTE Electric continues to participate in MISO LLWG and provide feedback to ensure coordination and alignment for final requirements as applicable.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.7a

Respondent: M. Witkowski

Page: 1 of 1

Question: 7. For transmission-connected Large Loads, has DTE established clear facility design, modeling, and performance criteria in its interconnection requirements for Large Loads? If so, please answer each of the following:
a. Provide the relevant Large Load language from interconnection requirements.

Answer: The Company objects to the question on the basis that the request to "provide the relevant Large Load language from interconnection requirements" relating to "facility design, modeling, and performance criteria" for large laod customers is not relevant to the Large Load Provision tariff changes presented in the Company's Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company states that the Company is developing facility design, modeling, and performance criteria through the customer-specific operating parameter process, ITC coordination, MISO rulemaking/LLWG activities, and technical studies. DTE Electric does not yet have a single completed generic Large Load Connection Requirements document, though such a document is planned to be developed.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.7b

Respondent: M. Witkowski

Page: 1 of 1

Question: 7. For transmission-connected Large Loads, has DTE established clear facility design, modeling, and performance criteria in its interconnection requirements for Large Loads? If so, please answer each of the following:
b. Provide the operational load ramp limits for normal operations in MW/min.

Answer: The Company objects to the question on the basis that the request to "provide the operational load ramp limits for normal operations in MW/min" is not relevant to the Large Load Provision tariff changes presented in the Company's Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company refers CEO to its response to CEODE-2.7a. Operational load ramp limits for normal operations will be determined on a site specific basis, with alignment to MISO reliability requirements.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.7c

Respondent: M. Witkowski

Page: 1 of 1

Question: 7. For transmission-connected Large Loads, has DTE established clear facility design, modeling, and performance criteria in its interconnection requirements for Large Loads? If so, please answer each of the following:
c. Provide the operational load ramp limits for abnormal or post-disturbance operations in MW/min.

Answer: The Company objects to the question on the basis that the request to "provide the operational load ramp limits for abnormal or post-disturbance operations in MW/min" is not relevant to the Large Load Provision tariff changes presented in the Company's Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company refers CEO to its response to CEODE-2.7a. Operational load ramp limits for abnormal or post-disturbance operations will be determined on a site specific basis, with alignment to MISO reliability requirements.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.7d

Respondent: M. Witkowski

Page: 1 of 1

Question: 7. For transmission-connected Large Loads, has DTE established clear facility design, modeling, and performance criteria in its interconnection requirements for Large Loads? If so, please answer each of the following:
d. Describe the design requirements for Large Loads to minimize and mitigate power oscillation interaction during normal operations.

Answer: The Company objects to the question on the basis that the request to "describe the design requirements for Large Loads to minimize and mitigate power oscillation interaction during normal operations" is not relevant to the Large Load Provision tariff changes presented in the Company's Application, is beyond the scope of the current proceeding, and not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company states that the Operating Parameters framework identifies load block oscillation/frequency bands and requires the customer to minimize significant signal injections and power fluctuations; it currently includes a working requirement that the customer may not cause power fluctuations greater than 30 MW over a five-second sliding window, subject to further investigation and potential mitigation requirements. Final limitations may be site specific and may vary in value.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.7f

Respondent: M. Witkowski

Page: 1 of 1

Question: 7. For transmission-connected Large Loads, has DTE established clear facility design, modeling, and performance criteria in its interconnection requirements for Large Loads? If so, please answer each of the following:
f. What is the maximum amount of load that can be disconnected (e.g., through tripping or customer isolation) from a single Contingency?

Answer: The Company objects to the question on the basis that the request to provide "the maximum amount of load that can be disconnected from a single Contingency" is not relevant to the Large Load Provision tariff changes presented in the Company's Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company states that the maximum disconnect/reconnect amount is site-specific and under study by DTE and ITC; subject to any future requirements from applicable regulations.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.7g

Respondent: M. Witkowski

Page: 1 of 1

Question: 7. For transmission-connected Large Loads, has DTE established clear facility design, modeling, and performance criteria in its interconnection requirements for Large Loads? If so, please answer each of the following:
g. Describe the implemented modeling requirements to meet established modeling needs.

Answer: The Company objects to the question on the basis that the request to "describe the implemented modeling requirements to meet established modeling needs" is not relevant to the Large Load Provision tariff changes presented in the Company's Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company states that modeling requirements are being developed and may include PSS/E load models, PSCAD/EMT models, short-circuit models, harmonic spectrum information, reactive-power data, active/reactive demand response to voltage/frequency disturbances, load composition, ramp-rate information, and other information requested through RFIs.

Attachment: None

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.7i

Respondent: M. Witkowski

Page: 1 of 1

Question: 7. For transmission-connected Large Loads, has DTE established clear facility design, modeling, and performance criteria in its interconnection requirements for Large Loads? If so, please answer each of the following:
i. Describe the performance requirements for voltage ride-through, voltage recovery characteristics, or other voltage response data deemed necessary. Include in this response how this is acquired from the Large Load entities.

Answer: The Company objects to the question on the basis that the request to "describe the performance requirements for voltage ride-through, voltage recovery characteristics, or other voltage response data deemed necessary" is not relevant to the Large Load Provision tariff changes presented in the Company's Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company states that voltage and frequency ride-through requirements are included in the operating parameter framework, including LVRT/HVRT and frequency ride-through curves/tables, with customer protective relay settings expected to coordinate with minimum ride-through requirements. The customer is expected to provide data and demonstrate capability through design information, relay/protection settings, models, testing, and post-energization validation as applicable.

Attachment: *None*.

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.7k

Respondent: M. Witkowski

Page: 1 of 1

Question: 7. For transmission-connected Large Loads, has DTE established clear facility design, modeling, and performance criteria in its interconnection requirements for Large Loads? If so, please answer each of the following:
k. Are high resolution recording (e.g., PMU, DFR) and/or low-resolution recording (e.g., SCADA scans) devices required to be installed for Large Loads in the interconnection requirements?

Answer: The Company objects to the question on the basis that the request to provide information on “high resolution recording” or “low-resolution recording” device requirements is not relevant to the Large Load Provision tariff changes presented in the Company’s Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company states that real-time and disturbance-recording requirements are under development and may include SCADA, utility meters/recorders, PMU/DFR or equivalent high-resolution monitoring, and customer-provided data.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.10i

Respondent: M. Witkowski

Page: 1 of 1

Question: 10. Has DTE established operating protocols and the necessary communication infrastructure to support reliable ongoing operations for Large Loads? If so, please answer each of the following:
i. Describe any plans DTE has within 2 years to include revisions to operating protocols and the necessary communication infrastructure.

Answer: The Company objects to the question on the basis that the request to "describe any plans DTE has within 2 years to include revisions to operating protocols and the necessary communication infrastructure" calls for speculation and is not relevant to the Large Load Provision tariff changes presented in the Company's Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company states that it will revise its operating protocols as needed consistent with any changes made to applicable NERC or MISO standards as they are revised and approved.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.14c

Respondent: M. Witkowski

Page: 1 of 1

Question: 14. The following questions relate to operational modeling, forecasting, and other operational requirements.
c. Describe any plans DTE has within 2 years to include changes related to operational modeling, forecasting, and other operational requirements.

Answer: The Company objects to the question on the basis that the request to "describe any plans DTE has within 2 years to include changes related to operational modeling, forecasting, and other operational requirements" calls for speculation and is not relevant to the Large Load Provision tariff changes presented in the Company's Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company states that it will revise its operating protocols as needed consistent with any changes made to applicable NERC or MISO standards as they are revised.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-2.16b

Respondent: M. Witkowski

Page: 1 of 1

Question: 16. Is DTE consulting with, or has DTE consulted with TOs to ensure the necessary RealTime communication infrastructure and monitoring capabilities related to Large Load Customers are in place?
b. Describe any plans DTE has within 2 years to include revisions to address the need for these capabilities.

Answer: The Company objects to the question on the basis that the request to “describe any plans DTE has within 2 years to include revisions to address the need for these capabilities” is not relevant to the Large Load Provision tariff changes presented in the Company’s Application, is beyond the scope of the current proceeding, and is not proportional to the needs of the case. Subject to and without waiving the foregoing objection, the Company states that it will revise its operating protocols as needed consistent with any changes made to applicable NERC or MISO standards as they are revised

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-3.1

Respondent: M. Witkowski

Page: 1 of 1

Question: Refer to the Company's July 28, 2026 response to CEODE-2.3bi, which references a draft operating parameters document provided in Case No. U-22058. Please provide a copy of that document.

Answer: Please see attached.

Attachment: NDA U-22061 CEODE-3.1 Confidential

Co-respondent: Legal

EXHIBIT CEO-6

CONFIDENTIAL

ATTACHMENT TO CEODE-3.1 DISCOVERY RESPONSE (NDA U-22061 CEODE-3.1 Confidential)

ESIG
Large Loads
Task Force

Interconnection Processes for Large Loads

CURRENT PRACTICES AND RECOMMENDATIONS



A Report by the
Energy Systems Integration Group's
Large Loads Task Force

June 2026

ESIG
ENERGY SYSTEMS
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The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

ESIG Publications Available Online

This report is available at https://www.esig.energy/working-groups/large-loads/. All ESIG publications can be found at https://www.esig.energy/resources/reports-and-briefs/.

Get in Touch

To learn more about the topics discussed in this report or for more information about the Energy Systems Integration Group, please send an email to info@esig.energy.

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Interconnection Processes for Large Loads: Current Practices and Recommendations

A Report by the Energy Systems Integration Group's Large Loads Task Force

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Disclaimer

This report was produced by a project team made up of diverse members with diverse viewpoints and levels of participation. Specific statements may not necessarily represent a consensus among all participants or the views of participants' employers.

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Preface to ESIG Large Loads Task Force Reports

This report is one of 11 reports by the ESIG Large Loads Task Force, which was formed to assist the power industry in addressing new challenges introduced by the rapid proliferation of large electronic loads such as data centers, as well as other large loads including manufacturing, electric vehicle fleets, and hydrogen production. The titles of the reports are as follows:

- Grid Integration of Large Loads: Introduction to the Large Loads Task Force, Data Needs, and Flexibility
- Forecasting for Large Loads: Current Practices and Recommendations
- Interconnection Processes for Large Loads: Current Practices and Recommendations
- Large Load Performance Requirements: Current Practices and Recommendations
- Large Loads: Behaviors, Capabilities, and Limitations
- Reliability Impacts of Large, Power Electronics–Interfaced Loads
- Large Load Disturbance Events
- Large Load Modeling for Dynamic Studies: Current Practices and Recommendations
- Transmission Planning with Large Loads: Current Practices and Recommendations
- Resource Adequacy with Large Loads: Planning for Flexibility to Accelerate Integration
- Wholesale Market Design and Operations for Systems with Large Loads: Current Practices and Recommendations

Contents

ix Abbreviations

x Executive Summary

1 Introduction

3 Issues with the Interconnection Process

5 Report Organization

6 Overview of the Large Load Interconnection Process

7 Milestones Distilled from Currently Complete Large Load Interconnection Processes

8 Differences in Transmission Interconnection Processes for Different Utility Types

12 Interconnection Studies

18 Lessons Learned from Large Generation Interconnection

20 Utilities' and ISOs/RTOs' Current Approaches and the Need for Coordination

21 Current Interconnection Approaches at Individual Utilities and ISOs/RTOs

24 Interconnection Process Challenges and Regional Responses

28 Interconnection Process Recommendations for Transmission-Connected Large Loads

32 Opportunities for Federal Action on Large Load Interconnection Processes

32 Current Status and Challenges for Defined Large Load Interconnection Processes and Requirements at the National Level

34 Recommendations

35 Distribution-Connected Large Load Interconnection Process

36 Current Status and Challenges

39 Interconnection Process Recommendations for Distribution-Connected Large Loads

41 Conclusions and Recommendations

41 Large Load Interconnection Process Overall

42 Large Load Interconnection Process Coordination

42 Large Load Interconnection Process Studies

43 Large Load Interconnection Technical Requirements

43 New Solutions to Speed up Large Load Interconnection

43 Staffing Resources

45 References

Abbreviations

AI	Artificial intelligence
ANOPR	Advance Notice of Proposed Rulemaking
BYOG	Bring your own generation
CAISO	California Independent System Operator
DCC	Demand Connection Code
DER	Distributed energy resource
EMT	Electromagnetic transient
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
HILL	High-Impact Large Load
HILLGA	High-Impact Large Load Generator Assessment
IBR	Inverter-based resource
ISO	Independent system operator
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
LLIA	Large Load Interconnection Agreement
LLIP	Large Load Interconnection Procedure
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
PSPD	Postive-sequence phasor-domain
RTO	Regional transmission organization
SPP	Southwest Power Pool
UPS	Uninterruptible power supply
U.S. DOE	U.S. Department of Energy

Executive Summary

The interconnection of large loads into the U.S. electric power system has accelerated sharply in recent years, driven primarily by the rapid proliferation of data centers and other high-demand facilities. Interconnection requests for these loads have grown exponentially in both number and magnitude, reshaping load growth forecasts across virtually every region of the country and placing new and unanticipated pressures across the electricity system. The interconnection process, encompassing the technical studies, legal agreements, and procedural requirements necessary to connect new electrical facilities to the grid while preserving system reliability, will need to expand to serve large loads' needs and fully capture their impacts on the grid.

The pressures inherent in the exponential growth of large load interconnection requests manifest in several interrelated challenges. These include reliability risks, concerns about cost allocation, and disputes between large load customers and grid owners and operators over rights, obligations, and timelines. At the bulk power system level, large load facilities introduce novel reliability risks stemming from their very large power demand, power electronic interfaces, and varying power demand dictated by computational processes' intensity, including artificial intelligence training and inference (application) workloads. Financially, the speculative nature of some large load interconnection requests raises legitimate concerns about cost allocation: infrastructure investments triggered by interconnection requests may ultimately be underutilized if large load projects do not advance to commercial operation. These dynamics also have implications for utility customer rates, wholesale market rates, and long-term system planning.

The interconnection process, encompassing the technical studies, legal agreements, and procedural requirements necessary to connect new electrical facilities to the grid while preserving system reliability, will need to expand to serve large loads' needs and fully capture their impacts on the grid.

Underpinning all of these challenges is the question of which regulatory authorities have jurisdiction over each aspect of large load interconnection. While generator interconnection is regulated by the Federal Energy Regulatory Commission (FERC) and state public utility commissions, regulatory authority over large load interconnection standards and procedures is less clear. Currently, FERC oversees generator interconnection "for the purpose of making sales of electric energy for resale in interstate commerce" (that is, when the generator plans to sell electricity at wholesale into interstate markets not directly to an end-use customer) (FERC, 2023a, 804). For regulated utilities, state public utility commissions oversee generator interconnection that does not involve sales for resale. The North American Electric Reliability Corporation (NERC), through a stakeholder-driven standards process, sets reliability standards for generation. The development of these standards can be mandated by FERC (e.g., FERC Order 901) or proposed by industry stakeholders (including NERC) based on reliability needs. Furthermore, the new Category 2 inverter-based resources, defined as those "that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA" (NERC, 2026d), face 11 applicable NERC reliability standards as of March 2026. However, there is no similar process today for reliability standards for large loads.



Historically, the lack of clarity around regulatory authority over large load interconnection standards and procedures did not lead to significant issues because load growth was incremental and more evenly geographically distributed; however, reliability challenges command much more attention in an era when individual loads may approach or exceed the scale of conventional generating units and connect at all voltage levels of the grid on the distribution system, sub-transmission level, and transmission system. At the time of this writing, load facilities are not required to register with NERC; since they are not NERC-registered entities, they do not have any applicable NERC reliability standards, even as a 1 GW data center can impact the bulk power system far more than, for example, a 20 MW wind plant. NERC is working to rapidly develop registration criteria and reliability standards for large loads in 2026 through its large load action plan (NERC, 2026e).

At the regional level, existing large load interconnection processes are not sufficient to maintain bulk power system reliability with the increase in interconnection requests and the growing set of risks to the system. Historically, utilities managed all load interconnections directly, regardless of size. As demand from large loads grows and the reliability risks become greater, additional coordination is needed in the large load interconnection process to ensure that all assumptions, data, models, and reliability solutions are shared and managed consistently. This includes coordination between independent system operators (ISOs) and regional transmission organizations (RTOs) and utilities.

The Energy Systems Integration Group's (ESIG's) Large Loads Task Force examined the large load interconnection process in detail, mapped current practices across select utilities and ISO/RTO regions where large load interconnection practices are evolving more rapidly, and identified the gaps, bottlenecks, and systemic risks. This report outlines the challenges and deficiencies and offers recommendations to make the process more harmonized, efficient, and transparent. The recommendations address the unique operational and technical characteristics of new large loads while allowing for local and regional differences.

Key Issues in the Large Load Interconnection Process

The large load interconnection process is the starting point for determining which projects will be able to interconnect to the grid, and when. Understanding this process is essential to any substantive discussion of large load deployment. The interconnection process for large loads needs to address an unusually broad range of issues, including these elements and fundamental questions.

Significant Variation in Large Load Interconnection Processes and Use of Processes Not Designed for Today's Complex Facilities

Load interconnection processes vary significantly across transmission utilities and regions, with many jurisdictions relying on ad hoc procedures that were not designed for facilities of the scale or complexity of today's large loads. In addition, flexible interconnection options, including non-firm, surplus, and provisional service offerings, are not uniformly available or well understood across the industry.

Large load facilities' increasingly common pairing with on-site generation puts additional strain on the generator interconnection process, requiring reconsideration of how to study and treat interconnecting generators when they are operationally coupled with large loads. Interconnection processes for co-located large load and generation resources are limited and inconsistently defined, creating uncertainty for developers as well as grid operators.

There is currently no clarity around which entities will regulate and harmonize the various large load interconnection processes (states, FERC, NERC, utilities, ISOs/RTOs) to promote the adoption of core process elements:

- Defined process milestones and timelines
- Defined site-control requirements (e.g., land ownership, leases, permits, easements)
- Milestone-based study fees and financial securities
- Penalties for late-stage withdrawal of interconnection applications
- Cluster study processes and open window application processes
- Option for the interconnection customer to build the interconnection substations and transmission lines to the utility's equipment and construction standards

A Lack of Coordination Between Utilities and ISOs/RTOs

Large load facilities are connecting across all levels of the electricity system through multiple, often separate, interconnection processes. Distribution- and sub-transmission-connected large loads are typically handled directly by utilities; transmission-connected large loads may follow utility-led transmission interconnection processes; and co-located large load and generation configurations may be studied through generation interconnection frameworks administered by ISOs and RTOs. This fragmented structure and lack of coordination creates duplication of effort and makes it difficult to ensure consistent visibility into cumulative system impacts, maintain reliability of the bulk power system, and apply consistent study assumptions, data exchange, timelines, and upgrade determinations across utilities, transmission owners, and ISOs/RTOs. A key question is:

- How can utilities and ISOs/RTOs ensure close coordination and information-sharing between all involved stakeholders?

Lack of Consensus Around Open Questions for Interconnection Studies

The studies performed during the interconnection process are essential to understanding the grid impacts of new large load facilities. In addition to their size, large loads connecting to the grid today are significant in that they have sophisticated equipment and systems and have new operational characteristics. This requires that detailed steady-state, positive-sequence phasor-domain (PSPD), short-circuit, and even electro-magnetic transient (EMT) studies be performed during the interconnection process to adequately evaluate the impacts these facilities have on the bulk power system. However, there are many open questions surrounding the studies' use, including:

- Which grid reliability studies will be conducted for large loads (e.g., steady state, PSPD, short circuit, EMT)?
- Which entities will run these studies (utilities, ISOs/RTOs, others)?

- What new contingencies and operational conditions need to be studied?
- How will co-located large load facilities with paired generation be studied (e.g., gross or net with what conditions)?

Incomplete or Absent Performance Requirements

Performance requirements for large load facilities are incomplete or absent throughout the industry at the NERC, state, ISO/RTO, and utility levels, leaving gaps in the reliability oversight framework for ensuring bulk power system reliability.

- What performance requirements will be placed on the large load facilities at the very beginning of the interconnection process and throughout commercial operation (e.g., voltage and frequency ride-through, power factor requirements, ramp limits)?
- Which entities will define, mandate, harmonize, and enforce these performance requirements (utilities, states, ISOs/RTOs, NERC, FERC)?
- How and when during the interconnection process will conformity with these performance requirements be assessed? How will conformity be verified or tested during commissioning and monitored during the life-time of the project?

Interconnection Costs and Network Upgrades

Cost allocation frameworks for large load interconnection substations/lines and transmission network upgrade costs lack the structure and clarity needed to protect all customers.

- How will allocation for direct interconnection costs and associated network upgrade costs be addressed for large load facilities?

Slow Speed of Large Load Interconnection

Speed to power is one of the primary drivers for most large loads today. As the industry evolves to handle these new facilities, the large load interconnection process must also evolve to become more efficient and consider new capabilities and grid interconnection arrangements that large loads bring with them.

- How can interconnection processes incentivize “bring your own generation” (BYOG)?
- How will transmission capacity limits and flexibility of large loads (non-firm transmission service) be factored into the large load interconnection process at different levels of the electricity system (distribution, sub-transmission, transmission)?



- How will new grid-service offerings (such as non-firm service, flexible service, surplus service) for large load interconnection at the transmission and distribution levels affect grid planning and operational studies?

Recommendations

Based on the Large Loads Task Force's review of current practices and challenges and drawing from the experience and expertise of task force participants including system operators, utilities, data center operators, regulators, and researchers, this report offers a set of recommendations to create a more harmonized, transparent, and efficient interconnection framework for large loads. The recommendations aim to preserve latitude for regional and local variation while establishing the consistency and rigor that large load integration demands.

Large Load Interconnection Process Overall

- The entities that are responsible for large load interconnection processes can follow the recommendations in this report to create more uniform, transparent interconnection processes across the U.S. that will help improve efficiency and speed of large interconnections. It is recommended that the processes be based on clearly defined milestones with readiness requirements that provide credible indication of project viability, roles and responsibilities, timelines, and cost allocation frameworks.
- The potential for development of a FERC Large Load Interconnection Procedure (LLIP) can be explored that establishes a baseline framework for large load interconnection under FERC jurisdiction, analogous to existing generation interconnection procedures, with transparent processes, defined milestones, timelines, and cost responsibility frameworks. States and non-FERC jurisdictional entities could consider adapting the LLIP for large load interconnections over which they have authority.
- The large load interconnection application packages, site control (land ownership, signed lease agreements, or options to purchase or lease land of sufficient size for the facility), and financial readiness requirements can be applied to filter speculative interconnection requests and reduce queue congestion driven by large load projects that lack the commitment to proceed. Harmonizing these requirements insofar as possible across the nation will further help to improve the clarity and efficiency of the large load interconnection process.
- Consistent financial security requirements can be implemented across all interconnection providers, including milestone payments and withdrawal penalties, to mitigate the risk of stranded infrastructure investment and ensure appropriate utility cost recovery from large loads.
- Material modification rules can be finalized to maintain the integrity of interconnection queues and study processes as project configurations evolve, balancing the need to accommodate technological change with the need to preserve study integrity and planning assumptions.
- Expanded use of hosting capacity maps early in the siting and interconnection process can guide large load developers toward locations with available grid capacity, reducing initial study complexity and queue processing time.

Large Load Interconnection Process Coordination

- Coordination among utilities and ISOs/RTOs needs to be enhanced throughout the interconnection process, including formal information-sharing protocols and joint study procedures for facilities that interact with multiple grid layers.
- Queue transparency can be improved at both utilities and ISOs/RTOs, including harmonized treatment of duplicate requests and consistent application of interconnection requirements across service territories.
- Large load interconnections can be integrated into regional transmission planning processes, ensuring that the infrastructure needs of large load growth are reflected in long-term planning and cost allocation frameworks.

Large Load Interconnection Process Studies

- When the volume of large load connection requests exceeds a preset level, utilities and ISOs/RTOs can transition to cluster study approaches for large loads,

consistent with reforms already underway for generator interconnection. This approach improves study efficiency and reduces the compounding delays created by serial study queues.

- For every large load interconnection, steady-state, PSPD, and short-circuit studies need to be performed that meet applicable NERC, ISO/RTO, and utility study requirements.
- A screening process can be established to determine when certain large load facilities require EMT studies and those studies performed for the large load facilities identified.
- Harmonized reliability study methods can be developed for studying co-located load and generation, including conditions under which they are studied as a single entity.

Large Load Interconnection Technical Requirements

- Clear performance and capability requirements for large loads can be developed that apply for the lifetime of these facilities. These include detailed technical modeling requirements for PSPD and EMT models that would be submitted as a part of the interconnection application and updated throughout the interconnection process as facility design and construction advances.
- Technical requirements and practices for assessing loads' conformity with the requirements can be unified across the U.S. grid to enable efficiency and consistency for all large load interconnections.
- NERC large load–specific reliability standards can be developed that address load modeling, performance and capability requirements, physical and cybersecurity, operational coordination, data sharing, emergency operating conditions, and other reliability topic areas. NERC has already started work to develop an interim set of requirements for large loads, to be followed by a more comprehensive applicable standards revisions effort.
- NERC can create an additional registration category that would specify which large loads would be subject to mandatory enforceable requirements within its regulatory area. This separation of large loads in the compliance space can allow for the more efficient creation of technology-specific requirements that will help enhance bulk power system reliability without overburdening traditional large loads (e.g., industrial loads such as steel and glass production) or creating insufficient requirements that fit all large load types. NERC has already begun the work of creating and defining this large load registered entity.

New Solutions to Speed Up Large Load Interconnection

- Harmonized voluntary flexibility products can be developed, including provisional, surplus, and non-firm service options, to give large load customers more flexibility options and accelerate interconnection where firm service is not immediately available.
- Clear, consistent rules can be established for bring-your-own-generation arrangements and generation resources co-located with large loads. The rules will need to clearly define how a co-located resource is treated, modeled, and studied at each of the large load interconnection process milestones.

Staffing Resources

- Utilities and ISOs/RTOs need sufficient staffing resources to process the growing volume and complexity of large load interconnection requests.

Taken together, these recommendations provide a practical and technically grounded pathway toward a large load interconnection framework that supports the reliable, efficient, and timely integration of large load facilities into the U.S. electric power system.

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Introduction

The interconnection of large loads into the U.S. electric power system is advancing quickly, with an exponential rise in the number and magnitude of new large load interconnection requests. These interconnections are driving up load growth forecasts across the nation. For some utilities, large load growth could increase their peak demand to several times the current levels in the next decade (ERCOT, 2026c).

The U.S. Department of Energy (U.S. DOE) estimates that national electricity demand is likely to grow by 15% to 20% over the next decade and could double by 2050 under certain scenarios (U.S. DOE, 2025a). This trend represents a reversal of the long period of flat or declining electricity demand in many regions. These projections are largely driven by data centers, cryptocurrency facilities, industrial electrification, electric vehicle fleets, and other concentrated loads that require significant capacity and reliability. Most such large loads seek fast development and grid interconnection schedules.

Data centers represent the majority of new large loads. As of February 2026, Cleanview estimated that more than 650 planned data center projects would add over 176 GW of peak demand nationally (Thomas, 2026). This highlights that there is both a significant number of large load projects in the interconnection queues and those large load projects have very high demand. While many of the requested large load projects may never mature due to a variety of factors—including bulk power system construction times, high interconnection costs, speculative requests submitted into interconnection queues, supply chain issues, and changes in the data center industry and computer chip technology—future data centers are still likely to have a huge impact on peak electricity demand.[1]

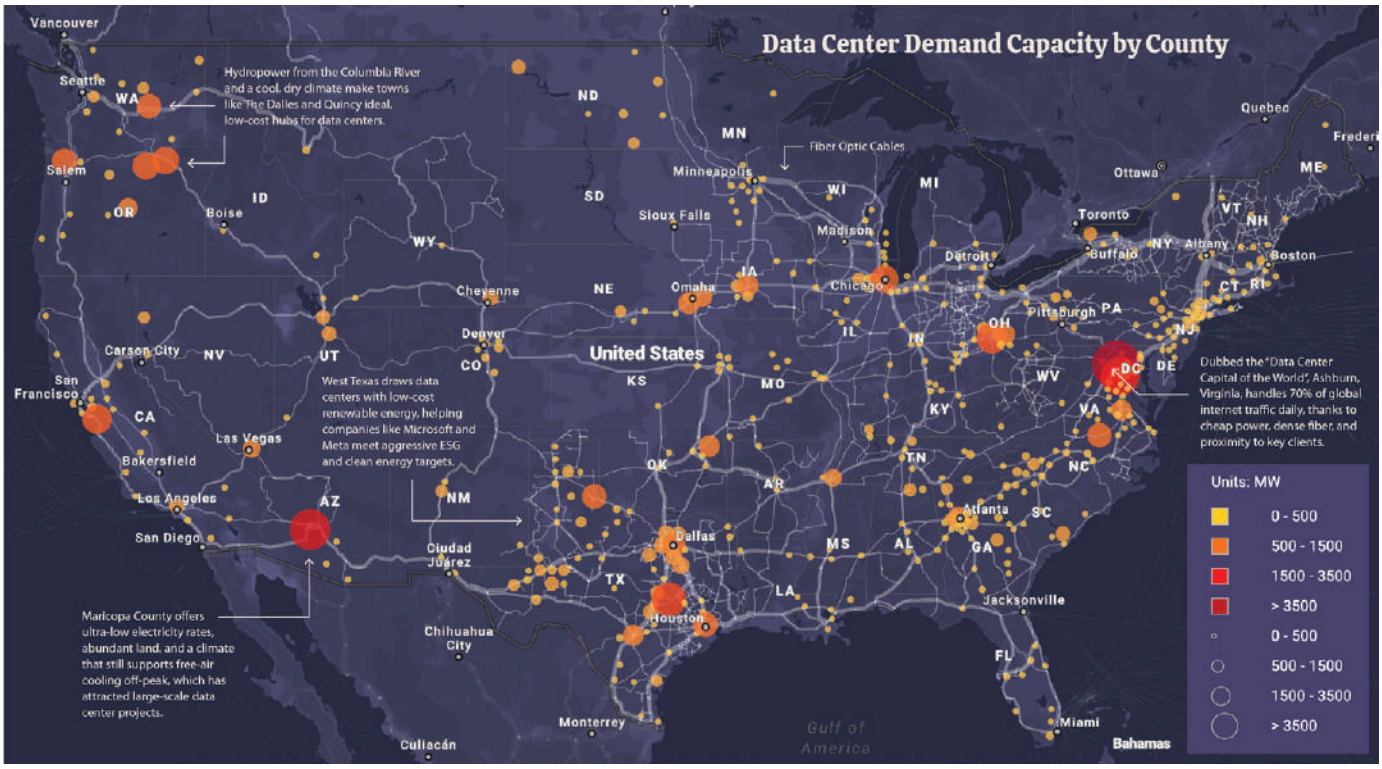
Currently, hundreds of gigawatts of potential large load capacity additions are sitting in interconnection queues across the nation. After a large load application completes the path through the queue and is deemed safe to interconnect, it may wait years until new grid facilities and upgrades are complete before it can physically connect to the grid at full capacity. Backlogs are particularly long in regions where new load interconnection requests are geographically concentrated due to favorable energy prices, available land, fast telecommunications links to major customer centers, available transmission infrastructure or potential for quick transmission expansion, and a robust local supply chain and hiring pool (see Figure 1, p.2). For example, as of March 2026, the Electric Reliability Council of Texas's (ERCOT's) large load interconnection queue contained over 410 GW of new load seeking to interconnect to the system (ERCOT, 2026c), and nearly 88% of those projects are data centers. The Midcontinent Independent System Operator (MISO) has more than 13 GW of potential new large load additions in its load interconnection queue (MISO, 2026a).

The rapid growth in both the scale and volume of large load interconnection requests presents important opportunities, as these projects can support economic development and technological innovation. However, large loads place unprecedented pressure on load forecasting practices, power system planning and operations, interconnection processes, and the ability to expand infrastructure on timelines that align with large load development. As large

1 Computer chip technology (such as graphics processing units) inside data centers is expected to continue to become more efficient and have more computational power as well as different operating characteristics.

FIGURE 1

Geographical Concentration of Operational and Under-Construction Data Centers Across the United States, as of September 2025



Data center projects (operational and under construction) are geographically concentrated in areas with favorable energy prices, available land, fast telecommunications links to major customer centers, available transmission infrastructure or potential for quick transmission expansion, and a robust local supply chain and hiring pool.

Source: N. Routley, "Mapped: The Massive Network Powering U.S. Data Centers," *Visual Capitalist*, September 20, 2025, https://www.visualcapitalist.com/map-network-powering-us-data-centers/; map/data sourced from https://maps.nrel.gov/speed-to-power/.

As large loads increasingly dominate queue activity in several regions, it will be essential to improve queue transparency, distinguish viable projects from speculative requests, and align grid build-out timelines with customer schedules to reliably accommodate this new era of electricity demand growth.

loads increasingly dominate queue activity in several regions, it will be essential to improve queue transparency and management, distinguish viable projects from speculative requests, and align grid build-out timelines with customer development schedules to reliably accommodate this new era of electricity demand growth.

Where it exists, the large load interconnection process in the U.S. includes seven sequential phases: the pre-application phase, the interconnection application, initial screening and feasibility studies, a system impact study, a facility study, a signed interconnection agreement, and construction/commissioning. Within these seven phases is a great deal of variation around the specifics of who executes, who approves, what documentation and data submission are required, and what dictates the phase's timeline. The interconnection process is the starting point for which large loads will be able to interconnect to the grid and when. Uncertainties in the interconnection process delay timelines and may trigger additional study requirements, leading to higher costs for large load developers.

To identify current practices, gaps, and challenges and develop harmonized best practices for integrating large

loads reliably and efficiently, the Energy Systems Integration Group (ESIG) launched the Large Loads Task Force, which convened a multi-stakeholder group of system operators, utilities, data center operators, regulators, and researchers.

The task force adopted the North American Electric Reliability Corporation's (NERC's) definition of a large load facility:

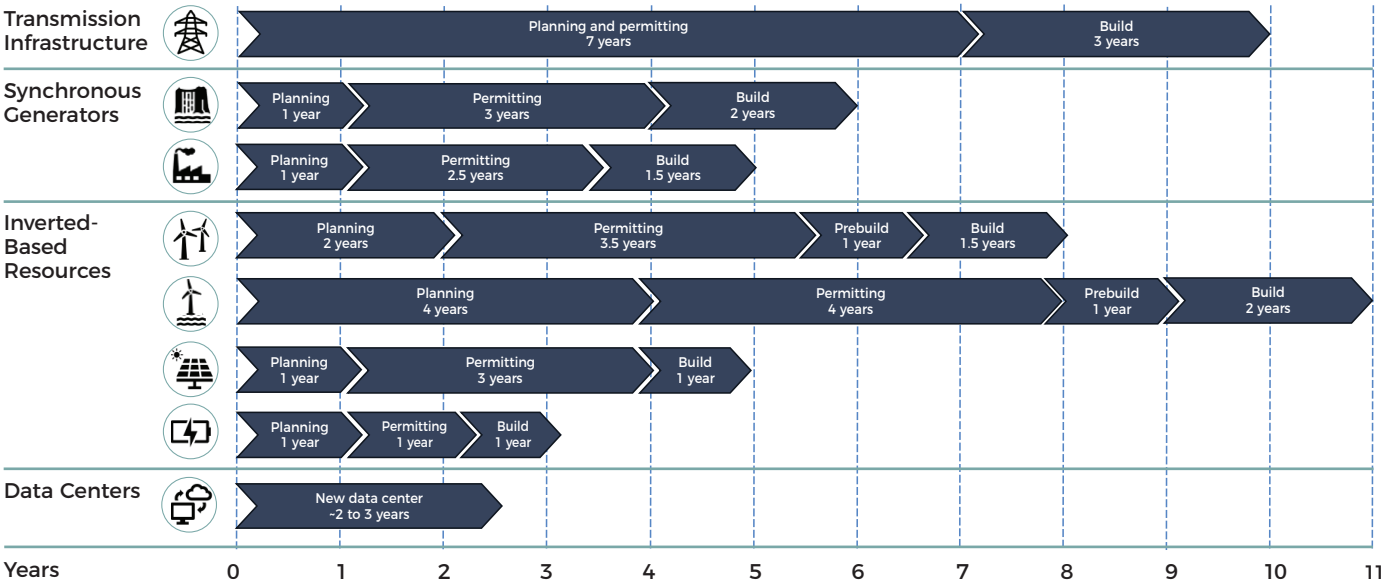
> Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS [bulk power system] due to its demand, operational characteristics, or other factors. Examples include, but are not limited to, data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces (NERC, 2025a).

ESIG's Large Loads Task Force consisted of seven specialized project teams, each focusing on a key aspect of large load integration, from interconnection and operations to planning and market design. This report reviews current large load interconnection processes across the nation and identifies impediments, inefficiencies, and potential reliability risks related to current interconnection processes. It then (1) offers recommendations for modifying the interconnection process to become more harmonized, efficient, and transparent; and (2) addresses the unique operational and technical characteristics of new large loads, while providing flexibility in the process for specific local and regional differences.

Issues with the Interconnection Process

While the proliferation of large loads represents an opportunity for economic development, it imposes significant stress on the grid. Figure 2 shows how new large loads such as data centers can be developed on relatively short timelines, much shorter than the time it takes to plan, permit, procure equipment for, and build transmission, distribution, and generation infrastructure to support these loads.

FIGURE 2
Timelines to Develop and Build Grid Infrastructure and Large Loads



Data centers can be developed on relatively short timelines, much shorter than the time it takes to plan, permit, procure equipment for, and build transmission, distribution, and generation infrastructure to support these loads.

Source: R. Quint et al., *Practical Guidance and Considerations for Large Load Interconnections* (Elevate Energy Consulting and GridLab, 2025), https://gridlab.org/wp-content/uploads/2025/07/GridLab-Report-Large-Loads-Interim-Report.pdf.zip.



Additionally, large load facilities pose challenges to the bulk power system that include:

- Reliability risks for planning, operations, and resource adequacy due to the rapid, high-volume interconnection of large loads (NERC, 2025a)
- Disputes between large load entities and transmission owners over interconnection rights and obligations
- Potential cost allocation concerns where speculative large load growth could trigger new infrastructure investments that are not sufficiently utilized to recoup costs from those loads
- Impacts on utility customer rates, wholesale rates, and system planning

Large load customers frequently struggle to understand interconnection timelines, costs, and technical requirements, and therefore sometimes submit multiple applications for a single facility to hedge the uncertainty. Utilities then must process redundant requests, which stresses staff resources that study and process interconnection requests for large loads, and causes delays with significant economic consequences. Speculative large load interconnection requests and uncertainties also send false signals such as inflated load forecasts to utilities and wholesale markets, misleading investment decisions.

The jurisdiction, applicable entities, and coordination of large load interconnection processes and queues are complex and rapidly changing. Traditionally, utilities and other transmission providers have been responsible for load interconnections, including for large loads, under either state or federal regulations and tariffs. These historical load interconnection processes remain today but may be ill-equipped to handle the quantity and size of today's loads. Additionally, there's an emerging need for closer coordination on large interconnection with independent system operators (ISOs) and regional transmission organizations (RTOs). Industry experience to date has highlighted the following important gaps, inconsistencies, and unresolved questions related to the large load interconnection:

- Load interconnection processes vary significantly across utilities and regions, with many jurisdictions relying on ad hoc procedures that were not designed for facilities of the scale or complexity of current large loads.

- There is significant variation in the scope and complexity of studies to determine whether the large load can be accommodated at its requested point of interconnection as well as variation in the interconnection cost and timing.
- There is inadequate coordination and information-sharing during the large load interconnection process between utilities and ISOs/RTOs. This often results in duplicated efforts, conflicting study assumptions, load forecasts that vary widely and change rapidly, and delayed processing of interconnection applications.
- There are open questions surrounding interconnection studies, including which grid reliability studies will be conducted for large loads, which entities will run these studies, what new contingencies and operational conditions need to be studied, and how co-located large load facilities with paired generation will be studied.
- Performance requirements for large load facilities are incomplete or absent throughout the industry at the NERC, state, ISO/RTO, and utility levels, leaving gaps in the reliability oversight framework for power systems.
- Cost allocation frameworks for large load interconnection substations/lines and transmission network upgrade costs lack the structure, clarity, and consistency needed to protect all customers.
- Interconnection processes for large loads can take a great deal of time, due in part to limited and inconsistently defined pathways for the interconnection of co-located large load and generation resources, and flexible interconnection options not uniformly available or well understood across the industry.

Report Organization

Given the rapid increase of large load interconnection requests in most regions, as well as the rise of combined facilities that include both a large load and co-located generation resource, utilities and regional grid operators are beginning to solve these challenges by collaborating and sharing responsibilities. These evolving issues vary by region, and the recommendations in this report focus on core aspects of the large load interconnection process, regardless of which entity manages it.

Given the rapid increase of large load interconnection requests in most regions, as well as the rise of combined facilities that include both a large load and co-located generation resource, utilities and regional grid operators are beginning to solve these challenges by collaborating and sharing responsibilities.

This report provides an overview of how large load interconnections are handled in the U.S. at both the transmission and distribution levels, including regulatory gaps, queue procedures, and timelines. The findings are based on information collected by the ESIG Large Loads Task Force from large load developers, owners, and operators; utilities; and ISOs/RTOs about what is working well and what challenges they face.

The next section of the report gives an overview of the large load interconnection process, including what this looks like for utilities of different types, the central role of interconnection studies, and lessons the industry can learn from recent experience with generation interconnection. The following section discusses the transmission-connected large load interconnection process from the perspectives of utilities and ISOs/RTOs. The report then discusses possible types of federal action on large load interconnection based on lessons learned from earlier generator interconnection reforms for inverter-based resources and offers recommendations for large load interconnection processes. Then, recognizing that some large loads may choose to interconnect at the distribution level, the report turns to interconnection processes for distribution-connected large loads, identifying gaps and challenges in existing processes and providing recommendations for future improvements. The report concludes with a summary of the recommendations of the Large Loads Task Force, intended to create a more harmonized, transparent, and efficient interconnection framework for large loads.

Overview of the Large Load Interconnection Process

Transmission-level large load interconnections are rapidly reshaping the planning and operational landscape of the bulk power system. Unlike traditional retail load growth that is incorporated gradually over time, today's large load projects are rapidly entering the system through discrete, high-capacity requests to utilities. These projects include the many large load facilities of more than 1 GW being planned and built across the country. Given their size, these new large load facilities materially affect regional reliability, transmission expansion needs, and resource adequacy. There is an urgent need to develop a systematic interconnection process framework with clearly defined milestones akin to that applied to the interconnection of generation facilities.

Traditionally, utilities have been responsible for load interconnections, including of large loads, under either state or federal regulations and tariffs. This approach was sufficient since large load interconnection requests were rare and geographically distributed. With the increased



number, size, and geographical concentration of today's large loads, their impacts on the bulk power system are increasing and there is a growing role for ISOs/RTOs in the large load interconnection process.

While there are diverse operating structures and regulatory environments across the industry, a complete large load interconnection process, which exists only in a minority of cases, can be distilled into seven distinct phases or milestones (Figure 3, p. 9), discussed in the next section.

Milestones Distilled from Currently Implemented Large Load Interconnection Processes

The following milestones have been synthesized from a review of the few holistic and currently active large load interconnection processes. Some regions use only a subset of these phases, and the actual implementation and details for each step vary widely. At a high level these milestones form a solid framework for a systematic large load interconnection process and can be adopted by areas that are just starting to develop their large load interconnection processes.

Milestone 1: Pre-Application Phase

Large load customers engage with utilities early in the process to discuss their tentative plans for load interconnection, including project details, siting, and other plans. Utilities share their expectations for interconnection timelines, requirements, processes, and more. This allows the utility/ISO/RTO and the customer to gain a mutual understanding and align on expectations.

Milestone 2: Interconnection Application

The large load customer submits a formal interconnection application with details about demand size, location, technical aspects (design, diagrams, models, etc.), and load growth trajectory, accompanied by financial deposits.

Milestone 3: Initial Screening and Feasibility Study

The utility conducts high-level viability assessments for the proposed large load interconnection, focused on items such as the voltage level required for interconnection, access to nearby transmission or distribution



infrastructure, potential direct-connect network impacts, the need for broader network upgrades, and known obstacles or issues.

Milestone 4: Large Load System Impact Study

The utility performs detailed reliability studies (see the section "Interconnection Studies") to quantify the effects the large load has on the transmission system and, if applicable, the distribution system. The studies analyze the load's impacts on thermal overloading, system voltages, stability, and other reliability factors. They also determine the necessary system upgrades needed to alleviate any identified adverse impacts from the large load on the system.

Milestone 5: Large Load Facilities Study

The utility performs a study focused on the detailed engineering designs, substation configuration, protection system upgrades, and upgrades required for direct-connect infrastructure modifications. This information is an input into the construction phase of the project.

Milestone 6: Signed Interconnection Agreement

The utility/ISO/RTO and customer sign an agreement to formalize the terms and conditions for interconnection. All parties draft and negotiate the terms, outlining roles and responsibilities, cost responsibility, schedule, and operational performance expectations, as well as ensuring compliance with regulatory requirements and other industry standards.

Milestone 7: Construction and Commissioning

The large load customer constructs the facility itself. Depending on their agreement, the utility and/or customer may construct the electrical facilities required to connect the load. The utility also makes any broader network upgrades required to connect the facility reliably. The load customer conducts testing and commissioning procedures to verify the facility's readiness. The utility may require documentation and verification that the facility is operating reliably and is compliant with applicable requirements.

Additional Considerations: Post-Commissioning Monitoring and Compliance

While the post-commissioning phase is outside of the interconnection process itself, it is important to cover it here for completeness. After a large load facility has been commissioned and started commercial operation, the utility and large load customer each monitor the reliability of the facility and adherence to the requirements and procedures as applicable. Post-commissioning monitoring equipment (e.g., power quality meters and disturbance recorders) needs to be installed to monitor and analyze the large load facility's performance. Periodic review may be performed by the utility or customer to verify compliance with applicable requirements.

Differences in Transmission Interconnection Processes for Different Utility Types

The U.S. electric utility industry operates under a complex set of organizational structures, each shaped by different power system characteristics, levels of inverter-based resources (IBRs) and large loads, regulatory environments, ownership models, and operational philosophies. This section examines the large load interconnection processes across four distinct utility types and discusses the nuances of how organizational structure can directly impact process efficiency, customer experience, and system reliability outcomes.

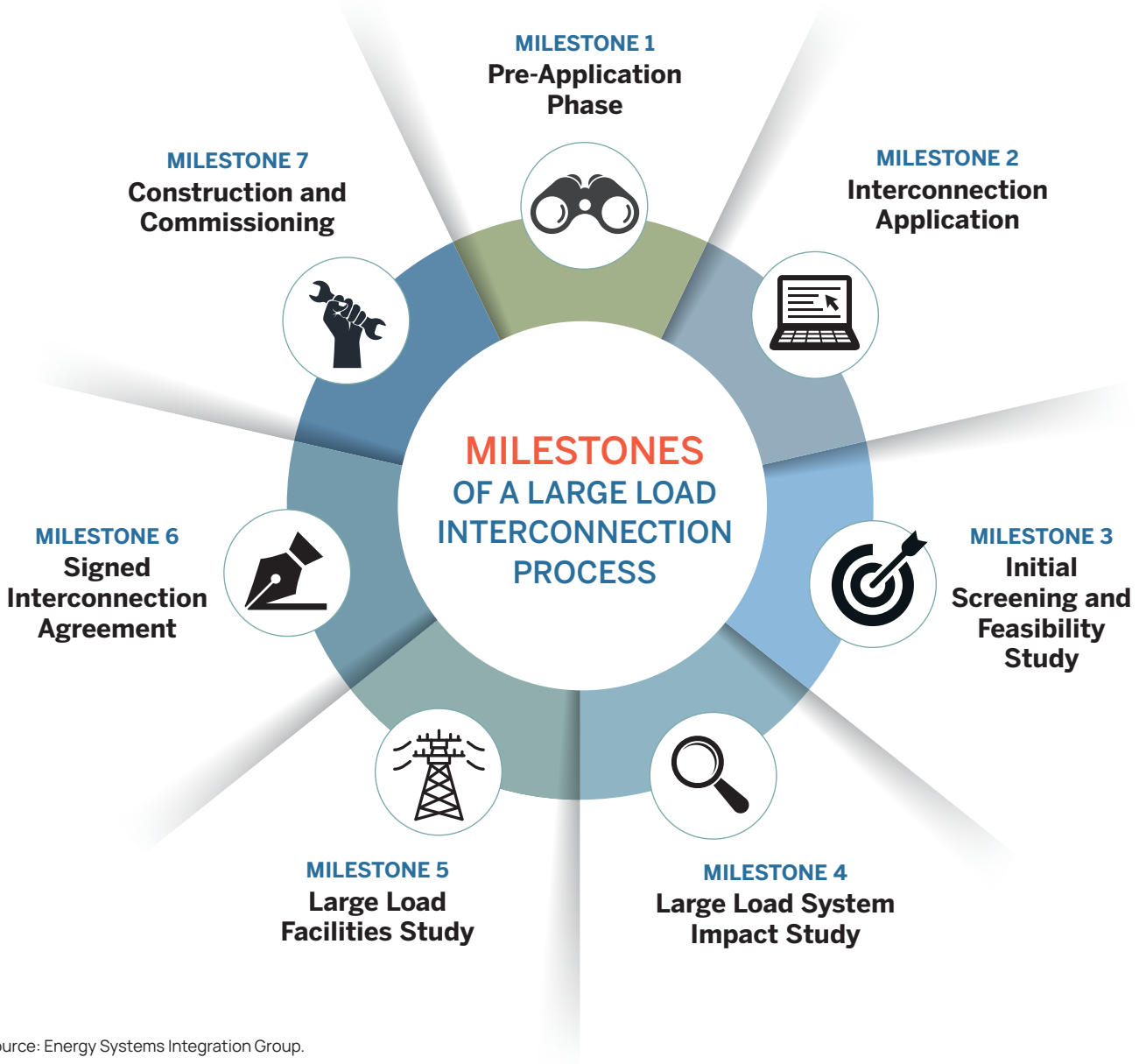
Large Load Interconnection Processes for Different Utility Types

The following four utility types have different considerations and practices for interconnecting large loads, with the differences primarily driven by whether the utility is within an ISO/RTO area and whether the utility owns generation:

- **Network-only utilities** operate primarily within ISO/RTO markets and do not own generation assets. Generation and load interconnection processes in their system need to be heavily coordinated with the ISO/RTO to ensure coordinated transmission planning efforts and adequate load forecasting and generation resource availability/adequacy.

FIGURE 3

Phases (Milestones) of a Large Load Interconnection Process



Source: Energy Systems Integration Group.

- **Vertically integrated utilities within ISO/RTO markets** have many similarities to the transmission- and network-only utilities, with the core difference being that the vertically integrated utility is responsible for securing or building enough generation to serve the load in its service territory, including large load interconnections. Both generation and large load interconnections need to be coordinated with the ISO/RTO. Vertically integrated utilities' interconnection processes must satisfy both their own internal requirements and external (ISO/RTO) obligations, creating complex regulatory and operational interfaces that require sophisticated coordination mechanisms.
- **Vertically integrated utilities outside of ISO/RTO markets** maintain full control over their

Vertically integrated utilities' interconnection processes must satisfy both their own internal requirements and external (ISO/RTO) obligations, creating complex regulatory and operational interfaces that require sophisticated coordination mechanisms.

load interconnection process, from initial application through energization. They coordinate internally between transmission, distribution, and generation planning functions. Operating outside of ISO/RTO markets, they retain full responsibility for system planning, operations, and reliability, including resource adequacy. This structure enables streamlined internal decision-making but requires comprehensive in-house expertise across all system functions, including all modeling and study activities. Their interconnection processes reflect this self-contained approach to system management; however, these utilities still require close coordination with neighboring transmission entities that may be affected by newly interconnecting generators or large loads.

- **Cooperative utilities (co-ops)** typically serve smaller service territories, but many are also facing growing numbers of large load interconnection requests that can significantly impact their systems. Distribution co-ops rely on generation and transmission cooperatives or other wholesale power suppliers for bulk power supply and often depend on a third-party or jointly owned transmission system for delivery and regional grid access. The electric cooperatives operate under a member-ownership model, emphasizing service to rural and suburban communities. Their not-for-profit structure and democratic governance create decision-making processes focused on member benefits rather than shareholder returns. As a result, large load interconnection requests may receive heightened scrutiny regarding cost allocation, impacts on existing members, required system upgrades, and long-term power supply obligations, and may also involve additional coordination among local co-ops, generation and transmission providers, boards, and transmission partners compared with more vertically integrated utilities.

While the technical challenges of integrating large loads remain consistent, the procedural, financial, and regulatory approaches vary significantly based on utility type and institutional requirements. Understanding these differences is crucial for developing harmonized processes that can accommodate diverse organizational models while maintaining interconnection process effectiveness.

As mentioned above (Figure 3, p. 9), the sequential phases of the large load interconnection process—pre-application phase, interconnection application, initial screening and feasibility study, system impact study, facility study, signed interconnection agreement, and construction and commissioning—create a fundamental structure for every interconnection request. While these seven phases are universally present, the specifics of who executes, who approves, and what dictates the timelines of each phase highlight the differences between the four major utility types, summarized in Table 1 (p. 10). The differences in interconnection process approaches highlighted in the table come from entities that already have significant experience with interconnecting large loads and the lessons they have learned to date.

While the technical challenges of integrating large loads remain consistent, the procedural, financial, and regulatory approaches vary significantly based on utility type and institutional requirements.

Evolving Role of ISOs/RTOs in the Large Load Interconnection Process

ISOs/RTOs and utilities have distinct roles in ensuring bulk system reliability and resource adequacy, including identifying the transmission facilities required to reliably serve new loads and ensure deliverability to new generation. Historically, load interconnection processes for transmission-connected loads were primarily run and managed by utilities directly, with little engagement with the ISO/RTO when a load was interconnecting in an ISO/RTO region.

TABLE 1

Large Load Interconnection Process Variations for Different Types of Utilities

Utility Type	Variations in Approach
Transmission- and distribution-only utilities and vertically integrated utilities within ISO/RTO markets	• **Pre-application phase:** There may be coordination between the utility and the ISO/RTO before the customer formally submits the interconnection application, including a kick-off call to review the scope of studies with all relevant documents and data that the customer has submitted. • **Limited customer identification/interaction:** Currently, limited pathways of communication exist between the ISO/RTO and large load customers, often because the large load customers historically have not had to interface directly with the ISO/RTO but rather just with the interconnecting utility. The interconnecting utility then informs the ISO/RTO of the large load interconnection when requesting the necessary transmission upgrades or expansion. • **Large load application and initial screening:** The customer works with the utility to complete a non-disclosure agreement, providing project application details, data survey, a one-line diagram, and site control information (e.g., land ownership, leases, permits, easements). This is followed by a point of interconnection review and realistic in-service date guidance. Increasingly there is a need to coordinate large load interconnection requests with ISOs/RTOs at this early interconnection phase. • **Study coordination:** Interconnection studies and updates to load models need to be coordinated with ISO/RTO planning departments for broader regional visibility. If the entity is transmission-only, it needs to further coordinate with assigned distribution service providers or load-serving entities in the geographical area. Large load customers may sometimes also be required to submit load interconnection requests to distribution service providers or load-serving entities. The ISO/RTO may review the utility's study report or perform its own "do no harm assessment" and assign supplemental project numbers (for tracking and planning purposes),[2] and then the project proceeds to an interconnection agreement with the utility. These studies need to be coordinated with a kick-off meeting for scoping, continued collaboration throughout the study review process, and a final approval from the ISO/RTO. • **Broader visibility of large loads in an area spanning multiple utility service areas:** Building on the previous point, since ISOs/RTOs usually have a broad view of their systems, they are best positioned to flag potential system-level reliability issues for transmission owners that narrower service-area studies could miss. • **Timeline management:** ISO/RTO studies or study review cycles and cluster processes, when they are implemented for large loads, increasingly affect process timelines.
Vertically integrated utilities outside ISO/RTO markets	• **Direct customer interface:** The utility serves as a single point of contact for interconnection customers. • **Streamlined decision-making:** These utilities are able to take advantage of internal coordination between all departments across transmission, generation, and distribution, which enables faster decision processes. • **Customizable system impact studies:** Vertically integrated utilities outside ISO/RTO markets have the ability to fully customize study scope based on expected system impacts from each project without having to coordinate with an ISO/RTO. • **Integrated planning:** Ideally, the vertically integrated utility coordinates large load interconnection processing across all system functions within the company. Critically, very large load interconnection studies must still be closely coordinated with neighboring utilities to ensure that appropriate system-wide analysis is performed by all impacted systems.

— CONTINUED —

2 One example of growing ISO/RTO coordination is within ERCOT, where, due to the high number of large load interconnection applications, the "clustering" or "batching" interconnection process was developed (and currently being finalized) in which multiple potential large loads and generators in a common geographical or grid topological region will be studied by the ISO together to capture the operational interactions and collective infrastructure requirements across that group of projects.

TABLE 1
Large Load Interconnection Process Variations for Different Types of Utilities CONTINUED

Utility Type	Variations in Approach
Cooperative utilities	• **Member-focused approach:** The large load interconnection process at cooperative utilities considers the impacts on existing cooperative members. • **Resource-limited studies:** The cooperative may rely on external consultants or generation and transmission cooperative expertise, and coordinates with the ISO/RTO where applicable. • **Community impact assessment:** The large load interconnection process evaluates local economic and social impacts. • **Collaborative decision-making:** Board-level involvement is common for major interconnection decisions, particularly when the size of the large load customer exceeds the size of the host cooperative utility. • **Load interconnection requests recieved by the utility:** The distribution cooperative utility receives the request, performs initial checks, and refers to the relevant transmission owner (or generation and transmission cooperative) when transmission impacts arise. • **Coordination of the resource adequacy assessment:** The co-op has to work with other utilities and supply resources to determine whether the region has enough resources to serve the new large load in addition to existing and other new loads.

Source: Energy Systems Integration Group.

As alluded to in the previous sub-section, this situation is now changing because of the impacts today's large loads have on grid planning and operation that need to be carefully considered at both the utility and ISO/RTO levels. Large load interconnection spans the interface between utilities and ISOs/RTOs. Utilities still manage the official large load interconnection process and interconnection queues, handling project intake, project screening, and local transmission impacts; defining interconnection costs; and developing construction plans to implement any required direct transmission interconnection facilities and transmission system upgrades. They are also responsible for tracking milestone requirements such as site control (land ownership, signed lease agreements, or options to purchase or lease land of sufficient size for the facility), financial commitments and advancement through the queue, the projects that withdraw or get removed from the queue, and other logistical aspects similar to generation interconnection queues. However, coordination with an ISO/RTO now needs to take place for the purpose of impact studies and study reviews, as well as regional coordination for broader system impact assessment (for clusters of new projects), transmission planning, and resource adequacy assessments, which are primary responsibilities for ISOs/RTOs.

Interconnection Studies

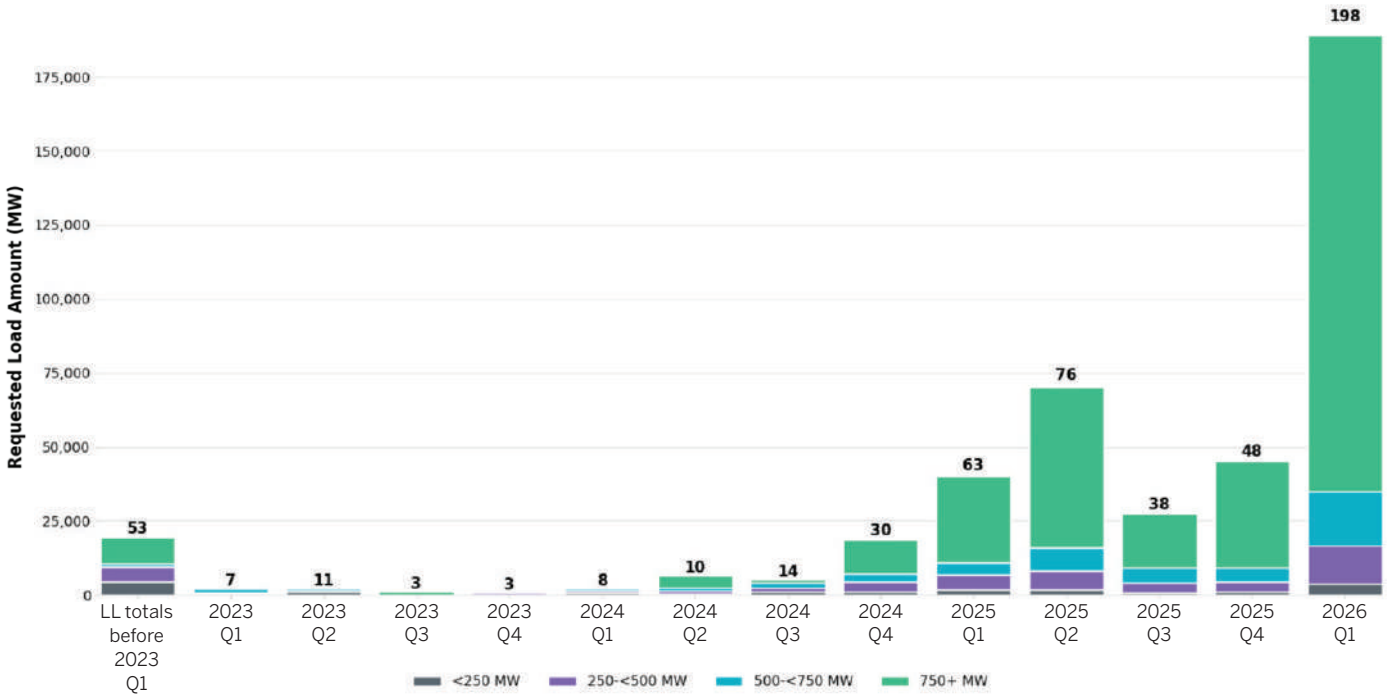
At the heart of the interconnection process are a variety of technical studies conducted to determine whether and how the new large load can be connected to the grid without causing harm to either the grid or its existing customers. These detailed, complex technical studies are performed by utilities and/or ISOs/RTOs. Technical study results inform what kind of new transmission infrastructure and generation infrastructure may be needed to serve the new large load, what mitigating equipment or behaviors are needed at the new large load facilities, and how the grid can be protected from the new load facility.

A Need to Capture Reliability Risks with New Large Loads in System Impact Studies

New large load facilities may require additional technical studies, analyses, and mitigating solutions that have historically not been needed for loads. These new loads are equivalent in size to some of the largest generation facilities on the electricity system. However, most current load interconnection processes were designed for loads under 50 to 100 MW and have not typically required the information, data, and modeling necessary to handle the

FIGURE 4

Number of Large Load Interconnection Project Applications in ERCOT from Q4 2022 Through Q1 2026



Source: Electric Reliability Council of Texas, "Large Load Interconnection Status Update," March 26, 2026, https://www.ercot.com/files/docs/2026/03/27/March-TAC-Report-Updated_03262026.pptx.

added complexity of new large load projects and their interconnection requests. Figure 4 shows the magnitude of this challenge through the rapid increase of large load interconnection applications and evolution of projects' size in ERCOT from late 2022 through Q1 2026 (ERCOT, 2026c).

The industry is learning some hard lessons from the existing fleet of large loads about the consequences of insufficient or inaccurate technical studies to support large load interconnections to the bulk power system.[3] In July 2024, a normally cleared grid fault in northern Virginia triggered the sudden loss of more than 1,500 MW of data center load across 60 facilities that switched nearly simultaneously to back-up power via uninterruptable power supplies (UPSs), because they were designed to disconnect from the grid after a preset number of voltage excursions (NERC, 2025b). The disconnected load did not come back completely until a few hours later. This and other similar disturbance events, covered in the ESIG Large Loads Task Force report *Large Load Disturbance Events*,[4] underscore the operating risk that a large fleet of large loads poses to power grid reliability (NERC, 2025c).

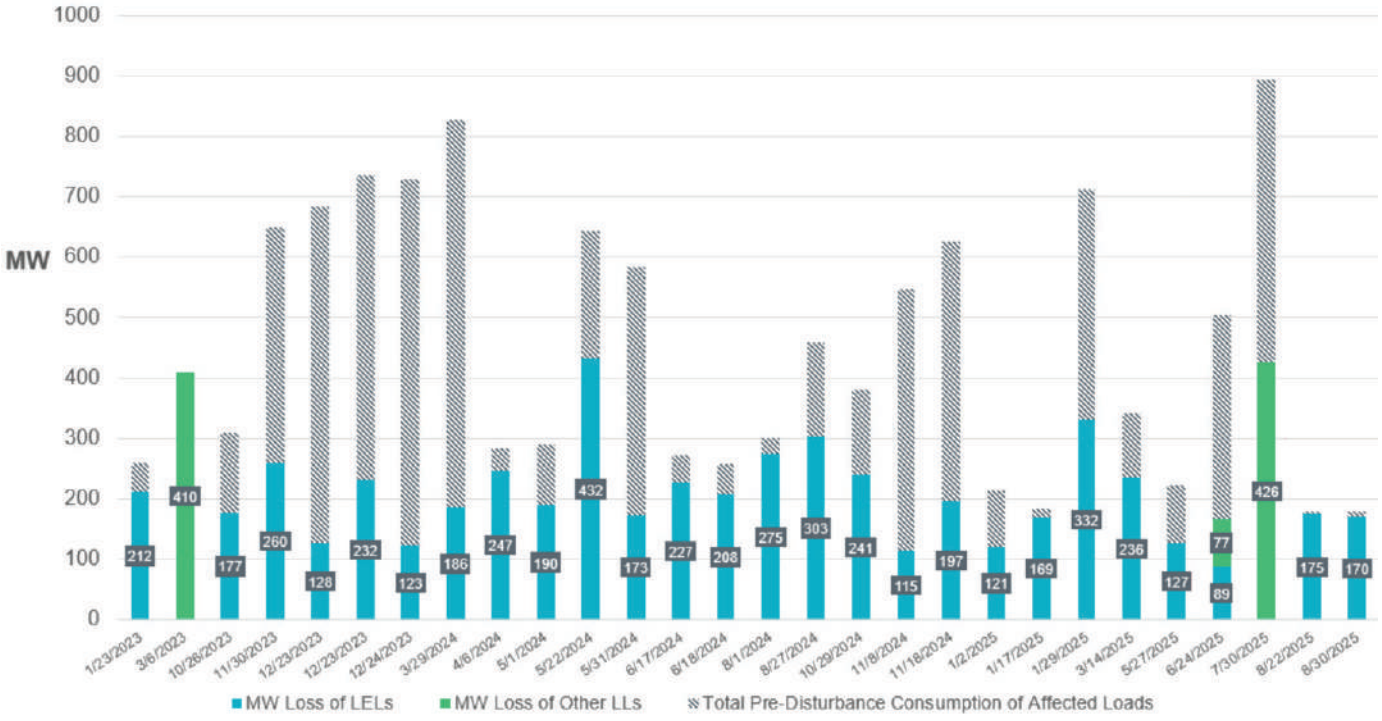
Sudden and frequent drops in electricity usage by large load facilities under 1 GW in size (see Figure 5, p. 14) for an ERCOT example) are also challenging system stability. While these specific disturbances did not result in widespread impact to the bulk power system themselves, the critical concerns are that many different large load

3 See the ESIG Large Loads Task Force reports *Large Load Performance Requirements: Current Practices and Recommendations* (https://www.esig.energy/reports-briefs/large-load-interconnection-performance-requirements/); *Large Loads: Behaviors, Capabilities, and Limitations* (https://www.esig.energy/reports-briefs/large-loads-behaviors-capabilities); *Reliability Impacts of Large, Power Electronics–Interfaced Loads* (https://www.esig.energy/reports-briefs/large-loads-reliability-impacts); and *Large Load Disturbance Events* (https://www.esig.energy/reports-briefs/large-load-disturbance-events/).

4 See https://www.esig.energy/reports-briefs/large-load-disturbance-events.

FIGURE 5

ERCOT Large Load Loss/Reduction Events Due to Poor Ride-Through Capability, 2023 to August 2025



From January 2023 through August 2025 the Electric Reliability Council of Texas experienced many sudden and frequent drops in electricity usage by large load facilities under 1 GW in size, which may challenge the system stability.

Source: Patrick Gravois, "ERCOT Recent Large Load Loss/Reduction Events," Presentation to ERCOT Large Load Working Group, October 24, 2025, https://www.ercot.com/files/docs/2025/10/22/ERCOT-Recent-Large-Load-Events_LLWG_24Oct2025.pptx.

facilities all experienced the issues at the same time, and the size of these disturbances may increase with the continued proliferation of large loads. Additionally, the disturbances are occurring unexpectedly because these large load behaviors are not captured in current models of the large load facilities that are used during interconnection, planning, or operations studies (Hobbs, 2025).

Another system stability concern with large loads is the emergence of forced power consumption oscillations, rapid fluctuations in power demand at the grid connection point of some large load facilities, particularly certain artificial intelligence (AI) data centers and some crypto-mining facilities. The resulting behavior can range from very fast oscillations in the 10 to 50 Hz range to slower cycling between roughly 0.1 and 2.5 Hz, and may appear intermittently or increase as facility loading rises. In ERCOT, for example, one large electronic load showed 23 Hz oscillations that increased from about 15 to 20 MW peak-to-peak at lower operating levels to around 50 MW at higher loading. A similar event was reported in the Dominion Energy system, where sustained oscillations near 14.7 Hz were linked to interactions between a data center UPS system and changing grid conditions.[5] The primary concern for the power system is that these oscillations could excite the bulk system modes, including sub-synchronous torsional interactions in synchronous generators, which can damage synchronous generator equipment, or wider-area electromechanical oscillations, depending on their frequency and where they occur on the network.[6] There is a need for cautious, deliberate

5 For more information, see the ESIG report *Large Load Disturbance Events*, https://www.esig.energy/reports-briefs/large-load-disturbance-events/.

6 For more information about power system oscillations, see ESIG's report *Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems: A Practical Guide* at https://www.esig.energy/oscillations-guide/.

processing and analysis of large load interconnection requests to ensure that technical problems such as voltage and frequency ride-through and forced or natural resonant oscillations caused by large load operations do not compromise bulk power system reliability.

In response to reliability events such as these, NERC issued a Level 2 Alert, "Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations" to all grid operators and transmission entities. NERC warned that "rapid, major swings in load, experienced both in typical operations as well as in response to grid disturbances, can impact the bulk power system's ability to maintain frequency, regulate transmission voltage, and otherwise maintain stability" (NERC, 2025c, 1). The summary of responses to the Level 2 Alert emphasized that transmission planners and operators often receive late or incomplete information about large load projects, including uncertain in-service dates, phased build-outs, changing demand profiles, and limited visibility into ride-through capability, behind-the-meter generation, or control systems, which can undermine the accuracy of technical studies during the interconnection process and lead to multiple restudies (NERC, 2026a). NERC also noted that representations of loads in traditional static load models may be insufficient for some large electronic loads whose dynamic behavior during faults, voltage disturbances, or automatic recovery following grid events can materially affect reliability, creating a need for better large load modeling and closer coordination among load developers, utilities, and reliability coordinators. Overall, the NERC alert's message was that interconnection processes, data requirements, and study methodologies need to evolve quickly to keep pace with the scale, speed, and technical characteristics of today's large loads. A NERC Level 3 Alert, "Essential Actions: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control" then followed, aiming to (NERC, 2026c):

- Improve the modeling and study of large computational loads in both planning and operational time frames, including simulations in the positive-sequence phasor and electromagnetic transient (EMT) domains, and increase visibility into load performance through enhanced monitoring, disturbance recording, and instrumentation.
- Establish better commissioning, testing, and validation practices so that as-built / as-operated behavior matches study assumptions.
- Address reliability concerns associated with fault response, automatic load recovery, oscillatory behavior, protection interactions, and power electronic controls.
- Encourage stronger coordination and information exchange between utilities, ISOs/RTOs, developers, manufacturers, and large load operators.
- Reduce the risk of widespread disturbances, instability, or unexpected load tripping caused by rapidly growing and increasingly complex large electronic loads.

Absence of Uniform National Performance Requirements

While the need to address reliability risks posed by the proliferation of large loads is widely acknowledged, utilities and system operators lack guidance from any uniform national performance standards or requirements for large loads. Uniform performance standards for large loads were not needed in the past because most industrial loads were not very large, there were not very many, and utilities could handle each one on an individual basis. However, the need for detailed technical performance requirements is clear from the high volume of large load interconnection requests, the large project sizes, technological complexity of the emerging large loads, and the already-observed large load disturbance events.

Today, utilities are using different, historically based large load interconnection study methodologies with limited requirements for large load interconnections. This leads to variations in system impact study outcomes, and the

While the electricity industry has for many years defined a suite of standardized, performance-based technical interconnection requirements for new generators and storage connecting to the grid, no comparable interconnection standards or requirements currently exist for new large loads.

necessary mitigation of any adverse grid impacts is not always defined or determined correctly. Large load developers are also facing risks in an uncertain regulatory environment, where large load performance requirements, modeling requirements, and study scopes may change during project development.

System reliability can be enhanced through the establishment of interconnection performance requirements for large loads, including:

- **Technical performance requirements** that articulate clear rules for voltage and frequency ride-through, harmonics and flicker limits, power factor ranges, and ramp-rate limits.
- **Protection coordination** that establishes customer-side protection coordinated with the transmission owner's or ISO's protection standards, including anti-islanding and transfer trip where needed.
- **Telemetry and controls** that define the required real-time data (MW/MVAR, voltage, UPS/generator status, curtailment setpoints) to ensure operational awareness and power system control capabilities for the grid operator.
- **Monitoring requirements** that define real-time measurements, including measured signals and measurement resolution and retention policies, for post-commissioning performance analysis and model validation.

Today the technical interconnection requirements for large loads are imposed either on a case-by-case basis or on all load interconnection requests to an individual utility or ISO/RTO. While the electricity industry has for many years defined a suite of standardized, performance-based technical interconnection requirements for new generators and storage connecting to the grid, no comparable interconnection standards or requirements currently exist for new large loads—in part because the growth of new large load demand is so recent that there has been little time to recognize the challenge, identify and study potential solutions, and reach consensus over what specific technical requirements to adopt. For a comprehensive review of the interconnection performance requirements for large load interconnections, see the ESIG Large Loads Task Force report *Large Load Performance Requirements: Current Practices and Recommendations*.[7]

A Need for More Comprehensive Models and Data to Characterize Large Loads

In many cases, due to lack of clear detailed data and modeling requirements as well as lack of model submission milestones in large loads' interconnection processes, system impact studies for these large load facilities may be based on incomplete or late-arriving information from the load entities. This forces transmission utilities and ISOs/RTOs to rely on potentially inaccurate models and studies based on unknown or inaccurate assumptions on load behavior (e.g., ride-through capability, ramp rates, demand profiles), facility configurations, load compositions (e.g., heating/cooling load versus computational load), and protection and control schemes. The result is that the technical studies yield either overly conservative conclusions regarding the grid impact of the large load interconnection (such as the rejection of the interconnection application or massive transmission upgrades) that impose excessive costs and delays, or overly optimistic projections regarding the grid impact of the large load interconnection (such as interconnection approval without any additional mitigation) that risk compromising system reliability.[8]

To accurately perform interconnection studies that capture large load performance risks, utilities and ISOs/RTOs need significantly more data and detailed load models earlier in the interconnection process from each large load customer. Table 2 (p. 17) describes essential data and model requirements for interconnection technical analyses.

For a comprehensive review of the modeling and data requirements for large load interconnections, see the ESIG Large Loads Task Force report *Large Load Modeling for Dynamic Studies: Current Practices and Recommendations*.[9]

7 See https://www.esig.energy/reports-briefs/large-load-interconnection-performance-requirements/.

8 From ESIG Large Loads Task Force discussions.

9 See https://www.esig.energy/reports-briefs/large-load-modeling.

TABLE 2
Data and Detailed Load Models Needed by Utilities from Each Large Load Customer

Data or Model Needed	Description
Load composition data	Detailed information on load components, such as load type (motor load (heating/cooling), electronic loads, etc.), uninterruptible power supply behavior, and the way they interrelate in shaping the load's overall electricity demand and usage patterns
Load ramp data	Two types of ramp data: (1) data detailing load ramp schedules, covering the magnitude and speed of anticipated electricity ramping ranging from the millisecond range to seconds, minutes, and hours; and (2) the schedule for how many megawatts of electricity demand per year are expected to be phased into operation over time to accurately evaluate network upgrades and model future dynamic behaviors
PSPD models	PSPD models that capture the system dynamics in the range of sub-seconds to seconds, to include uninterruptible power supply charge and discharge behavior, rectifier/inverter controls, fast transfer switch behavior, and back-up generators
EMT models	Simplified, parameterized models sufficient for feasibility-level screening, along with model documentation for converters and uninterruptible power supplies

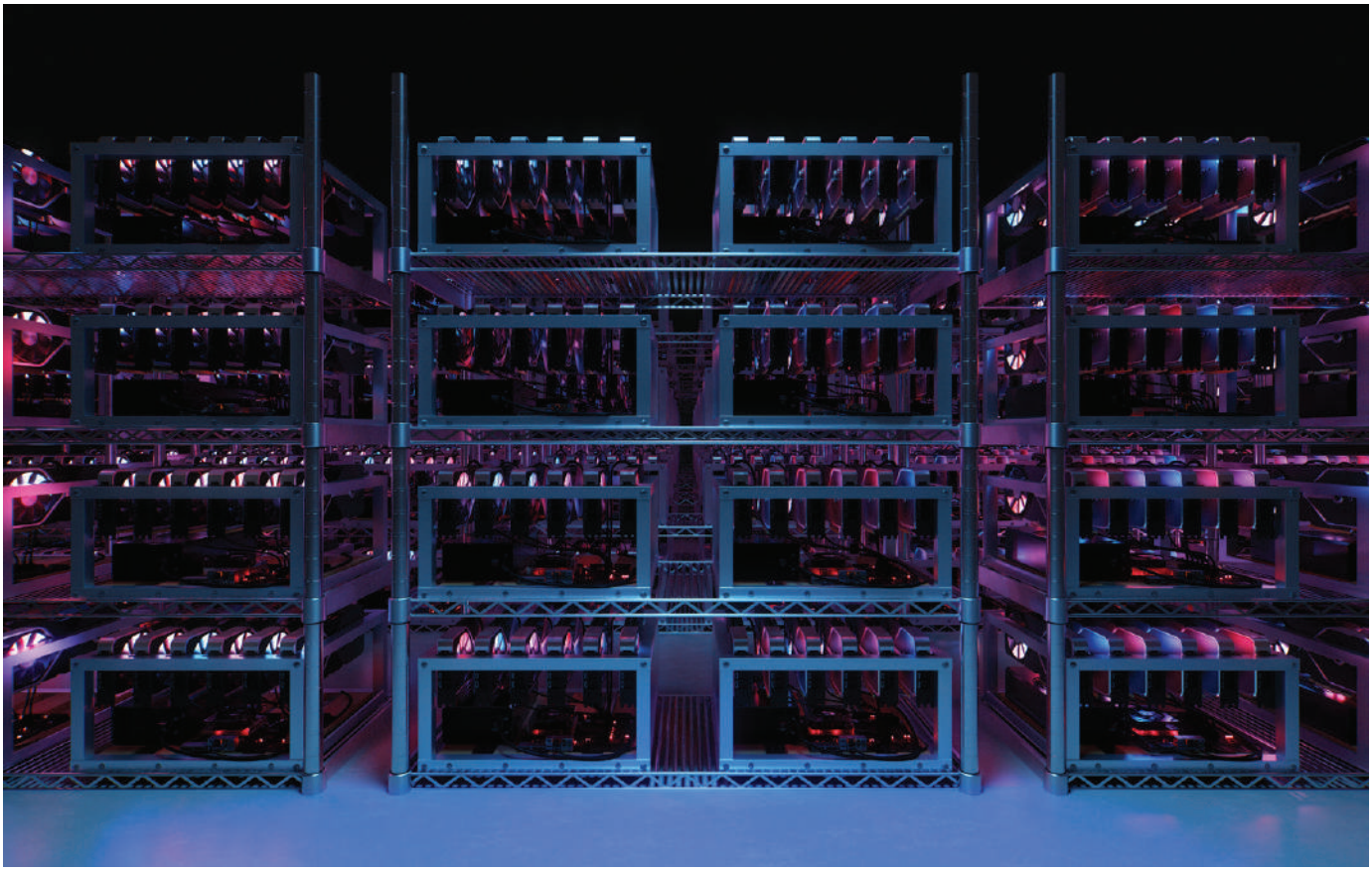
Source: Energy Systems Integration Group.

Study Requirements for Large Load Impact Assessments

Historically, load studies were generally conducted for each individual new load and focused primarily on steady-state conditions to assess for any thermal and voltage violations and identify network upgrades needed to reliably serve large loads. Dynamic studies for individual new large loads were not of major concern because most loads were resistive heating and motor loads that are long-standing and mature load technologies with well-understood system stability challenges. With the rapid emergence of power electronics–based large loads, study processes must evolve to adequately understand these large load facilities' impact on the bulk power system.

Utilities and ISOs/RTOs are establishing dedicated processes and associated studies (e.g., ERCOT PGRR 115, now codified as ERCOT Planning Guide Section 9 (ERCOT, 2026a)) detailing technical analyses that need to be carried out for large load interconnections. The interconnection process for large loads includes a comprehensive suite of studies to address the unique steady state and dynamic characteristics of today's large load facilities. These studies are:

- **Power flow (steady-state) studies:** This type of study remains foundational and is required to assess for any thermal and voltage violations and identify network upgrades needed to serve the large load reliably under many bulk power system loading, generator dispatch, and contingency conditions.
- **PSPD studies:** These studies are now critical because of the dynamic impacts of large loads, such as the sudden loss of a large load due to lack of ride-through capability, which can create immediate transient stability, voltage, and frequency issues, or slower (below 5 Hz) oscillatory behavior of large loads that can potentially impact overall system stability. PSPD models are used to assess transient stability, small-signal stability, and some of the voltage and frequency ride-through/recovery performance of large loads.
- **Short-circuit studies:** These analyses are performed mainly for the design of protection/control schemes and substation equipment to meet the short-circuit fault duty of circuit breakers, ensuring that grid equipment can withstand and clear maximum fault currents. For large load facilities that have on-site generation, the short-circuit analysis also needs to include



impacts from on-site generation on the bulk power system equipment.

- **EMT studies:** EMT analysis has become crucial due to the oscillatory behavior of AI facilities and dynamic characteristics of crypto currency loads. In particular, AI training loads have been shown to introduce forced sub-synchronous oscillations on the bulk power system, a phenomenon (above 5 Hz) that cannot be accurately represented in steady-state, short-circuit, or PSPD studies.[10] Therefore, EMT studies are now required to accurately model large load rapid ramp phenomena, switching transients, oscillations, and interactions of converter-based controls (UPS/rectifiers).

Lessons Learned from Large Generation Interconnection

With the rapid rise in large load demand over the past three years, predominantly from data centers and advanced manufacturing, there is an opportunity to apply the lessons learned from IBR integration.

In Order 2003, the Federal Energy Regulatory Commission (FERC) established the Large Generator Interconnection Agreement (LGIA) and Large Generator Interconnection Procedures (LGIP) to address the increasing number of disputes arising from utility and ISO/RTO handling of generator interconnection requests (FERC, 2003). Order 2003 created a standardized framework designed to expedite generator interconnections, establish transparent and non-discriminatory market entry rules for generators, preserve system reliability, and ensure that electricity rates remained just and reasonable for customers.

As demand for new generator interconnections increased, it became clear that the LGIA and LGIP processes needed further modifications. The existing framework was not keeping pace with the volume of interconnection

10 See the ESIG Large Loads Task Force report *Large Load Modeling for Dynamic Studies: Current Practices and Recommendations* at https://www.esig.energy/reports-briefs/large-load-modeling.

requests, especially from IBRs, and FERC was receiving complaints about piecemeal generation interconnection processes that were leading to inconsistent approaches across the country. FERC then adopted Order 2023, which consolidated best practices from individual filings, codified significant process reforms, and established updates to the uniform generation interconnection framework applicable across transmission providers (FERC, 2023a).

FERC Order 2023 revised the *pro forma* generator interconnection procedures and agreements (for both large and small generators) and includes several key reforms, as it:

- Moves from a serial "first-come, first-served" process to a "first-ready, first-served" cluster study approach, in which multiple interconnection requests submitted within the same window are studied as a group rather than individually in serial order.
- Establishes stricter readiness, site control, and financial commitment requirements.
- Imposes firm deadlines and penalties for delayed interconnection studies.
- Requires transparency and sharing of interconnection information between grid operators, utilities, and generator developers.
- Permits co-location of generation and storage resources, evaluates alternative transmission technologies, and clarifies the "option to build" for network upgrades, a provision allowing interconnecting customers to construct certain network upgrades themselves, subject to utility oversight and approval.

National actions to address reliability risks associated with the rapid growth and high levels of IBRs can also serve as a guide for handling large load interconnection requests. In the case of IBRs, NERC and the industry identified reliability gaps between the existing NERC standards, which were mostly designed for synchronous generators, and the new characteristics of IBRs (NERC, 2022). To address these gaps, FERC Order 901, issued in October 2023, mandates the development of new or modified reliability standards to address the integration of IBRs into the nation's bulk power system (FERC, 2023b). NERC is currently in the process of developing new or modifying reliability standards currently subject to mandatory enforcement pertaining to IBRs in four areas: data sharing, model validation, planning and operational studies, and performance requirements (NERC, 2024).

Today, large load interconnection requests, process issues, and undesirable grid events are proliferating at even faster rates than in generation and IBR interconnection, and the industry needs to learn from experience with IBRs and much more rapidly arrive at standardized interconnection processes and performance requirements for large loads.

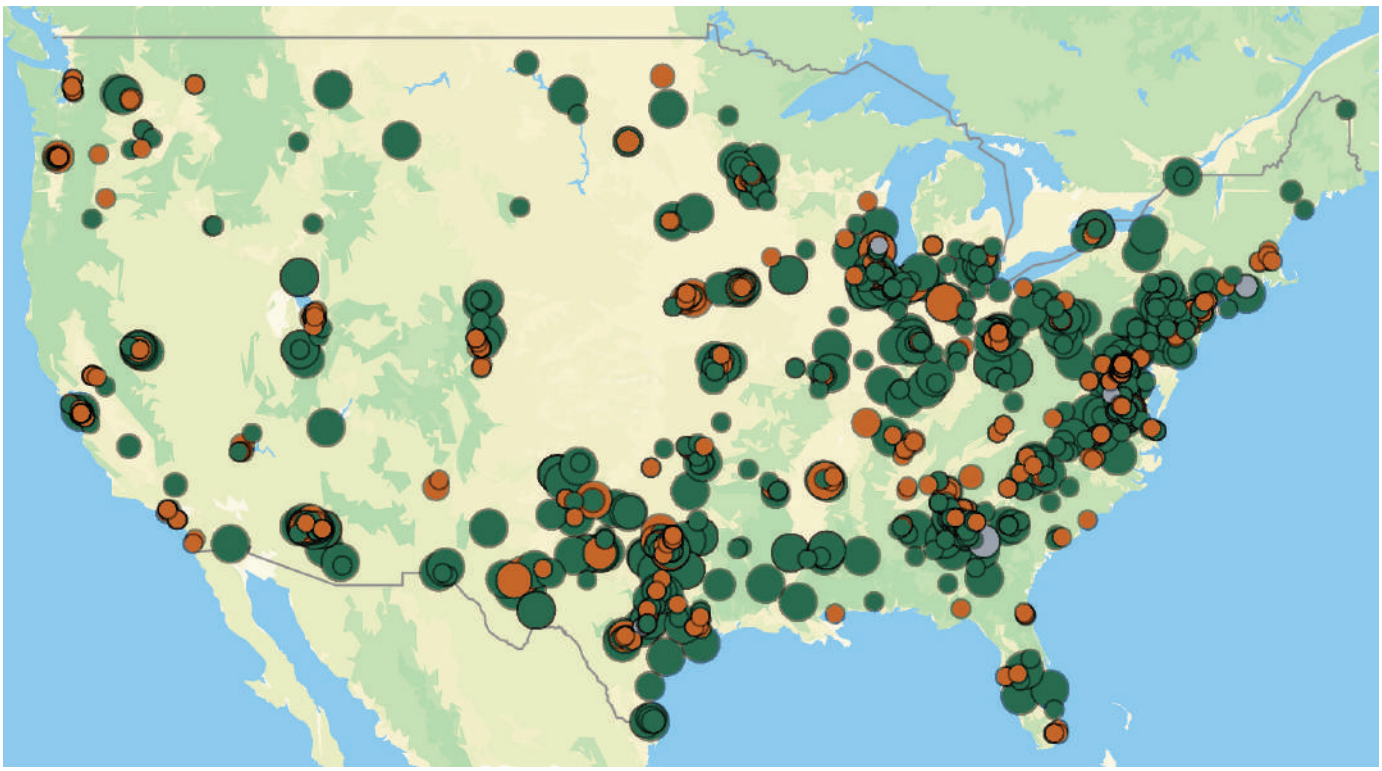
The ongoing effort to help ensure bulk power system reliability through more streamlined and rigorous IBR interconnection rules and performance requirements highlights how both FERC and NERC processes only slowly identified and resolved the risks inherent in outdated interconnection processes and reliability standards. Today, large loads have begun to show similar issues as seen during the early stage of IBR proliferation like interconnection process confusion and impediments, difficulty accurately studying the interconnecting technology, and power system stability issues. Given the rapid increase in large load facilities and the significant overlap in reliability concerns between large loads and IBRs, industry needs to learn from experience with IBRs and much more rapidly arrive at standardized interconnection processes and performance requirements for large loads.

It is essential to formalize clear interconnection processes and performance requirements for large loads to expedite energization timelines while preserving reliability. Even if only a small fraction of the large facilities in interconnection queues are developed, the demand from these large loads may may significantly exceed available supply and transmission capabilities. The large load interconnection process is the starting point for the ISO/RTO or utility to study these new facilities, understand transmission and generation expansion needs, determine whether an expedited interconnection timeline is feasible, and reliably interconnect the large loads.

Utilities' and ISOs'/RTOs' Current Approaches and the Need for Coordination

Today, as large load interconnection becomes the purview of both utilities and ISOs/RTOs, large load interconnection processes are evolving, with greater coordination required around interconnection requests and data intake, impact studies and study reviews, transmission planning, and resource adequacy assessments. Illustrating the importance of coordination between utilities and ISOs/RTOs, Figure 6 shows the number of data centers operating and proposed across the United States as of 2025, most of which (all but those in the Pacific Northwest) are concentrated in areas served by ISOs and RTOs. In this section we discuss the evolution of current large load interconnection processes and recent proposals and relevant industry/stakeholder

FIGURE 6
U.S. Data Center Trends



This map shows the number of data centers operating (orange) and proposed (green) across the United States as of May 2026, most of which (all but those in the Pacific Northwest) are concentrated in areas served by ISOs and RTOs.

Note: Marker size reflects capacity. Only facilities with reported capacity data are shown.

Sources: OpenStreetMap and its contributors, posted at Cleanview, https://cleanview.co/public/data-centers/us.

feedback at the ISO/RTO and the utility levels, informed by experiences of the large load owners, operators, and developers in the ESIG Large Loads Task Force.

Current Interconnection Approaches at Individual Utilities and ISOs/RTOs

Approaches at Utilities in Non-ISO/RTO Areas

With the proliferation of large loads, utilities are dealing with the same challenges in both ISO/RTO areas and non-ISO/RTO areas, namely, significant impacts to load forecasts, the need for more generation resources, the need for improvements in transmission planning, and others. Utilities faced with rapid growth of large load interconnection requests are already actively working to update their large load interconnection processes to address these challenges. In non-ISO/RTO regions, the utilities continue managing large load interconnections by themselves, as they've done historically. However, as pointed out in Table 1 (p. 12), having all system planning and operation functions contained within one organization (without ISO/RTO oversight) lessens the need for coordination with other parties and, potentially, allows for more nimble evolution of large load interconnection processes. Here we describe examples of recent changes to large load interconnection processes in three non-ISO/RTO utilities.

Grant Public Utility District

Grant Public Utility District (Grant PUD) is a customer-owned, non-profit utility in Washington state that has seen enormous large load development in its territory, including data center and manufacturing facilities. The sheer number of large load applications has led Grant PUD to refine its large load interconnection rules, revise its rates, create a formal queue management system, and update its system impact study processes. Grant PUD's transmission interconnection procedures provide a good example of the steps needed to address the explosion of large load interconnections at the utility (Grant PUD, 2023). Its "Transmission Interconnection Procedures" document already echoes many of the recommendations in this report, including having defined interconnection process steps, site control requirements for each customer, large study deposits, detailed study phases, and defined testing and commissioning requirements.

Southern Company

In 2025, Southern Company created guidelines in "Integration Process for Transmission Connected Large Loads," and throughout 2025 and 2026 updated this process based on some of the industry guidance and lessons learned (Southern Company, 2026). The utility defines transmission-connected large loads as those loads connected to its transmission system (at greater than 40 kV) and typically those that exceed 50 MW. The integration process has a defined set of five milestones:

- Milestone 1: Commencement of work
- Milestone 2: In-service date (substation ready to feed)
- Milestone 3: Initial energization of transmission-connected large load
- Milestone 4: Testing and verification
- Milestone 5: Full readiness for reliable operations

Southern Company's integration process already aligns with many of the recommendations in this report, including having defined milestones and associated target timelines, defined technical interconnection requirements for large loads, defined modeling data requirements, coordination requirements with transmission operators, and testing and verification of the facility during a defined commissioning process.

El Paso Electric

El Paso Electric is another non-ISO/RTO utility that has seen significant growth of large load facilities in its territory, with many large load projects in its interconnection queue (EPE, n.d.). It defines large loads as those exceeding 20 MW and has documented the process steps it takes for connecting large loads to its system. These process steps include defined milestones, interconnection application requirements, significant study deposits, and PSPD studies and EMT studies to thoroughly evaluate each large load facility's impact on its transmission system.

Approaches at ISOs/RTOs in the U.S.

ISOs and RTOs have started to develop and propose new policies and approaches to handling large load interconnections in their regions to address the challenges of managing load forecasting, resource adequacy assess-

ments, and transmission planning activities under the extreme large load growth requests their regions are seeing.

Several policy initiatives and large load queue management reforms are being discussed across ISOs/RTOs. These initiatives are influenced by stakeholder comments, federal directives, and regional reliability considerations, and many are yet to be finalized. The observations that follow are snapshots of the current approaches and policy directions drawn from the Large Loads Task Force's review as of the time of this writing and may change over time.

PJM Interconnection

PJM is addressing one of the nation's largest forecasted load increases through its Critical Issue Fast Path (CIFP), an accelerated stakeholder process for urgent matters. The initiative originally centered on a non-capacity backed load (NCBL) service that would allow large loads to interconnect without capacity market backing in exchange for being first to curtail during emergencies, such as during a generation supply shortfall relative to load demand in the region. The NCBL proposal met significant opposition from utilities and consumer advocates centered on concerns that new large loads could obtain grid access without fully contributing to capacity and reliability costs, potentially shifting burdens to existing customers and distorting market signals. Stakeholders also questioned whether emergency curtailment commitments would be sufficiently firm and enforceable, and noted that such loads could still drive transmission upgrades and congestion while receiving preferential treatment through an accelerated policy pathway. As a result of this pushback, PJM is exploring various new policies such as voluntary, incentive-based frameworks, including compensated load flexibility offerings; "bring your own generation" (BYOG) incentives to pair loads with dedicated generation resources; and an expedited interconnection track for state-sponsored generation projects exceeding 500 MW (Mills, 2026).

Electric Reliability Council of Texas

As of March 2026, ERCOT faced over 410 GW of potential new load from 551 large load interconnection requests—88% of which were from large data centers (ERCOT, 2026c). ERCOT also has 458 GW of new generation and storage interconnection requests, including storage, solar, and natural gas–fired generation (ERCOT, 2026d). For comparison, ERCOT's record peak demand as of this writing is 85.5 GW, set in 2023 (ERCOT, 2026b).

ERCOT has established the most formalized and prescriptive large load interconnection process in the country, shaped directly by Texas Senate Bill 6 (SB 6), passed in 2025.[11] ERCOT's process requires any new or aggregated load at a single site with a peak demand of 75 MW or more to undergo a formal large load interconnection study, analogous to a generator "full interconnection study," including comprehensive steady-state, short-circuit, and dynamic analyses. To combat speculative project application submittals, SB 6 mandates stringent commercial readiness requirements including flat study fees of at least $100,000, proof of site control, and substantial financial commitments for transmission infrastructure construction. The statute empowers ERCOT to require large loads to install equipment for remote disconnection during grid emergencies and mandates inclusion of large loads in the Quarterly Stability Assessment before energization.[12] Implementation details and technical issues continue to be vetted through ERCOT's Large Load Working Group stakeholder process and the Public Utility Commission of Texas.

ERCOT is also working to implement a clustering methodology, called a batch process, to study multiple large load interconnection applications in common geographical and electric topological locations (Ishak, 2026; Billo, 2026). Batch Zero of this new process is expected to start in July 2026.

Southwest Power Pool

The Southwest Power Pool (SPP) is addressing a potential doubling of its peak load over the next decade through its

11 This was codified by ERCOT through Nodal Protocol Revision Request 1234 (NPRR1234) and Planning Guide Revision Request 115 (PGRR115) (which has now been codified as Section 9 of the ERCOT Planning Guide).

12 The Quarterly Stability Assessment is a study carried out by ERCOT with the goal of assessing stability impacts from all new projects that have met specified interconnection process milestones. Originally, this assessment was introduced to evaluate combined stability impacts from newly connecting IBRs, and, more recently, new large loads have also been included.

High-Impact Large Load (HILL) policy approved by the board of directors. A load is classified as a HILL if it has peak demand greater than or equal to 10 MW at a point of interconnection of 69 kV or less, or peak demand greater than or equal to 50 MW at a point of interconnection above 69 kV. The integrated framework defines interconnection study requirements for applicable new large load interconnection requests, while also having operational requirements that include load forecasting, capability for the transmission operator to remotely disconnect the load from the transmission system, installation of phasor measurement units at large load facilities, and ride-through requirements. This development process serves as a case study in effective stakeholder engagement: after an initial proposal was rejected in July 2025 due to concerns about a rushed process and insufficient review time, SPP staff conducted additional workshops, revised their proposal based on feedback, and achieved 95.7% approval from the Markets and Operations Policy Committee. FERC approved SPP's HILL and High-Impact Large Load Generator Assessment (HILLGA) processes on January 15, 2026 (FERC, 2026a). The cornerstone of the HILLGA approach is an integrated, 90-day study-and-approval process designed specifically for large loads paired with new or existing generation resources.

New York Independent System Operator

The New York Independent System Operator (NYISO) uses a more established approach to large load interconnection, managing the challenge through its existing tariff and planning manual framework rather than developing entirely new processes (NYISO, 2026). Under NYISO's threshold-based system, any load of 10 MW or greater connecting at 115 kV or above, or any load of 80 MW or greater at sub-115 kV voltages, triggers a formal NYISO-administered system impact study—the sole study required for new loads that meet these criteria, analogous to generation interconnection studies. This study determines whether the load addition would degrade system reliability or affect New York's bulk transmission operations, with results reviewed by NYISO's Operating Committee. If problems are identified, NYISO specifies required system upgrades that the relevant utility evaluates and undertakes in coordination with the load customer, with cost responsibility worked out in an interconnection agreement. Stakeholders have been cautiously optimistic about NYISO's process,



citing the clear threshold criteria that give developers early certainty about study requirements.

Given the relatively small size of the New York grid and the area's extensive interconnections to PJM, ISO New England, and the Independent Electricity System Operator for Ontario, it is likely insufficient to consider the impact of large loads on New York grid alone. Accurate grid impact analysis may require joint evaluation with the Northeast's other grid operators and even the Northeast Power Coordinating Council. The New York State Reliability Council has created a Large Load Working Group to work on these issues (NYSRC, 2026).

California Independent System Operator

The California Independent System Operator (CAISO) is just beginning its large load activities, including initial proposed technical considerations and requirements for large loads and upcoming discussions with stakeholders (CAISO, 2026; MISO, 2026b).

Midcontinent Independent System Operator

MISO is also just beginning its large load activities, including initial proposed technical considerations and requirements for large loads, considerations for co-located large loads and generation, and upcoming discussions with stakeholders (MISO, 2026c).

Interconnection Process Challenges and Regional Responses

The overarching issues for ISOs/RTOs and utilities as they address large load interconnections center around: (1) stand-alone large loads seeking firm transmission service; (2) large loads co-located with new or existing generation resources and any expedited processes for such arrangements; and (3) large loads that seek non-firm transmission service (also known as flexible service or load curtailment), and any expedited processes for such arrangements.

In ISO/RTO regions, an additional challenge is the lack of coordination between ISOs/RTOs and utilities. Since most large load entities submit their interconnection requests directly to the interconnecting utility, the ISOs/RTOs are often not involved in these customer discussions and therefore have little to no awareness of the specifics of each large load customer interconnection until much later in the process when information is provided by the utility. This delay hinders accurate load growth forecasts and has adverse impacts on transmission planning and resource adequacy assessments. While ISOs/RTOs recognize the need for coordination with utilities to conduct joint system impact, transmission planning, and resource adequacy analyses, under newly developing large load interconnection approaches in several regions today the attempts for coordination may result in addition of duplicative steps and interconnection delays. Process improvements are needed through clearly defined assessment steps, specified roles and responsibilities, and continued coordination among all stakeholders. Such improvements are actively underway in both ERCOT and SPP.

The interconnection policies and study procedures vary by region, but many of the planning and operational challenges associated with large load integration are shared across regions. Table 3 summarizes these recurring issues in ISO/RTO regions and provides different stakeholder perspectives on each issue and some of the regional responses being undertaken. This table creates the basis for this report's recommendations that follow. While the table focuses on ISO/RTO regions, many of the challenges are applicable in non-ISO/RTO regions as well.

TABLE 3
Common Challenges Across ISO/RTO Regions

Challenge Area	Core Issue	Stakeholder Perspectives	Examples of Regional Responses
Defined large load interconnection process	Processes used for large load interconnection historically do not work for the amount of large load interconnection requests and the size of the interconnecting large loads seen today.	Utilities and ISOs/RTOs are overwhelmed with large load interconnection requests and need a systematic way to process them efficiently and without adverse impacts to grid reliability. Developers lack clear guidance on process, requirements, milestones, and roles and responsibilities.	ERCOT, PJM, and SPP, in close collaboration with the utilities and others, responded with developing and continuously improving large load interconnection processes in their service territories.
Resource adequacy and reliability risk	Rapid load growth without commensurate generation and supporting system resources threatens to result in capacity shortfalls and reliability events.	Grid operators are concerned about capacity shortfalls; large loads argue their business model requires rapid energization with high reliability. Customers say meeting new large load demand requirements will strain resources built to serve existing customers and raise electricity prices for everyone, even though they are not the cost-causers.	PJM is evaluating several proposals including curtailable service for large loads. ERCOT has mandated remote large load curtailment capability under Senate Bill 6. NYISO is incorporating load flexibility assumptions into reliability planning. SPP is proposing a faster interconnection timeline for load accompanied by new generation capacity.

— CONTINUED —

TABLE 3

Common Challenges Across ISO/RTO Regions CONTINUED

Challenge Area	Core Issue	Stakeholder Perspectives	Examples of Regional Responses
Transmission capacity and upgrade timelines	Load centers lack the transmission to support large incremental demand without significant, lengthy, capital-intensive transmission upgrades. Grid operators' need for load curtailment capability and lengthy infrastructure build-out time creates a challenge with large load customers' desires for high uptime and immediate grid service.	Grid operators cite system constraints based on the anticipated large queue. Large load developers want near-term energization and a path to scalability with timeline certainty. Many individual residents and communities do not want data centers or new transmission built nearby. Grid operators view large load curtailment as a critical safety valve to protect grid reliability. Large load developers (especially data centers) say they need near-perfect uptime. Grid operators also want better and stricter rules for large load curtailment due to impacts on load forecast methodologies, use of transmission, resource adequacy assessment, and market bidding. Grid operators desire more operation philosophy details from large loads such as voltage control, protection, and load flexibility to maintain grid reliability and improve load forecasts and operations planning.	Utilities increasingly use intake forms to screen large load requests and perform high-level transmission capacity need estimation to provide early insights into potential available transmission capacity. Examples include Dominion Energy Virginia in PJM. PJM offers non-firm and interim transmission service for large loads. ERCOT allows interim service contingent upon operational restrictions. Utilities in ERCOT offer service agreements at limited capacity until necessary transmission upgrades are completed. Under SPP's HILL process, certain large loads may receive conditional service in constrained areas, with curtailment obligations until transmission upgrades are completed. NYISO is exploring grid service offerings from flexible loads for scenarios with insufficient transmission capacity to accommodate the loads with firm transmission service. Some large loads are seeking to meet their high reliability needs using their own dedicated generation to supplement grid-supplied power.
Speculative queue clogging	Interconnection queues can be filled with projects lacking commercial viability, consuming engineering staff time and decreasing the accuracy of load forecasts used in resource adequacy assessments and transmission planning processes.	ISOs/RTOs and utilities report wasted engineering staff time and highly uncertain load growth forecasts. Large load developers express frustration with slow interconnection processes and unreliable timelines for energization, even though it is the aggregation of their projects that are slowing and complicating queue management.	ERCOT requires a study fee of more than $100,000, requires proof of site control, has financial security requirements, and collects more information to identify duplicative and speculative projects. NYISO requires interconnection deposits and has site control requirements. SPP and PJM Include similar project readiness requirements.

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TABLE 3

Common Challenges Across ISO/RTO Regions CONTINUED

Challenge Area	Core Issue	Stakeholder Perspectives	Examples of Regional Responses
Cost allocation and fairness	Transmission infrastructure upgrade costs for large loads are potentially spread amongst all customers.	Load customers and consumer advocates are concerned about rate increases for all customers. Large load developers recognize the need for significant transmission investment and expect cost transparency and reliable upgrade timelines. ISOs/RTOs indicate needs for reforms to allocate costs fairly to those entities that are responsible for the cost increases.	SPP assigns direct costs to the cost-causer (load and paired generation). ERCOT has fair cost contribution mandates under Senate Bill 6. NYISO negotiates cost responsibility in interconnection agreements.
Process transparency and speed	Large load facility development timelines (measured in months) are misaligned with utility planning and construction cycles for transmission and generation (measured in years).	Developers demand transparency in study assumptions and faster, predictable timelines. ISOs/RTOs and utilities need to have transparent interconnection queues, with appropriate information protection, and some are exploring providing hosting capacity maps to indicate points of connection with available transmission capacity and estimated times of connection in every region for even more transparency.	SPP has a defined 90-day integrated study process. NYISO has specified clear threshold criteria to provide early certainty. ERCOT uses a batch study process that includes clear interconnection process milestones and timelines.
Planning visibility	ISOs/RTOs lack early awareness of large load interconnection requests because these are submitted directly to utilities.	Information delays prevent effective long-range transmission and resource adequacy planning. ISOs'/RTOs' early involvement in the process is essential to better inform their regional load forecasts.	All regions are working to establish earlier notification and coordination mechanisms between ISOs/RTOs and utilities. NYISO established large load application requirements that ensure the ISO is aware of large load interconnections in its region. PJM has requirements on sharing load forecast information between the ISO and utilities that help to improve planning visibility into upcoming large load growth. ERCOT's batch study process includes one-time intake of all applications into the study cycle, in which large load developers submit applications to respective utilities with ERCOT coordinating, validating assumptions, and performing or overseeing the regional reliability/stability portions of the batch study. This ensures early-stage information sharing between the ISO and utilities.

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TABLE 3

Common Challenges Across ISO/RTO Regions CONTINUED

Challenge Area	Core Issue	Stakeholder Perspectives	Examples of Regional Responses
Undue discrimination	Some stakeholders are concerned that new rules unfairly target specific large load customer classes (such as data centers) rather than focusing on all large loads and any operational characteristics that can cause reliability risks to the bulk power system.	The large load industry groups are vigilant against singling out one class of large loads, such as data centers, with new rules. Regulators and existing customers believe cost causation rules justify making new large loads pay for all the costs and risks they are adding to the system, thus they do not consider these rules "undue" discrimination. Regulators aim to deliver reliable and cost-efficient power to customers. This includes fair cost allocation, interconnection process, and market design.	MISO is working with its stakeholders under the MISO Large Load Working Group to understand the operational characteristics that pose a reliability risk to the MISO transmission system and is working to create new definitions of facility types that may exhibit these operational characteristics.
Threshold gaming and project sizing	Developers may strategically structure the size of projects to avoid formal study requirements, creating visibility gaps for utilities and ISOs/RTOs and potential reliability blind spots.	Developers seek to minimize costs and timelines. ISOs/RTOs are concerned about aggregated impacts of sub-threshold projects (e.g., distribution-connected large loads, and large loads smaller than the defined thresholds). Some ISOs/RTOs are working on new rules for assessing the aggregated impacts of smaller projects.	In NYISO some large load developers are splitting projects into multiple ~35 MW facilities to stay below 80 MW threshold, causing NYISO to reconsider appropriate thresholds.
Modeling, study, and performance requirements	Due to the size and geographical concentration of large loads, previous modeling and study practices as well as performance requirements are insufficient to ensure system reliability.	Grid operators are experiencing reliability events attributed to large load behaviors. These events are not identified during large load impact studies due to inadequate models. Large load developers do not have clear guidance on what requirements their facilities should be designed for and what information needs to be included in the facility models.	ERCOT has developed large load modeling and study requirements and has proposed performance requirements for large loads. MISO and SPP are also currently developing modeling, study, and performance requirements for large loads.
Material modification process	The rapid rate of change in technology (particularly for data centers and AI facilities) is outrunning the utility industry's typical planning cycle and change management and material modification capabilities.	As large loads change their plans, technologies, and equipment, those changes need to be reflected in validated and verified large load models and interconnection dynamic analyses performed by utilities and ISOs/RTOs in order to adequately evaluate how changes in a large load's equipment or behavior impacts the system.	

Source: Energy Systems Integration Group.

Interconnection Process Recommendations for Transmission-Connected Large Loads

The regional examples reviewed above show that, while specific processes differ, many large load interconnection challenges are common across jurisdictions, including resource and transmission adequacy assessment challenges, timeline transparency, planning visibility, cost allocation, understanding of project readiness, and others. Drawing on these common themes, the following recommendations from the Large Loads Task Force are intended to improve the efficiency, transparency, and technical robustness of large load interconnection processes across ISO/RTO regions.

Drawing on common themes across regions, these recommendations aim to improve the efficiency, transparency, and technical robustness of large load interconnection processes across ISO/RTO regions.

Establish a Formal Large Load Interconnection Process

Utilities that are faced with increasing large load interconnection requests can establish a formal interconnection process with clearly defined milestones (e.g., adopting milestones illustrated in Figure 3, p. 9) as well as requirements, roles and responsibilities, and timelines for each milestone. In ISO/RTO areas, coordination and information exchange procedures and touchpoints can be established between the utility and ISO/RTO.

Establish a Formal ISO/RTO-Level Interconnection Request Intake Process

Those ISOs/RTOs working to develop their own large load interconnection process, in addition to the interconnection processes managed by utilities, can work with their member utilities to create a single, mandatory point of entry for all large load interconnection requests above a defined threshold (e.g., 20 to 25 MW) to capture loads with material system impacts. This centralized large load request interconnection intake process would require the submission of an extensive, standardized data package that provides all of the data needed for planning and technical reliability studies at both the utility and the ISO/RTO levels.[13] Having a centralized process will help the ISO/RTO maintain a comprehensive and transparent large load interconnection queue and incorporate the data directly into planning studies, thus addressing the fundamental planning visibility problem. NYISO's threshold-based approach provides a proven model, although careful consideration must be given to setting thresholds at appropriate levels to prevent developers from fragmenting projects into multiple facilities that are individually lower than the threshold. Those ISOs/RTOs not looking to centralize the large load interconnection process can create information-sharing mechanisms for all parties for large load interconnection projects.

Explore the Development of a FERC Large Load Interconnection Procedure

FERC can develop a *pro forma* Large Load Interconnection Procedure analogous to the Large Generator Interconnection Procedure, replacing the current patchwork of state- and utility-level processes. This standardized procedure could incorporate best practices including the rigor of SPP's multi-stage Load Limited Resource Interconnection Service (LLRIS) process, NYISO's threshold-based study triggers, and an optional accelerated pathway for integrated load-plus-generation projects as pioneered by SPP's HILLGA process, providing certainty and consistency for developers and grid planners alike.

Enhance Coordination Among Load Interconnection, Generator Interconnection, and Transmission Planning Processes

ISOs/RTOs can establish formal, documented procedures to ensure that data from the large load queue are a timely and integral input to (1) the generator interconnection study process, (2) the long-range transmission planning cycles, and (3) new load planning probabilistic scenarios that consider different rates of successful versus

13 For additional discussion of data needs, see the ESIG Large Loads Task Force report *Grid Integration of Large Loads: Introduction to the Large Loads Task Force, Data Needs, and Flexibility*, https://www.esig.energy/reports-briefs/large-load-task-force-introduction.

unsuccessful large load projects in the queues. This coordination ensures that all three planning functions (generation, transmission, and load forecasting) work from consistent and up-to-date assumptions, thus addressing the timing and information mismatch identified across regions. NYISO's Operating Committee review process and MISO's efforts to coordinate its Transmission Expansion Plan and Definitive Planning Phase offer models for effective coordination mechanisms.

Adopt Standardized Commercial-Readiness Requirements

To deter speculative projects and ensure efficient use of study resources, ISOs/RTOs can adopt a large load interconnection framework modeled on FERC Order 2023 (for generation) and ERCOT's SB 6, including, at a minimum: (1) requiring proof of 100% site control (land ownership, signed lease agreements, or options to purchase or lease land of sufficient size for the facility); (2) requiring substantial, non-refundable application and study fees as well as credit checks/verifications; (3) escalating financial security requirements for estimated transmission upgrade costs, paid at key interconnection process milestones; and (4) requiring engineering and procurement (E&P) commitments for long-lead items in order to mitigate stranded asset risk and utility rate recovery risk.

Applying these requirements consistently to all large load interconnection customers can prevent threshold avoidance strategies.

Develop Detailed Modeling, Study, and Performance Requirements

To ensure that the reliability impacts of large loads are adequately assessed, utilities and ISOs/RTOs can establish comprehensive requirements for the types of interconnection studies needed, appropriate large load facility models for each study type, the necessary model benchmarking and validation processes, large load performance, and the processes to evaluate large load facilities' conformity with these requirements during the interconnection process and throughout the lifetime of the facility.[14]

Establish Material Modification Process

ISOs/RTOs and utilities can work collaboratively with large load customers to establish a process for obtaining adequate information about material modifications that may be happening at the large load facility during the interconnection process and after commissioning. This may include criteria for triggering the material modification process and steps that the process should include, for example, information for the ISO/RTO/utility, provision of updated models (and any model benchmarking, validation, or model quality assessment reports), and criteria for identifying which (if any) studies need to be repeated to ensure that the changes do not adversely impact grid reliability and the facility is still in compliance with applicable performance requirements.

Develop Standardized, Voluntary Flexibility Products

ISOs/RTOs can work collaboratively with large load customers, particularly data center operators, to design and implement standardized, voluntary demand flexibility products, also referred to as demand response products or non-firm transmission service.[15] These market products will need to provide clear flexibility performance requirements and compensation structures, allowing loads to monetize their flexibility (or buy flexibility from other users on the grid) while contributing to grid reliability. Valuable starting points for this work include NYISO's exploration of grid services from flexible loads and PJM's evolution toward flexibility offerings for large loads (NYISO, 2024; PJM, 2026).

Transition to Cluster Studies for Large Loads and Integrate Large Load Interconnection into Transmission Planning

As large load queues continue to grow, the traditional serial study approach will become a significant

14 See the ESIG Large Loads Task Force reports *Large Load Performance Requirements: Current Practices and Recommendations* (https://www.esig.energy/reports-briefs/large-load-interconnection-performance-requirements) and *Large Load Modeling for Dynamic Studies: Current Practices and Recommendations* (https://www.esig.energy/reports-briefs/large-load-modeling).

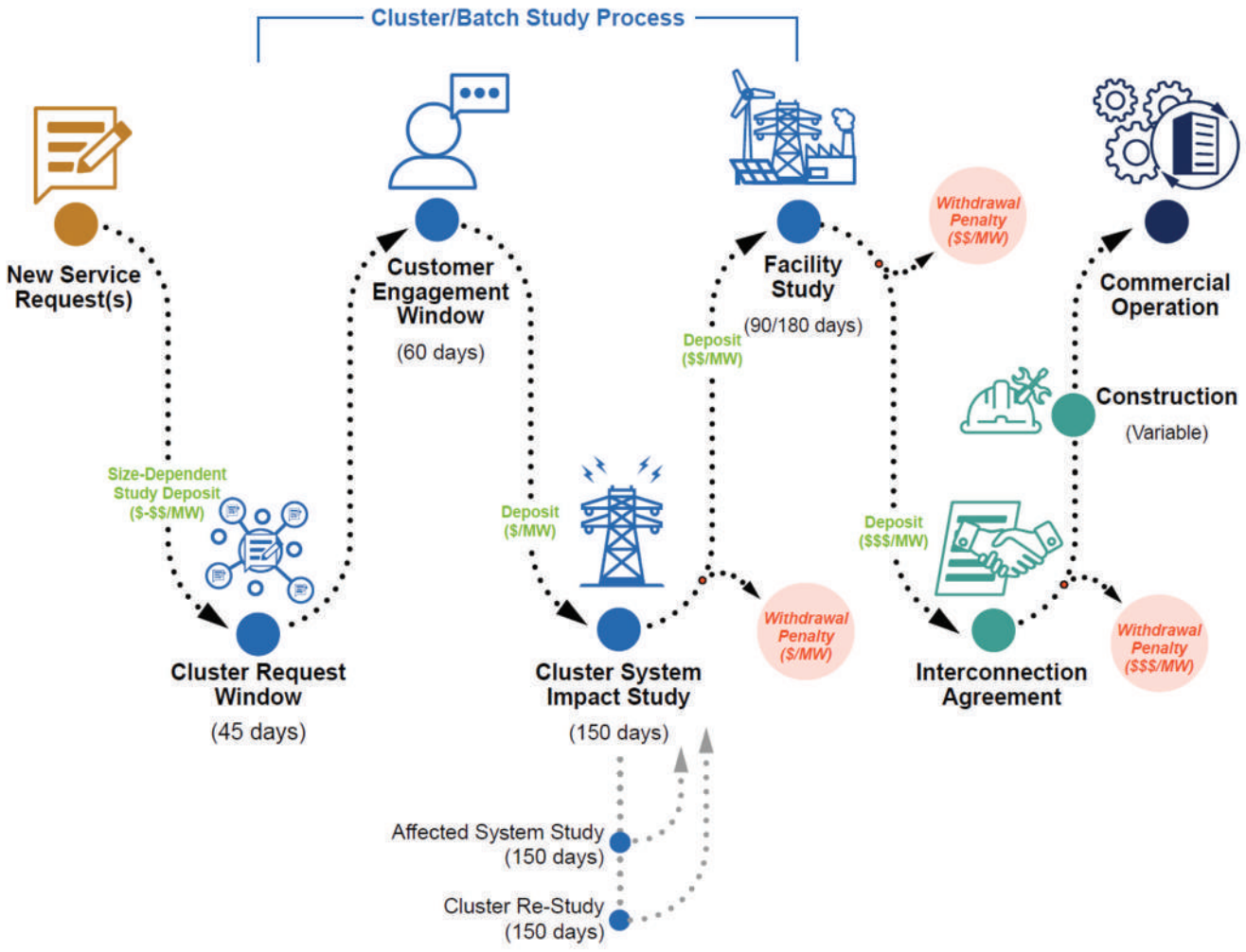
15 For additional discussion of large load flexibility potential and options, see the ESIG Large Loads Task Force report *Grid Integration of Large Loads: Introduction to the Large Loads Task Force, Data Needs, and Flexibility*, https://www.esig.energy/reports-briefs/large-load-task-force-introduction.

bottleneck. Figure 7 illustrates the cluster study process established by FERC for generator interconnection studies under Order 2023. ISOs/RTOs are exploring the use of similar clustering to process multiple large load interconnection requests, potentially in combination with supply resource additions. ISOs/RTOs and the transmission owners can proactively plan for a transition to a cluster study methodology for large loads, incorporating lessons learned from the often-difficult generator queue transitions to cluster studies. For regions with established processes, the transition can be carefully managed to preserve the benefits of existing frameworks while gaining efficiency from cluster approaches. They can also consider performing these cluster studies with not only large load interconnection projects but also generation interconnection projects and planned transmission system upgrade/new build projects as one integrated transmission planning study. This approach is likely to result in more effective transmission system build-outs.

Rules need to be defined that govern how projects are handled when material modifications are made late in the interconnection process and could potentially subject the

FIGURE 7

Generation Interconnection Procedures as Outlined in FERC Order 2023 Pro-Forma



Source: Joseph Rand et al., *Queued Up: 2024 Edition Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2023*, (Lawrence Berkeley National Laboratory, 2024), https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf.
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project to queue removal and entry into the next cluster study.

Transmission Capacity Maps and Proactive Transmission Planning

The industry needs to evolve away from the current reactive model of first processing interconnection requests and then planning transmission, and toward a model where long-range transmission planning identifies zones best suited for development, with the interconnection process then prioritizing projects in those zones. CAISO's Interconnection Process Enhancements approach, which aligns generation interconnection requests with planned transmission capacity, represents an example of an important first step that can be refined and adapted for large loads across all regions to improve efficiency and reduce costs by adopting many aspects discussed in this report. This zonal approach would prioritize projects by looking at areas with high transmission capacity, increasing the transparency of the large load interconnection queue or process status for all stakeholders and facilitating efficiencies by reducing backlogs.[16] ERCOT's Competitive Renewable Energy Zones (CREZ) initiative is another landmark example of this type of transmission planning and generation interconnection approach.[17] These can be key examples to consider for large load interconnections.

Establish Clear Rules for "Bring Your Own Generation" and Co-Located Resources

As the trend of large loads bringing their own generation becomes a common feature of the energy landscape, ISOs/RTOs can develop clear, standardized, and transparent rules governing these hybrid facilities' interconnection process and cost responsibility. The rules should span all milestones of the large load interconnection process to clearly define how a co-located resource is treated, modeled, and studied at each of the interconnection process steps. These rules would help to ensure equitable contribution to system reliability and costs, preventing undue socialization of costs onto other customer classes while maintaining a level playing field for all market participants. SPP's integrated study approach for load-plus-generation projects provides a valuable template for addressing these complex interconnection scenarios.[18]

16 See CAISO's "Interconnection Process Enhancements 5.0" at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Interconnection-process-enhancements-5-0.

17 For more information about ERCOT's CREZ initiative, see https://www.poweruptexas.org/wp-content/uploads/2018/12/Transmission-and-CREZ-Fact-Sheet.pdf.

18 See SPP's one-pager "SPP High Impact Large Load Generator Assessment" at https://www.spp.org/markets-operations/high-impact-large-load-hill-integration/.

Opportunities for Federal Action on Large Load Interconnection Processes

Much of the recent insight and action on large load interconnections arises from the national experience with the large numbers of large generation interconnection requests over the past decade. Initially, these exceeded utilities' and grid operators' interconnection capabilities and processes and resulted in long, backlogged generation interconnection queues, followed by multiple FERC Orders geared toward alleviating these challenges. Many of the current proposals for how to handle large load interconnection requests mirror the lessons learned from large generation interconnection. Recognizing that similar FERC action with regard to large loads may potentially springboard clearer, streamlined, and harmonized large load interconnection processes, this section zooms in on the current status of FERC efforts and provides recommendations for further evolution toward developing a standardized large load interconnection process.

Current Status of and Challenges with Defined Large Load Interconnection Processes and Requirements at the National Level

FERC has held technical conferences and proceedings on large loads and co-located generation and load, most notably the Talen case, which highlighted the jurisdictional and practical complexities at issue (FERC, 2024). In October 2025, The U.S. DOE, through Secretary Wright, issued an Advance Notice of Proposed Rulemaking (ANOPR) directing FERC to address reforms intended to ensure the timely and orderly interconnection of large loads to the transmission system (U.S. DOE, 2025b, 1). Since the issuance of the ANOPR in October 2025, FERC has taken several actions related to large load growth. These actions include:

- "Issuing a December 2025 order requiring the PJM Interconnection to implement transparent rules to accommodate substantial loads co-located with generation resources."
- "Approving the Southwest Power Pool's High-Impact Large Load initiative in January 2026, establishing new protocols intended to accelerate the interconnection of large loads and associated new generating resources while safeguarding consumer interests."
- Being "active on multiple proposed tariffs and agreements related to large load interconnections, accepting many, while rejecting those exceeding the Commission's jurisdiction or lacking reasonable cost allocation" (FERC, 2026b).

In addition to these actions, FERC announced in Docket No. RM26-4-000 issued on April 16, 2026, that the Commission intends to act with respect to this docket by the end of June 2026. FERC also stated that in June "we will address the problems discussed in the ANOPR in a manner that is quick, efficient, and legally durable" (FERC, 2026c).

Energy Secretary Wright's letter to FERC cites NERC's concern that "the size and speed with which data centers can be connected to the grid present unique challenges for demand forecasting and system planning" and calls for reforms to make the large load interconnection and cost allocation process efficient, effective, reliable, and fair (U.S. DOE, 2025b, 2). The letter calls for a transparent, orderly, and non-discriminatory process for large load interconnection and lays out 14 principles that can inform FERC rulemaking procedures:

1. Limit FERC's role to within its jurisdiction, namely, the bulk power system

2. Apply a large load process to new loads greater than 20 MW and seek comments on alternative thresholds
3. Study large load and co-located generation interconnection requests together to optimize siting and reduce costs
4. Standardize deposits, readiness, and withdrawal rules to deter speculative projects
5. Base studies of hybrid load/generation facilities on requested injection and withdrawal rights
6. Require protection systems for hybrid facilities
7. Allow faster studies for curtailable or dispatchable loads
8. Make loads fully responsible for network upgrades they trigger
9. Give loads the same "option to build" rights as generators for the interconnecting substation and associated equipment
10. Study any generator suspension (a situation in which a generator reduces its output to the transmission system to send a portion of its electricity directly to a co-located, new large load) like a system support resource or reliability must-run case
11. Base transmission service charges on actual withdrawal rights
12. Tie ancillary service charges to peak demand (no offsets)
13. Define a clear transition plan for large load interconnection studies that defines the timeline and structure for moving from historical large load interconnection studies to new large load interconnection processes/studies (such as moving to cluster studies for large loads)
14. Ensure that utilities serving large loads meet NERC/Open Access Transmission Tariff obligations, and ensure that NERC reviews/updates standards for possible new NERC registration criteria for large load facilities

NERC's focus on large loads has expanded significantly over the past few years in response to the rapid growth of large power electronics–interfaced loads such as data centers, cryptocurrency mining facilities, and other emerging industrial loads. Early efforts included the formation of the Large Loads Task Force under NERC's Reliability and Security Technical Committee to assess the operational, planning, and stability impacts of these facilities and identify gaps in existing reliability frameworks. NERC's task force produced a series of technical reports and recommendations addressing large load characteristics, disturbance behavior, interconnection studies, modeling, and operational visibility (NERC, 2025a; 2026a). Building on this work, NERC convened industry technical conferences and webinars focused on emerging large loads and issued reliability alerts highlighting concerns related to fault ride-through, oscillatory behavior, modeling deficiencies, and load loss events. In 2026, these activities evolved into the Large Loads Working Group and culminated in NERC's Large Loads Action Plan (NERC, 2026e), which outlines a coordinated path forward involving reliability guidelines, standards development, enhanced registration requirements, and improved interconnection, modeling, and operational practices for large loads.

The European Union's Demand Connection Code: An Example of Harmonized Mandatory Regulation for Loads

An example of how another region has set mandatory, technical rules for large load interconnections can be seen in the European Union's Regulation (EU) 2016/1388 (the Demand Connection Code (DCC)) (EU, 2016).[19] The DCC was drafted by the European Network of Transmission System Operators for Electricity (ENTSO-E) and approved by the European Commission in 2016. The DCC is currently under revision to further adapt it to new challenges brought about by the proliferation of large load facilities, primarily focusing on hydrogen facilities and electric vehicle charging infrastructure. Under the DCC, new transmission-connected load facilities (as well as load facilities on the distribution system and loads that may deliver demand-response services) must meet harmonized technical requirements. The key elements of the European technical requirements for transmission-connected loads are:

19 The term "demand connection" in Europe corresponds to "load interconnection" in the U.S.

- Frequency stability requirements and limits to prevent unnecessary tripping and instability
- Voltage stability requirements including voltage ride-through performance and reactive power support
- Provision of support during system restoration activities, including islanded operation and demand adjustment during blackstart efforts
- Provision of demand response including dynamic power consumption adjustments to respond to frequency and voltage deviations and participation in demand-response events
- Provision of detailed large load facility information with accurate, updated steady-state and dynamic models of the facility
- Applicability primarily to new large load facilities but potentially also to some existing load facilities

Few of the large load requirements defined in the European DCC have been adopted in U.S. regions to date, but it provides a detailed framework that can help the United States accelerate its creation of large load interconnection processes and technical requirements.

Recommendations

FERC and NERC can move forward expeditiously to consider and act on the U.S. DOE ANOPR, which would address many of the issues highlighted in this report. Additional steps that could be taken by FERC and NERC are the following.

- FERC can consider developing a *pro forma* Large Load Interconnection Agreement (LLIA) and Large Load Interconnection Procedure that cover all of the key issues relevant to large load interconnections including load forecasting, resource adequacy and reliability, interconnection facility design standards, cost responsibility, project schedule, ramp-up period, minimum operation period, large load interconnection queue management, readiness requirements, and interconnection study requirements and timelines. This would require extensive input from the industry (manufacturers of the equipment inside large load facilities, large load developers, owners, operators, and trade organizations; transmission system operators) and NERC.
- NERC can require large loads to register with the Electric Reliability Organization and create large load–specific reliability standards regarding large load modeling, capabilities and performance requirements, physical and cybersecurity requirements, operational requirements, data- and information-sharing, and emergency operation conditions and policies.

Distribution-Connected Large Load Interconnection Process

Distribution utilities typically consider a load of 10 to 20 MW as a large load that requires special handling (NERC, 2025a). These distribution-connected loads include many common types of facilities the industry has been interconnecting for decades as well as the new types of large load facilities that are the focus of this report (Table 4). In this section, "large load" covers new facilities from 10 to 30 MW rather than the much larger, 1-GW-and-above facilities connecting to utilities discussed up to this point.

Most loads of 10 to 30 MW connect to the grid on a dedicated distribution or sub-transmission circuit. Often distribution-level interconnections give both the utility and the customer greater speed to power and cost less than transmission-level interconnection. The technical scale and differences across load interconnection requirements are summarized in Table 5 (p. 36).

If a 10 or 30 MW load suddenly drops off the distribution system, its effect on the bulk power system is fairly limited

TABLE 4
Key Characteristics of Common Distribution-Connected Large Load Types (1 to 30 MW)

Load Type	Typical MW Range	Key Characteristics
Small enterprise data centers	1 to 5 MW	Servers, computing equipment, electrical switchgear, and cooling systems, all with a need for high redundancy, high power quality, and 24/7 operation
Large enterprise data centers	5 to 30 MW	Servers, computing equipment, electrical switchgear, and cooling systems, with continuous load, back-up generation, and strict uptime requirements
Automotive manufacturing	10 to 25 MW	Large motors, welding equipment, and robotics with high short-circuit contribution to the grid
Steel mini-mills	20 to 30 MW	Arc furnaces with fluctuating load and high reactive power demand
Semiconductor fabrication plants	10 to 30 MW	Precision equipment and clean rooms (highly controlled production environments to eliminate contaminates and particles) with constant load profiles
Cement plants	15 to 30 MW	Kilns and grinding mills with continuous heavy-duty operation
Water/wastewater treatment plants	5 to 20 MW	Large pumps with seasonal variability and motor starting impact
Medical/research campuses	1 to 15 MW	Imaging equipment and laboratories with back-up power requirements

Source: Energy Systems Integration Group.

TABLE 5

Differences Between Transmission- and Distribution-Level Large Load Interconnections

Aspect	Transmission	Sub-Transmission	Distribution
Voltage level*	69 kV or higher	34.5 to 69 kV	4 to 34.5 kV
Load size	Usually 20 MW or larger industrial facilities	Approximately 10 to 30 MW and includes large industrial plants, data centers, and other large regional loads	Typically less than 10 MW; often commercial, institutional, or light industrial loads
Modeling approach	Uses regional network models and considers inter-area effects	Uses local network models	Uses feeder-level models and focuses on local constraints
Responsibility for upgrades	Transmission owner or independent system operator coordinates cost allocation	Utility may require customer-funded upgrades on local circuits	Utility may require customer-funded upgrades on local circuits

* These are not standard voltage definitions but are intended to provide general examples of voltage cut-offs between these parts of the electricity grid.

Source: Energy Systems Integration Group.

compared to the loss of a 1,000 MW data center dropping off the transmission system; however, the distribution-connected load can cause significant local operational reliability problems. Moreover, when many "small" large loads drop simultaneously due to a common cause (as with a fleet of electronically coupled air conditioners triggered by a local transmission fault), their aggregate effect on system voltage and frequency can be significant. Therefore, most distribution-level large load technical interconnection processes, requirements, and studies need to be consistent with transmission-level large load interconnection processes, requirements, and studies.

In addition, new interconnection approaches such as "bridging interconnections" are emerging to address the mismatch between rapid facility development timelines and the longer timelines required for transmission upgrades. Under this approach, a large load initially interconnects at the distribution or sub-transmission level to support early phases of facility operation and load ramp-up, while permanent transmission infrastructure is being developed. This evolving interconnection model highlights the increasing need for coordination among utilities, transmission owners, and ISOs/RTOs, particularly as load facilities expand from modest initial demand to hundreds of megawatts over time and ultimately transition to direct transmission service.

Current Status and Challenges

Distribution interconnections generally fall under state jurisdiction, managed by public utility commissions or local utilities without direct FERC oversight. This allows for more utility-specific rules that can attract large load developers with facilities in the 1 to 30 MW range; however, this can lead to process and reliability inconsistencies across regions. For example, the boundary between transmission and distribution is not always clear; sub-transmission may blur the lines and is sometimes treated as part of the bulk power system if it impacts reliability. Therefore, it is important to coordinate across stakeholders to avoid inconsistent, reliability-compromising treatment of large loads interconnected at distribution or sub-transmission levels.

Large loads interconnecting at the distribution level may have shorter timelines to interconnect than transmission interconnections due to fewer queue backlogs or detailed

It is important to coordinate across stakeholders to avoid inconsistent, reliability-compromising treatment of large loads interconnected at distribution or sub-transmission levels.

studies, fewer permitting requirements, or a lower likelihood of a need for new major distribution infrastructure such as substations or lines.

A large load interconnection request on a utility distribution network typically begins with the customer submitting an interconnection or new service application with high-level technical details such as site address and location coordinates, anticipated load size (kW or MW), voltage level, and type of service (e.g., single-phase or three-phase). Additional details often include the desired in-service date, construction schedule, load shape, and desired load service (continuous or intermittent). Customers must also provide load characteristics, such as peak demand, power factor, and any special equipment that could affect power quality. For large or complex loads, utilities may request one-line diagrams, equipment specifications, operational characteristics, and protection/control settings. Typically, models of large load facilities are not required, but that may need to change in time due to the new operational characteristics of new large power electronics–based loads that can have important grid impacts.

So while transmission interconnection studies focus on assessing the impact of the new load on bulk power system reliability, distribution interconnection studies evaluate the impact of the new customer on local feeders, nearby customers, transformers, and voltage regulation to ensure safe and reliable distribution service.

Withdrawal capacity maps (a new term for load hosting capacity maps) show where the system has enough capacity to host additional large customers; they can be used to attract load developers to specific locations and thus shorten analysis time and uncertainty. These withdrawal capacity maps are interactive tools that show the grid's ability to accommodate additional demand such as electric vehicle fleet charging, data centers, or industrial facilities without compromising distribution asset loading, local power quality, or reliability. Unlike generation-focused hosting capacity maps, which indicate how many more distributed energy resources (DERs) such as solar photovoltaic systems can be added in specific places on the grid, load hosting capacity maps emphasize available capacity for new loads. They incorporate data on circuits, feeders, and substations; peak load conditions; and system voltage levels to inform interconnection decisions. By providing geospatial data on available capacity, publicly available maps facilitate more informed decision-making for interconnecting new loads. These maps provide transparency and allow developers, regulators, and end users to assess distribution system capacity initially without having to consult the utility. This enables stakeholders to identify opportunities for load additions, supports efficient site selection, and helps to ensure project viability. Developers can direct efforts toward locations with ample capacity, thus minimizing the risk of rejection during the formal interconnection application. In addition, load hosting capacity maps can aid utilities in identifying constraints that may warrant proactive upgrades, as well as support integrated resource planning efforts and flexible interconnections.

Distribution-Connected Large Loads and Distributed Energy Resources

Regulated electric utilities have an obligation to serve customers' demand, but that obligation is not unconditional. The customer's facility must connect to the distribution grid in a safe and reliable manner and not pose a threat to the grid and the other customers it serves. However, the high volatility and unpredictability of large loads can introduce distribution system risks such as rapid power flow fluctuations, voltage and frequency deviations, harmonics, and potential cascading failures. These necessitate imposing significant technical requirements and protections upon distribution-connected large load customers as a condition of electricity service, to protect the grid and other customers.

Utility Technical Requirements to Ensure a Reliable Distribution System

A utility's establishment of technical requirements and protections for large loads is similar in process and necessity to what utilities have implemented for the interconnection and operational requirements for DERs. Utility requirements for DERs are designed to ensure that customer-owned generation, such as solar photovoltaics, batteries, or small wind systems, can safely operate in parallel with the utility grid. These requirements include technical standards (IEEE 1547 for voltage and frequency, and protection coordination), interconnection studies to evaluate the grid impacts (voltage rise, voltage fluc-tuations, fault current contribution, protection, thermal loading, harmonics, and flicker), and operational

protocols such as communication, control, and metering to enable monitoring and dispatch coordination. The utility's role is to assess these impacts and define any necessary upgrades or protection settings before granting permission to operate.

Most large loads want highly reliable electricity service. To manage the risk of service interruptions and outages, many large loads are building back-up generation and storage behind the meter to ensure operational continuity. This means that many large load customers also seek to interconnect large DER installations at the same interconnection point (whether behind the meter or at the point of interconnection feeding into the utility distribution system). Traditional loads prioritize unidirectional supply reliability, but new large loads mirror DER challenges by needing bidirectional considerations for power quality and system protection impacts.

Distribution-level grid protection requirements for large loads (akin to the IEEE 1547 DER interconnection standard) need to include:

1. **Detailed interconnection studies and modeling:** Mandates for comprehensive assessments covering power flow, ramp rates, load operational behavior, and protection settings
2. **Performance criteria:** Performance requirements for large load voltage and frequency ride-through, power factor maintenance, power quality compliance, and ramp-rate limits (short term (to mitigate spikes from AI training) and long term (load size ramp up))
3. **Monitoring and data sharing:** Requirements for fault/disturbance recording and power quality monitoring for real-time visibility,[20] and mandatory sharing of forecasts or operational changes
4. **Protection and coordination:** Coordination of facility protection (e.g., UPS and parallel or back-up generation) with utility systems and enabling of demand response for curtailment during contingencies
5. **Operational and enforcement measures:** Contracts with minimum load factors, utility rights for inspections, corrective action or disconnection for non-compliance, and ensuring equitable cost allocation

New Types of Interconnection: Flexible, Bridging, and Others

One way to speed up and simplify the interconnection process for large loads is flexible interconnection. This approach allows large loads and DERs to connect to the grid under conditional arrangements rather than wait for all traditional upgrades to be completed (CHARGED, 2026). Instead of delaying projects until full distribution system capacity is available, utilities and customers agree on operating limits—such as phased energization, temporary capacity caps, or curtailment during peak demand conditions—while permanent upgrades are planned and executed. This method often uses real-time monitoring, advanced controls, and grid-enhancing technologies such as dynamic line rating, topology optimization software, and advanced power flow control devices to manage reliability risks. The result is faster project realization timelines, better use of existing infrastructure, and improved economic development opportunities, all while maintaining system stability and safety.

Due to the limited size of the load able to interconnect at the distribution level (dictated by the voltage level) and the complex and extended timeline of transmission interconnection process, new types of load interconnection configurations, like bridging interconnections, are surfacing. As mentioned above, a bridging interconnection allows a smaller large load to temporarily connect at a medium-voltage distribution level or a sub-transmission level while permanent transmission infrastructure is constructed and loads ramp up, eventually switching to a direct transmission tie. This approach is increasingly being considered for high-demand loads like data centers, where the build timeline outpaces the grid upgrades necessary. Many large loads ramp up from a few megawatts to hundreds of megawatts over several years (SCE, 2024; EPRI, 2024; Dominion Energy, 2024). The early phases of the facility ramp-up process could be served by local feeders. Some utilities are using this process to expedite the interconnection of new, mid-sized loads and start partial operations before the full transmission grid capacity is ready.

20 Some utilities require Power Quality meters to ensure sufficient resolution of fault recording, while supervisory control and data acquisition (SCADA)/advanced metering infrastructure (AMI) is used for real-time visibility.

The bridging interconnection process poses many complexities and risks, which highlight the need for coordinated distribution and transmission planning for such transitions. The bridging interconnection process requires clear load ramp-up and ramp-down agreements via temporary service agreements defining load caps, duration, upgrade cost recovery, and terms governing the load's eventual transition to the transmission system. Additionally, parallel load interconnection processes to the transmission system must be in place, requiring developers to maintain queue position for their permanent transmission interconnection. Detailed, granular load monitoring is needed to ensure the interconnection terms are not violated and distribution system reliability is not compromised. The regulatory complexity across state (public utility commission) and federal (FERC) jurisdictions must be navigated to ensure a proper transition between distribution to transmission, which requires precise planning and coordination. Lastly, there is a risk that the temporary facilities used to connect the new large load to the distribution system could be stranded or decommissioned once the load connects at the transmission level. There needs to be an explicit plan to repurpose temporary facilities for back-up, emergency feed, or future load expansion in the region.

Cost Allocation

Utilities allocate the cost of infrastructure upgrades through a combination of rate recovery mechanisms, interconnection agreements, and regulatory approved tariffs, guided by the principles of cost causation to ensure that those responsible for driving the need bear a proportional share. When demand growth occurs organically, through existing and gradual growth in residential, commercial, or small industrial customers, utilities typically forecast load-driven distribution infrastructure needs and recover upgrade costs (as for substation expansion, feeders, or lines) through broad-based retail rates approved by public utility commissions. This approach spreads expenses across all ratepayers in the form of high base rates or surcharges, reflecting the embedded cost of service where historical and projected system-wide investment are amortized over time. But with the surge in demand from new large loads like data centers, electric vehicle fleets, and manufacturing facilities, some utilities are adapting existing practices to isolate incremental costs, conducting detailed interconnection studies to identify upgrades required (such as new transformers, voltage support devices, or transmission reinforcement), and allocating those costs directly to the new user to avoid raising the cost burden on existing customers.

Interconnection Process Recommendations for Distribution-Connected Large Loads

As stated above, while distribution-connected large loads are much smaller than those connected to the transmission or sub-transmission systems, it is important to ensure that processes for distribution-connected large loads are clearly structured and establish formal coordination, data-sharing, and performance requirements. Given that today's large loads are predominantly power electronics–connected, there is an increased risk for multiple facilities to disconnect from the grid during similar grid conditions. This, combined with the total size of these distribution-connected large loads in the aggregate, means the process for these large loads must be thorough and ensure that what is connected represents what has been studied.

Establish Structured Interconnection Process

As distribution-connected large loads continue to grow in size and complexity, utilities will need more structured and transparent interconnection processes with clearly defined application requirements, study procedures, milestones, and timelines. Distribution-level studies increasingly need to evaluate dynamic load behavior, power quality, protection coordination, and interactions with behind-the-meter generation and storage. Additional modeling and operational data requirements may also be necessary.

Establish Formal Coordination Between Distribution and Transmission Planning

Closer coordination between distribution and transmission planning functions will become increasingly important, as some distribution-connected large loads can materially affect sub-transmission and bulk power system operations. Utilities can establish formal information-sharing and

coordination mechanisms, particularly for facilities expected to ramp significantly over time or transition from distribution to transmission service through bridging interconnection arrangements.

Develop Withdrawal Capacity Maps and Flexible Interconnection Approaches

Expanded use of publicly available withdrawal capacity maps (i.e., hosting capacity maps) and other pre-application screening tools can improve transparency, guide developers toward areas with available capacity, and reduce study uncertainty. Utilities can also continue exploring flexible interconnection approaches, including non-firm, provisional, and bridging service options, to accelerate interconnections where firm service is not immediately available.

Develop Distribution-Level Technical Requirements for Large Loads

Utilities, regulators, and industry organizations can consider developing more harmonized technical and performance requirements for distribution-connected large loads, similar in concept to requirements applied to DERs. These requirements may include voltage and frequency ride-through, power quality, monitoring and telemetry, disturbance recording, communications capabilities, and protection coordination requirements needed to support reliable system operation.

Conclusions and Recommendations

The rapid growth of large load interconnection requests, driven primarily by data centers and AI, marks a structural shift in how the electric power system must plan for and accommodate new demand. Without proactive reform, existing interconnection processes risk slowing economic growth, creating reliability challenges, and raising costs for all customers. Some of these challenges are analogous to those of the generation interconnection process. The electricity industry has a unique opportunity today to rapidly apply the lessons learned from generation interconnection reform to large load interconnection before these challenges become widespread.

The electricity industry has a unique opportunity today to rapidly apply the lessons learned from generation interconnection reform to large load interconnection before the challenges become widespread.

Large load interconnections can be more efficient, reliable, and faster by establishing a harmonized, transparent, and milestone-based interconnection framework spanning utilities, ISOs/RTOs, and federal and state regulators. Fragmented approaches will not scale to meet the magnitude of anticipated load growth. A coordinated response among utilities, ISOs/RTOs, large load owners and operators, and regulators is necessary—one that balances economic development with system reliability, cost protection for existing customers, and efficient infrastructure deployment.

These conclusions align closely with the U.S. DOE's ANOPR on large loads, which emphasizes the need for improved visibility into large load development, consistent interconnection practices, and proactive planning for high-impact demand (U.S. DOE, 2025b). Key principles proposed by DOE supported in this report include enhanced data collection and transparency for large load projects, improved load forecasting, interconnection process and planning coordination, clear cost responsibility frameworks, integration of demand flexibility and on-site generation, and explicit reliability considerations for high-density load growth.

The report's recommendations, intended to create a more harmonized, transparent, and efficient interconnection framework for large loads, are summarized below. They are based on the Large Loads Task Force's review of current practices and challenges and draw from the experience and expertise of task force participants including system operators, utilities, data center operators, regulators, and researchers. The recommendations aim to preserve latitude for regional and local variation while establishing the consistency and rigor that large load integration demands. Figure 8 (p. 44) illustrates of how other key recommendations align with the recommended milestone-based large load interconnection process.

Large Load Interconnection Process Overall

- The entities that are responsible for large load interconnection processes can follow the recommendations in this report to create more uniform, transparent interconnection processes across the U.S. that will help improve efficiency and speed of large load interconnections. It is recommended that the process be

based on clearly defined milestones with readiness requirements that provide credible indication of project viability, roles and responsibilities, timelines, and cost allocation frameworks.

- The potential for development of a FERC Large Load Interconnection Procedure can be explored that establishes a baseline framework for large load interconnection under FERC jurisdiction, analogous to existing generation interconnection procedures, with transparent processes, defined milestones, timelines, and cost responsibility frameworks. States and non-FERC jurisdictional entities could consider adapting the LLIP for large load interconnections over which they have authority.
- The large load interconnection application packages, site control (land ownership, signed lease agreements, or options to purchase or lease land of sufficient size for the facility), and financial readiness requirements can be applied to filter speculative interconnection requests and reduce queue congestion driven by large load projects that lack the commitment to proceed. Harmonizing these requirements insofar as possible across the nation will further help to improve the clarity and efficiency of the large load interconnection process.
- Consistent financial security requirements can be implemented across all interconnection providers, including milestone payments and withdrawal penalties, to mitigate the risk of stranded infrastructure investment and ensure appropriate utility cost recovery from large loads.
- Material modification rules can be finalized to maintain the integrity of interconnection queues and study processes as project configurations evolve, balancing the need to accommodate technological change with the need to preserve study integrity and planning assumptions.
- Expanded use of hosting capacity maps early in the siting and interconnection process can guide large load developers toward locations with available grid capacity, reducing initial study complexity and queue processing time.

Large Load Interconnection Process Coordination

- Coordination among utilities and ISOs/RTOs needs to be enhanced throughout the interconnection process, including formal information-sharing protocols and joint study procedures for facilities that interact with multiple grid layers.
- Queue transparency can be improved at both utilities and ISOs/RTOs, including harmonized treatment of duplicate requests and consistent application of interconnection requirements across service territories.
- Large load interconnections can be integrated into regional transmission planning processes, ensuring that the infrastructure needs of large load growth are reflected in long-term planning and cost allocation frameworks.

Large Load Interconnection Process Studies

- When the volume of large load connection requests exceeds a preset level, utilities and ISOs/RTOs can transition to cluster study approaches for large loads, consistent with reforms already underway for generator interconnection. This approach improves study efficiency and reduces the compounding delays created by serial study queues.
- For every large load interconnection, steady-state, PSPD, and short-circuit studies need to be performed that meet applicable NERC, ISO/RTO, and utility study requirements.
- A screening process can be established to determine when certain large load facilities require EMT studies and those studies performed for the large load facilities identified.
- Harmonized reliability study methods can be developed for studying co-located load and generation, including conditions under which they are studied as a single entity.

Large Load Interconnection Technical Requirements

- Clear performance and capability requirements for large loads can be developed that apply for the lifetime of these facilities. These include detailed technical modeling requirements for PSPD and EMT models that would be submitted as a part of the interconnection application and updated throughout the interconnection process as facility design and construction advances.[21]
- Technical requirements and practices for assessing loads' conformity with the requirements can be unified across the U.S. grid to enable efficiency and consistency for all large load interconnections.
- NERC large load–specific reliability standards can be developed that address load modeling, performance and capability requirements, physical and cybersecurity, operational coordination, data sharing, emergency operating conditions, and other reliability topic areas. NERC has already started work to develop an interim set of requirements for large loads, to be followed by a more comprehensive applicable standards revisions effort.
- NERC can create an additional registration category that would specify which large loads would be subject to mandatory enforceable requirements within its regulatory area. This separation of large loads in the compliance space can allow for the more efficient creation of technology-specific requirements that will help enhance bulk power system reliability without overburdening traditional large loads (e.g., industrial loads such as steel and glass production) or creating insufficient requirements that fit all large load types. NERC has already begun the work of creating and defining this large load registered entity.

New Solutions to Speed Up Large Load Interconnection

- Harmonized voluntary flexibility products can be developed, including provisional, surplus, and non-firm service options, to give large load customers more flexibility options and accelerate interconnection where firm service is not immediately available.[22]
- Clear, consistent rules can be established for bring-your-own-generation arrangements and generation resources co-located with large loads. The rules will need to clearly define how a co-located resource is treated, modeled, and studied at each of the large load interconnection process milestones.

Staffing Resources

- Utilities and ISOs/RTOs need sufficient staffing resources to process the growing volume and complexity of large load interconnection requests.

Figure 8 (p. 44) shows the alignment of the report's recommendations with the seven milestones of the large load interconnection process. Taken together, these recommendations provide a practical and technically grounded pathway toward a large load interconnection framework that supports the reliable, efficient, and timely integration of large load facilities into the U.S. electric power system.

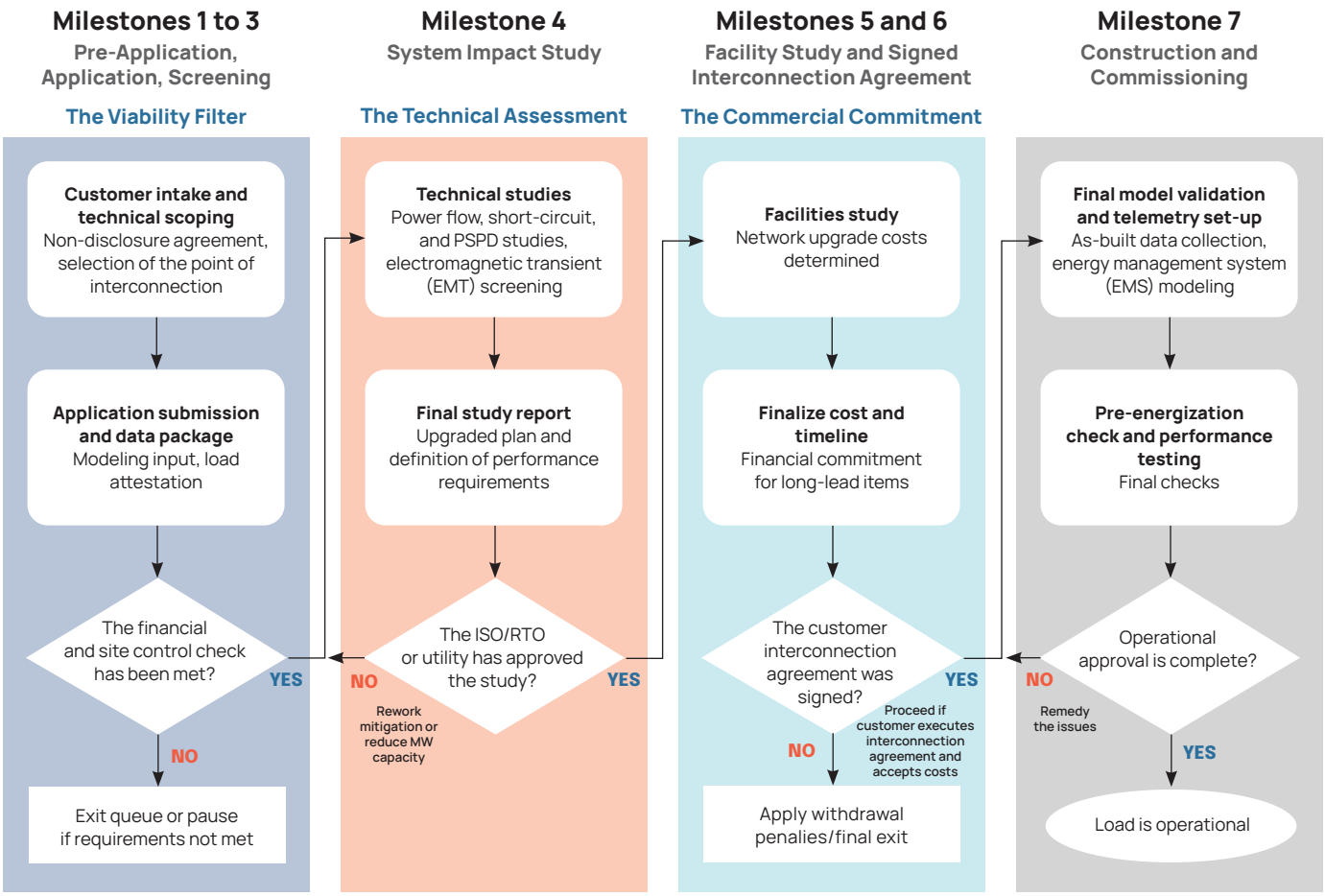
Taken together, these recommendations provide a practical and technically grounded pathway toward a large load interconnection framework that supports the reliable, efficient, and timely integration of large load facilities into the U.S. electric power system.

21 See the ESIG Large Loads Task Force reports *Large Load Modeling for Dynamic Studies: Current Practices and Recommendations* (https://www.esig.energy/reports-briefs/large-load-modeling) and Large Load Performance Requirements: Current Practices and Recommendations (https://www.esig.energy/reports-briefs/large-load-interconnection-performance-requirements).

22 For a longer discussion of large load flexibility, see the ESIG Large Loads Task Force report *Grid Integration of Large Loads: Introduction to the Large Loads Task Force, Data Needs, and Flexibility* (https://www.esig.energy/reports-briefs/large-load-task-force-introduction).

FIGURE 8

The Recommended Large Load Interconnection Process Presented in This Report



KEY RECOMMENDATIONS

- Implement standardized application packages and financial readiness criteria to filter speculative interconnection requests
- Establish centralized ISO/RTO-level interconnection request intake
- Use hosting capacity maps early to guide siting and reduce initial study complexity

- Develop consistent technical requirements for load modeling (e.g., PSPD, EMT), types of studies to be carried out, and interconnection requirements
- Establish study requirements for co-located generation
- Ensure adequate resources (i.e., staffing and tools) at ISOs/RTOs and utilities

- Standardize financial commitment requirements to mitigate stranded asset and utility rate recovery risks
- Establish a material modification process including triggers, model update requirements, and re-study criteria

- Establish requirements for model validation and conformity assessment with applicable performance requirements

Note: Each step may include nuances depending on the utility type.

- Implement a transparent large load interconnection process with clearly defined milestones, roles and responsibilities, and timelines for each milestone

- Establish clear rules and requirements for cluster studies, flexibility product provision, and "bring your own generation" considerations

Large load interconnections are a primary driver of grid investment and operational risk, and without standardized processes, the industry will face escalating delays; potential cost-shifting from large loads to other, existing customers; and significant reliability risks. Proactive implementation of standardized large load interconnection processes, grounded in both the lessons of generation interconnection reform and the U.S. Department of Energy's emerging policy framework, offers the most effective path forward for accommodating rapid load growth while protecting the public interest and preserving the reliability of the electric power system. This figure gives a high-level overview of the recommended large load interconnection process presented in this report.

Source: Energy Systems Integration Group.

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Interconnection Processes for Large Loads: Current Practices and Recommendations

A Report by the
Energy Systems Integration Group's
Large Loads Task Force

The report is available at https://www.esig.energy/resources/reports-and-briefs/.

To learn more about ESIG's work on this topic, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads

NERC Large Loads Working Group White Paper

March 2026

RELIABILITY | RESILIENCE | SECURITY






Table of Contents

Preface v
Executive Summary vi
A New Challenge on the Horizon vi
NERC's Response vi
Building a Strong Foundation vii
Essential Insights: Key Reliability Recommendations vii
Chapter 1: Introduction to Emerging Large Load Gap Analysis 1
Intended Audience 1
NERC Large Loads Task Force 1
Large Load Definitions 2
Background 2
Changing Gaps 3
Chapter 2: Interconnection Processes and Requirements 4
Gaps Related to Interconnection Processes 4
Lack of Standardization in Comprehensive Load Interconnection Studies and Performance Requirements 5
Lack of Data Sharing 6
Lack of Collaboration and Coordination 7
Chapter 3: Planning and Resource Adequacy 8
Demand Forecasting Gaps 8
Resource Planning Gaps 9
Transmission Planning Gaps 10
Lack of Standardization/Coordination Between Entities 11
Chapter 4: Balancing and Operations 12
Balancing Gaps 12
Short-Term Demand Forecasting 12
Impact of Large load Ramping and Disturbance Ride-Through Limitations on Area Control Error 13
Operations Gaps 14
Impact of Large load Ramping on System Reliability and Operations Planning 14
Real-Time Operations and Outage Coordination 15
Operations Tools 15
Chapter 5: Disturbance Ride-Through, Stability, and Power Quality 16
Voltage Disturbance Ride-Through Gaps 16
Frequency Disturbance Ride-Through Gaps 17

Harmonics and Interharmonics Gaps 18
Stability Gaps 19
Rotor-Angle Stability 20
Frequency Stability and Voltage Stability 20
Converter-Driven Stability 22
Resonance Stability 23
Forced Oscillations 23
Chapter 6: Security, Resilience, and Event Analysis 24
Physical and Cyber Security Gaps 24
Communication Security Gaps 25
Operational Security Gaps 26
System Restoration 27
Event Analysis and Data Collection Gaps 27
Chapter 7: Modeling of Large Loads 29
Modeling Philosophy and Terminology 29
Gaps in Model Availability 29
Phasor Domain or Positive Sequence Models 29
EMT Models 31
Gaps in Modeling Information 31
Gaps in Modeling Guidance and Practices for Large load Facilities 32
Gaps in Modeling Validation and Model Quality Tests 33
Chapter 8: Risk Categorization and Mitigations 35
Risk Likelihood/Impact and Ability to Mitigate 38
Long-Term Planning Risks 38
Operations/Balancing Risks 40
Stability Risks 42
Power Quality Risks 45
Security Risks 46
Load-Shedding & System Restoration Risks 47
Chapter 9: Conclusion 49
Addressing the Challenges and Shaping the Future 49
Unveiling the Critical Gaps: A Path to Reliability 49
Interconnection Processes and Requirements Gaps 49
Planning and Resource Adequacy Gaps 50
Balancing and Operational Gaps 50

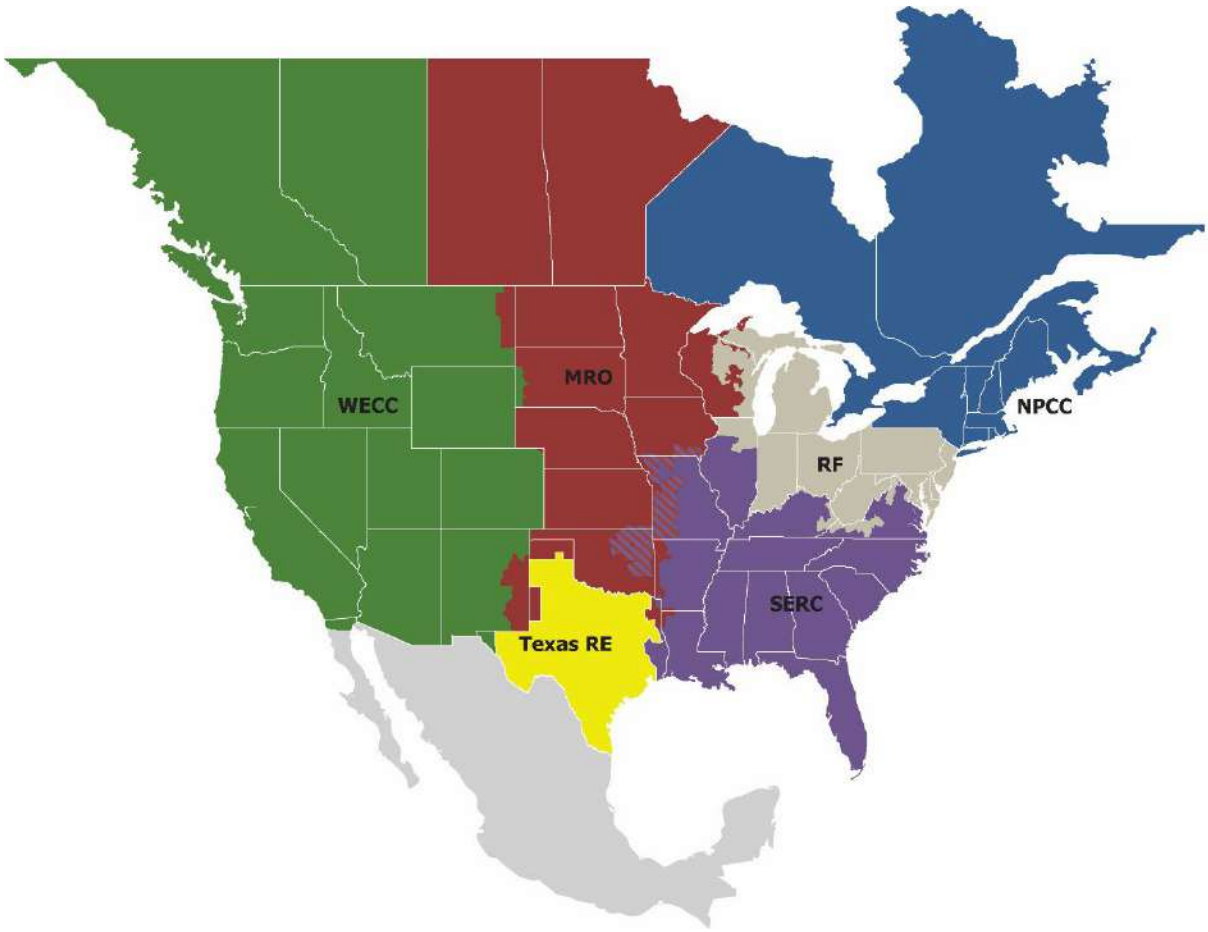
Disturbance Ride-Through, Stability, and Power Quality Gaps 51
Security, Resilience, and Event Analysis Gaps 51
Modeling Gaps 52
Risk Categorization and Mitigations 52
Critical Reliability Recommendations 52
Appendix A: Phasor/Time Domain Simulation Tools, Modeling Terminology, and Applications 56
Appendix B: NERC Standards and Applicable Sections 58
Appendix C: Acknowledgements 60

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

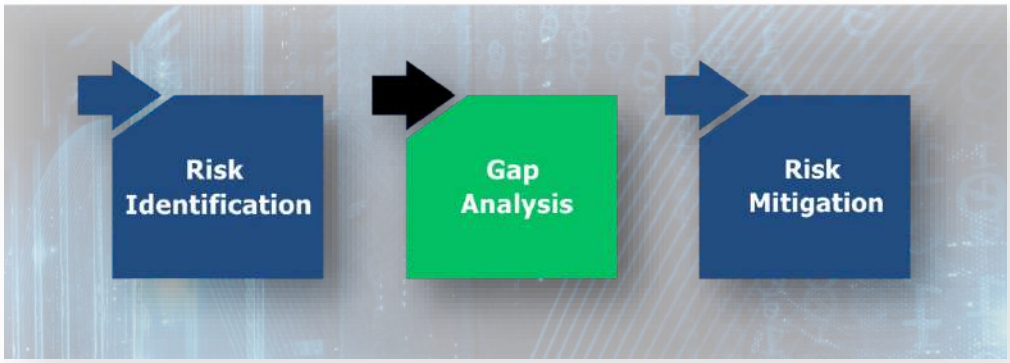
A New Challenge on the Horizon

As the North American electric system evolves, emerging large loads are challenging the reliability, resilience, and security of the North American bulk power system (BPS).[1] These large load facilities are rapidly increasing in number, scale, and operational complexity, creating challenges under existing NERC Reliability Standards, interconnection practices, and system planning assumptions that were not designed to account for their unique characteristics.

NERC's Response

To respond to this evolving landscape, NERC commissioned the Large Loads Working Group (LLWG)[2] of NERC's Reliability and Security Technical Committee (RSTC) to identify potential gaps related to large load[3] integration in Reliability Standards, interconnection requirements, and Institute of Electrical and Electronics Engineers (IEEE) Standards,[4] as well as in utility practices like load forecasting and load modeling practices. This paper comes after previous work that outlined the characteristics of large loads and identified the reliability risks they may present to the BPS.

Large load facilities are rapidly increasing in number, scale, and operational complexity



NERC's *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads* evaluates gaps related to the following:

- **Interconnection processes and requirements**
- **Planning and resource adequacy**
- **Balancing and operations**
- **Disturbance ride-through, stability, and power quality**
- **Security**
- **Resilience and event analysis**
- **Load modeling**

[1] Glossary of Terms Used in NERC Reliability Standards
[2] In December 2025, the Reliability and Security Technical Committee promoted the Large Loads Task Force to a working group.
[3] See Chapter 1 for the definition of "large load" for this paper.
[4] IEEE Standards are voluntary and must be adopted by a governing body to become enforceable. By contrast, NERC Reliability Standards are developed for the purpose of becoming mandatory and enforceable on users, owners, and operators of the BPS in North America.

Furthermore, this white paper categorizes the risks to the BPS related to large loads to determine the appropriate mitigations.

Overall, this white paper finds that the existing Reliability Standards and the existing processes and requirements related to BPS planning, operations, security, and other areas are inadequate to address the risks posed by emerging large loads that are forecasted to make up a significant portion of the future grid. This inadequacy exists because the regulatory regime was established at a time when most significantly sized loads had different operating characteristics when compared to the data center or cryptocurrency mining and other emerging large loads currently seeking interconnection.

…existing Reliability Standards and the existing processes and requirements related to BPS planning, operations, security, and other areas are inadequate to address the risks posed by emerging large loads

Building a Strong Foundation

This paper serves as a foundational step in updating industry practices to address the challenges of integrating large loads into the evolving electric grid. Alongside the Large Loads Task Force (LLTF) *Characteristics and Risks of Emerging Large Loads* white paper,[5] it performs Step 1 of the RSTC Standard Authorization Request (SAR) Process.[6] The RSTC or others may[7] consider developing SARs or other mitigating measures to mitigate the reliability gaps discussed in this paper.

Essential Insights: Key Reliability Recommendations

The following provides a summary of the LLWG recommendations based on the gaps assessed in this paper. The detailed list of recommendations can be found in the **Conclusion**.

- ✓ **Recommendation 1:** There are multiple high-impact risks to the BPS from large loads that NERC registered entities[8] cannot adequately address. The LLWG recommends that NERC pursue registration of a type of entity (or types of entities) that is able to perform specific functions to address the risks.[9]

- ✓ **Recommendation 2:** The LLWG and other groups should propose SARs to address the unmitigated risks to the BPS related to emerging large loads.

- ✓ **Recommendation 3:** The LLWG should identify potential mitigations to risks posed by emerging large loads through improvements to existing planning and operations processes and interconnection procedures for large loads as planned for the LLWG's work item titled *Reliability Guideline: Risk Mitigation for Emerging Large Loads*.

- ✓ **Recommendation 4:** Registered entities should coordinate and collaborate with large load entities and update their practices to address the gaps discussed in this paper.

[5] Available here: White Paper Characteristics and Risks of Emerging Large Loads
[6] Available here: RSTC SAR Development Process clean Sept 20 2023.pdf
[7] *Ibid. See also*, the NERC Rules of Procedure regarding submittal of SARs.
[8] See NERC Rules of Procedure Appendix 5A and NERC Rules of Procedure Appendix 5B for more information on registered entities. Available here: Rules of Procedure
[9] The findings of the NERC Level 2 Alert: Large Load Interconnection, Study, Commissioning, and Operations, distributed on September 9, 2025, will likely help provide more information regarding the need to pursue registration of an entity type (or types of entities).

- ✓ **Recommendation 5:** To address the gaps discussed in this paper, Transmission Owners (TO) should coordinate with other registered entities as applicable to update their interconnection requirements; Planning Coordinators (PC) and Transmission Planners (TP) should update their interconnection study processes.

- ✓ **Recommendations 6-8:** The NERC Load Modeling Working Group should work to address the applicable gaps identified in this paper. Additionally, the Security Working Group and the System Protection and Control Working Group should further assess applicable gaps and propose mitigations to address the gaps.

- ✓ **Recommendations 9-10:** Federal and/or state regulators, as applicable, should consider the gaps identified in this paper and coordinate with utilities to assess whether incorporating additional interconnection requirements and/or studies are appropriate to reliably support integration of large loads. State regulators should work with regulated utilities to review how new loads and planned additional generation impact existing planning and risk assessment frameworks. States may need to adjust their resource adequacy criteria and/or work with their utilities on energy infrastructure expansion.

- ✓ **Recommendation 11:** Policymakers should review interactions between interconnection requirements, existing state regulations and planning processes, and regional grid operator requirements. Additionally, policymakers should work to better understand the full impact of large load integration in their jurisdiction, and review requirements for large load customers to provide operational data and information to TOs, TOPs, TPs, and other entities.

Chapter 1: Introduction to Emerging Large Load Gap Analysis

Intended Audience

This paper is intended for the following NERC registered entities, external entities, and broader groups:

- Planning Coordinators (PC)
- Resource Planners (RP)
- Transmission Planners (TP)
- Transmission Owners (TO)
- Transmission Operators (TOP)
- Distribution Providers (DP)
- Balancing Authorities (BA)
- Reliability Coordinators (RC)
- Large Load Developers, Owners, Operators, or Other Related Companies
- Generator Owners (GO)
- Generator Operators (GOP)
- Load-Serving Entities (LSE)
- Reliability and Security Technical Committee (RSTC) Subgroups
- FERC
- State Regulators and Other Regulatory Entities
- Consumer Advocates

This paper analyzes the gaps in existing practices,[10] requirements,[11] and NERC Reliability Standards related to emerging large loads and provides recommendations for addressing the gaps. Entities responsible for operating and planning the BPS should be aware of these gaps and work to address the gaps in their own practices and requirements to reliably plan and operate the BPS. This paper also identifies areas where potential gaps associated with emerging large loads require further assessment by related RSTC groups.

NERC Large Loads Task Force

The NERC LLWG aims to understand the reliability impacts that emerging large loads, such as data centers and other computational loads, large industrial loads, and hydrogen fuel plants, will have on the BPS. The LLTF has two primary phases identified in the NERC LLTF scope as follows:[12, 13]

- Phase 1: Identify unique characteristics and risks of large loads
- Phase 2: Identify gaps and potential risk mitigation

[10] As NERC Reliability Standards are the minimum performance needed for BPS reliability, utilities have practices that extend beyond the NERC standards. These practices are often related to NERC standards but may extend beyond the standards.
[11] These requirements include interconnection requirements as well as IEEE standards
[12] LLTF Scope
[13] At the time of the writing of this white paper, a new scope for the working group has not yet been RSTC approved. In the interim, the LLWG has inherited the scope of the LLTF.

This paper completes the gap identification portion of Phase 2 of the LLTF scope. This paper, in conjunction with the planned reliability guideline, additionally addresses the mitigation identification portion of Phase 2 of the LLTF scope. The remaining portions of Phase 2 of the scope will be completed in future LLWG activities.

Large Load Definitions

As defined in the NERC LLTF *Characteristics and Risks of Emerging Large Loads* white paper,[14] the definition of "large load" for this paper is the following:

"Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors. Examples include, but are not limited to, data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces."

Regulatory updates could develop more specific definitions at a later date. On page 16 of NERC's comments submitted in response to FERC's Advance Notice of Proposed Rulemaking on potential reforms to enable the interconnection of large loads to the transmission system, NERC has provided an example timeline for addressing the issues related to the reliable integration of large loads onto the BPS. This example timeline includes filing NERC Rules of Procedure registry criteria changes, along with aligned standards glossary revisions, in Q1 2027. This timeline also includes drafting and filing NERC Reliability Standards during 2027.

More specific definitions could also differentiate within the large load category. The potential impact of several 100 MW loads may be less than the impact of a 500 MW load and may require different treatment. The emergence of gigawatt-scale loads may create exponential complications for study, planning and operations.

Additional definitions related to large load facilities for this paper are the following:

- **Data Center:** "…[A] physical room, building or facility that houses [information technology (IT)] infrastructure for building, running and delivering applications and services."[15]
  - Categories of data centers include traditional data centers, artificial intelligence (AI) training data centers, and AI inference data centers.[16]
- **AI Training:** "…[T]he creation and modification of an AI model and its associated model weights."[17]
- **AI Inference:** "…[T]he process of using a pre-trained AI model to generate output(s) based on new input."[18]
- **Cryptocurrency Mining Facility:** A physical facility housing IT infrastructure for performing cryptocurrency mining.
- **Cryptocurrency Mining:** "…[t]he process of verifying and recording transactions on a blockchain using advanced computing power."[19]

Background

According to NERC's 2025 *Long-Term Reliability Assessment* (LTRA), the aggregated summer peak demand forecast for the North American BPS is predicted to increase by over 224 GW over the 2026–2035 time frame; the aggregated winter peak demand forecast is predicted to increase by 245 GW over this same time frame. Overall, data centers

[14] Available here: White Paper Characteristics and Risks of Emerging Large Loads
[15] What Is a Data Center? | IBM
[16] White Paper Characteristics and Risks of Emerging Large Loads
[17] *Ibid.*
[18] *Ibid.*
[19] What is Cryptocurrency Mining & How Does it Work? - Crypto.com International

account for the majority of this demand increase, while cryptocurrency mining facilities are one of the primary demand drivers for this growth in two portions of the North American BPS.[20]

Changing Gaps

While the gaps in practices, requirements, and modeling identified in this paper were accurate when the content of this paper was initially being drafted, many utilities, entities in the large load industry, and others are working to address the gaps (e.g. by implementing ride-through requirements). Therefore, some of the requirements, practices, and modeling at the time of the publishing of this paper may be different than discussed in this paper.

[20] 2025 Long-Term Reliability Assessment

Chapter 2: Interconnection Processes and Requirements

Due to the complexity and risks that emerging large loads introduce to the BPS, large load interconnection requirements and energization processes must be designed to support grid reliability and incorporate any needs and requirements of the applicable TO, BA, RC, and other applicable entities. Without thorough system study, analysis, review, and approval processes, TOs may interconnect large loads with inadequate design and before operational readiness is ensured. The BPS impacts from emerging large loads can extend beyond the immediate system to which they are connected; they present performance implications of which neighboring systems need to be aware. This section discusses gaps and key issues in the interconnection of emerging large loads, including the lack of comprehensive study and performance requirements in the interconnection process, data sharing, and coordination and collaboration between large load entities, utilities and other entities.

On November 21, 2025, NERC submitted comments in response to FERC's Advance Notice of Proposed Rulemaking on potential reforms to enable the interconnection of large loads to the transmission system. NERC's filing emphasized the need for consistent visibility into new large loads, clear coordination requirements among entities, and robust planning processes that support reliability in a rapidly transforming grid environment. The LLWG supports FERC's examination of these issues in Docket No. RM26-4.

Gaps Related to Interconnection Processes

Because: (i) large loads have not been a focus under Reliability Standards for existing registered entities and (ii) neither large loads nor LSEs are registered entity functions under the NERC registry criteria, this white paper finds that the existing Reliability Standards and interconnection requirements do not adequately mitigate large loads' reliability impacts on the BPS.[21]

- For example, Reliability Standard FAC-001[22] requires TOs to establish interconnection requirements for generators as well as loads, and Reliability Standard FAC-002[23] requires TPs and PCs to study impacts and correct identified reliability risks; however, challenges have been observed with how the interconnection requirements used for generators and traditional loads apply to emerging large loads.
- Even though FAC-001 allows TOs to establish interconnection requirements for "end-user Facilities"[24] like large loads, the current interconnection requirements may not adequately identify the impacts on the BPS, and the requirements may lack clarity and specificity for the interconnection of large loads. The BPS impact from emerging large loads can be much greater than those of historical load additions.
    - A recent NERC report[25] on a large load event highlighted issues that are not adequately captured by existing TO interconnection requirements. Interconnection requirements may have gaps related areas such as voltage/frequency disturbance ride-through, sensitive protection settings, ramping, power quality, and oscillation.
- There are currently no NERC standards for model quality to ensure that the load models reflect the real-time behavior of large loads during system disturbances that cause frequency or voltage variations.[26] Large load entities are currently not directly obligated under existing NERC standards to provide data and timely updates or to maintain data accuracy and appropriate load models. Further discussion on model validation and model quality gaps can be found in **Chapter 7**.

[21] Based on specific facts and circumstances approximately 10 years ago, the LSE function was removed from the NERC Rules of Procedure. However, the role of this previous function may be able to be tailored to address large load risks.
[22] Available here: FAC-001-4
[23] Available here: FAC-002-4
[24] FAC-001-4
[25] Available here: Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions
[26] See Chapter 7 for more information regarding load modeling gaps.

- Existing Reliability Standards (e.g. FAC-001) do not require TOs to include in their interconnection requirements any BA- and RC-specific requirements for large loads to address unique local system needs such as operational ramping and oscillation monitoring and mitigation. This is likely a gap.

While FAC-002 requires TPs and PCs to study the reliability impact of large load interconnection and requires that the facilities are studied for "…[a]dherance to applicable…[f]acility interconnection requirements…", there is currently no consideration to ensure that the **as-built configuration and parameters**[27] of these large loads are assessed for conformance with applicable facility interconnection requirements (as created per FAC-001); the review via FAC-001 may only involve the **as-planned configuration and parameters.**[28] Also, without a specific assessment process for design, pre-energization requirements, performance validation, ongoing operation, and future modification, TPs and PCs are not in a position to verify that large loads meet capability and performance requirements prior to energization. This also results in a gap in the ability to assess real-time performance in comparison to assumptions studied and impacts the results of planning studies. FAC-002 requires TOs to coordinate with PCs and TPs on studying the reliability impact of end-user facilities. As large loads are not a NERC registered function, the standard does not mandate any coordination or assistance from the large loads during the interconnection studies.

It is evident that industry lacks well-defined and comprehensive interconnection standards and guidelines for large loads that adequately address the potential risks and reliability concerns that large loads pose to the performance of the BPS. Some regional efforts, such as those undertaken by the Electric Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP), and other registered entities,[29] are underway to address the reliability impact posed by these large loads, with proposed changes aimed at better integrating these new loads and enhancing the overall reliability of the grid. As noted above, NERC supports federal and state attention to interconnection matters.

Commissioning gaps related to real-time operations and outage coordination are discussed in the **Real-Time Operations and Outage Coordination** sub-section of **Chapter 4**.

Lack of Standardization in Comprehensive Load Interconnection Studies and Performance Requirements

Key Point
There is a lack of standardization in the interconnection studies and performance requirements for large loads. This can lead to inaccurate forecasting, modeling data, and performance requirements, making accurate analysis challenging.

There is a broad alignment with generation interconnection studies and performance requirements in the industry with many entities following the FERC interconnection procedures and agreements[30] for generators. All TOs are required to have facility interconnection requirements per FAC-001 for both generators and loads. However, for large load interconnections, the process is often affected by local utility tariffs (which are under State jurisdiction), so study approaches and performance expectations vary.

These variations highlight the need for more comprehensive and coordinated study components that ensure accurate modeling data and clearly defined performance requirements. Without such requirements, interconnection studies may yield inaccurate analyses, complicating the assessments of system impacts and the identification of necessary network upgrades. This can affect grid reliability and ability of the system to accommodate the increasing number of large load interconnection requests. Furthermore, the limited input from the BA and RC in the development of the interconnection requirements can create operational risk as TOs and utilities may not clearly understand the specific characteristics and operational requirements of large loads.

[27] The configuration and parameters of a facility following commissioning and tuning, representing its final operational state.
[28] The planned parameters and layout of a facility, based on preliminary engineering design prior to construction or installation.
[29] W-A032522-01 Interim Large Load Interconnection Process
[30] Generator Interconnection

Lack of Data Sharing

The effective interconnection of large loads requires a thorough understanding of the loads' specific operational characteristics, including precise energy consumption profiles, power quality impacts, ramp rates, reactive power needs, and resilience or redundancy measures.[31] However, substantial gaps exist in data transparency and standardization, limiting the ability of grid operators and planners to accurately assess and accommodate these new demands.

One key contributing reason for this gap is that, because most large load customers are not registered entities under NERC standards, there are no direct requirements for the load entities in NERC standards.[32] Furthermore, the entity serving this load may also no longer be a function in the registry criteria. LSEs were a registered function under the NERC registry criteria in the Rules of Procedure (ROP).[33] Based on specific facts and circumstances dating from approximately 10 years ago, the function was removed from the ROP.[34] This white paper examines whether the BPS impacts associated with large loads might warrant reconsidering reactivation of the LSE function to support the efficient integration of large loads into the grid. As most being non-registered entities, data centers and similar large loads are not obligated to comply with stringent data reporting and sharing Reliability Standards typically mandated for generation resources. The lack of clear data reporting and sharing requirements can limit operators' ability to request comprehensive operational and performance data, resulting in an incomplete understanding of these facilities' behaviors and impacts on the grid.

The performance of data centers and other power electronic loads is based in part on their hardware and software configurations, and these configurations can be modified (including after initial energization of the load) resulting in changes to the performance characteristics. As part of the process in FAC-002, PCs should have a definition of qualified change[35] that captures impactful changes to these performance characteristics, as these changes can complicate long-term characterization and modeling of load behavior. However, PCs may not have adequate knowledge of data centers to understand what should be considered a qualified change for data centers or other power electronic loads. This could lead to situations in which a large load performs a configuration change that significantly impacts the performance of the facility but does not meet the PC's definition of qualified change, resulting in these impactful changes not being assessed for BPS impacts via the FAC-002 process.

Data center operators are inherently protective of their operational data due to commercial sensitivity, cyber security concerns, and competitive pressures. Sharing detailed consumption patterns or operational profiles could inadvertently reveal proprietary information regarding internal workloads, operational efficiencies, and business practices. As such, data centers are typically reluctant to provide detailed data, preferring to safeguard their competitive advantage, intellectual property, and sensitive infrastructure details. Operators of cryptocurrency mining facilities in particular may avoid sharing detailed operational data due to market competitiveness and strategic responses to electricity price fluctuations. In addition, utilities do not have observability into different categories of loads that are inside the data centers. This leads to operational challenges amid unexpected load dynamics.

The large load developer can be different than the entity that owns or operates the computational equipment. The developer might not have information on the end-user of the facility until late in the interconnection process. This can lead to gaps in the utility's ability to accurately study the proposed facility earlier in the interconnection process.

[31] See Chapter 7 for more information on the load modeling gaps.
[32] See NERC Rules of Procedure Appendix 5A and NERC Rules of Procedure Appendix 5B for more information on which entities are required to be registered. Available here: Rules of Procedure
[33] Available here: Rules of Procedure
[34] For more information about the history of the NERC Registry Criteria and the removal of certain load-serving entities, see Risk-Based Registration: Phase 1- Enhanced Draft Design Framework and Implementation Plan
[35] See Reliability Standard FAC-002 for more information on the PC defining "qualified change" and the resulting assessments.

This combination of factors creates persistent barriers to robust data sharing and detailed understanding of large loads as well as the modeling of large loads.

Lack of Collaboration and Coordination

The lack of structured communication creates a gap that can result in inefficiencies, misalignment, and increased risk to system reliability. Lack of coordination exists between load owners and the following entities during the interconnection planning, site building, energization, and operation phases of project development:

- Grid operators, owners, and planners
- Regulatory bodies
- State and local governing agencies

Therefore, the coordinated integration of large loads necessitates identification of the stakeholders for every phase of executing the project. Improvement of the collaboration and coordination between these entities will help ensure that large loads can be integrated in a reliable and timely manner.

Moreover, the rapid development timelines of data centers, which can progress from conception to readiness for operation in one to two years,[36] stand in stark contrast to the lengthy timelines required for new transmission and generation infrastructure, which can take four or more years.[37] This mismatch poses significant challenges for ensuring that the grid can accommodate growing demand. To navigate these complexities and support large load integration, deeper collaboration between data center developers and electric utilities is urgently needed.

The LLWG identified a gap in coordination of transmission protection and large load protection. TOs set relay pickups, breaker clearing times, and reclosing schemes on their side of the meter. However, the TOs historically did not need to share those curves with the large load facility owner and operator who program uninterruptible power supply (UPS) and variable frequency drive disturbance ride-through logic. Therefore, the two protection schemes operate independently of one another. Without that visibility and communication, a normally cleared transmission fault can trigger protective systems on the load side even when it is cleared appropriately by the utility. The gap in addressing this risk lies in the current lack of communication and coordination of protective settings from the TO to the large load facility and vice versa. **Chapter 6** further discusses the disturbance ride-through concerns related to large loads.

Certain design considerations (e.g., the facility's transfer to backup power supply and the return to utility during/after voltage disturbances) for large loads can significantly impact the characteristics and risks of that large load as seen by the grid. There may currently be gaps in the coordination between the grid operators/planners and the large load entities regarding these design decisions. This coordination would help ensure that the BPS reliability impacts are considered in the design of the facility. This consideration could also extend to decisions regarding how data center compute is implemented from a software perspective.

[36] The utility may require more time for interconnection.
[37] However, the data centers may not reach their full operational capacity upon initial energization but may ramp up to their full capacity at a later date.

Chapter 3: Planning and Resource Adequacy

Many emerging large loads are seeking to connect to the system in time frames prior to the system planning horizon. This poses planning and resource adequacy challenges, as the amount of load attributed to large loads was not included in long-term planning forecasts, meaning that current transmission planning and generation procurements generally do not account for these new large loads. This can result in the BPS struggling to accommodate the new large loads without resource shortfalls or transmission constraints.

A number of gaps are preventing large loads from being accurately included in new studies. These include a lack of data around emerging large loads (including their demand patterns, project information, and demand responsiveness) and a lack of data standardization and sharing. When information is received by grid planners, it is often only shared when loads are seeking interconnection, which is commonly in the near term and prevents the loads from being included in long-term planning before they are energized. There are also gaps in current resource adequacy studies, practices, and generation procurements as well as transmission planning Reliability Standards.

This chapter identifies the gaps related to planning and resource adequacy. Portions of this chapter related to demand forecasting reflect the research performed by the Energy Systems Integration Group (ESIG) Large Loads Task Force.[38]

Demand Forecasting Gaps

The increase in large loads is impacting system demand in a number of ways. Large loads impact intraday demand shapes as well as seasonal and annual demand patterns. There is also significant uncertainty associated with these loads that makes them difficult to forecast. Traditional load forecasting methods may not be sufficient to capture these changes accurately, for reasons which will be expanded upon below.

Planners lack certainty about key mid- and long-term forecasting parameters for prospective large loads, including the following:[39]

- Schedule for initial energization
- Ramp rate[40]
- Ultimate load after ramping from initial energization
- Load shape (or load factor)

Key Point
Planners lack a historical basis to assess the collective certainty of some types of large loads.

One reason for this is that planners lack visibility into the certainty of individual large loads' business plans, as some are evaluating interconnection in different areas and most face risks related to construction schedule, technical plans that relate to energization ramps, economic viability, financial challenges, and the comparative cost and schedule for interconnection. Furthermore, planners lack a historical basis to assess the collective certainty of some types of large loads on these forecasting parameters, particularly for novel industrial or data center loads. Accordingly, planners typically apply professional judgment to the available data when evaluating these uncertain forecasting parameters.

Demand forecasts are developed by utilities, system planners, and PCs. The PCs may source some or all of their demand forecasts from member utilities and may also develop portions of the demand forecast themselves. In the

[38] Large Loads Task Force - ESIG
[39] This list is essentially identical to four of the metrics provided in Figure ES-1 of the ESIG Large Loads Task Force report titled "Forecasting for Large Loads: Current Practices and Recommendations". Available here: Forecasting for Large Loads: Current Practices and Recommendations
[40] Many large loads do not initially energize at their full demand but ramp to this demand over multiple years.

case of information on large loads, PCs, TPs, and RPs are mostly or wholly dependent on information provided by the utilities, which may lead to forecasts relying on what has become out-of-date information.

Some system planners provide guidance to their members on the information that they require and collaborate with their members on practices. Some utilities and system planners have established standardized practices (e.g., via gates, stages, policy support, financial commitment) for evaluating the key forecasting parameters as large loads request interconnection and engage in obtaining utility service or otherwise securing power. The divergence of large load demand forecasts is a result of the lack of well-established practices, and at least until technology evolution stabilizes, the certainty of those forecasts cannot be guaranteed.

Key Point
Current resource adequacy practices may not fully account for the complexities introduced by large loads.

At this time, due to customer confidentiality and the lack of institutional data sharing practices, utilities and regional TPs do not typically share detailed information with one another on the operating characteristics, ramp rates, and load profiles necessary for improved forecasting of the various types of large loads. Development of such practices could compensate for the lack of historical basis for assessing collective certainty of forecasting parameters faced by planners in many areas.

Uncertainty exists around how large loads may participate in peak-shaving, demand-response, or price-responsiveness programs. Program participation has typically been evaluated on a post hoc basis and then factored into resource adequacy and demand forecasts. Existing NERC and regional standards as well as engineering practices do not explicitly address how system operators or planners should incorporate potential large load participation scenarios into resource adequacy and demand forecasts. Without knowing how the loads will participate, utilities are forced to make assumptions that can result in under-procuring both transmission and generation. In a similar vein, there is a gap in requirements for large loads to share information on behind-the-meter generation information at prospective load sites and for utilities on how to include that information when performing studies. Currently, many load forecasters do not obtain adequate information on behind-the-meter generation. This may be because it is not commonly planned. In any case, it is unclear if and how utilities should consider information about behind-the-meter generation in load forecasts and resource adequacy studies. This information is necessary for planners as they consider the impacts of peak-shaving, demand-response, or price-responsiveness programs in their studies.

Resource Planning Gaps

Since NERC Reliability Standards are not directly applicable to most large loads and to LSEs, the information provided to planners from the large load customers or TOs may be inaccurate, challenging long-term planners' efforts to ensure that the system is designed to serve additional load growth and maintain additional generating capacity. Although Reliability Standard BAL-502-RF[41] is applicable strictly to the ReliabilityFirst region, it is indicative of the process that can be used for the determination of an entity's planning reserve margin (PRM). However, large loads are not included explicitly in this standard or mentioned in the context of resource adequacy analysis, representing gaps in this standard. Reliability Standard MOD-031[42] requires registered entities to provide accurate demand forecasts and energy data for resource adequacy planning. However, since neither LSEs nor most large loads are NERC-registered, MOD-031 does not explicitly require information from the owner of the end-user equipment. This can affect the sharing of critical load forecasting data or detailed consumption profiles that represent the consumption of end-user equipment. This omission reduces the accuracy and reliability of resource adequacy studies.

Current resource adequacy studies do not fully account for the impact of new large loads on demand growth and geographic load patterns. The current approach primarily focuses on conventional supply-side metrics and

[41] Available here: BAL-502-RF-03
[42] Available here: MOD-031-3

retirements, which may not be sufficient to address the unconventional yet significant demand posed by these large loads. Furthermore, data centers are bidding into multiple areas for interconnection, which results in overstatement of expected demand for these large loads. Additionally, existing load forecasting methods, procurement strategies, and development of generation and transmission infrastructure may be insufficient to manage the rapid and concentrated growth in demand from large loads.

While resource adequacy planning traditionally focuses on ensuring sufficient generating capacity and reserves to meet expected demand using metrics like loss of load expectation (LOLE) and PRM, existing practices may not fully account for the complexities introduced by large loads. Specifically, the addition of large loads, combined with a number of other factors—such as the increase of variable inverter-based resources (IBR) and distributed energy resources (DER), the frequency of thermal outages during periods of extreme weather (which are becoming more common and less predictable), and aging infrastructure—can all further complicate risk assessment. Additionally, the data used in resource adequacy models to determine PRM does not reflect the effects of large loads in intra-hour behavior and reserve requirements, hourly load shapes, peak and energy forecasts, load forecast uncertainties, and the potential for delays or constraints associated with the development of necessary transmission and generation infrastructure are not considered in resource planning models.

There are no requirements in NERC standards explicitly requiring resource adequacy checks before integrating a new large load onto the system or before the peak demand of an existing large load is increased. This may be a gap in FAC-002. Additional discussion on FAC-002 and related processes can be found in **Chapter 2**.

Transmission Planning Gaps

Large loads are evaluated and planned for by DPs, TOs, TPs, and PCs in various ways depending on their engineering practices, requirements, and the Reliability Standards[43] with which they are required to comply. Transmission planning is based on multiple NERC standards that establish the actions that entities must take to evaluate the BPS and ensure its reliability. Most notably, Reliability Standards TPL-001[44]and MOD-032[45] have been the basis for the development of planning requirements and modeling data submissions for PCs and TPs to perform their work.

TPL-001 establishes planning performance requirements and requires TPs and PCs to conduct annual planning assessments. The event categories in the standard do not explicitly include the loss of large loads unless they are extreme events or unless the load isolated because of the loss of other transmission elements. Another gap in the existing process is in the comprehensive analyses, especially regarding steady-state or dynamic risks due to clustered loss of large loads in an area (e.g., failure to ride through disturbances, sensitive protection settings). As a result, the current evaluations may not be sufficient to plan a system that can accommodate the growing number of large load interconnection requests. Similarly, MOD-032, which establishes the modeling data requirements for the development of transmission planning models, does not adequately cover all modeling requirements for large loads, such as peak demand, load power factor, and dynamic behavior.

The scenario selection for conducting the reliability assessments with large loads is critical in understanding the reliability risks. TPL-001 requires dynamic load models only for near-term studies that look into peak load conditions. However the impacts to the system from the large load could be unique and material during off-peak conditions, when a certain large load[46] might be the biggest load on the system with a very different generation dispatch than was studied in the peak load assessment. These considerations will be important for reliability assessments with large loads. Additionally, TPL-001 does not require load models to be used in long-term stability studies or specify that peak and off-peak conditions should be studied in the long-term stability studies. These may be gaps in this standard.

[43] Historically, the LSE was one of the entities that had standard obligation to provide demand data for these Reliability Standards.
[44] Available here: TPL-001-5
[45] Available here: MOD-032-1
[46] Given that a data center has a very different load consumption pattern as compared to older large industrial facilities like a paper or steel mill.

Key Point
Traditional planning practices are often focused on the mid- to long-term time frames, while some large loads can connect very quickly in the near-term time frame.

FAC-002 studies help ensure that end-use facilities are reliably integrated to the system. TPL-001 studies focus on the near- to long-term planning horizons spanning 1–10+ years and look at the system from a more holistic perspective. While FAC-002 studies help address many of the impacts from large loads, the TPL-001 studies are still important as they help identify upgrades needed when looking at the overall system. In North America, transmission project development starting from the planning phase to the construction phase can take 5–10 years or even longer to complete. However, it has been observed that some large loads are seeking to interconnect to the system in very short time frames, some within a year. Additionally, some TPs may normally develop models that represent scenarios that are at least two years in future, meaning that such models would not be adequate to assess the impact of large loads interconnecting in shorter time frames. This issue becomes more pronounced for dynamic models as several entities develop dynamic models that represent scenarios at least five years into the future. Therefore, while localized impacts to the BPS from large loads might be addressed in the FAC-002 processes, overall system issues, such as ensuring bulk transfer capability for energy deliverability to clusters of large loads, may not be addressed via TPL-001 processes before the large loads are energized.

Accurately predicting the demand from large loads for long-term planning studies is complex. Misestimations of the magnitude or location of future loads can lead to underbuilding transmission infrastructure or building transmission infrastructure in the wrong locations, which can significantly impact reliability. While many of the issues caused by misestimation of demand can be addressed by FAC-002 interconnection studies for end-use facilities, misestimation of demand can still lead to system-level issues such as lack of bulk transfer capability on the system. It is challenging for TPs or TOs to determine in advance which large load interconnection requests will materialize; however, there is no guidance or Reliability Standards that provide a framework to determine which potential loads to include in long-term planning studies. With the rapid increase in large loads seeking interconnection, load may also outstrip generation in transmission planning cases. TPL-001 does not provide a framework for how to address the situation when load exceeds generation in long-term planning models; there is also a lack of guidance in the industry regarding how to address this situation.

Lack of Standardization/Coordination Between Entities

With current planning practices in some, but not all, markets and areas operating in silos, there can be a lack of standardization and coordination across load forecasting, generation, and transmission planning on how to deal with new large load requests and interest. For example, a regional transmission organization (RTO) may perform transmission planning studies with limited load forecast and generation information provided by LSEs; additionally, there is no standard or guidance for RTOs on how to interpret this load forecast and generation information when conducting studies.

Chapter 4: Balancing and Operations

In the operations horizon, system operators are responsible for ensuring that the BPS is reliable and secure. This includes ensuring that load and generation are balanced, which is required to maintain stability. Many emerging large loads, particularly computational facilities, are power electronics-driven load and are highly responsive (changing consumption patterns based on external triggers) and exhibit pulsating or nonlinear demand profiles and voltage sensitivity to grid conditions. In fact, it is arguable that these large loads can operate as controllable Bulk Electric System (BES)[47] elements that can significantly ramp up and down with high oscillatory behavior, impacting grid reliability. Their size, controllability, and variability introduce potential reliability risks to the BPS comparable to those of a generator but with the added complexity of being on the demand side.

Balancing Gaps

If a BA lacks awareness of large load ramping, the rapid ramping up and/or down of one or more large loads may cause a variety of reliability impacts, including frequency excursions, voltage and thermal violations, and instability risks. The gap in addressing ramping risks affects both real-time operations and the operation planning horizon. This complicates unit commitment decisions and next-day reliability studies. Since there are no specific requirements in place in the NERC standards for large loads to provide necessary information such as large load models and ramp rates to RCs, BAs, and TOPs, the ability to conduct analysis and assessments on the impacts of large load ramping on system reliability is hindered. Without adequate data, real-time operators may not be aware of the risk posed by large loads, and issues may go undetected until they are observed in real time. This could place the burden on real-time system operators to mitigate reliability risks related to voltage violations and frequency deviations in real time.

Key Point
NERC standards do not provide specific requirements for large loads or LSEs to provide data; this leads to real-time operators being unaware of risks posed to the BPS.

BAs might not have visibility of the demand of individual large loads and may not have sufficient information to know when the large load is expected to increase demand to pre-disturbance levels after a large load demand reduction occurs for a system disturbance. This lack of visibility and information could lead to the BA unnecessarily bringing generation off-line to balance the frequency after a large load demand reduction. If the large load increases its demand to pre-disturbance levels after the BA brings generation off-line, further difficulty in controlling frequency could be experienced. This lack of visibility of individual large load demand (both real-time and forecasted) may be a gap. Additionally, the lack of information may be a gap in coordination between the TOP and BA.

Current gaps in NERC standards also include the absence of explicit requirements to represent or consider the operational behavior of large loads in reliability assessments and situational awareness. While Reliability Standards IRO-010[48] and TOP-003[49] require BAs, TOPs, and RCs to obtain data necessary to perform reliability assessments, these standards do not obligate large loads to provide ramping characteristics, dynamic performance data, or usage profiles. Insufficient data and representation could compromise analysis accuracy, including among new NERC standards like Reliability Standard BAL-007-1 – Near-term Energy Reliability Assessments.[50]

Short-Term Demand Forecasting

Accurate forecasting of large loads in the transmission grid is critical for ensuring BPS reliability. However, several challenges complicate this task, requiring advanced methods and continuous improvements in forecasting techniques. There is a clear gap in how the utilities develop forecasts when considering large loads.

[47] Glossary of Terms Used in NERC Reliability Standards
[48] Available here: IRO-010-5
[49] Available here: TOP-003-6.1
[50] Available here: BAL-007-1

Load data, especially for large commercial and industrial customers, is often incomplete, aggregated, or lacks necessary granularity, such as hourly or daily usage trends for use in short-term load forecasting. System operators' forecasting methods may not account for rapid changes in load forecasts for industrial and commercial loads caused by business decisions related to the load. Reliability Standards TOP-001[51] and TOP-002[52] cover operations and operations planning. When considering large loads, these standards may not adequately cover the gaps associated with load ramping and forecasts. Additional discussion regarding gaps related to demand forecasting is provided in **Chapter 3**.

Impact of Large load Ramping and Disturbance Ride-Through Limitations on Area Control Error

Large loads can significantly impact a BA's load profile, posing operational challenges in controlling area control error (ACE), the real-time indicator of generation-load balance and interconnection frequency stability. An example of sample ACE variations due to large loads when compared to BA ACE Limits (BAAL) is provided in **Figure 4.1**.

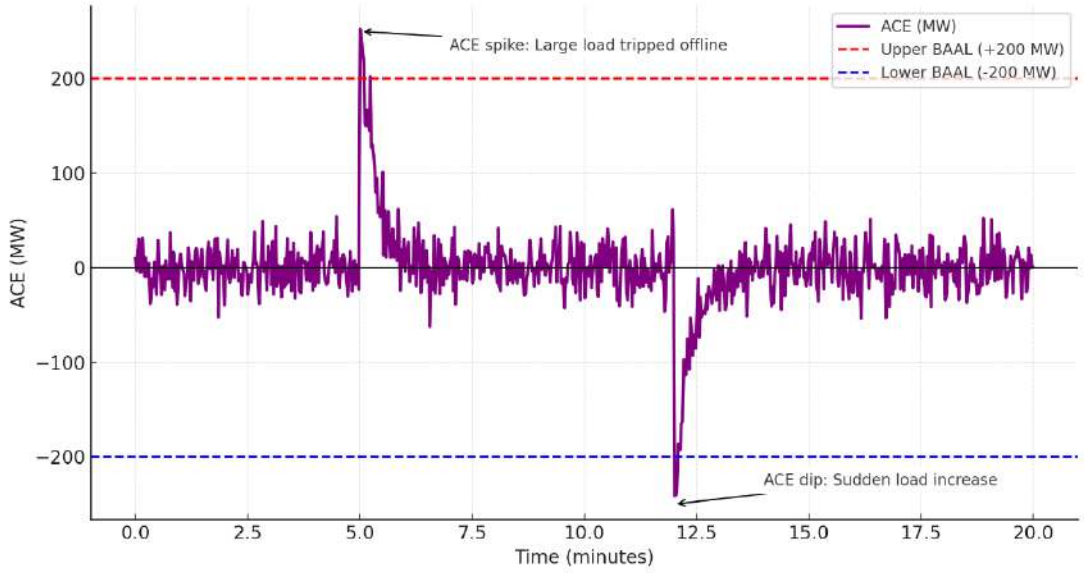


Figure 4.1: Sample ACE Variations Due to Large Loads

- **Existing Reliability Standards contain gaps in addressing the impacts of large loads on ACE:** Although the BAL-001 Reliability Standard[53], which includes Control Performance Standard 1 and Balancing Authority ACE Limit, provides a framework for managing ACE, it does not explicitly account for scenarios where large loads exhibit rapid and unpredictable ramping behavior. This standard requires that "[e]ach [BA] shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes." Frequency excursions due to large load ramping behavior or other behavior that are corrected within 30 minutes are not a violation of this standard. However, frequency stability may still be at risk in these scenarios. Adherence to the Control Performance Standard 1 requirement in BAL-001 is based on overall performance during the previous 12 months. Sub-optimal performance during one portion of the year can be compensated for with good performance during another portion of the year. As with the BAAL requirement, frequency stability may be at risk in specific timeframes, although Control Performance Standard 1 requirements may be met during the overall 12 months. Additionally, current Reliability Standards lack specific guidance or constraints on how quickly large loads may ramp.

[51] Available here: TOP-001-6
[52] Available here: TOP-002-5
[53] Available here: BAL-001-2

- **Existing NERC Standards do not fully address the need for faster and more flexible balancing actions necessitated by the inherent variability and unpredictability of large loads:** While Reliability Standards BAL-001, BAL-002[54], and BAL-003[55] collectively set standards for overall ACE control and frequency stability, they do not explicitly differentiate the operational treatment between large generator outages and large load perturbations. This lack of specificity could result in inadequate preparedness and insufficient operational tools to manage ACE effectively amid the growing prevalence and unique characteristics of large, dynamic loads.
- **There is a gap in the analysis of the largest reasonable load loss:** All BAs submit their largest credible generator N-1 losses as well as their largest generation loss from a remedial action scheme event as part of the Reliability Standard BAL-003 process. This largest credible loss of generation feeds directly into the calculation that determines the amount of frequency response required from the interconnection and from each BA. If the largest credible load loss is not analyzed on a recurring basis, there could be a gap in preparing for the load loss/reduction events.
- **BAL-002 does not explicitly include large load tripping or ramping events within the balancing contingency event definition:** This standard, focused on the disturbance control standard, primarily addresses the sudden loss of large generation resources or restoration of demand utilized as a resource but does not explicitly include large load tripping or ramping events within the balancing contingency event definition. This represents another critical gap, as the sudden addition or loss of large loads can have equivalent reliability impacts as generation contingencies. Gaps related to large load disturbance ride-through are also discussed in **Chapter 5**.

Additional discussion on gaps related to frequency stability is provided in **Chapter 5**.

Operations Gaps

The following discussions identify gaps related to large load ramping, real-time operations, and outage coordination.

Impact of Large load Ramping on System Reliability and Operations Planning

Today, when operating or planning for operations, system reliability is assessed by evaluating recognized contingency events and monitoring expected outcomes. With respect to large loads, these events could include the loss of a single point of connection for a load station. However, as noted above, multiple large loads in a region could collectively reduce or increase their consumption by unknown amounts, which are not events currently considered in operations or operations planning. These events could lead to reliability issues including thermal violations/exceedances, unacceptable voltage levels and voltage instability, and transient instability of the system.

Currently, planning (TPL-001, FAC-002, FAC-011[56]), operations planning (TOP-002, IRO-008[57]), and operations (TOP-001, IRO-008) related Reliability Standards do not consider the impacts of large-scale ramping, disconnection, and reconnection events. Given the possible significant impacts to the BPS, potentially leading to uncontrolled separation and cascading outages, there is a gap in appropriately considering the impacts of these types of events.

In addition, disturbance ride-through performance remains an area of concern for data centers and cryptocurrency mining facilities that are sensitive to transient voltage drops. These facilities have demonstrated tendencies to disconnect for faults outside of their zone of protection—or more simply for faults on lines they are not connected to—which is unexpected. This type of behavior is not modeled in operational or operations planning analyses, and excessive facility tripping can also lead to thermal violations/exceedances, unacceptable voltage levels and voltage

[54] Available here: BAL-002-3
[55] Available here: BAL-003-2
[56] Available here: FAC-011-4
[57] Available here: IRO-008-3

instability, and transient instability of the system. As discussed in **Chapter 2**, some of the disturbance ride-through performance issues can be due to a lack of communication and coordination of protective settings from the TO to the large load facility and vice versa. Gaps related to large load ride-through are also discussed in **Chapter 5**.

Real-Time Operations and Outage Coordination

Large loads pose a risk to the BPS if their operations are not coordinated with BPS operators. If a large load operates in a way that is not expected by the existing or neighboring RC/TOP/BA, there could be concerns about operating reserves and system stability. To support safe and reliable integration of large loads, TOPs/BAs, RCs, LSEs, and large loads need to coordinate.

As previously mentioned, RCs/BAs/TOPs need data that accurately represents large load facilities to properly account for these facilities in studies and analysis. During commissioning, the system operator needs to conduct multiple checks to ensure the operational readiness prior to energization. RCs/BAs/TOPs may have gaps in the following engineering practices that should be reviewed:

- Pathways for integrating new loads into their modeling tools and energy management systems (EMS)
- Processes for obtaining as-built modeling data and update studies, if required based on changes, prior to initial energization and to integrate the latest data into modeling tools and EMS
- Operational agreements covering communication for normal and emergency operations
- Processes for verifying communication pathways
- Processes for verifying protection configurations and setup including monitoring (such as power quality and oscillation detection)
- Processes for large loads coordinating planned outages with the TO and/or TOP as well as the BA.

Large loads are not currently obligated to establish interpersonal communication capabilities with system operators as outlined in Reliability Standard COM-001.[58] Unlike generators, which must adhere to requirements regarding communication and operating instructions within Reliability Standards PER-005, COM-002,[59] and TOP-001, large loads are not subject to these requirements. These gaps can lead to inefficiencies and miscommunications during critical situations, potentially exacerbating emergencies and hindering effective mitigation efforts.

A key component of maintaining BPS reliability is the ability to coordinate transmission and generation outages to ensure that an outage does not cause a contingency violation or generation shortage prior to the outage. BAs and TOPs currently review transmission and generation outages but not load outages. Reliability Standard IRO-017[60] addresses the outage coordination process for RCs/TOs/BAs but does not consider outages of large loads. The procedures of RCs/TOs/BAs also do not currently cover large load outages.

Operations Tools

Advanced tools like stability analysis or oscillatory signal analysis tools may not be available to operators in real time. These tools are likely needed in areas with high penetrations of IBRs; similarly, they are also likely needed in areas with high penetrations of large loads such as data centers.

[58] Available here: COM-001-3
[59] Available here: COM-002-4
[60] Available here: IRO-017-1

Chapter 5: Disturbance Ride-Through, Stability, and Power Quality

Since large loads can significantly impact BPS reliability, it is crucial to evaluate their performance characteristics, such as ride-through capabilities during grid disturbances, and their effects on system stability and power quality. There are minimal NERC Reliability Standards and regional requirements that adequately capture and mitigate the reliability impacts of large load interconnections to the grid. There are also limited established industry-wide capability and performance expectations (e.g., IEEE 2800[61] for IBRs) for how large loads should be designed and operated to support the needs of the grid or avoid negatively impacting BPS or local reliability. IEEE and International Electrotechnical Commission (IEC) standards applicable to large loads regarding harmonics and other factors exist, but there are no requirements to help ensure that large loads do not negatively impact BPS reliability. For more information on simulation tools, modeling terminology, and application of the tools and models, see **Appendix A**.

Voltage Disturbance Ride-Through Gaps

Many large loads have internal protection and control systems that are sensitive to grid disturbances. As a result, large loads are prone to disconnect or transfer load to backup systems during normally cleared system faults. Large load ride-through capability and performance need to be studied and understood by system operators. Otherwise, this lack of disturbance ride-through can lead to large amounts of load disconnecting or reducing demand during voltage and frequency perturbations that would not normally result in such behavior. This limited voltage disturbance ride-through capability can pose multiple reliability challenges to the grid, such as balancing and stability impacts. The protection and control standards such as Reliability Standards PRC-019,[62] PRC-024,[63] and PRC-029[64] do not discuss large load performance during voltage and frequency deviations.

NERC Reliability Standards and regional requirements that dictate how system studies and analyses are performed do not conventionally assess transmission contingencies that involve the simultaneous loss of nearby voltage-sensitive load in addition to one or more faulted transmission facilities. Without predictable disturbance ride-through performance from large loads, such as the performance required by generators with the enforceable Reliability Standard PRC-029 or even the voluntary IEEE 2800, conducting studies to appropriately gauge and mitigate this risk is challenging. Additionally, there is a gap in capturing high-resolution data needed for studies and analyses that assess the performance characteristics of large loads. NERC standards like Reliability Standard PRC-028[65] lack data monitoring requirements for large loads to assist TPs and PCs with disturbance ride-through performance evaluations.

There is a lack of coordination and data sharing between RCs, BAs, TOPs, TOs, TPs, and large load entities on how and when large loads should ramp to pre-disturbance demand levels upon voltage recovery after a voltage disturbance. Because of this, the BAs in the system may reduce total generation due to an observed high frequency after a large load demand reduction or trip event, not knowing when the load will return to pre-disturbance demand levels. However, after the generation has been re-dispatched, large loads might suddenly begin ramping back to the grid, causing frequency to drop due to the mismatch of generation levels and load levels. Additionally, this return to pre-disturbance demand levels after a voltage disturbance cannot be studied in simulation due to lack of information being shared regarding when and how quickly the load will return to pre-disturbance levels; this presents a significant gap between system response in simulation studies compared to what may happen during a real event. In

[61] Available here: IEEE 2800-2022
[62] Available here: PRC-019-2
[63] Available here: PRC-024-3
[64] Available here: PRC-029-1
[65] Available here: PRC-028-1

comparison, ride-through performance and recovery of IBRs during system disturbances have been well defined and adopted in performance standards such as PRC-029.

RCs, BAs, and TOPs may use the Information Technology Industry Council (ITIC) curve to make assumptions about when large electronic loads will reduce consumption or transfer to backup UPS or generation. The ITIC curve is commonly used in the design of IT equipment, such as computers and servers. The ITIC curve is applicable to power supplies, but it may not be applicable for grid studies if there is a UPS between the grid and the power supplies. UPS settings or other site-level protections may impact the disturbance ride-through characteristics of the load. Disturbance ride-through characteristics may vary significantly between large load facilities, which may notably impact area-wide studies involving loss of large loads during grid disturbances. This is another potential gap due to the lack of verifiable large load ride-through data as previously mentioned.

IEEE Standard 1668[66] provides recommended practices for voltage sag and short interruption ride-through testing for end-use electrical equipment rated below 1,000 V. The Tennessee Valley Authority uses this standard to assess the voltage sag ride-through performance of large loads, including industrial and data center loads. Compatibility with IEEE 1668 allows loads to ride through the most common transmission-caused voltage sags but allows load to trip off-line for deeper or longer voltage sags. Although this standard does provide recommended disturbance ride-through capability of end-use equipment, it does not establish minimum ride-through performance requirements for large loads connecting to the BPS.

The absence of a clearly defined voltage disturbance ride-through capability leads to highly variable responses among large loads. Furthermore, RCs, BAs, and TOPs often lack visibility into these behaviors. Large load interconnection requests do not currently require submission of dynamic models with specified disturbance ride-through capabilities, nor are such capabilities typically verified through testing after commissioning.

Key Point
The absence of a clearly defined voltage ride-through capability leads to highly variable responses among large loads.

However, entities including ERCOT, SPP, and Dominion Energy are developing disturbance ride-through requirements for large loads. This work will help to address the gaps discussed above.

Frequency Disturbance Ride-Through Gaps

Frequency disturbance ride-through refers to the ability of a resource to remain connected to the grid during system frequency deviations within defined thresholds and durations. This capability supports grid stability by preventing unnecessary tripping of generation resources during events so the system can recover.

Frequency disturbance ride-through standards are currently focused on generators, with no equivalent requirements established for large loads. While loads are generally expected to remain connected through “reasonable” frequency disturbances, there is no formal definition of what constitutes reasonable, nor any enforceable criteria for performance. Historically, loads dropping off during low-frequency events has been a net positive for grid reliability. However, if large loads trip or transfer to backup generation for high-frequency events, the problem could be exacerbated. This identifies a potential gap since large loads fall outside the scope of existing NERC Reliability Standards that govern frequency disturbance ride-through.

PRC-024 and PRC-029 define the allowable frequency and voltage protection settings for generating resources, ensuring that generators do not trip off-line during system disturbances that fall within a defined “no-trip zone.” The intent is to ensure that generator protection settings do not exacerbate grid instability. Although PRC-024 and PRC-029 were written for generating resources, some elements of the standards may have relevance when considering

[66] Available here: IEEE 1668-2017

performance expectations for large loads, particularly the sections that define frequency thresholds and minimum ride-through times.

Similarly, IEEE 2800 sets performance requirements for IBRs, including frequency disturbance ride-through capabilities. IEEE 2800 applies to generation resources only and does not address load facilities. PRC-024 and PRC-029 are also only applicable to generation resources. However, it is worth noting that both these NERC standards and the IEEE standard provide a structured framework for how resources interact with frequency disturbances on the grid, which could potentially inform future approaches to load behavior.

Harmonics and Interharmonics Gaps

Electronic devices such as adjustable speed drives, rectifiers, and switched-mode power supplies—commonly found in emerging large loads—produce harmonics and interharmonics[67] that can contribute to unacceptable levels of voltage and current distortion in the BPS. While the large quantity of electronic devices present in emerging large loads is remarkable, existing standards provide guidance on acceptable limits that can be effectively applied to large loads.

IEEE Standard 519 establishes voltage and current distortion limits that, if followed, minimize the chances of adverse impacts related to distortion. As the limits set by IEEE 519[68] are intended to ensure compatibility between the load and public power supply system, they are applied exclusively to the point of common coupling (PCC) and do not apply to individual devices or buses within the facility. In IEEE 519, management of distortion is seen as a joint responsibility between the system owners or operators and the user (e.g., the owner/operator of the large load). Broadly speaking, the user is responsible for limiting the current distortion that their loads produce, whereas the grid operator is responsible for limiting the voltage distortion that is produced when distorted currents flow through system impedances. The guidelines defined in IEEE 519 can be effectively applied to large loads. The standard specifies allowable distortion limits for nominal voltages ranging from 120 V to above 161 kV. The standard accounts for the fact that larger loads can have greater effects on voltage and current distortion. Allowable limits are adjusted based on the short-circuit ratio of the user's facility and nominal voltage of service. Users connected to higher voltages and lower short-circuit ratios have the potential to produce greater distortion and are therefore subjected to stricter limits.

Some large load sites have significant quantities of generation (more than or equal to 10% of the annual average load demand). If this generation contains IBRs and/or DER, IEEE 519 may not be applicable—either IEEE 2800 or IEEE 1547[69] should instead be referred to for harmonic and interharmonic limits. IEEE 2800 addresses transmission-connected IBRs and IEEE 1547 addresses DERs.

IEEE standards provide requirements that can be applied to limit harmonics; the limits, applicable to both voltage and current, are common to all large load interconnections without any further coordination among them. However, lack of coordination among different large load interconnections may create situations where individual loads are compliant with limits at their connection point but create non-compliance at other portions of the system (in comparison, other jurisdictions, such as most European transmission system operators, provide individual harmonic emission limits to each customer and these are enforced as part of the compliance process).

Some industry practices may have gaps when it comes to determining interharmonic limits. IEEE 519 does not provide universally applicable limits for interharmonics. This is because the sensitivity of differing loads to interharmonics varies significantly, and a set of limits intended to accommodate all possibilities appeared to be very restrictive to the

[67] The term "interharmonic" is used as defined in IEEE 519-2022 and encompasses subharmonics and supraharmonics as well.
[68] Available here: IEEE 519-2022
[69] Available here: IEEE 1547-2018

committee that developed IEEE 519. Thus, if a large load is anticipated to produce interharmonics, analyses beyond those defined in IEEE 519 are likely necessary.

Some system owners/operators may encounter instances where there are no existing technical solutions by which a large load can meet typical interharmonic limits. While the technical solutions themselves are not the focus of this white paper, the possibility that it may not be technically feasible to employ standard limits does indicate an important gap in industry practices. Prior work by the IEEE Interharmonic Task Force suggests that interharmonic voltages in the subharmonic range[70] should be limited to less than 0.1% of nominal.[71] Some AI workloads may produce subharmonics that are tens or hundreds of megawatts in magnitude. Reducing subharmonic magnitudes below suggested limits is sometimes beyond the capability of traditional solutions such as static VAR compensators. Load smoothing with utility-scale battery storage and grid-forming inverters can reduce the subharmonic current magnitude by roughly 70%.[72] Other methods for load smoothing include static synchronous compensators[73] with supercapacitors.

Some industry practices may have gaps when it comes to managing transmission system voltage distortion. Even if the anticipated current distortion produced by the large load is within the current limits recommended in IEEE 519, high system impedance or an electrical resonance (e.g., involving a nearby transmission system capacitor) may still result in unacceptably high voltage distortion. System owners/operators who have previously had very little current distortion present in their transmission system may not have practices in place to proactively identify and mitigate unacceptable levels of transmission voltage distortion.

Stability Gaps

Maintaining a stable power system requires addressing a broad range of issues. For consistency and clarity, gaps related to stability problems are discussed in terms of the taxonomy shown in **Figure 5.1**.[74] Forced oscillations are also discussed in this section. Even if the power system is technically stable, forced oscillations can interact with the dynamics associated with different stability problems in a way that can cause power outages or equipment damage.

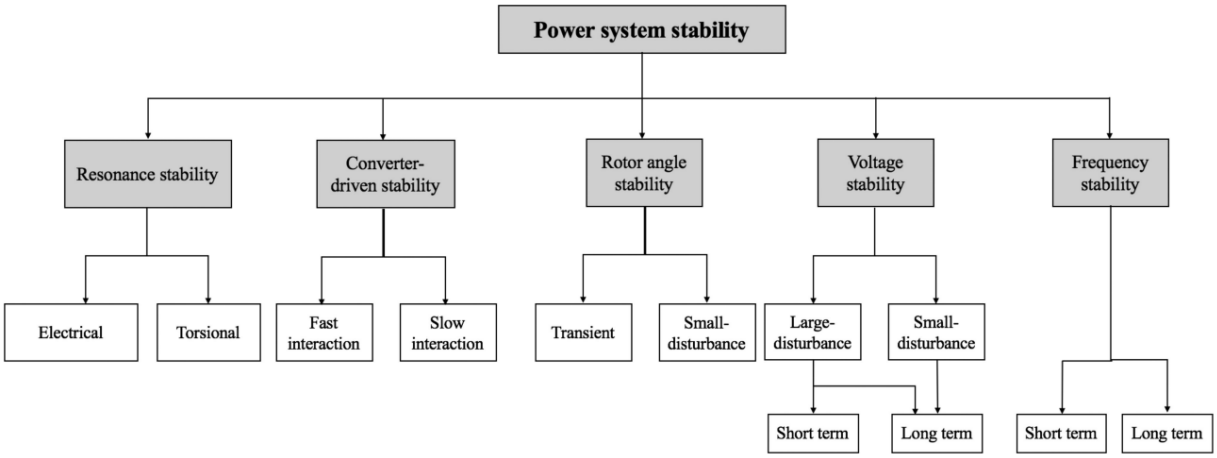


Figure 5.1: Taxonomy of Power System Stability

[70] Interharmonics with frequencies that are "below the system fundamental frequency" (IEEE 519-2022)
[71] See Issues and Challenges Related to Interharmonic Distortion Limits
[72] See page 77 of LLTF April Meeting & Technical Workshop Presentations
[73] Also known as STATCOMs
[74] See Definition and Classification of Power System Stability -- Revisited and Extended

- Gaps relating to rotor angle stability, voltage stability, and frequency stability primarily relate to concerns that the existing practices used to conduct transient stability studies are not accurate or comprehensive enough. These concerns stem from ways in which emerging large load dynamics differ from most traditional load.
- Gaps relating to resonance stability and converter-driven stability are more fundamental in nature; the specific mechanisms by which large loads might contribute adversely to converter-driven or resonance stability are ill-defined, representing a major obstacle to defining study and modeling requirements clearly enough for practices to be developed around them.

Because accurate modeling is an essential part of maintaining power system stability, many of the gaps relating to stability are modeling related. General gaps in large load modeling practices are discussed in **Chapter 7**, and the scope of modeling discussions in the following subsections is limited to specific modeling gaps that are important for the stability studies under discussion. All models are flawed, and different stability problems require different modeling approaches. Each kind of stability study will require practice improvements tailored to the study's specific purpose.

Rotor-Angle Stability

Large loads can produce rapid and significant fluctuations in real power that can result in generators swinging beyond their rotor-angle stability limits and losing synchronism. There are gaps in the models used and scenarios considered in the transient stability studies used to identify specific contingencies where rotor-angle stability might occur.

- **Model-related gaps stem primarily from the lack of well-defined disturbance ride-through behavior, as discussed earlier in the chapter:** Existing load models used to represent large loads in transient stability studies do not accurately predict whether the large loads will trip off-line or remain connected during a given disturbance.[75] They also may not accurately predict large loads' real and reactive power consumption during the fault or postfault recovery and/or reconnection dynamics. All these modeling aspects can significantly affect the outcome of rotor-angle stability studies. Note that, from a stability and modeling perspective, the essential gap is not necessarily the lack of formal requirements, it is the mismatch between the models and reality.
- **Contingency-related gaps are likely present because large loads can produce system-level impacts in scenarios that differ from those typically included in transient stability studies:** For example, a control misconfiguration or settings error at a large load site could theoretically result in a gigawatt-scale load coming on-line in only a few power system cycles. Thus, it may be necessary to expand the contingencies considered in studies such as those done to meet TPL-001. What these additional contingencies should be is unclear.

Frequency Stability and Voltage Stability

The model- and contingency-related gaps for frequency stability studies and voltage stability studies are similar to those discussed for rotor-angle stability. The primary gaps for frequency stability studies are that the large load modeling practices are insufficiently accurate and commonly considered scenarios may not be sufficiently conservative. These gaps apply both to issues related to frequency stability and managing rate of change of frequency. For voltage stability studies, the dynamic performance of large loads during voltage deviations is the primary area needing better fidelity.

Key Point
The primary gaps for frequency stability studies are that the large load modeling practices are insufficiently accurate and commonly considered scenarios may not be sufficiently conservative.

[75] It is worth noting that the ride-through characteristics of large loads can depend in part on whether the load has a leading or lagging power factor.

Automatic under-frequency load shedding (UFLS) programs are essential for maintaining frequency stability. The disconnection of a large load in a UFLS scenario could exacerbate ongoing reliability issues. For this reason, large loads are inherently difficult to integrate into UFLS programs. Studies need to be performed to evaluate whether the disconnection of that large load could cause further reliability concerns. These studies may need to be performed at interconnection, not just on the five-year Reliability Standard PRC-006[76] UFLS study cycle. Additionally, the five-year PRC-006 UFLS study frequency might not be often enough, because the rapid growth of large loads might significantly change the results of these studies in some areas, even if the large load is not part of the UFLS program.

PRC-006 defines design and documentation requirements for automatic UFLS programs. It intentionally avoids prescribing the method by which utilities meet these requirements. The practices that utilities employ to meet PRC-006 requirements will likely need to be revised. There may also be gaps relating to how automatic UFLS settings are coordinated with any frequency disturbance ride-through requirements to which the large load is subjected via its interconnection agreement.

UFLS entities (the entities that provide automatic load tripping), such as TOs, are required to have available a load-shed amount above a minimum per their PC's UFLS program to ensure that enough load can be shed to arrest frequency decline and avoid complete grid collapse in case of severe low-frequency events. Large loads might not currently be included in UFLS programs. Thus, an interconnecting large load introduces a potential reliability risk that the UFLS entity's existing load-shed amount may fall below the minimum load-shed amount and hence may fail to arrest frequency decline if a severe low-frequency event occurs. The fact that the large load may not be added to the UFLS program may be a gap in utility practices.

Additionally, the manual or UFLS shedding of the entirety of a very large load could lead to over-frequency or overvoltage. The ability to partially shed large loads, either manually or as part of a UFLS scheme, may not be part of existing utility practices.

Undervoltage load shedding (UVLS) programs are an essential tool for mitigating voltage stability problems. The inclusion of large loads in UVLS schemes introduces challenges similar to those associated with their inclusion in UFLS programs. Reliability Standard PRC-010[77] establishes an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS programs. There may not be any gaps in PRC-010, but there are likely gaps in the ability of existing UVLS design strategies to reliably include large loads.

There may be gaps related to the coordination of UVLS programs and voltage disturbance ride-through requirements placed on large loads. Requiring large loads to remain connected during disturbances such as faults may mitigate rotor-angle or frequency stability problems by better maintaining generation-load balance following system disturbances. However, a large load maintaining full consumption during undervoltage conditions will increase the dynamic reactive power support necessary to maintain voltage stability. Thus, the effects of changes in disturbance ride-through requirements must be considered in UVLS program design. As disturbance ride-through requirements for large loads are being developed in many parts of North America, the coordination of UVLS programs and voltage disturbance ride-through requirements should be considered.

Interconnection Frequency Response

The first portion of the stated purpose of BAL-003-2 is "[t]o require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value."[78]

[76] Available here: PRC-006-5
[77] Available here: PRC-010-2
[78] BAL-003-2

Current calculations for required frequency response (Interconnection frequency response obligation, measured in MW per 0.1 Hz) are based on the margin to the first level of UFLS in each Interconnection but do not separately consider the margin to system over-frequency limits. This is especially important because the considerations and equipment tolerances for over-frequency conditions may be different from that of under-frequency conditions. The assumption that these considerations and equipment tolerances are exactly the same has previously been adequate due to load losses historically being much smaller and less frequent compared to generator losses.

Additionally, large load facilities do not always have good dynamic models showing trip and reduction behaviors and do not always provide the models to all appropriate entities that need them in order to assess potential risks to frequency stability from customer-initiated load reduction events. BAs will need accurate dynamic models in order to reliably assess these risks; therefore, the fact that current models have limited ability to reflect the load reductions is a gap and the fact that accurate dynamic models are not required for all BAs is a gap. The gaps related to load modeling are further discussed in **Chapter 7**.

Additional discussion regarding frequency stability and balancing gaps is provided in **Chapter 4**.

Converter-Driven Stability

Existing practices are unable to adequately define the essential issues underlying converter-driven stability.[79] In order to identify and study a specific converter-driven stability problem, especially at the planning stage (where very little is known about the power converters that will be used by the large load), it is generally necessary to have both a well-bounded idea of the kind of issue at hand and a high-fidelity model that has been designed to replicate the issue. There is currently no clear understanding of the specific kinds of converter-driven stability issues to which large loads will be prone. Without this, study practices and model requirements cannot be effectively defined. Even the most detailed electromagnetic transient (EMT) models must omit some potentially relevant control details.

While this white paper later details gaps relating to high-fidelity modeling (see **Chapter 7**), gaps relating to converter-driven stability should not be viewed as solely, or even primarily, a modeling gap, nor should it be assumed that addressing gaps related to modeling will address gaps relating to converter-driven stability. Many control interactions involving power converters are not identified proactively using studies but rather observed in the field unexpectedly.[80] Often, the control interactions are, by their very nature, the result of inevitable differences between models and reality. These differences may come from minor variations in model implementation, settings errors or device malfunctions, or changes in system or site conditions that take place after the study is performed.

For system owners/operators who have experience with converter-based stability problems, existing practices for managing converter-driven stability primarily consist of identifying system-level factors that have historically proven influential in converter-driven stability issues. The presence of flexible ac transmission system devices, HVdc lines, and IBRs has been a common factor in historical issues with converter-based stability. Weak grid conditions often contribute to the issues. If the presence of these system-level factors is identified, more detailed studies are performed. The proximity of large loads to other large-scale power electronics devices can provide some use baseline for identifying cases of concern, but this criteria is far from the level of detail needed for productive study of the converter-driven stability of large loads.

Converter-driven stability issues are not common and require specialized expertise to analyze. Many system owners/operators may have gaps in their existing practices due to a lack of prior need to analyze such issues.

[79] See the Stability section of Chapter 3 of the White Paper: Characteristics and Risks of Emerging Large Loads for more information on convertor-driven stability.

[80] See Data Center Power System Stability — Part I: Power Supply Impedance Modeling,
ERCOT experience with Sub-synchronous Control Interaction and proposed remediation,
Large Load Oscillation Event, and
Understanding the Inception of 14.7 Hz Oscillations Emerging from a Data Center

There may be gaps in Reliability Standards such as TPL-001, FAC-001, FAC-002 and MOD-032 relating to study requirements for converter-based stability issues involving large loads. However, until the issues themselves are better characterized, gaps in Reliability Standards defining practices for modeling and studies will be difficult to assess accurately.

Resonance Stability

Many of the gaps discussed in the section on converter-driven stability apply to resonance stability as well. The essential nuance is that resonance stability issues can involve other devices, such as series or shunt capacitors and turbines. The practice currently employed by some system owners/operators is to identify the proximity of the large load to such devices and then initiate detailed EMT studies. However, this is subject to the same drawbacks and limitations associated with current approaches for studying converter-driven stability in large loads.

Forced Oscillations

Large loads can be a source of significant forced oscillations in the 0.1 Hz to 30 Hz range, either as the result of unintended control interactions or as part of their processes (e.g., AI training). There are significant gaps when it comes to defining allowable limits for forced oscillations in terms of BPS reliability. These forced oscillations can excite oscillatory dynamics in the power system, such as electrical resonances, interarea modes, and torsional modes, potentially leading to far-reaching impacts to BPS reliability. However, there are no guidelines or limits by which a system owner/operator can identify that a given forced oscillation is a reliability risk.

Key Point
There are significant gaps regarding the defining of allowable limits for forced oscillations.

IEEE 519 guidance surrounding interharmonics is of very limited applicability; the limits given therein are very stringent, and violations are sufficient only to indicate that nearby users with sensitive loads may experience issues. Power quality violations are not sufficient to indicate an imminent reliability risk, and power quality standards are not intended to be used as a basis for meeting reliability requirements.

Some system owners/operators do conduct screening studies to evaluate whether forced oscillations from proposed large loads might interact with oscillatory modes in the power system, but these are not required by any Reliability Standards, nor are there guidelines regarding what level of interaction is acceptable.

Some system owners/operators do perform oscillation detection and localization in an operational setting and use this to identify oscillating loads. However, adoption of such tools varies widely throughout industry. Again, the lack of acceptable limits for system reliability remains a challenging gap. Even if an oscillating load is identified, there is no established practice for determining whether the oscillation is a risk to reliability and what level of urgency is associated with the issue.

Chapter 6: Security, Resilience, and Event Analysis

While data centers and other emerging large loads have security practices, existing practices, requirements, and NERC Reliability Standards may present security gaps concerning large loads, particularly with the increasing complexity of large loads and their integration of advanced technologies. Reliability Standards are not directly applicable to most large loads as most of them are not NERC registered entities; therefore, the Reliability Standards do not directly provide a minimum level of security measures to be implemented by the large loads. While Critical Infrastructure Protection (CIP) Reliability Standards provide a framework for cyber security, their applicability and granularity concerning the unique operational characteristics and potential vulnerabilities of emerging large loads, such as data centers and industrial facilities with behind-the-meter power generation/microgrids/demand-side management capabilities, may not be fully comprehensive. The growing adoption of internet-connected control systems and the potential for these loads to utilize these control systems introduces new cyber-attack vectors that might not be adequately addressed via current standards or industry protocols. Furthermore, the physical security of these large load sites and their potential impact on grid stability during both normal operations and cyber incidents may require a more holistic and adaptive security approach that goes beyond traditional utility- or ISO/RTO-centric perspectives.

The LLWG has not identified any system restoration gaps related to large loads because large loads will not usually be included in restoration plans. However, if large loads are included in restoration plans, then there are considerations needed to ensure that the load does not impact the stability of the island.

The lack of large load registration can also potentially impact event analysis by making it more difficult to acquire information on an incident. This leads to difficulty in identifying and implementing corrective actions and developing lessons learned for industry. Additionally, there are no Reliability Standards requiring disturbance monitoring equipment. This is a potential gap as high-resolution data provided by disturbance monitoring equipment is essential to monitoring and analyzing the performance of large loads during events such as voltage disturbances and oscillations.

Physical and Cyber Security Gaps

Physical security threats to large loads are diverse, ranging from theft and vandalism to sabotage and insider threats. Environmental factors like severe weather also pose risks. Vulnerabilities often arise from the size and complexity of these loads, extensive perimeters, reliance on cyber-physical systems, aging infrastructure, and human factors. A security gap for some large load categories may be a lack of design basis threat assessments. These assessments define potential adversaries' capabilities and intentions, serving as a benchmark for designing and evaluating security systems. Regular design basis threat reviews are essential to adapt to evolving threats.

NERC Reliability Standards, including CIP-006,[81] CIP-008,[82] and CIP-014,[83] aim to enhance the security and resilience of the BPS. These standards are not directly applicable to large loads since most large loads are not registered entities under NERC's purview. While these standards are also not applicable to generators, the lack of applicability of these standards to large loads may be a gap.

- CIP-006 focuses on the physical security of BES cyber systems, mandating measures like access control, surveillance, and alarm systems to protect against compromise.
- CIP-008 focuses on cyber security incident reporting and response planning.

[81] Available here: CIP-006-6
[82] Available here: CIP-008-6
[83] Available here: CIP-014-3

- CIP-014 specifically addresses physical security for critical transmission equipment and substations, requiring risk assessments and security plans to protect against physical attacks. The benefits of CIP-014 include ensuring grid reliability, reducing risks from physical threats, and building trust in the security of critical infrastructure.

While CIP-014 is a significant security Reliability Standard, areas for improvement or potential gaps may include the depth of risk assessments required and the need for more specific minimum physical protection standards across a broader range of BES assets. This may be a gap related to the CIP Reliability Standards.

Cyber security gaps concerning NERC BPS threats and vulnerabilities might pose significant challenges to the reliability of the electric grid, especially as emerging technologies introduce new risks. Adversaries could exploit vulnerabilities in systems governed by standards issued by standards organizations like the IEEE, the IEC, the National Institute of Standards and Technology (NIST), the International Organization for Standardization (ISO), and NERC. These standards help to safeguard the BPS, but changes to these standards may be needed due to the evolving threat landscape. One critical gap might be in the monitoring and control of interconnected systems such as data centers or energy Internet of Things (IoT) devices employed by large industrial loads (with and without sophisticated microgrids and/or behind-the-meter power generation capabilities). Adversaries could coordinate cyber attacks that might intentionally overload the grid or initiate simultaneous disconnections that might destabilize the system. Similarly, vulnerabilities in IoT devices with BPS applications often lack robust security protocols. This could present a backdoor for cyber attacks that could allow adversaries to impact the BPS.

Data centers also present unique risks due to their massive and variable power demands. [84] Attackers may be able to manipulate workloads, potentially changing the demand of the load. These manipulations fall outside traditional operational parameters and may highlight the gaps in current cyber security frameworks; data center security protocols are not reviewed or vetted via NERC standards.

Communication Security Gaps

Security gaps related to information sharing and data communication protocols for large loads present significant challenges.

- **A primary concern lies in the diverse and often proprietary nature of communication protocols used by different components and systems within a large load infrastructure.** This heterogeneity can create silos of information, which can hinder effective and timely sharing of critical security data, such as sensor readings, access logs, and threat intelligence. Inconsistent data formats and a lack of standardized communication protocols can impede interoperability between security devices and control systems, making it difficult to achieve a holistic view of the security posture.
- **The reliance on legacy communication protocols, which may lack robust encryption and authentication mechanisms, exposes sensitive operational and security data to potential interception and manipulation.** Insufficiently secured communication channels between remote monitoring stations and the large load site may also be a vulnerability, as unauthorized access to these channels could allow attackers to gain insights into operations or even issue malicious commands.
- **The absence of well-defined and enforced data sharing policies, including protocols for incident reporting and information dissemination among relevant stakeholders, could further exacerbate security gaps by delaying response times and hindering coordinated mitigation efforts.**

[84] See White Paper: Characteristics and Risks of Emerging Large Loads for more information on the risks posed by data centers to the BPS:

- **The increasing integration of IoT devices and cloud-based services into large load management introduces new attack vectors and complexities in securing data communication pathways and ensuring data integrity across distributed environments.**

Operational Security Gaps

Key Point
No NERC standards provide requirements to prevent bad actors from accessing and controlling operational systems related to large loads.

While large loads have security measures implemented, no Reliability Standards provide requirements to prevent bad actors from accessing and controlling operational systems related to large loads and their inherent energy demand profiles. Bad-actor control of a large load could result in excessive ramp rate, oscillations, or other performance aberrations that could impact the BPS. Furthermore, no Reliability Standards provide requirements to prevent an insider threat from accessing operational systems of large loads. Reliability Standard PER-003[85] requires RC, TOP, and BA staff performing reliability-related tasks associated with the respective entity's functions to have NERC certifications. These certifications ensure that staff members are competent in the necessary areas. However, no such standards exist applicable to large loads. Additionally, PER-005 provides requirements for the training of system operators and specific GOP dispatch staff; Reliability Standard PER-006[86] also provides requirements for the training of GOP personnel. Again, no such standards are applicable to large loads.

While multiple Reliability Standards touch upon personnel security and training, the CIP Reliability Standards are the most directly relevant to mandating employee vetting. Reliability Standard CIP-004[87] focuses on minimizing the risk of compromise to BES cyber systems by individuals with authorized access. CIP-004 mandates a baseline level of employee vetting through identity verification and criminal background checks for individuals who have access to critical cyber assets within the North American BPS. This is a crucial component of a layered security approach aimed at mitigating insider threats and ensuring the reliability of the grid. It is important to note that, while CIP-004 is the most direct Reliability Standard addressing employee vetting, other CIP Standards related to physical security (e.g., CIP-006) and access control (e.g., Reliability Standard CIP-007[88]) also have implications for who is granted access to critical facilities and systems, thus indirectly relating to personnel considerations. Lastly, as previously stated, PER-005 focuses on the qualifications and training of personnel but does not specifically mandate the initial vetting process in the same way as CIP-004. Again, these CIP and Personnel Performance, Training, and Qualifications (PER) Reliability Standards are not applicable to large loads.

The lack of requirements for limiting access and control of large loads and for the training of operators of large loads may be a gap in the NERC Reliability Standards.

Existing NERC registered entities rely upon event reporting frameworks within the EOP-004[89] and CIP-008 Reliability Standards to communicate material cyber and physical security event details to regulators and other electric market participants. Large load asset owners have no such mandate related to event reporting for the purpose of grid integrity, reliability, and resilience. This may be an operational security gap.

[85] Available here: PER-003-2
[86] Available here: PER-006-1
[87] Available here: CIP-004-7
[88] Available here: CIP-007-6
[89] Available here: EOP-004-4

System Restoration

The LLWG does not see any gaps regarding large loads in practices, requirements, or Reliability Standards related to system restoration as large loads will not usually be included in restoration plans.

Key Point
Because large loads will not usually be included in system restoration plans, the LLWG has not identified any gaps related to large loads and system restoration.

- The initial loads energized during system restoration are chosen primarily for the purpose of controlling frequency and voltage. Because of the size of large loads and because of the disturbance ride-through characteristics and varying demand of large loads, large loads will likely not be energized in the initial stages of system restoration due to the risk to the stability of the island.
- The choice of loads to restore may be prioritized by criticality, such as loads serving hospitals. Large loads may serve a critical function, but these will likely have backup generation and the need for prioritized restoration would be evaluated on a case-by-case basis.

However, if a large load was included in a system restoration plan, then aspects such as varying demand, disturbance ride-through, and other characteristics of the load need to be studied to ensure that the load does not impact the stability of the island.

Event Analysis and Data Collection Gaps

NERC, the Regional Entities, RCs, GOs, and TOPs typically have standard practices for grid event analysis that require coordination and communication between multiple entities. If additional information is needed for a particular event, NERC, the Regional Entities, and RCs have the ability to send requests for information to authorized representatives of the applicable entities to initiate root-cause analysis and develop mitigation plans when necessary. Registered entities are required to respond to requests for information according to Section 1600 of the NERC ROP.[90] If the analysis of the event uncovers potential violations of existing Reliability Standards, regional requirements, or utility best practices, the applicable entity can be required to develop and implement a corrective action plan to mitigate the potential of similar future events.

Lack of LSE and large load registration can impair event analysis of incidents involving large loads. Multiple events in the Eastern Interconnection (EI)[91] and ERCOT[92] have involved large loads reducing significant amounts of load during voltage disturbances; data center oscillations have also been observed.[93, 94] The significant gaps in existing practices, requirements, and standards can impair NERC and the Regional Entities from obtaining the needed information directly from the large load entities to perform thorough root-cause analysis on these events. Therefore, it is difficult to identify and implement proper corrective actions and develop lessons learned to prevent additional events.

There are existing Reliability Standards and regional requirements for GOs and TOs regarding disturbance monitoring and reporting requirements. Examples include Reliability Standards PRC-002[95] and PRC-028 and ERCOT Nodal Operating Guide[96] Section 6.1. These standards and requirements mandate the installation and configuration of disturbance monitoring equipment (DME) such as digital fault recorders, dynamic disturbance recorders, and phasor measurement units. Standards include location requirements and requirements to provide data to requesting entities such as NERC, the Regional Entities, and RCs within specified timelines. ERCOT revised Nodal Operating Guide Section

[90] Available here: Rules of Procedure
[91] See Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions
[92] See *ERCOT Large Load Loss/Reduction Events 2020-2024* presentation from the December 12, 2024, NERC LLTF meeting. December 2024 LLTF meeting presentations available here: https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_presentations_december_12_2024.pdf
[93] See Understanding the Inception of 14.7 Hz Oscillations Emerging from a Data Center
[94] See Data Center Power System Stability — Part I: Power Supply Impedance Modeling
[95] Available here: PRC-002-5
[96] Available here: Current Nodal Operating Guides

6.1 in 2024 to state that the interconnecting TOP of a large load with peak demand greater than or equal to 75 MW must install and configure DME upon request from ERCOT. However, since this requirement does not exist in NERC standards, there is a potential gap in assessing and mitigating the operational risks of large loads. High-resolution data provided by digital fault recorders, dynamic disturbance recorders, and phasor measurement units is essential to monitoring and analyzing the performance of large loads in events involving large load loss during voltage disturbances and oscillations.

Chapter 7: Modeling of Large Loads

Numerous postmortem analyses of grid events have underscored the necessity of modeling loads with precision to accurately re-create the evolution of these events. The composite load model is the most advanced version of load modeling used for bulk system reliability analysis. EMT models of loads have also been used frequently for specialized assessments, focusing on higher frequency dynamics and harmonic evaluations. Historically, modeling efforts have concentrated on improving representations of three-phase and single-phase motors, which constitute the largest portion of system load in terms of installed megawatt capacity. However, recent years have witnessed significant growth in large load facilities that differ markedly from traditional industrial load. These new types of loads are not only substantial in size but also predominantly consist of numerous rectifiers that supply power to the end process, contrasting sharply with traditional industrial loads dominated by large induction or synchronous motors. This shift has introduced two major challenges. Firstly, existing phasor domain load models, such as composite load models, are not equipped to accurately represent large power electronic rectifier-driven loads.[97] Secondly, even if suitable models were developed, there is a lack of information necessary for engineers to properly parameterize these models. The recent events in ERCOT,[98] the EI,[99] and EirGrid[100] have demonstrated that these devices can operate in ways that put the system reliability at risk. Therefore, accurate models for these devices that reliably predict their behavior are essential for maintaining grid stability and reliability. This chapter documents industry's needs and gaps related to the modeling of emerging large load facilities.

Key Point
Even if the needed phasor-domain large load models were developed, there is still a gap in information necessary to properly parameterize the models.

Modeling Philosophy and Terminology

Before discussing modeling gaps, it is important to acknowledge that models of physical systems are never perfectly accurate. Instead, models aim to capture the phenomena of interest related to a physical system as accurately as possible to aid in decision-making through simulation studies. Furthermore, in the context of power system dynamic assessments, a single simulation platform is generally not suitable for all types of assessment; simulation tools are selected depending on the type of dynamics. The use cases of various simulation tools, as well as the common terminologies related to power system modeling and how these are applied to reliability risk assessments, are discussed in **Appendix A**. To define modeling gaps, the common terminologies related to power system modeling and how these apply to reliability risk assessments must be understood.

Gaps in Model Availability

It is worthwhile to discuss model availability gaps separately for phasor domain (or positive sequence models) and EMT models.

Phasor Domain or Positive Sequence Models

As mentioned earlier, until the past few years, the load modeling space was mostly focused on modeling single-phase residential air-conditioning systems, known to cause fault-induced delayed voltage recovery. The composite load model that is currently used by most utilities is extremely simplistic for electronic loads. The simplified electronic load

[97] The EV charger model developed by the Electric Power Research Institute does allow for modeling some aspects of large power electronic rectifier-driven loads. Additionally, after the initial drafting of this paper, the Power Electronic Reconnecting and Ceasing (PERC1) model was developed and is the most state-of-the-art model for large power-electronic loads. While the modeling gaps identified in this paper were accurate when the content of this paper was initially being drafted, some of the gaps may be reduced with the new PERC1 model.
[98] See *ERCOT Large Load Loss/Reduction Events 2020-2024* presentation from the December 12, 2024, NERC LLTF meeting. December 2024 LLTF meeting presentations available here: https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_presentations_december_12_2024.pdf
[99] See Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions
[100] See *CIGRE/IEEE Webinar – Large Loads and Their Impact on the Grid an Emerging Reliability Risk* presentation, available here: https://cigre-usnc.org/wp-content/uploads/2025/05/NGN-Webinar-May-21-2025.pdf

model was sufficient when the majority of the electronic loads on the system were consumer electronic equipment such as computers and televisions. However, this model is insufficient when trying to model the behavior of large loads, which are now dominated by power electronic rectifier systems. Industrial UPS systems, large industrial rectifiers such as electrolysis power supply equipment, and large power electronic motor drives have sophisticated controls; their ride-through during disturbances cannot be modeled using an electronic load component in the composite load model.

In 2022, the Electric Power Research Institute, with funding from the Lawrence Berkeley National Laboratory, developed a positive sequence model for aggregated representation of vehicle chargers.[101] This model (see **Figure 7.1**) allows some more flexibility in modeling the disconnection and reconnection of electronic loads. Some studies have used this model to investigate the impact of data center disconnection.[102] However, much work is still needed to accurately model data centers. Key gaps that need to be bridged are as follows:

- **Rectifier Dynamics Representation**: The dynamics of the rectifier are currently represented by simple first-order transfer functions in this model; this is based on the assumption that loads will have stable control and that only the slower dynamics are relevant in the positive sequence. Although validated using some lab test results for electric vehicle (EV) chargers and EMT models, it still needs to be compared against a wide array of large rectifier performances (e.g., industrial UPS, electrolysis power supply equipment) to confirm whether the simplification is appropriate.
- **Control Logic Limitations in Existing Models**: The control logic in the model was primarily designed to replicate the observed disturbance ride-through behavior in EV chargers. It may not be sufficient to replicate the behavior of UPSs or other power electronic equipment. It is also unclear whether a single model will be adequate or if multiple power electronic models are needed.
- **Cyclic Load Injection**: Some large load facilities, such as AI training data centers, have cyclic load injections that this model cannot replicate.
- **Collocated Generator and Battery Dynamics**: The model cannot capture the dynamics of any collocated generator or battery energy storage systems.
- **Library Model Availability**: Importantly, the model is not available as a library model in any simulation tool other than GE PSLF.™

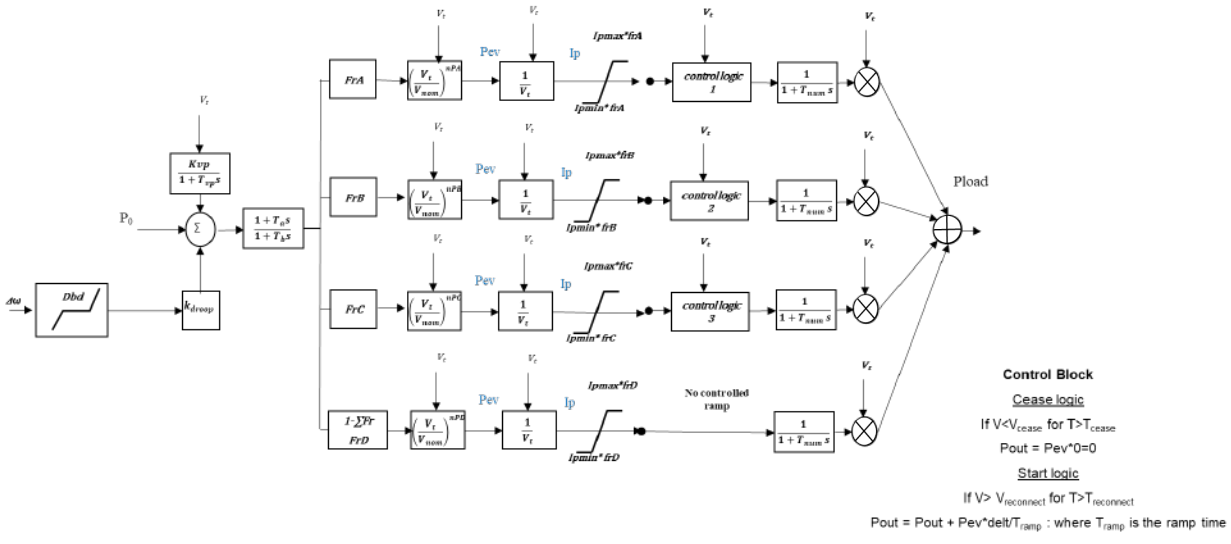


Figure 7.1: Active Power Loop for the Aggregated EV Charger Load Model

[101] A Positive Sequence Model for Aggregated Representation Electric Vehicle Chargers

[102] See Impact of Large Load Disconnection on System Stability 2024 Grid of the Future Symposium 1

EMT Models

Unlike positive sequence tools, EMT tools do not have library models of loads. Rather, EMT tool libraries have a wide array of motor models as well as power electronic device models that can be used to create complex load model structures. Generic structures for models are also available via some tools; these models can be customized as needed. In that respect, a particular model availability gap does not exist for EMT. However, generic structures for large load facilities are not readily available, which might present a roadblock for someone without significant expertise in EMT to create such a model on short notice.

A key gap in EMT model availability lies in the absence of standardized guidelines for modeling different components of large load facilities. For IBRs, IEEE 2800 Section G.4 provides dynamic modeling data requirements for EMT models of IBRs, including accuracy, usability, and efficiency features. For example, under model accuracy features, it specifies that sufficient detail should be included to represent the different components of an IBR plant. These requirements ensure that EMT models for IBRs are accurate, practical, and efficient for use in a wide range of studies. As another example, SPP publishes an EMT Model Requirements document that sets detailed standards for IBR models. This guidance covers aspects such as model accuracy, usability, and simulation performance.[103] However, no comparable standard or guideline exists for modeling large load facilities, which can consist of multiple UPS systems, variable frequency drives, and other power electronic components. Without clear guidance, vendors might be uncertain about the level of detail required in their developed models and could include insufficient detail, potentially reducing the accuracy and reliability of the overall facility model. Establishing standardized modeling requirements for large loads would address this gap, enabling the development of more reliable EMT models.

Gaps in Modeling Information

While the previous section discussed the unavailability of library models, another significant challenge is the lack of information about equipment in large load facilities. Traditionally, industrial load models have been developed based on survey data collected by NERC or regional working groups. For large load models, facility models have been developed based on the available literature, which is quite generic. However, the existing information is insufficient for new large facilities for several key reasons:

- **Limited Experience with Newer Facilities**: The industry lacks significant experience with newer large load facilities like data centers and hydrogen electrolysis plants. Utility engineers are often unfamiliar with the types of equipment used in these facilities to support the main processes. For example, in a data center, the UPS can operate in a double conversion mode, where the grid supply always passes through the UPS, or in an eco-mode (see **Figure 7.2**), where the grid supply is bypassed when the voltage is above a certain threshold. Similarly, for hydrogen electrolysis facilities, the power supply equipment could be either thyristor- or insulated gate bipolar transistor-based, depending on the size and type of electrolysis stack being used. These details are crucial for developing accurate models.

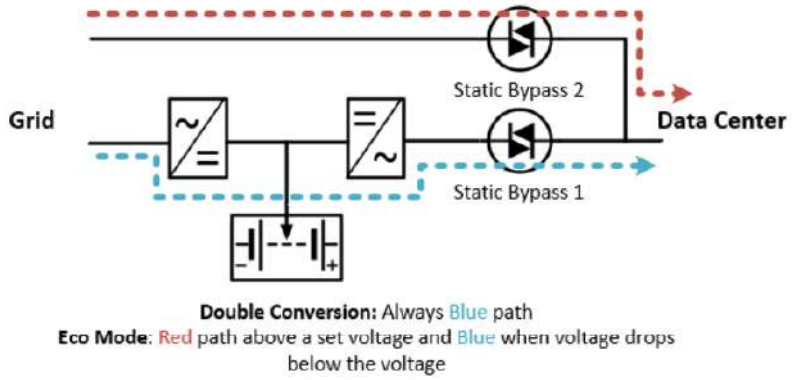


Figure 7.2: Double Conversion vs. Eco Mode Operation of Static UPS

[103] SPP EMT_Model_Requirements_R1

- **Balance of Plant Modeling**: Apart from the main process, modeling the balance of plant, such as cooling loads for data centers and pumps and compressors for hydrogen electrolysis facilities, is essential. Information about balance of plant equipment is not readily available.
- **Highly Controllable Equipment**: Large load facilities like data centers are equipped with UPSs and other power conditioning equipment that are highly controllable and have voltage-sensitive grid disconnection thresholds. Accurately modeling the disturbance ride-through behavior of such facilities for grid studies requires TPs and utility engineers to understand how these devices detect grid anomalies and the thresholds that trigger grid disconnection and transfer of load to local backup. Such information is not readily available for inclusion in models.
- **Variable Load Patterns**: Loads such as AI training facilities create spiky (**Figure 7.3**), variable load patterns that can impact power system reliability and need to be modeled. Information about these load patterns is not readily available for inclusion in models. Furthermore, some facilities have battery energy storage systems that operate in parallel to smooth the spikes. Having information about such configurations and their control methods will be essential for developing facility models for large loads.

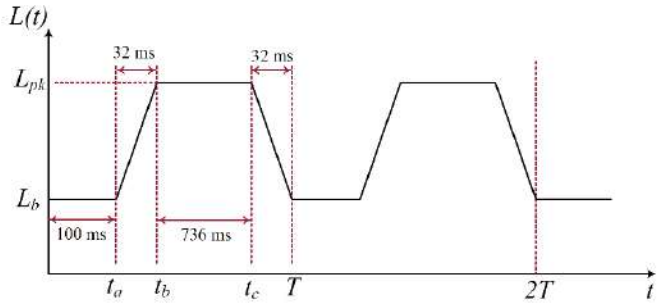


Figure 7.3: Possible AI Training Load Profile[104]

The lack of proper information presents a significant challenge for the modeling community. Without detailed information, even if models could be created, the models can never be parameterized properly for the purposes of any reasonable assessment. The gaps in modeling information are primarily due to the following:

- There are no requirements in the NERC standards specifically for load facility owners to submit validated models (or just models) to the relevant TPs. The responsibility of modeling a load facility lies with the TPs.
- Since load facility owners are not required to submit models, they might not participate in industry forums where load modeling is discussed. As such, avenues for interactions between the load modeling community and load facility owners may be very limited.
- Load facility owners may not have a clear idea as to the requirements of grid modeling. Load modeling for assessing the issues within a load facility/process is quite different than the concerns that grid engineers have and the model requirements are different.
- TOs do not always have clear data and model sharing requirements for the large loads. Additionally, large loads may be unfamiliar with utility coordination requirements.
- Large loads may be unwilling to share information due to data sensitivity concerns.

Gaps in Modeling Guidance and Practices for Large load Facilities

Since large load facilities have multiple components, guidance on how these facilities should be modeled for different studies is needed. Similar guidance has been issued in the past for modeling of wind and photovoltaic plants in phasor domain simulations. The lack of adequate guidance for modeling large load facilities needs to be addressed.

[104] Grid-Forming Inverter Applications for Improved Reliability and Power Quality in AI Data Centers

As mentioned before, EMT studies are not currently suitable for large-scale grid simulations. However, EMT studies will be increasingly important for large load facilities to ensure that the risks requiring specialized EMT modeling (e.g., resonance stability, converter-driven stability, and forced oscillations occurring at frequencies >5 Hz)[105] can be evaluated. Hence, screening methods for determining the need for EMT evaluations are necessary. Some of these screening techniques exist for IBR and HVDC interconnections that can be leveraged; however, these need to be evaluated for large load interconnections as well. Additionally, guidance on the level of modeling details needed and where aggregated modeling is acceptable in EMT simulations with large load facilities is important. The lack of adequate guidance in this area is a gap that needs to be addressed.

Traditionally, loads have not been modeled in short-circuit studies as their impact to fault currents has usually been negligible. However, the lack of representation of large load behavior during faults, particularly under weak grid conditions, may present a gap in current short-circuit and protection analysis practices. These loads can significantly impact voltage and current waveforms during disturbances, potentially compromising the accuracy and dependability of protection systems. Incorporating their dynamic characteristics into fault analysis may be important for improving the reliability and security of protection schemes in evolving grid conditions.

Gaps in Modeling Validation and Model Quality Tests

Model validation plays an important role in ensuring that the developed models are a reasonable representation of the dynamic responses of the actual devices. GOs are required to submit model validation reports on a regular basis to fulfill the requirements of Reliability Standards MOD-026[106] and MOD-027.[107] The models are validated based on staged tests[108] or based on measurements from grid disturbances.[109] Model validation has also been found to be necessary for IBRs. However, such practices are not commonplace for loads.

Load models are often validated as part of the Reliability Standard MOD-033[110] assessment; however, the MOD-033 assessment is not explicitly meant for loads but for overall system model validation. This practice was considered sufficient as loads were smaller in size and distributed across the grid. However, the advent of emerging large loads changes this assumption and model validation becomes important. For loads, model validation has a few challenges that need to be overcome:

- No standard exists today that would require a load facility owner or LSE to perform a regular model validation exercise. As such, the burden of parameterizing load models falls on TPs and is only done during the load interconnection process and fine-tuned or modified during event validation.
- Even if a model validation standard is in place, the same process as exists for generators cannot be adopted. Staged tests are generally not possible in a load facility like the exciter step response tests that can be conducted in power plants. Load model validation would then have to rely on grid disturbances. Furthermore, frequent events like single line-to-ground (SLG) faults or shallow voltage sags may not be able to excite all relevant controls in a facility to be able to model those controls.
- Proper measurement devices with desired sampling rates might not be deployed on the grid at preferred locations that would allow a modeler to isolate the response of a single facility and be able to validate the relevant models.

Model quality testing is a process used to screen dynamic models, typically IBRs, for completeness and stability before incorporating them into planning cases. The goal is not to verify a model's accuracy against real-world performance

[105] See Data Center Power System Stability — Part I: Power Supply Impedance Modeling | CSEE Journals & Magazine | IEEE Xplore
[106] Available here: MOD-026-1
[107] Available here: MOD-027-1
[108] See Automated parameter derivation for power plant models based on staged tests | IEEE Conference Publication | IEEE Xplore
[109] See Power plant model validation for achieving reliability standard requirements based on recorded on-line disturbance data | IEEE Conference Publication | IEEE Xplore
[110] Available here: MOD-033-2

but to ensure that it initializes correctly, responds reasonably to disturbances, and does not cause convergence or stability issues during simulation. These tests help maintain the integrity of system-wide base cases and reduce the risk of unreliable behavior in planning studies. While model quality testing is now standard practice for IBRs, there is no consistent industry approach for applying similar screening to large loads, creating a gap in how these resources are evaluated. This becomes increasingly important as fast-acting, transmission-connected loads, such as data centers, cryptocurrency mining facilities, and industrial facilities, become more prevalent and start to influence overall system behavior. Some operators have developed detailed model quality testing procedures for generators. For example, ERCOT publishes a Model Quality Guide[111] that outlines expectations for model structure, initialization behavior, simulation response, and performance under fault conditions. The process includes verification methods, such as comparison to field-measured parameters via a parameter verification report or unit model validation, to ensure that the submitted model reflects the behavior of the physical resource. These layers of screening help prevent overly idealized models from being accepted into study cases. Similar practices are not currently applied to large loads, even when their modeling could materially impact study outcomes.

[111] Available here: https://www.ercot.com/services/rq/re

Chapter 8: Risk Categorization and Mitigations

This white paper discusses the gaps in existing Reliability Standards, practices, and requirements. However, the solution to address each gap may not always be to update the specific Reliability Standard, requirement, or process that has the gap.[112] The mitigations used should be tailored based on the likelihood or severity of a BPS impact from the risk. To help determine proper mitigations for each of the risks, this chapter describes the likelihood and impact of the risks and whether those risks can be adequately mitigated by the existing registered entities. Most of the risks discussed in this chapter are based on the risks provided in Chapter 4 of the LLTF *Characteristics and Risks of Emerging Large Loads* white paper.[113] For the risks that the LLWG has determined cannot be mitigated by existing registered entities, this chapter also provides information regarding what is needed from a potential new registered entity to adequately mitigate the risk. The detailed discussions are provided in the **Risk Likelihood/Impact and Ability to Mitigate** section of this chapter.

The NERC *Framework to Address Known and Emerging Reliability and Security Risks*[114] document provides direction regarding how the risks from emerging large loads should be addressed. The LLWG recommends that this framework document is utilized to determine appropriate risk mitigations. **Figure 8.1** provides a visual overview from this framework document of the mitigations that should be used based on the likelihood and impact of a risk.

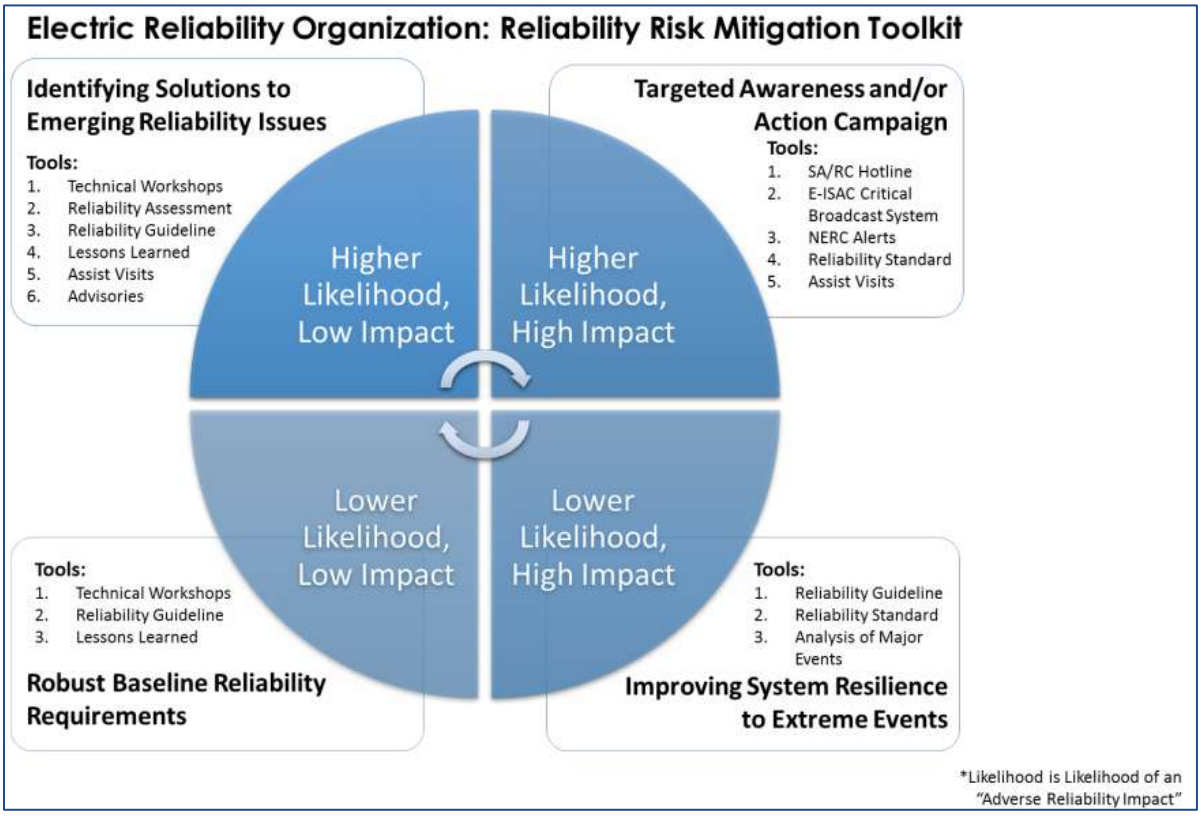


Figure 8.1: ERO Reliability Risk Mitigation Portfolio

[112] For example, this paper has found that there are gaps related to emerging large loads in BAL-001, BAL-002, and BAL-003; however, accurate load modeling data and enforced disturbance ride-through requirements could help reduce the need for updates to the BAL Reliability Standards and help address risks such as voltage stability.
[113] Available here: White Paper Characteristics and Risks of Emerging Large Loads
[114] Available here: Framework to Address Known and Emerging Reliability and Security Risks

Figure 8.2 provides a similar figure as shown above, populated based on the findings in this chapter. The LLWG hopes that this will be useful as its recommendations are prioritized. The findings in this chapter have informed several of the recommendations provided in the **Conclusion**. Specifically, the risks with the following risk categorizations have been identified as needing to be addressed with Reliability Standards and this is reflected in Recommendation 2 in the **Conclusion**:

- High impact risks
- High likelihood risks
- Moderate likelihood, moderate impact risks

All risks discussed in this chapter, except for the System Restoration risk (which has been determined to not have any associated gaps), have been identified as needing to be addressed with Reliability Guideline(s) and this is reflected in Recommendation 3 in the **Conclusion**. Additionally, for the risks that existing NERC registered entities are not able to address, as discussed later in this chapter, the specific actions needed from a new type of registered entity(ies) are provided and are listed in Recommendation 1 in the **Conclusion**.

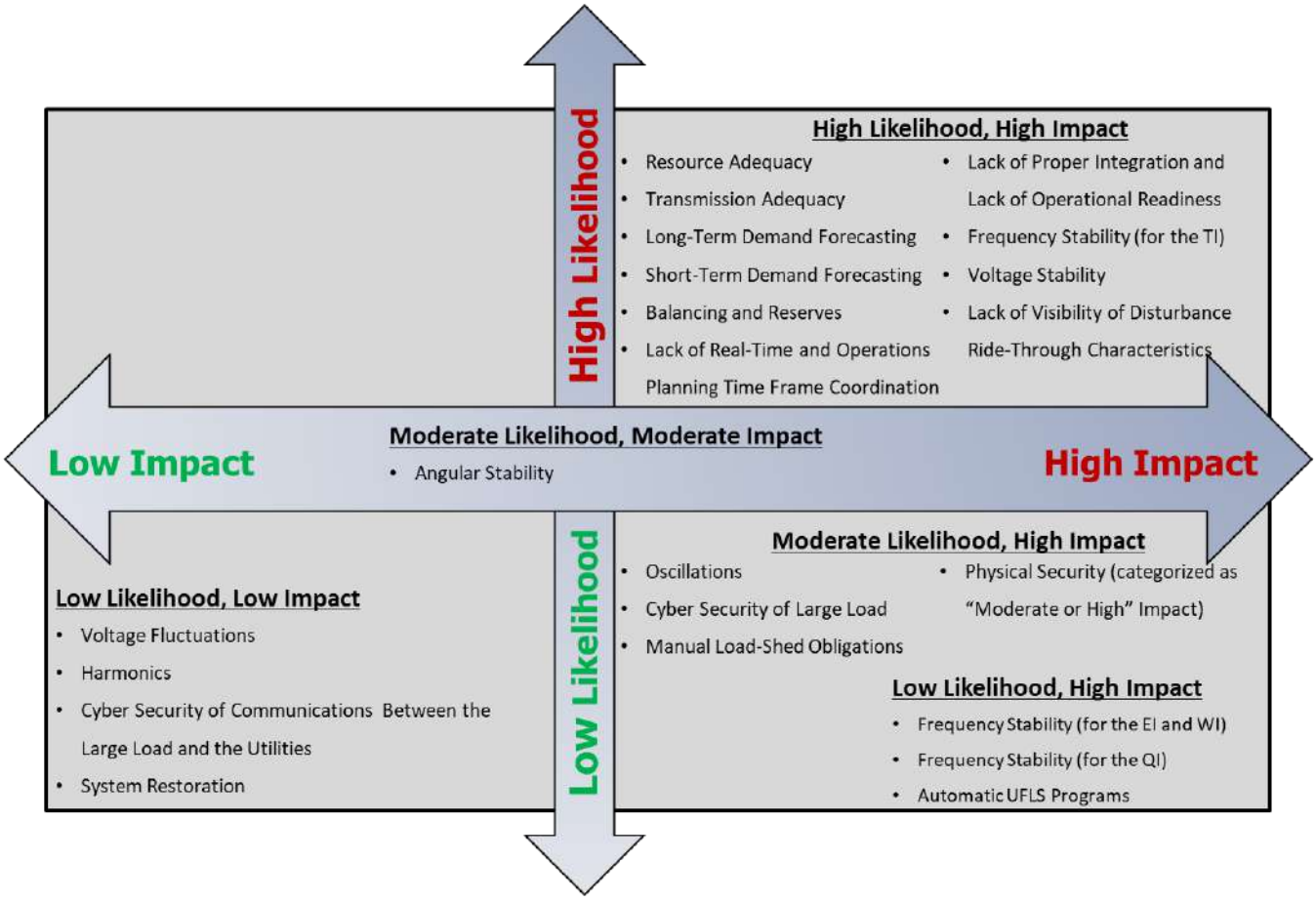


Figure 8.2: Likelihood and Impact of BPS Risks from Emerging Large Loads

For this white paper, risk likelihood and risk impact severity are defined as follows:

- Risk **likelihood** is defined in terms of the qualitative[115] probability that an event from a given risk category causes a measurable adverse reliability impact. [116] For example, harmonics are present to some extent across the entire BPS. However, this does not mean that harmonics are necessarily a high-likelihood risk—it is seldom the case that harmonics cause attributable damage to BPS equipment or result in forced outages. It is often the case that events from a particular risk category can manifest in different ways, each with a different impact severity. For example, an angular instability event could consist of a single generator disconnecting or unintentional islanding (and potential subsequent blackout) of a large region of the grid. In such cases, the likelihood rating should represent a blend of the different possible outcomes, weighted according to the impact.
- Risk **impact** severity is defined in terms of the adverse impact to the reliability of the BPS.[117] For example, an event that causes the forced outage of a single generator has a low impact, as this is a routine disturbance that the BPS is designed to withstand. On the other hand, an event that results in sudden forced outages for several dozen transmission lines has a high impact as the BPS is not designed to operate with so many assets unexpectedly out of service and may experience a collapse resulting in region-wide power outages.
- Within this white paper, there are nuances that must be handled through industry consensus among subject-matter experts. One such example is the relationship between the **duration** of a forced outage and impact severity: Whether a generator is tripped off-line by disturbance ride-through protection or because it has experienced a catastrophic turbine shaft failure, the immediate impact on the BPS is much the same—one generator is removed from service. However, the shaft failure is clearly a much more impactful event overall: The generator will be out of service for quite some time owing to repairs that require a large duration of time to implement. The capacity constraints introduced by a long-term forced generation outage can result in the BPS becoming less resilient to future disturbances. Thus, it is inappropriate to treat generator tripping and turbine shaft failure as equivalent reliability impacts.

A key consideration when determining the ability of existing registered entities to mitigate many specific risks is to determine the ability to mitigate them through interconnection requirements. Many of the requirements that are needed for large loads, such as disturbance ride-through and modeling requirements, can be placed in TO interconnection requirements via FAC-001. However, interconnecting utilities generally do not have the authority to assess performance-based financial penalties except under certain very limited circumstances. Therefore, depending on the significance of the impact from the risk, interconnection requirements may not adequately mitigate the risk; directly enforceable NERC standards may be needed instead. For generators, there are risks that are currently addressed via NERC standards, rather than only through interconnection requirements; examples of this are the frequency and voltage disturbance ride-through requirements found in NERC standards. Additionally, NERC standards provide consistent performance requirements across the BPS, while interconnection requirements can vary between TOs or regions; with that being said, interconnection requirements can have consistency if they are a result of NERC standards applicable to the TOs. A further argument supporting NERC standards being more appropriate than interconnection requirements for addressing significant BPS risks is that, if large loads, LSEs, or a similar entity do not have NERC standards directly applicable to them, the existing registered entities will then be responsible for the performance of the large loads. While this may have been appropriate for historical loads of significant size, emerging large loads are comparable to the size of significantly large generators and have unique operational characteristics, both of which create challenges for having a third party be responsible for their performance. Last, enforcement of interconnection procedure/agreement terms and conditions may vary, while enforcement mechanisms that exist for the NERC standards provide clarity.

[115] While assessments of probability are usually quantitative in nature, the assessments of risk likelihood in this chapter were developed based on the experience-based judgement of the paper contributors.
[116] Per the NERC Glossary of Terms Used in NERC Reliability Standards, adverse reliability impact is defined as "[t]he impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection."
[117] *Ibid.*

This chapter considers whether or not existing NERC registered entities can address the BPS risks presented by emerging large loads, and the language provided assumes that NERC standards are the more appropriate mechanisms for this risk mitigation for significant risks, as opposed to interconnection requirements. If it holds that NERC standards are the more appropriate mechanism, it may necessitate the registration of large loads or LSEs in order for these standards to be directly enforceable. However, if interconnection requirements are seen as being more appropriate for addressing specific gaps, the LLWG's opinion in this area may change and this may reduce the need for registration of these new entities.

Figure 8.3 provides a conceptual overview of the types of large loads that may become registered entities if, in order to address the risks posed by data centers and cryptocurrency mining facilities, (1) all large loads were registered, (2) power electronic-interfaced loads were registered, or (3) loads with a significant amount of IT equipment load were registered. As shown in the figure, registration of all large loads or registration of power electronic-interfaced loads would include other large loads in addition to data centers or cryptocurrency mining facilities.

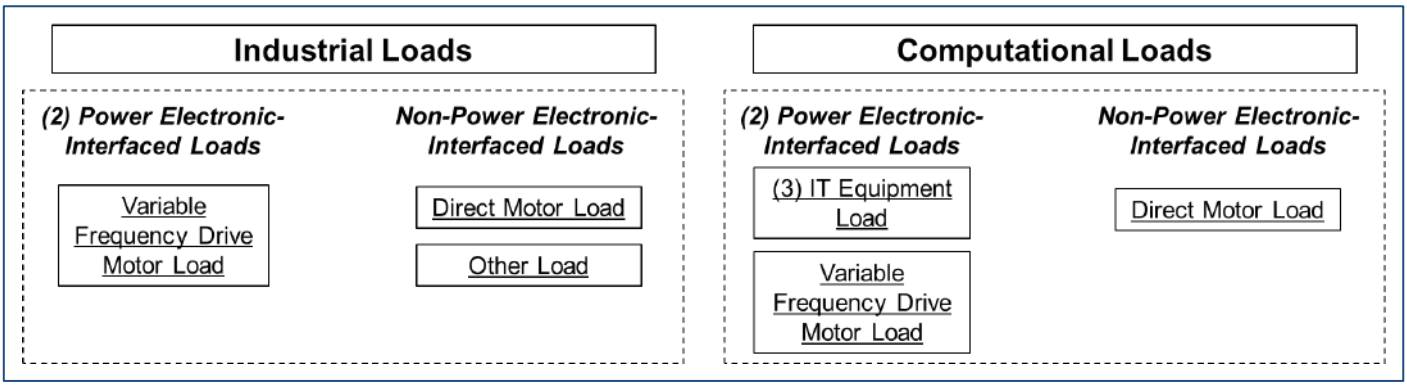


Figure 8.3: Load-Type Conceptual Overview

Risk Likelihood/Impact and Ability to Mitigate

Long-Term Planning Risks

Resource Adequacy

The impact of the Resource Adequacy risk is **high** because if the amount of load that needs to be served is close to or greater than the amount of available generation, then frequency stability may be at risk. Although work is being done in this area, many regions do not currently perform resource adequacy checks before connecting a large load. The likelihood of a reliability impact from this risk is **high** because generation can take a long time to build and data centers can come on-line very quickly. Additionally, load forecasts over the next 10 years show rapid load growth, with data centers accounting for most of the demand growth according to the 2025 NERC LTRA. Additionally, this LTRA has flagged several areas as high risk ("[i]n high-risk areas, planned resources…would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load") starting within the next 5 years.[118]

This risk can be mitigated with existing registered entities. While information on large load location, timing, size, operational flexibility, likelihood of materialization, and other variables is needed significantly earlier than the energization date (years before the energization date), this can be obtained by existing registered entities by requiring this information with enough lead time in interconnection requirements; the TO could require that delays in the provision of necessary data by load entities result in delayed energization of load or delayed ramping of load. This information would need to be provided to the RPs by the TOs.

[118] 2025 Long-Term Reliability Assessment

Transmission Adequacy

The impact of the Transmission Adequacy risk is **high** because if the amount of load that needs to be served is greater than the available transmission capacity, then the transmission system is being run closer to its limits with respect to bulk power flows resulting in exacerbated stability risks due to increased voltage angle differences across transmission lines, increased voltage magnitude differences across transmission lines, or other factors. The likelihood of a reliability impact from this risk is **high** because large loads can come online quickly and exhibit unique system behaviors that need to be accurately modeled. Moreover, building transmission and coordinating outages require significant time, which must be studied and considered when validating the expected in-service dates of new transmission.

This risk cannot be adequately mitigated with existing registered entities. In the steady-state domain, the existing NERC registered entities have the tools to manage these thermal and voltage violations. TPs and PCs have processes in place to manage transmission expansion and resolve violations that are discovered in the planning process. During real-time operations, TOPs, RCs, and BAs can manage thermal and voltage violations by preventing load energization, re-dispatching generation, performing transmission switching, or performing load shedding. While information on large load location, timing, size, operational flexibility, likelihood of materialization, and other variables is needed significantly earlier than the energization date (years before the energization date), this can be obtained by existing registered entities by requiring this information with enough lead time in interconnection requirements; the TO could require that delays in the provision of necessary data by load entities result in delayed energization of load or delayed ramping of load. This information would need to be provided to TPs (and others) by the TOs. However, in the dynamics domain, the existing NERC registered entities do not possess the detailed information about the large load facility design and cannot build accurate dynamic models for simulations without the information possessed by large load entities. Without Reliability Standards ensuring that the dynamic modeling information provided by loads is accurate, there is concern that the information provided might not be accurate enough. Therefore, this risk cannot be adequately mitigated by existing registered entities.

To adequately mitigate the Transmission Adequacy risk, the following is needed from new type(s) of registered entity(ies):

- Provide accurate information (as accurate as possible and as early as possible) regarding large load dynamic model to support interconnection and transmission planning studies
- Inform the TP and TO and/or other applicable entities of any pertinent changes to the characteristics of the load

Long-Term[119] Demand Forecasting

The impact of the Long-Term Demand Forecasting risk is **high** because if the long-term demand forecasts are inaccurate, adequate amounts of generation might not be built to serve the load. This could result in frequency stability being at risk. Additionally, inaccurate long-term demand forecasts could lead to transmission adequacy risks. There is an influx of large loads with various amounts of certainty or uncertainty. There is not a process to determine how much of the load will materialize. The likelihood of a reliability impact from this risk is **high** because load forecasts over the next 10 years show rapid load growth, and the load forecasts are changing as well. There is a large difference between the higher and lower load forecasts, showing a large amount of uncertainty in the expected load growth.

This risk can be mitigated with existing registered entities. While information on large load location, timing, size, operational flexibility, likelihood of materialization, and other variables is needed significantly earlier than the energization date (years before the energization date), this can be obtained by existing registered entities by requiring this information with enough lead time in interconnection requirements; the TO could require that delays in the

[119] i.e., later than operational

provision of necessary data by load entities result in delayed energization of load or delayed ramping of load. This information would need to be provided to the demand forecasters by the TOs.

Operations/Balancing Risks

Short-Term[120] Demand Forecasting

The impact of the Short-Term Demand Forecasting risk is **high** because large loads such as data centers are known to fluctuate rapidly and it is known that their demand is difficult to forecast. The variability can also cause significant electricity market price impacts that can in turn impact the forecast. The large size of the load can have a significant impact on the local resource dispatch needs because of the relative size of the load compared to the area. There is also a lack of history to help inform forecasting. The likelihood of a reliability impact from this risk is **high** because large loads such as data centers are known to have varying demand and it is known that their demand is difficult to forecast. The high ramping frequency of some large loads can be difficult to capture with existing forecasting models and data processes, as well as generator automatic generation control.

This risk cannot be adequately mitigated with existing registered entities. Accurate short-term demand forecasts of large loads will likely often require the large load to participate in the developing of the forecast. This coordination could occur without requirements for the large load. However, because of the importance of short-term demand forecasts, this coordination likely needs requirements enforcing it.

To adequately mitigate the Short-Term Demand Forecasting risk, the following is needed from new type(s) of registered entity(ies):

- Provide sufficient data to applicable entities (e.g., RC, TOP, and BA) for the development of short-term demand forecasts
- Provide accurate short-term demand forecast data

Balancing and Reserves

The impact of the Balancing and Reserves risk is **high** because the large amount of demand variability that large loads such as data centers can have can lead to exhaustion of operating reserves (spinning). The likelihood of a reliability impact from this risk is **high** because large loads such as data centers are known to have rapid, unexpected demand variations. This characteristic of data centers is very well known.

This risk cannot be adequately mitigated with existing registered entities. Gaps related to short-term demand forecasting are discussed earlier in this paper.[121] Lack of accurate short-term demand forecasts for the large loads could be very impactful to the ability to balance generation and load because these loads are expected to become a significant portion of system load. However, existing registered entities cannot get accurate short-term demand forecast data.[122] Additionally, ramp rate limits on large loads, along with real-time coordination as previously discussed, are important for effective ACE management. Ramp rate limits, developed in consultation with the BA, must ensure that sufficient high-speed reserves are dedicated to managing high intra-hour and intra-minute volatility. However, because interconnection requirements do not currently require TOs to coordinate with BAs in their development, a strong mechanism is needed to obtain ramp rate limits.

[120] (operational)
[121] See Chapter 4.
[122] See the Short-Term Demand Forecasting sub-section of this chapter for more information.

To adequately mitigate the Balancing and Reserves risk, the following is needed from new type(s) of registered entity(ies):

- Provide sufficient data to applicable entities (e.g., RC, TOP, and BA) for the development of short-term demand forecasts and operating plans
- Provide accurate short-term demand forecast data
- Ensure compliance with ramp rate requirements (down ramp and up ramp)

Lack of Real-Time and Operations Planning Time Frame[123] Coordination

The impact of the Lack of Real-Time and Operations Planning Timeframe Coordination risk is **high** because a lack of real-time coordination or coordination in the operations planning time frame between the large load and the TOP/BA can lead to thermal, voltage, or frequency stability impacts if the load changes demand without coordination or begins/ends a non-forced outage without coordination. The likelihood of a reliability impact from this risk is **high** because there are no requirements in the NERC Reliability Standards for real-time coordination between large loads and BAs/TOPs/RCs. The coordination that occurs between large loads and BAs/TOPs/RCs is often inadequate.

This risk cannot be adequately mitigated with existing registered entities. Interconnection requirements can contain requirements for real-time coordination and operations planning time frame coordination. However, because this risk is a high-likelihood, high-impact risk, a stronger mechanism to mitigate the risk is needed. For example, NERC standards, in addition to interconnection requirements, are used to mitigate the impact to the BPS from IBRs. Additionally, it is essential to establish requirements for operating protocols, communication protocols, and other operational and operations planning needs based on coordination with the BA/RC/TOP. These requirements might not be adequately covered in interconnection requirements.

To adequately mitigate the Lack of Real-Time and Operations Planning Time Frame Coordination risk, the following is needed from new type(s) of registered entity(ies):

- Perform real-time (and operations planning timeframe) coordination with the TOP, BA, and/or RC, as applicable
- Adhere to necessary operating protocols, communication protocols, etc.
- Comply with operating instructions from the TOP, BA, and/or RC, as applicable and ensure appropriate training for receiving those instructions

Lack of Proper Integration and Lack of Operational Readiness[124]

The impact of the Lack of Proper Integration and Lack of Operational Readiness risk is **high** because lack of effective integration and operational readiness can lead to other high impact risks discussed in this chapter, such as Lack of Real-time and Operations Time Frame Coordination, Frequency Stability, and Voltage Stability. Examples of operational readiness can include trip settings being different than were studied and demand behavior being different than was studied, as well as other characteristics. The likelihood of a reliability impact from this risk is **high** because even without large loads, lack of operational readiness for new major BPS additions (such as new generators) is already a likely concern. Adding more large loads to the grid significantly compounds this issue.

This risk cannot be adequately mitigated with existing registered entities. FAC-001 and FAC-002 provide a framework that helps mitigate this risk, but the large load might not provide the necessary data for performing

[123] "Near-term" operations planning time frame
[124] See NERC Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations

interconnection studies. While interconnection requirements are a powerful way to address issues, integration processes that incorporate feedback from operational registered entities are essential. Additionally, interconnection requirements can vary (by region, for example). Similar efforts are underway to increase the robustness of generation integration and validation processes. Because this risk is a high-impact risk, a stronger mechanism to mitigate the risk may be needed.

To adequately mitigate the Lack of Proper Integration and Lack of Operational Readiness risk, the following is needed from new type(s) of registered entity(ies):

- Provide TOs and/or other applicable entities with accurate information necessary for performing interconnection studies
- Coordinate with TOs and/or other applicable entities to establish a comprehensive commissioning process that ensures operational readiness
- Inform TOs and/or other applicable entities of any pertinent changes to the characteristics of the load after energization

Stability Risks

Frequency Stability (for the EI and Western Interconnection (WI))

The impact of risks to frequency stability in the EI or WI is **high** because "[t]he impact of an event that results in frequency-related instability…that affects a widespread area of the Interconnection" is an adverse reliability impact according to the NERC Glossary of Terms Used in NERC Reliability Standards.[125] The likelihood of frequency instability causing adverse impacts to BPS reliability in the EI or the WI is **low** because historical frequency response measures[126] demonstrate extreme resilience to even the largest load-loss events, coupled with a very large amount of on-line inertia historically at all times of the year.

This risk cannot be adequately mitigated with existing registered entities. Without accurate modeling data to assess the large load performance and resulting impact to the BPS, and disturbance ride-through requirements to address the impact, frequency stability may be at risk. Because this is a high-impact risk, a strong mechanism is needed to obtain these. Therefore, the existing registered entities are not able to adequately mitigate the risk. The accurate modeling data is needed to study frequency stability. The disturbance ride-through requirements are needed to help ensure frequency stability.

To adequately mitigate the Frequency Stability (for the EI and WI) risk, the following is needed from new type(s) of registered entity(ies):

- Ensure compliance with disturbance ride-through requirements
- Provide accurate load model data and ongoing model updates

Frequency Stability (for the Texas Interconnection (TI))[127]

The impact of risks to frequency stability in the TI is **high** because "[t]he impact of an event that results in frequency-related instability… that affects a widespread area of the Interconnection" is an adverse reliability impact according to the NERC Glossary of Terms Used in NERC Reliability Standards.[128] The likelihood of frequency instability causing adverse impacts to BPS reliability in the TI is **high** because a significant number of large loads are interconnecting in

[125] Available here: Glossary of Terms Used in NERC Reliability Standards
[126] See BAL-003-2 R1
[127] Note: The TI and QI Frequency Stability risks are separated from the EI and the WI because the TI and QI are smaller Interconnections than the EI and WI, leading to different likelihood/impact considerations for these Interconnections.
[128] Available here: Glossary of Terms Used in NERC Reliability Standards

areas that already have lower system strength. Following a fault, low voltages can therefore affect a wider geographic area and increase the risk of large loads tripping, causing frequency instability. The risk is further exacerbated during conditions with low load (when grid inertia is reduced) and low IBR output, which limits downward frequency response from these resources.

This risk cannot be adequately mitigated with existing registered entities. Without accurate modeling data to assess the large load performance and resulting impact to the BPS, and disturbance ride-through requirements to address the impact, frequency stability may be at risk. Because this is a high-impact risk, a strong mechanism is needed to obtain these. Therefore, the existing registered entities are not able to adequately mitigate the risk. The accurate modeling data is needed to study frequency stability. The disturbance ride-through requirements are needed to help ensure frequency stability.

To adequately mitigate the Frequency Stability (for the TI) risk, the following is needed from new type(s) of registered entity(ies):

- Ensure compliance with disturbance ride-through requirements
- Provide accurate load model data and ongoing model updates

Frequency Stability (for the Québec Interconnection (QI))[129]

The QI, although smaller than the EI, has unique characteristics that influence the nature of the Frequency Stability risk. The Québec system operates synchronously within its own boundaries and is interconnected with other North American Interconnections through HVdc links. This configuration limits the propagation of frequency-related events to or from other interconnections. The potential impact of a frequency instability event in the QI is **high**, as in the other interconnections, since "[t]he impact of an event that results in frequency-related instability… that affects a widespread area of the Interconnection" is an adverse reliability impact according to the NERC Glossary of Terms Used in NERC Reliability Standards.[130] However, the likelihood of such events occurring remains **low** due to several factors:

- **High Inertia:** Québec's generation fleet is predominantly hydroelectric, providing significant natural inertia and frequency regulation capabilities.
- **Historical Performance:** The Québec system has demonstrated strong resilience to major load-loss events, with effective and well-managed frequency response.
- **Regulation Margin:** Hydro-Québec normally has 1,000 MW of regulation margin (up or down) at any time. This allows for responding to large load losses or variations when they occur.
- **Emerging Load Growth:** While major industrial projects are under development (e.g., electrification of processes, data centers, hydrogen production), their integration is typically well planned and supported by rigorous grid-impact studies, which helps mitigate the risk of unexpected disturbances. While the largest load on the Hydro-Québec system is about 1,000 MW, it is an arc smelter, which likely poses fewer risks to the BPS than emerging large loads such as data centers. The largest data center load in Québec is roughly 30 MW in size; Québec is not expecting data center loads larger than this to energize in the coming years.

This risk can be mitigated with existing registered entities. The risk from emerging large loads in the QI to frequency stability is not significant.

[129] Note: The TI and QI frequency stability risks are separated from the EI and WI because the TI and QI are smaller Interconnections than the EI and WI, leading to different likelihood/impact considerations for these Interconnections.
[130] Available here: Glossary of Terms Used in NERC Reliability Standards

Voltage Stability

The impact of the Voltage Stability risk is **high** because over-voltages from large load demand changes or trips can lead to tripping of nearby generation or loads, creating a cascading effect. The likelihood of a reliability impact from this risk is **high** because it is well known that many large loads do not ride through common voltage disturbances.

This risk cannot be adequately mitigated with existing registered entities. Without accurate modeling data to assess the large load performance and resulting impact to the BPS, and disturbance ride-through requirements to address the impact, voltage stability may be at risk. Because this is a high-impact risk, a strong mechanism is needed to obtain these. Therefore, the existing registered entities are not able to adequately mitigate the risk. The accurate modeling data is needed to study voltage stability. The disturbance ride-through requirements are needed to help ensure voltage stability.

To adequately mitigate the Voltage Stability risk, the following is needed from new type(s) of registered entity(ies):

- Ensure compliance with disturbance ride-through requirements
- Provide accurate load model data and ongoing model updates

Angular Stability

"The portion of the BPS affected by a particular loss of synchronism event can vary greatly, and consequences range from the outage of a single plant to the islanding of large sections of an interconnection."[131] Therefore, the impact from the Angular Stability risk is categorized as **moderate** to reflect both scenarios. The sudden disconnection of large load(s) can lead to angular stability impacts. This effect becomes more significant for loads that are larger in size. Impact is higher in areas with heavy co-location of large loads and large generators. The likelihood of a reliability impact from this risk is **moderate**. An SLG fault can cause voltage-sensitive large loads such as data centers to disconnect, leading to potential loss of synchronism of nearby generation.[132] This is notable because, without the disconnection of the large load(s), SLG faults would not usually impact nearby generation. The likelihood of angular stability-related reliability impacts due to large load disconnection is higher in areas with heavy co-location of voltage-sensitive large loads and generators.

This risk cannot be adequately mitigated with existing registered entities. Without accurate, detailed modeling data to assess the large load performance and resulting impact to the BPS, and disturbance ride-through requirements to address the impact, angular stability may be at risk. Interconnection requirements may not be a strong enough mechanism to provide these mitigations. Because this risk is a moderate-likelihood, moderate-impact risk, a stronger mechanism to mitigate the risk is needed. Therefore, the existing registered entities are not able to adequately mitigate the risk. Additionally, due to angular stability posing system-wide risks, the requirements for dynamic modeling and studies should be established on a system-wide basis.

To adequately mitigate the Angular Stability risk, the following is needed from new type(s) of registered entity(ies):

- Ensure compliance with disturbance ride-through requirements
- Provide accurate load model data and ongoing model updates

[131] White Paper Characteristics and Risks of Emerging Large Loads
[132] Note: The amount of voltage sensitivity, re-connection behavior, and system topology affect the likelihood of this risk.

Oscillations

The likelihood of a large impact (e.g., cascading or large number of generators tripping) due to large load oscillation(s) is probably low to moderate. However, the potential impact of such an event is extremely high. The likelihood of a small impact (single generator trip) due to a large load oscillation(s) is likely high because data centers are known to have oscillatory behavior and a significant portion of the overall system load in the future will be composed of large loads such as data centers. Additionally, the average size of these large loads in the future will also be very large, leading to a higher chance of impacts from data center oscillations. Because of these high-impact scenarios, the impact for the Oscillations Risk is categorized as **high.** Because the likelihood of the impact depends on the severity of the impact, the likelihood of a reliability impact from this risk is categorized as **moderate** to reflect both of the types of scenarios.

This risk cannot be adequately mitigated with existing registered entities. Existing registered entities in many areas actively monitor for oscillations in real time. It will likely be necessary for the large loads to collaborate with the registered entity to mitigate oscillations, but this collaboration can likely be achieved without Reliability Standards because the TOP has the ability to deny the large load permission to operate if it is causing oscillation issues. However, the reliability of the BPS cannot rely on detecting oscillations in real time and delayed operator response to preserve the reliability of the grid. Oscillations need to be mitigated before they occur so that they do not occur in real time. Detecting the oscillation risks before they occur is more challenging because of the lack of accurate large load model data and the fact that sub-synchronous resonance studies are very dependent on the quality of the large load models. Additionally, this risk needs to be considered on an interconnection-wide basis, not for single registered entities, as compounding frequency content injection across an interconnection can lead to severe consequences. Therefore, existing registered entities cannot adequately mitigate this risk. Large loads need to provide accurate modeling data, and Reliability Standard requirements on large loads are needed to enforce the provision of accurate load modeling data.

To adequately mitigate the Oscillations risk, the following is needed from new type(s) of registered entity(ies):

- Provide accurate load model data and ongoing model updates
- Ensure compliance with performance requirements (such as requirements from the TO, TP, or PC) to minimize and mitigate unintentional local area or interconnection-wide power oscillation interaction during normal and post-event conditions

Lack of Visibility of Disturbance Ride-Through Characteristics

The impact of the Lack of Visibility of Disturbance Ride-Through Characteristics risk is **high** because lack of disturbance ride-through can lead to frequency stability risks, voltage stability risks, or other risks. The likelihood of a reliability impact from this risk is **high** because it is well known that grid planners and operators often do not know the disturbance ride-through characteristics of large loads.

This risk can be mitigated with existing registered entities. Accurate model data for large loads is needed so that frequency stability can be accurately studied. Without accurate models, frequency stability may be at risk. This risk can be addressed by TOs if they have interconnection requirements that include model validation, model verification, commissioning testing, and other key requirements to ensure that the model data regarding disturbance ride-through characteristics is accurate.

Power Quality Risks

Voltage Fluctuations

The impact of the Voltage Fluctuations risk is **low** because voltage fluctuations (i.e., flicker) are known to not be a major issue for BPS reliability. The likelihood of a reliability impact from this risk is **low** because the likelihood of voltage fluctuations having an impact on BPS reliability is known to be low.

This risk can be mitigated with existing registered entities. This is not a significant impact to BPS reliability.

Harmonics

The impact of the harmonics risk is **low** because harmonics, even when above recommended limits, seldom cause generator damage directly impacting BPS reliability and seldom cause forced outages in BPS equipment. Additionally, the impacts from harmonics are generally localized. If it is found that harmonics, such as supraharmonics, caused by data centers cause more significant impacts to the BPS, this impact level could change. The likelihood of a reliability impact from this risk is **low** because mature and commonly used design practices and solutions exist for reducing the harmonics from electronic loads to below recommended limits.

This risk can be mitigated with existing registered entities. Interconnection requirements could address this issue. It is not a significant impact to BPS reliability, so NERC-enforceable requirements are not necessary. This can be adequately addressed with existing registered entities' policies.

Security Risks

Cyber Security of Large Load

Bad actors could induce many other high-impact risks through adversarial control which could bypass controls that mitigate other risks. If this occurred with multiple large loads, the impact from the cyber security of large load risk could be high. If this occurred with a single large load, the impact would likely be moderate. To reflect both scenarios, this Cyber Security of Large Load risk is categorized as **high** impact. The penetration of large loads on the BPS is growing, especially computational loads. Data sharing and collaboration are increasing, which increases the cyber security attack surface. Additionally, the adversaries are growing more capable. The likelihood of a high impact from this risk is low. The likelihood of a low impact from this risk is high. To reflect both scenarios, this risk is categorized as **moderate** likelihood.

This risk cannot be adequately mitigated with existing registered entities. Existing registered entities do not have adequate visibility of the large load asset owner's security protocols and practices to be able to appropriately provide requirements to mitigate the cyber security risks. Additionally, data is needed from the large load entities regarding their cyber security fabrics.

To adequately mitigate the Cyber Security of Large Load risk, the following is needed from new type(s) of registered entity(ies):

- Provide utility with site vulnerability/risk assessment and mitigate issues discovered in this assessment
- Notify utility (in close to real time) of security breaches

Cyber Security of Communications Between the Large Load and the Utilities

The impact of the Cyber Security of Communications Between the Large Load and the Utilities risk is **low** because data centers already have security practices. Existing registered entities already have NERC CIP standards in place as well. Data centers usually have tiered cyber security protection practices. Communication between the large loads and the DP, TO, TOP, BA, RC, or PC is usually going to be secure because data centers already have security practices, although the security practices may not be consistent across the industry. The tiered cyber security protection practices need to be extended out to the communication between the large loads and the utilities, and the cyber security practices for this communication should be designed in coordination with the utilities. The likelihood of a reliability impact from this risk is **low**. Some communication could be more impactful to BPS reliability, such as communication for demand response; however, this communication will likely involve more advanced security practices.

This risk can be mitigated with existing registered entities. This is a low-likelihood, low-impact risk. If needed, NERC standards can be written or modified, or guidance written, to address the cyber security risks posed by the large load to the BPS. If these standards were enforceable to existing registered entities (or the guidance addressed to existing registered entities), they could use their interconnection requirements and other processes to help ensure that the requirements in the standards or the recommendations in the guidance are followed.

Physical Security

The impact from the Physical Security risk is **moderate or high** because a physical security incident could result in some of the other BPS risks discussed in this chapter. The likelihood of a reliability impact from this risk is **moderate** because substations serving these loads may be easily accessible. Additionally, these incidents could be random targets.

This risk cannot be adequately mitigated with existing registered entities. While TO interconnection requirements could be used to help achieve the needed security protocols, lack of standardization across the BPS areas would lead to inadequate reliability. Although NERC standards applicable to the TOs could address this and the TOs could put these requirements in their interconnection requirements, the TOs may not own the substations and do not own the data centers. Physical security is not one-size-fits-all; design basis threats are used to design physical security systems and protocols. The responsibility for physical security will depend on the location. For example, the data center will have to be responsible for the security inside the data center and the TO might be responsible for the security outside of the data center (e.g., the substation).

To adequately mitigate the Physical Security risk, the following is needed from new type(s) of registered entity(ies):

- Provide utility with site vulnerability/risk assessment and mitigate issues discovered in this assessment
- Notify utility (in close to real time) of security breaches.

Load-Shedding & System Restoration Risks

Manual Load Shed Obligations

The impact of the Manual Load Shed Obligations risk is **high** because, for a situation in which a TOP or DP needs to shed a portion of a large load but the particular load is not able to be segmented, other issues, such as voltage instability, could be caused by the shedding of the entirety of the load. The likelihood of a reliability impact from this risk is **moderate** because the likelihood of needing to shed load to maintain reliability has increased due to significant generation and transmission expansion deficiencies, and a more constrained grid.

This risk can be mitigated with existing registered entities, although a more optimal solution could be reached if large loads were a registered entity.

Automatic UFLS Programs

The impact of the Automatic UFLS Programs risk is **high** because "UFLS programs are the last line of defense for BPS reliability."[133] If there is not enough load on the UFLS program, or the UFLS program does not function as expected to mitigate the frequency decline, then system-wide instability can occur, leading to cascading generator outages. The likelihood of a reliability impact from this risk is **low** because the chances of needing to use UFLS are low; historically, use of UFLS has been rare. With the current penetration, the likelihood of not having enough load on UFLS programs is low. However, with the load expected to be connected in the coming years, more load will need to be added to the UFLS programs; if load is not added, the risk may be higher. But again, the likelihood of needing to use UFLS is historically low.

[133] White Paper Characteristics and Risks of Emerging Large Loads

This risk can be mitigated with existing registered entities. Because shedding an entire large load simultaneously may cause stability concerns, there is a need to segment some large loads if they are on the UFLS program. This segmentation likely needs to be a requirement in the TO's interconnection requirements. Because this segmenting may lead to needing to have UFLS relays within the load, there may be situations where it is necessary for the large load to own UFLS relays and other related equipment. A non-registered entity owning UFLS equipment might be a risk. Therefore, the load entity might need to be registered as a UFLS-Only DP. However, none of this indicates a need to have a new type of registered entity. Additionally, there is a concern of having an inadequate amount of load on the UFLS program due to a significant amount of load being added to the system after the last PRC-006 UFLS design assessment. However, PCs can partially address this concern by reviewing their UFLS programs when large load interconnection requests are submitted to the TOs.

System Restoration

The impact of the System Restoration risk is **low** because large loads will not typically be energized early in the system restoration process.[134] The likelihood of a reliability impact from this risk is **low** because the likelihood of being in a restoration scenario is low.

This risk can be mitigated with existing registered entities. This is a low-likelihood, low-impact risk.

[134] Note: If the load was energized early in the restoration process, then this risk may be higher impact due to some large loads being known to rapidly change demand

Chapter 9: Conclusion

Addressing the Challenges and Shaping the Future

It is imperative that NERC and industry stakeholders prioritize the reliability of the grid to ensure that large loads can be connected in a reliable manner. The LLWG has identified critical reliability gaps across the lifecycle of large load integration from interconnection to long-term planning, operations, modeling, and security. Identifying and addressing these gaps will help ensure that the North American grid is ready to safely, reliably, and securely integrate these advancing technologies.

It is imperative that NERC and industry stakeholders prioritize the reliability of the grid to ensure that Large Loads can be connected in a reliable manner

This white paper identified the following critical items:

1. **Opportunities to enhance NERC Reliability Standards to better accommodate large loads**
2. **Gaps in existing standards and practices concerning large loads**
3. **The lack of a registered function attributable to large loads or BPS users specifically or to LSEs**

In addition to opportunities for reforming the interconnection process at the federal or state government level, the identified gaps and opportunities could also be addressed by enhancing Reliability Standards for existing registered entities as well as updating registry criteria and Reliability Standards for large loads and/or LSEs. Updates to registration criteria are needed so that Reliability Standards can be applicable to large loads and/or LSEs. These recommended updates would support a grid that can safely, reliably, and securely accommodate large load users of the BPS.

This paper serves as a foundational step in updating industry practices to address the challenges of integrating large loads into the evolving electric grid. Alongside the LLTF *Characteristics and Risks of Emerging Large Loads* white paper,[135] it performs Step 1 of the RSTC Standard Authorization Request (SAR) Process.[136] The RSTC or others may[137] consider developing SARs or other mitigating measures to mitigate the reliability gaps discussed in this paper.

Unveiling the Critical Gaps: A Path to Reliability

The following provides a summary of many notable gaps identified in this white paper. Additional details and gaps identified can be found in the applicable sections of this paper.

Interconnection Processes and Requirements Gaps

Current interconnection processes for large loads lack standardization in comprehensive study components and performance requirements to assess reliability impacts to the grid. In many cases, large load developers or LSEs do not provide accurate modeling and operational characteristics data. As a result, TOs and TPs often study these loads with limited visibility into their performance characteristics. Additionally, NERC Reliability Standards do not require TOs to establish specific interconnection requirements reflecting the needs of their respective BAs and RCs, leading to incomplete system impact assessments. The difficulty of studying large load performance is further compounded by the accelerated development timelines typical of large load projects, which frequently outpace necessary transmission upgrades, resource construction, or operational readiness.

Current interconnection processes for large loads lacks standardization in comprehensive study and performance requirements to assess reliability impacts

[135] Available here: White Paper Characteristics and Risks of Emerging Large Loads
[136] Available here: RSTC SAR Development Process clean Sept 20 2023.pdf
[137] *Ibid. See also*, the NERC Rules of Procedure regarding submittal of SARs.

Unlike generator interconnections, large load interconnections typically lack requirements for post-energization model validation, performance validation, or other information gathering. This results in a gap to assess real-time performance compared to planning and operational planning assumptions. Greater emphasis is needed in detailed modeling data and performance validation process to ensure that the large loads are adhering to the design and performance requirements. Additionally, there is a lack of collaboration and coordination between large load entities, utilities, and other entities. For example, there may be gaps in the coordination between grid operators/planners and the large load entities regarding important large load design decisions, such as those related to the facility's transfer to backup power supply and the return to utility during/after voltage disturbances.

Planning and Resource Adequacy Gaps

Many traditional long- and short-term planning processes may not account for the scale, uncertainty, and dynamic behavior of emerging large loads

Many traditional long- and short-term planning processes may not account for the scale, uncertainty, and dynamic behavior of emerging large loads. Unlike conventional load additions, many of these facilities energize incrementally over months or years, often deviating from initial development timelines and forecasted demand profiles. Current load forecasting methods lack well-established mechanisms to incorporate these long-term load ramping profiles, the impact of behind-the-meter generation or storage, and the potential for participation in demand-response or price-responsive programs. Although not all large load interconnection requests will materialize, there is no uniform guidance across the industry on when and how large loads should be integrated into planning studies. The absence of standardized input assumptions for these loads significantly impacts the accuracy of resource adequacy assessments. This gap increases the risk of misalignment between actual system needs and infrastructure procurement, potentially leading to under-investment in generation and transmission or investing in transmission infrastructure in the wrong locations. There is an opportunity for stronger coordination among planning entities and other entities and for improved accuracy. Additionally, a potential gap in Reliability Standard FAC-002 is that there is no requirement for resource adequacy to be checked before integrating a new large load onto the system or before the peak demand of an existing large load is increased.

Balancing and Operational Gaps

Large loads may exhibit sudden changes in power consumption under normal conditions or reduce demand during voltage or frequency excursions, leading to an imbalance between generation and load. Computational facilities are loads driven by power electronics and can be highly responsive to grid conditions and other signals. In fact, it is arguable that computational large loads essentially operate as controllable BES elements. As most large load users of the BPS are not NERC registered entities, they are not directly subject to coordination requirements with BAs (such as the requirements in Reliability Standard TOP-001). Furthermore, LSEs were also removed from the NERC registry criteria based on specific facts and circumstances approximately 10 years ago, so they are not subject to the coordination requirements with BAs. Without modifying the NERC registry criteria and Reliability Standards in order to have enforceable coordination requirements and other requirements for large loads, large load real-time operating behavior can result in ACE volatility and exhaustion of generation resources used for frequency regulation. Gaps may exist in the BAL-001, BAL-002, and BAL-003 Reliability Standards and associated processes as they do not fully address the risks related to balancing posed by large loads. For example, in the process associated with BAL-003, all BAs submit their largest credible generation contingencies, but this standard does not have a similar process for load loss contingencies. This generator loss information is used to determine the amount of frequency response required for the interconnection and for individual BAs. Operators often lack telemetry or observability into large load facilities,

As LSEs and most large load users of the BPS are not NERC registered entities, they are not directly subject to coordination requirements with BAs

resulting in a lack of situational awareness that can impact real-time decision-making. Additionally, gaps exist in requiring large loads to provide RCs/BAs/TOPs with the data necessary to perform reliable operations. Furthermore, as highly controllable and impactful facilities, gaps exist in that large loads are not obligated to establish interpersonal communication protocols with system operators nor be trained in critical reliability related tasks. Additionally, gaps may exist in the engineering practices related to checking operational readiness prior to energization of large loads. Examples of these practices include integrating new loads into modeling tools and energy management systems, and operational agreements covering communication for normal and emergency operations. There may also be a gap in IRO-017 and related practices in that this standard does not explicitly consider outages of large loads. Overall, many of the NERC standards related to planning, operations, and operations planning do not consider the impacts of large-scale ramping, disconnection, and reconnection events.

Disturbance Ride-Through, Stability, and Power Quality Gaps

Utilities do not always know the voltage and frequency disturbance ride-through characteristics of large loads, making it difficult to assess stability concerns. No existing NERC Reliability Standards provide requirements for voltage or frequency disturbance ride-through of large loads, and the lack of data on large load performance makes it difficult to study these loads. There is also a lack of coordination between existing registered entities and large loads on when a load should return to pre-disturbance demand levels after a voltage/frequency disturbance. Regarding existing registered entities, gaps exist related to the following:

Utilities do not always know the voltage and frequency disturbance ride-through characteristics of large loads, making it difficult to assess stability concerns

- Load models used and scenarios considered in transient stability studies
- Load modeling practices related to frequency and voltage stability studies
- Scenarios used for frequency stability studies.
- The impacts of large loads on UFLS and UVLS programs.

IEEE standards, such as IEEE 519, provide requirements for limiting harmonics and this standard can be applied to large loads. The limits, applicable to both voltage and current, are common to all interconnections without further coordination among them. However, the lack of coordination among different large load interconnections may create situations where individual projects are compliant with limits at their connection point but create non-compliance at other nodes in the system.[138] Furthermore, there are gaps in determining interharmonic limits.

There are also gaps in the modeling and practices related to converter-driven stability, resonance stability, and allowable limits for forced oscillations.

Security, Resilience, and Event Analysis Gaps

Large loads often deploy extensive cyber-physical systems, including private IoT infrastructure, that introduce opportunities for potential attacks by threat actors that are not addressed by current NERC CIP Standards. Because most large load facilities are not registered entities, they are not obligated to follow NERC CIP or PER Standards even though their size and connectivity may pose reliability risks. Additionally, with most not being NERC registered entities, these loads are not subject to post-event analysis reporting requirements. Large loads are also not subject to disturbance monitoring requirements in the NERC Reliability Standards; this may also be gap.

[138] In comparison, other jurisdictions, such as most European transmission system operators, provide individual harmonic emission limits to each customer enforced as part of the compliance process.

Large loads often deploy extensive cyber-physical systems, including private IoT infrastructure, that introduce opportunities for potential attacks by threat actors that are not addressed by current NERC CIP Standards

Modeling Gaps

Existing phasor domain load models do not adequately reflect the characteristics of large power electronic loads.[139] Data center UPS systems, hydrogen electrolyzer power supplies, and AI training facilities exhibit dynamic and nonlinear responses during system events. In many cases, even when a phasor domain or EMT model is developed, engineers lack the necessary parameter inputs or operational data to validate the models. EMT models may be required in weak grid conditions, but there is limited guidance or standardization on when or how to apply them to load studies. Additionally, model quality testing procedures are not used for large loads, increasing the risk of invalid or unstable models being used in planning or operational assessments.

In many cases, even when a phasor domain or electromagnetic transient (EMT) model is developed, engineers lack the necessary parameter inputs or operational data to validate the models

Risk Categorization and Mitigations

To determine the proper mitigation to address each of the gaps discussed in this paper, the relevant risk was categorized by likelihood and impact. Existing NERC registered entities cannot address many of the risks to the BPS from emerging large loads. Requirements are needed for additional entities (such as large loads, LSEs, or similar entities) to adequately address the risks, especially due to the severity of the risk.

Critical Reliability Recommendations

To ensure that large loads can be reliably integrated into the BPS, the LLWG recommends updating Reliability Standards and NERC registry criteria to reflect the electric grid of today and the future. Registry criteria for large loads and LSEs should be considered so that NERC Reliability Standards can be directly applicable. Reliability Standards modifications should be made for existing registered entities and large load entities. As discussed in this paper, many gaps exist in areas such as interconnection requirements, operations and balancing standards, and load modeling. Without updates to registry criteria, large loads and LSEs are not subject to Reliability Standards.

The LLWG recommends a combination of Reliability Standards updates, registry criteria revisions, educational material/guidance, and coordination with relevant stakeholders to help address the gaps identified in this white paper. The solution to address the gap may not always be to update the specific NERC standard, requirement, or process that has the gap. To tailor risk mitigation, the LLWG recommends a holistic and nuanced approach for the design of mitigation measures to ensure that the grid is ready to safely and reliably integrate emerging large loads. This approach needs to consider the likelihood of impact to the BPS from the risk and the severity of the impact. The NERC *Framework to Address Known and Emerging Reliability and Security Risks*[140] document provides direction regarding how the risks from emerging large loads should be addressed. The LLWG recommends that this document be utilized to determine appropriate risk mitigations. Applicable stakeholders should consider the gaps discussed in this paper and implement risk mitigations to address the risks posed by emerging large loads.

The following recommendations are offered as guidance to ensure the reliability and security of the BPS.[141]

[139] The EV charger model developed by the Electric Power Research Institute does allow for modeling some aspects of large power electronic loads. Additionally, the Power Electronic Reconnecting and Ceasing (PERC1) model allows for modeling some aspects of large power electronic loads.

[140] Available here: Framework to Address Known and Emerging Reliability and Security Risks

[141] See Chapter 8 for an analysis of the risk categorization and mitigations that led to the Recommendations 1–3.

Recommendation 1: Because there are multiple high-impact risks to the BPS from large loads that NERC registered entities cannot adequately address, the LLWG recommends that NERC pursue registration of a type of entity (or types of entities) that is able to perform the following regarding large loads:[142]

- Provide accurate short-term demand forecast data
- Provide sufficient data for applicable entities (e.g., RC, TOP, and BA) for the development of short-term demand forecasts and operating plans
- Provide accurate load model data and ongoing model updates
- Inform the TO and/or other applicable entities of any pertinent changes to the characteristics of the load before and after energization
- Perform real-time (and operations planning time frame) coordination with the TOP, BA, and/or RC, as applicable
- Comply with operating instructions from the TOP, BA, and/or RC, as applicable, and ensure appropriate training for receiving those instructions
- Ensure compliance with disturbance ride-through requirements
- Ensure compliance with ramp rate requirements (down ramp and up ramp)
- Provide accurate information (as accurate as possible and as early as possible) regarding large load dynamic model to support interconnection and transmission planning studies
- Provide TOs and/or other applicable entities with accurate information necessary for performing interconnection studies
- Coordinate with TOs and/or other applicable entities to establish a comprehensive commissioning process that ensures operational readiness
- Adhere to necessary operating protocols, communication protocols, etc.
- Ensure compliance with performance requirements (such as requirements from the TO, TP, or PC) to minimize and mitigate unintentional local area or interconnection-wide power oscillation interaction during normal and post-event conditions
- Provide utility with site vulnerability/risk assessment and mitigate issues discovered in this assessment
- Notify utility (in close to real time) of security breaches

Recommendation 2: The LLWG and other groups should propose SARs, including a SAR for adding a definition of "large load" to the NERC *Glossary of Terms*,[143] to address the following unmitigated risks to the BPS related to emerging large loads:[144]

- **Long-Term Planning Risks**
  - Resource Adequacy
  - Transmission Adequacy

[142] The findings of the NERC Level 2 Alert: Large Load Interconnection, Study, Commissioning, and Operations, distributed on September 9, 2025, will likely help provide more information regarding the need to pursue registration of an entity type (or types of entities).
[143] Available here: Glossary of Terms Used in NERC Reliability Standards
[144] NERC requirements written for large loads may need to be coordinated with NERC requirements for generation, such as in the case of a generator(s) and a large load facility being co-located with a common point of interconnection.

  - Long-Term[145] Demand Forecasting
- **Operations/Balancing Risks**
  - Short-Term[146] Demand Forecasting
  - Balancing and Reserves
  - Lack of Real-Time and Operations Planning Time Frame[147] Coordination
  - Lack of Proper Integration and Lack of Operational Readiness[148]
- **Stability Risks**
  - Frequency Stability
  - Voltage Stability
  - Angular Stability
  - Oscillations
  - Lack of Visibility of Disturbance Ride-Through Characteristics
- **Security Risks**
  - Cyber Security of Large Load
  - Physical Security
- **Load-Shedding Risks**
  - Manual Load Shed Obligations
  - Automatic UFLS Programs

Recommendation 3: The LLWG should identify potential mitigations to risks posed by emerging large loads through improvements to existing planning and operations processes and interconnection procedures for large loads as planned for the LLWG's work item titled *Reliability Guideline: Risk Mitigation for Emerging Large Loads*. This guideline should address the risks discussed in Recommendation 2 of this white paper as well as the following risks:

- **Power Quality Risks**
  - Voltage Fluctuations
  - Harmonics
- **Security Risks**
  - Cyber Security of Communications Between the Large Load and the Utilities

Recommendation 4: Registered entities should coordinate and collaborate with large load entities and update their practices to address the gaps discussed in this paper. The upcoming LLWG reliability guideline will help provide guidance on addressing the BPS risks posed by emerging large loads.

Recommendation 5: TOs should coordinate with TPs, TOPs, PCS, BAs, and RCs as applicable to update their interconnection requirements in a timely manner to address the gaps discussed in this paper, including coordination

[145] i.e., later than operational
[146] (operational)
[147] "Near-term" operations planning time frame
[148] See NERC Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations

and collaboration with large load entities. Additionally, PCs and TPs should update their interconnection study processes to address the gaps discussed in this paper.

Recommendation 6: The NERC Load Modeling Working Group should work to address the gaps in load modeling practices and scenarios to study as identified in this paper.

Recommendation 7: The NERC Security Working Group should further assess security gaps related to emerging large loads and propose mitigations for these gaps (including potential SARs).

Recommendation 8: The NERC System Protection and Control Working Group should further investigate any gaps related to system protection and control systems and propose mitigations for these gaps (including potential SARs).[149]

Recommendation 9: Federal and/or state regulators, as applicable, should consider the gaps identified in this paper and coordinate with utilities to assess whether incorporating additional interconnection requirements and/or studies are appropriate to reliably support integration of large loads. The LLWG supports federal and state efforts to enhance consistency in interconnection processes where possible. As of Fall 2025, the Federal Energy Regulatory Commission (FERC) is examining this question in Docket No. RM26-4.

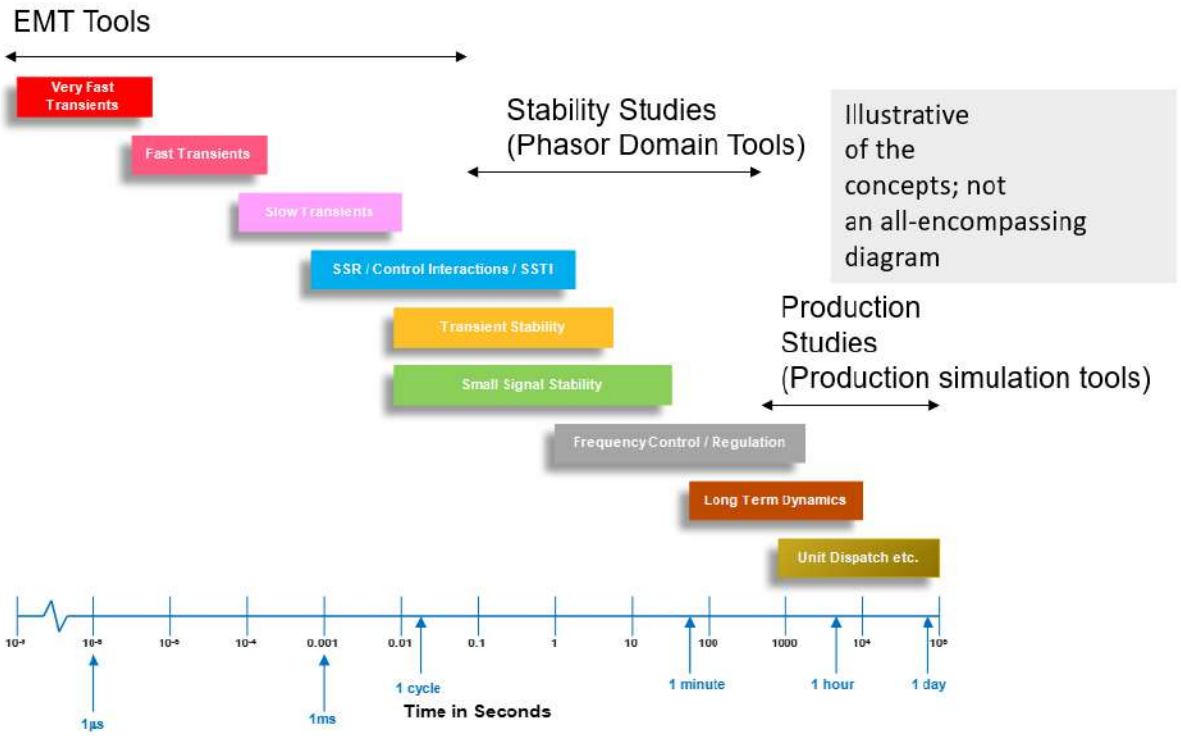
Recommendation 10: State regulators should work with regulated utilities to review how new loads and planned additional generation impact existing planning and risk assessment frameworks. States may need to adjust their resource adequacy criteria and/or work with their utilities on energy infrastructure expansion.

Recommendation 11: To ensure that adequate resources are added or in place to meet the needs of the BPS, policymakers should review interactions between interconnection requirements, existing state regulations and planning processes, and regional grid operator requirements. Additionally, policymakers should work to better understand the full impact of large load integration in their jurisdiction, and review requirements for large load customers to provide operational data and information to TOs, TOPs, TPs, and other entities.

[149] This white paper discusses gaps related to system protection in Chapter 2. However, additional gaps may exist, and further work is needed to assess the extent of the gaps and provided recommendations to address the gaps.

Appendix A: Phasor/Time Domain Simulation Tools, Modeling Terminology, and Applications

The use cases of various simulation tools are provided in **Figure A.1**.



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Figure A.1: Simulation Tool Applicability Based on Dynamics Being Simulated

Terminology related to models and modeling platforms is provided below:

1. **Phasor Simulation Tools and Models:**
   a. **Purpose**: Used to study reliability risks related to slower local and inter-area oscillatory dynamics, angular and voltage stability, and unacceptable voltage and frequency excursions resulting from unexpected loss of large load during grid disturbances and unexpected load ramps.
      - **Characteristics**: These tools use simplified models to study bulk system reliability impacts, which are generally slower frequency events. Models in positive sequence platforms need to be reasonably accurate without being computationally burdensome. For example, the composite load model, with about 130 parameters, already slows down simulations for large interconnections. New large load models should not significantly add to the existing computational burden while still accurately modeling the phenomena of interest.
2. **EMT Simulation Tools and Models:**
   a. **Purpose**: Used to study reliability risks related to faster dynamics, such as subsynchronous resonances and interactions, ferroresonances, switching transients, and harmonic stability assessments.
   b. **Characteristics**: EMT models are significantly more detailed than phasor models, including faster controls and the switching of power electronic devices for certain evaluations. EMT studies typically involve detailed models of the local system connected to an external system. Due to their high level of detail,

EMT models and tools are generally not used for bulk system analysis, although some utilities maintain EMT models for their entire footprints. Most utilities use EMT studies for screened parts of the system where the reliability challenges can only be captured by modeling the faster dynamics systems, (e.g., phase-locked loop instability for weak grids, subsynchronous interactions).

3. **Generic and Original Equipment Manufacturer (OEM) Models:**

   a. **Generic Models**: Representations of power system equipment based on the basic physics of the device being modeled, covering key stability and control features common to most manufacturers. These models do not include proprietary control methods and are well documented. They are useful for long-term transmission planning studies where equipment manufacturers are not yet decided. OEMs may parameterize these models to reflect their device's dynamic performance and submit them to the relevant TP.

   b. **OEM Models**: Developed by OEMs to reflect the controls and dynamics of their own equipment, including proprietary controls. These models are often black-boxed to protect intellectual property and are submitted as user-defined library-linked models, with modeling details hidden from the TP. OEM models are used when generic models cannot sufficiently replicate the behavior of the equipment. OEM models can be in either the phasor domain or EMT.

Appendix B: NERC Standards and Applicable Sections

Table B.1 provides a list of the NERC Reliability Standards that are discussed in this paper and the paper sections (excluding the **Conclusion** chapter) in which these standards are discussed:

Table B.1: NERC Reliability Standard Discussions

Relevant Paper Chapter	Standard[150]
Chapter 2: Interconnection Processes and Requirements	FAC-001
	FAC-002
Chapter 3: Planning and Resource Adequacy	BAL-502-RF
	FAC-002
	MOD-031
	MOD-032
	TPL-001
Chapter 4: Balancing and Operations	BAL-001
	BAL-002
	BAL-003
	BAL-007
	COM-001
	COM-002
	FAC-002
	FAC-011
	IRO-008
	IRO-010
	IRO-017
	PER-005
	TOP-001
	TOP-002
	TOP-003
	TPL-001
Chapter 5: Disturbance Ride-Through, Stability, and Power Quality	BAL-003
	FAC-001
	FAC-002
	MOD-032
	PRC-006
	PRC-010
	PRC-019
	PRC-024
	PRC-028
	PRC-029
	TPL-001
Chapter 6: Security, Resilience, and Event Analysis	CIP-004

[150] The NERC Reliability Standards can be found here: Reliability Standards

Table B.1: NERC Reliability Standard Discussions	
Relevant Paper Chapter	**Standard[150]**
	CIP-006
	CIP-007
	CIP-008
	CIP-014
	EOP-004
	PER-003
	PER-005
	PER-006
	PRC-002
	PRC-028
Chapter 7: Modeling of Large Loads	MOD-026
	MOD-027
	MOD-033
Chapter 8: Risk Categorization and Mitigations	FAC-001
	FAC-002
	PRC-006

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DRAFT

Large Load Disturbance Performance

Impact Analysis and Ride-Through Recommendations

December 10, 2026

DRAFT

Table of Contents

Preface iv
Executive Summary .....
Essential Insights: Key Reliability Recommendations .....
Introduction .....
Intended Audience .....
NERC Large Loads Working Group .....
Definitions .....
Chapter 1 : Customer-Initiated Load Reduction Events 1
Events in Northern Virginia 1
July 10, 2024 Event 2
February 2025 Event 3
May and June 2025 Events 3
Data Center Behavior 3
Effects on BPS Reliability–July 2024 Event 5
Mitigations Implemented 7
Events in Texas 8
Cryptocurrency Mining Customer-Initiated Load Reductions 8
Effects on BPS Reliability 11
Mitigations Implemented 11
Events Near Columbus, Ohio 11
February 9, 2025 Event 11
February 20, 2025 Event 11
March 11, 2025 Event 12
Mitigations Implemented 12
Events in Ireland 12
Effects on Grid Reliability 13
Mitigations Implemented 13
Chapter 2 : Large Load Facility Characteristics Affecting BPS Reliability 14
Load Site Protection and Transfer to Backup Generation 14
UPS Versus Non-UPS Configuration 14
Centralized vs. Decentralized UPS Control 15
Battery Energy Storage Systems 16
Large Load Constant Current and Constant Power Behavior 16

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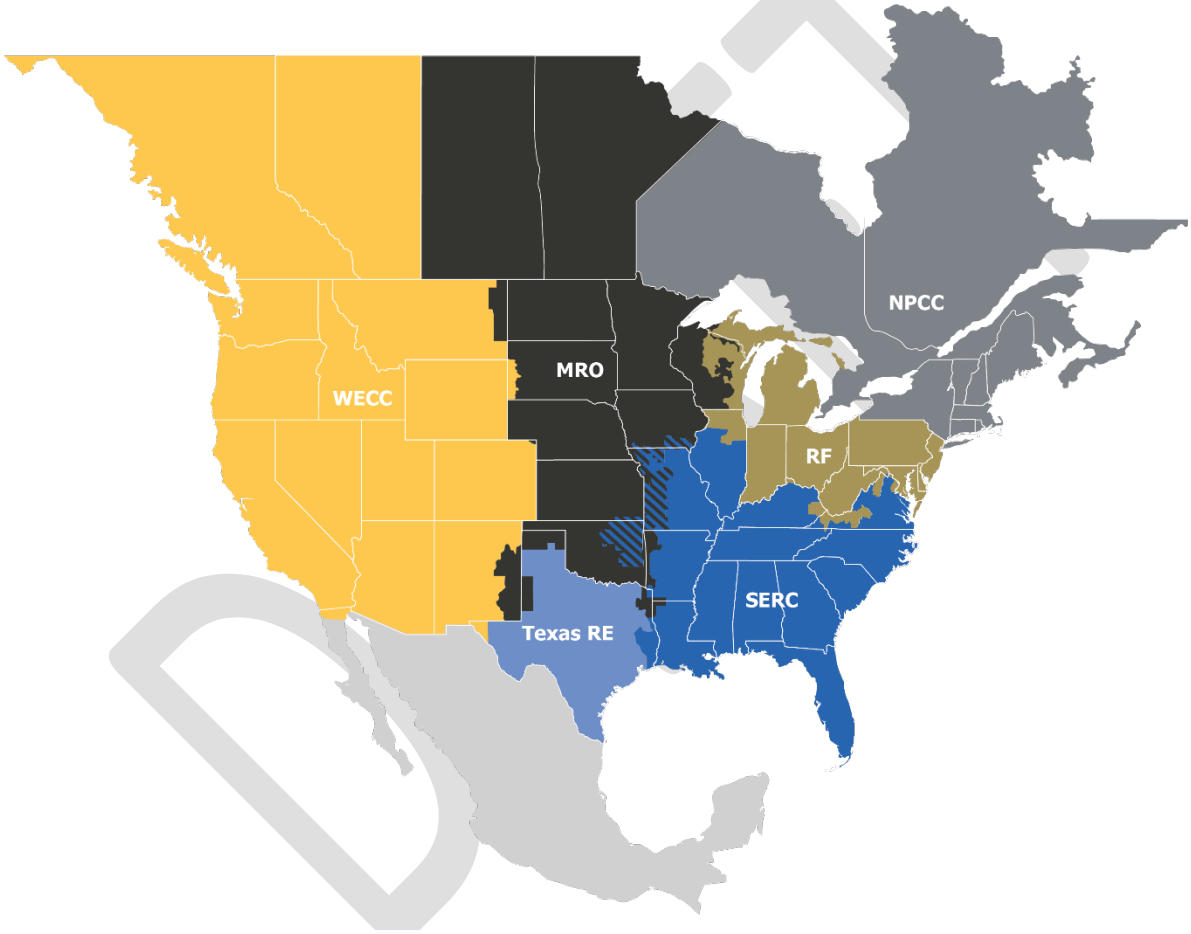
Impact of Load Characteristics on Disturbance Performance and Post-Fault Recovery 17
Cooling Load 18
Type of Load 18
Size of Load 19
Transformer Winding Configuration 20
Chapter 3 : Grid Attributes Affecting Large Load Disturbance Performance 22
System Strength and Other Local Grid Characteristics 22
Interconnection Voltage Level 23
Proximity to Generation 23
Protection Methodology 23
Size of Interconnection 24
Balancing Authority's Ramp Rate Capabilities 24
Type of Disturbance 24
Length of Disturbance 25
Voltage Management Technology/Philosophies 26
Chapter 4 : Considerations for Disturbance Performance and Post Fault Active Power Recovery Requirements 27
Industry Review of Existing Requirements 27
Considerations for Voltage Ride-Through Requirements 28
Considerations for Multi-Disturbance Ride-Through and Consecutive Event Survivability 31
Considerations for Post-Fault Active Power Recovery 31
Considerations for Frequency Ride-Through Requirements 33
Recommended Frequency Ride-Through Requirements 33
Ride-Through Requirements for Co-Located Generation 34
Retroactivity and Applicability to Existing Sites 37
Recommended Voltage Ride-Through and PFAPR Requirements 38
Chapter 5 Other Considerations for Customer-Initiated Load Reduction Impacts 40
Grid-Side Mitigations 40
Managing CILR: Operational Tools, Telemetry and Event Analysis 40
Largest Load Loss at Interconnection- or Balancing Authority-Level 41
Chapter 6 Conclusion 43
NERC Event Analysis Program Review of Large Load Performance Events 43
Critical Reliability Recommendations 44
Appendix A : Acknowledgements 46
Appendix B : Columbus, Ohio Area Events 47

Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

NERC has identified that large load ride-through and ramping characteristics are a risk to BPS reliability and that the lack of predictable ride-through performance for large loads is a reliability gap.[1] NERC, through its Reliability and Security Technical Committee, commissioned the Large Loads Working Group (LLWG) to provide a better understanding of the reliability risks when large loads reduce demand during normal disturbances as well as the factors that affect the risks.

As the volume of large loads on the BPS continues to grow, the frequency of customer-initiated load reduction (CILR) events also continues to grow. These events pose a reliability risk to the BPS as computational load sites behave in ways that for the grid was not originally designed for. This paper analyzes the disturbances that have occurred and factors that impact large load performance during disturbances. These include factors within the large load site and the properties of the BPS itself.

Based on the analysis of the data from disturbances that have occurred, the dynamic responses of computational loads to voltage disturbances vary from site to site; and the risks posed by computational loads related to ride-through and post fault active power recovery also vary from site to site. Minimum requirements for ride-through and post-fault active power recovery (PFAPR) are needed to address these new reliability risks.

Essential Insights: Key Reliability Recommendations

The following is a summary of the LLWG recommendations based on the gaps assessed in this paper. The detailed list of recommendations can be found in the **Conclusion**.

Recommendation 1: NERC Reliability Standards should define a minimum technical capability floor for computational load voltage ride-through (VRT) and PFAPR while allowing regional or local modification where system-specific analysis demonstrates a need for more stringent requirements.

Recommendation 2: NERC Reliability Standards should establish frequency ride-through (FRT) and rate of change of frequency (RoCoF) requirements for computational loads, based on IEEE 2800[2] and PRC-029-1[3] requirements.

Recommendation 3: Regional transmission organizations (RTO), independent system operators (ISO), and utilities should perform detailed dynamic simulations to determine if more stringent VRT requirements or if modified PFAPR timing requirements are needed for specific computational load interconnections.

Recommendation 4: NERC Reliability Standards should require computational load sites above a defined capacity threshold to provide verified and validated dynamic load models calibrated to actual site characteristics.

Recommendation 5: BAs and reserve sharing groups with significant concentrations of computational loads should evaluate whether their operating reserve requirements are adequate to manage the largest credible cluster-level CILR event. Reliability coordinators should additionally review UFLS program designs to confirm that CILR events are reflected in the load availability assumptions underlying set-point calculations.

[1] Characteristics and Risks of Emerging Large Loads
Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads
[2] IEEE 2800-2022
[3] PRC-029-1

Recommendation 6: Ride-through and PFAPR requirements should include a tiered applicability structure that addresses the existing installed base rather than applying exclusively to new sites entering the interconnection queue.

Recommendation 7: Large load sites sharing a common POI with co-located generation should be modeled as integrated units in interconnection and planning studies to identify worst-case net POI power swing scenarios.

Recommendation 8: The NERC Event Analysis Subcommittee should expand the scope of the EAP[4] to include analysis of large load behavior during grid disturbances.

DRAFT

[4] ERO Event Analysis Process (EAP) - Version 5

Introduction

Intended Audience

This paper is intended for the following NERC registered entities, external entities, and broader groups:

- Planning Coordinators (PC)
- Resource Planners (RP)
- Transmission Planners (TP)
- Transmission Owners (TO)
- Transmission Operators (TOP)
- Distribution Providers (DP)
- Balancing Authorities (BA)
- Reliability Coordinators (RC)
- Large Load Developers, Owners, Operators, or Other Related Companies
- Generator Owners (GO)
- Generator Operators (GOP)
- Load-Serving Entities (LSE)
- Reliability and Security Technical Committee (RSTC) Subgroups
- FERC
- State Regulators and Other Regulatory Entities
- Consumer Advocates

NERC Large Loads Working Group

The LLWG aims to provide ongoing technical guidance, industry collaboration, and reliability risk assessment and monitoring for the increasing integration of large, complex, and rapidly evolving loads including data centers, cryptocurrency mining, hydrogen production facilities, and other large loads that may present risk to the BPS.[5]

Definitions

- **Large Load:** "Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors. Examples include, but are not limited to, data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces."[6]
- **Computational Load:** Large loads that are data centers (including AI, inference, traditional, and others) or cryptocurrency mining facilities.
  - This paper uses the term computational load to describe the physical end-use load equipment owned and operated by the entity or entities that will eventually be required to register with

[5] Large Loads Working Group Scope
[6] Characteristics and Risks of Emerging Large Loads

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NERC (aligning with the description of data centers and other computational loads in the white paper *Characteristics and Risks of Emerging Large Loads*). This term is not meant to align with the initially proposed Rules of Procedure update[7] that includes the capitalized term "Computational Load Entity" and describes the general entities that own and operate the end-use loads. This paper recognizes that NERC's Rules of Procedure changes are ongoing and also subject to change.

- **Ride-Through:** The ability of a large load site to remain electrically connected to the BPS and to continue consuming some level of active power from the BPS during and following a voltage or frequency disturbance within defined magnitude and duration thresholds, without disconnecting, transferring to backup generation, or otherwise reducing consumption outside of allowed limits in a manner that adversely affects BPS reliability. Ride-through encompasses the following:
  - Low voltage ride-through (LVRT), in which the site withstands undervoltage conditions
  - High voltage ride-through (HVRT), in which the site withstands overvoltage conditions.
  - Low frequency ride-through (LFRT), in which the site withstands underfrequency conditions.
  - High frequency ride-through (HFRT), in which the site withstands overfrequency conditions.
- **Post-Fault Active Power Recovery (PFAPR):** The process by which a large load site that temporarily reduced or interrupted its consumption from the BPS during or following a disturbance restores that consumption to pre-disturbance levels within a specified time and at a specified ramp rate after BPS conditions have recovered. PFAPR requirements are a necessary complement to VRT requirements. While VRT governs whether a site remains connected during a disturbance, PFAPR governs how quickly and in what manner the site restores demand once the disturbance has cleared. PFAPR obligations apply both to sites that reduced consumption proportionally while remaining connected and to sites that fully transferred to backup generation, though the specific timing requirements may differ between these two cases.

Disturbance performance can mean multiple things as shown in **Table 0.1**. This paper addresses the performance of large load sites with respect to voltage ride-through (VRT), frequency ride-through (FRT), PFAPR, multiple disturbance ride-through and consecutive event survivability, and protection coordination.

Table 0.1: Disturbance Performance Metrics

Metric	Addressed in This Paper?
Voltage Ride-Through	Yes
Frequency Ride-Through	Yes
Rate of Change of Frequency (RoCoF) Withstand Capability	No
Ramp Rate Management	No
Oscillation Damping	No
Post-Fault Active Power Recovery	Yes
Voltage Control and Reactive Power Management	No
Phase Angle Withstand Capability	No
Multiple Disturbance Ride-Through and Consecutive Event Survivability	Yes
Protection Coordination	Yes

[7] Summary available here: computational-load-entity-summary-of-changes-april-2026-posting.pdf

Chapter 1: Customer-Initiated Load Reduction Events

Notable events on the BPS that involve computational load ride-through issues have been occurring for years (see **Figure 1.1**). Events in ERCOT have occurred since January 2023 with regularity, especially starting in late 2023. Significant events have occurred in Dominion Energy Virginia's (DEV) territory starting in July 2024. Events have also occurred in AEP's Ohio area starting in 2025. As with past events related to inverter-based resource (IBR) ride-through issues, much can be learned from the events that involve computational loads.

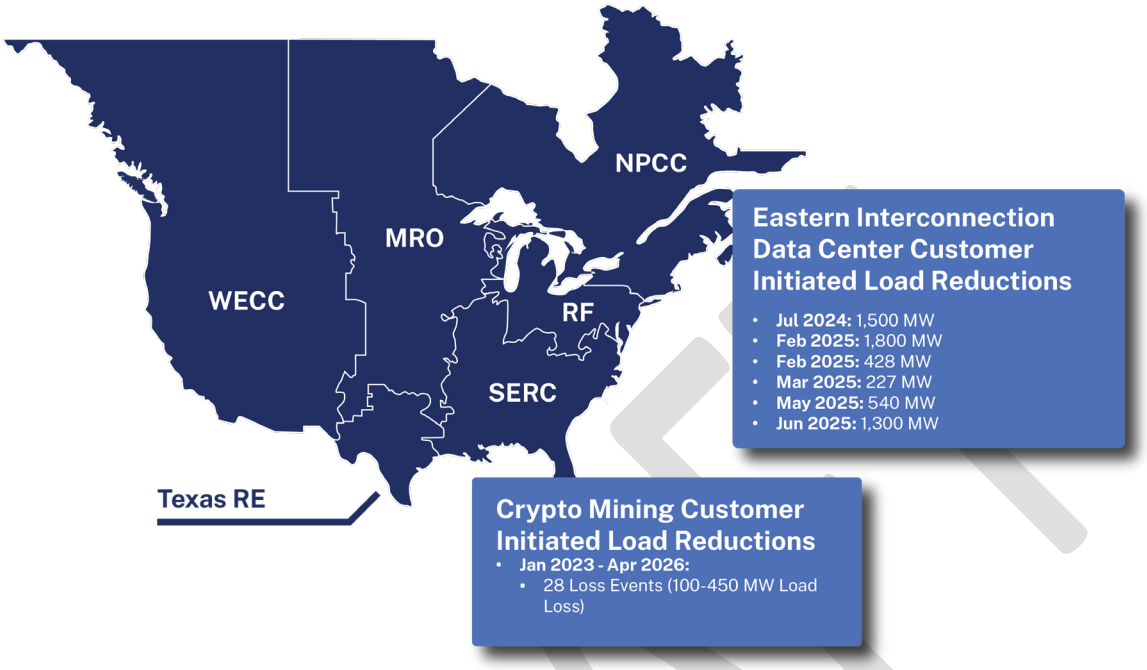


Figure 1.1: Computational Load Customer-Initiated Load Reductions

Events in Northern Virginia

As of April 2026, Northern Virginia has one of the highest concentrations of data center load in the world, comprising primarily conventional data centers rather than AI-focused computing campuses or cryptocurrency mining sites. DEV, which serves most of this area, continues to project significant load growth driven by new and expanding data center developments. PJM's load forecast also identifies the Dominion zone as an area of substantial growth in data center demand.[8]

Electrically, Northern Virginia is a strong portion of the BPS. The area is served by a highly meshed transmission network with multiple 230 kV and 500 kV facilities, providing strong electrical coupling to the PJM system and the Eastern Interconnection more broadly. Given the large geographic span of the Eastern Interconnection and the substantial concentration of synchronous generation across its footprint, Northern Virginia generally exhibits strong voltage performance, high short-circuit strength, and stable frequency response under both normal and contingency conditions.

Despite these characteristics, recent computational load transfer events in DEV have highlighted an emerging reliability concern. These are specified as load transfer events because the load is not electrically disconnected from the BPS due to the system event. However, the individual loads perform a CILR by

[8] 2025 PJM Long-Term Load Forecast Report

transferring to long-term backup energy supplies, and this transfer to backup sources appears as a reduction of load to the BPS.[9]

July 10, 2024 Event

NERC partnered with DEV to develop an incident review titled, "Considering Simultaneous Voltage-Sensitive Load Reductions," which focused on the DEV July 10, 2024 event.[10] The event was initiated by the failure of a lightning arrestor on a 230 kV transmission line, resulting in a single-line-to-ground (SLG) fault. The transmission protection system operated as designed, and the line was subject to an automatic reclosing sequence. Per the NERC incident review, the auto-reclose scheme was configured for three staggered reclosing attempts at each line terminal, resulting in six successive fault applications within approximately 82 seconds before the line ultimately locked out. The fault and reclosing sequence did not directly disconnect the affected data centers from the BPS. However, the associated voltage disturbances caused a substantial amount of voltage-sensitive data center load to transfer to backup generation through customer-side controls and protection systems. The event resulted in approximately 1,500 MW of sustained simultaneous data center CILR for several hours after the initial fault. However, some sites that were at the same substation as sites which experienced CILR did not transfer to backup generation. Additionally, there were sites which decreased load temporarily and ramped back to full output over seconds following the voltage depression. **Figure 1.2** and **Figure 1.3** show the responses of two data centers connected to the same substation. The site in **Figure 1.2** rode through the fault, while the site in **Figure 1.3** temporarily reduced load before ramping back to full output over several seconds after each voltage depression.

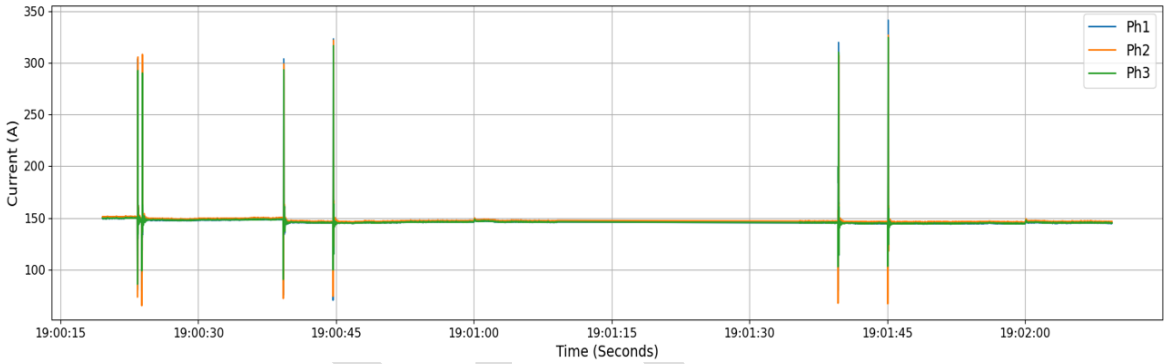


Figure 1.2: Data Center Site Successfully Riding Through the Disturbance Without Load Reduction

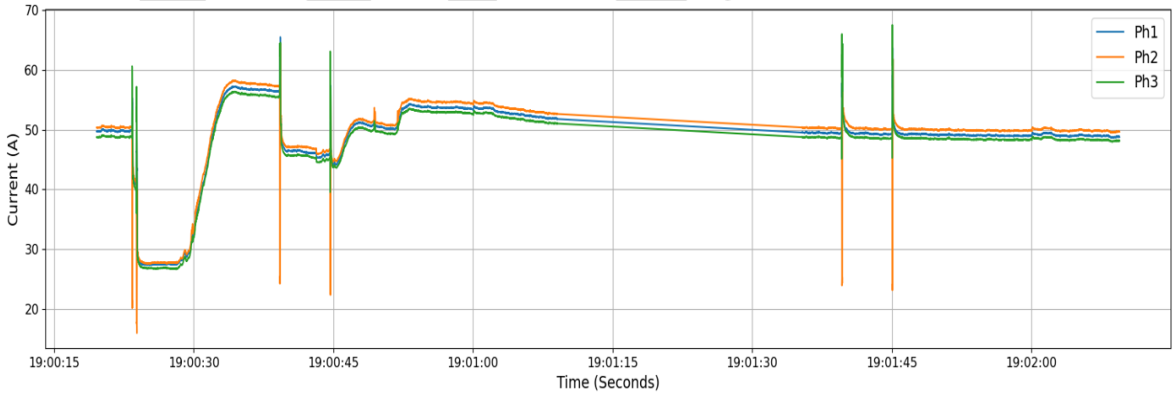


Figure 1.3: Data Center Site Exhibiting Temporary Load Reduction in Response to Voltage Depressions

[9] See "Possible Misunderstandings of the Term "Load Loss""

[10] Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions

February 2025 Event

Similarly to the July 10, 2024 event, the February 17, 2025 disturbance was initiated by a sustained SLG fault on the 230 kV transmission system. Unlike the July 10, 2024 event, one terminal locked out immediately while the opposite terminal completed its auto-reclosing sequence, resulting in four voltage depressions across the area that were observed at the affected data center sites. The protection system operated correctly; however, the fault clearing time was approximately 5.9 cycles, which was longer than typical due to the use of electromechanical relaying.

Although service to the affected sites was never interrupted, approximately 1,800 MW of data center CILR occurred during the reclosing sequence, affecting 18 substations and 44 transformers. As with the July 10, 2024 event, most of the CILR occurred after the third voltage depression, although some sites briefly transferred some of their load off the BPS during each of the voltage depressions and ramped back to pre-fault load within seconds or minutes without switching to their backup generation. Additionally, some sites did not decrease their load after each voltage depression.

May and June 2025 Events

In addition to the previously described events, DEV has observed other data center CILR events in Northern Virginia. However, the notable differences are their magnitude and restoration characteristics, which varied from seconds to minutes.

On May 3, 2025, approximately 540 MW of data center CILR occurred, with most of the affected load reconnecting within 15 to 20 minutes. This event was associated with a line-to-line fault on the transmission system. Under normal circumstances, only two voltage depressions would have been expected because the line locked out after the instantaneous reclosing attempt. However, three voltage depressions were observed within approximately one second because the slower response of an electromechanical relay at one terminal during the instantaneous reclose caused the breaker operations at the line terminals to be non-simultaneous. The fault clearing time was approximately 5.9 cycles, consistent with the slower operating characteristics of the electromechanical relay technology in service at that time.

On June 19, 2025, approximately 1,300 MW of data center CILR occurred. In this event, one terminal completed its reclosing sequence while the opposite terminal locked out instantaneously because the automatic reclosing was blocked while work was being performed on the energized line. Unlike the other events described earlier, the initiating disturbance involved a three-phase fault during the first reclosing attempt that subsequently evolved into a high-resistance SLG fault. Only two significant voltage depressions were observed within one second as the later reclosing attempts produced less severe voltage disturbances because of the resistive nature of the evolved fault. A significant portion of the affected load reconnected in less than one minute.

Data Center Behavior

Because of high-fidelity monitoring installed at many of the points of interconnection (POI) next to the revenue meter for these large loads, DEV was able to perform detailed root cause analysis on the behavior of individual sites impacted by different faults in the Northern Virginia area. In addition to the POI monitoring, a vast network of synchrophasor data and fault recorders on the transmission network helped in understanding the larger system response and how different BPS-connected devices operated during these events including, but not limited to, system frequency changes and static VAR compensator (SVC) and generator responses.

DRAFT

NERC's incident review "Considering Simultaneous Voltage-Sensitive Load Reductions" indicates that site response to voltage disturbances varies across data centers.[11] DEV's review of all the events indicates that even if multiple sites have a common owner, the individual sites can behave differently even when exposed to very similar voltage depressions. However, most sites owned by the same entity generally perform similarly across their buildings or campuses. Load can react differently from one event to another based on the specifics of the fault and voltage signature experienced by the site. For example, **Figure 1.4** and **Figure 1.5** are the voltage and current profiles of the different responses of a specific data center during the May and June 2025 events. During the May 2025 event, there was approximately 20% CILR, and the load recovered within about 5 minutes, despite a minimum phase voltage of 0.7205 pu and a maximum sag duration of 67 ms. However, the site performed a CILR of its full load during the initial fault during the June 2025 event. During this event, the minimum phase voltage was higher at 0.7538 pu with a maximum sag duration of 75 ms.

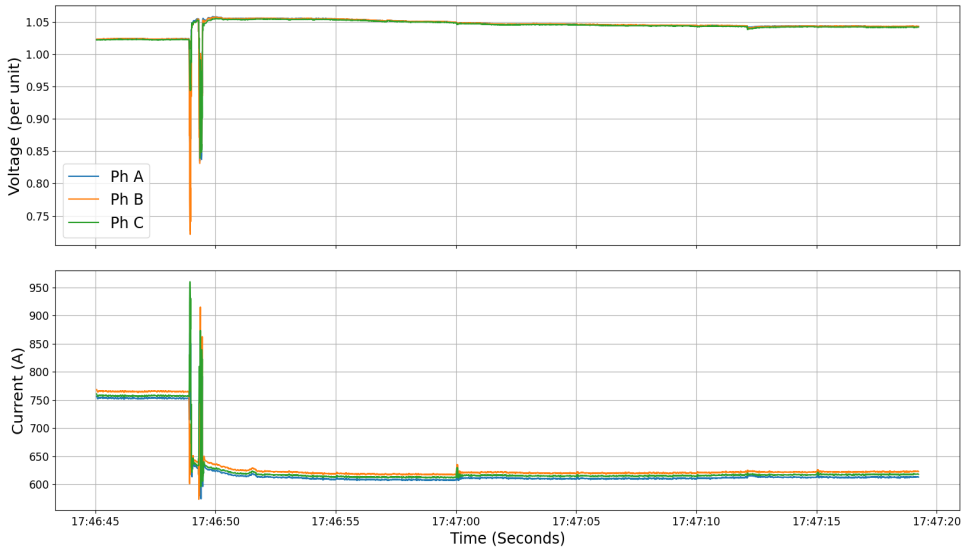


Figure 1.4: Data Center Voltage and Current Profile During May 3 Event

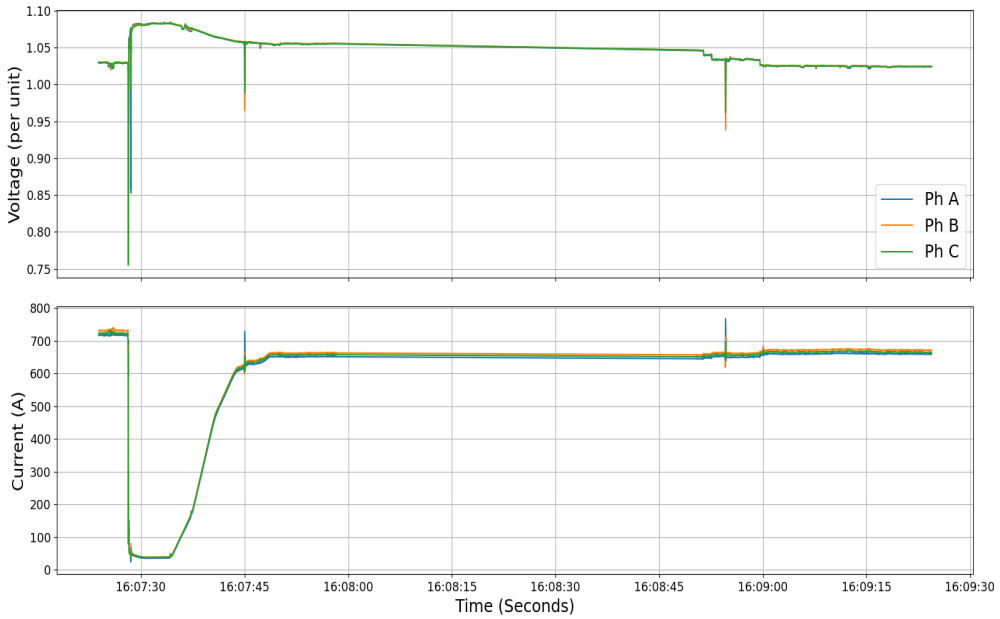


Figure 1.5: Data Center Voltage and Current Profile During June 19 Event

[11] Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions

Effects on BPS Reliability–July 2024 Event

The sudden CILR produced the expected BPS response, including a measurable frequency deviation, a change in area control error (ACE) and a localized overvoltage condition associated with the abrupt reduction in power transfer and reactive demand. As highlighted in the **System Characteristics** section, Northern Virginia is electrically strong because it is deeply embedded within the Eastern Interconnection and served by a highly meshed transmission network. Even so, the abrupt loss of load resulted in a frequency deviation as shown in **Figure 1.6**, but the frequency remained within acceptable operating limits. The frequency then gradually returned toward its pre-disturbance value as generator governors responded to the generation-load imbalance.

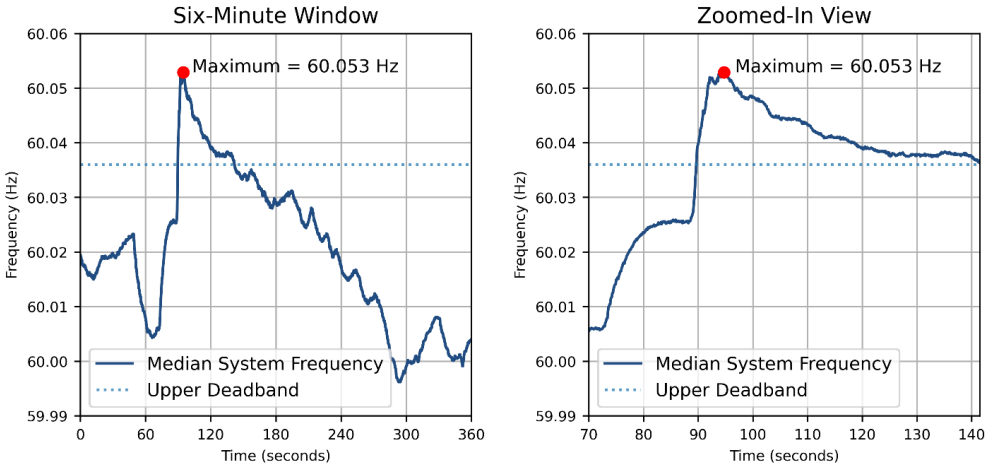


Figure 1.6: Eastern Interconnection Over-Frequency Following Customer-Initiated Load Reductions on July 10, 2024 (Source: University of Tennessee: Knoxville)

Contrary to the frequency response that remained within normal operating limits and recovered through normal governor action, the voltage response was more operationally significant and required additional local mitigation. While nearby SVCs and generators responded automatically to the disturbance, these responses alone were not sufficient to fully mitigate the post-transfer voltage swell. **Figure 1.7** shows the response of a representative SVC, and **Figure 1.8** shows the reactive power response of a nearby generator. However, as shown in **Figure 1.9**, elevated voltages persisted at several substations, necessitating additional reactive switching actions by the DEV's system operators, including energizing shunt reactors and removing capacitor banks from service, to restore voltages within the normal operating range.

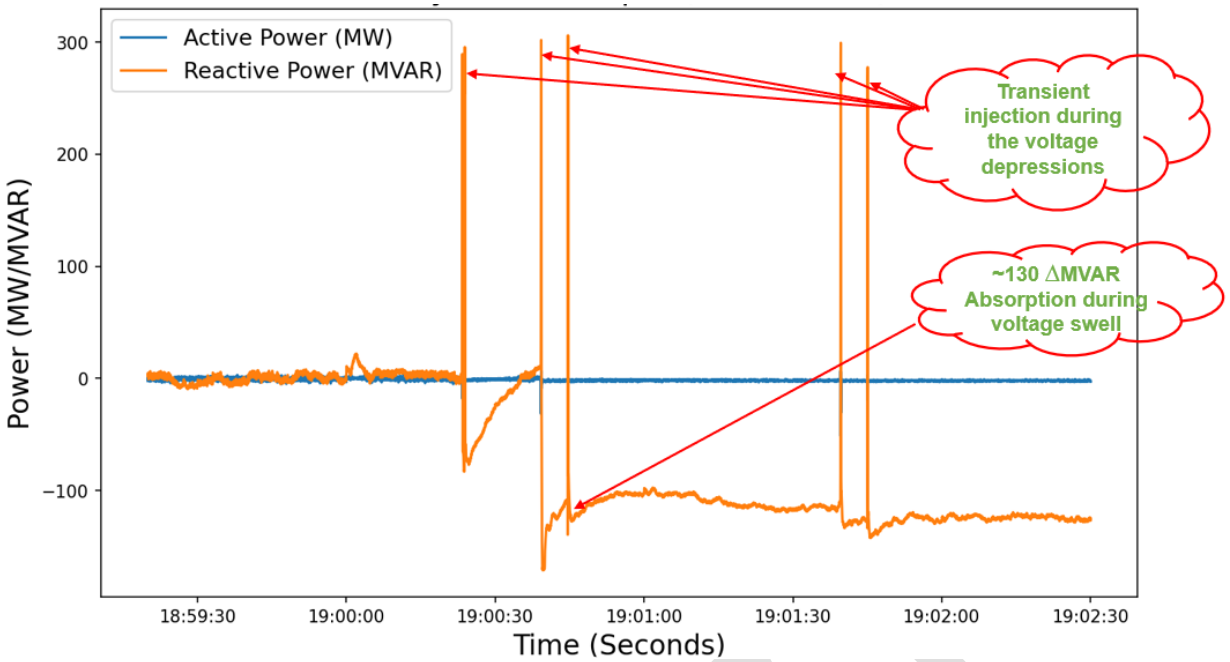


Figure 1.7: Active and Reactive Power Plot of a Static VAR Compensator

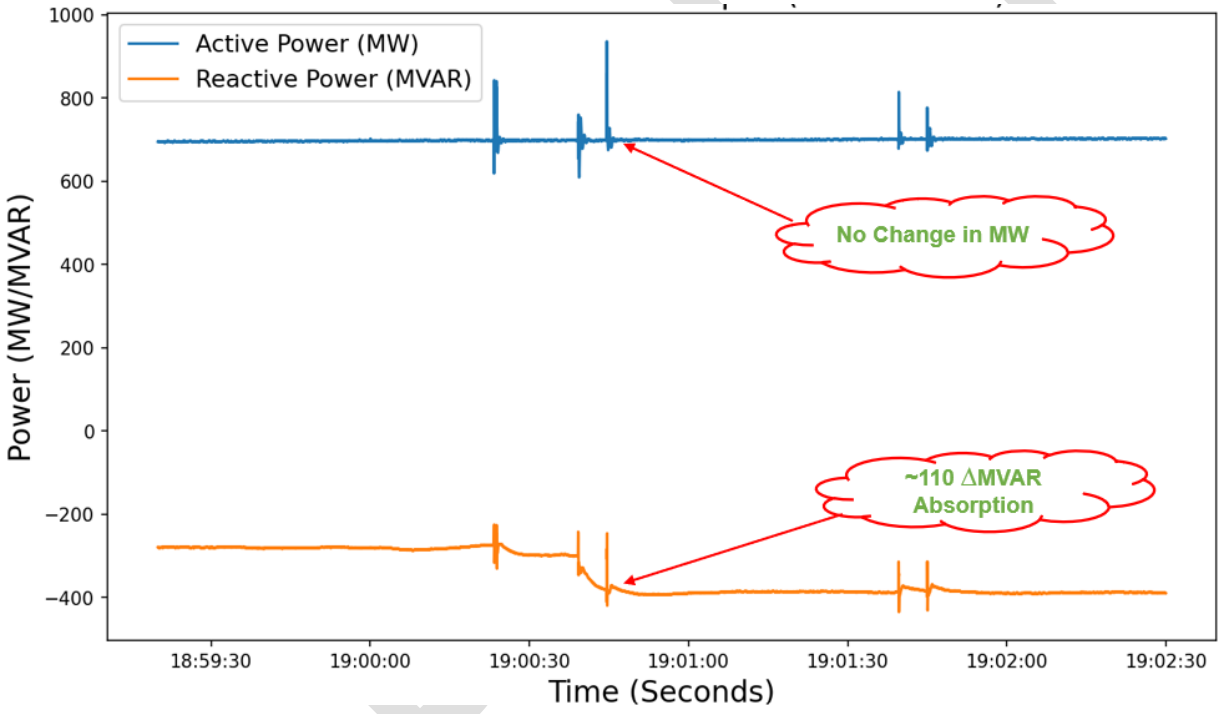


Figure 1.8: Plot of Active and Reactive Power at Generator Bus

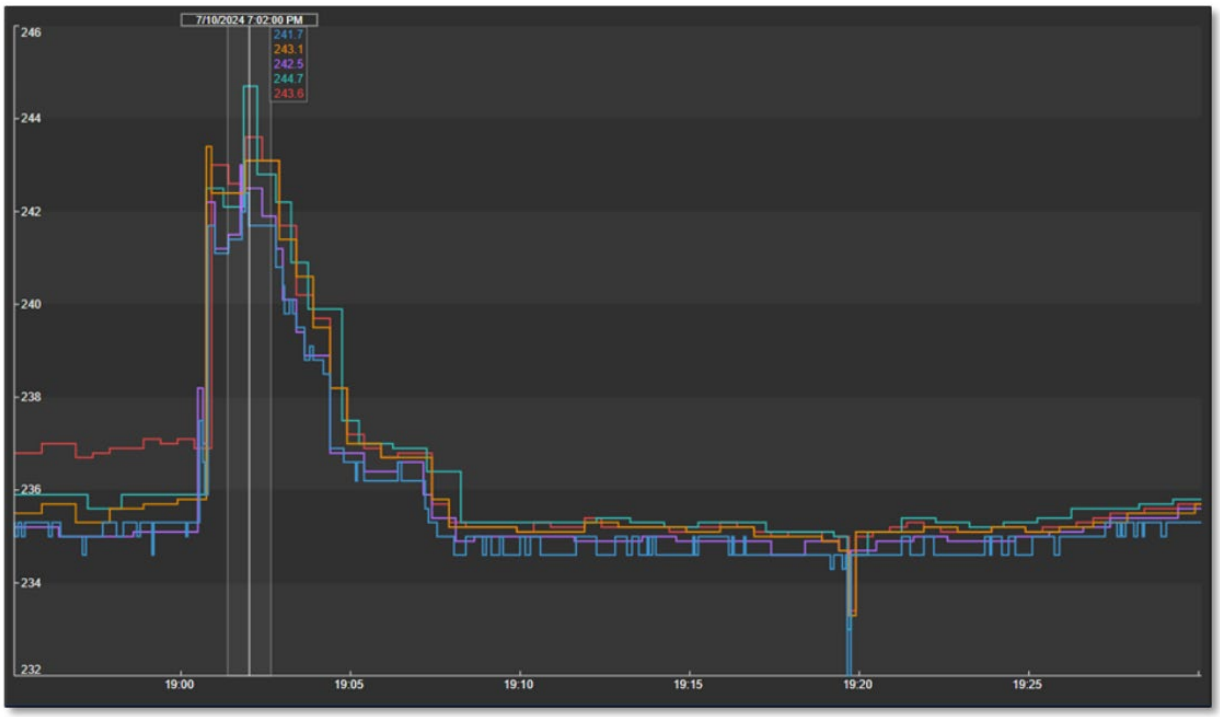


Figure 1.9: Voltage Profile Showing the Voltage Swell After CILR with SCADA Data

Mitigations Implemented

DEV is taking multiple actions to mitigate the risks from CILRs during disturbances:

- DEV increased deployment of high-fidelity POI metering to improve post-event root cause analysis, facility response validation, and model development.
- DEV updated its facility interconnection requirements[12] to better align customer performance expectations with disturbance characteristics associated with standard transmission reclosing schemes, including revisions related to voltage sag magnitude, sag duration, and the counting logic for successive disturbances.
- DEV has also been performing dynamic studies to better understand the impact of large CILR behavior on the BPS and to support updates to ride-through curves and related ride-through requirements to include in future updates to their facility interconnection requirements.
- DEV also engaged directly with sites that did not successfully ride through prior disturbances to revise applicable protection and control settings, including disturbance duration thresholds, VRT thresholds, and related logic, to better align facility response with standard transmission reclosing schemes.

Nevertheless, DEV continues to engage with data center owners, original equipment manufactures (OEM), utilities, regulators, and universities to improve understanding of large load behavior and support ongoing refinement of modeling, monitoring, and interconnection requirements. DEV will be replacing electromechanical relays that contributed to longer clearing times, non-simultaneous terminal operations, and more severe or repeated voltage depressions in some of the events.

[12] Dominion Energy Virginia—Electric Transmission Facility Interconnection Requirements

Events in Texas

The Texas Interconnection operates as an asynchronous Interconnection with a current system peak of approximately 85 GW. ERCOT is the Planning Coordinator, Reliability Coordinator, and Balancing Authority (BA) for the Texas Interconnection. As of April 2026, ERCOT has approximately 9 GW of large loads that are operational or approved to energize. The large computational loads (LCL)[13] are primarily concentrated in several regions across ERCOT, including Central Texas, West Texas, the Panhandle, and the North Zone.

To date, ERCOT has analyzed 32 large-load ride-through events with CILR of 100 MW or greater between January 2023 and April 2026 (see **Figure 1.10**). The CILR magnitudes correlated with fault type and severity. Non-computational loads have contributed to four VRT events and have proven to be sensitive to voltage sags, especially for multi-phase faults. The largest of these resulted in 818 MW of CILR due to voltage-ride-through sensitivity of the affected sites' variable frequency drives (VFDs). Cryptocurrency mining sites account for the rest of the 32 events, consistently tripping or reducing consumption with the faulted phase(s) experiencing the most significant active power reductions, though substantial variance in the percentage of CILR has been observed across events with comparable POI voltage dips. To date, ERCOT has not observed any VRT events at a traditional data center via transferring its load to UPS systems and, for longer disturbances, to backup generation. An analysis of events in ERCOT, including event-level fault characteristics, facility-level response patterns, and recovery profiles, is presented in the *ESIG Large Load Disturbance Events report*.[14]

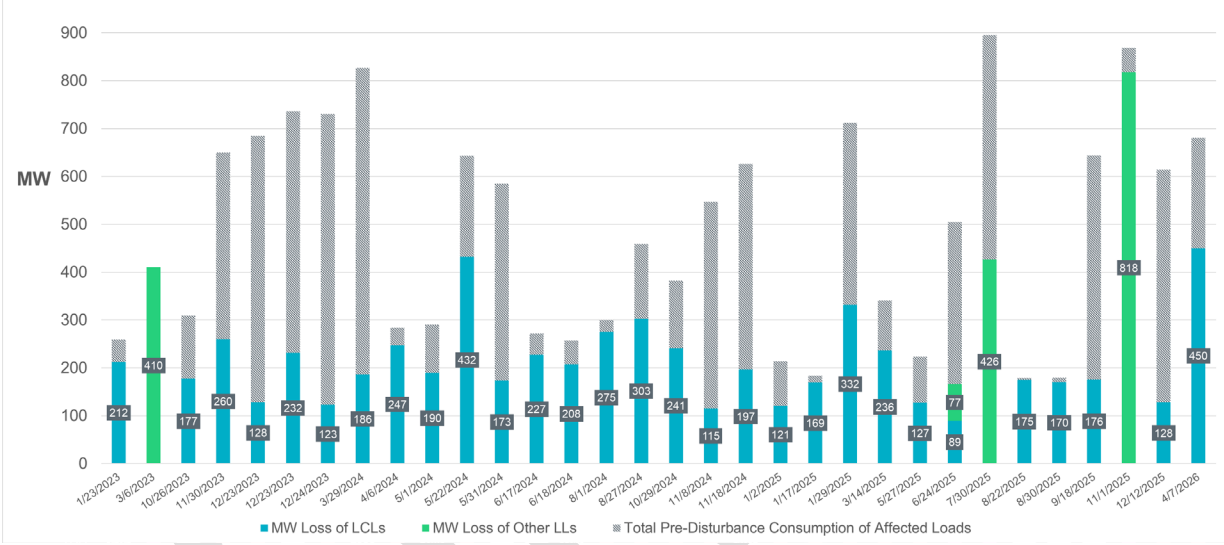


Figure 1.10: ERCOT Large Load Ride-Through Events[15]

Cryptocurrency Mining Customer-Initiated Load Reductions

Across the 28 events involving cryptocurrency mining sites, event analysis reveals a consistent VRT response to voltage sags including a current rise proportional to the voltage depression (consistent with constant-power load behavior) and a rapid concentration of active power reduction on the faulted phase(s).

The June 24, 2025 event, which involved two cryptocurrency mining sites, Load A and Load B, illustrates this pattern (see **Figure 1.11** and **Figure 1.12**). A normally cleared line-to-line-to-ground fault on an external 138 kV transmission line depressed voltage at the service delivery point of each site below 0.7 pu for more than 20 milliseconds. Current rose to approximately 150–160% of pre-fault values, driven by constant-power load

[13] ERCOT considers loads like data centers and cryptocurrency mining facilities to be LCLs.
[14] ESIG LLTF: Large Load Disturbance Events
[15] Incident Review: Voltage-Sensitive Crypto Load Reductions

behavior. Active power reduction was concentrated on the faulted phases, accounting for approximately 80% of Load A's 52 MW reduction and approximately 70% of Load B's 38 MW reduction. The recovery was facility-design-dependent. Load B returned to pre-fault consumption in approximately five minutes while Load A returned in approximately two hours.[16]

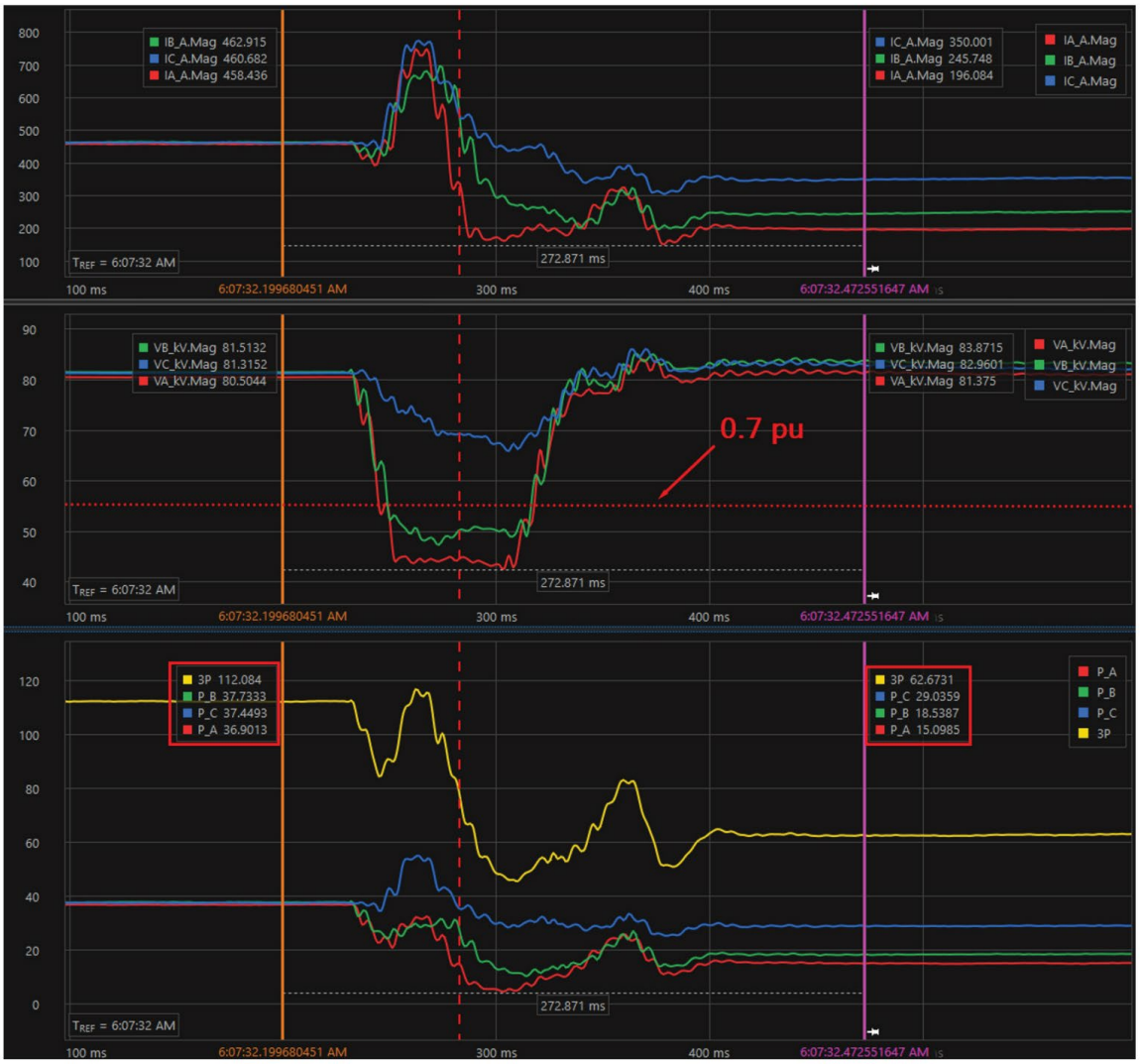


Figure 1.11: Cryptocurrency Load A Waveforms During the June 24, 2025 Event[17]

[16] Source: ERCOT Recent Large Load Loss/Reduction Events
[17] Source: ERCOT Recent Large Load Loss/Reduction Events

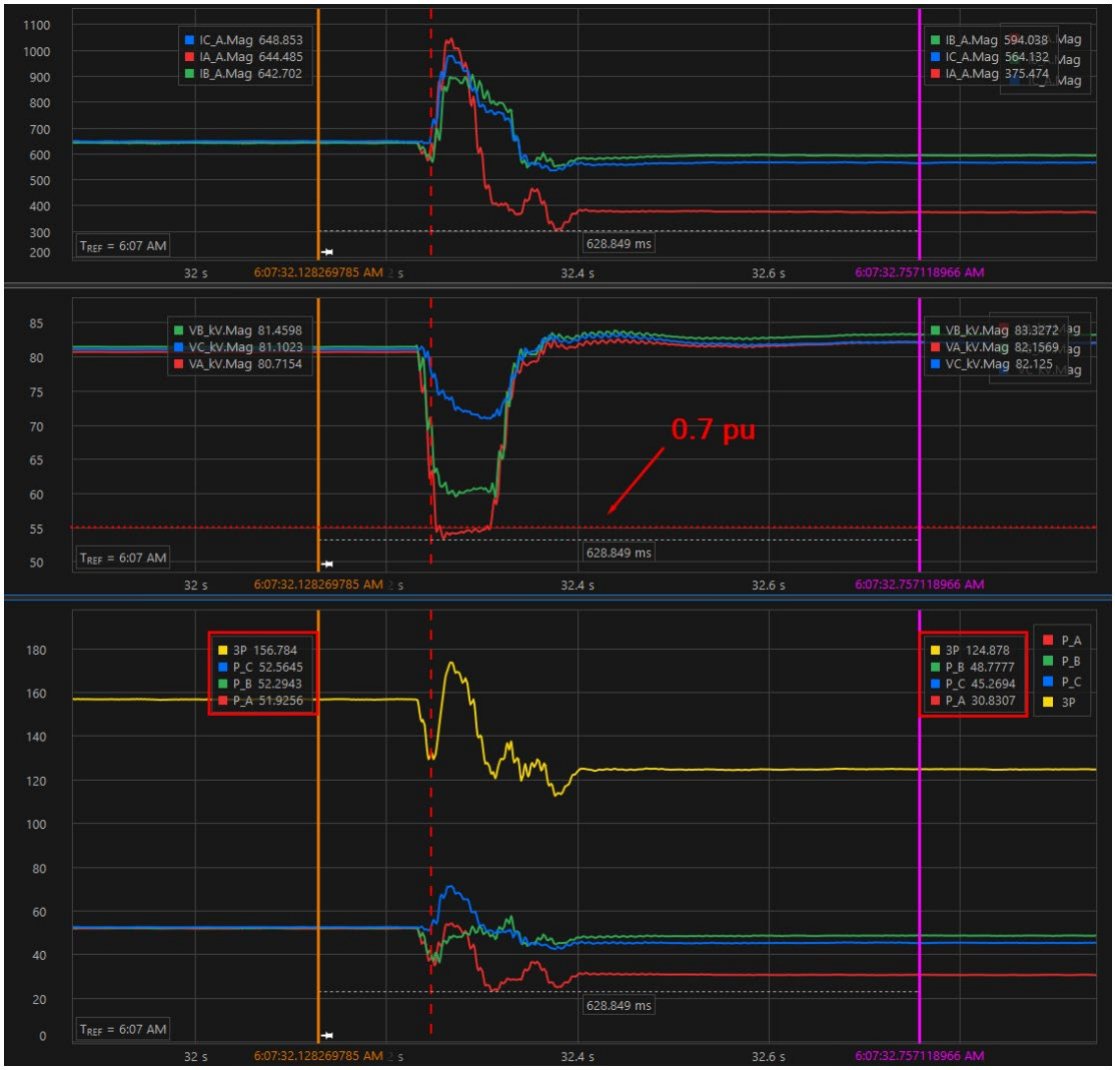


Figure 1.12: Cryptocurrency Load B Waveforms During the June 24, 2025 Event[18]

NERC's *Incident Review: Voltage-Sensitive Crypto Load Reductions* discusses events that involve cryptocurrency mining sites experiencing CILRs in the Texas Interconnection and discusses that CILRs are caused by factors including the following: [19]

- Equipment design (The ride-through capability of IT equipment is typically roughly based on the Information Technology Industry Council (ITIC) curve.[20])
- Neutral overcurrent protection
- Overcurrent tripping
- Transformer winding configuration for the transformers between the utility's high voltage side and the site's low voltage side
- Ride-through performance of cooling load due to low-voltage protection of variable frequency drives or variable speed drives

[18] Source: ERCOT Recent Large Load Loss/Reduction Events
[19] Incident Review: Voltage-Sensitive Crypto Load Reductions
[20] Curve formerly published by the Computer and Business Equipment Manufacturers Association (CBEMA)

Effects on BPS Reliability

The reliability impact for these large-load ride-through events in ERCOT has been minimal to date. The resulting system frequency from these events ranged from 60.02 to 60.06 Hz and recovered within minutes with no voltage stability issues.

However, the forward-looking reliability concern is one of scale. At the projected energization levels, the same normally-cleared fault in ERCOT that causes a several-hundred-megawatt CILR event could result in a multi-gigawatt CILR event within a few years. To date, ERCOT's load loss threshold analysis has shown that the simultaneous loss of 3.2 GW of load under certain BPS conditions may pose significant reliability risk to the Interconnection's system frequency and voltage stability. The reliability impact of large loads may also require ERCOT to lower system operating limits for existing transmission interfaces in the affected areas to mitigate large-load CILRs or disconnections triggered by system disturbances.[21]

Mitigations Implemented

As additional computational loads are interconnected to the system, the reliability risk of a major event in ERCOT will increase if the risk is not mitigated. ERCOT is pursuing FRT and VRT requirements on LCLs to mitigate the reliability risk of multiple LCLs simultaneously tripping during a common system disturbance, potentially resulting in frequency and voltage instability.[22] ERCOT may take action to prevent loss of more than 3.2 GW of load during an event, which may include curtailing LCLs. Since the FRT and VRT requirements are not retroactive, exempt LCLs will be incentivized to meet the proposed ride-through requirements to avoid potential curtailment under certain system conditions. ERCOT may pursue market participant registration for large loads, paralleling NERC's proposed computational load registration.

ERCOT has also identified ride-through risks associated with non-LCLs and intends to address those risks through its stakeholder process.

Events Near Columbus, Ohio

AEP has experienced multiple data center CILR events in the Columbus, Ohio area. AEP has several large data centers in this area, concentrated in a small number of sites in close proximity thereby increasing exposure to single-event impacts. The following discusses these events. The CILR amounts for the three events near Columbus, Ohio were not significant enough to trigger any system level impact. For more information on the data centers in this area and these events, see **Appendix B**.

February 9, 2025 Event

On February 9, 2025, a CILR event occurred when a 138 kV transmission circuit faulted due to a crane collision and remained out after two unsuccessful auto-reclose attempts. Out of a total of 814 MW of data center load operating at the time, 428 MW of CILR occurred. All of the sites that performed CILR reduced their demand to 0 MW. The 428 MW of CILR was all from data centers with the same owner.

One data center saw four voltage sags below 0.9 pu but did not experience any CILR. This data center has protection logic implemented that counts the number of voltage dips within a pre-determined period of time.

February 20, 2025 Event

On February 20, 2025, a 138 kV reactor circuit breaker tripped and locked out on differential protection, resulting in a single voltage dip at data centers and 25 MW of CILR. As opposed to the February 9 event, no

[21] Engaging with Large Loads | ESIG
[22] ERCOT NOGRR282

data centers performed a complete CILR. Rather, several data centers performed a partial CILR during this event.

March 11, 2025 Event

On March 11, 2025, a double circuit 138kV line fault occurred affecting multiple phases followed by subsequent unsuccessful auto-reclose attempts. This resulted in 227 MW of CILR. Three data centers performed a complete CILR. Six data centers experienced only two voltage sags and did not perform CILR; the three data centers that performed a complete CILR experienced four strikes and performed CILR immediately after the third strike.

Mitigations Implemented

AEP is working with the data center involved in one of the events to look into possible adjustments to voltage dip counting protection logic. The data center involved in the events has adjusted their settings to only count voltage dips if the duration is more than six cycles and below 85%.

Events in Ireland

Similar to ERCOT, the Ireland grid operates as its own Interconnection with no synchronous ties to other transmission systems. By 2024, the data center demand reached to 24% of Ireland's total demand.[23] In January 2022, EirGrid effectively halted new data center connections in the Dublin region due to grid capacity constraints. In late 2025, the data centers were allowed to apply for connections in Dublin, but only if they meet strict connection requirements.

The Ireland grid has experienced several CILR events, discussed in the EirGrid and SONI report titled "Large Demand Facility Fault Ride Through Issue and Proposed Solutions"[24]. The findings in this report are summarized here:

- In January, 2022, a SLG fault occurred on a 220 kV line, causing voltages in Dublin to reach 0.7 - 0.8 pu and resulting in 74 MW of data center CILR (around 16% of the connected data center load).
- In December, 2022, a SLG fault occurred on a 220kV line, causing voltages in Dublin to reach 0.3 - 0.5 pu and resulting in 204 MW of data center CILR (around 34% of the connected data center load); the rate of change of frequency (RoCoF) reached 0.12 Hz/s and the system frequency rose to 50.22 Hz[25] due to the load reduction.
- In January, 2025, a SLG fault on a 220kV reactor occurred, leading to 321 MW of data center CILR (44% of the total data center load).
- As shown in **Figure 1.13**, a SLG fault on a 220kV line occurred in May, 2025, resulting in 387 MW of data center CILR (52% of the total data center load); this rapid load reduction led to a RoCoF of about 0.26 Hz/s and a system frequency increase to 50.341 Hz.

[23] Large Demand Facility Fault Ride-Through Issue and Proposed Solutions
[24] Large Demand Facility Fault Ride-Through Issue and Proposed Solutions
[25] Nominal frequency in Ireland is 50 Hz.

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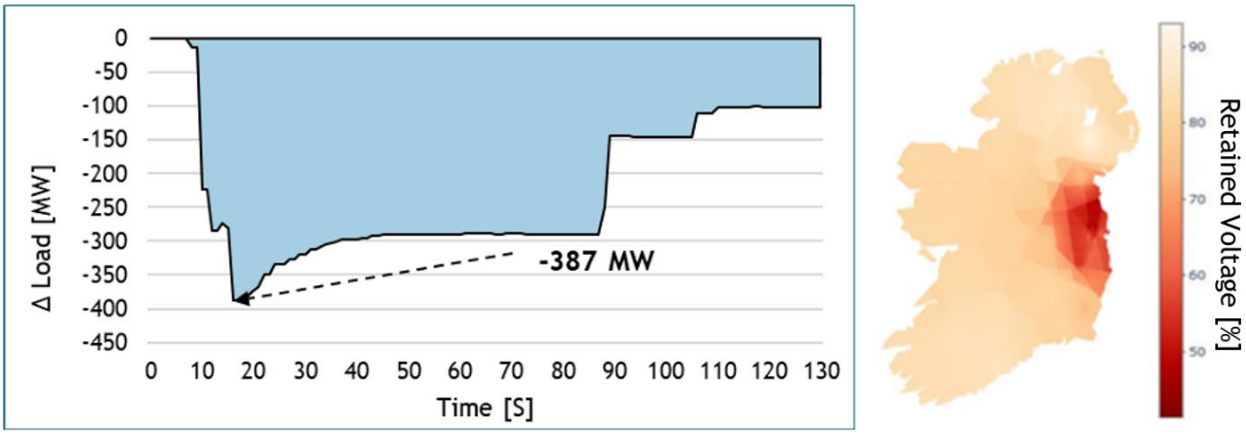


Figure 1.13: Load Reduction and Voltage Propagation Contour Map for May 8, 2025, Event

Effects on Grid Reliability

All four events did not lead to violations of system operating limits. However, more severe scenarios, such as three-phase faults or faults electrically closer to major data center clusters, are expected to result in significantly larger demand reductions, which could pose greater challenges to overall system stability.

Mitigations Implemented

The ESIG Large Load Disturbance Events report notes that EirGrid is updating its grid code to require load sites "to remain connected to the transmission system during and following a fault that results in voltage deviations and continue to operate." [26]

[26] ESIG LLTF: Large Load Disturbance Events

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Chapter 2: Large Load Facility Characteristics Affecting BPS Reliability

The performance of large loads during and after disturbances can affect the reliability of the BPS, and their performance is significantly impacted by specific design aspects of the site. Specifically, the site's demand reduction during and shortly after a fault is significantly impacted by its UPS configuration and settings if a UPS is installed, internal protection schemes, transformer winding configuration, and other factors. The performance of the load is of interest because this performance affects BPS reliability.

Load Site Protection and Transfer to Backup Generation

Computational load sites can be designed with protection and backup power systems that allow them to maintain internal operation throughout disturbances on the BPS. From the site standpoint, transferring to backup power is part of a normal design philosophy. Systems like battery energy storage systems (BESS), UPSs, and on-site generation are used to ride through short-duration voltage or frequency events while keeping critical processes online. Protection schemes within these sites are generally set based on internal equipment limits and performance expectations rather than directly coordinating with BPS protection objectives.

If available, transfers to backup power may be triggered by voltage magnitude, duration of voltage sags and swells, frequency deviations, number of voltage dips within a period of time, or internal system conditions. In many cases, these settings are intentionally conservative to prevent damage to power electronics-based equipment and to avoid repeated stress on sensitive systems. Because of this, portions of the site may transfer off the BPS even when a disturbance is cleared within normal BES protection timelines. Battery systems play a key role in this approach. Their fast response allows the site to maintain continuity without interruption when BPS conditions worsen. From the site's perspective, the goal is to stabilize internal voltage and avoid unnecessary shutdowns. After a transfer occurs, the site may delay reconnection or bring load back in stages.

UPS Versus Non-UPS Configuration

Large load sites, such as data centers, may be designed with either UPS systems or non-UPS configurations. This design choice fundamentally influences the site's ability to ride through BPS disturbances and, in turn, its impact on overall BPS reliability. In non-UPS configurations, the site load is directly coupled to the transmission or distribution system without intermediate energy buffering. As a result, the load is fully exposed to BPS disturbances, including voltage dips, frequency excursions, and short-duration interruptions. Even relatively shallow voltage sags or transient faults can lead to protection system operation, contactor dropout, or process interruptions, causing partial or complete load disconnection. Consequently, such sites exhibit low inherent ride-through capability and are highly sensitive to transient events. The partial or complete load disconnection can impact BPS reliability.

From a system-level perspective, the sudden disconnection of large non-UPS loads during grid disturbances, such as transmission faults or major contingencies, can result in a rapid and substantial reduction in system demand and cause BPS reliability impacts. This abrupt load loss can lead to BPS frequency excursions (typically over-frequency events) due to generation-load imbalance, particularly in systems with low inertia or limited primary frequency control responsiveness. Additionally, the spatial concentration of large load tripping may introduce localized voltage recovery challenges and dynamic oscillations, depending on the level of system strength and reactive power support. Therefore, high penetration of non-UPS large loads can exacerbate transient stability concerns and complicated system operation during disturbances.

DRAFT

As described above, UPS-equipped sites could have substantially greater inherent ride-through capability than non-UPS sites. As large load ride-through can help support BPS reliability, this aspect of the load design is of interest. The UPS battery provides a time buffer between grid disturbance onset and the need for internal load reduction or generator transfer, typically on the order of seconds to minutes depending on battery sizing. Non-UPS sites, by contrast, are directly exposed to every grid voltage transient, and even shallow, sub-cycle sags can trigger protective relay operations or power supply brownout shutdowns. The distinction is most consequential for the under-voltage range between approximately 0.5 and 0.9 pu, where UPS-equipped sites could ride through events that non-UPS sites typically cannot. Since this performance is dependent on the UPS design and protection settings, proper documentation and modeling are important to reflect the equipment capabilities.

The broader framing for this section is the availability of energy buffering at the site level. UPS systems are the most common form of energy buffer in conventional data centers. However, the landscape is evolving. Modern hyperscale sites are increasingly deploying 48V and 800V DC power distribution architectures that integrate rack-level lithium-ion batteries directly at the server chassis. In these architectures, each server rack contains its own ride-through capability, and the traditional centralized UPS may be eliminated or reduced in scope. The ride-through characteristics of these distributed energy buffer architectures differ from centralized UPS systems.

Centralized vs. Decentralized UPS Control

Traditionally, UPS systems are designed to isolate the computing load from grid disturbances as quickly as possible. At the scale of modern hyperscale data centers, this isolation-first approach creates a systemic grid stability problem in that simultaneous disconnection of large data center loads during a disturbance amplifies grid instability rather than mitigating it. The architecture of UPS control systems is a decisive factor in a data center's ability to ride through system-wide voltage disturbances.

- **Centralized UPS Control**: A centralized controller uses site-wide real-time voltage measurements (via data center infrastructure management or a dedicated monitoring network) to optimally dispatch controllable resources such as UPS inverter reactive power injection, IT load reduction via dynamic voltage and frequency scaling, cooling curtailment through VFDs, and battery discharge, minimizing voltage excursions across buses, prioritizing lowest-cost actions, and conserving battery state of charge for sustained events. However, LVRT occurs on millisecond-to-second timescales, so performance degrades with measurement-to-command latency, and at sufficiently high delays commands arrive too late to prevent internal voltages from crossing equipment trip thresholds, requiring dedicated low-latency communications.

- **Decentralized UPS Control:** Decentralized control removes communication dependency by having each resource (UPS inverter, VFD-driven cooling unit, rack-level battery) respond to its local terminal voltage. As voltage falls below a reference threshold, it proportionally injects reactive power and/or curtails active power draw then restores output as voltage recovers. With no measurement transmission or central computation, it is inherently immune to latency and communication failures and can be deployed in existing sites via UPS inverter and VFD firmware updates. The trade-off is reduced optimality because local-only decisions can allocate effort inefficiently across the site resources (e.g., excessive curtailment in one area while higher-capacity resources elsewhere within the site remain underutilized), but it remains an accessible, effective option where dedicated low-latency communications are unavailable.

Both control paradigms extend naturally to post-fault recovery. A centralized controller can orchestrate staged IT and cooling load ramp-up as bus voltage recovers, respecting back-up generator walk-on constraints and monitoring for subsequent instability. Decentralized control provides an inherent rate-

limiting analog: as voltage recovers, each resource's local feedback loop restores output proportionally, limiting reconnection rate without requiring explicit coordination.

Battery state of charge at fault clearance constrains post-fault recovery under both architectures in two compounding mechanisms. First, after fault clearance the generator must both ramp the constant-power load and recharge a depleted UPS battery; the combined current can exceed generator rating, forcing a slower load ramp (or risking overload) and prolonging partial-power recovery beyond the walk-on constraint. The second mechanism becomes relevant when disturbances occur in rapid succession: if a subsequent fault arrives before the battery has fully recharged, it begins with less stored energy than the previous event. Each successive event therefore offers shorter effective hold-up duration, meaning later faults in a sequence are more dangerous than earlier ones even if the grid disturbances are of similar severity.

Battery Energy Storage Systems

The configuration of a BESS within a data center's power architecture materially affects its transient response during grid disturbances. Two primary integration approaches are used in practice:

- **AC-Coupled Configuration:** The BESS inverter is connected in parallel with the UPS on the ac bus. This arrangement allows the BESS to respond to grid disturbances by injecting ac current to support bus voltage, but the response speed is limited by the BESS inverter's ac control loop and grid synchronization requirements.
- **DC-Coupled Configuration:** The BESS is connected directly to the UPS DC bus through a bidirectional dc-dc converter. This arrangement offers significantly faster response, typically sub-millisecond, because energy transfer occurs entirely within the DC domain without the latency of dc synchronization. DC-coupled BESS configurations are therefore more effective at preventing UPS transfer during fast, transient voltage events. DC-Coupled BESSs can play a central role in large load ride-through. When grid voltage drops below the internal UPS hold-up threshold, a site-level BESS can instantaneously discharge to maintain the dc bus voltage, preventing the UPS from flagging a transfer condition. The BESS effectively decouples the site's apparent grid demand from its internal power requirement for the duration of the disturbance, which is the key mechanism enabling ride-through without CILR.

Large Load Constant Current and Constant Power Behavior

Large load sites can draw power from the BPS through a complex chain of power conversion equipment, and the aggregate load characteristic presented at the POI reflects the combined behavior of all devices in that chain. Understanding this aggregate characteristic is essential for assessing site disturbance performance and for constructing dynamic load models suitable for transmission planning studies.

Electrical loads are commonly classified by their voltage-current relationship into three types:

- **Constant Impedance:** A constant impedance load draws current proportional to voltage, so power consumption decreases as voltage drops; this type is self-stabilizing during voltage disturbances.
- **Constant Current:** A constant current load draws fixed current regardless of voltage, so power consumption decreases linearly with voltage, but the current signal itself does not amplify the disturbance.
- **Constant Power:** A constant power load maintains fixed power consumption by increasing current as voltage drops, which can amplify voltage disturbances by placing greater reactive burden on the system when it is already stressed.

Computational loads are dominated by switched-mode power supplies (SMPS) and power electronics-based front ends that typically exhibit constant power behavior over the voltage range in which they remain operational, though some can operate as constant current loads outside typical ranges. This constant power characteristic is the most consequential factor affecting disturbance performance. As voltage drops following a fault, the SMPS increases its input current to maintain regulated output voltage and power, deepening the voltage sag on the supply bus rather than allowing the voltage sag to self-correct. At the aggregate level of a large site, this behavior can meaningfully slow voltage recovery and may trigger protective relay operations at adjacent load or generation buses.

In the context of transmission planning studies, constant power loads require explicit dynamic representation. The widely used composite load model for dynamic studies CMLD framework provides a structured approach for representing the mix of motor and electronic load characteristics at a bus. For computational load sites, the power electronics component of CMLD should be parameterized to reflect the dominance of constant power behavior, with appropriate settings for the under-voltage trip threshold, the current-limiting regime entry point, and the post-fault reconnection ramp rate. Reliance on default CMLD parameters calibrated to residential or commercial load mixes may substantially understate the disturbance impact of computational loads in planning base cases.

In electromagnetic transient (EMT) domain studies, the distinction between positive-sequence and three-phase representation becomes important. Single-phase mining equipment and rack-level server power supply units respond to phase-specific voltage signals; their aggregate response to an unbalanced SLG fault will differ from that implied by positive-sequence analysis, which averages the three-phase voltage. EMT studies are particularly warranted where computational load concentration is high, system strength is low, or where the interaction between large load power electronics and nearby inverter-based resources (IBRs) raises the risk of sub-synchronous control interactions (SSCI).

The constant power behavior of computational loads also varies with site operating conditions. Under full utilization (e.g., sustained AI training workloads), a computational load presents near-constant power consumption and the SMPS operates well within its current-limiting regime. Under partial utilization (e.g., inference-heavy or variable workloads), the site may exhibit a mixed characteristic with some proportion of constant impedance behavior, which would reduce the severity of the constant power effect during disturbances. Computational load site operators and interconnection engineers should therefore characterize the range of utilization scenarios including both typical and peak loading when developing dynamic load models for interconnection studies.

Impact of Load Characteristics on Disturbance Performance and Post-Fault Recovery

The constant power characteristic of computational loads is the most consequential factor limiting their performance. As the performance of computational loads can affect BPS reliability, this characteristic is of interest. Constant power loads sustain full power draw by increasing current, deepening the voltage drop across supply impedances and actively impeding bus voltage recovery. At the UPS battery level, this higher current at depressed voltage accelerates discharge, shortening the hold-up window available for backup generator startup and transfer. At the distribution level, a large aggregate constant power load presents negative incremental impedance to the internal bus, which can amplify voltage perturbations on weakly coupled buses rather than damping them.

In the context of a backup generator, the most operationally critical consequence arises where constant power loads defeat the V/Hz compensation mechanism. With constant impedance loads, the generator automatic voltage regulator's (AVR) proportional voltage reduction in response to a frequency dip reduces electrical power draw, relieving engine braking torque and enabling speed recovery. With constant power

loads, the same AVR voltage reduction is immediately countered by increased current, leaving engine torque unchanged regardless of the V/Hz setting. V/Hz compensation thus provides no benefit for constant power loads and may worsen outcomes by driving higher winding currents and I^2R losses without any engine torque relief.

Load characteristics also influence a computational load site's ability to restore full load consumption after a disturbance has cleared (i.e., PFAPR). PFAPR can reduce the impact of the computational load on the BPS. Because constant power loads draw higher current at reduced voltage, the internal bus voltage recovers more slowly than it would with constant impedance loads, potentially delaying restoration of loads that dropped out when SMPS regulators fell below their hold-up voltage floor. More critically, when multiple constant power loads reconnect simultaneously after a disturbance, the aggregate surge of constant power demand at a still-depressed voltage can produce a further voltage sag, potentially retriggering SMPS dropout and creating a recovery loop. Staged or rate-limited reconnection is therefore essential for constant power-dominant sites.

Additionally, some UPS systems may exhibit a hybrid behavior where for a voltage range near nominal voltage, the load is constant power, but when voltage drops below a certain threshold, the UPS may enter a current limiting regime. Transitioning loads toward constant current or hybrid behaviors can improve PFAPR. This transition effectively converts the constant power load into a constant current type, which reduces power consumption linearly as voltage continues to drop. By providing this marginal load relief, hybrid UPS controls allow backup generators to accept larger step loads without stalling.

Cooling Load

The operation of computational loads, including data centers and cryptocurrency mining operations, depends on both the performance of power electronics-based equipment and the electrically supplied cooling systems that support it. While much of the focus is typically placed on the information technology (IT) equipment itself, the reliable operation of a data center is equally and critically dependent on its electrically-supplied cooling systems. IT load and cooling load are interdependent with changes in computing activity directly affecting cooling demand, and cooling system availability influencing allowable computing output. These cooling loads are essential to maintaining thermal limits and are closely tied to site power quality, voltage tolerance, and protection and control schemes. The NERC incident review focused on cryptocurrency load reductions highlights the impact of cooling load and facility protection. Without cooling systems, cryptocurrency mining sites can completely shut down.[27] This complete shut-down can cause BPS stability concerns. Industry experience has also shown that protection schemes applied to power electronic-based cooling systems require careful coordination to avoid mis-operation during normally cleared disturbances.

Type of Load

The type of large load site, as defined by its primary computational workload and associated power architecture, is a significant determinant of disturbance performance. The major large load types present in the current large load landscape differ in their equipment composition, power draw profiles, energy buffering capability, and protection logic, all of which affect both ride-through performance and post-fault active power recovery.[28]

- **Traditional enterprise and colocation data centers** are characterized by multi-tenant server infrastructure serving a wide range of enterprise applications, typically supported by centralized UPS

[27] Incident Review: Voltage-Sensitive Crypto Load Reductions

[28] It should be noted that computational loads can change the type of processes that occur within that facility. For example, cryptocurrency mining sites can be updated to be AI data centers. Additionally, a single site can have multiple types of load within the site (e.g., data centers with multiple tenants).

systems with battery runtimes of 5–15 minutes and diesel backup generators for sustained outages. Centralized UPS provides meaningful ride-through capability for the duration of the battery hold-up window; however, multi-strike and dip-counting protection logic implemented in the UPS transfer controls has been the primary driver of CILR in the Northern Virginia events. Recovery time following a full transfer to backup generation is typically 15 to 60 minutes, constrained by generator synchronization, protective interlock sequences, and the site operators' reconnection protocols.

- **Hyperscale AI training sites** represent a newer and rapidly growing type of large load, characterized by very high power density and large aggregate loads at single interconnection points (often 100 MW or greater per campus). These sites are typically UPS-backed, often with distributed 48 V dc or 800 V dc rack-level battery systems replacing or supplementing centralized UPS infrastructure. The distributed battery architecture offers potentially superior ride-through capability with faster response, no centralized transfer switch to misoperate; however, the behavior of this architecture during multi-strike voltage sequences and its aggregate POI-level response during faults is not yet well characterized in interconnection study models.

- **Cryptocurrency mining sites** exhibit the most severe and consistent CILR behavior of any computational load type documented to date. Graphics processing unit (GPU) and application-specific integrated circuit (ASIC) mining equipment is predominantly single-phase, unprotected by UPS, and directly coupled to ac power distribution with no energy buffering. As a result, any voltage depression that pushes phase voltage below the equipment's hold-up threshold, often as shallow as 0.85 to 0.90 pu, causes immediate load reduction proportional to the faulted phase voltage deficit. The ERCOT incident reviews document this behavior as well as neutral overcurrent and overcurrent protection mechanisms triggered by unbalanced faults.[29] Recovery time for mining sites following a CILR can range from minutes (if the equipment self-restores after voltage recovery) to hours (if manual intervention is required to restart mining processes or if thermal management systems require a full cool-down and restart cycle).

- **AI inference sites** can have a varied load profile, causing the effective constant power characteristic to be less dominant during disturbances. The aggregate site response to a fault may depend on the current workload mix at the time of the event. Whether inference sites are UPS-backed depends on the specific operator; hyperscale inference deployments typically are, while smaller inference deployments may not be. Dynamic load models for any data center sites, including AI training, AI inference, or other types of data centers, should capture a range of utilization scenarios rather than assuming constant full-load conditions.

- **Other large load types** including hydrogen electrolyzers, arc furnaces, and industrial manufacturing sites present different disturbance performance characteristics that are not the primary focus of this paper. Hydrogen electrolyzers rely on power electronics-based rectifier systems that may exhibit constant power behavior similar to computational loads, but the specific ride-through and recovery requirements for this load type are expected to differ and are the subject of separate regulatory development. Arc furnaces present inherently variable and reactive-power-intensive load profiles that interact differently with the power system during disturbances than either data centers or mining sites. The ride-through and PFAPR requirements discussed in this paper are developed primarily from the computational load evidence base, and their applicability to these other large load types should be evaluated separately by the relevant standards development processes.

Size of Load

The capacity of a large load site at its point of interconnection is a direct factor in both its BPS impact when a CILR occurs and in the design rigor typically applied to its protection and power systems. Size interacts with

[29] Incident Review: Voltage-Sensitive Crypto Load Reductions

other site and BPS attributes rather than acting as an independent predictor of disturbance performance, but several specific mechanisms link site MW capacity to reliability risks:

1. **From a BPS reliability perspective, the primary concern is whether a single CILR event or a group of correlated CILR events at co-located sites can produce a load loss equivalent to or exceeding the largest credible generation contingency in the relevant balancing authority area.** In ERCOT, NERC's incident review data and ERCOT's own analysis indicate that a single normally cleared fault in the West Texas area could, at projected large load growth rates, produce simultaneous CILR of several gigawatts. In Northern Virginia, the July 2024 and February 2025 events each produced 1,500 to 1,800 MW of simultaneous CILR from sites concentrated within a small geographic area, a load loss significantly exceeding the Eastern Interconnection's largest N-1 generation contingency. These examples illustrate that the relevant planning unit is not the individual large load, but the cluster of sites sharing common electrical exposure to the same credible fault.

2. **From a facility design perspective, larger sites are generally more likely to have undertaken formal protection coordination studies, to have engaged with the interconnecting utility on ride-through requirements, and to have invested in centralized UPS infrastructure with battery capacity sufficient to bridge the full automatic reclosing sequence**. Smaller interconnecting sites at distribution voltages, particularly cryptocurrency mining operations and smaller colocation sites, have historically been subject to less rigorous interconnection requirements and may lack the engineering resources to evaluate and optimize their ride-through settings. Ride-through requirements applied uniformly above a defined POI capacity threshold capture the majority of grid-relevant sites while limiting compliance burden on genuinely small loads.

3. **The aggregation effect warrants specific attention in planning studies.** Multiple sites connected to the same substation or to substations within the same protection zone may all experience the same voltage disturbance profile during a transmission fault. If their protection settings are similar, as is common when sites use the same UPS vendor or the same standard commissioning specifications, a single fault may produce simultaneous CILR from all of them. This correlated behavior means that the effective "size" of the load at risk from a given fault cannot be assessed on a site-by-site basis; it requires analysis of the aggregate load and aggregate protection behavior across the entire cluster. Planners should therefore assess concentrated load areas using realistic correlated tripping models rather than assuming staggered or independent site responses.

Transformer Winding Configuration

For large loads served from the transmission system, the step-down transformer configuration affects how upstream unbalanced faults, harmonic currents, and grounding phenomena are presented to the site. Two configurations are commonly used by North American utilities:

- Delta / grounded-wye (D/Yn)
- Grounded-wye / grounded-wye (Yn/Yn).

These configurations do not expose the connected load to the same voltage conditions during SLG disturbances. **Figure 2.1** illustrates the representative interconnection arrangements for the two configurations.

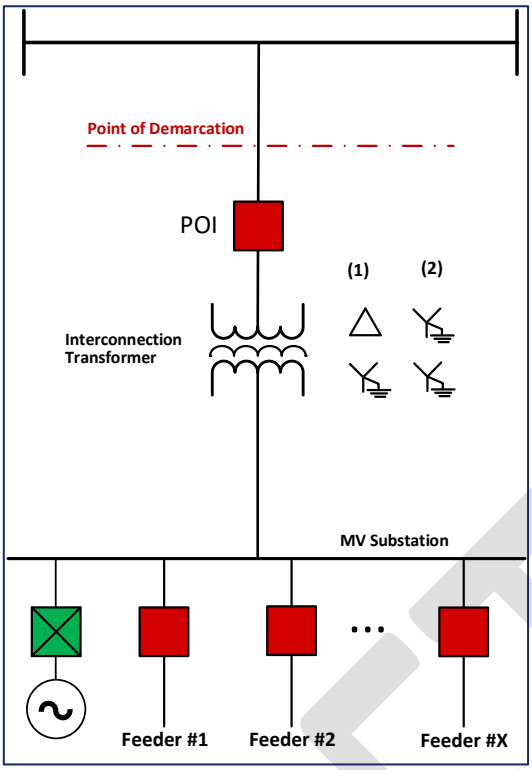


Figure 2.1: Representative Interconnection Single-Line Diagram

The key differences between the two configurations include:

- **Disturbance transfer:** In a D/Yn transformer, the delta winding blocks direct zero-sequence current transfer across the transformer during SLG events. This reshapes the secondary voltage sag experienced by three-phase loads improving ride-through for some grounded-wye or phase-to-neutral sensitive loads. A Yn/Yn transformer passes grounding effects more directly unless a tertiary or stabilizing winding is provided.
- **Harmonics and imbalance:** A D/Yn configuration gives triple and circulating currents a closed delta path and generally handles load imbalance better. A Yn/Yn configuration is more sensitive to neutral shift and is one reason IEEE treats stabilizing windings as a specific design issue for wye-wye transformers.[30]
- **Protection and on-site generation:** With on-site generation, a delta-connected side can create ground-fault overvoltage concerns after the utility source is removed, often requiring an added overvoltage detection scheme such as 3V0 or transfer-trip logic from the high-side to isolate the on-site generator before reclosing the substation breaker. A Yn/Yn configuration gives a simpler grounded reference, but it also allows ground-fault contribution to transfer more directly.

Transformer selection should therefore be evaluated together with grounding, protection, onsite generation behavior, clearing time, and the ride-through characteristics of the critical site equipment.

[30] IEEE Std C57.158-2017, IEEE Guide for the Application of Tertiary and Stabilizing Windings in Power Transformers

Chapter 3: Grid Attributes Affecting Large Load Disturbance Performance

While the design of the large load site plays a significant part in determining the performance of the site during and after a disturbance, the attributes of the electrical system in the area also significantly impact the site's performance as they can determine the length, depth, and number of voltage disturbances that are experienced by the site. The large load's performance during and after voltage disturbances can impact BPS reliability. The impact that the site has on the BPS is also affected by the attributes of the electrical system, such as size of the Interconnection, system strength, generation ramp rate capabilities, and other factors.

System Strength and Other Local Grid Characteristics

Large load ride-through can help support BPS reliability, and system strength is emerging as a decisive factor in defining ride-through requirements for large loads. Traditionally, ride-through requirements are derived assuming relatively strong grids dominated by synchronous generation to ensure power synchronism of dynamic elements, thereby guaranteeing stable and reliable system operation. That assumption no longer holds for the next generation grid. As generation portfolios diversify and grid topology evolves, system strength at a given POI can vary widely. Any robust framework for system reliability planning should explicitly account for this variability to avoid disturbance ride-through related implications.

At a continental scale, the contrast between the Eastern Interconnection and the Texas Interconnection illustrates the range of system strength conditions that may exist. The Eastern Interconnection, with its vast geographic span and dense network of synchronous machines, generally exhibits higher short-circuit strength and inertia. In contrast, the Texas Interconnection operates as an electrically isolated system with a rapidly increasing share of IBRs, leading to comparatively lower system strength in certain areas and operating conditions. These structural differences translate directly into different voltage recovery characteristics, fault current levels, and dynamic responses which influence how long and how deeply voltage excursions may persist following a disturbance. However, Interconnection-level comparisons only scratch the surface. For example, within a single utility territory, such as DEV, system strength can vary significantly across planning zones due to differences in load density, transmission topology, and resource mix.

From a planning perspective, this variability argues strongly for a conservative, system-wide ride-through envelope (i.e., operation region) that encompasses all identified worst-case conditions. While this may impose stricter requirements than those needed in stronger areas, it ensures that large loads remain connected and stable under the most challenging but credible scenarios anywhere on the system, maintaining a safe reliability margin. Such an approach reduces the risk of cascading load loss, enhances overall BPS reliability, and provides clarity to developers by establishing a consistent and forward-looking technical benchmark.

Utilities including TPs and PCs should perform detailed fault-induced dynamic studies across all relevant planning zones, capturing a spectrum of scenarios including high-load/low-generation conditions, high IBR penetration, and stressed transmission configurations. The objective is to identify the weakest system conditions, characterized by low short-circuit ratios, slow voltage recovery, or high sensitivity to disturbances for credible set of critical contingencies across the system. Typically, the "worst case" is not uniform across the system. For example, Northern Virginia may present worst cases driven by load density and transmission constraints, whereas the south-eastern PJM coastal zone may be defined by inverter-dominated dynamics, and central Virginia by emerging load growth. Each of these conditions can produce distinct voltage profiles during and after faults.

Interconnection Voltage Level

With the increasing penetration of large loads, both transmission and distribution systems are receiving applications to interconnect these sites. The voltage level at the POI can be used as an indicator of the type of network to which the site is connected. This section focuses on how transmission and distribution systems differ in their network structure, voltage sensitivity, operating characteristics, and protection schemes, and how those differences affect the voltage observed at the large load site during and after a disturbance.

Higher voltage interconnections are generally associated with stronger parts of the system, higher short-circuit levels, more parallel transmission paths, and better access to voltage support resources. Lower voltage interconnections are usually supplied through step-down transformers, sub-transmission lines, distribution feeders, and other network elements that add impedance between the site and the stronger upstream system.

- **Radial versus Meshed Network:** Distribution systems are usually radial. This creates two effects that should be considered separately. First, the added upstream elements and lower redundancy can make the voltage at the POI more sensitive to local changes and disturbances. Second, a fault on an upstream feeder, transformer, or supply path may remove the large load from service by configuration. In that case, the issue is not ride-through performance; the supply path itself has been isolated. This is different from a meshed transmission network, where a faulted element may be removed while the large load remains connected through other paths.
- **Network Resistance-to-Reactance Characteristic:** Transmission systems are usually more inductive, so voltage behavior is more strongly influenced by reactive power. In distribution and lower voltage systems, the resistance component is more significant, so both active and reactive power changes can affect voltage. This means local load variation, distributed energy resources operating behavior, inverter controls, and feeder configuration can have a more visible impact on the voltage at the POI. This should be considered when defining ride-through and post-disturbance performance expectations for large loads connected at lower voltage levels.
- **Protection Practices:** Transmission systems usually use faster and more redundant protection schemes, especially at higher voltage levels where transient stability and BPS reliability drive clearing time requirements. Distribution systems protection practices might expose the large load site to longer clearing times or repeated voltage disturbances at the POI.

Proximity to Generation

Factors like the severity and extent of voltage sags, the availability of reactive support during and after faults, and the speed of voltage recovery are heavily influenced by the area's generation mix. Among grid-related considerations, the distance and type of generation, especially the ratio between synchronous generators and IBRs, affects whether and how broadly large loads disconnect, and how these large loads restore their active power consumption after a disturbance. Synchronous machines supply short-circuit current during a fault and continue providing reactive current support after fault clearing, which consequently accelerates bus voltage restoration and shortens the period over which load buses remain below UPS reconnection thresholds. This faster recovery reduces the interruption duration and allows active power ramp-up to begin sooner.

Protection Methodology

Protection methodology plays a critical role in how large load sites interact with the BPS during both normal system operation and disturbance conditions. For large loads, protection behavior is influenced by system attributes such as fault clearing times, reclosing practices, voltage recovery characteristics, and system strength at the POI. Reliable large load integration depends not only on individual protection practices but also on coordination between utility-side protection assumptions and site-level protection methodologies.

From a utility perspective, protection systems are generally applied with the objective of isolating faulted elements while maintaining service to customers during temporary disturbances. Traditional protection and planning practices have assumed that large loads will ride through short-duration voltage depressions and will not disconnect during normally cleared faults. However, the increasing penetration of large loads challenges these assumptions. System attributes such as fast or repeated reclosing schemes, deeper voltage depressions in weak system areas, and delayed voltage recovery can interact with site protection logic in ways that lead to simultaneous large load disconnections. Transmission protection methodologies typically incorporate automatic reclosing to improve service availability and reliability by allowing temporary faults to clear without unnecessarily removing transmission elements from service. This avoids creating a contingency condition for a non-permanent disturbance. However, each reclosing attempt into a fault that persists can produce an additional voltage depression, particularly during permanent faults. As voltage-sensitive data center load becomes more prevalent, these repeated voltage depressions present an increasing reliability concern. During each voltage depression, UPS dynamic response may result in CILR and sites may transfer to long-term backup generation if internal controls determine that continued disturbance exposure could deplete available UPS ride-through capability before the event is resolved.

Size of Interconnection

Interconnection size fundamentally determines the system's ability to dampen frequency excursions caused by CILRs. In smaller Interconnections, an abrupt loss of a large load(s) can represent a significant fraction of the load-generation balance, increasing the risk of frequency spikes that may trigger over-frequency generation control actions. Conversely, larger Interconnections better absorb these events through higher aggregate inertia and broader primary frequency response capabilities; however, this does not eliminate reliability risks. A key planning criterion is the maximum tolerable load loss that avoids encroaching on exceeding over-frequency relay settings.

Balancing Authority's Ramp Rate Capabilities

BA ramp-rate capabilities are a significant factor in the overall impact of the large load disturbance performance on frequency stability. The ramp-rate capability of a BA represents the aggregated ability of generation, controllable demand, and energy storage resources to respond to MW/min variability introduced by large loads. Such sites can exhibit fast and often cycling demand fluctuations that directly stress automatic generation control performance and increase the requirement for system-wide balancing resources. BESSs can significantly enhance BA ramping capabilities due to their fast response characteristics and ability to accurately follow automatic generation control dispatch signals. By rapidly injecting or absorbing active power, BESS can effectively mitigate short-term load-generation imbalances, thereby reducing ACE deviations and improving frequency regulation performance. However, their effectiveness is inherently constrained by energy capacity limits, state-of-charge management requirements, aggregation scale, and operational availability within the balancing footprint.

Type of Disturbance

The response of computational loads to grid disturbances depends strongly on the type, severity, and electrical characteristics of the disturbance. In particular, voltage- and frequency-driven disturbances affect computational loads through different mechanisms and pose distinct reliability considerations for the BPS.

- **Voltage Disturbances:** Voltage disturbances are commonly associated with transmission and distribution faults, load transfer events, and post-disturbance recovery. Rapid load disconnection following a voltage disturbance can result in localized or system-wide overvoltage conditions, particularly in electrically weak areas or where reactive power resources are insufficiently coordinated. Similarly, the restoration of computational loads following a disturbance can exacerbate voltage impacts if load ramp rates are uncoordinated, particularly when local reactive support in the area has tripped offline and is no longer available during the load ramp up.

- **Frequency Disturbances**: Frequency disturbances follow a related but system-wide pathway. Computational load disconnections can contribute to over-frequency conditions, requiring sufficient operating reserves and appropriate frequency response from generation resources. Conversely, uncoordinated or simultaneous restoration of multiple large loads can result in significant frequency depressions. Effective management of frequency disturbances therefore depends on both adequate system reserves and coordinated communication between large load operators and transmission operators during post-disturbance recovery.

The type of fault is an important distinction. Computational loads can respond differently to unbalanced faults, such as SLG or line-to-line faults, than to balanced three-phase faults due to the introduction of negative- and zero-sequence voltage components. These unbalanced conditions produce asymmetric voltage depressions across phases, resulting in phase-specific voltage excursions at the load terminals. Event analysis indicates this behavior is particularly evident in cryptocurrency mining sites, which are predominantly composed of single-phase, constant-power electronic equipment.[31] During SLG faults, even relatively shallow single-phase voltage sags can trigger partial phase-specific load loss, disproportionate increases in phase and neutral currents, and, in some cases, the operation of neutral or feeder overcurrent protection that disconnects the entire site. This behavior contrasts with three-phase faults, which produce balanced voltage depressions across all phases and generally result in deeper but symmetric voltage sags and more uniform load response. By contrast, hyperscale data centers can be composed of three-phase resulting in more uniform response to voltage disturbances regardless of fault type. However, there is currently no standardized industry requirement governing the voltage deviation logic used by UPS systems to transfer load to backup generation. As a result, data center protection and control schemes may be based on different criteria, such as average three-phase RMS voltage, the largest individual phase deviation, or measurements from a specific phase. This diversity in implementation introduces sensitivity to the type of system fault observed, particularly under unbalanced conditions. Consequently, similar voltage disturbances may cause some data centers to transfer to backup generation while others continue to ride through, leading to non-uniform system response across sites exposed to the same grid event.

Length of Disturbance

For large load sites, disturbance severity depends not only on voltage magnitude, but also on disturbance duration and the number of successive voltage depressions within a short time interval. The NERC incident review for the July 2024 Northern Virginia event indicates that these factors can materially affect ride-through performance and the likelihood of transfer to backup generation.[32]

Disturbance duration is affected by contingency type, protection clearing time, and the reclosing sequence. Permanent faults and delayed fault isolation can expose nearby sites to repeated or prolonged voltage depressions, and breaker failure conditions can be more severe because they extend disturbance duration. The effective duration observed by the site can also vary with the voltage recovery profile following fault clearing. In a stronger system, voltage generally recovers faster, whereas in a weaker system recovery may be slower. Although the difference may only be in the order of milliseconds, that difference can still be sufficient to determine whether a sensitive site rides through the event or disconnects/transfers to backup generation. Electromechanical relays increased disturbance duration in certain DEV area CILR events, causing more CILR. The NERC incident review for the July 2024 Northern Virginia event documented six successive fault applications over approximately 82 seconds, illustrating how repeated short-duration disturbances can become significant for large load sites. [33]

[31] Incident Review: Voltage-Sensitive Crypto Load Reductions
[32] Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions
[33] Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions

Voltage Management Technology/Philosophies

Voltage management for large, voltage-sensitive loads relies on a combination of planning philosophies and fast-acting dynamic reactive devices to maintain an acceptable voltage profile under both steady-state and dynamic conditions.

- **Steady-State:** Transformer tap changers, switched capacitor and reactor banks, flexible alternating transmission system (FACTS) devices depending on their control design, and synchronous generator excitation systems provide baseline voltage control. Switched capacitor and reactor banks are widely deployed due to their simplicity and cost effectiveness and are well suited for addressing gradual voltage changes associated with predictable variations in load and generation when voltage variations are relatively slow and system conditions are stable. Transformer tap changers regulate voltage and influence reactive power flows to meet network operating requirements, while generator excitation systems provide reactive power support within machine capability limits.
- **Dynamic:** As load dynamics become faster and less predictable, particularly with computational loads, steady-state controls alone are insufficient. Dynamic voltage management is therefore provided through power electronics-based devices such as SVCs and static synchronous compensators (STATCOM), which offer rapid, continuous, and bidirectional reactive power control. SVCs are generally effective in electrically strong systems; however, their voltage-dependent reactive output limits performance during deep voltage depressions or fault-induced disturbances. STATCOMs, by contrast, are capable of maintaining nearly constant current injection independent of voltage, making them more effective in weaker grids and during severe or fast transient events. As a result, STATCOMs typically provide improved voltage recovery and damping of fast disturbances associated with large load changes. Additionally, there are new grid-forming STATCOM technologies which could be useful in areas with a particularly weak short circuit strength.
- **Synchronous Condensers:** Synchronous condensers represent an additional voltage support option that bridges steady-state and dynamic control philosophies. These machines operate without a prime mover and regulate voltage through excitation control while also contributing inertia and short-circuit strength to the system. Although slower than fully electronic solutions such as STATCOMs, synchronous condensers provide system attributes that can be valuable in areas experiencing reduced system strength or high concentrations of IBRs.

The coordination of these voltage management resources is particularly important when serving large loads. Some of the events described in **Chapter 1** demonstrated overvoltage following load transfer events; in these cases, coordinated actions involving the removal of static capacitors and the rapid response of SVCs resulted in a well-contained voltage profile. As large load penetration increases, more deliberate coordination between steady-state and dynamic voltage control schemes becomes necessary to prevent adverse interactions and maintain reliability.

In addition to discrete load transfer events, computational loads can exhibit operating duty cycles that result in repetitive and rapid variations in voltage magnitude, as well as in real and reactive power demand. These operating characteristics increase the frequency and speed of voltage excursions compared to traditional load behavior and place additional performance requirements on voltage control resources. In such applications, voltage management technologies with fast response and limited energy buffering capability may be used to supplement conventional reactive power devices. Solutions such as E-STATCOMs (STATCOMs with enhanced energy capability), supercapacitors, and other forms of energy storage are being evaluated for their ability to improve voltage regulation during short-duration and repetitive disturbances associated with large load operation.

DRAFT

Chapter 4: Considerations for Disturbance Performance and Post Fault Active Power Recovery Requirements

The evidence reviewed in the previous chapters demonstrates that computational loads can materially affect BPS reliability during transmission disturbances, and that the absence of formal disturbance performance requirements has contributed to unexpected, large-scale CILRs. This chapter discusses the considerations that should inform the development of ride-through and PFAPR requirements, drawing on the industry review, real-world events, and system simulation evidence presented earlier in this paper.

The ride-through and PFAPR requirements proposed in this paper are currently specific to the load only. This position is consistent with the applicability language in ERCOT NOGRR 282[34] and SPP's HILL[35] framework, both of which scope their requirements to the large load customer and treat any co-located generation operating in parallel with the BPS as subject to its own distinct compliance pathway. This paper adopts the same applicability framing.

Industry Review of Existing Requirements

A growing number of transmission system operators across North America and internationally have developed or proposed ride-through requirements for large loads. The approaches vary in scope and structure, reflecting different grid characteristics and regulatory frameworks, but several common themes and precedents are emerging that can inform the development of requirements in the United States. In North America, ERCOT has proposed one of the most detailed frameworks through NOGRR 282, which defines explicit VRT and FRT requirements for Large Computational Loads (LCL), including requirements for deep voltage sag survival and continuous operation between 58.8 and 61.2 Hz.[36] ERCOT's PFAPR requirement specifies that facilities must return to at least 90% of pre-disturbance consumption within two seconds of voltage recovery to 0.9 pu SPP's High Impact Large Load framework[37] similarly establishes performance-based ride-through regions aligned with ERCOT and NERC PRC-029 FRT requirements.[38] MISO has proposed a framework structured around VRT envelopes, transient overvoltage ride-through, consecutive voltage disturbance capability, and FRT envelopes aligned with IEEE 2800[39] and PRC-029.[40]

At the utility level, requirements are also being developed. Southern Company's Transmission Connected Large Load requirements[41] includes pre-commissioning simulation requirements, performance validation periods, and ongoing monitoring obligations. Attachment 8 of the DEV Electric Transmission Facility Interconnection Requirements[42] requires Power Electronic Interface Large Loads to survive a minimum of six automatic reclosing attempts.

Requirements have also been developed internationally. AESO in Alberta has published requirements for transmission-connected data centers including LVRT, HVRT, FRT, and PFAPR, with a configurable recovery timing of 1–10 seconds based on system strength. Fingrid requires data centers to restore 90% of pre-disturbance power within 0.5 seconds.

[34] NOGRR282 Issue
[35] High Impact Large Load (HILL) Integration - Southwest Power Pool
[36] NOGRR282
[37] High Impact Large Load (HILL) Integration - Southwest Power Pool
[38] PRC-029-1
[39] IEEE 2800-2022
[40] PRC-029-1
[41] Southern Company - webSmartOASIS
[42] Dominion Energy Virginia—Electric Transmission Facility Interconnection Requirements

Figure 4.1 provides a comparison of published and proposed VRT requirements for several entities, both in North America and international.

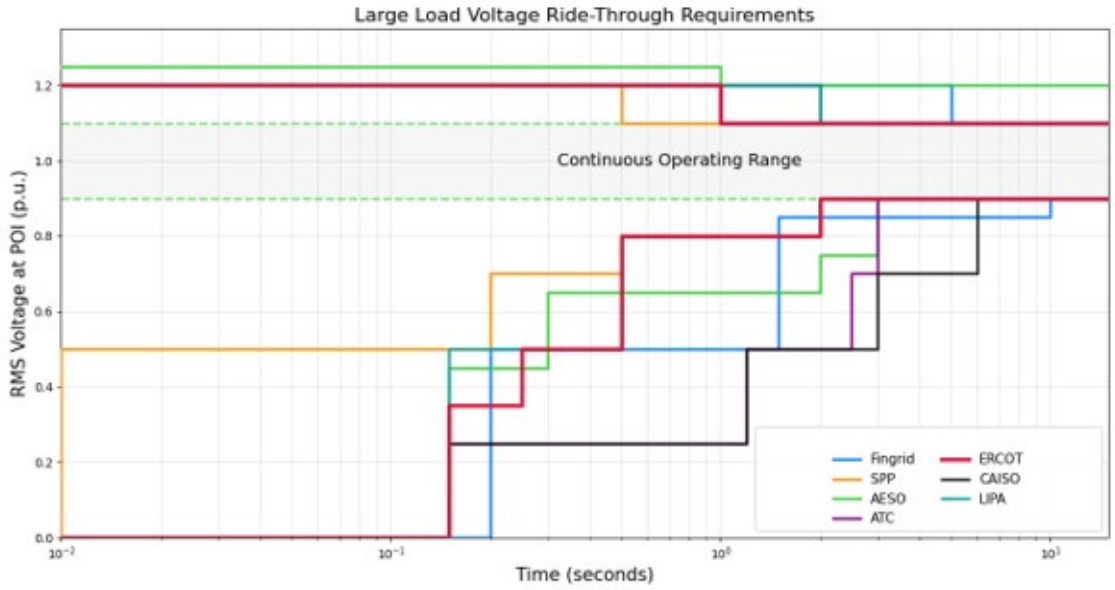


Figure 4.1: Published and Proposed Large Load Voltage Ride-Through Requirements

Organizations including EPRI and ESIG have published papers discussing ride-through. EPRI's recently published white paper on ride-through requirements for large loads provides a useful analytical framework and corroborates many of the observations made in this paper.[43] The ESIG Large Load Performance Requirements report recommends that RTOs, ISOs, and utilities develop VRT curves based on local, delayed, and remote fault-clearing times, applicable contingency events, and automated post-contingency actions specific to their system. For FRT, the ESIG report recommends adoption of the IEEE 2800[44] and NERC PRC-029[45] IBR criteria as the minimum standard for large loads, on the basis that frequency is an Interconnection-wide phenomenon and a coordinated, consistent response is essential.[46]

Considerations for Voltage Ride-Through Requirements

VRT requirements are among the most consequential and most contested elements of any large load performance framework. Unlike frequency, which is an Interconnection-wide quantity that is largely uniform across the synchronous grid, voltage is a local phenomenon strongly influenced by fault type, system topology, protection clearing times, and the availability of reactive support. This spatial variability makes it difficult to prescribe a single, universal VRT region that is appropriate for all systems and all operating conditions.

Evidence presented in **Chapter 1** and **Chapter 3** illustrates this variability concretely. Fault clearing times for 230 kV transmission faults range from approximately 4-6 cycles in some systems to 8 cycles or more in others, with some 115 kV systems seeing clearing times as long as 16-21 cycles where electromechanical relaying remains in service. Voltage recovery profiles following three-phase bolted faults differ substantially between the Western, Texas, and Eastern Interconnections, driven by differences in system inertia, reactive

[43] Large Load Ride Through For Data Centers: Identifying Gaps in Requirements, Interpretation, and Compliance
[44] IEEE 2800-2022
[45] PRC-029-1
[46] Large Load Performance Requirements | ESIG

support infrastructure, and load density or composition. A VRT region that is appropriate for a highly meshed, synchronous-machine-dominated system such as the northern Virginia area may be inadequate in a weak-grid area in ERCOT with high IBR penetration, or overly conservative in a strong, urban Eastern Interconnection bus. **Figure 4.2** shows the characteristic voltage response to three phase faults across several locations. Plots are obtained from simulations conducted for different Interconnections.

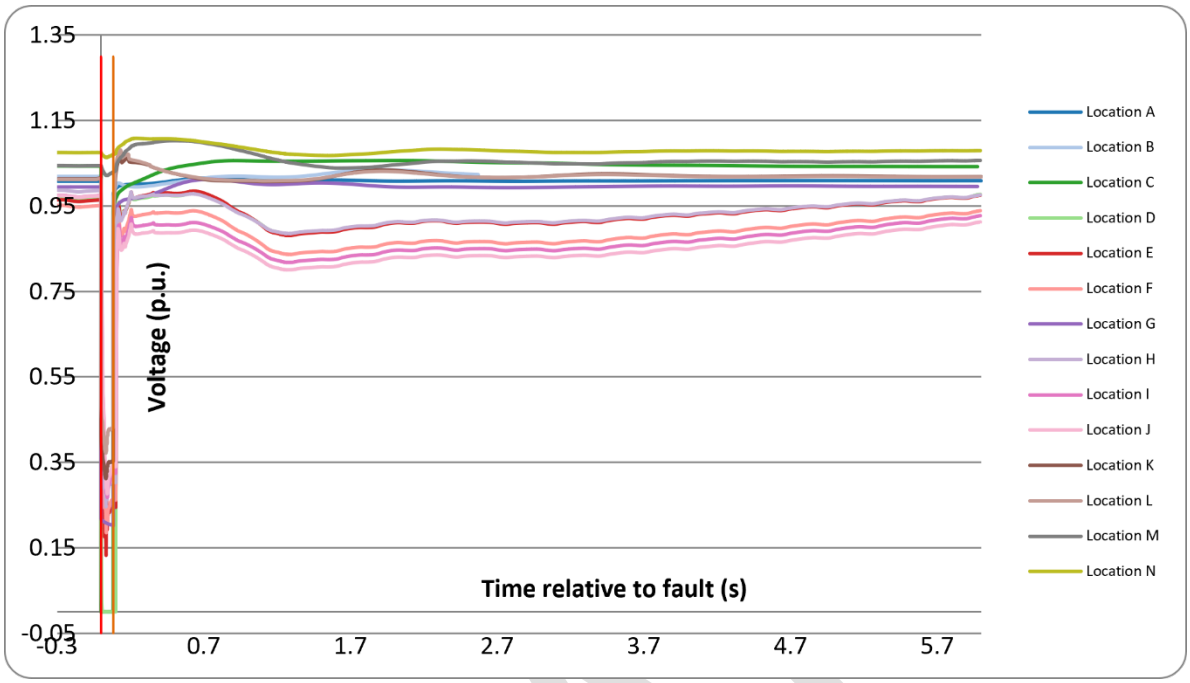


Figure 4.2: Location-Dependent Voltage Recovery

At the same time, a purely case-by-case approach where each utility or BA specifies its own VRT region without any common baseline introduces significant challenges for equipment manufacturers and data center developers and operators. Designing site protection and UPS systems to meet dozens of different VRT profiles across sites imposes cost, complexity, and the risk of misconfiguration. Industry participants have consistently expressed a preference for consistent requirements as a minimum baseline. This mirrors the precedent established for IBRs in PRC-029 which sets a minimum technical capability that all entities must meet or exceed, while allowing utilities and system operators to impose more stringent requirements where local conditions warrant.[47]

To the greatest possible extent, future NERC Reliability Standards activity should seek to define a minimum technical capability floor for computational load VRT while allowing regional or local modification where system-specific analysis demonstrates a need for more stringent requirements. RTOs, ISOs, and utilities should further refine the low- and high-VRT regions based on the local fault-clearing times, credible contingency events, and automated post-contingency actions applicable to their system. The development of these regions should follow a methodology analogous to the following:

- Identifying the envelope of disturbances that must be survived
- Determining the minimum voltage floor and maximum voltage ceiling associated with each fault type and clearing time

[47] PRC-029-1

- Establishing recovery timing expectations that are consistent with generator and reactive support response characteristics

Utilities with concentrations of large loads should be encouraged to perform detailed dynamic simulations across a range of operating conditions, including weak-grid, high-IBR scenarios, to validate that their proposed VRT region is appropriate and does not leave any credible worst-case scenario unaddressed.

While the derivation of specific VRT region boundaries requires dynamic simulations, beyond the scope of this white paper, across the range of system conditions and contingency types described above, the LLWG believes a possible structural framework for a computational load VRT region is broadly consistent with the event record documented in **Chapter 1**, the large load site and system attributes analyzed in **Chapter 2** and **Chapter 3**, and with existing frameworks.

As an example, the four-region structure described below and shown in **Figure 4.3** is offered as a starting point to be refined with specific voltage and time thresholds and should be validated through regional dynamic simulations before being adopted in enforceable standards. Requirements should primarily be developed as a table of voltages and respective ride-through times, similar to PRC-024[48] or PRC-029,[49] rather than primarily being a "graph." However, the example is shown here as a graph for simplicity of discussion.

- **Region A** corresponds to normal, continuous operation covering voltage magnitudes near nominal. The site shall remain connected and compliant with other steady-state performance requirements, including applicable ramp rate limits.
- **Region B** covers mild overvoltages and under voltages where most power electronic loads can operate temporarily without special design considerations or changes in control mode. Active power consumption is expected to remain within a specific percentage (+/-) of the pre-disturbance level during the disturbance, and to return to within a specific percentage (+/-) of pre-disturbance consumption within a specific amount of time after the voltage returns to Region A.
- **Region C** corresponds to a severe voltage sag where power electronic loads will likely need to limit input current or cease consuming current altogether to avoid equipment damage or manage disruption to downstream processes. Active power consumption may decrease to zero or increase modestly, up to a specific percentage above the pre-disturbance level, but shall return to within a specific percentage (+/-) of pre-disturbance consumption within a certain amount of time after voltage recovery to Region A. Meeting this requirement in practice generally means ensuring that no mechanical circuit breaker operations or transfers to backup generation are initiated within the site; the reduction in active power should instead result from the power electronic load limiting or zeroing its input current through control of the power electronic switches, not from a site-level transfer event.
- **Region D** covers the most severe voltage conditions, where it is expected the site may consume little or no active power for an extended period. The reduction to zero consumption might be permissible. Return to pre-disturbance active power consumption within a certain amount of time after voltage recovery might be permissible but not required; slower return times, up to a certain amount of time, might also be permissible but shall be accurately represented in site model data provided to the interconnecting utility and transmission planner.

[48] PRC-024-4
[49] PRC-029-1

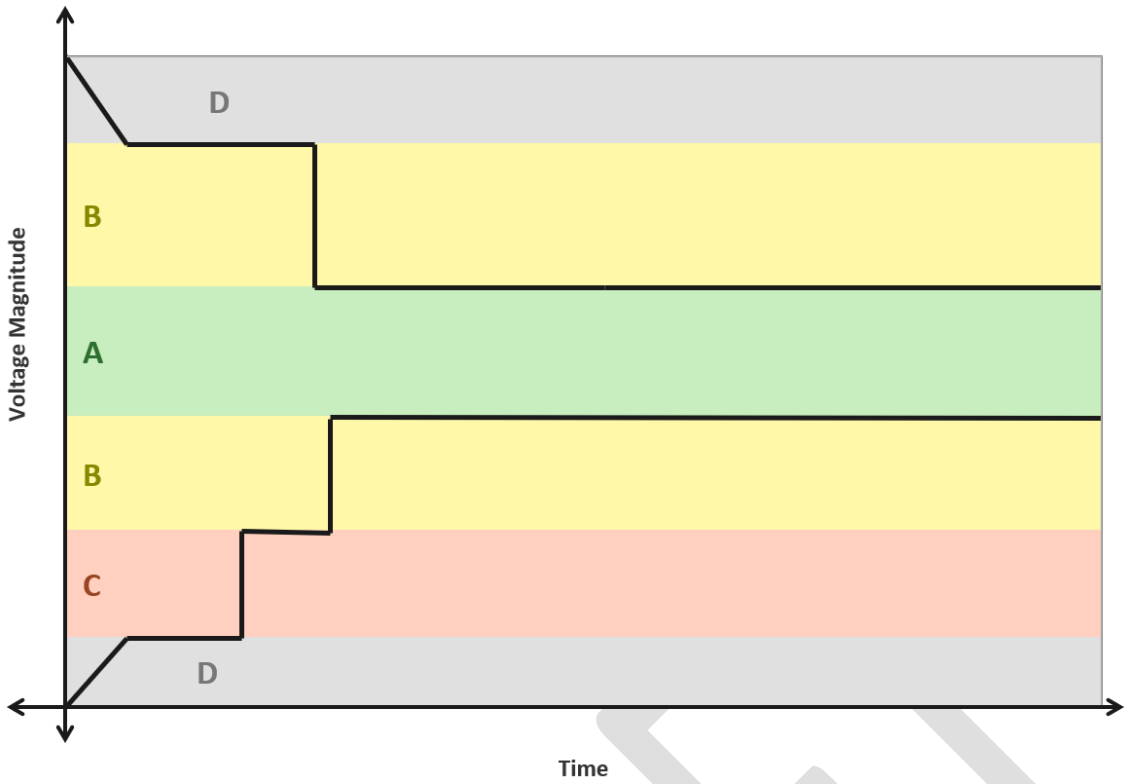


Figure 4.3: Example Voltage Ride-Through Structure

Considerations for Multi-Disturbance Ride-Through and Consecutive Event Survivability

Events in the Northern Virginia and AEP service areas described in **Chapter 1** demonstrate that real-world transmission disturbances frequently involve multiple successive voltage depressions rather than a single isolated fault. Automatic reclosing sequences can produce two, three, or in the July 2024 DEV event, six successive fault applications within a short time window. Site protection schemes that count successive events and transfer to backup generation after a predefined threshold number of events may be entirely appropriate from a site reliability perspective but can contribute to large-scale simultaneous CILR when many sites share similar counter thresholds.

This paper recommends that VRT requirements explicitly address multi-disturbance survivability. Where sites elect to include disturbance counter logic in their protection designs, the counter threshold should be set to accommodate the full automatic reclosing sequence expected on the transmission system serving the site, typically a minimum of three to six reclosing attempts within a 90-second window. Sites should also be required to demonstrate that their protection and control settings do not cause them to transfer to backup generation based solely on the number of voltage sags within a defined window without regard for the voltage magnitude or duration of those sags, unless the voltage sags are outside of the ride-through region.

Considerations for Post-Fault Active Power Recovery

PFAPR refers to the expectation that a large load site with a CILR during a disturbance will restore that consumption in a timely, controlled manner after the disturbance has cleared. In the absence of PFAPR requirements, load may remain at reduced levels for extended periods following a fault, contributing to adverse system impacts. The PFAPR requirement is therefore a necessary complement to ride-through. Ride-through prevents sudden load loss during the fault, while PFAPR ensures that any permitted temporary reduction is reversed promptly once BPS conditions have recovered.

Before specifying PFAPR obligations, it is necessary to establish what what behaviors are expected across the VRT operation region. At a minimum, the VRT operation region can be divided into three behavioral regions. **This regional structure, analogous to the momentary cessation framework established for IBRs, provides the definitional foundation for PFAPR obligations:**

- **Normal Operations Region:**
  - **Condition:** Voltage is near nominal.
  - **Obligation:** The site remains connected and maintains pre-disturbance consumption.
- **Partial Reduction Region:**
  - **Condition:** Voltage has deviated but remains within the ride-through region.
  - **Obligation:** The site stays connected but may temporarily reduce consumption in proportion to the voltage deviation and the PFAPR obligation applies upon voltage recovery.
- **Momentary Cessation or Disconnection-Permitted Region**
  - **Condition:** Voltage has fallen outside the ride-through region.
  - **Obligation:** The site is not obligated to remain connected, and return-to-service is governed by ramp rate requirements rather than the PFAPR window.

A significant source of confusion in current practice concerns the relationship between the VRT region and the PFAPR obligation. When a fault occurs and the voltage at the site's POI remains within the defined ride-through region (i.e., the voltage does not fall below the LVRT boundary or rise above the HVRT boundary for the relevant fault duration), then the site is expected to ride through without disconnecting, and the PFAPR obligation applies: once voltage recovers to at least 0.9 pu, the site should restore at least 90% of its pre-fault power consumption within the time specified by the applicable requirement (typically one second as a default, or a longer period where system strength conditions warrant). When a fault occurs and the voltage falls outside the ride-through boundary, and upon disconnecting, is not obligated to restore its full pre-fault load within the one-second PFAPR window, because reconnecting the entire load of a large site within one second of disconnection is not physically achievable. In this case, the return-to-service expectations should be governed by ramp rate requirements and coordination with system operators rather than a strict one-second PFAPR.

The distinction between these two scenarios (i.e., operating within the ride-through region versus falling outside it), has significant operational and compliance implications and should be made explicit in any formal PFAPR requirement. Transmission system operators should be cautious about imposing one-second reconnection obligations on sites that have fully disconnected from the BPS following a fault that exceeds the ride-through region, as doing so may be technically unachievable and could create perverse incentives for site protection design.

The PFAPR timing should also account for system strength. In stronger portions of the BPS, where voltage recovers rapidly and generation can absorb the ramping demand, a one-second recovery to 90% of pre-fault consumption is achievable and appropriate. In weaker areas, a more gradual recovery that is potentially configurable up to ten seconds, as allowed under AESO's TCDC requirements[50], may be necessary to avoid introducing voltage instability or oscillations through rapid reloading of a system that has not fully stabilized. The ramp rate at which a site restores load after a fault should be treated as an integral part of the PFAPR framework and not determined independently.

[50] Guide-to-AESO-Connection-Requirements-for-Transmission-Connected-Data-Centres.pdf

DRAFT

It is important to note that PFAPR applies not only to sites that fully reduce consumption to zero (momentary cessation) but equally to those that partially reduce demand in proportion to the voltage dip while remaining connected. ERCOT's NOGRR 282, for example, requires that for newer facilities, the permitted degree of load reduction during a voltage disturbance be proportional to the magnitude of the voltage deviation.[51] Even if a site reduces consumption by only 50% during the disturbance, the 90% recovery obligation and the two-second recovery window still apply once voltage returns to at least 0.9 pu. Requirements should therefore be careful to address the full spectrum of disturbance responses, from minor proportional reductions through full momentary cessation, and not scope PFAPR solely to the full-cessation case.

Considerations for Frequency Ride-Through Requirements

Frequency deviations result from system-wide imbalances between electricity generation and demand, propagating throughout the entire synchronous Interconnection. Unlike voltage disturbances, which are localized and shaped by local network characteristics, a frequency event experienced in one part of an Interconnection is experienced simultaneously by all sites within that Interconnection. This Interconnection-wide nature of frequency disturbances provides a strong technical basis for recommending that FRT requirements be adopted at the Interconnection level, consistent with the structure of existing NERC Reliability Standards such as PRC-029.[52]

The disconnection of large loads during frequency excursions can exacerbate rather than relieve grid stress. During an under-frequency event caused by sudden generation loss, the simultaneous disconnection of multiple large load sites, whether due to internal UPS transfer logic or protective relay settings, removes a significant portion of reactive and real power demand from the system. This apparent relief may cause frequency to overshoot, creating a subsequent over-frequency event that could trigger generator over-frequency protections. Conversely, during an over-frequency event caused by sudden load loss, the disconnection of large loads would reduce demand further, worsening the over-frequency condition. FRT requirements help mitigate both failure modes by requiring sites to remain connected and maintain their pre-disturbance power consumption within defined frequency excursion limits.

Review of the existing and proposed FRT requirements across North American jurisdictions reveals a high degree of alignment. A review of common industry benchmark requirements shows that jurisdictions are adopting FRT profiles closely aligned with or identical to the IEEE 2800 and NERC PRC-029[53] criteria for IBRs: continuous operation between 58.8 and 61.2 Hz, a 299-second ride-through capability between 58.8 and 57.5 Hz and between 61.2 and 63.0 Hz, and optional tripping outside those bounds. Additionally, most reviewed standards prescribe a withstand capability for rate-of-change-of-frequency (RoCoF) of at least ±2 Hz/s, with AESO targeting 5 Hz/s.

Recommended Frequency Ride-Through Requirements

Based on this evidence, this paper recommends that the IEEE 2800[54] and NERC PRC-029-1[55] FRT and RoCoF criteria, with the possible modification described below, be adopted as minimum standards for computational loads. This recommendation is supported by the following reasoning:

- Frequency is an Interconnection-wide phenomenon, making a uniform Interconnection-level standard technically appropriate (see **Figure 4.4)**.

[51] NOGRR282
[52] PRC-029-1
[53] PRC-029-1
[54] IEEE 2800-2022
[55] PRC-029-1

- The IEEE 2800[56] and PRC-029-1[57] FRT regions have been developed through rigorous standards processes and reflect the credible frequency excursions associated with the loss of the largest single infeed in each Interconnection.
- All major North American RTOs and ISOs that have implemented FRT requirements for large loads have converged on these same criteria, providing strong industry precedent.
- Adopting the same FRT criteria as those applied to IBRs eliminates a coordination gap between the load and generation sides of the BPS.

The under-frequency load shedding (UFLS) coordination implications should also be addressed. FRT requirements should be designed so that large loads do not trip before UFLS schemes operate, which could deprive the system of demand relief it relies on during severe under-frequency events. Careful review of each site's internal protection settings against the applicable UFLS scheme is therefore recommended as part of the interconnection study process.

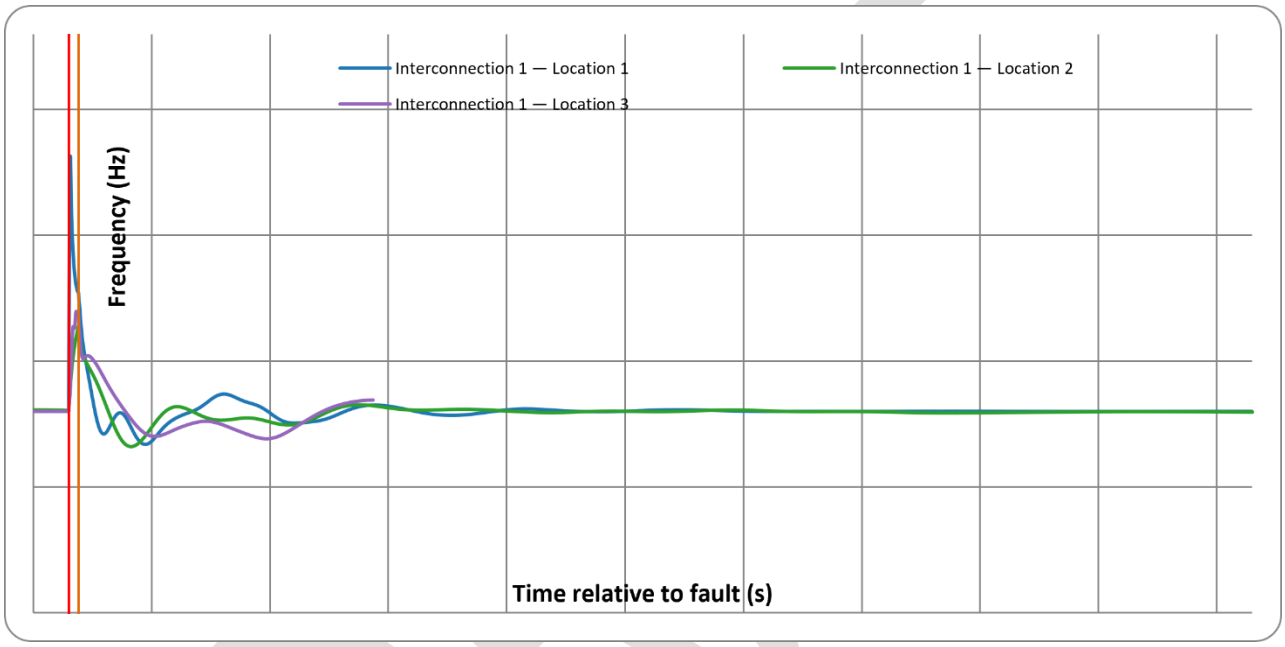


Figure 4.4: Comparison of Frequency Response to Disturbances Across Same Interconnection

Modifications to the PRC-029 Requirements for Suitability for Large Loads

The PRC-029 requirements are recommended as a starting point for FRT requirements. However, to coordinate the interactions between load and generation, the duration associated with the high FRT requirements for computational loads may need to be adjusted to prevent simultaneous disconnection of generation and load during frequency excursions.

Ride-Through Requirements for Co-Located Generation

Large load sites increasingly include co-located generation operating in parallel with the BPS ranging from utility-scale BESS to co-located gas turbines. The ride-through obligations of this co-located generation are generally governed by separate standards. Generators registered with NERC as Generator Owners are

[56] IEEE 2800-2022
[57] PRC-029-1

subject to PRC-024-4[58] for voltage and frequency protection settings. Co-located IBR generation interconnecting above applicable size thresholds is subject to PRC-029-1[59] and IEEE 2800-2022.[60]

This creates a coordination challenge at sites where the computational load and its co-located generation are both connected through a common POI. The net interchange at the POI, which may be a combination of load consumption and generation output, can change dramatically if the load disconnects to backup generation while the co-located grid-connected generation continues operating or vice versa. The resulting net change in active power at the POI may be unexpected by system operators and may stress nearby transmission elements or reactive support resources. **This paper recommends that transmission planners and interconnection engineers explicitly study the behavior of the combined site, treating load, co-located generation, and on-site storage as an integrated unit, to identify worst-case POI power swings and ensure that ride-through and protection coordination requirements address the full range of credible combined behaviors.**

It is worth noting that the ride-through and PFAPR requirements proposed in this paper are currently applied to the load only. The co-located generation is separately subject to PRC-024-4[61] and, where applicable, PRC-029-1[62] and IEEE 2800-2022.[63] This position is consistent with the applicability language in ERCOT NOGRR 282[64] and SPP's HILL[65] framework, both of which scope their requirements to the large load customer and treat any co-located generation as subject to its own distinct compliance pathway. This paper adopts the same applicability framing. Requirements discussed herein apply to the load (computational and cooling infrastructure) at the POI, and co-located generation is excluded from their scope.

An open question remains, however, as to whether a single POI-level performance region evaluated at the net interchange point, rather than separately for load and generation, might better reflect operational reality at sites where load and generation are tightly integrated. For example, when a site has deployed BESS that can actively offset CILR at the POI, the grid may be largely unaware that any internal transfer occurred. In such cases, a POI net-flow performance expectation could be a simpler and more outcome-focused framework than maintaining separate load and generation ride-through obligations, as the grid operator primarily cares about what is observed at the POI. **This question is not resolved in this paper and is identified as an important area for further work, potentially including analysis of how existing POI-level requirements interact with co-located generation in practice.**

The coordination of VRT and FRT requirements with co-located generation ride-through obligations (PRC-024,[66] PRC-029,[67] and IEEE 2800[68]) is also essential, particularly at sites where large generation and load share a common POI.

Beyond the coordination challenge at the POI level, a foundational reliability concern is that individual components of a co-located site can each satisfy their applicable ride-through requirements independently (i.e., the load complying with VRT and FRT obligations and the co-located generator complying with PRC-

[58] PRC-024-4
[59] NOGRR282
[60] IEEE 2800-2022
[61] PRC-024-4
[62] NOGRR282
[63] IEEE 2800-2022
[64] NOGRR282 Issue
[65] High Impact Large Load (HILL) Integration - Southwest Power Pool
[66] PRC-024-4
[67] NOGRR282
[68] IEEE 2800-2022

024[69] or PRC-029[70]) while the combined site behavior at the POI remains problematic from a BPS reliability standpoint. Separate standards were designed for standalone resources and contain no explicit provisions governing the interaction between a load and a generator sharing a common POI that may respond differently to the same disturbance event.

The voltage-duration ride-through regions defined in PRC-024[71] and PRC-029[72] are not identical to the large load VRT regions currently implemented in ERCOT NOGRR 282 and SPP's HILL framework. There are specific voltage magnitude and duration combinations where a synchronous generator subject to PRC-024[73] is permitted to trip while the computational load remains connected, and conversely, where the load is permitted to reduce consumption while the generator continues operating. At sites with co-located natural gas generation subject to PRC-024[74], these mismatched regions can convert what might otherwise be a simple load reduction into a simultaneous load reduction and generation loss at the same POI, effectively doubling the net power swing observed by the transmission system relative to what either event would produce independently. Transmission planners should therefore map these mismatched regions explicitly when modeling co-located site disturbance behavior in interconnection and planning studies, and should use the PRC-024[75] and PRC-029[76] ride-through regions as inputs to worst-case POI power swing calculations rather than analyzing load and generation separately.

A further consideration warranting evaluation is whether requirements or controls based on a site's net import or export at the POI during disturbed conditions are appropriate, in addition to the component-level requirements currently applicable to load and generation individually. A requirement that constrains the maximum rate of change of net POI power transfer during voltage or frequency events, analogous to ramp rate requirements applied to generation resources, could significantly reduce the worst-case power swing observed by the transmission system. Reliable coordination of this kind requires continuous real-time monitoring of net POI interchange, communications between load-side and generation-side control systems, and documented coordinated operating procedures for disturbance events and post-fault restoration. Future interconnection requirements for co-located sites above a defined capacity threshold should address each of these elements explicitly, rather than treating load and generation protection as independent systems with no common operating protocol.

Post-disturbance restoration of a co-located site should be coordinated across both the load and generation components to prevent secondary reliability events. If a site's computational load reconnects from backup generation while co-located grid-connected generation simultaneously ramps back from a low-output ride-through mode, the combined increase in net demand at the POI can substantially exceed the pre-disturbance load level and may occur at a ramp rate that the balancing authority has not pre-positioned resources to absorb. Conversely, if generation reconnects before load, the site may briefly export power to the grid at a level and ramp rate not anticipated in the interconnection study, potentially causing overvoltage conditions at the delivery substation. Interconnection agreements and site operating procedures for co-located configurations should specify the sequencing and maximum ramp rates for combined restoration, and the balancing authority should receive advance notification before any planned reconnection event involving a co-located site above a defined MW threshold.

[69] PRC-024-4
[70] NOGRR282
[71] PRC-024-4
[72] NOGRR282
[73] PRC-024-4
[74] PRC-024-4
[75] PRC-024-4
[76] NOGRR282

Additional complexity arises where a data center campus is connected through multiple points of interconnection (e.g., where computational load is served at a dedicated 230 kV substation while co-located generation interconnects at a separate 138 kV delivery point) or where load and generation are introduced in phases over an extended development timeline. In multi-POI configurations, the relevant power swing analysis should consider interactions across all points simultaneously, and protection coordination should account for the possibility that a disturbance at one POI triggers responses that propagate to the other. In phased developments, the co-location relationship between load and generation changes materially as each new phase is added, and the aggregate POI behavior in the final built-out configuration may differ substantially from that studied at the time of initial interconnection. Phased co-located developments should therefore require updated combined-site interconnection studies and protection coordination reviews at each phase gate, not only at the time of initial commercial operation.

Retroactivity and Applicability to Existing Sites

One of the most consequential and contested aspects of any large load ride-through framework is the question of retroactivity: whether requirements apply only to new sites entering the interconnection queue after the effective date, or whether they also apply to sites that are operational or that are late in the interconnection process. This paper does not prescribe a specific retroactivity policy as that is a regulatory and policy decision, but it provides the analytical context that should inform that decision.

The case for applying requirements to existing sites rests on the reliability record. The CILR events that prompted this paper involved sites that were already operational at the time of the events. A framework that applies only to new sites does nothing to address the existing installed base, which in Northern Virginia and West Texas already represents multiple GW of load with inconsistent or inadequate ride-through settings. Without retroactive application, the reliability risk documented in **Chapter 1** will persist for the lifetime of those sites, even after new sites enter service meeting the required standards.

The case against broad retroactivity rests on practical and economic grounds. Many existing sites were designed, sited, and financed under interconnection agreements that contained no ride-through requirements. Applying new requirements to these sites may require hardware replacement (e.g., UPS systems, transfer switches, protection relays), software reprogramming (e.g., dip-counting logic, UPS control firmware), or operational changes that were not contemplated in the original economics. For some site types, particularly cryptocurrency mining sites with thin margins and short asset lifespans, the compliance cost of retroactive requirements could be disproportionate.

ERCOT's approach in NOGRR 282 offers a practical model for navigating this tension. Rather than applying requirements uniformly to all operational facilities or exempting all existing facilities, NOGRR 282 establishes a grandfathering date (November 14, 2025) based on operational status or the execution of interconnection agreements, while providing a tiered compliance timeline for new facilities. Facilities satisfying interconnection requirements between the grandfathering date and January 1, 2028 must meet a proportional current reduction standard "if capable," while facilities satisfying requirements after January 1, 2028 face a mandatory proportional reduction requirement.[77] This tiered approach acknowledges both the need to address the existing installed base over time and the practical limits of imposing immediate full compliance on facilities already committed to a specific design. **A NERC Reliability Standard could adopt a similar structure:**

- **A grandfathering date for sites that are already operational or that have executed interconnection agreements prior to the standard's effective date,**

[77] NOGRR282

- **A best-effort voluntary compliance pathway for grandfathered sites supported by utility engagement and incentives focused on changes that offer the most reliability benefits at the least cost,**
- **A mandatory compliance date for sites entering the queue after the standard's effective date,**
- **A requirement that if the equipment limiting the ride-through or PFAPR capability of the site is replaced, then the site is required to meet the ride-through or PFAPR requirements.**[78]

As additional examples, the DEV Facility Interconnection Requirements and SPP's HILL framework both include provisions for periodic review of protection settings in existing facilities, which provides a vehicle for nudging the existing installed base toward compliance without requiring immediate mandatory retrofits.

Recommended Voltage Ride-Through and PFAPR Requirements

The LLWG recommends adopting the ERCOT large computational load VRT and PFAPR requirements,[79] **with the modifications described below, as the minimum technical capability baseline for computational loads.** This mirrors the role that NERC PRC-029 plays for inverter-based resources, establishing minimum requirements that all applicable facilities must meet or exceed, while allowing more stringent regional requirements where local conditions warrant. This recommendation is intended to provide an initial recommended baseline that the industry can evaluate now, ahead of and in support of the more rigorous engineering work that is anticipated to follow through the formal NERC Reliability Standards development process. It is expected, and is appropriate, that the NERC standards development process will subject this baseline to detailed testing and may refine or adjust it.

The rationale for recommending the ERCOT requirements is based on the characteristics of the ERCOT system rather than on a claim that ERCOT's numbers are uniquely correct:

- **Most vulnerable credible environment**: The Texas Interconnection is a comparatively small, electrically isolated interconnection. It contains weak-grid pockets prone to wide-area voltage disturbances, and it hosts among the highest concentrations of data center and cryptocurrency mining load in North America. Ride-through requirements that are sufficient to maintain reliability in that environment is, by extension, sufficient as a minimum floor on the stronger, more meshed interconnections.
- **Consistency with observed disturbance behavior:** For a typical three-phase fault-clearing sequence, the time spent in each voltage band during and after the fault falls within the ERCOT ride-through region. The requirements therefore covers the credible disturbance signatures documented in event analysis as a minimum, with modification needed only to extend coverage across the full disturbance duration.
- **Lowest adoption friction:** Because ERCOT's requirements were among the first published, equipment manufacturers and data center developers have already been designing toward them. Adopting the ERCOT curve as the minimum leverages that existing design effort and reduces the risk of stranded or non-compliant equipment.

Modifications to the ERCOT VRT and PFAPR Requirements for Suitability for BPS

The ERCOT requirements recommended as a starting point for VRT and PFAPR requirements, and the following modifications are recommended to make these requirements suitable for the North American BPS:

[78] This equipment replacement framework is taken from NERC PRC-029-1 R4.3.1.
[79] Available here: NOGRR282

- **Extend to full disturbance duration:** Extend the ERCOT LVRT requirements beyond their published time boundary so that the ride-through obligation is defined across the full duration of a credible multi-stage reclosing sequence rather than terminating at the last published time point.
  - **Rationale:** The published ERCOT LVRT requirements are defined over the duration relevant to its own reclosing practices and fault clearing practices. A national minimum must cover the longer clearing and reclosing sequences observed in other regions, including 115 kV systems with electromechanical relaying.
- **Simplify requirements:** Reduce the number of discrete voltage-time steps in the ERCOT low-voltage boundary to a smaller set of segments suitable for a NERC Reliability Standard, without materially relaxing the boundary.
  - **Rationale:** The ERCOT curve might be considered more granular than is practical for a BPS-wide standard. A simplified, clearly bounded envelope is easier to specify, implement, and verify.
- **Cooling load applicability with case-by-case leeway:** Provide for case-by-case relief where a facility demonstrates, through study, that its cooling configuration cannot meet the requirement and that the associated reliability risk is acceptable.
  - **Rationale:** Cooling load can represent a very large share of total facility demand, and its loss on presents the same reliability concern as IT-load CILR. A blanket exemption would leave a material fraction of facility demand outside the requirement, undermining its reliability intent. At the same time, it is recognized that meeting the ride-through requirement on the cooling side may be more difficult and more costly than on the IT side, since it may require extending UPS or equivalent ride-through capability to pumps, fans, and chiller systems that are not conventionally protected to that standard. A site may seek relief where it demonstrates, through study, that its cooling configuration cannot practically meet the requirement and that the associated reliability risk is acceptable in its specific electrical context. This preserves the reliability-driven default while accommodating genuine, study-supported constraints on an individual basis rather than through a blanket exemption.
- **PFAPR held at 90% with case-by-case exceptions:** Retain a PFAPR obligation of at least 90% of pre-disturbance consumption, with recovery timing coordinated to the ride-through requirements. Permit relaxed recovery levels or timing only on a case-by-case basis where BPS and facility characteristics justify it, as shown in studies.
  - **Rationale:** A 90% recovery floor preserves the reliability intent of PFAPR as a minimum. For entities seeking more relaxed values, this can be determined via a study process rather than by weakening the baseline. Large load entities might seek relaxed values due to equipment limitations. Grid entities might seek relaxed values due to FIDVR concerns, for example.
- **Regional stringency layer:** Allow RTOs, ISOs, and utilities to impose more stringent voltage-time boundaries than the ERCOT-based minimum where local fault-clearing times, system strength, or voltage recovery characteristics demonstrate a need.
  - **Rationale:** Voltage is a local phenomenon. Several published curves (AESO, Fingrid, CAISO) are more stringent than ERCOT over portions of the envelope, reflecting local conditions. The minimum should be a floor, not a ceiling.

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Chapter 5: Other Considerations for Customer-Initiated Load Reduction Impacts

Even where formal VRT and FRT requirements are in place, disturbances exceeding the ride-through region will still occur; a well-prepared grid must have the tools and procedures to manage the resulting CILRs. This chapter identifies grid-side and load-side mitigations that can reduce either the probability or the severity of reliability impacts from computational-load CILRs. These mitigations are not presented as alternatives to ride-through requirements; rather, they are complements that address the residual risk that remains even after ride-through requirements are implemented.

Grid-Side Mitigations

The most effective grid-side mitigation for voltage disturbance-induced CILR is the rapid deployment of dynamic reactive power support resources in areas with high concentrations of computational loads. SVCs and STATCOMs can inject or absorb reactive power nearly instantaneously during and after a fault, reducing the depth of the voltage depression observed at the site POI and accelerating post-fault voltage recovery. STATCOMs are particularly effective in weak-grid conditions because they maintain full current injection capability even at severely depressed voltages, whereas SVCs experience reduced output at low voltage. The events in northern Virginia demonstrated that even in a strong, meshed transmission system, the combined reactive demand of simultaneous large load transfers can exceed the capability of nearby SVCs and generators, requiring manual operator intervention to energize shunt reactors and remove capacitors. Proactive installation of STATCOMs or other grid-forming reactive devices in areas with projected large load growth can reduce the severity and duration of post-fault voltage swells and reduce the probability of cascading load transfers.

Protection coordination is another important grid-side mitigation. The events described in **Chapter 1** repeatedly showed that electromechanical relays with longer operating times contributed to more severe and repeated voltage disturbances, which in turn triggered larger load transfers. Replacing electromechanical relays with digital relaying technologies in areas with high concentrations of large loads can reduce fault clearing times and decrease the number and duration of voltage depressions experienced by site equipment. Utilities should also review their automatic reclosing schemes in areas with large concentrations of power-electronic-coupled loads: reducing the number of reclosing attempts on permanently faulted lines, or extending the dead time between reclosing attempts, can reduce the number of successive voltage depressions that site protection systems need to survive. Any changes to reclosing schemes should be evaluated carefully against the full range of reliability implications, including the N-1 consequences of not reclosing on a temporary fault.

Managing CILR: Operational Tools, Telemetry and Event Analysis

When a CILR event occurs, BAs and TOPs must have the tools and procedures to manage the resulting generation surplus and voltage swell in real time. Fast-responding downward reserves including BESS, controllable generation, and demand response programs can absorb the excess generation created by sudden large-load CILR and prevent frequency from overshooting into the over-frequency trip range of generators. Procurement of adequate downward reserves in balancing areas with high concentrations of computational loads should be evaluated as a reliability planning matter.

Improved visibility and telemetry are essential for effective CILR event management. NERC's experience with the northern Virginia events demonstrated that high-fidelity POI metering installed at individual site interconnection points providing MW, MVAR, and voltage data at rates sufficient for post-event root cause analysis was critical to understanding site-by-site behavior and initiating targeted remediation conversations

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with data center operators. **Extending this type of monitoring to all large load sites above a size threshold is a priority recommendation. Real-time visibility into the aggregate consumption of computational loads within a BA area, ideally through enhanced telemetry and short-term forecasting, would allow operators to anticipate the generation surplus that would result from a large-scale CILR event and pre-position responsive resources accordingly.**

Including large loads in the ERO EAP[80] is also recommended. Currently, the EAP is focused on the performance of generation and transmission assets. **As computational loads become a significant source of BPS reliability risk, the EAP should be expanded to include analysis of large load behavior during grid disturbances, with the same rigor applied to root cause identification, remediation tracking, and lessons-learned dissemination that is currently applied to generator and transmission events.**

Largest Load Loss at Interconnection- or Balancing Authority-Level

Even where comprehensive VRT and FRT requirements are in place, voltage disturbances that exceed the ride-through region will occur, either because an extreme fault produces conditions outside the design region or because some sites will not meet requirements at the time of a disturbance. Interconnection-level and balancing authority planning should therefore account for the residual risk of large-scale CILR as a credible contingency, separate from and in addition to the generation loss contingencies that have historically defined worst-case planning scenarios.

1. **The first planning question is how to define the "largest credible CILR event" for contingency planning purposes**: Traditional N-1 planning assumes the loss of the single largest generation unit. For computational-load CILR, the relevant contingency is not a single site but the aggregate of all sites that would experience voltage below their ride-through threshold from a single credible fault. This is a number that depends on the fault location, fault type, system strength, and the distribution of site protection settings in the area. In Northern Virginia, a single SLG fault on a 230 kV line produced simultaneous CILR from sites across 18 substations. The effective contingency size was 1,500 to 1,800 MW which is an order of magnitude larger than any single site. **Planning frameworks should define the largest credible CILR event as a cluster-level contingency derived from dynamic studies that model site-level protection behavior explicitly, rather than relying on single-site capacity as the planning unit.**

2. **The second question is how this contingency should be reflected in reserve requirements**: Balancing authorities currently size reserves to cover the largest single contingency in their footprint, which is typically a large generation unit or a transmission line. Where the largest credible CILR cluster exceeds this contingency, the BA's reserve requirements may be insufficient to manage the resulting frequency and voltage excursion. BAs with significant concentrations of computational loads should evaluate whether their operating reserve requirements, including downward ramping capability, are adequate to manage the largest credible CILR event under their most stressed operating conditions. ERCOT's analysis establishing a 3.2 GW simultaneous load loss threshold as a reliability risk boundary provides a model for this type of assessment.

3. **The third question is how UFLS schemes should interact with large-load CILR events**: UFLS is designed to shed load in response to severe under-frequency conditions caused by generation loss, using pre-determined sets of loads that are removed when frequency drops below defined thresholds. A large CILR event, by contrast, causes a sudden reduction in demand that initially produces an over-frequency condition before generation re-dispatch restores the load-generation balance. In this scenario, UFLS should not activate, and ride-through requirements explicitly carve out UFLS compliance from FRT obligations. However, if a CILR event coincides with or follows a

[80] ERO Event Analysis Process (EAP) - Version 5

generation contingency, the combined load loss and generation loss may create conditions where UFLS activation is warranted, but its load targets may already have been removed by CILR. BAs and reliability coordinators should review their UFLS program designs to confirm that CILR events in their footprint are adequately reflected in the load availability assumptions underlying UFLS set-point calculations.

4. **Finally, the post-CILR recovery period presents its own reliability risk.** When sites reconnect following a CILR event, whether after 15 minutes (typical for UPS-supported sites returning from backup generation) or after several hours (for sites requiring manual intervention), the simultaneous reconnection of a large cluster creates a step increase in demand that the balancing authority must be prepared to manage. This recovery demand surge can be comparable in magnitude to the original CILR event and occurs at a time when generation dispatch may already have been adjusted to compensate for the initial load loss. Coordinated reconnection protocols, including notification to balancing authorities and staged site reconnection, are necessary to prevent the recovery from becoming a second reliability event. This paper recommends that interconnection agreements and operational procedures for large load sites above a defined capacity threshold require advance coordination with the relevant BA before reconnecting following any CILR event exceeding a defined magnitude.

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Chapter 6: Conclusion

Based on the analysis of the data from previous disturbances, the dynamic response of computational loads to voltage disturbances varies from site to site; and the risks posed by data centers related to ride-through and PFAPR also varies from site to site.

This paper has examined the reliability implications of computational load disturbance performance through three interconnected lenses: the real-world events that have demonstrated the BPS impact of large-scale CILRs (**Chapter 1**), the site-level design factors that govern how a computational load responds to a disturbance (**Chapter 2**), and the system-level attributes that shape the nature and severity of the disturbances that sites must withstand (**Chapter 3**). Drawing on this analysis together with a review of existing and proposed requirements across North American and international jurisdictions (**Chapter 4**), and the mitigations available on both the grid side and the load side (**Chapter 5**), this chapter presents the paper's key conclusions and recommendations.

The central conclusion of this paper is that disturbance performance requirements for computational loads are necessary for maintaining BPS reliability. The events documented in **Chapter 1** demonstrate that in the absence of such requirements, the simultaneous transfer of computational loads to backup power during normally cleared transmission faults can produce frequency deviations, voltage swells, and operational challenges of a scale that requires active operator intervention. As the aggregate capacity of computational loads on the BPS continues to grow—with ERCOT alone reporting over 9 GW of large loads operational or approved as of April 2026, and many multiples of that in interconnection queues across the continent—the reliability risk associated with uncoordinated large load behavior during disturbances will grow proportionally. Additionally, as the technical solutions available to address reliability concerns from large loads evolve, ride-through and PFAPR requirements provide a design criteria for these solutions.

NERC Event Analysis Program Review of Large Load Performance Events

Understanding the causes and effects of reliability events is essential for preventing recurrences and improving system performance and resilience. Through rigorous post-event analysis, NERC's Event Analysis team identifies root causes, shares lessons learned, and implements corrective measures for a secure and reliable BPS.[81] Evaluating BPS events to determine their causes, understanding failure modes, tracking efforts to prevent future incidents, and sharing best practices with industry directly contributes to our goal of ensuring a reliable BPS. This process also provides valuable input for training and education, trend analysis, and NERC Reliability Standards development, all of which support continued reliability improvement.

Although the current EAP[82] does not include criteria to review large load ride-through events, the NERC Event Analysis team created the two incident reviews discussed in this paper. These incident reviews demonstrate the flexibility of the Event Analysis Program, enabling the team to examine events that provide value to the industry even when they fall outside the program's formal criteria.

The EAS is conducting a scheduled review of the EAP document in 2026 and is developing criteria supporting the analysis of events involving large loads riding through system faults. This new version of the EAP will clarify the ERO's expectations when a large load fails to ride through a system disturbance. As these events are analyzed, industry can deepen its understanding of their causes and identify effective mitigation actions

[81] Event Analysis
[82] ERO Event Analysis Process (EAP) - Version 5

by publishing lessons learned documents and related work products. These efforts will ultimately enhance the reliability of large load interconnections.

Critical Reliability Recommendations

Recommendation 1: NERC Standards should define a minimum technical capability floor for computational load VRT and PFAPR while allowing regional or local modification where system-specific analysis demonstrates a need for more stringent requirements. The LLWG recommends using the ERCOT large computational load VRT and PFAPR requirements,[83] with the modifications described in the **Modifications to the ERCOT VRT and PFAPR Requirements for Suitability for BPS** section of **Chapter 4**, as the minimum technical capability baseline for computational loads. Specific voltage thresholds and time boundaries within that structure should be validated through regional dynamic simulations before adoption in NERC Reliability Standards. The VRT requirements should also include requirements for multi-disturbance ride-through. Where sites include disturbance counter logic in their protection designs, counter thresholds should be required to be set to accommodate the full reclosing sequence expected at the applicable interconnection point if each individual event falls within the applicable ride-through region.

Recommendation 2: NERC Reliability Standards should use the IEEE 2800[84] and PRC-029-1[85] FRT and RoCoF criteria, possibly modified to prevent simultaneous load and generation tripping for high frequency excursions, as requirements for computational loads.

Recommendation 3: RTOs, ISOs, and utilities should perform detailed dynamic simulations across a range of operating conditions, including weak-grid, high-IBR scenarios and considering fault-clearing times, to determine if more stringent VRT requirements or if modified PFAPR timing requirements are needed for specific computational load interconnections.

Recommendation 4: NERC Reliability Standards should require computational load sites above a defined capacity threshold to provide verified and validated dynamic load models calibrated to actual site characteristics while including UPS configuration, dip-counting logic thresholds, and PFAPR information as a condition of interconnection, rather than relying on default parameters designed for residential or commercial load mixes.

Recommendation 5: BAs and reserve sharing groups with significant concentrations of computational loads should evaluate whether their operating reserve requirements are adequate to manage the largest credible cluster-level CILR event, defined as the aggregate load of all sites sharing common electrical exposure to a credible fault rather than the capacity of any single site. Reliability coordinators should additionally review UFLS program designs to confirm that CILR events are reflected in the load availability assumptions underlying set-point calculations, given that a CILR coinciding with a generation contingency could simultaneously remove both UFLS load targets and generation from service.

Recommendation 6: Ride-through and PFAPR requirements should include a tiered applicability structure that addresses the existing installed base rather than applying exclusively to new sites entering the interconnection queue. The reliability risk documented in this paper derives primarily from sites already operational at the time of the events, and a framework applicable only to new interconnections leaves that risk unaddressed for the lifetime of the existing fleet.

[83] Available here: NOGRR282
[84] IEEE 2800-2022
[85] PRC-029-1

Recommendation 7: Large load sites sharing a common POI with co-located generation should be modeled as integrated units in interconnection and planning studies, using the PRC-024[86] and PRC-029[87] VRT and FRT regions simultaneously with the applicable large load VRT and FRT regions to identify worst-case net POI power swing scenarios.

Recommendation 8: The NERC Event Analysis Subcommittee should expand the scope of the EAP[88] to include analysis of large load behavior during grid disturbances.

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[86] PRC-024-4
[87] PRC-029-1
[88] ERO Event Analysis Process (EAP) - Version 5

Appendix A: Acknowledgements

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this white paper.

Table A.1: Contributors

Name	Company	RSTC Group
Amin Zamani	Danovo Energy Solutions	LLWG
Benjamin Rodriguez	El Paso Electric	LLWG
Brad Gordon (NERC Coordinator)	NERC	NERC
Cindy Robert (EAS Vice Chair)	Hydro-Quebec	EAS
Eric Meier (LLWG Chair)	ERCOT	LLWG
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Rahul Anilkumar	Danovo Energy Solutions	LLWG
Rahul Chakraborty	Dominion Energy	LLWG
Ramtin Khalili	Jacobs	LLWG
Sean Jones	Tesla	LLWG
Sudip Manandhar (LLWG Vice Chair)	Southern Company	LLWG
Todd Bickel	PJM	EAS
Xi Wang	University of Calgary	LLWG

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Appendix B: Columbus, Ohio Area Events

Table B.1: Contributors Anonymized Data Center Profile of Sites Around Columbus, Ohio.	
Anonymized Data Center Name	**Estimated Capacity (MW)**
DC-A	230
DC-B	25
DC-C	73
DC-D	70
DC-E	110
DC-F	65
DC-G	80
DC-H	84
DC-I	66
DC-J	74
Total estimated area data center load: 877 MW	

Table B.2: Ride-Through Performance Comparison of Multiple Data Centers Across Three Events				
Data Center	**Sags**	CILR (MW)	**Ride-through**	**Voltage Magnitude During Worst Sag**
February 9, 2025				
A	3	0	100%	82.07%
B	3	0	100%	82.35%
C	3	70	0%	76.80%
D	3	60	0%	76.00%
E	4	0	100%	64.89%
F	3	65	0%	82.02%
G	3	78	0%	82.90%
H	3	82	0%	76.80%
I	3	0	100%	78.68%
J	3	73	0%	76.80%
Total CILR: 428 MW				
February 20, 2025				

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Table B.2: Ride-Through Performance Comparison of Multiple Data Centers Across Three Events				
Data Center	**Sags**	CILR (MW)	**Ride-through**	**Voltage Magnitude During Worst Sag**
A	1	0	100%	79.70%
B	1	0	100%	78.20%
C	1	5	93%	67.20%
D	1	0	100%	77.80%
E	1	0	100%	65.70%
F	1	0	100%	78.75%
G	1	6	92%	78.26%
H	1	0	100%	71.40%
I	1	0	100%	78%
J	1	14	81%	68.30%
Total CILR: 25 MW				
March 11, 2025				
A	2	0	100%	86.42%
B	2	0	100%	87.50%
C	4	73	0%	79.27%
D	2	0	100%	83.74%
E	2	0	100%	86.42%
F	2	0	100%	86.42%
G	2	0	100%	86.42%
H	4	80	0%	81.48%
I	N/A	N/A	N/A	N/A
J	4	74	0%	81.48%
Total CILR: 227 MW				

Notes:

- CILR = Pre fault MW – Post fault MW
- Ride-through % = Post fault MW ÷ Pre fault MW.
- Cells marked N/A indicates data not available.

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MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-4.1a

Respondent: Legal

Page: 1 of 2

Question: 1. Refer to the rebuttal testimony of Michael J. Witkowski at page 4, which states: "The Company's Operating Parameters document will apply to all new large load customer interconnections that request electric service under the Company's Large Load Provision amendments to Rate Schedule D11." Does DTE consider the application of its Operating Parameters to all new large load customer interconnections to be a legally binding requirement on the Company?

a. If yes, explain the source of that binding requirement (i.e., tariff provision, regulation, or law).

Answer: DTE Electric objects to this request to the extent it calls upon a Company witness to provide a legal conclusion regarding whether the application of the Operating Parameters constitutes a "legally binding requirement" and to identify the legal source of any such requirement. Subject to and without waiving this objection, DTE Electric responds as follows:

The quoted testimony describes DTE Electric's engineering practice and commitment to develop and apply customer-specific Operating Parameters for each new large load customer requesting service under the proposed Large Load Provision. It does not state that an existing tariff provision, regulation, or law independently requires DTE Electric to use a document titled "Operating Parameters" for every such interconnection.

The Operating Parameters process is the mechanism DTE Electric uses to identify and implement the technical requirements necessary for the safe and reliable interconnection and operation of each large load customer. The specific parameters are developed based on the characteristics of the customer's facility, the topography of the local and regional Bulk Electric System, the results of applicable system studies, coordination with the transmission owner, and applicable reliability requirements. Once finalized and incorporated into the customer's applicable agreement or operating procedures, those customer-specific requirements are binding in accordance with the terms of that agreement and applicable tariffs, rules, and reliability requirements.

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-4.1a

Respondent: Legal

Page: 2 of 2

DTE Electric will also comply with any applicable NERC, FERC, MISO, or other enforceable requirements governing large load interconnections as those requirements become effective.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-4.2a

Respondent: M. Witkowski

Page: 1 of 1

Question: 2. Refer to the rebuttal testimony of Michael J. Witkowski at page 20, which states: “I recommend that the Commission recognize that DTE Electric’s study-driven, customers pecific Operating Parameters process is the appropriate engineering mechanism for identifying and implementing reliability requirements for large load customers. DTE Electric will continue to coordinate with ITC, participate in applicable MISO and industry processes, and comply with applicable NERC, FERC, MISO, and other enforceable requirements as they become effective.”

a. After applicable NERC, FERC, MISO, or other enforceable reliability requirements become effective, would DTE continue to implement the “Operating Parameters process” referenced in witness Witkowski’s rebuttal testimony?

Answer: Yes. Pending final approval and upon the effective dates of applicable NERC, FERC, MISO, or other enforceable reliability requirements, DTE Electric would integrate all applicable technical standards and requirements into the Operating Parameters framework.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-4.2ai

Respondent: M. Witkowski

Page: 1 of 1

Question: 2. Refer to the rebuttal testimony of Michael J. Witkowski at page 20, which states: “I recommend that the Commission recognize that DTE Electric’s study-driven, customerspecific Operating Parameters process is the appropriate engineering mechanism for identifying and implementing reliability requirements for large load customers. DTE Electric will continue to coordinate with ITC, participate in applicable MISO and industry processes, and comply with applicable NERC, FERC, MISO, and other enforceable requirements as they become effective.”

a. After applicable NERC, FERC, MISO, or other enforceable reliability requirements become effective, would DTE continue to implement the “Operating Parameters process” referenced in witness Witkowski’s rebuttal testimony?

i. If yes, how does DTE intend to incorporate the new requirements into its Operating Parameters process?

Answer: Building upon CEODE-4.2a, site-specific studies will still be performed to determine if the enforceable reliability requirements are sufficient when considering specific customer load behaviors and dynamic conditions of the electrical system.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-4.2aii

Respondent: M. Witkowski

Page: 1 of 1

Question: 2. Refer to the rebuttal testimony of Michael J. Witkowski at page 20, which states: “I recommend that the Commission recognize that DTE Electric’s study-driven, customerspecific Operating Parameters process is the appropriate engineering mechanism for identifying and implementing reliability requirements for large load customers. DTE Electric will continue to coordinate with ITC, participate in applicable MISO and industry processes, and comply with applicable NERC, FERC, MISO, and other enforceable requirements as they become effective.”

a. After applicable NERC, FERC, MISO, or other enforceable reliability requirements become effective, would DTE continue to implement the “Operating Parameters process” referenced in witness Witkowski’s rebuttal testimony?

ii. If no, explain why not.

Answer: Refer to CEODE-4.2a.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-4.2b

Respondent: M. Witkowski

Page: 1 of 2

Question: 2. Refer to the rebuttal testimony of Michael J. Witkowski at page 20, which states: "I recommend that the Commission recognize that DTE Electric's study-driven, customerspecific Operating Parameters process is the appropriate engineering mechanism for identifying and implementing reliability requirements for large load customers. DTE Electric will continue to coordinate with ITC, participate in applicable MISO and industry processes, and comply with applicable NERC, FERC, MISO, and other enforceable requirements as they become effective."

b. When applicable NERC, FERC, MISO, or other enforceable reliability requirements become effective in the future, does DTE intend to apply these requirements to existing, planned, or under construction Large Load Customers to which the above requirements do not apply (due to legacy or grandfathering clauses)? Please include an explanation of whether and how DTE would evaluate the need for application of new requirements on existing, planned, or under construction Large Load Customers.

Answer: The Company will apply final and effective NERC, FERC, MISO, or other enforceable requirements in accordance with the specifications contained in those standards. The Company does not intend to treat a requirement as directly applicable to an existing, planned, or under construction large load customer if the final requirement excludes that customer through a legacy, grandfathering, or other transition provision.

Independent of whether a future requirement directly applies to a particular customer, DTE Electric will evaluate the final requirements and determine whether changes are required or otherwise appropriate, including to customer-specific Operating Parameters. That evaluation would consider the scope and purpose of the final requirement; the customer's development and operating status; facility design, equipment, load characteristics, controls, and operating behavior; the point of interconnection and relevant system conditions; the results of applicable technical studies; existing contractual and operating requirements; coordination with ITC and, as applicable, MISO; and any

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-4.2b

Respondent: M. Witkowski

Page: 2 of 2

authority provided under the final requirement to apply specified provisions where necessary to mitigate identified reliability impacts.

Accordingly, an existing, planned, or under construction customer's status alone would not necessarily determine whether a future requirement applies or whether a corresponding change to the customer's Operating Parameters is proper. The determination would depend on the final requirement's applicability provisions and the results of the Company's customer- and site-specific technical evaluation.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-4.2bi

Respondent: M. Witkowski

Page: 1 of 1

Question: 2. Refer to the rebuttal testimony of Michael J. Witkowski at page 20, which states: “I recommend that the Commission recognize that DTE Electric’s study-driven, customerspecific Operating Parameters process is the appropriate engineering mechanism for identifying and implementing reliability requirements for large load customers. DTE Electric will continue to coordinate with ITC, participate in applicable MISO and industry processes, and comply with applicable NERC, FERC, MISO, and other enforceable requirements as they become effective.”

b. When applicable NERC, FERC, MISO, or other enforceable reliability requirements become effective in the future, does DTE intend to apply these requirements to existing, planned, or under construction Large Load Customers to which the above requirements do not apply (due to legacy or grandfathering clauses)? Please include an explanation of whether and how DTE would evaluate the need for application of new requirements on existing, planned, or under construction Large Load Customers.

i. If yes, explain whether DTE will update Large Load Customers’ specific Operating Parameters document to incorporate any newly effective requirements.

Answer: Please see the response to CEODE-4.2b.

Attachment: *None*

MPSC Case No: U-22061

Requester: CEO

Question No.: CEODE-4.2bii

Respondent: M. Witkowski

Page: 1 of 1

Question: 2. Refer to the rebuttal testimony of Michael J. Witkowski at page 20, which states: “I recommend that the Commission recognize that DTE Electric’s study-driven, customerspecific Operating Parameters process is the appropriate engineering mechanism for identifying and implementing reliability requirements for large load customers. DTE Electric will continue to coordinate with ITC, participate in applicable MISO and industry processes, and comply with applicable NERC, FERC, MISO, and other enforceable requirements as they become effective.”

b. When applicable NERC, FERC, MISO, or other enforceable reliability requirements become effective in the future, does DTE intend to apply these requirements to existing, planned, or under construction Large Load Customers to which the above requirements do not apply (due to legacy or grandfathering clauses)? Please include an explanation of whether and how DTE would evaluate the need for application of new requirements on existing, planned, or under construction Large Load Customers.

ii. If no, explain why not.

Answer: Please see the response to CEODE-4.2b.

Attachment: *None*

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

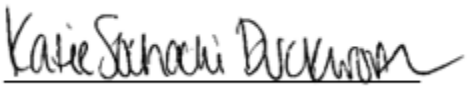
In the matter of the application of DTE Electric Company for approval of amendments to Rate D11 and related relief.	)))	Case No. U-22061

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Corrected Official Exhibits and Exhibit List on behalf of the Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar* were served by electronic mail upon the following Parties of Record, this Friday, September 18, 2026.

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