North American Electric Reliability Corporation
Digitally signed by North American Electric Reliability Corporation
Date: 2026.10.21 14:31:08 -04'00'

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)**	**Docket No. RD26-7-___**
	)	**RR-_____ _**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF REVISIONS TO THE NERC RULES OF PROCEDURE REGARDING COMPUTATIONAL LOAD AND REQUEST FOR EXPEDITED ACTION

Marisa Hecht
Senior Counsel
North American Electric Reliability Corporation
1401 H Street NW, Suite 410
Washington, D.C. 20005
202-400-3000
marisa.hecht@nerc.net

Counsel for the North American Electric Reliability Corporation

October 21, 2026

TABLE OF CONTENTS

I. SUMMARY 2
II. NOTICES AND COMMUNICATIONS 7
III. BACKGROUND 7
A. Regulatory Framework 7
B. Overview of NERC Registration Process and Registry Criteria 9
C. Development of the Proposed Revisions to the NERC Rules of Procedure 10
IV. THE NEED TO ADDRESS COMPUTATIONAL LOAD 11
A. NERC Large Loads Action Plan 12
1. NERC Large Loads Working Group 12
2. NERC Alerts and Incident Reviews 15
3. Need for New Functional Entities 17
B. ANOPR and FERC Directive 20
V. AUTHORITY TO REGISTER COMPUTATIONAL LOAD 21
VI. PROPOSED REVISIONS TO THE NERC RULES OF PROCEDURE 23
A. Appendix 2 24
1. Computational Load Site 24
2. Computational Load Operator and Computational Load Owner 27
B. Appendix 5A 28
C. Appendix 5B 29
VII. REQUEST FOR EXPEDITED ACTION 31
VIII. CONCLUSION 33

Attachment 1 Technical Support for Proposal
1-A Whitepaper #1
1-B Whitepaper #2
1-C Level 2 Alert Report
1-D Incident Reviews
1-E Technical Reasoning
Attachment 2 Clean Proposed Revisions
2-A Appendix 2 Clean
2-B Appendix 5A Clean
2-C Appendix 5B Clean
Attachment 3 Redline Proposed Revisions

TABLE OF CONTENTS

3-A	Appendix 2 Redline
3-B	Appendix 5A Redline
3-C	Appendix 5B Redline
Attachment 4	Comments and Consideration of Comments
4-A	August 2026 Posting
4-B	April 2026 Posting
Attachment 5	NERC Engagement Activities

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)**	**Docket No. RD26-7-___**
	)	**RR-_____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF REVISIONS TO THE NERC RULES OF PROCEDURE REGARDING COMPUTATIONAL LOAD AND REQUEST FOR EXPEDITED ACTION

Pursuant to Section 215(f) of the Federal Power Act ("FPA")[1] and Section 39.10 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] and consistent with the July 16, 2026 order[3] in the above-captioned docket directing the North American Electric Reliability Corporation ("NERC")[4] to develop registry criteria necessary for the registration of computational loads ("Computational Loads Order"), NERC hereby submits for Commission approval proposed revisions to the NERC Rules of Procedure Appendices 2, 5A, and 5B. NERC respectfully requests that the Commission approve the proposed revisions, provided in Attachment 2 hereto, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. In addition, NERC respectfully requests that the Commission afford expedited treatment to this filing to enable immediate action to address identified risks to the Bulk Power

[1] 16 U.S.C. § 824o.
[2] 18 C.F.R. § 39.10 (2026).
[3] *Order Directing the North American Electric Reliability Corporation to file Reliability Standard(s) Pertaining to Computational Load Integration*, 196 FERC ¶ 61,031 (2026).
[4] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006) [hereinafter ERO Certification Order].

System ("BPS") and grant the regulatory certainty to support integration of computational loads into the ERO Enterprise[5] regulatory framework.

I. SUMMARY

NERC respectfully requests Commission approval of proposed Rules of Procedure revisions that add two new functional entities to the NERC registry criteria – Computational Load Owner and Computational Load Operator. Through this proposal, NERC takes steps to address the most immediate risks of large computational loads to the reliability of the BPS before impacts are more fully realized.

Over the past few years, NERC identified, through the Long-Term Reliability Assessments ("LTRAs"), reliability risks posed by the unprecedented amount of large load, such as data centers and large industrial facilities, connecting rapidly to the BPS.[6] Trends documented in the LTRAs showed higher demand growth than at any point in the last two decades.[7] In addition to the proliferation of large load interconnecting to the BPS, NERC observed emerging concerns over the electrical behavior of large data centers and other computational load. Specifically, large-scale customer-initiated load reductions during normal grid faults could lead to voltage and frequency excursions, posing risks to the operation of the BPS.[8] Moreover, existing registered entities could

---

5 The ERO Enterprise includes NERC and the six Regional Entities: Midwest Reliability Organization, Northeast Power Coordinating Council, Inc., ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, Inc., and Western Electricity Coordinating Council.

6 NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026) at 9, https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf [hereinafter *2025 LTRA*]; NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024, updated July 2025) at 8, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf [hereinafter *2024 LTRA*]. NERC develops the LTRA annually in accordance with the NERC Rules of Procedure and Title 18, § 39.112 of the Code of Federal Regulations; this is also required by Section 215(g) of the Federal Power Act, which instructs the ERO to conduct periodic assessments of the North American BPS.

7 *Id.*

8 *2025 LTRA* at 28; *2024 LTRA* at 38.

not perform all the actions needed to address the risks.[9] It became clear that computational load did not behave like other large load, and with the projected increase connecting to the grid, NERC needed to quickly understand how to mitigate any impacts from the aggregate risks posed by large amounts of load with unique electrical behaviors.

NERC launched the Large Loads Action Plan to address risks comprehensively and expeditiously,[10] engaging with its technical stakeholder committee to consider characteristics of these loads and how to mitigate impacts to the BPS. Similarly, the United States Secretary of Energy and the Commission acknowledged the need for prompt mitigation of emerging risks through the Advance Notice of Proposed Rulemaking ("ANOPR") docket[11] and subsequently the Computational Loads Order. As a result of the work under the Large Loads Action Plan and the need highlighted by the Secretary of Energy and the Commission, NERC determined now was the time to regulate computational loads.

While new electrical behavior and load growth drives the need to regulate these users of the BPS, Congress[12] and the Commission[13] long ago contemplated that such large customers may someday need to be regulated under section 215 of the Federal Power Act.[14] Even with this expansive reliability authority under section 215, however, NERC has always relied on identified risk, stakeholder input from across industries, and a targeted focus on the engineering and physics

---

9 NERC, *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads* (March 2026), https://www.nerc.com/globalassets/our-work/guidelines/reliability/white-paper---assessment-of-gaps.pdf.

10 Information on the NERC Large Loads Action Plan is available at https://www.nerc.com/initiatives/large-loads-action-plan.

11 *Ensuring the Timely and Orderly Interconnection of Large Loads*, *Advance Notice of Proposed Rulemaking,* Docket No. RM26-4-000 (Oct. 27, 2025) [hereinafter ANOPR].

12 148 Cong. S1874 (daily ed. Mar. 14, 2002) (statement of Sen. Thomas), https://www.congress.gov/107/crec/2002/03/14/CREC-2002-03-14.pdf.

13 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC 61,104 at PP 98-99 (2006) [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC 61,328 (2006).

14 16 U.S.C. § 824o(b)(1).

behind a reliable grid to determine which entities should be registered on its NERC Compliance Registry as subject to mandatory Reliability Standards. Historically, NERC focused on owners and operators of the Bulk Electric System ("BES"), a subset of BPS facilities, as those entities who must comply with Reliability Standards. However, recently, new risks led to expansion of the NERC Compliance Registry to include entities owning and operating non-BES generating resources (i.e. inverter-based resources) due to their impact to the BPS.[15]

Based on the newly emerging reliability risks and recommended mitigation, NERC is proposing for the first time to regulate certain large customers based on their impact on the reliable operation of the BPS. NERC launched extensive stakeholder outreach and held multiple public comment periods to revise the Rules of Procedure Appendices 2, 5A, and 5B that include provisions on registration processes and registry criteria to add new functional entity types to the NERC Compliance Registry. Once registered on the NERC Compliance Registry, these new functional entity types would need to comply with mandatory applicable Reliability Standards.[16] The two new proposed functional entity types are proposed to be defined as follows:

- "Computational Load Operator" means the entity that operates a Computational Load Site.
- "Computational Load Owner" means the entity that owns and maintains a Computational Load Site.

[15] *N. Am. Elec. Reliability Corp.*, Order Approving Revisions to North American Electric Reliability Corporation Rules of Procedure and Requiring Compliance Filing, 187 FERC ¶ 61,196 (2024). Entities with these resources are registered as a Generator Owner or Generator Operator of non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV (Category 2 GO or GOP).

[16] The foundational Reliability Standards were developed in Project 2026-02 Computational Loads and will be filed with the Commission for approval at a later date, https://www.nerc.com/standards/reliability-standards-under-development/2026-02-computational-loads.

These functional entities "own and maintain" or "operate" a "Computational Load Site", which is proposed to be defined as follows: [17]

> one or more buildings, structures, or installations at a single location that
> 1) Primarily contains information technology infrastructure used for:
> - creating, executing, and delivering software applications and services;
> - artificial intelligence training, deployment, and delivery;
> - cryptocurrency mining; or
> - other computational activities at a data center; and
> 2) is supplied through electrical equipment that is connected to the BPS.

To appropriately identify those Computational Load Owners and Computational Load Operators who should be registered, NERC developed additional criteria for Computational Load Sites to tailor registration to the associated BPS risks. Specifically, NERC proposes to register entities who are Computational Load Owners or Computational Load Operators of a Computational Load Site "with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection."

NERC determined the proposed criteria address the aggregate risks posed by computational loads while also helping to ensure NERC does not capture smaller entities that pose less risk to the BPS at this time. The proposed thresholds include approximately 86% of the overall total (all sizes and voltages) amount of computational load projected by the end of 2027. Therefore, the threshold encompasses a majority of those Computational Load Sites of the size and connected voltage that can create unforeseen and unique electrical dynamic behaviors when connected to the BPS. Nevertheless, NERC continues to monitor impacts of all computational load to assess whether there are any material risks to the BPS.

[17] The proposed definition references artificial intelligence, which is also called "Super Intelligence" or "SI," per Presidential Executive Order 14434, 91 Fed. Reg. 63,129 (Sept. 29, 2026).

Given the rapid proliferation of large computational load, NERC respectfully requests the Commission provide expedited treatment in considering its approval of the proposed revisions to the Rules of Procedure. While the proposed applicable Reliability Standards will be filed at a later date for Commission approval along with associated implementation plans, expedited action on the registry criteria will permit NERC and the Regional Entities to more effectively engage new potential registrants and provide targeted education and outreach to appropriate entities. Furthermore, the regulatory certainty provided by approved registry criteria would encourage entities to engage early with NERC and the Regional Entities, providing the best outcomes for compliance preparation prior to the effective date of any applicable Reliability Standards.

As described above, NERC exercises prudence in any expansion of its registry criteria, employing a targeted, impact-based approach to development. It is through this lens that NERC determined that now is the time to stay a step ahead of risk and register Computational Load Owners and Computational Load Operators.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

Soo Jin Kim
Vice President, Registration and Standards
Marisa Hecht
Senior Counsel
North American Electric Reliability
Corporation
1401 H Street NW
Suite 410
Washington, D.C. 20005
202-400-3000
soo.jin.kim@nerc.net
marisa.hecht@nerc.net

III. BACKGROUND

The following background information is provided below: (1) an explanation of the regulatory framework undergirding the NERC registration process and the NERC Rules of Procedure revisions; (2) an overview of the NERC registration process and NERC registry criteria; and (3) the development process for the proposed Rules of Procedure revisions in this petition.

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[18] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the BPS, and with the duty of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards.[19] Under section 215, the Federal Power Act provides the Commission, via the ERO, authority to regulate "users, owners and operators of the bulk-power system [BPS]."[20]

---

18 16 U.S.C. § 824o.
19 *Id.* § 824o(b)(1).
20 *Id.*

NERC is the Commission-certified ERO under Section 215 of the Federal Power Act.[21] As such, under section 215, NERC cannot: (1) develop and enforce Reliability Standards for reliable operation of facilities used in the local distribution of electric energy, or (2) order the construction of additional generation or transmission capacity or set and enforce compliance with standards for adequacy or safety of electric facilities or services.[22] While the Federal Power Act defines the BPS, it does not define the terms "users", "owners", or "operators" of the BPS.

FERC's regulations echo Federal Power Act section 215 by requiring that "each user, owner and operator of the [BPS] within the United States…shall register with the [ERO] and the Regional Entity for each region within which it uses, owns or operates [BPS] facilities, in such manner as prescribed by the Rules of the [ERO] and each applicable Regional Entity."[23] In the Commission's Order No. 672 implementing section 215 of the Federal Power Act, the Commission held that such a registration requirement helps identify those entities subject to Reliability Standards and ERO rules, such as the NERC Rules of Procedure.[24] As with the Federal Power Act, FERC's regulations do not further define the terms "users", "owners", or "operators" of the BPS, leaving it to NERC and the Regional Entities to identify those entities through their rules, such as the NERC registry criteria.[25]

Section 215(f) of the Federal Power Act provides the regulatory framework for revisions to the NERC Rules of Procedure.[26] This provision states, "[t]he [ERO] shall file with the Commission for approval any proposed rule or proposed rule change, accompanied by an

---

21 *See* ERO Certification Order, *supra* note 4.
22 16 U.S.C. § 824o(i)(1) and (2).
23 18 C.F.R. § 39.2(c).
24 Order No. 672, *supra* note 13 at P 117.
25 NERC's current registry criteria are listed in Appendix 5B of the NERC Rules of Procedure, available at https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/Appendix-5B.pdf.
26 The Commission has defined NERC's Rules of Procedure as ERO Rules in its regulations. *See* 18 C.F.R. § 39.1.

explanation of its basis and purpose."[27] Section 215(f) further states that the proposed rule or rule change "shall take effect upon a finding by the Commission, after notice and opportunity for comment, that the change is just, reasonable, not unduly discriminatory or preferential, is in the public interest, and satisfies the requirements of subsection (c) [of section 215]."[28] The Commission's regulations require that the filing include "a description of the proceedings conducted by the [ERO]… to develop the proposal."[29] The NERC Rules of Procedure are ERO rules as defined in Section 39.1 of the Commission's regulations.[30]

B. Overview of NERC Registration Process and Registry Criteria

Within the regulatory framework described in Section III.A above, NERC follows the process in the Rules of Procedure Appendix 5A to identify and register owners, operators, and users of the BPS that could materially impact the reliability of the BPS and should therefore be responsible for performing reliability-related functions in accordance with approved Reliability Standards. To further inform the registration process, NERC developed the Rules of Procedure Appendix 5B, NERC's Statement of Compliance Registry Criteria ("Registry Criteria"), which articulates the BPS users, owners, and operators that must be registered. Section I of the Registry Criteria in Appendix 5B states that owners, operators, or users of the BPS are candidates for registration. Section II of the Registry Criteria provides functional entity types into which registration candidates identified in Section I are assigned. Section III provides additional threshold criteria for further refining certain entities identified as candidates for registration under Sections I and II. Should a candidate meet the Registry Criteria in Appendix 5B, then the candidate

27 16 U.S.C. § 824o(f).
28 *Id.*
29 18 C.F.R. § 39.10.
30 *Id.* § 39.1.

is registered, listed on the NERC Compliance Registry, and subject to compliance and enforcement of applicable Reliability Standards.[31]

C. Development of the Proposed Revisions to the NERC Rules of Procedure

NERC developed the proposed criteria through an open and inclusive stakeholder process. Under the NERC Large Loads Action Plan directed by the NERC Board in February 2025[32] and presented to the NERC Board in May 2025,[33] NERC worked with stakeholder subject matter experts to analyze the impact of large loads and initiated a three-pronged approach to mitigate risks of that impact: 1) development of NERC Alerts and Reliability Guidelines; 2) development of Registry Criteria through revisions to the NERC Rules of Procedure; and 3) initiation of a standards development project creating foundational Reliability Standards covering immediate risks posed by computational loads.[34]

Even before the first posting of proposed Rules of Procedure and throughout the development process, NERC launched a robust engagement effort to ensure stakeholders could meaningfully contribute input. NERC conducted outreach using public webinars and presentations to trade associations, including those representing the data center community and other computational loads, and other interested stakeholders. **Attachment 5** to this petition includes a detailed list of these engagements and demonstrates NERC's efforts to fully engage entities affected by the proposed revisions and who may be new to NERC processes.

---

[31] While registration decisions are based on the application of the Registry Criteria, NERC may determine whether an entity should be included or not included on the NERC Compliance Registry based on the entity's material impact on the reliability of the BPS. These materiality determinations are made by a NERC-led Registration Review Panel on a case-by-case basis, as detailed in Rules of Procedure Appendix 5A, Section III.D.

[32] *NERC Board of Trustees*, Minutes (Feb. 13, 2025), https://www.nerc.com/globalassets/who-we-are/board-of-trustees/minutes---board-of-trustees-open--february-13-2025.pdf.

[33] *NERC Board of Trustees*, Minutes (May 8, 2025), https://www.nerc.com/globalassets/who-we-are/board-of-trustees/minutes---board-of-trustees-open-meeting--may-8-20252.pdf.

[34] The foundational Reliability Standards were developed in Project 2026-02 Computational Loads and will be filed with the Commission for approval at a later date, https://www.nerc.com/standards/reliability-standards-under-development/2026-02-computational-loads.

Consistent with the NERC Bylaws[35] and Rules of Procedure,[36] NERC provided notice and opportunity for public comment on the proposed revisions to the Rules of Procedure. NERC posted initial proposed revisions to Appendices 2, 5A, and 5B for a 45-day public comment period from April 1 – May 15, 2026. NERC received 32 sets of comments from 44 commenters (**Attachment 4-B**). Upon considering comments, NERC further revised Appendices 2, 5A, and 5B and posted the updated proposed revisions for a 30-day public comment period from August 19 – September 18, 2026. NERC received 30 sets of comments from 35 commenters on the second posting (**Attachment 4-A**). NERC presented the proposed revisions and its consideration of comments to the NERC Board of Trustees ("Board") for approval. The Board approved the proposed revisions on October 8, 2026.[37]

IV. THE NEED TO ADDRESS COMPUTATIONAL LOAD

NERC, through its engineering staff and technical industry groups, assessed the impacts to the BPS of unprecedented load growth that has occurred over the past few years. Through that work, NERC determined that there are unique electrical characteristics and behaviors of computational loads that pose risks to the BPS. As described in this section, NERC determined certain aspects of these risks needed to be addressed through mandatory Reliability Standards applicable to the owners and operators of Computational Load Sites. Moreover, the Department of Energy and FERC identified the need to address the interconnection of large loads to the transmission system.[38] NERC agreed with the need for action. Accordingly, NERC proposed development of new functional entities as part of the NERC Compliance Registry. In Section A,

---

35 Article XI, Section 2 – Adoption, Amendment, and Repeal of Rules of Procedure.

36 Section 1400 – Amendments to the NERC Rules of Procedure.

37 *NERC Board of Trustees*, Open Meeting Agenda Item 5b (Oct. 8, 2026), https://www.nerc.com/globalassets/who-we-are/board-of-trustees/20261007_board_open_meeting_package.pdf.

38 ANOPR, *supra* note 11.

NERC describes the activities conducted under the NERC Large Loads Action Plan, including the work of the Large Load Working Group and NERC Alerts and Incident Reviews, to develop NERC's proposal. In Section B, NERC describes United States federal governmental involvement in addressing the reliability risks posed by large computational loads.

A. NERC Large Loads Action Plan

Over the past few years, NERC in its Long-Term Reliability Assessments identified unprecedented load growth, noting that demand growth is higher than at any point in the last two decades.[39] This projected increase in North American electricity demand is largely driven by computational load, such as data centers for artificial intelligence and other uses underpinning the digital economy, interconnecting with the BPS.[40] With this large increase, unique challenges include demand forecasting and planning for system behavior when some large loads are substantially larger and constructed more quickly than prior large loads using the BPS.[41] NERC recognized a need for quick and decisive action to address any potential impacts to reliability to support the exponential growth in an economy dependent upon reliable electricity. Accordingly, NERC initiated further study and collaboration with stakeholders to help ensure a reliable transmission system for all through its Large Loads Action Plan.

1. NERC Large Loads Working Group

As part of the NERC Large Loads Action Plan, NERC engaged the Reliability and Security Technical Committee Large Loads Working Group ("LLWG")[42] to assess the risks to the reliability of the BPS posed by large loads. NERC documented this assessment in whitepapers,

---

39 *2025 LTRA*, *supra* note 6 at 9; *2024 LTRA*, *supra* note 6 at 8.

40 *Id.*

41 *2024 LTRA* at 8.

42 Prior to April 2026, the Large Loads Working Group was known as the Large Loads Task Force ("LLTF"), and some documents developed before that date reference the LLTF.

and NERC continues its work to better understand the reliability impacts to the BPS of emerging large loads.[43]

In the first whitepaper, entitled "*Characteristics and Risks of Emerging Large Loads*" ("Whitepaper 1") (**Attachment 1-A**), NERC identified characteristics of large loads and defined the reliability risks that they may pose to the BPS.[44] While of course the size and proliferation of large loads is a defining characteristic, NERC further recognized that certain large loads, particularly those that are power electronic loads (referred to interchangeably as computational loads in the whitepaper), such as data centers for supporting cloud computing, artificial intelligence, cryptocurrencies, and other digital services, have electrical characteristics that pose reliability risks to the BPS. The power electronic loads "consist of high-performance computing… systems in which large clusters of computing resources work in concert to perform complex analysis and other tasks. These loads are further characterized by high energy consumption, variable operational demand, and significant cooling requirements."[45] In addition, those new power electronic loads "use software controls to manage the load behavior rather than the mechanical controls used by older motor loads."[46] These control systems enable computational loads to "rapidly change electricity consumption, creating previously unseen load behavior that can cause BPS planning and operational challenges."[47] Specifically, "[s]ome data center loads are known to have pulsed… characteristics, giving them extremely quick ramping potential that can

---

43 Current activities of the LLWG are outlined on its web page, https://www.nerc.com/who-we-are/committees/reliability-and-security-technical-committee-rstc/subcommittees-working-groups-and-task-forces/large-loads-working-group-llwg.

44 NERC, *Characteristics and Risks of Emerging Large Loads: Large Loads Task Force White Paper* (July 2025), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf [hereinafter Whitepaper 1].

45 *Id.* at 3.

46 *Id.*

47 *Id.*

introduce power quality and stability issues." Accordingly, Whitepaper #1 established that these characteristics are unique, new, and scaling quickly.

In the second whitepaper, "*Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*" ("Whitepaper 2") (**Attachment 1-B**), NERC identified potential gaps in Reliability Standards, as well as gaps in other industry standards and practices and interconnection requirements, in addressing the risks posed by the characteristics identified in Whitepaper #1.[48] Should those gaps remain, NERC then assessed the 1) likelihood of the risk occurring and 2) the severity of the risk to the BPS. Next, NERC analyzed whether mitigating actions by existing registered entities could close those gaps through new applicable Reliability Standards, interconnection requirements, or other means. The following risks were identified as 1) high likelihood; 2) high impact to the BPS; and 3) could not be adequately mitigated with existing registered entities:

- Transmission Adequacy
- Short-term Demand Forecasting
- Balancing and Reserves
- Lack of Real-Time and Operations Planning Time Frame Coordination
- Lack of Proper Integration and Lack of Operational Readiness
- Frequency Stability for the Texas Interconnection
- Voltage Stability
- Oscillations (if high impact, then high likelihood)

[48] NERC, *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads* (March 2026), https://www.nerc.com/globalassets/our-work/guidelines/reliability/white-paper---assessment-of-gaps.pdf.

Based on the identified multiple high-impact risks to the BPS that existing NERC registered entities cannot adequately address,[49] Whitepaper #2 recommended that NERC pursue registration of a type of entity (or types of entities) that could provide forecasting and modeling data, provide relevant information, coordinate with other functional entities, and comply with Operating Instructions or performance requirements (such as ride-through during disturbances), among other actions to be codified in Reliability Standards.[50]

2. NERC Alerts and Incident Reviews

Another component of the NERC Large Loads Action Plan, NERC published a Level 2 Alert on September 9, 2025 that provided additional insight into the impacts of the integration of large loads and industry preparedness.[51] In addition to recommendations for applicable registered entities to help mitigate risks to BPS reliability resulting from integrating large loads, the Level 2 Alert requested responses to questions intended to support NERC's evaluation of actions taken thus far in integrating large loads. NERC analyzed the responses to the Level 2 Alert and issued a public report (**Attachment 1-C**) that further highlighted the need for new functional entities and Reliability Standards.[52] Specifically, among other takeaways, the Level 2 Alert report noted that responding entities reported they could not gather modeling information or did not have direct coordination with large load entities, corroborating the gaps identified in Whitepaper #2.

---

[49] Chapter 8 of Whitepaper #2 describes the likelihood and impact of the risks and whether those risks can be adequately mitigated by the existing registered entities (Attachment 1-B at 35).

[50] *Id.* at 53 (Recommendation 1).

[51] NERC, *Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations* (Sept. 9, 2025) [hereinafter Level 2 Alert], https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2--large-loads.pdf.

[52] NERC, *Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations*, (posted on website Mar. 17, 2026), https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/aggregated-report-level-2-large-load-interconnection-study-commissioning-and-operations.pdf.

While the work under the Large Loads Action Plan identified the potential risks to the reliability of the BPS, NERC determined to act quickly before these risks become actualized. Indeed, while not rising to the level of significant events, two incident review reports highlight the risks, particularly in light of the expected growth of computational load over the next year and into the future (**Attachment 1-D**).

The first incident involved large amounts of voltage-sensitive load reductions during a 2024 disturbance in the Eastern Interconnection.[53] In particular, "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."[54] During review of the incident, NERC determined that the 1,500 MW of load reduction was exclusively data center-type load.[55] The voltage did not rise to a level that posed a reliability risk, but operators did need to take action to reduce the voltage within normal operating levels.[56] NERC noted, "as the potential for this type of load loss increases, the risk for frequency and voltage issues also increases."[57]

The second incident review covered several load-loss events in the Electric Reliability Council of Texas ("ERCOT") Interconnection resulting from the unique ride-through characteristics of crypto-mining facilities. Specifically, crypto-mining facilities, a subset of computational load, depend on constant-power electronic power supplies that are highly sensitive to voltage drops, which makes these facilities shut down almost instantly when voltage dips below a certain level.[58] As further described in the incident review, these characteristics of crypto-mining

---

53 NERC, *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions* (Jan. 2025), https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_large_load_loss.pdf.

54 *Id.* at 1.

55 *Id.* at 2-3.

56 *Id.* at 1.

57 *Id.*

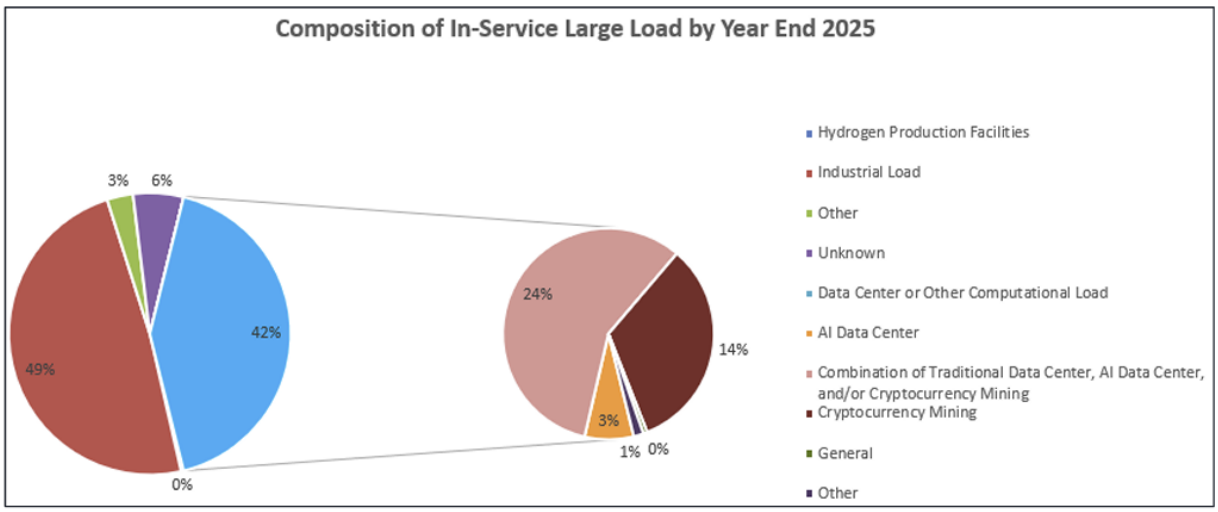
58 NERC, *Incident Review: Voltage-Sensitive Crypto Load Reductions* at 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_considering_voltage-sensitive_crypto_load_reductions.pdf.

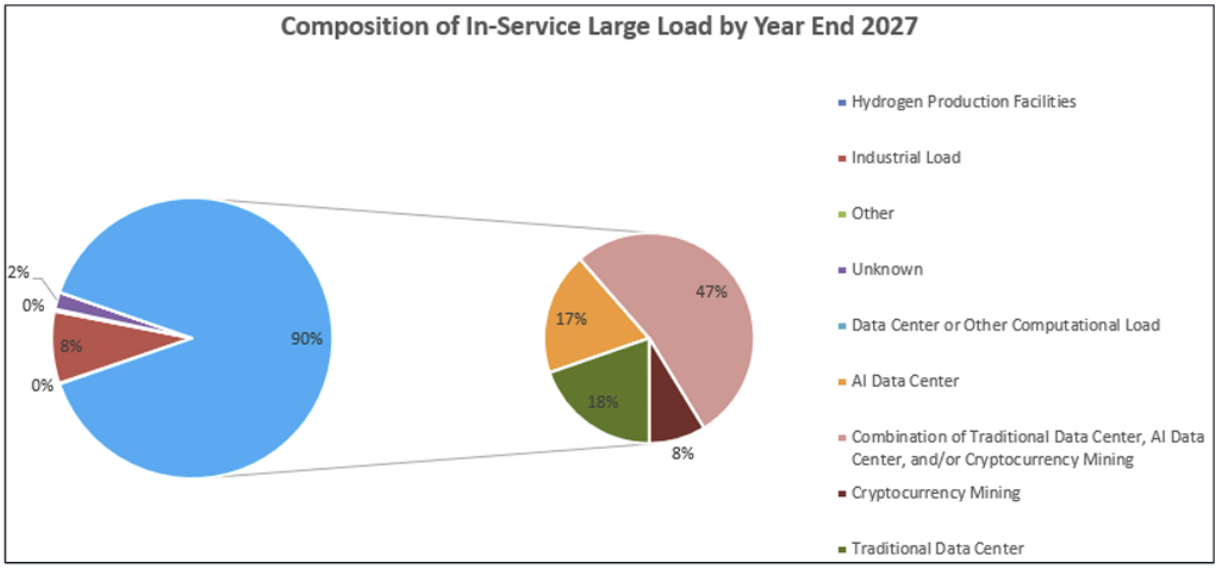
facilities have led to a series of indirect load loss in response to normally cleared transmission line faults on the system. Should these facilities continue to integrate and consume more MW on the grid, the need for grid operators to understand the load behaviors of these facilities becomes more urgent as sudden loss of large amounts of loads could eventually lead to reliability issues.

In fact, more disturbances have occurred since NERC performed the above incident reviews. A recent incident in July 2026 resulted in nearly 3,900 MW of customer-initiated load reduction from computational loads, causing system voltage to spike. NERC's review of this incident is ongoing as of the time of this filing.

3. Need for New Functional Entities

The severity of the aggregate risk posed by the types of occurrences outlined in the incident reviews grows with the amount of computational load expected on the system. In the Level 2 Alert report, NERC illustrated the changing composition of load types from the profile in 2025 to the projected profile by end of 2027:





Computational load is expected to be 90% of large load by the end of 2027, demonstrating the potential for incidents involving computational load to have a greater impact on BPS reliability moving forward. Moreover, the Level 2 Alert report noted that some geographic areas have heavily concentrated amounts of computational load. Reliability Standards applicable to these types of entities would permit grid planners and operators to better understand the load profile, and what characteristics to expect, on their system.

As such, the Large Loads Action Plan led to the proposal for new registry criteria and Reliability Standards based on the identified gaps and aggregate risks posed by the proliferation of large loads connecting to the BPS. NERC determined the primary risk to address was the aggregate impact of the large amount of computational load, with its unique electrical behaviors, integrating into the system. Specifically, aggregate impact in this context refers to the impact of several computational loads connecting to the BPS in a similar manner where their aggregate characteristics impact BPS reliability. NERC continues to assess the impacts of all types and sizes of large load, but the need for registry criteria at present addresses the unique and impactful behavior of computational load specifically.

In the interim while NERC developed the proposed registry criteria, NERC pursued other risk-mitigating activities. In May 2026, NERC issued the Level 3 Essential Action Alert[59] outlining the actions registered entities should implement to address current risks posed by computational loads interfacing with the BPS. NERC issued this action alert in response to its observation that large load reductions and oscillations impacted real-time response of system operators. In addition, NERC issued a Reliability Guideline[60] with risk mitigation strategies for emerging large loads to ensure that large loads connected to the grid participate in practices that protect grid stability. NERC also continued to address gaps in knowledge with respect to data center load modeling through workshops and technical references.

[59] NERC Level 3 Essential Action Alert (May 4, 2026), https://www.nerc.com/globalassets/programs/bpsa/alerts/level-3-computational-load-alert.pdf.

[60] Reliability Guideline: Risk Mitigation for Emerging Large Loads (May 2026), https://www.nerc.com/globalassets/our-work/guidelines/reliability/RG_Risk-Mitigation-For-Emerging-Large-Loads.pdf.

The work under the Large Loads Action Plan demonstrated the need for Reliability Standards applicable to new functional entity types, leading to the proposed revisions to the Rules of Procedure in this petition.

B. ANOPR and FERC Directive

While NERC implemented its Large Loads Action Plan, the Secretary of the United States Department of Energy ("DOE") and FERC also recognized the need for action to address the reliable integration of large loads with the transmission system. On October 23, 2025, the Secretary of Energy directed FERC to consider an Advance Notice of Proposed Rulemaking ("ANOPR") seeking public comment on interconnection of large loads to the interstate transmission system.[61] Issued pursuant to the DOE Secretary's authority under section 403 of the DOE Organization Act[62] for Commission consideration and final action, the proposed ANOPR directs the Commission to initiate rulemaking procedures on potential reforms to enable the interconnection of large loads to the transmission system. Accordingly, on October 27, 2025, the Commission issued a notice inviting comments on the proposed ANOPR.[63] Among other proposals on market issues, the Commission invited comment on a proposal that NERC should review its Reliability Standards and determine whether new or modified registration categories should be developed.

On November 21, 2025, NERC submitted comments in the ANOPR proceeding. NERC expressed appreciation for the Secretary's acknowledgement of the important role its Reliability Standards play in ensuring the BPS can meet the needs of large loads. NERC underscored its extensive activity and collaboration with stakeholders under the Large Loads Action Plan beginning in 2024. NERC's comments detailed how the Large Loads Action Plan includes

---

61 ANOPR, *supra* note 11.

62 42 U.S.C. § 7173(a).

63 *Interconnection of Large Loads to the Interstate Transmission System*, *Notice Inviting Comments,* Docket No. RM26-4-000 (Oct. 27, 2025).

modifications to Reliability Standards and registry criteria, as needed, to mitigate any reliability concerns associated with large load interconnections. Since filings its initial comments, on March 20, 2026, NERC submitted an updated timeline highlighting NERC's plan to file revised registry criteria and Reliability Standards on or before December 31, 2026 with a Level 3 Alert in the interim to support reliability.

In the Computational Loads Order, FERC directed NERC to submit proposed registry criteria and an initial set of Reliability Standards for computational loads by December 31, 2026. This directive is consistent with NERC's Large Loads Action Plan timeline and demonstrates FERC's support for addressing these risks in a timely manner. In addition, the Commission highlighted NERC's efforts to document recent grid disturbances resulting from computational loads on the grid. The Commission noted that the purpose of the directive is to provide greater certainty in the timelines proposed in NERC's plan.

V. AUTHORITY TO REGISTER COMPUTATIONAL LOAD

As the ERO, NERC possesses the authority to register entities creating this impactful computational load as "users of the BPS." While owners and operators of the BPS are well-defined through NERC's registry criteria, NERC currently has limited registry criteria applicable to "users" of the BPS. Nevertheless, FERC precedent and legislative history of the Federal Power Act indicate that "users" of the BPS should be broadly defined to encompass all those who "use" the BPS, including large end-users of electricity connected to the BPS.

Legislative history of the Federal Power Act provides insight into the intent of the term "user" of the BPS. During debate on the amendment that incorporated user of the BPS into the Federal Power Act, the author of the amendment, United States Senator Craig Thomas, explained that "[t]he new reliability organization will have enforcement powers, with real teeth to ensure reliability. The amendment provides that mandatory reliability rules will apply to all users of the

transmission grid. There are no loopholes. No one will be exempt."[64] United States Senator Jeff Bingaman, who while opposing the Thomas Amendment was a proponent of a mandatory system of reliability rules, recognized that "[t]he reliability system needs to apply to all users. The rules need to be enforceable. There need to be penalties if you do not comply with the rules."[65]

Consistent with that intent, when the Commission reviewed the initial suite of NERC Reliability Standards, it declined to define user of the BPS, leaving it to a case-by-case, risk-based analysis, stating:

> While we recognize the desire of some commenters for a concise, generic definition of "user of the Bulk-Power System," we are concerned that any attempt to define the term at this time will either be overly broad so as not to provide any helpful guidance or overly narrow so as to exclude entities that should be covered. The Commission believes that it has employed a reasonable approach by endorsing NERC's compliance registry process and requiring that each Reliability Standard identify the subset of users, owners and operators to whom that particular Reliability Standard applies.[66]

Nevertheless, FERC precedent indicates that "users" of the BPS subject to NERC regulation could include large end-use customers connected to the BPS. In discussing NERC's initial attempts to define "user" of the BPS, FERC stated its concerns that "[under NERC's proposed definition] a large industrial customer that receives electric energy directly from the [BPS] may not be defined as a user of the BPS, even though it may directly affect the reliability of the [BPS]."[67] Even in developing the narrow scope of its first set of registered entities, NERC

---

64 148 Cong. S1874 (daily ed. Mar. 14, 2002) (statement of Sen. Thomas).

65 *Id.* (statement of Sen. Bingaman). NERC originally highlighted this legislative history in a notice of penalty proceeding. See NERC, *Notice of Penalty regarding U.S. Army Corps of Engineers – Tulsa District,* Docket No. NP09-26-000 at 6 (June 24, 2009). In issuing a determination on NERC's jurisdiction under section 215 in that penalty proceeding, the Commission concluded that Congress intended section 215 to be comprehensive and was added to prevent cascading blackouts, as demonstrated by the provisions of the Federal Power Act and its legislative history. See *Order Addressing Applicability of Section 215 of the Federal Power Act to Federal Entities*, 129 FERC ¶ 61,033 (2009), *reh'g denied*, *order rejecting reh'g request*, 130 FERC ¶ 61,002 (2010).

66 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218 at P 116, (2007) [hereinafter Order No. 693], *order on reh'g*, Order No. 693-A, 120 FERC 61,053 (2007).

67 Order No. 672, *supra* note 13 at P 99.

agreed with the Commission "that Congress intended to give the Commission broad jurisdiction over the reliability of the [BPS]," but NERC did not consider it necessary for "the Commission to extend its jurisdiction to the limits in a single step."[68]

Accordingly, the expansive authority over owners, operators, and users of the BPS under section 215 of the FPA provides statutory and regulatory support for the proposed revisions to the NERC Rules of Procedure.

VI. PROPOSED REVISIONS TO THE NERC RULES OF PROCEDURE

NERC respectfully requests that the Commission approve the proposed revisions to Appendices 2, 5A, and 5B in satisfaction of the directive in the Computational Loads Order to develop registry criteria to address the risks posed by computational loads. This Section VI discusses the proposed registry criteria for those computational load entities NERC proposes to register to comply with Reliability Standards. This section provides technical justification for the proposed criteria and how it addresses the risk identified.

To add new functional entities, NERC must revise Rules of Procedure Appendix 2 (Definitions Used in the Rules of Procedure); Appendix 5A (Organization Registration and Certification Manual); and Appendix 5B (Statement of Compliance Registry Criteria). These appendices work together as follows when NERC registers an entity: NERC and the Regional Entities follow the registration process outlined in Appendix 5A and assess an entity against the criteria provided in Appendix 5B, with the definitions in Appendix 2 providing clarity on capitalized terms used throughout the Rules of Procedures and its appendices. Section A discusses the terms added to Appendix 2. Section B summarizes the revisions to the registration process in

[68] Order No. 693, *supra* note 66 at P 59.

Appendix 5A. Section C presents the revisions to the Registry Criteria in Appendix 5B and provides technical reasoning for the capacity and voltage thresholds for Computational Load Sites.

A. Appendix 2

Appendix 2 (**Attachments 2-A** and **3-A**) to the NERC Rules of Procedure provides the definitions of terms used throughout the Rules of Procedure. The proposed revisions add the following three new terms: Computational Load Operator, Computational Load Owner, and Computational Load Site. Each of these terms is discussed below, beginning with Computational Load Site as it is nested in the other two definitions.

1. Computational Load Site

NERC proposes the following new definition in Appendix 2 of the NERC Rules of Procedure:

> "Computational Load Site" means one or more buildings, structures, or installations at a single location that
>
> 1) Primarily contains information technology infrastructure used for:
>
> - creating, executing, and delivering software applications and services;
> - artificial intelligence training, deployment, and delivery;
> - cryptocurrency mining; or
> - other computational activities at a data center; and
>
> 2) is supplied through electrical equipment that is connected to the BPS.

NERC developed the Computational Load Site definition in response to comments requesting clarity on the site boundaries to determine who owned or operated the site and to better calculate the total connected Load (**Attachment 4-B**). The proposed definition creates this boundary through three main concepts: 1) the site is a "single location"; 2) the site "primarily contains information technology infrastructure"; and 3) the site is "supplied through electrical equipment that is connected to the BPS." Each of these concepts is discussed in turn below.

As noted in NERC's consideration of comments on the August posting (**Attachment 4-A**), the "single location" concept has been used in other regulatory contexts related to generation, such as implementing the Public Utility Regulatory Policies Act ("PURPA"),[69] where FERC may consider certain physical or ownership characteristics of generation facilities to determine separate sites for Qualifying Facilities purposes. While NERC does not borrow all regulatory concepts from PURPA given the distinctions between load sites and generation, the use of "single location" in this instance was appropriate to convey that the MW calculation for purposes of the registry criteria threshold (discussed below) should not aggregate distinct sites that may be geographically near but unrelated operationally or do not share other characteristics.

While a Computational Load Site will be reviewed based on its specific factors to determine applicability, the registration process may consider many factors pertaining to the buildings, structures, or installations, including, but not limited to, ownership, shared or common infrastructure (e.g., auxiliary or cooling load), or coordinated use across the information technology infrastructure to perform its computational activities. However, single location does not necessarily refer to real estate boundaries, such as parcels.

A Computational Load Site is intended to "primarily" contain the information technology infrastructure that contributes to the electrical behavioral risk of computational loads. While several commenters suggested more quantitative measures of how much information technology infrastructure is part of a site, the use of "primarily" is intended to indicate that entities with the infrastructure performing computational activities that contribute to the unique impacts to the BPS are registration candidates, whereas load that is more industrial or primarily manufacturing is excluded. NERC declines to impose a specific percentage or amount of the 50 MW that must be

[69] 16 U.S.C. § 2601 et seq.

computational load at a site as that may arbitrarily exclude entities with the same reliability impact based on a percentage despite performing the same computational activities that pose an impact to the BPS.

NERC does not anticipate the lack of a numerical percentage will introduce issues in defining Computational Load Sites. For instance, NERC identified in the LLWG Whitepaper #1 that data centers and other computational loads' information technology-related equipment that consists of servers, storage, and networking gear driven by power electronics, "generally comprise[s] at least half of the data center's energy consumption. Data center industry experts state that IT-related equipment may make up 60–95% of a data center's total energy demand."[70]

To that end, as entities are registered, the site associated with their functions would be considered on a case-by-case basis such that Regional Entities reviewing each site would not look to register manufacturing facilities or generating facilities that may have certain computational equipment that helps run their manufacturing processes or generating operations. Rather, the Regional Entities would look to whether the buildings, structures, or installations on the site primarily contain information technology infrastructure that has been a driver of the unique characteristics of computational load with a reliability impact on the BPS.

In using the phrase "supplied through electrical equipment that is connected to the BPS," the focus of the Computational Load Site definition is not on the common point of connection, as may be typically defined in an interconnection agreement, but rather the kV level to which the electrical equipment supplying the Computational Load Site is connected to the BPS. In other words, this would typically be the high-side voltage level of the electrical equipment connected to the BPS that is supplying the Computational Load Site, which may or may not be the documented

[70] Whitepaper 1, *supra* note 44 at 4.

point of interconnection in an interconnection agreement. As Computational Load Owner and Computational Load Operator candidates go through the registration process, the applicable Regional Entities will assess the voltage level of the Computational Load Site to determine whether registration is required based on the Computational Load Site's connection to the BPS, irrespective of electrical equipment ownership.

2. Computational Load Operator and Computational Load Owner

In feedback on the April posting, commenters recommended the proposed criteria use the same "Owner" and "Operator" model for computational loads to remain consistent with the registration criteria currently in the NERC Rules of Procedure for Transmission Owner, Transmission Operator, Generator Owner, and Generator Operator.[71] Commenters stated that this structure is in place because, for transmission and generation facilities, there are often situations where the owner of the facilities is different from the operator of the facilities. This registration criteria structure allows the different entities to be responsible only for the activities that they are contractually set up for as the owner or operator.

NERC proposes the following new definition be included in Appendix 2:

> "Computational Load Operator" means the entity that operates a Computational Load Site.

Generally, a Computational Load Operator can impact the day-to-day control of the Computational Load Site's electrical operations or has communications capabilities with its transmission or reliability entities, as appropriate, or both, among other considerations as to operations.

NERC proposes adding the following new definition to Appendix 2:

> "Computational Load Owner" means the entity that owns and maintains a Computational Load Site.

[71] Appendix 4A, Comments of Data Center Coalition and Comments of Trade Associations.

NERC recognizes entities may have differing organizational structures and business relationships that led commenters to question how the "owns and maintains" language applies to scenarios where there may be multiple owners or there may be other entities who are responsible for maintaining a Computational Load Site. In the context of computational loads, the Computational Load Owner who "owns and maintains" the Computational Load Site helps establish that it is intended to be the entity that plays a more active role in ownership rather than a passive role. Specifically, the inclusion of "maintains" helps better define the role of the entity that will be considered as a candidate for registration so that NERC is not registering every passive owner with only a small financial interest in a Computational Load Site.

Moreover, NERC has been applying the "owns and maintains" language to the Transmission Owner and Generator Owner functions, and the various organizational structures of those entities, for many years. Within the NERC registration process, there are mechanisms available to help those generation or transmission projects, for example, understand which entity should be registered as a Generator Owner or Transmission Owner. Under the existing registration construct, entities may wish to establish bilateral contracts with other entities to take responsibility explicitly for the requirements applicable to the Generator Owner function, as appropriate.

B. Appendix 5A

Appendix 5A (**Attachments 2-B** and **3-B**) contains the process used by NERC and the Regional Entities to register certain functional entity types to which mandatory and enforceable Reliability Standards apply. NERC proposes to revise Appendix 5A to add "Computational Load Owner (CLO)" and "Computational Load Operator (CLOP)" as types of entities that are required to register on the NERC Compliance Registry. In addition, proposed revisions to Appendix 5A

include minor administrative corrections to remove references to figures previously removed from the Rules of Procedure.

C. Appendix 5B

Appendix 5B (**Attachments 2-C** and **3-C**) contains the specific criteria NERC and the Regional Entities use to identify which organizations may be candidates for registration for functional entity types. In accordance with the Federal Power Act, NERC must identify the owners, operators, and users of the BPS who have a material impact on the BPS. The proposed revisions in Appendix 5B add threshold criteria to identify those users of the BPS that should be registered as Computational Load Owners and Computational Load Operators as follows:

- Computational Load Owner of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection.
- Computational Load Operator of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection.

NERC determined the 50 MW and 100 kV thresholds based on NERC Level 2 Alert data as well as additional analysis and consideration of comments during the Rules of Procedure revisions process. In its initial proposal in the April posting, NERC based its threshold recommendation of 20 MW and 60 kV on data provided from responses to the Level 2 Alert. Transmission Owners, Resource Planners, Transmission Operators, Transmission Planners, Balancing Authorities, Planning Coordinators, Distribution Providers, and Reliability

Coordinators provided the total capacity of large loads on their system that are currently operational and expected to be in-service by the end of 2027, including the voltage level at the interconnecting point. The report concluded that large load additions are expected to change composition dramatically, moving from a split between industrial and computational load to almost entirely computational. Accordingly, NERC initially considered a 20 MW and 60 kV threshold would include a majority of entities contributing to the reliability risk posed by the connection of computational loads to the BPS.

After further analysis and consideration of comments on the initial proposal, NERC proposed the 50 MW and 100 kV threshold as it balances the need to include a large amount of computational load while also helping to ensure smaller, less impactful entities are excluded, as outlined in its technical reasoning document (**Attachment 1-E**). NERC's analysis, conducted using comprehensive data collected by a third-party who tracks existing and future data center activity,[72] revealed there is 41,827 MW of active data center load (at all voltages) as of June 2026 and an additional 37,675 MW under construction and expected to be in-service by the end of 2027. This amounts to a total of approximately 79,502 MW by year end 2027. Furthermore, NERC's voltage analysis revealed that for entities at 50 MW and above, most are likely to connect at 100 kV or more. This is because it is physically difficult for such loads to connect at smaller kV thresholds to achieve the desired level of reliability. In addition, at the 50 MW threshold, there was a small difference of only 2% of the overall total load comparing 100 kV to the previously proposed 60 kV threshold. The 2% of load represents those Computational Load Sites that

[72] NERC has a license with Aterio to access its "US Data Center Locations and Power Demand" data set which "provides a comprehensive inventory of data centers across the United States, including those currently operational, under development, and planned for future construction." Data includes individual building, campus, their locations, electric utility information, and load estimates.

generally have smaller capacity, are dispersed across the BPS, and represent a smaller portion of the collective load where they are located, thus representing less aggregate risk.

As a result, NERC estimates that the proposed 50 MW and 100 kV threshold should lead to the registration of owners and operators of approximately 68,288 MW from Computational Load Sites, as estimated in July 2026. This amount equals approximately 86% of the overall total computational load projected by the end of 2027 and includes the majority of Computational Load Sites that pose aggregate risks to the BPS. As such, the threshold encompasses those Computational Load Sites that are of the size and connected voltage that cause aggregate impacts, creating reliability risk, when connected to the BPS if not mitigated appropriately.

Essentially, the proposed 50 MW and 100 kV threshold ensures BPS-connected entities are subject to registration while excluding entities that have not been seen to negatively impact BPS reliability. While NERC maintains that its proposal is just and reasonable based on its analysis, NERC will continue to monitor computational total connected Load and connection voltage with respect to the aggregate risks and reserves the right to propose additional Registry Criteria changes in the future to address any risks to the BPS.

VII. REQUEST FOR EXPEDITED ACTION

NERC respectfully requests expedited Commission action on this filing. As discussed in previous sections, the Rules of Procedure revisions proposed in this filing are both necessary and timely. Prompt Commission action on the proposed revisions would provide regulatory certainty for both NERC and industry to initiate more effective education and outreach on NERC registration and compliance processes. Based on the ERO Enterprise's recent experience

onboarding new entities registered as Category 2 Generator Owners and Generator Operators,[73] NERC and the Regional Entities engage with entities and initiate registration processes long before entities are placed on the NERC Compliance Registry and become subject to compliance with applicable Reliability Standards. Such early interactions help entities understand their Regional Entities' processes, connect with appropriate registration and compliance monitoring staff, and ask any compliance questions prior to Reliability Standards becoming effective.

In addition, NERC and the Regional Entities have initiated work on the Computational Load Owner and Computational Load Operator Registration Reference document that will provide guidance and consistency across the ERO Enterprise. The ERO Enterprise develops Registration Reference documents to further support consistency in applying NERC Registry Criteria.[74] Developing a Registration Reference document for Computational Load Owners and Computational Load Operators was an important consideration in NERC's response to comments on the August posting, as a large number of commenters requested application to specific scenarios or configurations. Such efforts will be more effective with approved NERC Registry Criteria. The ERO Enterprise will do as much of this work as possible prior to FERC approval but requests the Commission consider expedited action to make these interactions more certain and meaningful.

Moreover, NERC can help entities understand how their business relationships and ownership structures fit within the NERC registration processes. The NERC registration process includes several mechanisms, such as Joint Registration Organization or Coordinated Functional Registration, available to accommodate different business relationships or responsibilities. As the

[73] The IBR Registration Initiative provided comprehensive education and outreach to generating resources that were candidates for registration. More information on the IBR Registration Initiative is available at https://www.nerc.com/initiatives/ibr-registration-initiative-quick-reference-guide.

[74] As an example, NERC developed an ERO Enterprise Registration Reference to support application of the Category 2 Generator Owner and Generator Operator registry criteria to non-BES generating resources, https://www.nerc.com/globalassets/programs/registration/registration-documentation/application-of-the-registration-criteria-for-category-2-generator-owner-and-generator-operator-inverter-resources.pdf.

registration process progresses, NERC and the Regional Entities assist entities in ensuring the appropriate entity is placed on the NERC Compliance Registry.

The ERO Enterprise will continue extensive engagement to assist entities in understanding their options under the registration process. Based on all the comments received on the proposed revisions, NERC understands continued engagement and education on NERC processes will greatly assist entities in understanding responsibilities. NERC, along with the Regional Entities, commit to providing engagement and educational opportunities to help ensure new registration candidates can integrate reliably into the ERO Enterprise regulatory framework. Accordingly, prompt Commission action supports these efforts.

VIII. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve the proposed revisions to Appendices 2, 5A, and 5B to address computational loads that in aggregate materially impact reliable operation of the BPS. In addition, NERC requests expedited action on its proposal to support efficient and effective resolution of the risks to reliability and afford regulatory certainty on the Registry Criteria. In doing so, NERC and the Regional Entities can more effectively work with appropriate entities to undergo the registration process prior to the effective date of Reliability Standards applicable to Computational Load Owners and Computational Load Operators.

Respectfully submitted,

/s/ Marisa Hecht

Marisa Hecht
Senior Counsel
North American Electric Reliability Corporation
1401 H Street NW, Suite 410
Washington, D.C. 20005
202-400-3000
marisa.hecht@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: October 21, 2026

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in the above-referenced proceeding.

Dated at Washington, D.C. this 21st day of October, 2026.

/s/ Marisa Hecht

Marisa Hecht

Counsel for North American Electric Reliability Corporation

Attachment 1

Technical Support for Proposal

Attachment 1-A

Whitepaper #1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Characteristics and Risks of Emerging Large Loads

Large Loads Task Force White Paper

July 2025

RELIABILITY | RESILIENCE | SECURITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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

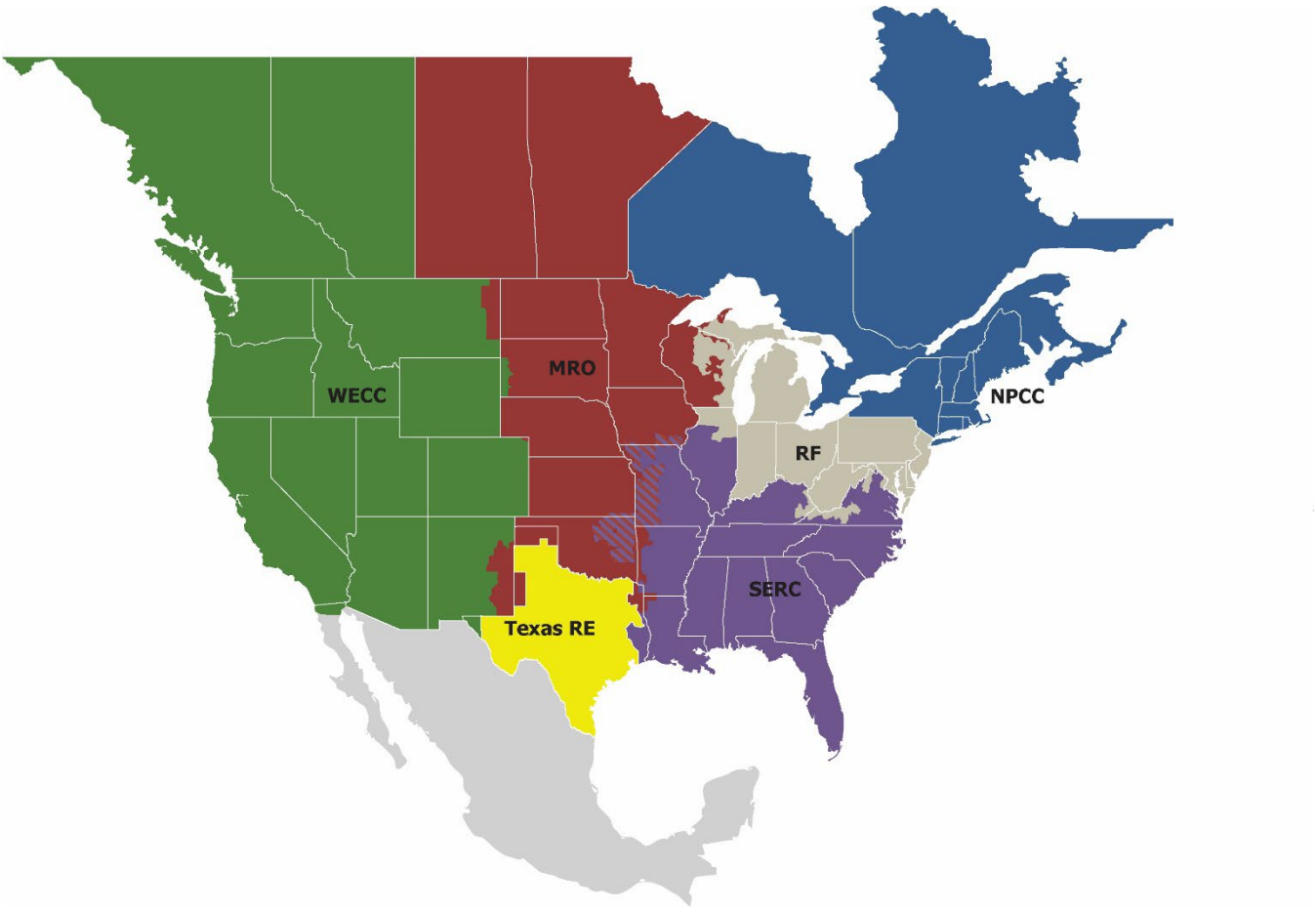
Outage Coordination in Operations Planning 21
Stability 21
Ride-Through 22
Frequency Stability 23
Rotor Angle Stability 25
Voltage Stability 27
Resonance- and Converter-Driven Stability 28
Forced Oscillations 29
Power Quality 32
Harmonics 32
Voltage Fluctuations 34
Physical and Cyber Security Risks 36
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

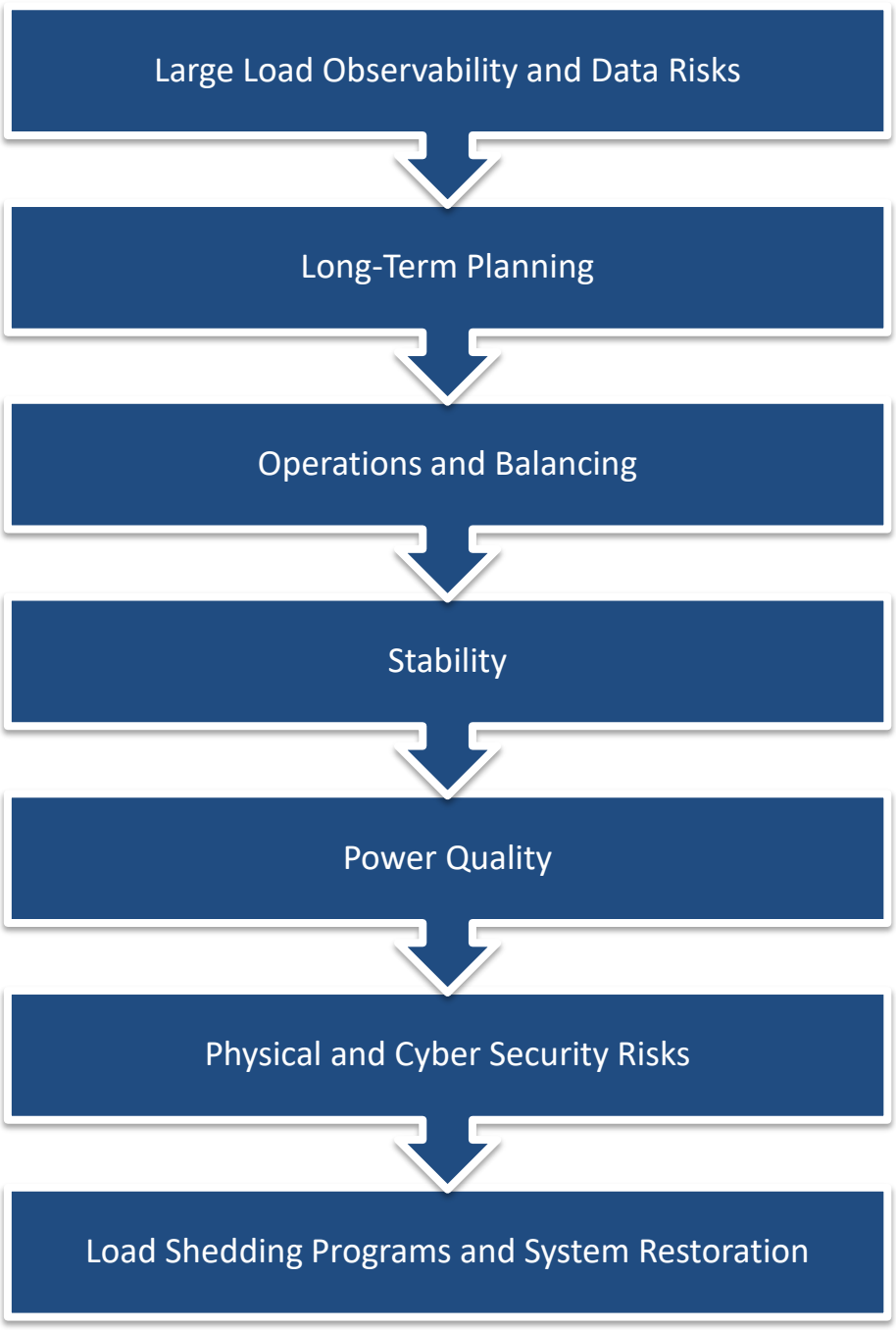
NERC's Reliability and Security Technical Committee (RSTC) established the Large Load Task Force (LLTF) to analyze the reliability impacts related to emerging large loads (e.g., data centers (including cryptocurrency mining and AI), industrial facilities, and hydrogen production facilities). This white 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:

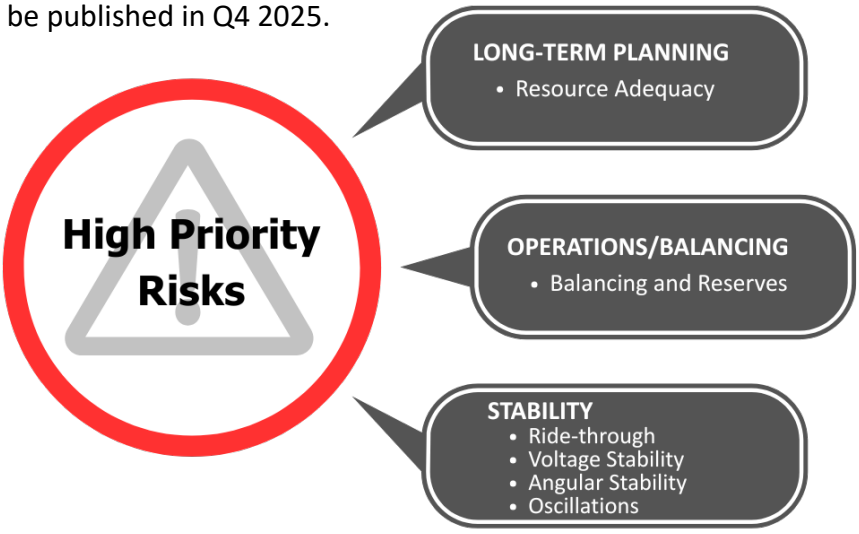


The following recommendations are offered as guidance for future work to ensure the reliability and security of the BPS:

- ✓ **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 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 megawatts (MW) 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 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.

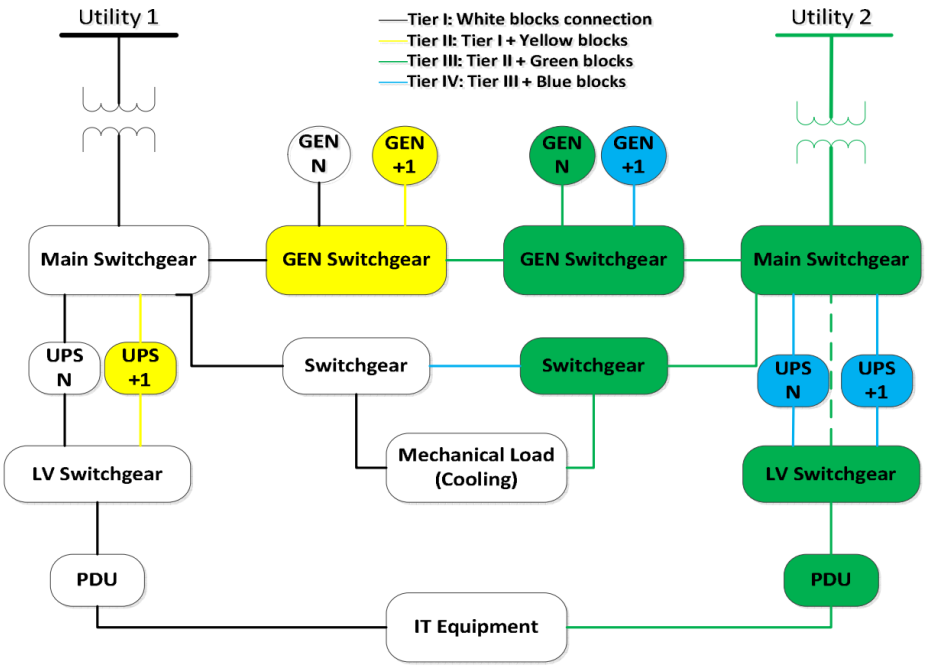


Figure 2.1: Tier I–IV Data Center One-Line[9]

[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 uptime—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."

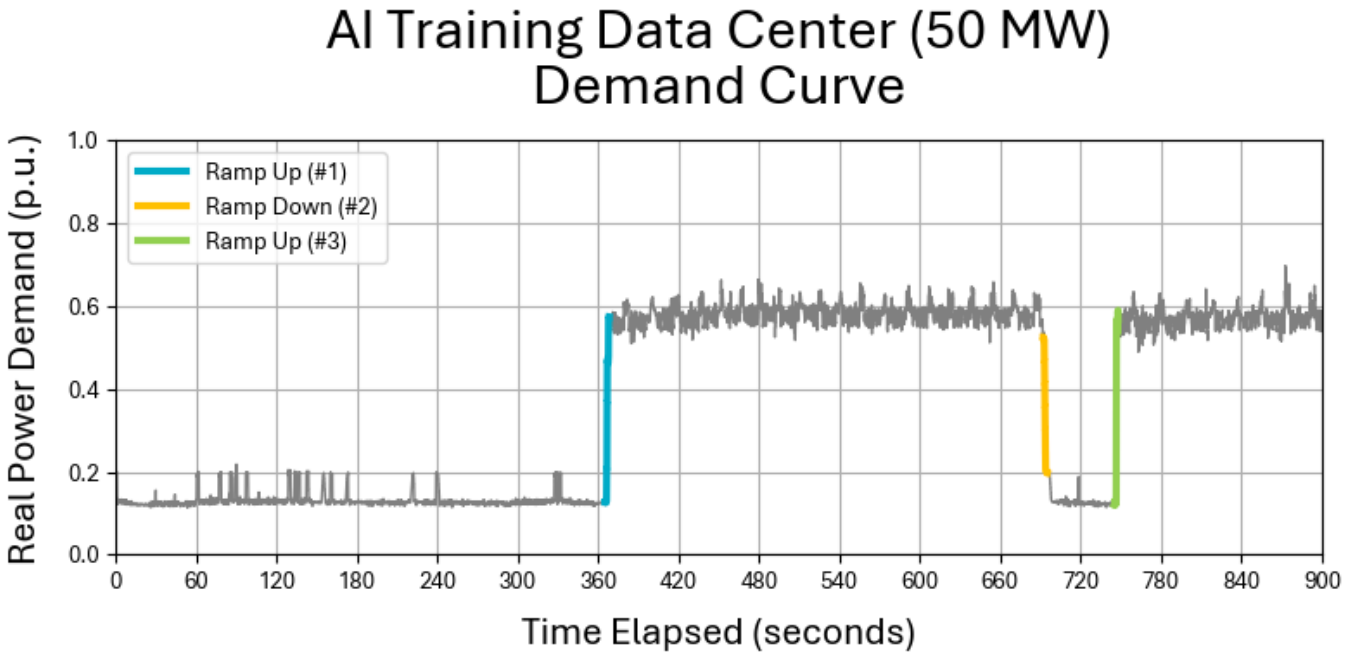


Figure 2.2: An AI Training Data Center Begins a Training Run (EdgeTunePower)

[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).

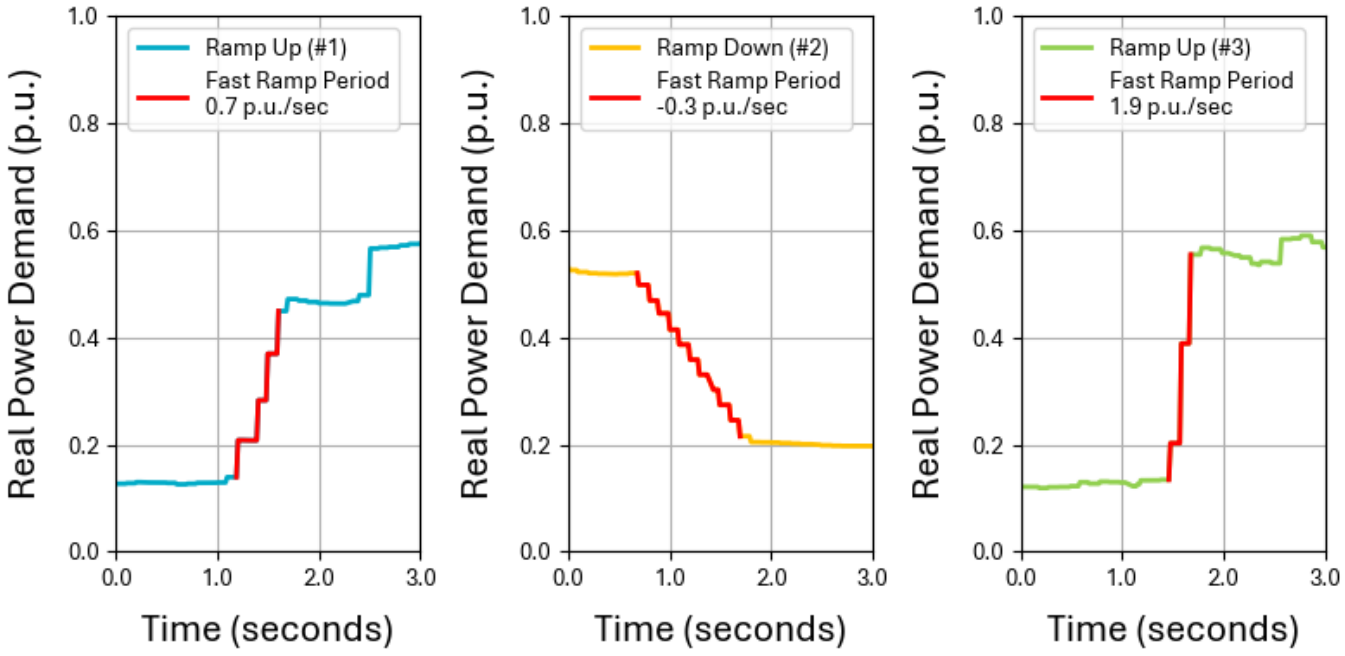


Figure 2.3: Zoomed-In Views of AI Training Data Center Ramping Up and Down Due to Transitioning Between Training and Saving Checkpoint Progress

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.

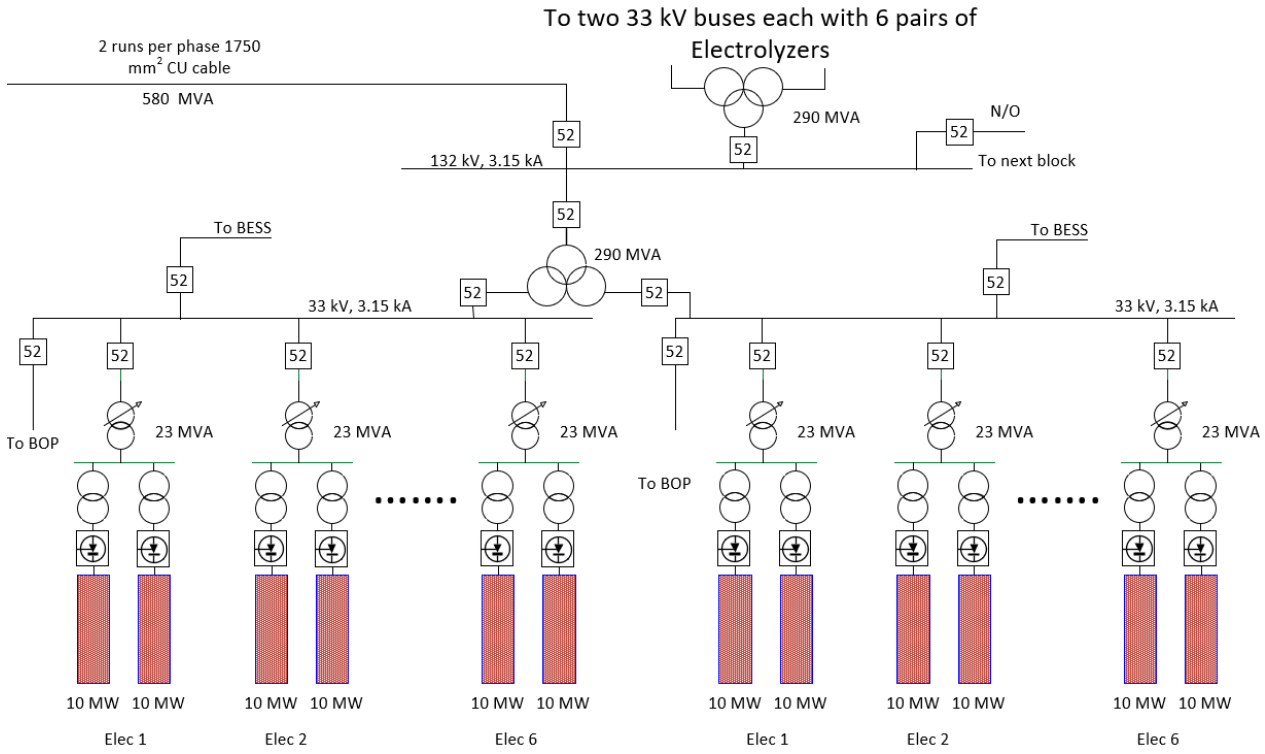


Figure 2.4: Example Hydrogen Production Facility One-Line Diagram (EPRI)

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.

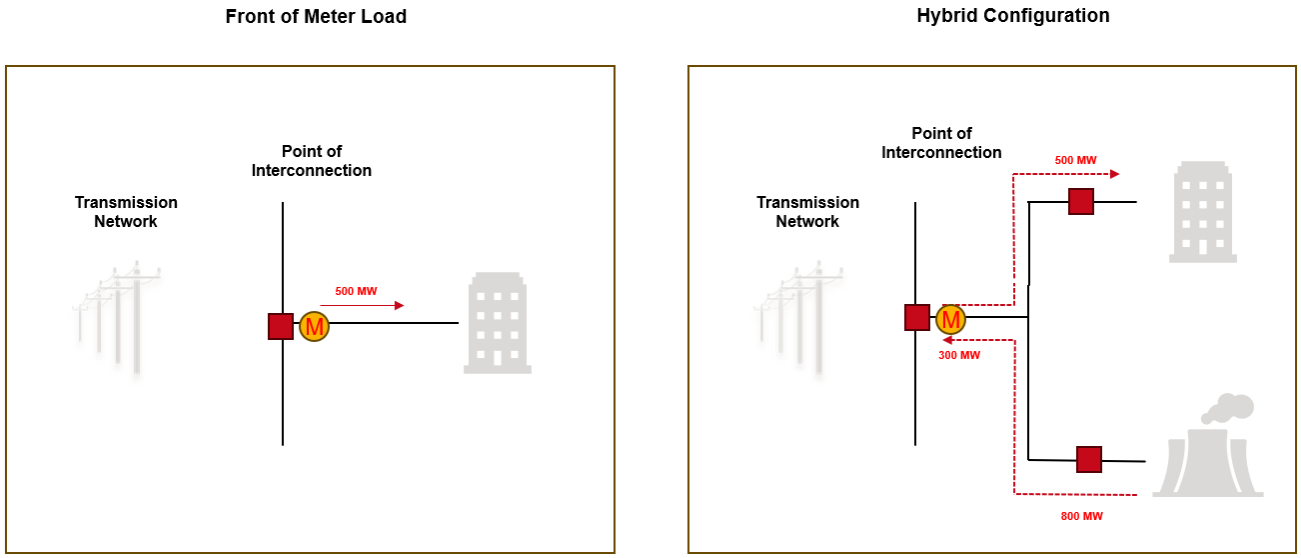


Figure 2.5: FOM vs. BTM Load Illustrations[21]

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.

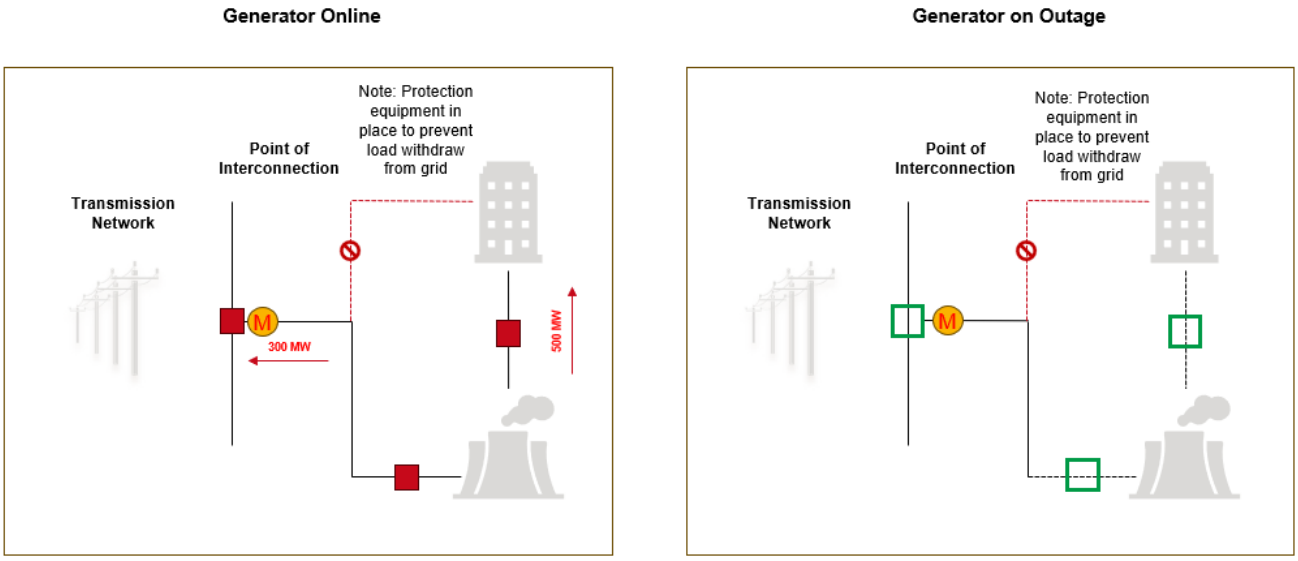


Figure 2.6: BTM Online vs. On Outage

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.

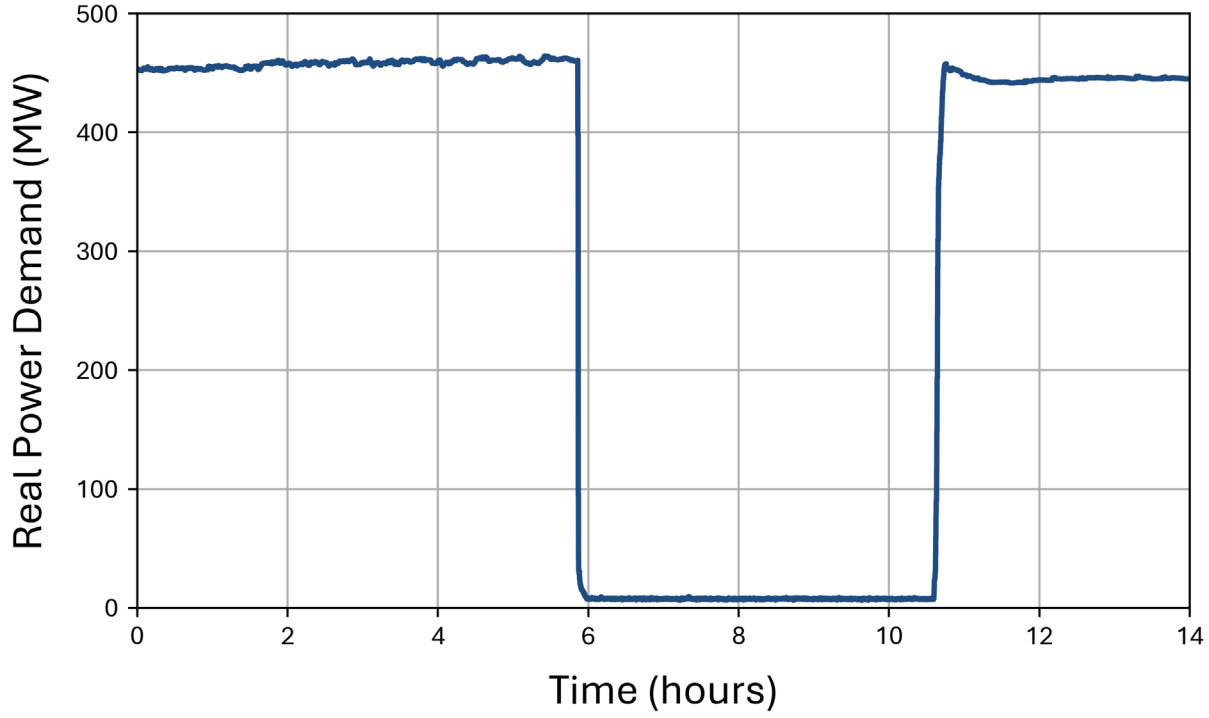


Figure 3.1: Data Center Load Ramp Down and Up

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.

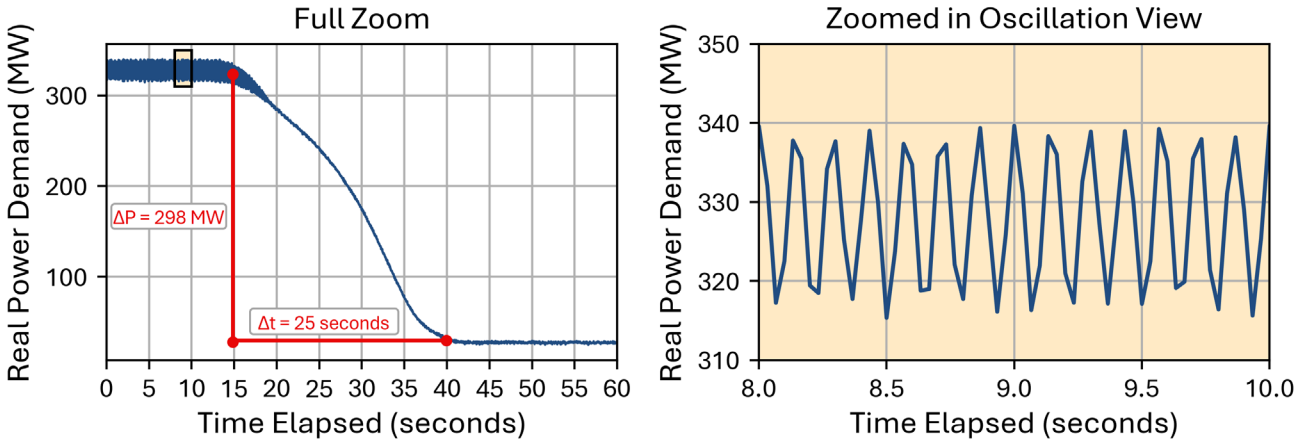


Figure 3.2: Cryptocurrency Mining Facility Load Oscillation and Ramp Down

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]

[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

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 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**.

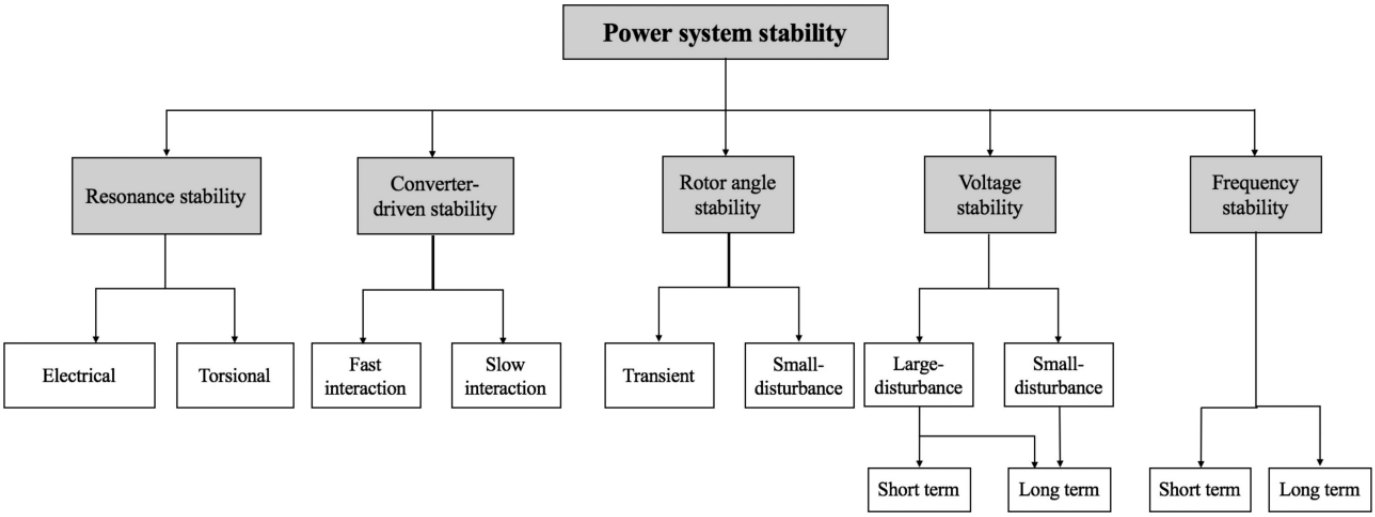


Figure 3.3: Taxonomy of Power System Stability

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.

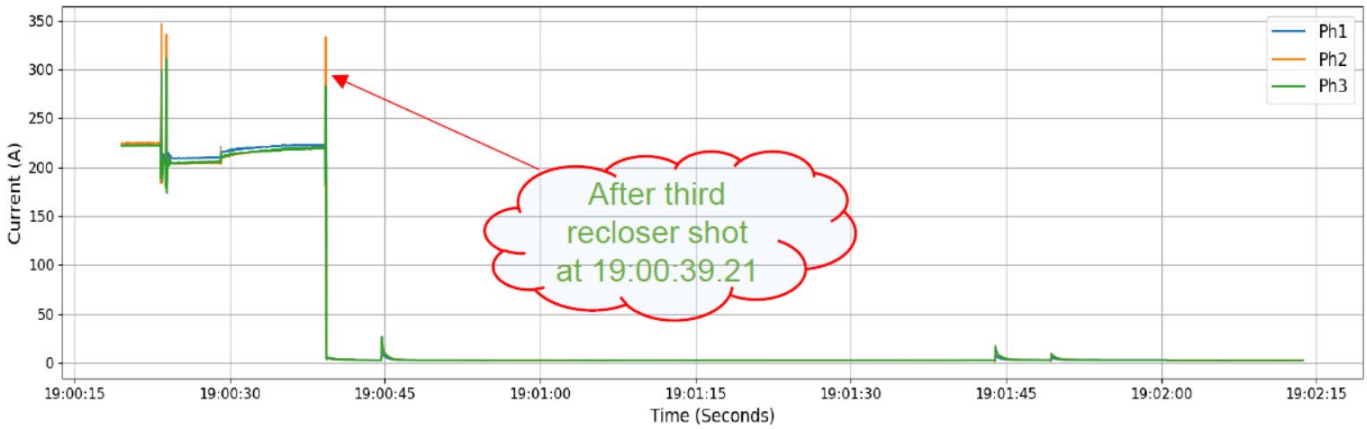


Figure 3.4: Data Center Load Trip

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).

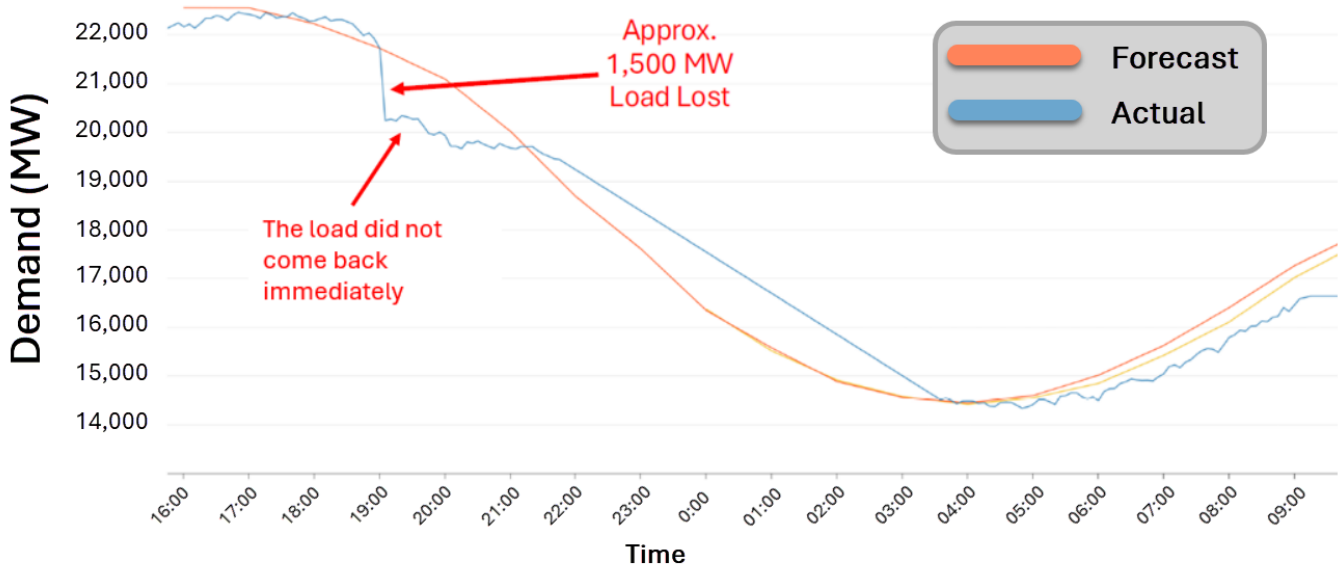


Figure 3.5: System Load Chart[1]

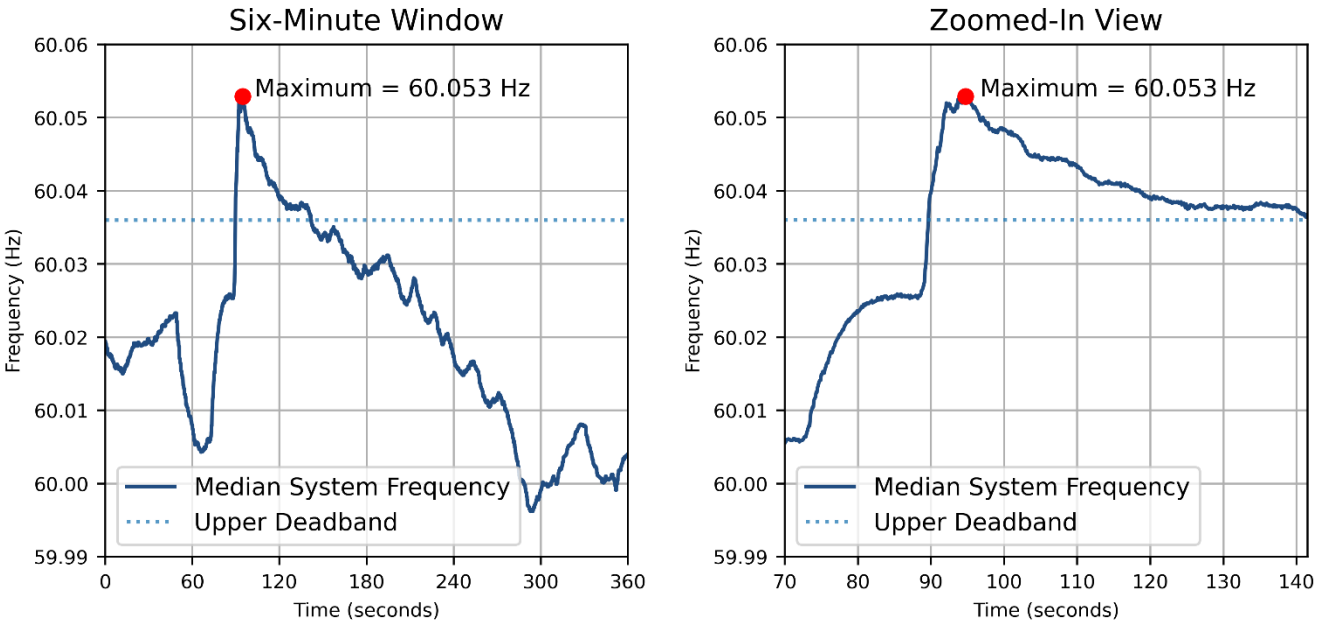


Figure 3.6: Frequency Plot for Eastern Interconnection 1,500 MW Large Load Loss/Transfer on July 10, 2024 (Provided by University of Tennessee: Knoxville)

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.

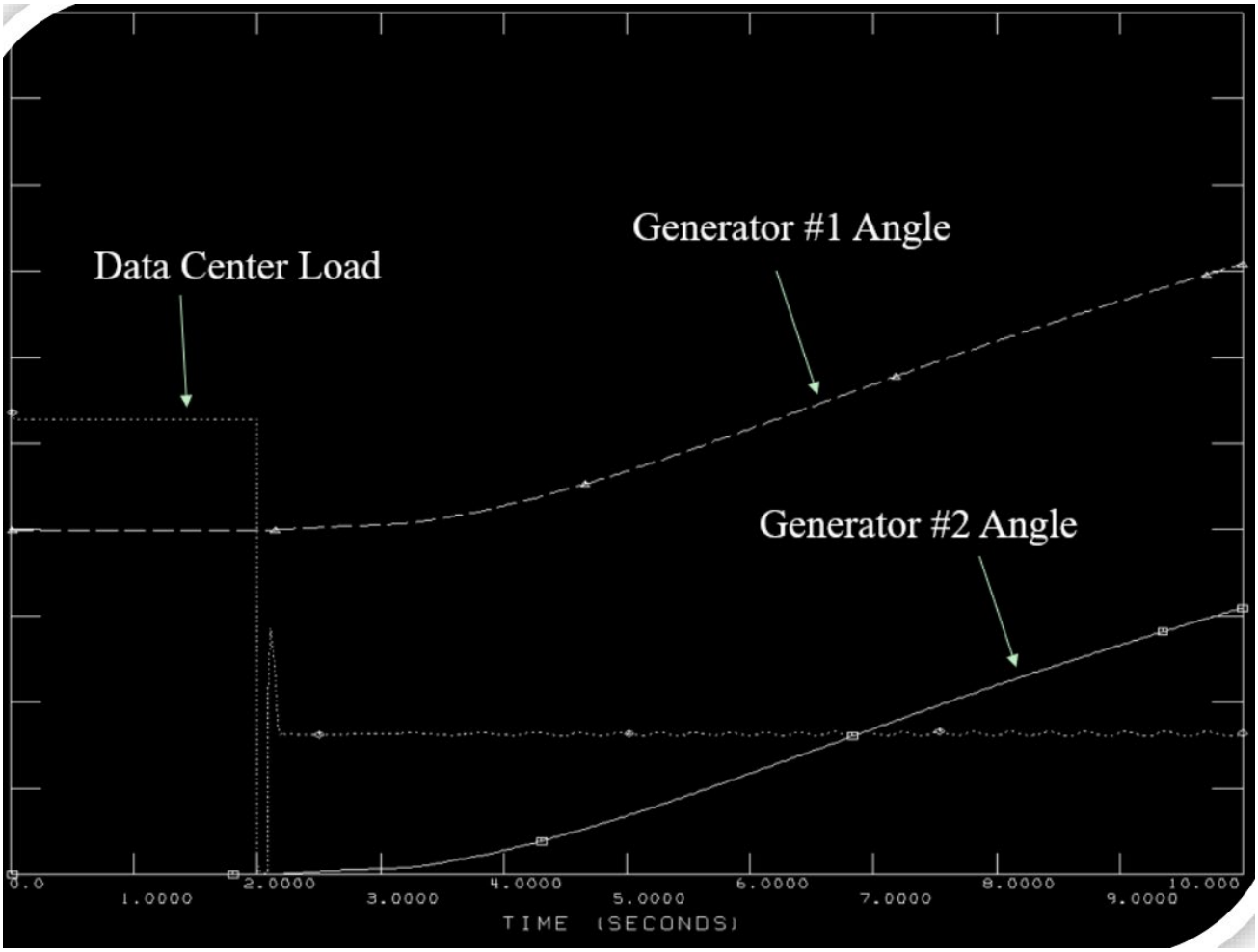


Figure 3.7: Simulation Showing Generators Losing Angular Stability Following Nearby Data Center Load Trip

[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

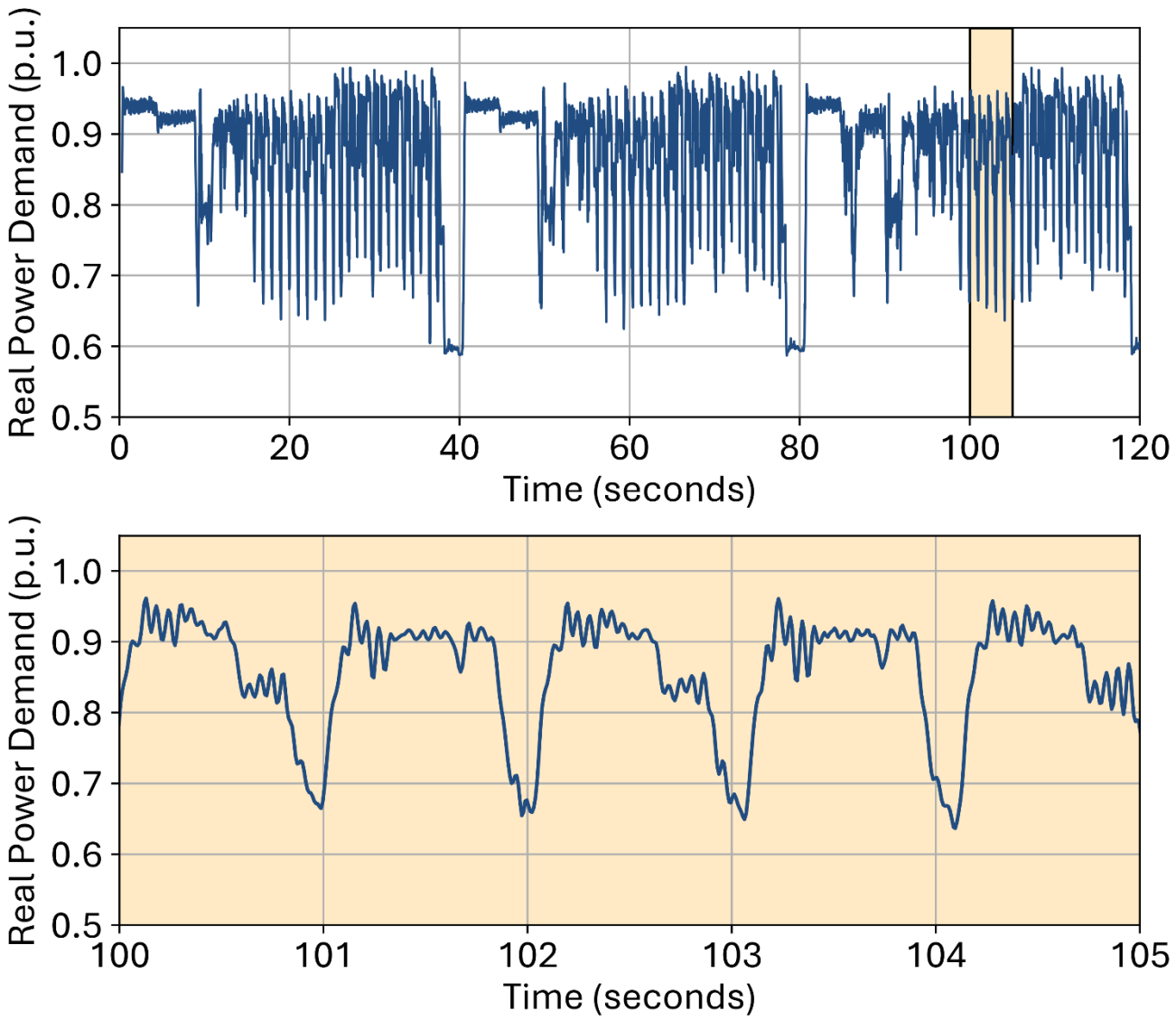


Figure 3.8: Example AI Data Center Load Profile During Training Over Two Minutes (Top) and in a Five-Second Period (Bottom)

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

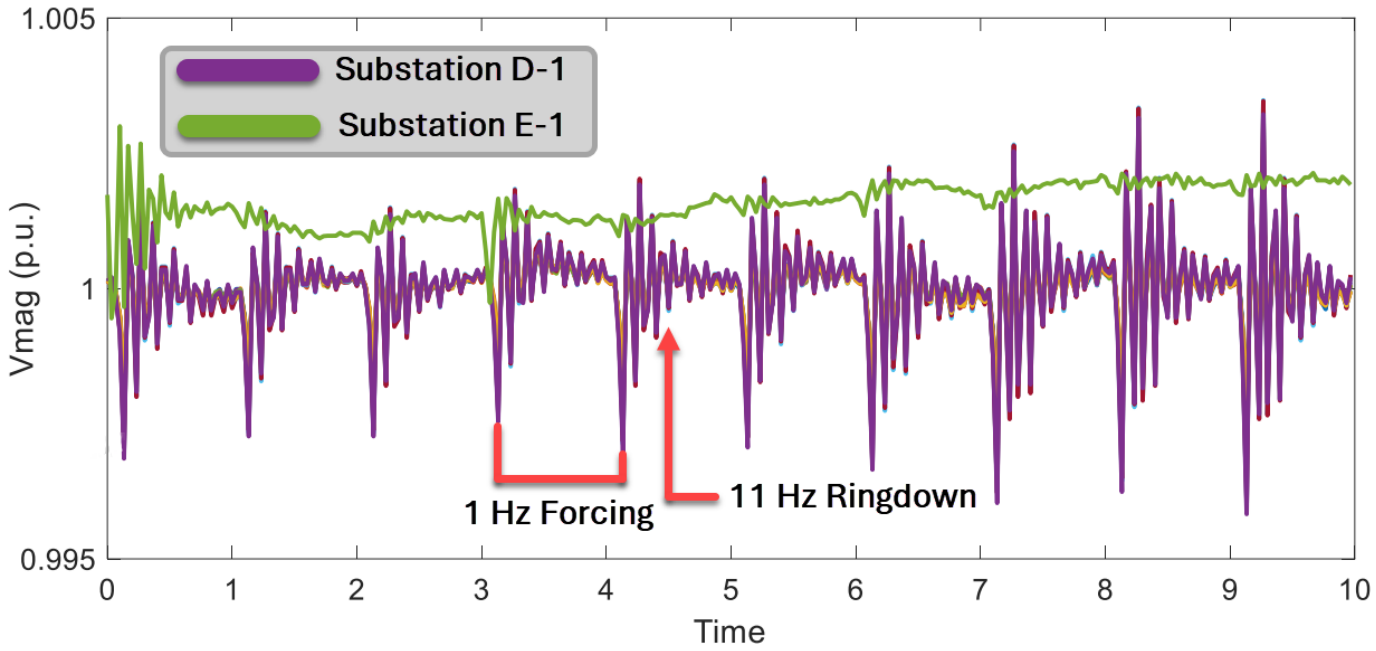


Figure 3.9: Field Measurement of Forced Oscillations Occurring at 1 Hz[40]

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

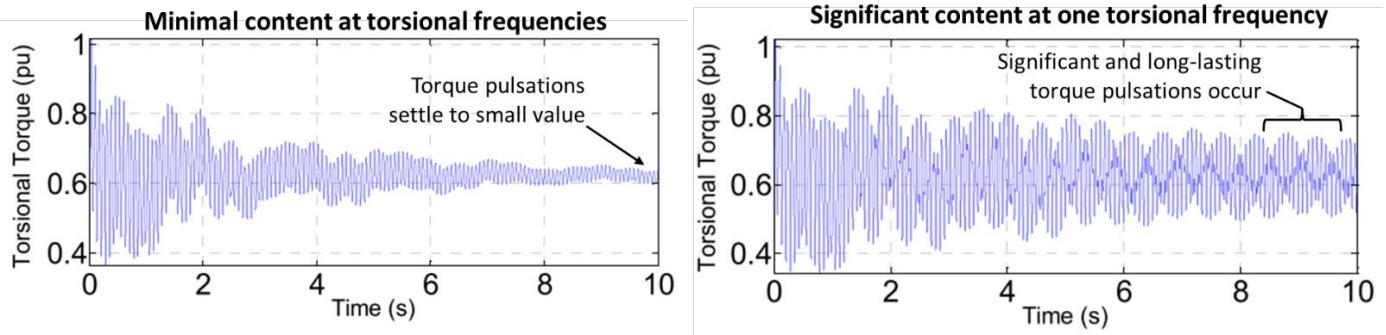


Figure 3.10: Torques Produced in a Steam Turbine for EAF Loads That Do Not (Left) and Do (Right) Contain Frequency Content at the Steam Turbine's Torsional Modal Frequency

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.

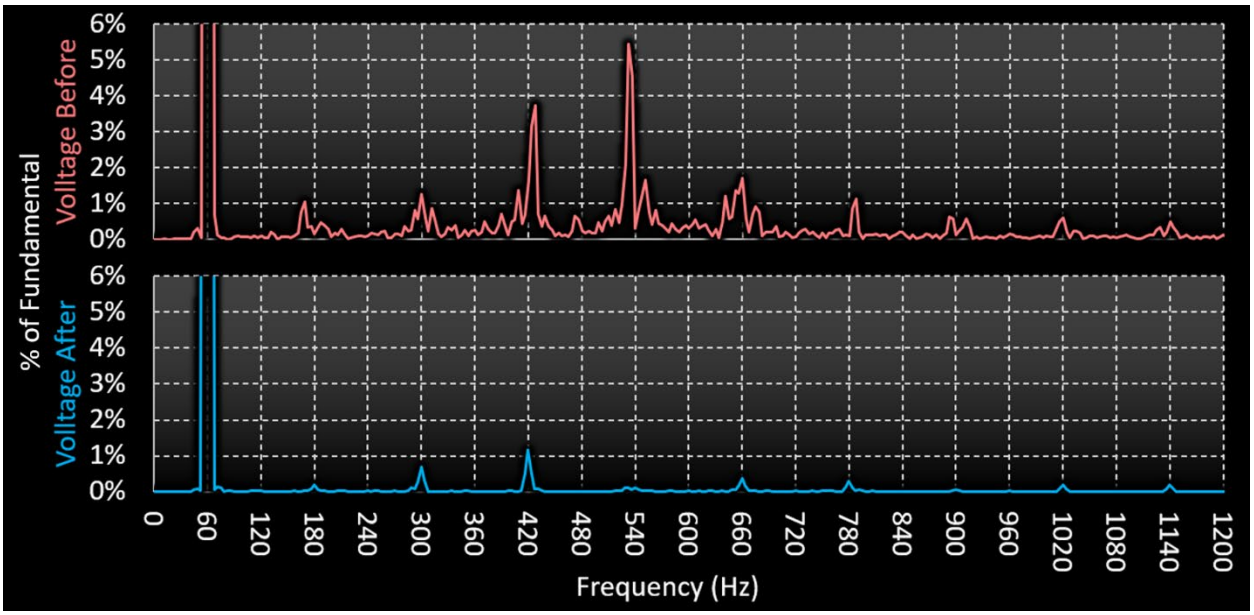


Figure 3.11: Voltage Distortion Before and After Harmonic Correction for a Data Center Facility

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.

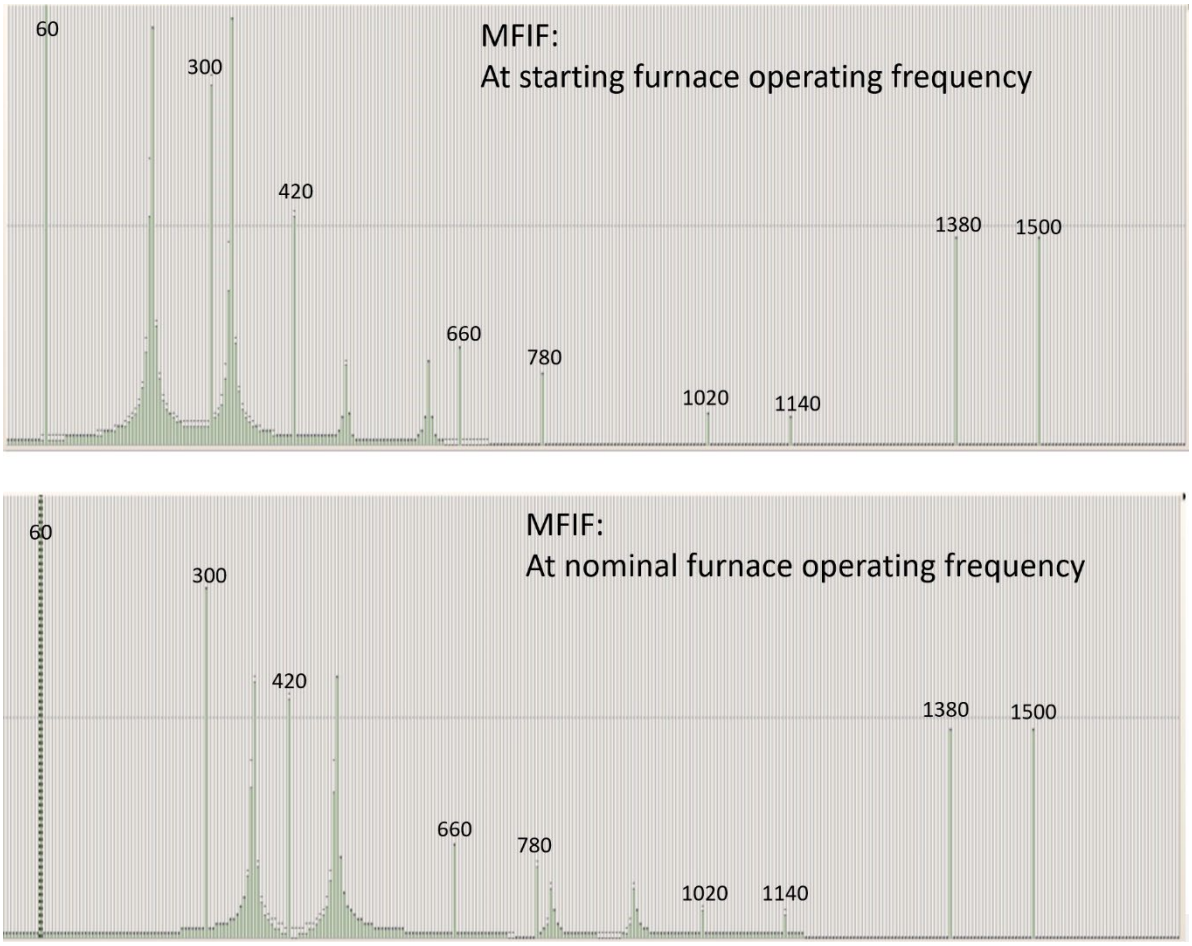


Figure 3.12: MFIF Current Spectrum for Starting and Normal Operation

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.

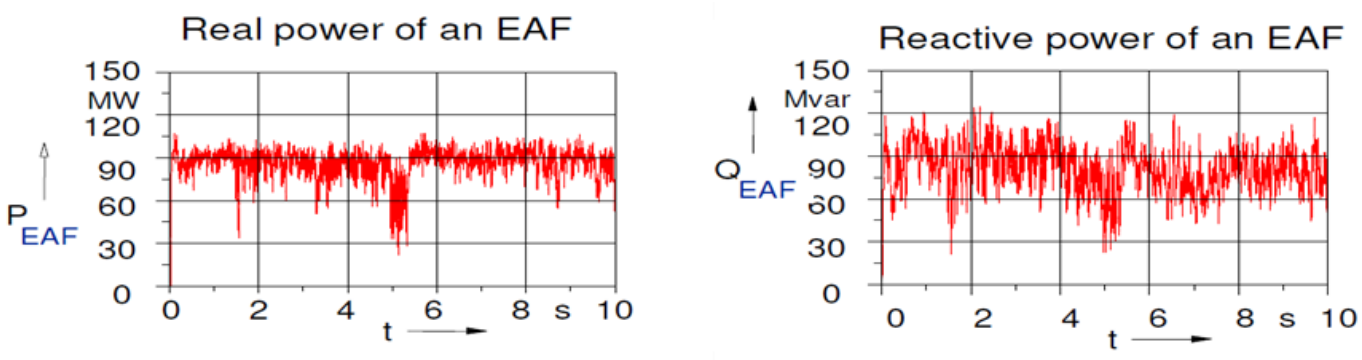


Figure 3.13: Load Profile of an Electric Arc Furnace

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.

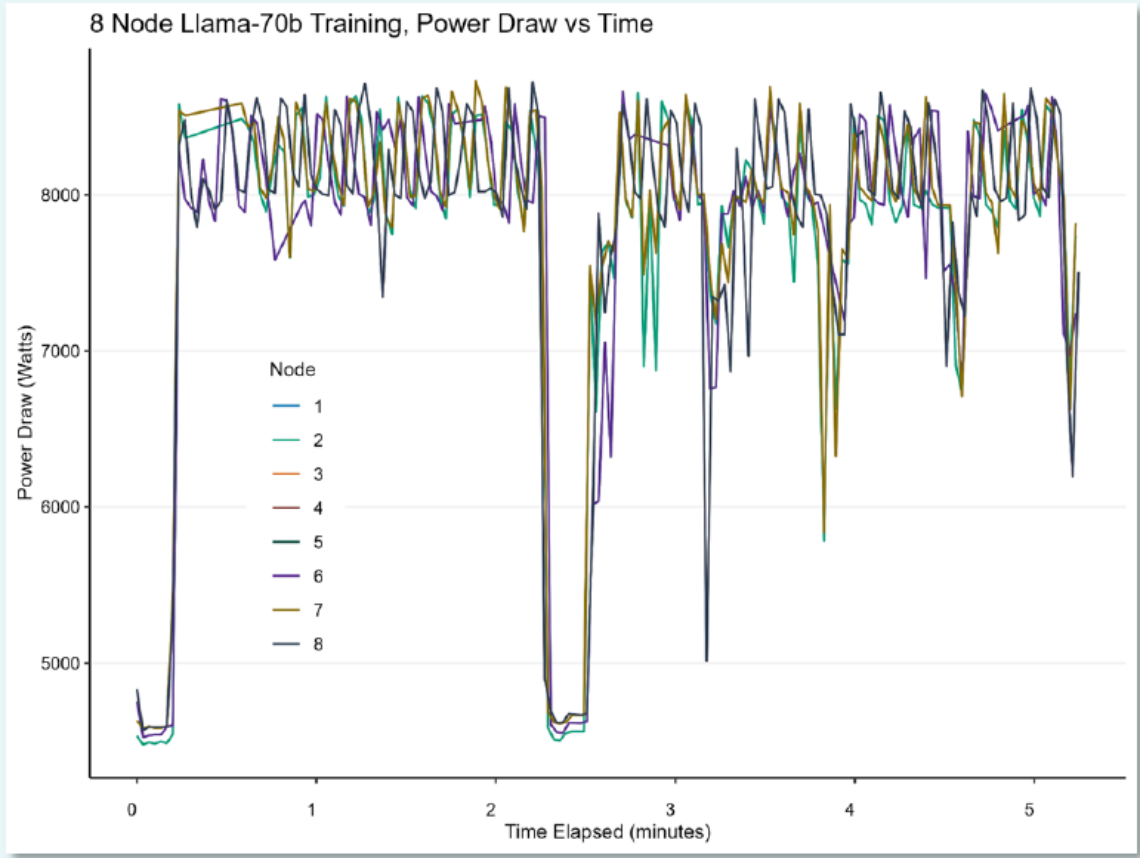


Figure 3.14: AI Training Load Profile Example

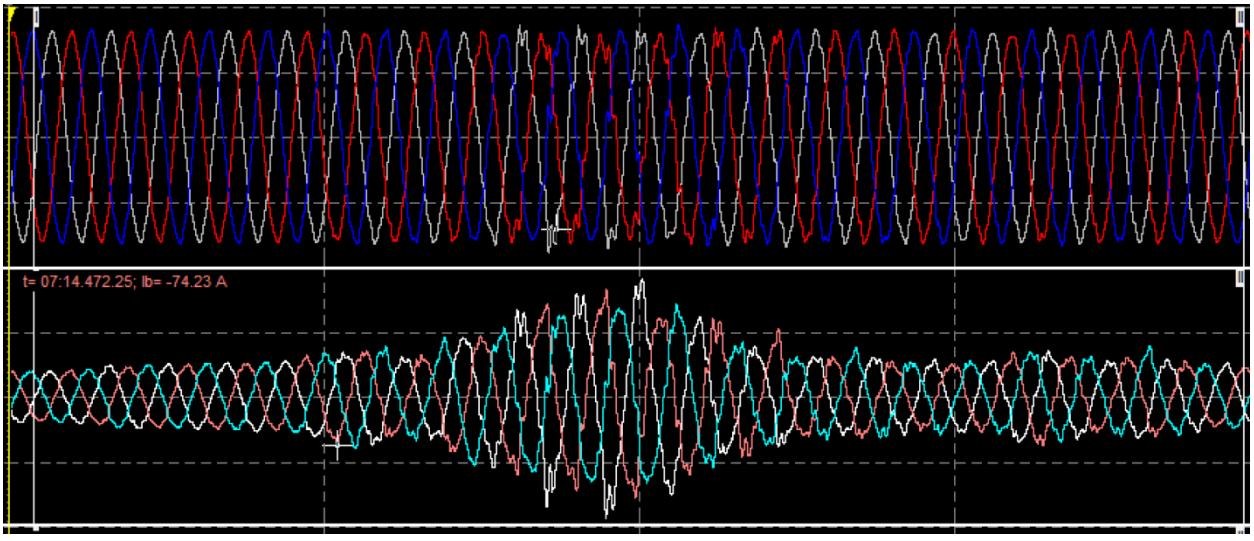


Figure 3.15: Data Center Load Pulse (Top: Voltage; Bottom: Line Current)

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 **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
Meg Albright	Bonneville Power Administration (BPA)
Rahul Anilkumar	Quanta Technology
Bob Arritt	Electric Power Research Institute (EPRI)
Sagnik Basumallik	New York Power Authority (NYPA)
Julie Booth	North American Electric Reliability Corporation (NERC)
Alexander Carlson	North American Electric Reliability Corporation (NERC)
Valerie Carter-Ridley	North American Electric Reliability Corporation (NERC)
Candice Castaneda	North American Electric Reliability Corporation (NERC)
Horea Catanase	Electric Power Engineers (EPE)
Michael Cohen	MITRE
Amin Dadashzade	Zero-Emission Grid LLC
Sudipta Dutta	Electric Power Research Institute (EPRI)
Zia Emin	Electric Power Research Institute (EPRI)
Arman Ghasaei	EdgeTunePower
Jack Gibfried	North American Electric Reliability Corporation (NERC)
Patrick Gravois	Electric Reliability Council of Texas (ERCOT)
Martha Henson (lead)	Oncor
Sam Holeman	Duke Energy
James Huang	Enchanted Rock
Pranav Kishore	1898 & Co.
Adam Kliber	Independent Electricity System Operator (IESO)
Brett Kruse	Calpine
Mike Mathieu	Elevate Energy Consulting
Eric Meier	Electric Reliability Council of Texas (ERCOT)
Evan Mickelson	North American Electric Reliability Corporation (NERC)
Shivani Nathoo	Independent Electricity System Operator (IESO)
Brett Ross	Pacific Northwest National Laboratory (PNNL)
Herb Schrayshuen	Power Advisors, LLC
Mostafa Sedighizadeh	Southwest Power Pool (SPP)
Mohamed Shamseldein	Independent Electricity System Operator (IESO)
Harish Sharma	Southern Company
Agee Springer (LLTF vice-chair)	Electric Reliability Council of Texas (ERCOT)
Tyler Springer	American Electric Power (AEP)
Nathan Strobel	North American Electric Reliability Corporation (NERC)
Kyle Thomas (lead)	Elevate Energy Consulting
John Tomczak	-
Matthew Veith (LLTF chair)	American Electric Power (AEP)
Scott Warren	Southern Company
Matthew Wharton	PJM
Jiecheng Zhao	Elevate Energy Consulting

Attachment 1-B

Whitepaper #2

NERC
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

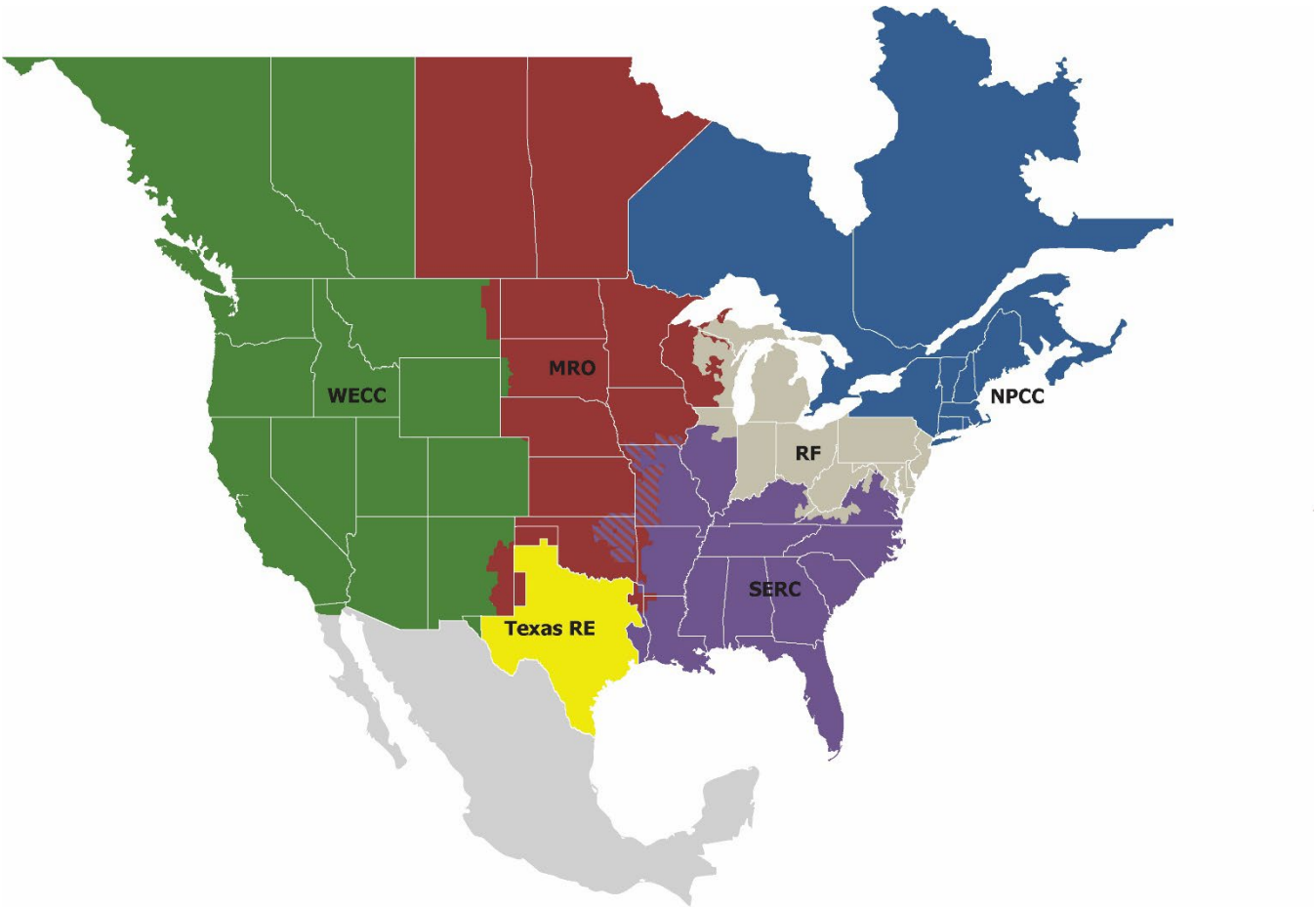
Disturbance Ride-Through, Stability, and Power Quality Gaps 51
Security, Resilience, and Event Analysis Gaps 51
Modeling Gaps 52
Risk Categorization and Mitigations 52
Critical Reliability Recommendations 52
Appendix A: Phasor/Time Domain Simulation Tools, Modeling Terminology, and Applications 56
Appendix 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

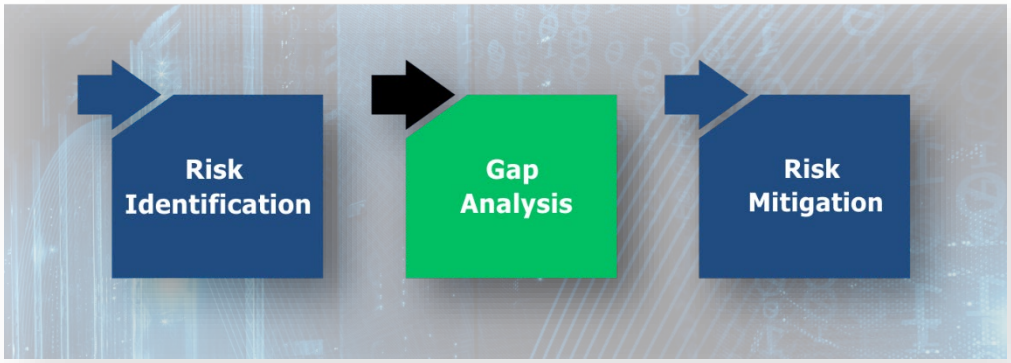
A New Challenge on the Horizon

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.

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.

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.

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**.

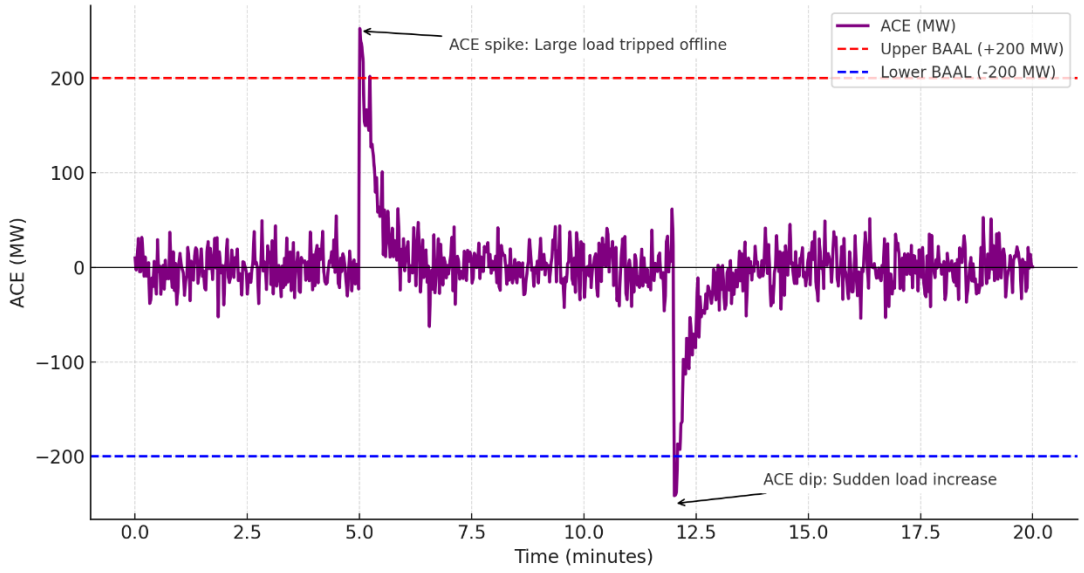


Figure 4.1: Sample ACE Variations Due to Large Loads

- **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.

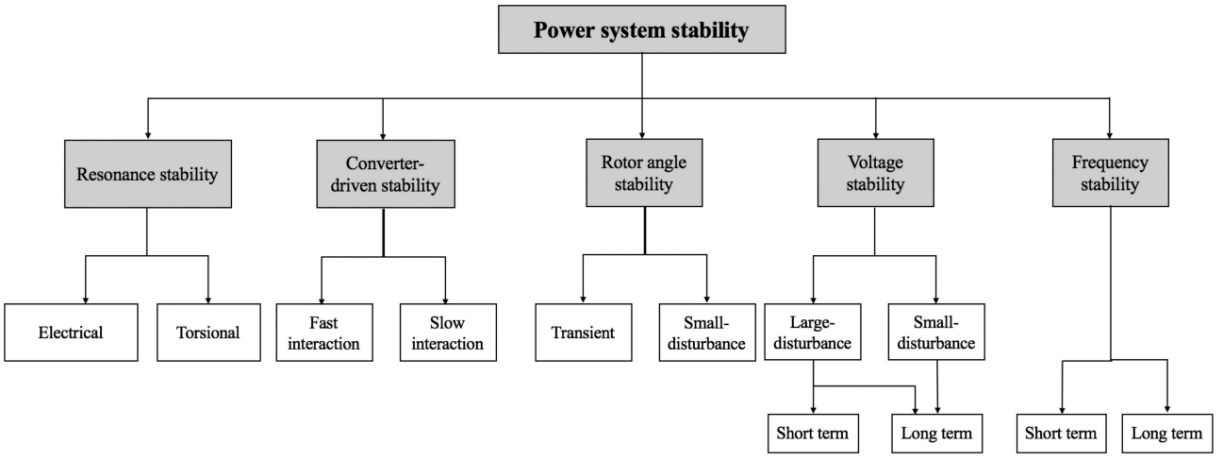


Figure 5.1: Taxonomy of Power System Stability

[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.™

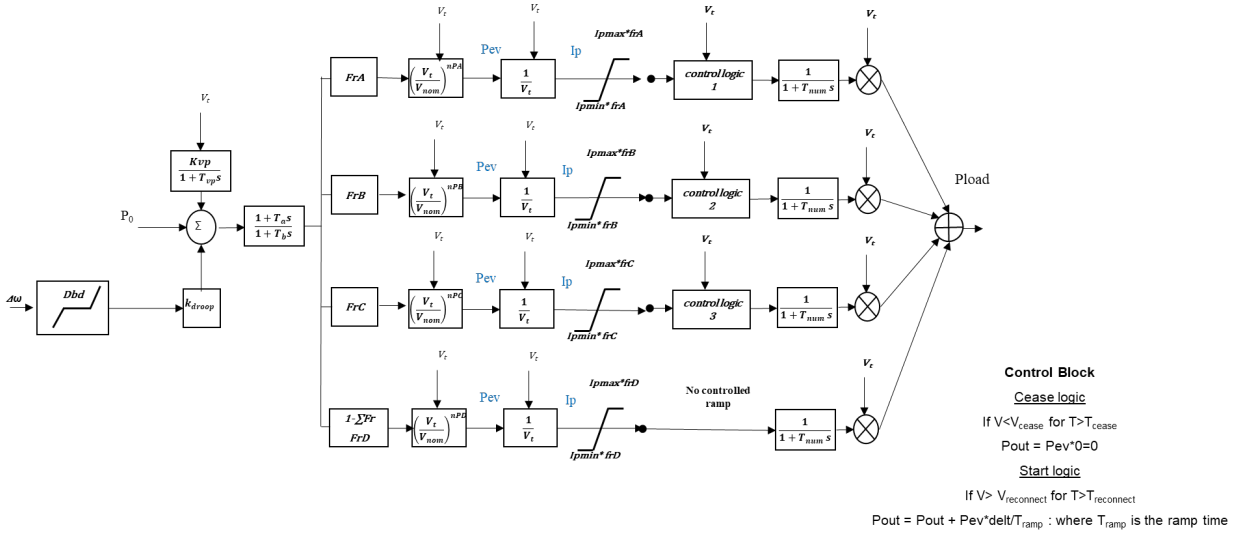


Figure 7.1: Active Power Loop for the Aggregated EV Charger Load Model

[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.

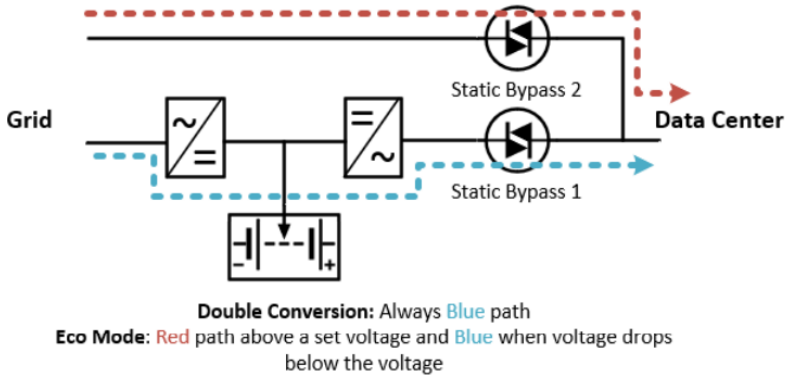


Figure 7.2: Double Conversion vs. Eco Mode Operation of Static UPS

[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.

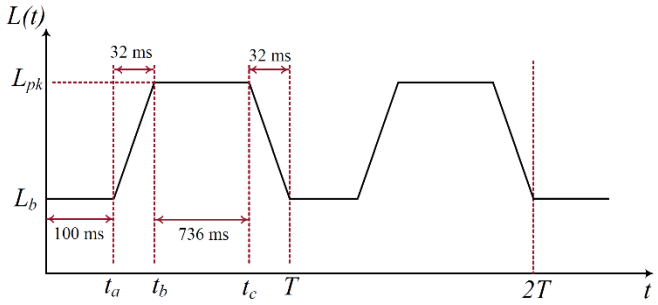


Figure 7.3: Possible AI Training Load Profile[104]

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.

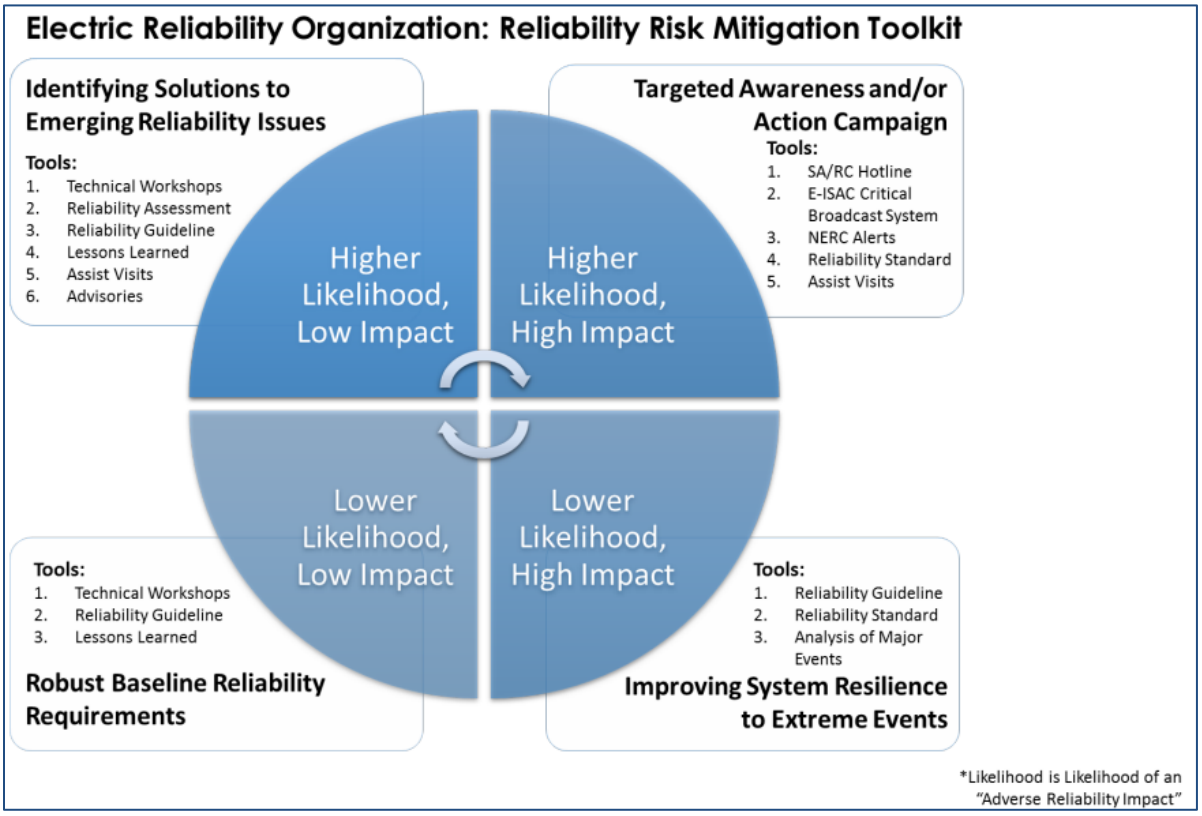


Figure 8.1: ERO Reliability Risk Mitigation Portfolio

[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**.

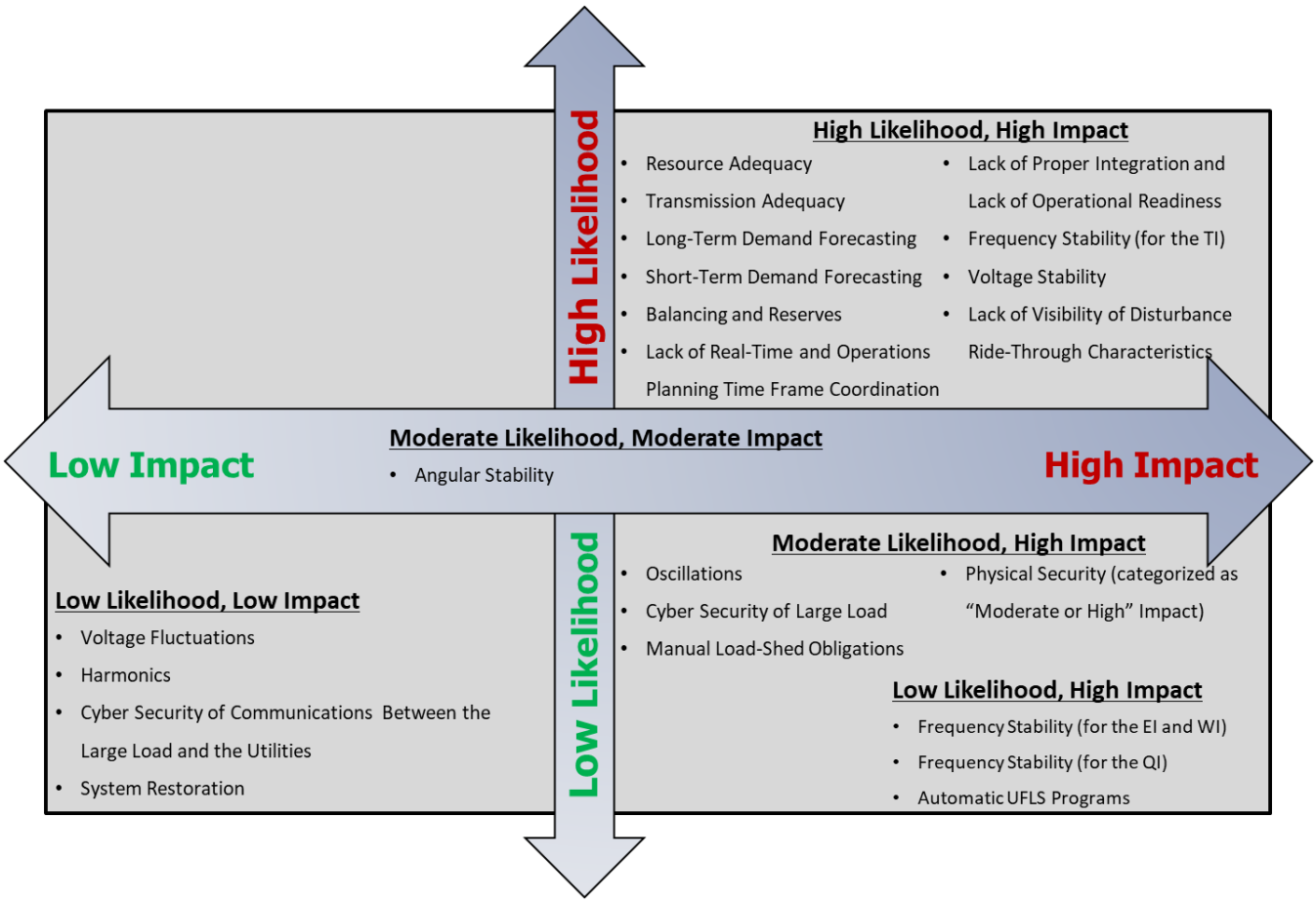


Figure 8.2: Likelihood and Impact of BPS Risks from Emerging Large Loads

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.

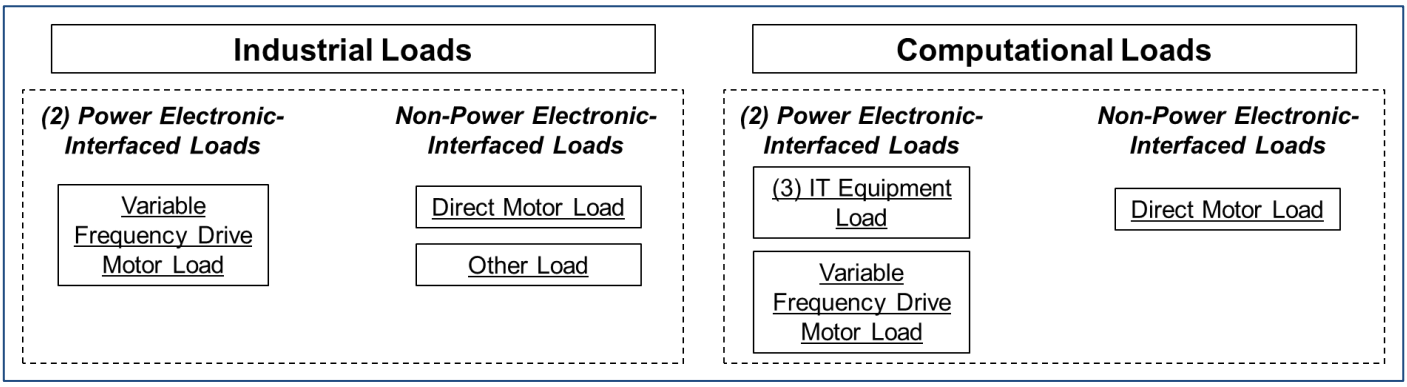


Figure 8.3: Load-Type Conceptual Overview

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.

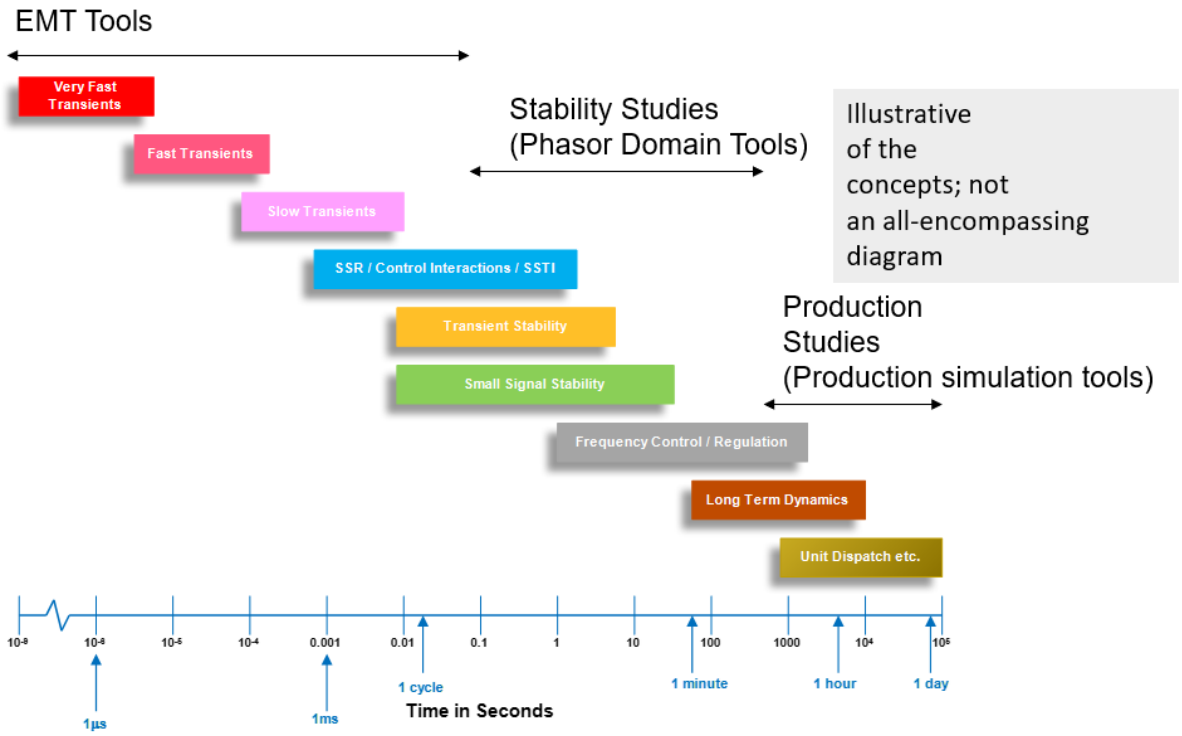
Recommendation 10: State regulators should work with regulated utilities to review how new loads and planned additional generation impact existing planning and risk assessment frameworks. States may need to adjust their resource adequacy criteria and/or work with their utilities on energy infrastructure 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**.



Source: reproduced with permission from Power and Energy, Analysis, Consulting and Education, PLLC (© PEACE® 2025)

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

Appendix C: Acknowledgements

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this white paper.

Table C.1: Contributors	
Name	**Company**
Adam Kliber	IESO
Agee Springer (Past LLWG Vice Chair)	ERCOT
Ahmed Rashwan	Electric Power Engineers, Inc.
Amin Dadashzade	Zero Emission Grid
Anupama Konara	Manitoba Hydro
Arber Caushaj	NYISO
Arman Ghasei	ET Power
Brett Ross	PNNL
Brett Kruse	Calpine
Doug Eakins	Exelon Corporation
Dr. Michael Cohen	University of Minnesota
Eric Meier (LLWG Chair)	ERCOT
Evan Mickelson (NERC Coordinator)	NERC
Hasala Dharmawardena	NERC
Hubert Côté	Hydro-Québec
Iknoor Singh	MISO
Jack Gibfried (NERC Coordinator)	NERC
Jiecheng Zhao	Elevate Energy Consulting
John Varnell	Tenaska Power Services
Julia Hariharan	ERCOT
Julie Snitman	ERCOT
Lakshmi Sundaresh	EPRI
Libin Varghese	NYPA
Manish Jain	Sargent & Lundy
Marilyn Jayachandran	ERCOT
Mark Reeves	Georgia System Operations Corporation
Matthew Veith (Past LLWG Chair)	AEP
Maryclaire Peterson	Entergy
Michael Cohen	MITRE
Mohamed Shamseldein	IESO
Mostafa Sedighizadeh	SPP
Parag Mitra	EPRI
Patrick Gravois	ERCOT
Radha Krishna Moorthy	Oak Ridge National Lab
Rahul Anilkumar	Quanta Technology
Rahul Chakraborty	Dominion Energy
Raj Dontireddy	NYISO
Reza Salehi	RMS Energy
Sam Holeman	Duke Energy
Sam Maleki	RMS Energy LLC
Sarah Kent	AEP

Table C.1: Contributors	
Name	**Company**
Scot Heath	Microsoft
Sharon Brown	PSEG
Shivani Nathoo	IESO
Sudip Manandhar (LLWG Vice Chair)	Southern Company
Tyler Springer	AEP
Valerie Carter-Ridley	NERC

Attachment 1-C

Level 2 Alert Report

Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations

Summary

The Alert was published on September 9, 2025, and required Transmission Owners (TO), Resource Planners (RP), Transmission Operators (TOP), Transmission Planners (TP), Balancing Authorities (BA), Planning Coordinators (PC), Distribution Providers (DP), and Reliability Coordinators (RC) on the NERC Compliance Registry (NCR) to respond by January 28, 2026.

The purpose of the Alert was to recommend and encourage the following to facilitate the integration of large loads with the bulk power system (BPS) in a manner that supports continued reliability:

- TOs, in collaboration with relevant TPs, PCs, RCs, TOPs, and BAs, should establish clear facility design and performance criteria in their interconnection requirements for large loads.
- TPs and PCs should establish a comprehensive interconnection and system-wide study process to assess the reliability impacts of large loads.
- TOs should enhance their load commissioning activities to establish a comprehensive commissioning process that ensures operational readiness for large loads.
- TOs should establish operating protocols and the necessary communication infrastructure to support reliable ongoing operations after large load facilities enter into commercial operations.
- TPs, RPs, and PCs should, in consultation with their appropriate regulatory bodies, identify and implement a process to include large loads in their long-term transmission planning horizon demand forecasts as well as their near-term transmission planning horizon demand forecasts.

The full text of the Alert has been posted to the NERC website.[1] Responses to this Alert have informed NERC of the extent of the condition of the rapid and unprecedented rise in large electronic loads (sometimes also referred to as computational loads). Additionally, this Alert raised industry awareness of the potential reliability concerns associated with such large loads and provided recommendations to TOs, RPs, TOPs, TPs, BAs, PCs, DPs, and RCs to mitigate these concerns.

Background

The purpose of this Alert is to expeditiously address the risks observed from the analyzed large load behavior and assess the status of industry preparedness in relation to large loads.

As part of its normal course of business, NERC often either discovers, identifies, or is provided with information that is critical to ensuring the reliability of the BPS in North America. In order to effectively disseminate this information, NERC utilizes email-based “alerts” designed to provide concise, actionable information to the

[1] https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2--large-loads.pdf

electric industry. As defined in its Rules of Procedure, NERC alerts are divided into three distinct levels, as follows:

1. **Industry Advisory**: Purely informational, intended to alert registered entities to issues or potential problems. A response to NERC is not necessary.
2. **Recommendation to Industry**: Recommends specific action be taken by registered entities. A response from recipients, as defined in the alert, is required.
3. **Essential Action**: Identifies actions deemed to be "essential" to BPS reliability and requires NERC Board of Trustees approval prior to issuance. Like recommendations, essential actions also require recipients to respond as defined in the alert.

NERC issued the Level 2 Alert with the present recommendations based on the results of its efforts under the Large Loads Action Plan.

Key Takeaways and Next Steps

NERC identified the following key takeaways based on the responses to the Alert:

- Many entities at the time of this Alert do not have specific procedures to handle the unique challenges associated with large loads.
- Many entities do not have a process to coordinate with TOs and DPs to establish protection coordination and post-disturbance recovery requirements for large loads.
- Many entities report waiting on or coordinating with a separate entity, primarily their independent system operator (ISO) or regional transmission organization (RTO), before changing their procedures to address the reliability concerns in the recommendations of this Alert.
- Many entities have not developed a list of detailed modeling data, settings, and parameters needed from large loads.
- Entities did not contact their large load entities to respond to this Alert even if they have established strong contacts with the large load customer.
- Entities do not have a standardized requirement for operational ramp limits in a post-disturbance state to address the reliability concerns raised in Recommendation 1.
- Entities report not being able to gather modeling information to represent large loads as raised in Recommendations 1 and 2.
- Entities generally do not have a commissioning process to address the concerns discussed in Recommendation 3.
- Entities broadly do not have a direct level of coordination with large load entities as they either do not have large load entities or a problem arose that prevented communication in their established process. These are issues that are addressed in Recommendation 4.
- Entities do not have a good way to capture large loads in the near- or long-term transmission planning horizons as recommended in Recommendation 5.

As explained in the report, these key takeaways demonstrate that additional steps are needed to reliably integrate computational loads (including, for example, data centers). Such next steps range from coordination to revisions to standards and NERC registry criteria, to ensure that relevant parties take essential actions to maintain BPS reliability. NERC plans the following next steps:

- Issue a Level 3 Alert by May 2026 with essential actions to ensure BPS reliability and integration of computational load with the grid.
- Explore and draft starting in the second quarter of 2026:
  - (i) registry criteria updates to address the integration of computational load and
  - (ii) develop new and update existing Reliability Standards applicable to new registrants and existing registered entities.
- Release a reliability guideline in mid-2026 to share best practices as developed by the Reliability and Security Technical Committee's Large Loads Working Group. This guidance as well as the Level 3 Alert will be crucial for entities as they will immediately share methods to improve reliability.

To stay current with updates, follow NERC's Large Loads Action Plan initiative webpage.[2]

Overview of the Report

The Alert required registered entities belonging to the TO, RP, TOP, TP, BA, PC, DP, and RC functional groups to respond to a total of 105 questions. The distribution of questions among the groups was as follows:

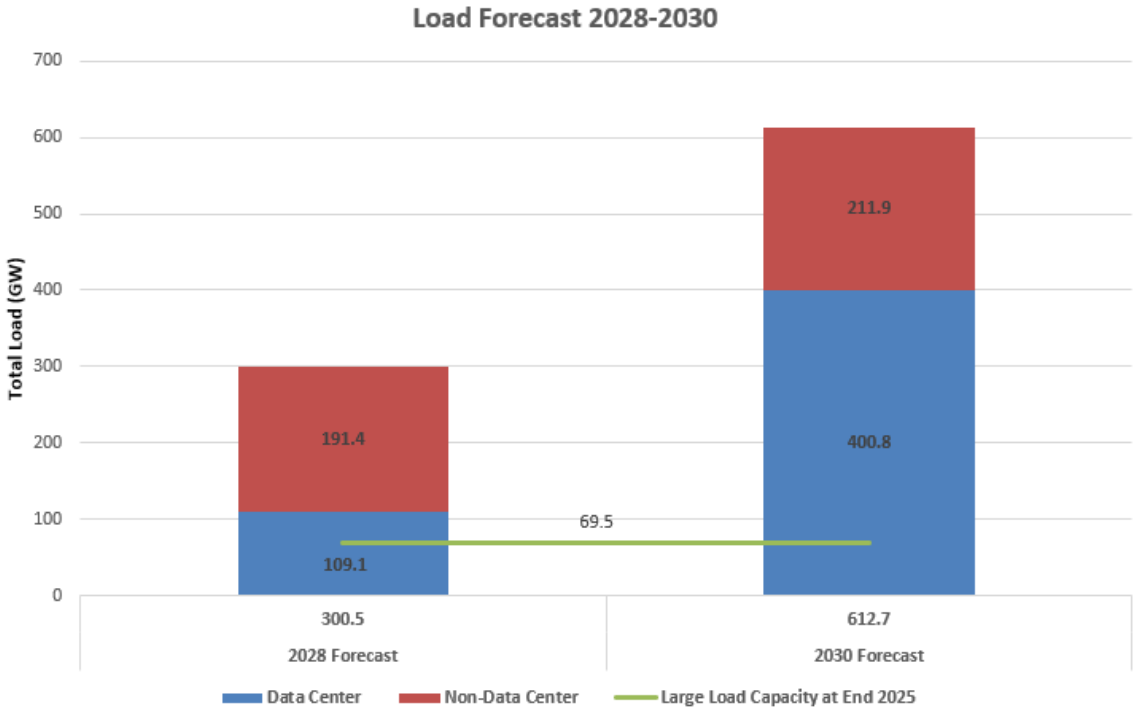
- TOs and DPs – Questions 1–44 (total of 44)
- TPs and PCs – Questions 45–67 (total of 22)
- RCs, BAs, and TOPs – Questions 68–95 (total of 27)
- RPs – Questions 96–105 (total of 9)

The questions were a combination of multiple choice, Yes/No, and requests for free-text narratives. The requirement to answer certain questions was contingent on the entity's previous answers. Additionally, the uploading of a Data Submission Spreadsheet was mandatory for entities that answered "Yes" to Question (3) *(Do you have Large Loads or are you expecting to integrate Large Loads by 12/31/2027 within your footprint? [Yes/No])*.

The worksheet information indicated that for TOs and DPs that currently have large loads on their system or are expecting to integrate large loads by the end of 2027, major load growth is anticipated during the next five years. Forecasts collected from the worksheet information indicate that load may increase by 300 GW between 2028 and 2030, with the bulk of this increase represented by data centers.

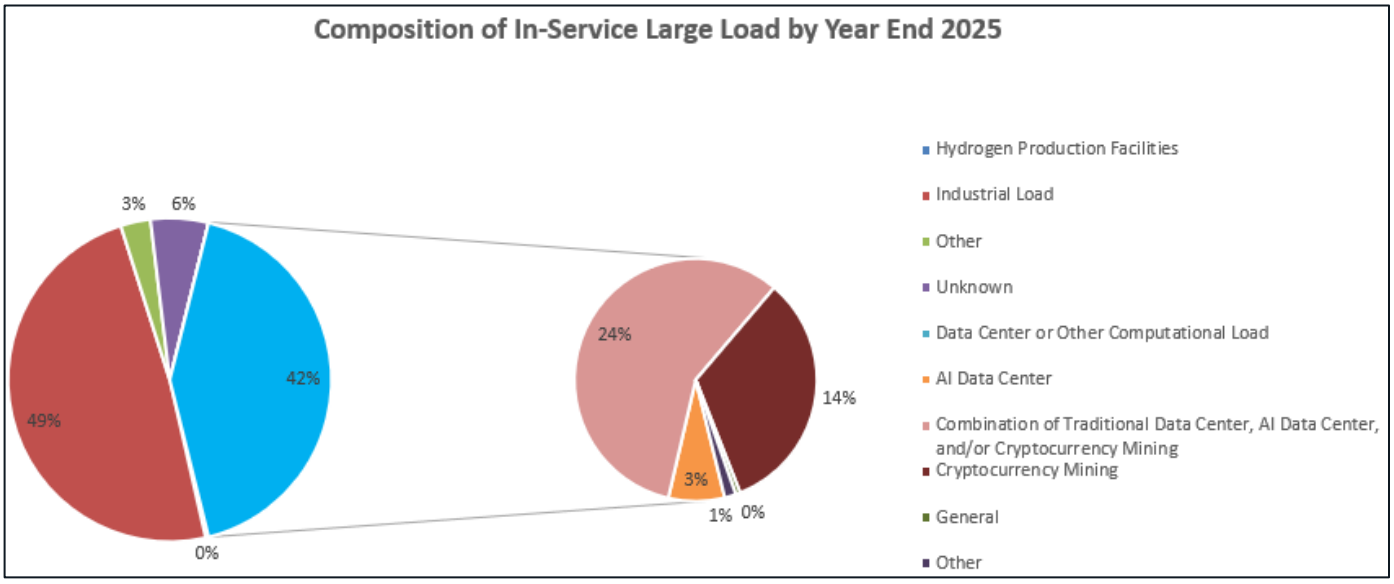
[2] Available here: https://www.nerc.com/initiatives/large-loads-action-plan

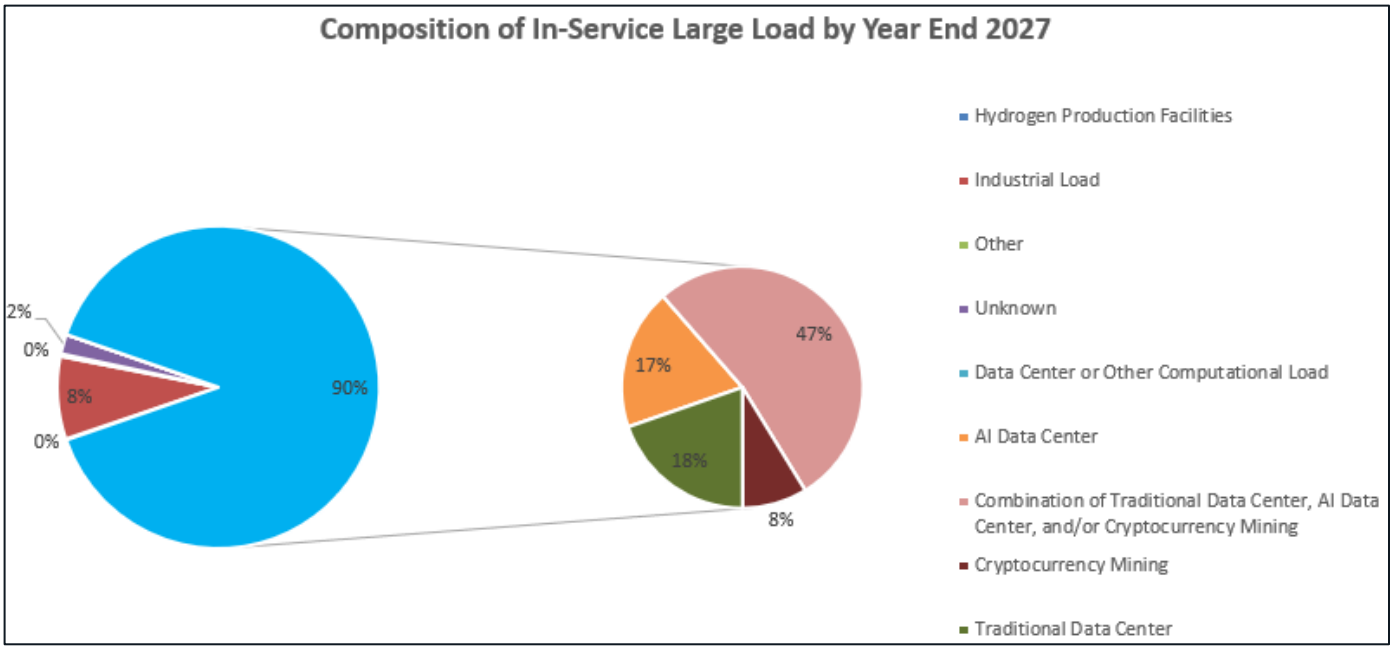
The figures in the chart show the aggregate values reported in the Data Submission Spreadsheets. While the values of the submissions were generally in line with dramatic growth, some entities provided very high values of demand growth. These entities' values were included in the charts below; however, the confidence of demand materializing at the 2028 and beyond values is questionable due to the differences associated with entity interpretations on the word "forecast."[3]



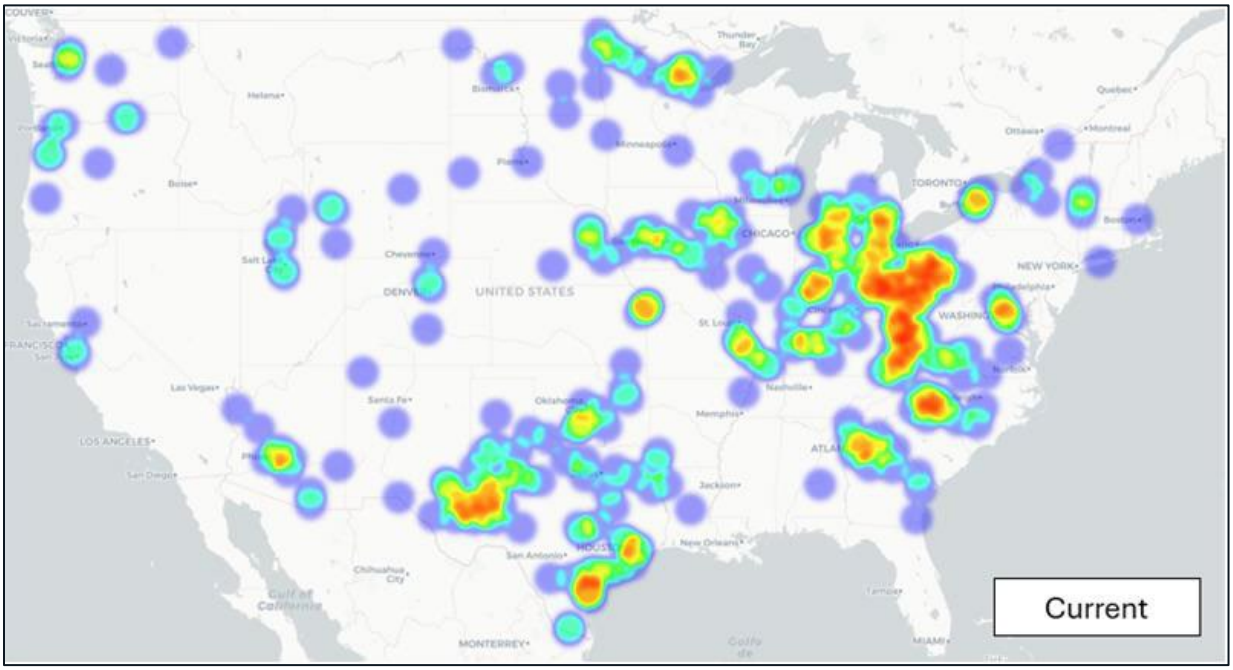
[3] For example, some entities could provide maximum projected load as the "forecast," while others could provide a 50/50 confidence value "forecast." This highlights the findings of the Alert for no clear method to identify Demand growth in the horizon.

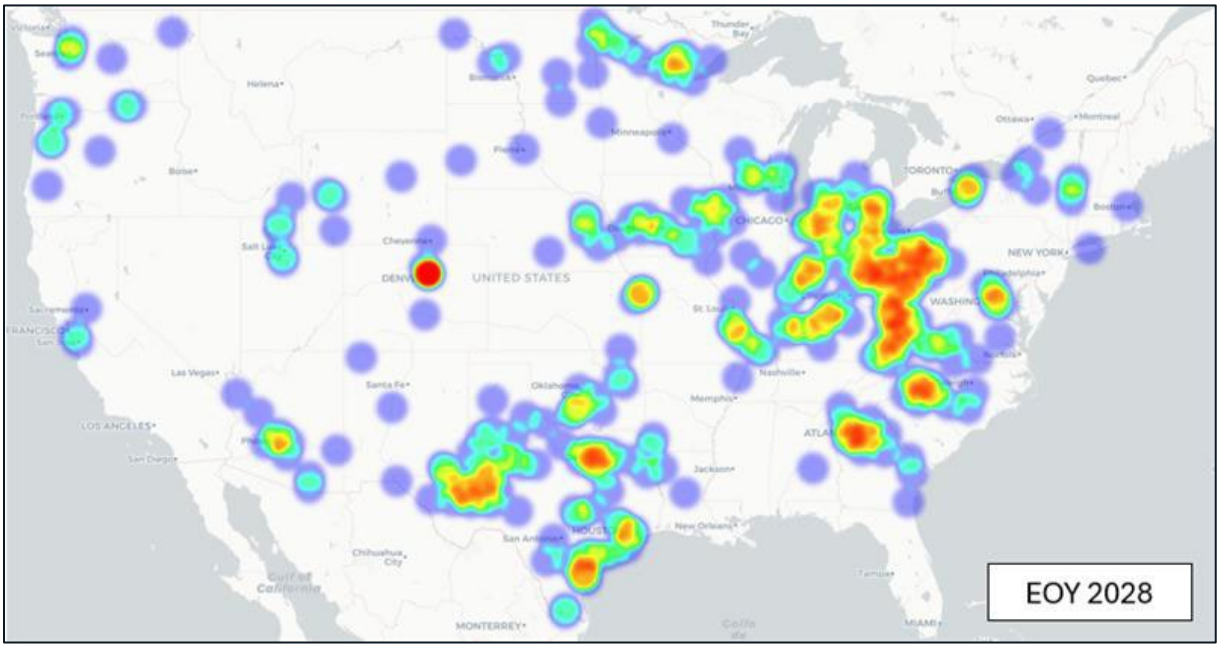
This load is expected to change its composition dramatically, moving from a split between industrial and computational load to almost entirely computational, as shown below. A large share of the expected load growth will come from the "Traditional Data Center," "AI Data Center," and "Cryptocurrency Mining" categories (or a combination of the three). This is highlighted by the light-blue portion of the in-service load. While there are significant single-use load facilities, the breakdown of this light-blue portion shows that roughly half of the future large load growth is a combination of "Traditional Data Center," "AI Data Center," and "Cryptocurrency Mining" (light red).





Additionally, entities were asked to supply some locational information for their current and forecasted loads. The heat maps below show that there are certain concentrations of this new load growth, largely comprised of the computational load described in the above charts. These maps illustrate the load growth in defined transmission corridors, with a focus in the East North Central, South Atlantic, and West South Central U.S. Census zones.[4]





[4] US Census Regions and Divisions maps are available here: https://www2.census.gov/geo/pdfs/maps-data/maps/reference/us_regdiv.pdf

Furthermore, the Alert asked for model data files to be submitted representing the large load. These data submittals were in file formats (e.g., a sav, dyd, or dyr file format) for specialized industry engineering software. Analysis of these files indicates that some entities use advanced load models such as the PERC1 (power electronic reconnecting and ceasing load model) or EV1 (electric vehicle) models to represent their loads. Some entities use the complex load (CLOD) or composite load (CMLD) dynamic models, primarily for traditional industrial loads, with generic representations for large loads on the system, thereby using similar representations for computational load consumption. One entity's response indicates that some organizations may be using the user-defined model functions of their software to implement industry models as their software platform currently does not have the model implemented in their standard library. These are all expected outcomes and align with the need to represent large loads in planning studies; however, they were the minority.

Roughly three quarters of all data center load models are insufficient to represent data center dynamic behavior, reflected in the dynamic model files included in the response to this Alert. Nearly 33,282 MW of currently operational data centers were evaluated. For "type of PSPD (power system protection device) model the large load submitted to represent their facility," entities indicated "None" for 10,536 MW of data center load. Another 14,968 MW of data center load had a blank response. This means that 25,504 MW of data center load relies on the inherent ZIP (constant impedance (Z), constant current (I), or constant power (P)) model representation in stability software. Only 7,641 MW of data center load was indicated to use the CMLD (or CLOD) model, and 137 MW was indicated to use a user-defined model (to leverage the recently released PERC1 or similar EV1 model).

The summaries, narratives, and analysis related to the 105 questions are summarized below.[5] To maintain respondent anonymity, regional breakdowns are not presented for questions when a region only has a single respondent. When this occurs, data is presented in aggregate. Furthermore, there was a significant portion of entities registered as TOs excluded from analysis as they have only point-to-point HVdc lines and are not impacted by the content of this Alert.[6]

1. In the free text field provide your definition of Large Loads including any MW or kV threshold or other operational characteristics about the load profile. Also indicate in this response other registered entities (e.g., BA, TOP, TP, or similar) that were consulted when defining Large Loads in your footprint. Enter "None" if your organization has not formally defined Large Loads. - TO, DP

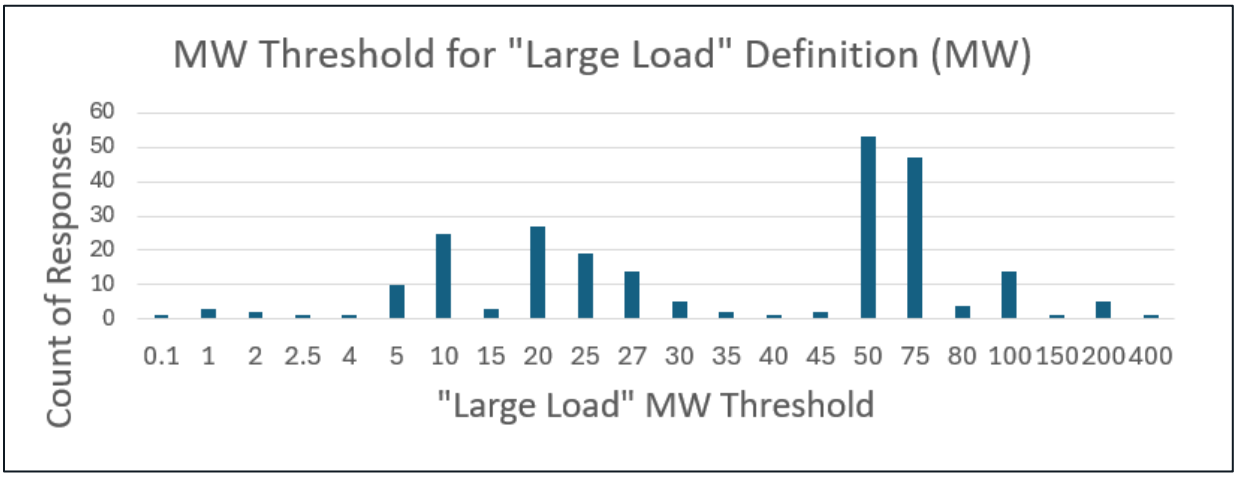
This question was shared among all entities that received this Alert (see Questions 45, 68, and 95). By referencing this against the in-service and projected information requested in the Worksheet, the 20 MW and above threshold captures roughly 90–95% of electrical size all large load facilities.

The analysis for all responses is below as there was no significant difference in responses. Entities largely did not have a formalized definition of "large load" to handle the new type of process; however, those that did

[5] Percentages are rounded, and, as a result, totals may not equal 100%.

[6] That is, large loads are not seeking multi-point HVdc interconnection, but rather ac interconnection at various voltage classes. So, these results were excluded from the analysis as the content of the Alert was on the interconnection, study, commissioning, and operations of large loads.

ranged between 100 kW and 400 MW, with clear cutoffs at 20, 50, and 75 MW (see diagram below). These values show that the entities that already defined "Large Load" have breakpoints depending on their context. The reporting DPs had thresholds typically below 20 MW, and the TOs' thresholds were all captured above the 20 MW threshold. Some transmission entities (including BAs, RCs, TOPs, TPs, PCs, and TOs) included specific language to describe the composition of the "Large Load" definition to tailor it to define data center loads, aligning with the growth of this type of load. Some entities did refer to the NERC Large Loads Working Group's (LLWG) definition that directly ties the risk to the BPS to this new category of load. For those entities that reported a size, a histogram of the size threshold for entities' "Large Load" definition is shown below. While the count of entities that have a definition below 20 MW, analysis of the worksheet demonstrates that a 20 MW or greater (aligning with the transmission entity natural breakpoint) captures 90–95% of the electrical size of these facilities.



Some entities included other qualifiers to their formal large load definition to be used in their interconnection processes. Some qualifiers were connecting voltage class (e.g., 100 kV and up) or through tiered thresholds (e.g., 10 MW at 115 kV or above and 80 MW below 115kV). Additionally, many TOs, DPs, TPs, and TOPs referred to their PC, BA, or RC definitions and indicated that they have either formally adopted or practically adopted those definitions in their processes, meaning that there are inherent expectations for TOs, DPs, TPs, and TOPs to follow their PC, BA, or RC definition in this area. This is also true for RPs; however, practices in the data demonstrate that the RP's studies do not explicitly account for large load behavior but rather total demand.

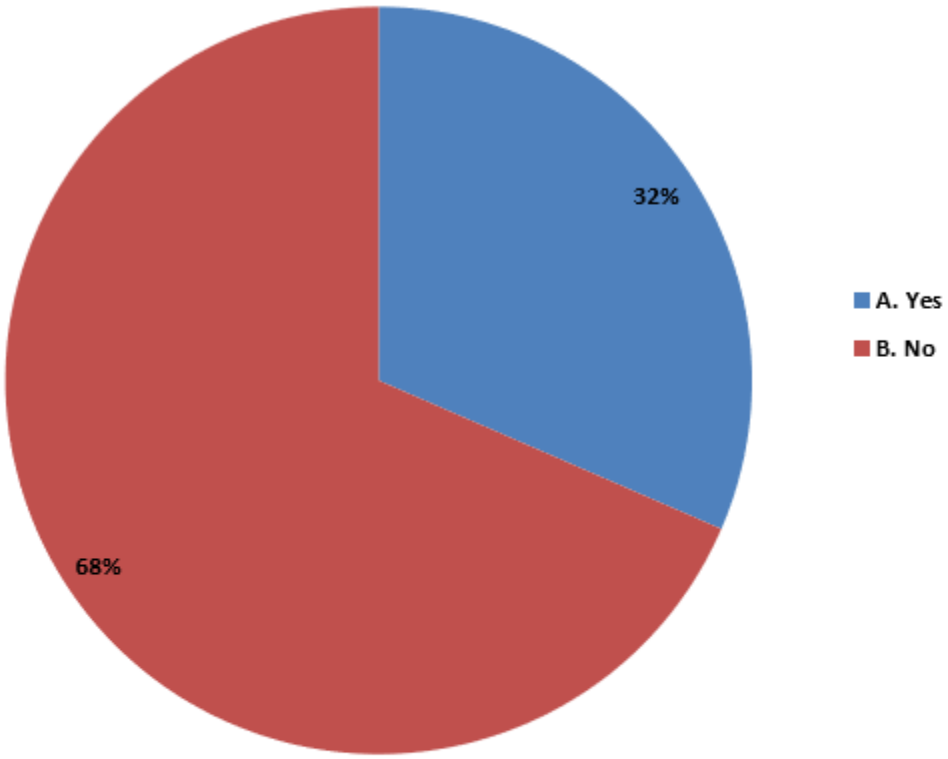
2. In the free text field provide your experience in integrating Large Loads. Include in this response the number of years of experience in integrating Large Loads and other highlights or lessons learned as part of this experience. - TO, DP, TO, DP

This question was shared among all entities that received this Alert (see Questions 46, 69, and 97). The analysis for all responses is below as there was no significant difference in responses. Nearly two-thirds of all submitting entities indicated a lack of experience in integrating modern data centers or other large loads. Of those that have experience, a third had less than five years of experience, a third had six or more years of experience, and a third had experience only serving "traditional" industrial large loads.

The large share of entities submitting a lack of experience indicates that they either have no large loads or have not yet completed (but may have received) interconnection requests for this category of load. The entities that have a concentration of large load experience (six or more years) typically also reported that their experience from traditional loads has informed them for their approach to current large loads and that they have either adapted their traditional process or crafted new requirements based on disturbance findings or to address risk observed in their own or similar systems.

3. Do you have Large Loads or are you expecting to integrate Large Loads by 12/31/2027 within your footprint? [Yes/No] - TO, DP

Slightly less than one-third of the respondents registered in the TO and/or DP functions reported that they expected to integrate large loads in their footprint over the next two years. Of those that do expect to integrate large loads, the expected electrical sizes are significant. See the summary section above for quantity and composition changes for the entities that expect to integrate large loads by December 31, 2027.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	31.5%	36.5%	9.8%	42.6%	27.8%	46.7%	30.5%
B. No	68.5%	63.5%	90.2%	57.4%	72.2%	53.3%	69.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

4. In the free text field provide how you are contacting, interacting, or otherwise coordinating with Large Loads that are operational or nearly operational (i.e., 2 years or less) to collect information or resolve ongoing issues that arise. - TO, DP

This question was shared between TOs, DPs, TPs, and PCs (see Question 47). There was no significant difference in responses across the different entity types (e.g., TO and DP vs RP). Roughly half of the responses indicate that the respondents have recurring contacts with procedurally defined entities during the interconnection process and provide a "key accounts manager," "customer accounts manager," or similar title/position to continue to engage with operational or nearly operational large loads.

In the responses, NERC found that TOs, in concert with their load-serving entities (LSE), contact data centers directly. That is, the TOs and LSEs are the ones that collect information and supply it to the TP, PC, RC, or other functional entity. Some TOs are also "coordination only" when collecting or resolving ongoing issues as they coordinate with either the large loads or the LSE to gather information. In general, the entities that have large loads have great contact with them either directly or through the LSE; however, many reporting entities do not have large loads.

The other half of reporting entities did not have this direct level of coordination among large loads for a variety of reasons. Some do not have large loads on their system, and others had erroneous contact information (in processes like the above) or did not receive a response from the large load entity through their typical communication methods

5. In the free text field provide any challenges experienced while coordinating with operational Large Load entities for the process development and data submittals necessary to respond to this alert. Enter "Not Relevant" if your organization did not coordinate with Large Load entities to respond to this alert. - TO, DP

Roughly all (~85–90%) respondents indicated that they did not coordinate with large load entities when responding to this Alert. This finding is counter to the expectation that entities work with their large loads to gather the information requested in the Worksheet. Some entities (<5%) indicated that they had no issues with coordinating and gathering information to fill out this Alert.

Those that did reach out to their large loads indicated that their challenges included confidentiality of the data between the customer and the Alert response, resource adequacy to serve end-use customer demand, and modeling challenges. Some reported that their large load entities are fatigued by the multitude of data requests, and others have reported challenges with gathering any information from their contacts.

This indicates that while entities may have set up avenues to gather information, these are simply not effective vehicles to gather information to address emerging risks associated with this technology as reported by entities. One TO in an area with a high penetration of large loads mentioned that out of five entities contacted for a dynamic model, only one was able to provide a dynamic model. The original data request for the dynamic model was from a recent request for information sent before this Alert was issued.

6. In the free text field provide any comments you wish to provide to help explain your answers to these questions. - TO, DP

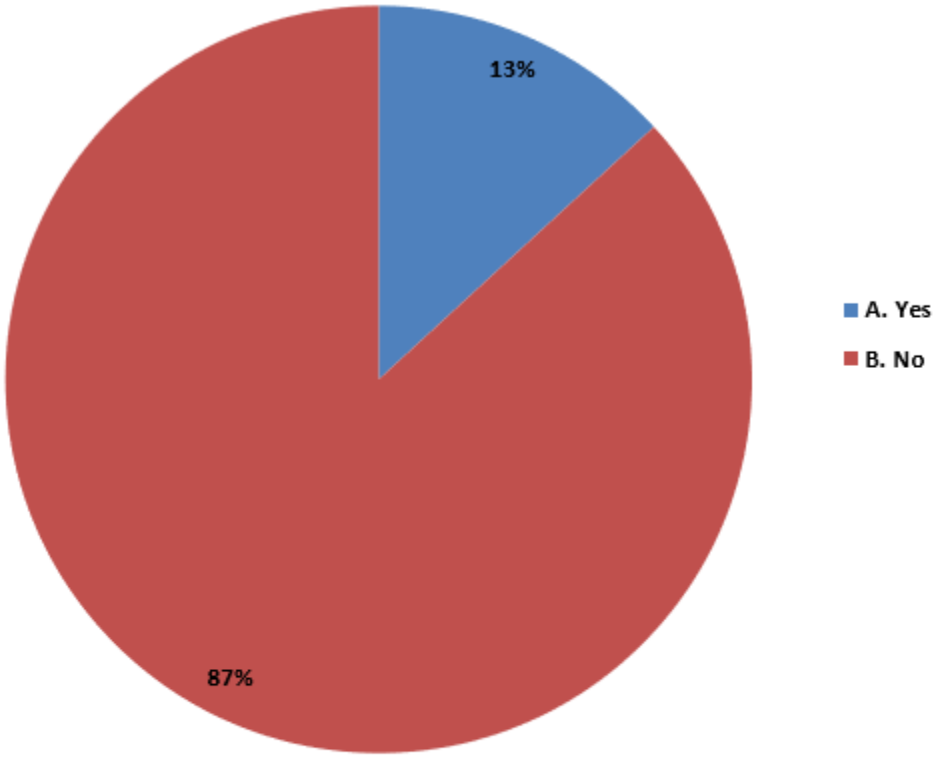
This question was shared among all entities that received this Alert (see Questions 48, 70, and 100). There was no significant difference in responses. Many entities did not provide information in this column; however, those that did used this field to share more about their current practices, discuss potential challenges with contacting or getting information on large load entities, or explain how they plan to engage with their PC, RC, BA, or another entity to align their internal processes to the recommendation. Common themes included the following:

- Many entities expressed that they did not or do not expect in the next two years to interconnect any large loads.
- Many entities highlighted concerns with the hypothetical load that burdens their processes.
- Many entities stated that they defer to the ISO or RTO for additional work and implementation of the Alert Recommendations.
- Entities reiterate that they have limited experience with these loads.
- Some entities stated they use steady-state models and studies only and do not perform dynamic studies.
- Some entities shared using a CMLD model to represent data centers in transient studies.
- Some entities stated they rely on consultants to study or perform some of their duties.
- Some entities stated that tariff revisions are ongoing to solidify their work.
- Some entities use a loss of load expectation (a probabilistic measure of energy adequacy) study to determine if additional requirements or changes are needed from large load entities.
- A minority of entities indicated that they have large load-specific interconnection processes. These are ones with more significant experience or that have proactively acted.

7. Have you established clear facility design, modeling, and performance criteria in your interconnection requirements for Large Loads? [Yes/No] - TO, DP

Most respondents have not established clear facility design, modeling, and performance criteria in their interconnection requirements. Clear load facility performance criteria are expected for any loads, even if the design, modeling, and performance criteria are generic to all interconnecting loads.

Clear facility design, modeling, and performance criteria in an entity's interconnection requirements ensures that any end-use facility design will include specifications that improve reliability. In this context, these requirements form the design parameters and basis for a facility's construction. Without these clear design, modeling, and performance criteria, entities may not design (and thus operate) their facilities in a way that is consistent with BPS reliability.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	13.2%	9.5%	2.0%	21.3%	13.5%	30.0%	11.6%
B. No	86.8%	90.5%	98.0%	78.7%	86.5%	70.0%	88.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

8. Attach the relevant Large Load language in your interconnection requirements as a separate file. - TO, DP

Entities submitted relevant files; see summary in Question 9.

9. Describe in the free text field a summary of the relevant Large Load language in your interconnection requirements. Include in this response the relationship to how a qualified change would require re-study by the TP and PC for a given Large Load. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. The entities that attached their language in Question 8 further explained in detail the ways large loads interact with their interconnection requirements. Many explained that their requirements also included a Data Center Information Collection Questionnaire that the NERC Load Modeling Working Group (LMWG) developed, indicating that the entities that have interconnection requirements are leveraging available industry documentation to help standardize the information requested of large loads. Some entities explained that they mirror the Small Generator Interconnection Agreement (SGIA) or Large Generator Interconnection Agreement (LGIA) processes to study these loads due to their complexity, while others mirrored traditional industrial load processes.

These interconnection requirements include relevant language on the following:

- Power system oscillations
- Load ramps
- Voltage ride-through or expected performance
- System protection
- Some include operating protocols and operational readiness
- Factors that trigger a qualified change, including the following:
  - Growth of the load facility in the future
  - Changes to energy consumption

10. Enter the operational load ramp limits for normal operations in MW/min. Enter "N/A" if no operational load ramp limit is established. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many still left this blank or indicated that no operational ramp is established. This is not a normal requirement for load, but the fast-ramping nature of computational loads may necessitate this for large loads. The entities that did respond varied between 8 MW/min to 300 MW/min. Many responses that did include a load ramp limit largely fell between 10 MW/min and 30 MW/min.

11. Enter the operational load ramp limits for abnormal or post-Disturbance operations in MW/min. Enter "N/A" if no operational load ramp limit is established. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many still left this blank or indicated that no operational ramp is established. The entities that responded to Question 11 typically repeated the same value for Question 10. There does not seem to be a consistent requirement concerning the recovery of load in a post-disturbance state.

12. Enter in the free text field the design requirements for Large Loads to minimize and mitigate power oscillation interaction during normal operations. Enter "N/A" if no design requirements are in place. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many indicated that there are no design requirements in place for large loads to minimize power oscillation interaction during normal operations. Those that did have some requirements fell into one of these categories:

- Requirements are based on a study to identify oscillation interaction with defined mitigations.
- Requirements are set to not inject at known system modes.
- Requirements are set to limit the peak-to-peak measurement of the active power oscillation to 25 MW.

13. Enter in the free text field the design requirements for Large Loads to minimize and mitigate power oscillation interaction in the recovery period following a System Disturbance. Enter "N/A" if no design requirements are in place. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many indicated that there are no design requirements in place for large loads to minimize power oscillation interaction in the recovery period following a system disturbance. Those that did largely repeated the same result for Question 12. Some entities indicated that they establish a minimum damping ratio for oscillatory behavior following the system disturbance.

14. Enter the TP-, PC-, RC-, or BA-provided maximum amount of load that can be disconnected (e.g., through tripping or customer isolation) from a single Contingency. Enter "Not provided" if no entity has provided this number or "not applicable" if no such number is included in the interconnection requirements. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many indicated that there is not a number associated with this type of contingency loss. Of those that reported this value of load, the value ranged from 300 MW to 2,600 MW depending on the context. These contexts ranged from any given (P1–P7) contingency during the interconnection (e.g., FAC-002) process, versus system operating limits from a

frequency stability study. There was a plurality of entities that shared the 300 MW value from those entities that did contain a maximum amount of load loss.

Many responding to this question indicated that they plan to study this for future changes, even if there was currently not a number provided by the TP, PC, RC, or BA or that the entity did not yet include this in their interconnection requirements.

15. Enter the implemented modeling requirements to meet TP and PC established modeling needs. Enter "Not defined" if no TP and PC requirements exist. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many indicated that there are no modeling requirements to meet the TP- or PC- established requirements. In some instances, this was because the TP or PC did not establish those requirements. Those that do have requirements typically reference Interconnection-wide bodies that coordinate models to represent load, generation, transmission, and other elements. Some entities include specific electromagnetic transient or positive sequence phasor domain model types to represent large loads.

16. Describe how the Large Load entities supply data or models to meet the established TP or PC modeling needs. Enter "Unable to gather" if the Large Load entity does not provide you with the TP and PC needed information to meet their established modeling needs. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many indicated that they used a procedural process (e.g., through a tariff queue or other regulated mechanism) to provide models to the TP and PC for interconnection studies. Some entities reiterated that if an entity was unable to provide a model, a study could not be performed. These are expected mechanisms for processing an interconnection request using a TO or DP's system.

Some other responses indicated that entities were unable to gather information needed from large load entities. Some entities reported that they could not gather this information because they lacked the authority to do so. In these two cases and more, there was a general concern of a knowledge gap of the large load facility, inhibiting the ability to provide sufficient dynamic modeling data for grid modeling. Entities did not explicitly state where this knowledge gap exists, but there is a lack of understanding from both the utility or the large load facility on what is needed to model the facility.

17. Describe the performance requirements for voltage ride-through, voltage recovery characteristics, or other voltage response data deemed necessary by TPs and PCs. Include in this response how this is acquired from the Large Load entities. Enter "Not defined" if there are no requested voltage data from TPs or PCs. Enter "Not available" if no data is provided. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many indicated that there is no voltage ride-through, recovery, or other voltage response data submission requirements to evaluate this performance. In some cases, there were citations for pending rule approvals[7] that included both voltage ride-through and frequency ride-through requirements. In other cases, the requirement language submitted included some form of ride-through, recovery, or other expected voltage performance for system disturbances. Based on a past NERC incident review,[8] these sudden disconnections for faults can lead to instability and are the basis for NERC's Alert Recommendation for these requirements.

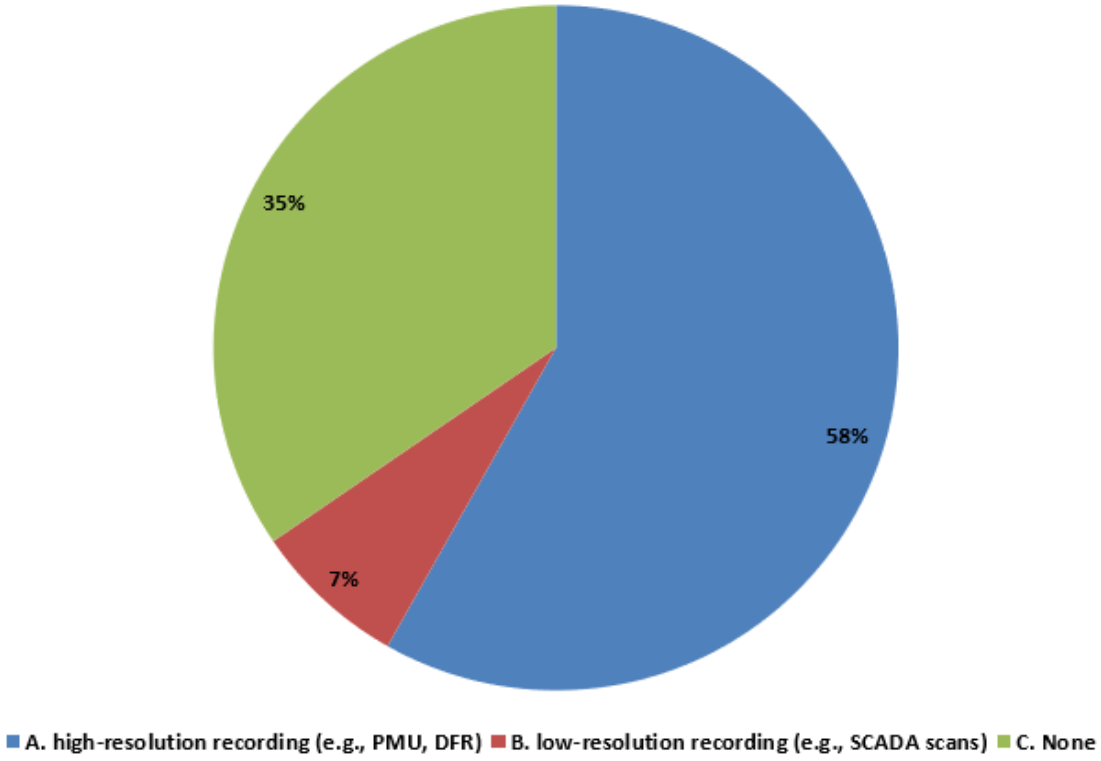
18. Describe the performance requirements for frequency ride-through, frequency recovery characteristics, or other frequency response data deemed necessary by TPs and PCs. Include in this response how this is acquired from the Large Load entities. Enter "Not defined" if there are no requested voltage data from TPs or PCs. Enter "Not available" if no data is provided. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many indicated that there is no frequency ride-through, recovery, or other voltage response data submission requirements to evaluate this performance. In some cases, there were citations for pending rule approvals[9] that included both voltage ride-through and frequency ride-through requirements. In other cases, the requirement language submitted indicated that a specific study would be conducted to determine if frequency ride-through or other performance was necessary for a given load facility.

[7] For example, NOGRR282 available here: https://www.ercot.com/mktrules/issues/NOGRR282
[8] Available here: https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_large_load_loss.pdf
[9] For example, NOGRR282 available here: https://www.ercot.com/mktrules/issues/NOGRR282

19. Select from the choices the recording devices required to be installed for Large Loads in your interconnection requirements. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. These entities largely identified that high-resolution recordings are the dominant choice to be installed for large loads, with some entities selecting a lower resolution. In total, roughly one-third of entities did not include electrical recording devices as part of their requirements.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. high-resolution recording (e.g., PMU, DFR)	58.2%	50.0%	100.0%	23.1%	84.6%	66.7%	63.6%
B. low-resolution recording (e.g., SCADA scans)	7.3%	37.5%	0.0%	0.0%	7.7%	0.0%	0.0%
C. None	34.5%	12.5%	0.0%	76.9%	7.7%	33.3%	36.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

20. Describe the disturbance recording equipment for Large Load and where such devices are located in reference to the load's Point of Interconnection. Include details for the device types, electrical locations (including any phase-to-phase differences), and sample rates. Enter "no monitoring devices" if no devices are required for Large Loads. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Some entities indicated that there are no devices required for large loads; however, most entities indicated that they generally included supervisory control and data acquisition (SCADA) telemetered values at the large load facility's point of interconnection along with some form of high-resolution data for disturbance-based event capture. In some areas, these requirements were met by a demand threshold (e.g., 75 MW or more behind the delivery point). A small minority of entities included extreme sample rate devices used to capture fast transient behavior; however, this was not a common practice. In some regions, it was noted that existing rules dictate that the PC/RC (primarily the ISO or RTO) may require the installation of fault recording and sequence of events recording equipment.

21. Describe the method to access and retrieve data from disturbance recording equipment at the Large Load. Enter "Not accessible" if devices are installed, but you are not able to access these recordings. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many indicated that these recordings are not accessible for the utility but that the device is present. Of those that could access and retrieve data, there was about an even split between an "on-demand" access versus a request for information formal procedure. A very small minority stated that a local field technician would be required to retrieve this information through coordination with the load facility. Some of the entities that could not access these devices typically cited that if the recording is owned by the load, their only method was a formal information request that may not be successful.

22. Describe how you review your interconnection requirements, change the requirements, and enforce any changes to these requirements for Large Loads. Enter "Not reviewed specifically" if this process is not done uniquely for Large Loads. - TO, DP

This question was only required of the 55 entities that answered "Yes" to Question 7. Many of the entities review their interconnection requirements on a periodic basis, with most reviewing them annually; however, most entities did not review this uniquely for large loads. Some entities have specific processes where they review their requirements against industry guidelines for alignment that are large load specific. Additionally, some entities review their requirements prior to an interconnection agreement or in other ad-hoc manners.

23. Describe any plans you have within 2 years to include revisions to address the issues raised in Recommendation 1. Enter "No plans" if you do not have plans to revise your Facility interconnection requirements. Include in this any coordination efforts among TPs, PCs, RCs, or BAs to enhance your Facility interconnection requirements. - TO, DP

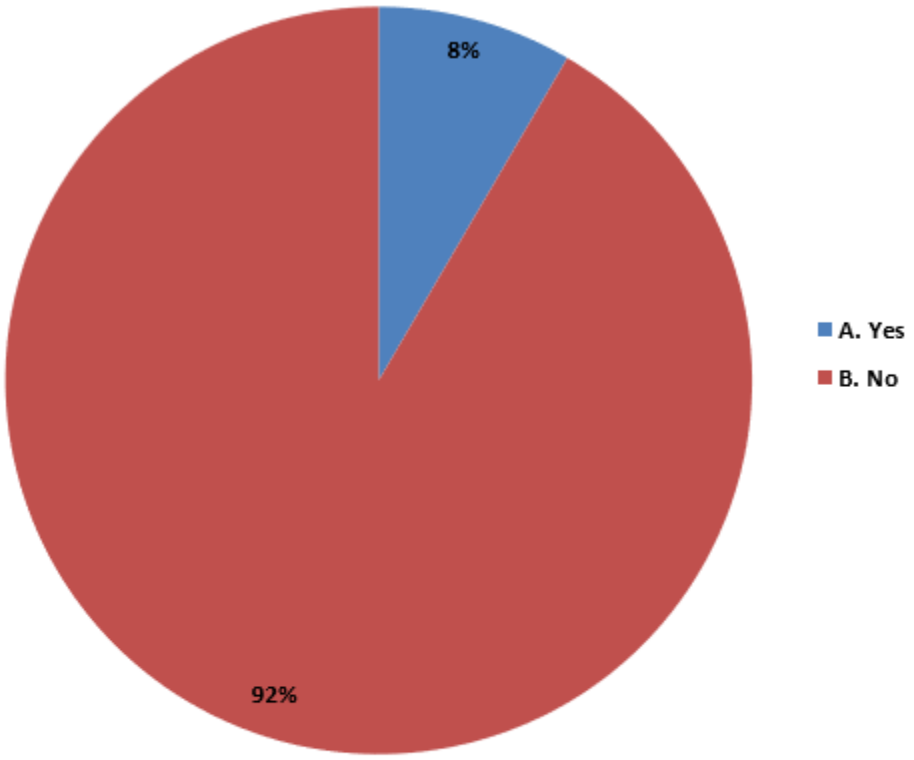
This question was required of all TO and DP entities. Of these entities, roughly half of them do not plan to address or revise their processes to address the issues raised in Recommendation 1. The other half of entities that do plan to make changes indicated that they may start a long-term process within two years; however, the completion of this may go beyond the two-year period asked in the question. Some entities cited their ISO or RTO making changes to align with Recommendation 1 and are waiting to make changes to align with their ISO or RTO. Some other entities also highlighted that they plan to align with NERC Reliability Standards during these two years.

Some entities reported that they will align with the Recommendation because many of their requirements are already in line with the Recommendation content. These entities also have indicated they will continue to align with industry best practices and NERC recommendations for treatment of large loads beyond the timeline asked in this question.

24. Have you established a Large Load commissioning process to help ensure operational readiness for Large Loads? [Yes/No] - TO, DP

A large majority of entities do not have an established commissioning process that ensures operational readiness for large loads. Those that do have varied degrees of complexity, outlined in the response to further questions.

Commissioning processes enable entities to identify any inconsistencies from their designed plans that occur during a large project's construction. These checks ensure that the installed equipment matches the studied designs and that resulting models and performance from the equipment will meet reliability objectives. A lack of specific commissioning process to ensure operational readiness decreases the certainty that equipment will operate in a reliable manner.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	8.4%	9.5%	2.0%	13.3%	7.3%	16.7%	6.4%
B. No	91.6%	90.5%	98.0%	86.7%	92.7%	83.3%	93.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

25. Enter how you are consulting with RCs, TOPs, and BAs in this commissioning process. Enter "Not coordinated" if this process does not exist. - TO, DP

This question was only required of the 35 entities that answered "Yes" to Question 24. Many entities coordinate with their RCs, TOPs, and BAs when performing their commissioning practices for large loads. Some entities claim that they have no formal process to perform this coordination; however, they typically follow either an ad-hoc process or an "energization checklist" given to them by the RC, TOP, and BA. This indicates that some level of commissioning coordination for large loads already occurs with the RC, TOP, and BA.

One unique consideration is that many vertically integrated entities[10] stated that they have robust internal coordination and provided details. These entities indicated that coordination was facilitated by the relevant RC, TOP, or BA being part of the same company. This unique consideration is in line with the generic response that if an entity has established strong requirements in its TO function, it will be more likely to have a commissioning process to follow from its RC, TOP, or BA.

26. Describe your process to verify on-site settings and verify the as-built model. Enter "Not performed" if this process does not exist. - TO, DP

This question was only required of the 35 entities that answered "Yes" to Question 24. Most responses indicated that no model verification is performed against on-site settings to verify the as-built model of the load facility. The small minority that do perform this action are also split between verification of only protection settings versus verification of the entire facility dynamic model.

Model verification of as-built facilities is a crucial step in improving the accuracy of dynamic models. Model verification processes capture changes that occur between the design and construction phase of any large-scale project. The lack of a verification process during commissioning increases the uncertainty that planners and operators have in their models reflecting these facilities. Decreased dynamic model accuracy increases the risk of instability in real-time operations.

27. Describe your process to validate performance of Large Loads to adhere to the design criteria and interconnection requirements after energization. Enter "Not performed" if this process does not exist. - TO, DP

This question was only required of the 35 entities that answered "Yes" to Question 24. Nearly all entities do not validate performance after energization. Of those that do, some are split between monitoring the point of interconnection with the large load via SCADA telemetered values versus offline download of data recorded in a power quality meter.

[10] Note that these types of entities were more likely to respond that they have specific large load interconnection requirements than other types of entity responses.

Model validation is a key step to ensure that a facility's model is aligned with real performance. The lack of validation increases uncertainty and poses a risk that the model may be unable to predict small- or large-scale behavior against disturbances.

28. Describe your process to update as-planned modeling information and coordinate with TPs and PCs to perform additional analysis during commercial operations of Large Loads. Enter "Not performed" if this process does not exist. - TO, DP

This question was only required of the 35 entities that answered "Yes" to Question 24. Almost all entities did not have a process to update models for large loads. Some of the entities that did have a process mentioned that MOD-032[11] or similar formal processes covered updates to the as-planned model. During the interconnection stage, the MOD-032 processes do not cover model submissions as the FAC-002 standard covers the exchange of necessary information at the interconnection setting.

29. Describe your process to review performance and modeling at different points of time for multi-year load growth Large Load projects or as major equipment updates are made. Enter "Not performed" if this process does not exist. - TO, DP

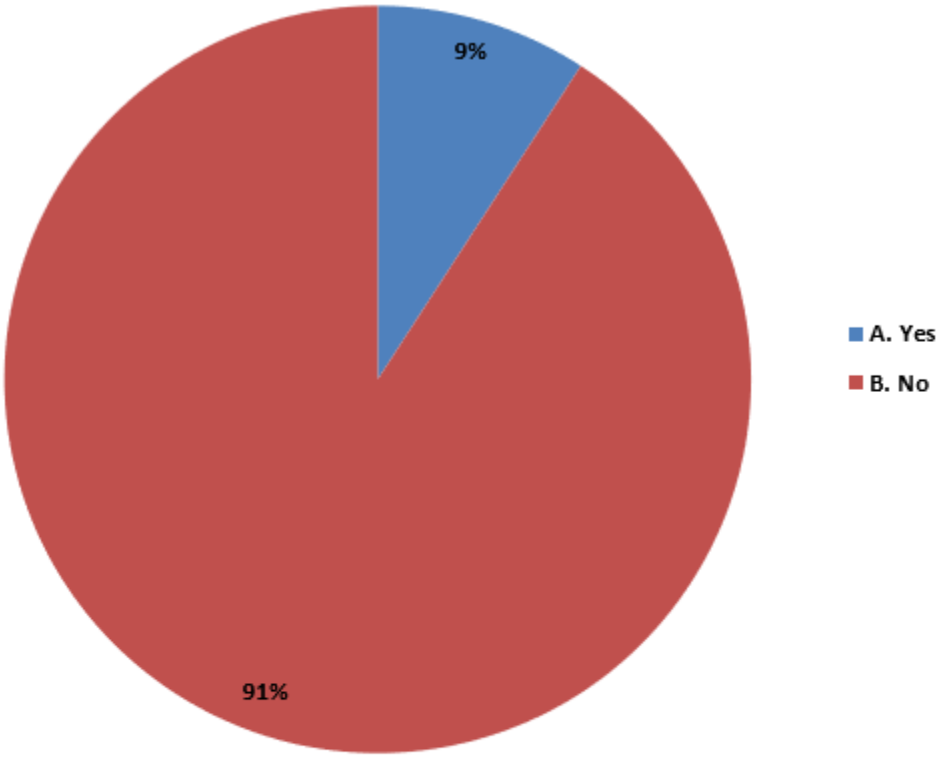
This question was only required of the 35 entities that answered "Yes" to Question 24. Almost all of the entities indicated that they did not have a process to review performance and modeling during a multi-year load growth for large load projects. The entities that did have this process indicated that the commissioning process handles the multi-year buildouts and that the review of performance and modeling is not performed for buildout updates. Furthermore, these entities that do have a process to review performance and modeling for multi-year load growth indicate that many of the changes happen during the study phase of the process rather than throughout the construction of the various phases.

[11] Available here: https://www.nerc.com/globalassets/standards/reliability-standards/mod/mod-032-1.pdf

30. Do you have processes to require Large Loads to provide and update modeling data based on design changes, upgrades, and disturbance-based model validation? [Yes/No] - TO, DP

A large majority of entities do not have an established process to provide updated modeling information for design changes, upgrades, or disturbance-based model validation. Some amount of process is expected for any "Qualified Change" to an end-use customer facility, as indicated in NERC Reliability Standards.[12] The data indicates that most respondents did not elect to equate design changes, upgrades, and disturbance-based model validation for large loads with this process.

However, the data in Questions 31–33 reflects that where respondents do have processes in place, modeling practices are robust.

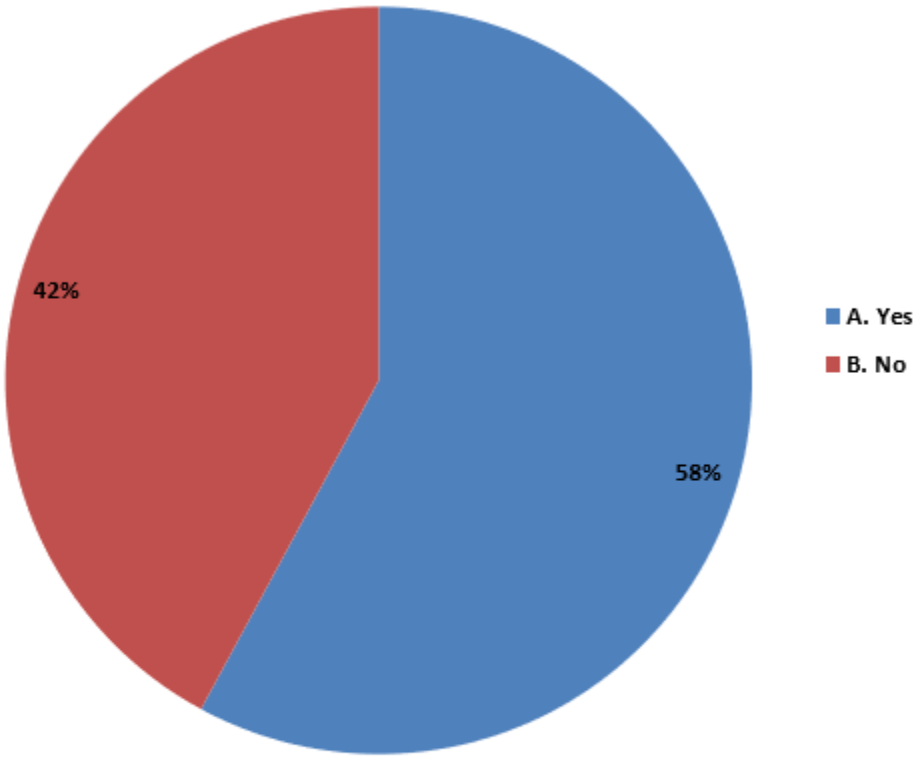


Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	9.2%	11.9%	0.0%	8.2%	11.6%	20.0%	6.3%
B. No	90.8%	88.1%	100.0%	91.8%	88.4%	80.0%	93.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

[12] Primarily FAC-001 and FAC-002.

31. Do you have a process to update modeling data during commissioning? [Yes/No] - TO, DP

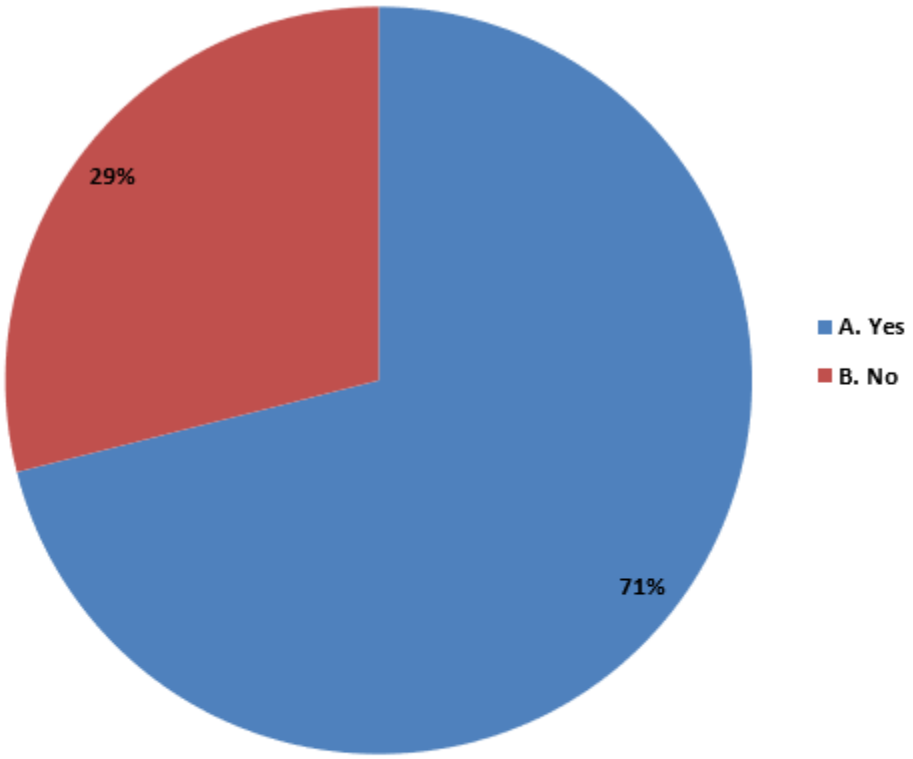
This question was only intended for the 38 entities that answered "Yes" to Question 30. This means that, for the entities that require updates based on design changes, upgrades, or disturbance-based model validation, roughly half include a process that handles model changes or data from factors uncovered during commissioning.



Answer	Percentage	MRO	RF	SERC	TRE	WECC
A. Yes	57.9%	60.0%	60.0%	63.6%	66.7%	33.3%
B. No	42.1%	40.0%	40.0%	36.4%	33.3%	66.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

32. Do you have a process to update modeling data during normal operations? [Yes/No] - TO, DP

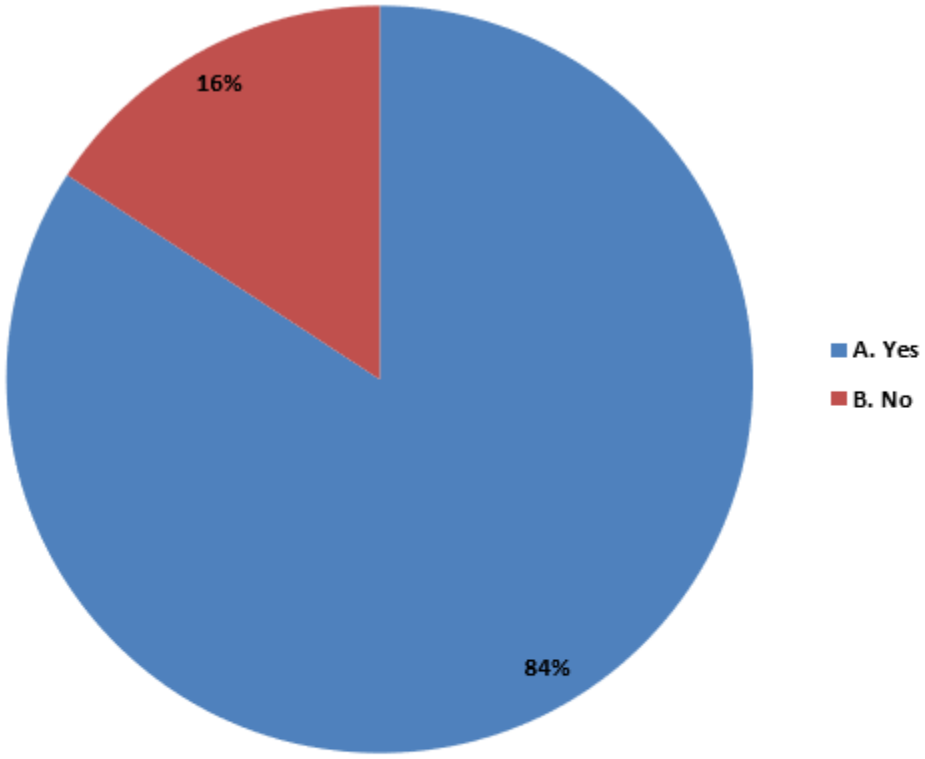
This question was only intended for the 38 entities that answered "Yes" to Question 30. Roughly three quarters of all respondents to this question have a process during normal operations of large loads to update modeling data for design changes, upgrades, or disturbance-based model validation.



Answer	Percentage	MRO	RF	SERC	TRE	WECC
A. Yes	71.1%	60.0%	60.0%	81.8%	83.3%	66.7%
B. No	28.9%	40.0%	40.0%	18.2%	16.7%	33.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

33. Do you have a process to update modeling data after a qualified change occurs? [Yes/No] - TO, DP

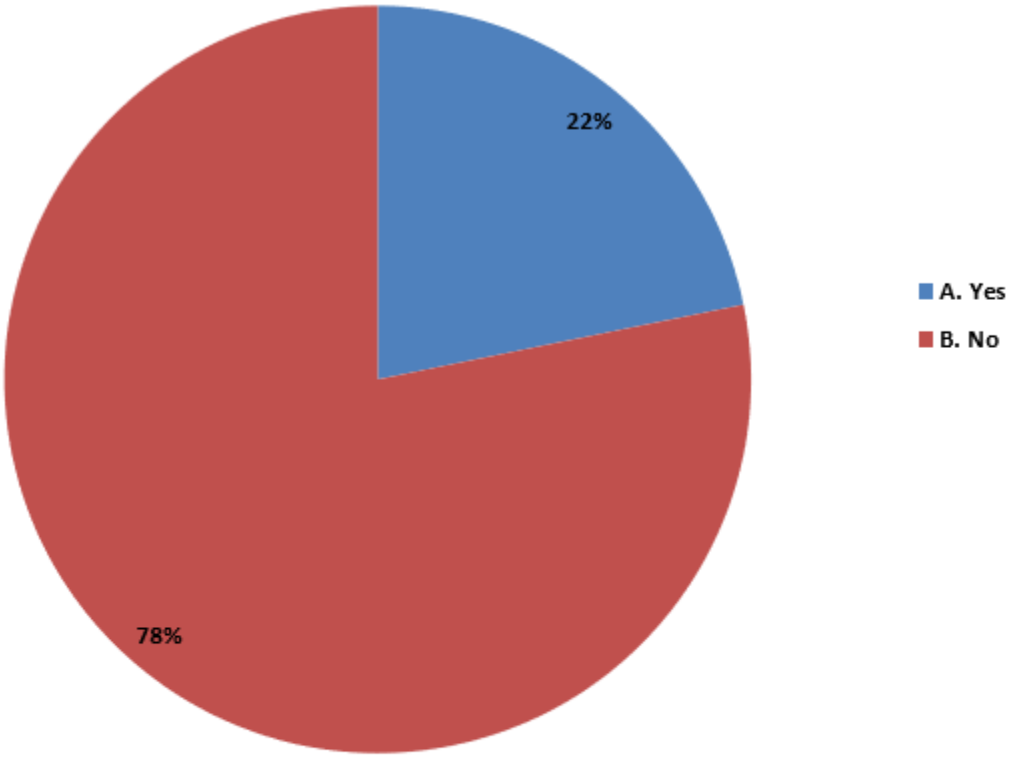
This question was only intended for the 38 entities that answered "Yes" to Question 30. Using the same language as identified in FAC-001 and FAC-002 for a "qualified change," the data indicates that entities that have a process to update modeling data based on design changes, upgrades, or disturbance-based model validation largely include those as a "qualified change."



Answer	Percentage	MRO	RF	SERC	TRE	WECC
A. Yes	84.2%	90.0%	100.0%	81.8%	83.3%	66.7%
B. No	15.8%	10.0%	0.0%	18.2%	16.7%	33.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

34. Have you established operating protocols and the necessary communication infrastructure to support reliable ongoing operations for Large Loads? [Yes/No] - TO, DP

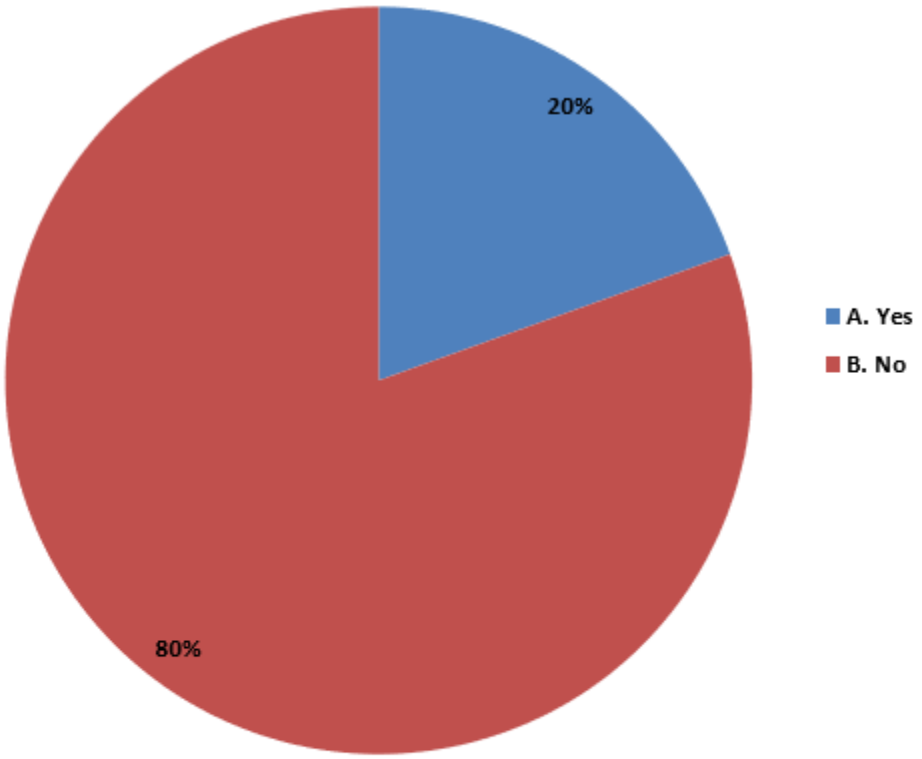
Roughly three quarters of entities indicated that they do not have operational protocols and communications infrastructure to support ongoing operations for large loads. Entities that do have these established are discussed in further responses to the questions.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	21.8%	25.0%	2.0%	38.3%	22.1%	23.3%	17.9%
B. No	78.2%	75.0%	98.0%	61.7%	77.9%	76.7%	82.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

35. Have you coordinated with the BA, TOP, and RC to develop a method that allows for Real-Time monitoring capability of Large Loads? [Yes/No] - TO, DP

A similar, but slightly larger, percentage of entities that indicated that they do not have adequate operational protocols and communications infrastructure to support ongoing large load operations also indicated that they did not coordinate with the BA, TOP, or RC to develop a method for real-time monitoring of large loads.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	19.5%	17.9%	2.0%	32.2%	20.0%	34.5%	17.0%
B. No	80.5%	82.1%	98.0%	67.8%	80.0%	65.5%	83.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

36. Describe the way you have consulted or plan to consult with BAs, TOPs, and RCs in respect to Questions 34 and 35. Enter "Not coordinated" if no such consultation has occurred. - TO, DP

This question was applicable to all TOs and DPs to assess how their yes/no responses in Questions 34 and 35 were performed. Roughly two-thirds of respondents did not consult with their BA, TOP, or RC to answer Questions 34 and 35. Typically, those that did consult with these entities were provided the operating guidelines and protocols, or they handle this coordination through working groups. Similar to other questions, vertically integrated utilities typically held more robust coordination for these responses than other types of entities.

37. Describe the method used to collect disturbance recordings or other data to aid in post-hoc event analysis. Enter "N/A" if this does not exist. - TO, DP

This question was only intended for the 90 entities or 25% that answered "Yes" to Question 34. Many entities did not indicate that they use or have a method to collect disturbance recordings or other data for event analysis. For those that do have a process, they either collect this through their energy management system (EMS), SCADA, or other system for telemetry. Some of these entities used revenue meters to collect this data.

38. Describe the method the Large Load entities provide operational load forecasts. Enter "N/A" if this does not exist. - TO, DP

This question was only intended for the 90 entities that answered "Yes" to Question 34. Nearly all these entities did not indicate how the large load entity provides operational load forecasts or indicated that the process does not exist. The entities that do have a process for large loads to provide operational load forecasts primarily receive these forecasts through customer account representatives or other formal tariff procedures. Not all entities ask for the same granularity of forecasts or for the same periodicity. Some entities, albeit a minority of entities, receive these forecasts seasonally, monthly, weekly, or daily through contact to the operating floor. Some of these forecasts are hourly demand expectations for the large load.

Some responses seemed to indicate that the question was asking for long-term transmission planning forecasts and not expected load consumption during real-time to day-ahead operations.

39. Include the list of common Real-Time communication protocols used. Enter "N/A" if none exist. - TO, DP

This question was only intended for the 90 entities that answered "Yes" to Question 34. Many entities have some form of real-time communication protocols between the large load facility and the operating entities. Entities reported a wide variety of operating protocols used for automatic monitoring, like DNP3 (distributed network protocol), ICCP (Inter-Control Center Communications protocol), SCADA, and Modbus. Most entities responding to this question have one or more of those protocols.

Some entities reported that they have an oral communication protocol for these large loads. Some entities further indicated that they have no real-time communication protocols.

40. Describe the process by which a Large Load entity notifies you, the BA, TOP, RC, or a combination of these entities of a major equipment status change. Enter "N/A" if this does not exist. - TO, DP

This question was only intended for the 90 entities that answered "Yes" to Question 34. Most of these entities use a direct call, email, or other notice system to alert operating personnel of a BA, TOP, or RC of a major equipment status change. Some of these entities also used a customer-facing account manager to alert operators of an equipment status change. Fewer than five organizations indicated that their process is largely a coordination one with joint and sole responsibilities to interface with the large load customer and the BA, TOP, or RC. Each structure, while unique, highlights that those with defined interconnection requirements for large loads have processes in place for major equipment status changes.

41. Describe the coordination process Large Loads will follow in normal operating conditions with BAs, TOPs, or RCs (E.g., telemetry via SCADA). Enter "N/A" if this does not exist. - TO, DP

This question was only intended for the 90 entities that answered "Yes" to Question 34. Many entities provided the same answer to both Questions 40 and 41. However, more entities indicated that direct calls to operating personnel were followed in normal operating conditions over longer, more formal procedures. Many indicated that the telemetered values via SCADA and calls to operating personnel were the expected method for coordination between large load entities and BAs, TOPs, and RCs.

42. Describe the coordination process Large Loads will follow in System Emergency operating conditions with BAs, TOPs, or RCs (E.g., telemetry via SCADA or operator calls). Enter "N/A" if this does not exist. - TO, DP

This question was only intended for the 90 entities that answered "Yes" to Question 34. Entities answered this question largely the same as Question 41 with only a few notable exceptions, typically around the content of the operator calls, issuing of operating instructions, and other items necessary to maintain the stability of the BPS. One entity mentioned that the RC has telemetry set up so that they can issue curtailment commands directly to the load. Similarly, some entities included real-time management capabilities; however, most entities expected operating calls and issuing of operating instructions.

These points emphasize the importance of the Alert Recommendation to establish coordination with large loads to return the BPS to normal operations.

43. Describe the coordination process Large Loads will follow in the post-Disturbance period following a Contingency with BAs, TOPs, or RCs, (E.g., Operator calls). Enter "N/A" if this does not exist. - TO, DP

This question was only intended for the 90 entities that answered "Yes" to Question 34. Many entities answered this question with the same category of response as Question 41 with some notable differences. The same emphasis on the need for operating calls was raised by responding entities, but some emphasized the need for direct calls to operating personnel prior to reconnecting the large load following a system disturbance. These details, as in Question 42, also emphasize the importance of the Alert Recommendation to establish coordination with large loads to return the BPS to normal operations following a system disturbance.

44. Describe any plans you have within 2 years to include revisions to address the issues raised in Recommendation 4. Enter "No plans" if you do not have plans to revise your operating protocols and the necessary communication infrastructure. - TO, DP

This question was expected for all TOs and DPs responding to the Alert. Roughly half of entities did not have a plan to revise their processes to address the items raised in Recommendation 4. For those that did include plans to revise, a majority were waiting on a separate entity to proceed before revising their internal processes. The entity for which most respondents were waiting was their ISO or RTO. Only a few entities planned to align within the two-year time frame raised in Question 44. Given the communication needs of operators, the TOs and DPs looking to their ISO or RTO (i.e., their BA, PC, or RC) is an expected outcome to ensure coordination among these large loads.

45. In the free text field provide your definition of Large Loads including any MW or kV threshold or other operational characteristics about the load profile. Also indicate in this response other registered entities (e.g., BA, TOP, TP, or similar) that were consulted when defining Large Loads in your footprint. Enter "None" if your organization has not formally defined Large Loads. - TP, PC

This question is the same as Question 1, except responses were asked of TPs and PCs rather than TOs and DPs. See Question 1 for analysis of these responses.

46. In the free text field provide your experience in integrating Large Loads. Include in this response the number of years of experience in integrating Large Loads and other highlights or lessons learned as part of this experience. - TP, PC

This question is the same as Question 2, except responses were asked of TPs and PCs rather than TOs and DPs. See Question 2 for analysis of these responses.

47. In the free text field provide how you are contacting, interacting, or otherwise coordinating with Large Load entities that are operational or nearly operational (i.e., 2 or less years) to collect information or resolve ongoing issues that arise. - TP, PC

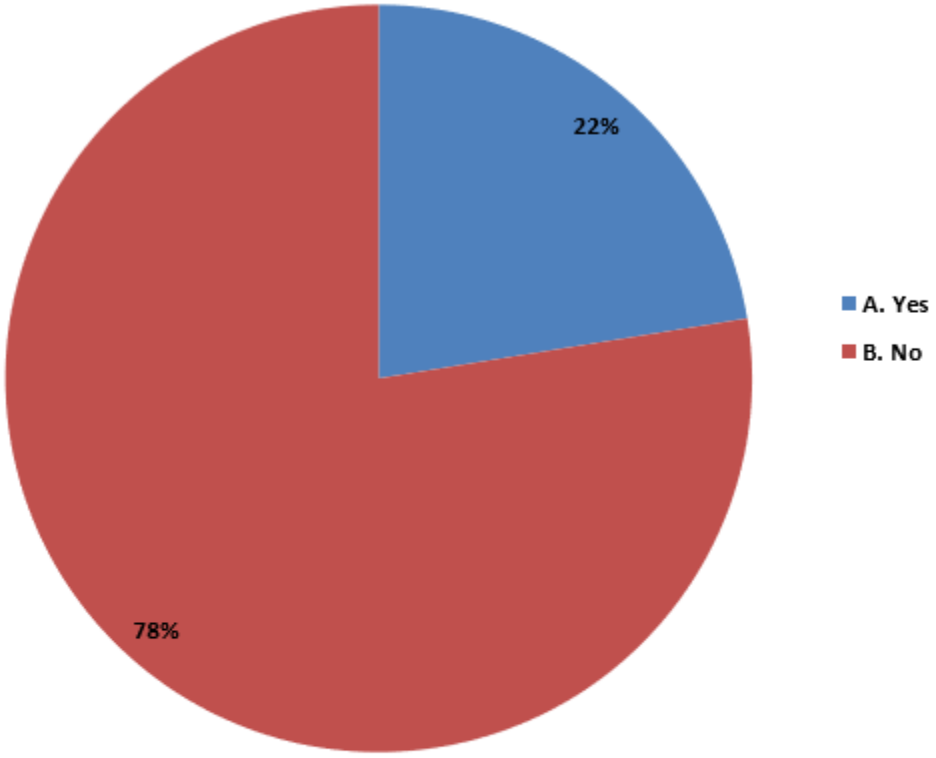
This question is the same as Question 4, except responses were asked of TPs and PCs rather than TOs and DPs. See Question 4 for analysis of these responses.

48. In the free text field provide any comments you wish to provide to help explain your answers to these questions. - TP, PC

This question is the same as Question 6, except responses were asked of TPs and PCs rather than TOs and DPs. See Question 6 for analysis of these responses. Some entities provided additional clarity to highlight the various industry working groups that are part of defining, disseminating, and reviewing model and study requirements. These explanations were helpful to understand the entities' answers for Questions 49–67.

49. Have you developed a list of detailed modeling data, settings, and parameters needed from Large Loads? [Yes/No] - TP, PC

The data indicates that roughly three quarters of all TPs and PCs do not have a detailed list of modeling data, settings, and parameters needed from large loads for their studies.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	22.4%	21.3%	12.5%	21.4%	26.7%	34.6%	18.2%
B. No	77.6%	78.7%	87.5%	78.6%	73.3%	65.4%	81.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

50. Describe how you distributed these requirements for detailed modeling data, settings, and parameters to TOs and DPs. Enter "Not distributed" if this process does not exist. - TP, PC

This question was only intended for the 48 entities that answered "Yes" to Question 49. Most entities indicated that they distribute their modeling requirements publicly through mechanisms like an Open Access Same-Time Information System (OASIS) or similar distribution system. As some entities were also the TO or DP, they indicated that internal coordination accounts for the distribution of detailed model data, settings, and parameters. Some entities did not distribute modeling data, settings, and parameters to their TOs and DPs.

51. Describe how these model requirements discussed in Questions 49 and 50 address acceptable model types, structures, necessary parameter values, out of range parameters, and other reasonability checks on data. Enter "Not addressed" if this does not exist. - TP, PC

This question was only intended for the 48 entities that answered "Yes" to Question 49. Most entities responding to this question indicated that they only check for acceptable model types, structures, parameter values, and other reasonability checks on data when a model is submitted. Few entities perform a full verification or validation of the model to identify any unreasonable responses. Many entities also indicated that they are focusing their reasonability checks for large loads on the composite load model. This type of model is largely updated for reasonable parameters and values by Interconnection-wide model builders.

This demonstrates that many of the reasonability checks on submitted models may be coming from the Interconnection-wide model building context, which contains a different scope than local reliability studies like an interconnection request for large load entities.

52. Describe any plans you have within 2 years to include revisions to address the issues raised in Recommendation 1. Include any plans to consult with TOs and DPs to establish your modeling data, settings, and parameter requirements as well as whether you plan to establish an independent set of model requirements for Large Loads. - TP, PC

This question was required of all TPs and PCs responding to the Alert. Roughly half of the entities responding indicated that they had no plans to address the issues raised in Recommendation 1. Of the entities that indicated they have a plan to address the issues raised in Recommendation 1, the processes to finalize the changes may take longer than the two-year period seen in Question 52. Some entities indicated that they are waiting on another organization (primarily their ISO or RTO).

53. Describe in the free text box how you are coordinating with TOs and DPs to establish performance-based post-Disturbance recovery requirements for Large Loads. Enter "Not coordinated" if this process does not exist. - TP, PC

This question was required of all TPs and PCs responding to the Alert. Nearly all entities responding to this question indicated that there is not a process to coordinate with TOs and DPs to establish post-disturbance recovery requirements. The very limited number of entities that do have a process for this purpose shared that this is done via a formalized process like a tariff or that the TO and DP is the same company as the TP or PC. Most of the largest, non-vertically integrated PCs indicated that they have an open stakeholder process that takes input from TOs, DPs, and many other relevant stakeholders to establish post-disturbance recovery requirements for large loads.

54. Describe in the free text box how you are coordinating with TOs and DPs to establish protection coordination requirements for Large Loads. Enter "Not coordinated" if this process does not exist. - TP, PC

This question was required of all TPs and PCs responding to the Alert. Nearly all entities responding to this question indicated that there is not a process to coordinate with TOs and DPs to establish protection coordination requirements for large loads. The entities that do have a process for this purpose shared that this is done via a formalized process like a tariff or that the TO and DP is the same company as the TP or PC. Some PCs indicated that they have an open stakeholder process that takes input from TOs and DPs to establish protection coordination requirements. These coordination requirements typically are focused on voltage ride-through and known mitigations to address ride-through performance.

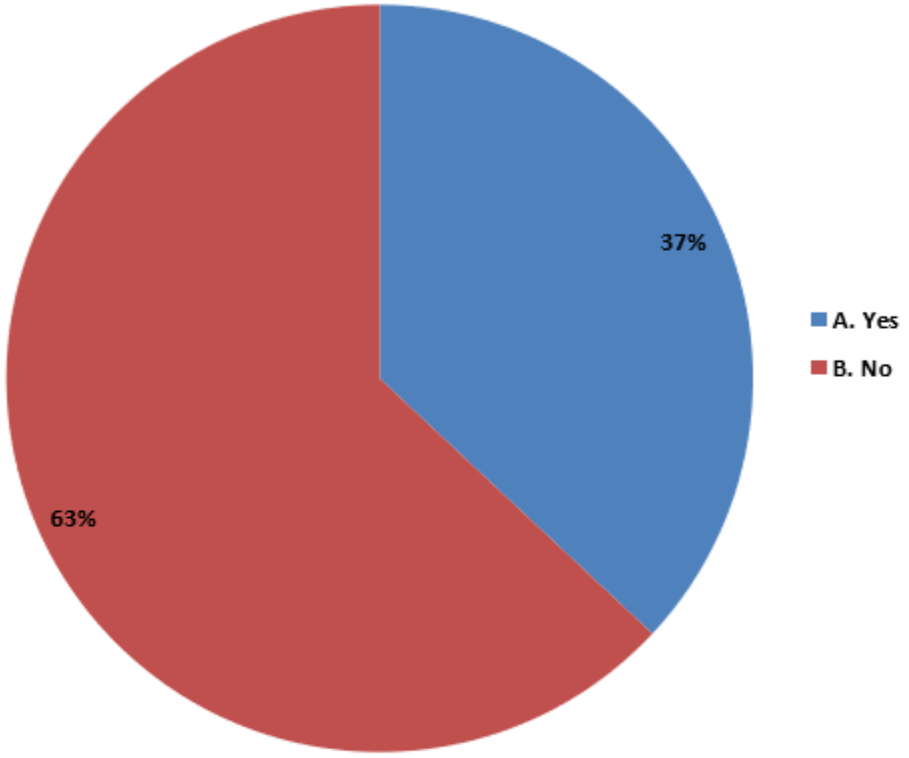
55. Describe in the free text box how you are coordinating with TOs and DPs to establish design requirements to minimize and mitigate power oscillation interactions during normal operations and in the recovery post-System Disturbance requirements for Large Loads. Enter "Not coordinated" if this process does not exist. - TP, PC

This question was required of all TPs and PCs responding to the Alert. Nearly all entities responding to this question indicated that there is not a process to coordinate with TOs and DPs to minimize and mitigate power oscillations for large loads. However, more entities explained that there is some coordination to reduce power oscillations than in Questions 52 (for model requirements), Question 53 (for post-disturbance recovery), and Question 54 (for protection coordination).

The entities that do have a process for this purpose shared that this is done via a formalized process like a tariff or that the TO and DP is the same company as the TP or PC. Some PCs indicated that they have an open stakeholder process that takes input from TOs and DPs to establish protection coordination requirements. A handful of entities also have established screening tests or have put into place a taskforce to understand and implement power oscillation mitigations concerning large loads.

56. Do you have Large Loads on your system for which transient dynamic performance is unknown, including, but not limited to, voltage/frequency ride-through characteristics? [Yes/No] - TP, PC

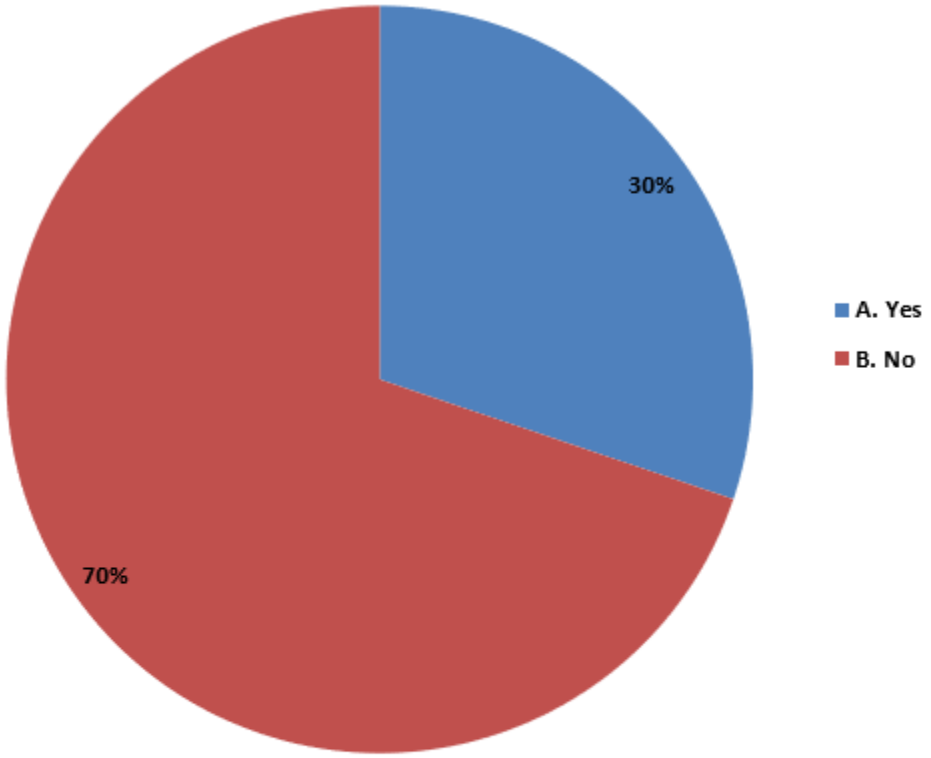
Approximately one-third of respondents for this question stated that they have large loads on their system for which transient dynamic performance is unknown. These results align with prior findings where it was discovered that many entities do not perform or require model verification and model validation for large loads in their area. The figure below shows the aggregate of both PC and TP findings; however, looking at PCs that are not also a TP, two-thirds of these entities have large loads of unknown transient dynamic performance. Furthermore, one-third of TPs that are not also a PC indicated that they have large loads with unknown transient dynamic performance, which is in line with the generic results displayed in the figure.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	37.0%	41.3%	37.5%	57.1%	36.4%	30.8%	32.3%
B. No	63.0%	58.7%	62.5%	42.9%	63.6%	69.2%	67.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

57. Have you established an interconnection and System-wide study process using steady state and dynamic models to assess reliability impacts of Large Loads in alignment with Recommendation 2? [Yes/No] - TP, PC

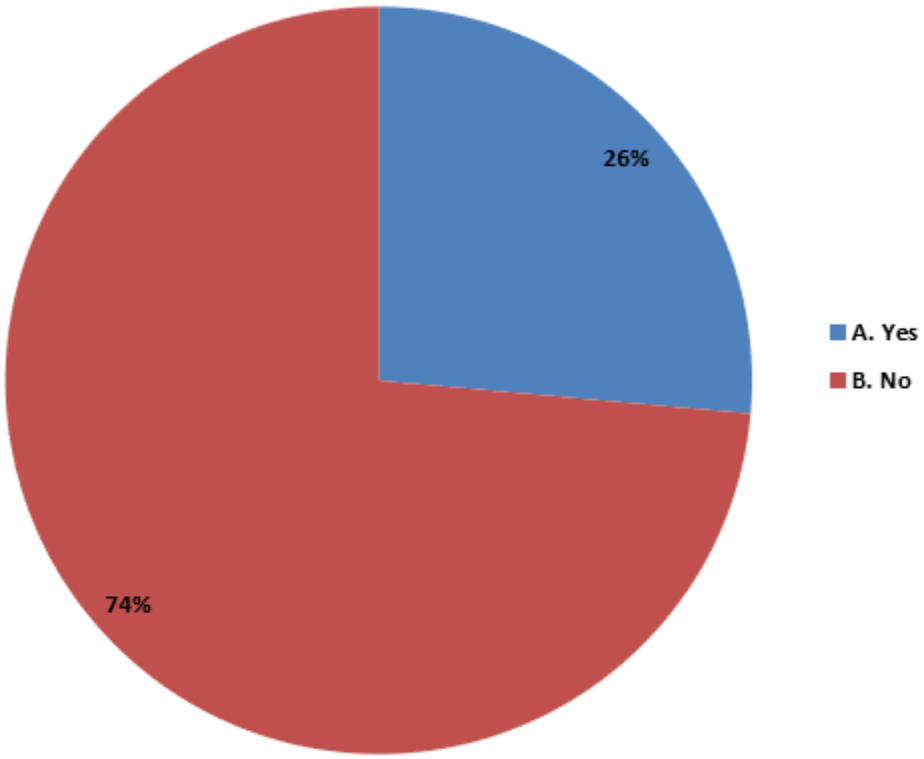
Considering only the PCs, most have a process to use steady-state or dynamic models, while the TPs do not have this process. Rather, the TPs are relying on their PC to perform or coordinate among its relevant TPs for the studies using these models to address impacts of large loads. Both the TP and PC perform this evaluation separately and together when performing annual planning analysis.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	30.2%	31.1%	31.3%	42.9%	31.1%	53.8%	16.7%
B. No	69.8%	68.9%	68.8%	57.1%	68.9%	46.2%	83.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

58. Have you established an interconnection and System-wide study process using short-circuit models to assess reliability impacts of Large Loads? [Yes/No] - TP, PC

Looking at only the PCs, most of them have a process to use short-circuit models, while the TPs do not have this process. TPs rely on their PC to perform or coordinate among its relevant TPs the studies using short-circuit models to address impacts of large loads.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	26.4%	24.4%	31.3%	14.3%	24.4%	57.7%	18.2%
B. No	73.6%	75.6%	68.8%	85.7%	75.6%	42.3%	81.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

59. Describe the accuracy of the models mentioned in Question 57 and 58 to reflect the Large Load facility in the post-Disturbance period, including its recovery performance. Include in this description the ability to assess any interaction with other loads or System protection devices. Enter "No models" if no Large Load models exist. - TP, PC

This question was only for the 56 entities that answered "Yes" to both Questions 57 and 58. Responding entities were split between indicating that the models were accurate enough for their studies versus indicating that the models were not accurate to depict known performance of large loads. This was apparent in one region where most of the TPs claimed that their models were accurate enough, but the PC for that area stated that most models are not when compared to real system events. Furthermore, some entities indicated that their planning area does not contain enough large loads to include a requirement to assess the accuracy of large load models.

The entities that indicated that their models were accurate primarily use the CMLD model for representing large load facilities. However, the composite load model's structure is unable to capture the key features of computational load performance. The entities that indicated that the models were inaccurate claimed that their model did not use site-specific (generic or user-defined) parameters or settings and supported new model development. There is evidence of disagreement forming between TPs and PCs on the accuracy of the model to be used in their studies.

60. Describe how the models mentioned in Question 57 and 58 are validated with as-designed, as-built, or as-studied parameters. Enter "Not validated" if no Large Load models are validated or do not exist. - TP, PC

This question was only for the 56 entities that answered "Yes" to both Questions 57 and 58. Most entities indicated that they were unable to validate the large load model either due to a lack of models or a lack of process. Some entities indicated that this activity is done at the commissioning phase of the facility compared to the studied model, with a few indicating that this activity is done following event analysis through mechanisms like disturbance playback. While most entities have indicated that they were unable to validate the model, a large number of entities also indicated that ongoing exercises are at work to ensure large load model validation.

These entities are working toward validation of large load models; however, even these entities have yet to execute model validation to their satisfaction.

61. Describe how the post-Disturbance Large Load frequency and voltage performance related to the included Large Load model(s). Include in this description the largest aggregate loss of load and the largest single load loss due to the most severe Contingency. Further explain any change to these losses expected in the next five years. Enter "Not performed" if you do not evaluate post-Disturbance Large Load frequency and voltage performance. - TP, PC

This question was only for the 56 entities that answered "Yes" to both Questions 57 and 58. Most entities reported that there is no evaluation of post-disturbance large load frequency and voltage performance for the single largest aggregate loss of load. This was generally either due to a lack of post-disturbance analysis or due to a contingency definition not including aggregate load loss but rather singular loss of a given load facility. Some entities stated that they are studying aggregate load-loss impacts, but such efforts were not finalized or completed at the time of the entity response. Of those that evaluated the frequency and voltage performance, entities performed ad-hoc studies or annualized data quality reviews. Some indicated that their criteria only contain studies for the loss of the largest single load and not aggregate load loss.

One PC collects large load models that demonstrate post-disturbance frequency and voltage performance. Each facility has unique voltage sensitivity and post-disturbance recovery performance. The PC uses all the mentioned models in interconnection-wide studies to identify any major effects of aggregate load loss from large load facilities that trip off-line from voltage disturbances and do no reconnect. The study is ongoing, and the PC plans to present its results at a future public stakeholder meeting.

62. Describe how EMT studies are being conducted when a proposed Large Load is in the vicinity of generation or other facilities where there may be complex dynamic interactions. Include in this response any criteria used to determine if an EMT study is required. Enter "No EMT study" if no EMT study is performed. - TP, PC

This question was only for the 56 entities that answered "Yes" to both Questions 57 and 58. Nearly all entities indicated that no EMT study was performed when integrating large loads. Some entities indicated that they will run a study if their ISO or RTO requires the study or if other screening studies coupled with engineering judgment indicate an EMT study is necessary.

63. Describe how you are coordinating with TOs and DPs for mitigation measures for identified poor performance. Include any coordination and recommendations on items such as transmission protection coordination changes or operational changes. Enter "Not coordinated" if this process does not exist. - TP, PC

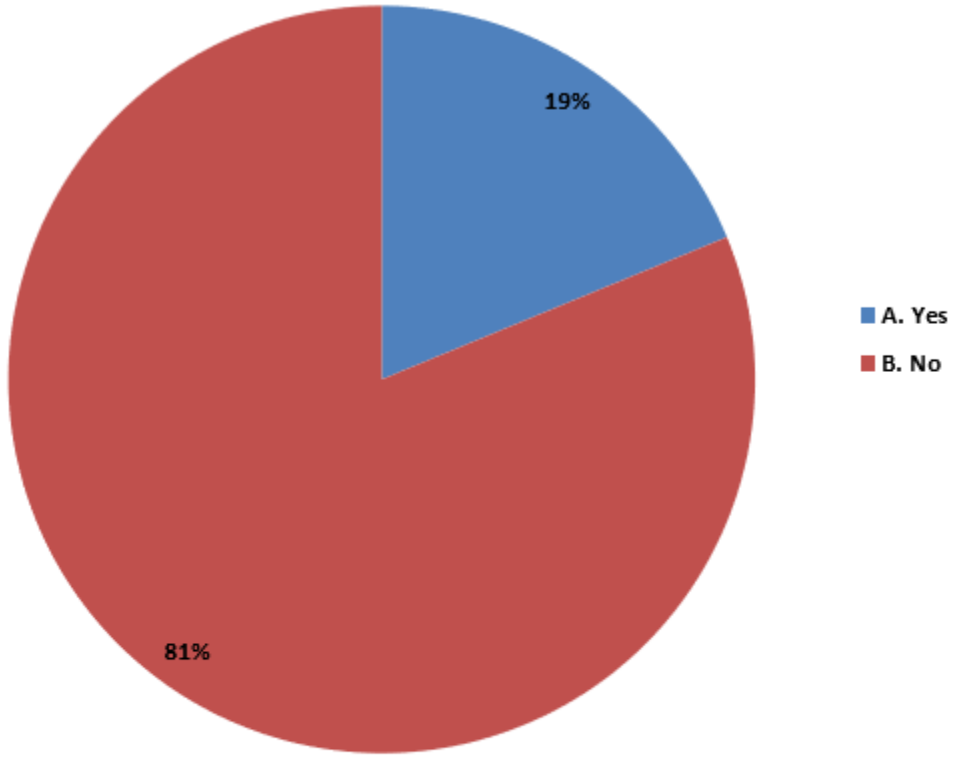
This question was only for the 56 entities that answered "Yes" to both Questions 57 and 58. Most entities indicated that some manner of coordination with the TO and DP occurs regarding mitigation steps for identified poor system performance for large loads. This includes the internal coordination inherent for entities that are a TP or PC and a TP or DP. Some responding entities have a registration category of TO/DP and TP/PC. These entities largely rely on their PC to perform this coordination. The content of the level of coordination regarding transmission protection changes or operational changes was varied with no clear consistent method on solutions, and entities indicated that individual studies would establish this content. Some entities indicated that no coordination takes place for defined mitigating measures.

64. Describe any plans you have within 2 years to include revisions to address the issues raised in Recommendation 2. - TP, PC

This question was required for all TPs and PCs responding to this Alert. Most entities indicated that they have some form of a plan to address the issues raised in Recommendation 2. Some entities indicated that they have no plans. The entities that do have a plan largely are waiting on another entity, primarily their ISO or RTO, to establish modeling requirements and other procedures. Some entities that have no plans indicated that they do not have or do not expect to have large loads integrated into their system within the two-year timeline indicated in Question 64.

65. Are you coordinating with TOs to perform additional analysis of Large Loads in the post-commercial operation period using updates to as-planned modeling information provided by Large Loads? [Yes/No] - TP, PC

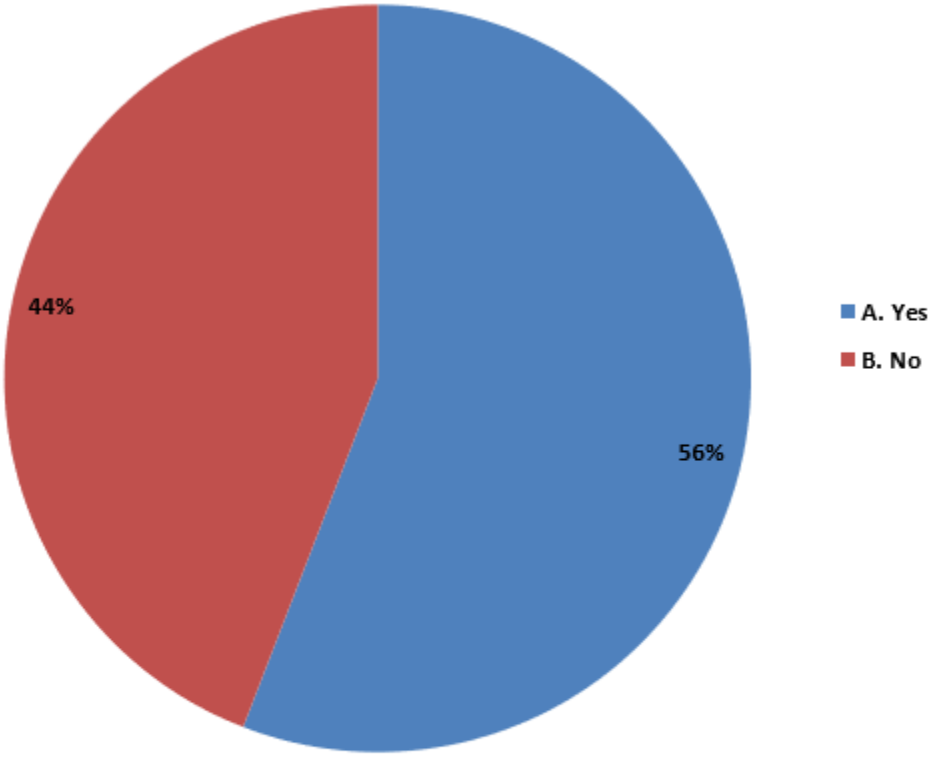
This question was required for all TPs and PCs responding to this Alert. Over 80% of all TPs and PCs indicated that they are not coordinating with TOs to perform additional analysis for post-commercial operation for large load entities. There is a small break between PC-only entities and the generic results for this question. PC-only entities largely indicated that they do coordinate with TOs to perform additional analysis.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	18.8%	17.4%	0.0%	14.3%	22.2%	46.2%	12.1%
B. No	81.2%	82.6%	100.0%	85.7%	77.8%	53.8%	87.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

66. Are you identifying and implementing a process to include Large Loads into your Near-Term Planning Horizon Demand forecasts? [Yes/No] - TP, PC

This question was required for all TPs and PCs responding to this Alert. Roughly half of all entities identify and implement a process to include large loads into their near-term transmission planning horizon demand forecasts. While the word "transmission" was excluded in the question, entities that reached out for clarification interpreted the question to refer to the term used in the *NERC Glossary of Terms*,[13] which was the intent of Question 66. There is a small break between PC-only entities and the generic results for this question. PC-only entities (i.e., PC not TP) overwhelmingly indicated that this process exists.

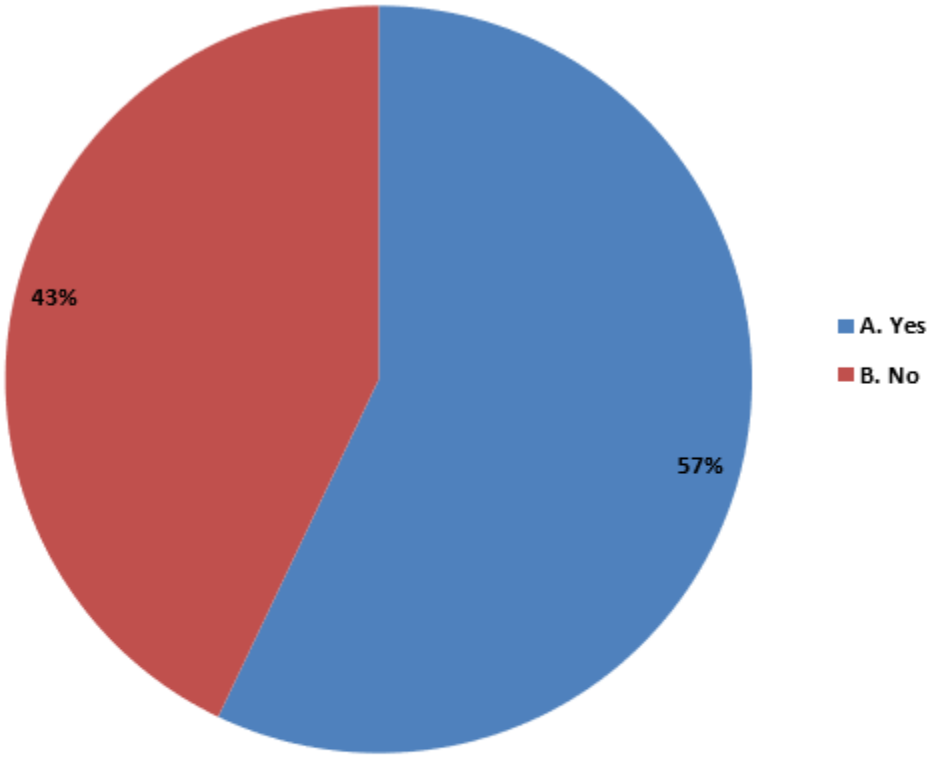


Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	55.9%	56.5%	75.0%	57.1%	55.6%	65.4%	47.0%
B. No	44.1%	43.5%	25.0%	42.9%	44.4%	34.6%	53.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

[13] Available here: https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf

67. Are you identifying and implementing a process to include Large Loads into your Long-Term Planning Horizon Demand forecasts? [Yes/No] - TP, PC

This question was required for all TPs and PCs responding to this Alert. Entities largely responded the same as in Question 66. While the word "transmission" was excluded in the question, entities that reached out for clarification interpreted the question to refer to the term used in the NERC *Glossary of Terms*,[14] which was the intent of Question 67. There is a small break between PC-only entities and the generic results for this question. PC-only entities (i.e., PC not TP) overwhelmingly indicated that this process exists.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	57.1%	56.5%	75.0%	57.1%	54.5%	73.1%	48.5%
B. No	42.9%	43.5%	25.0%	42.9%	45.5%	26.9%	51.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

[14] Available here: https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf

68. In the free text field provide your definition of Large Loads including any MW or kV threshold or other operational characteristics about the load profile. Also indicate in this response other registered entities (e.g., BA, TOP, TP, or similar) that were consulted when defining Large Loads in your footprint. Enter "None" if your organization has not formally defined Large Loads. - RC, BA, TOP

This is the same as Question 1 except answered by the RCs, BAs, and TOPs. See Question 1 for analysis of this response. Some entities indicated here that they are working with industry to define and develop generic models and data to understand large loads.

69. In the free text field provide your experience in integrating Large Loads. Include in this response the number of years of experience in integrating Large Loads and other highlights or lessons learned as part of this experience. - RC, BA, TOP

This is the same as Question 2 except answered by the RCs, BAs, and TOPs. See Question 2 for analysis of this response. Responding entities here also highlighted the lack of, or very limited, experience of their entity.

70. In the free text field provide any comments you wish to provide to help explain your answers to these questions. - RC, BA, TOP

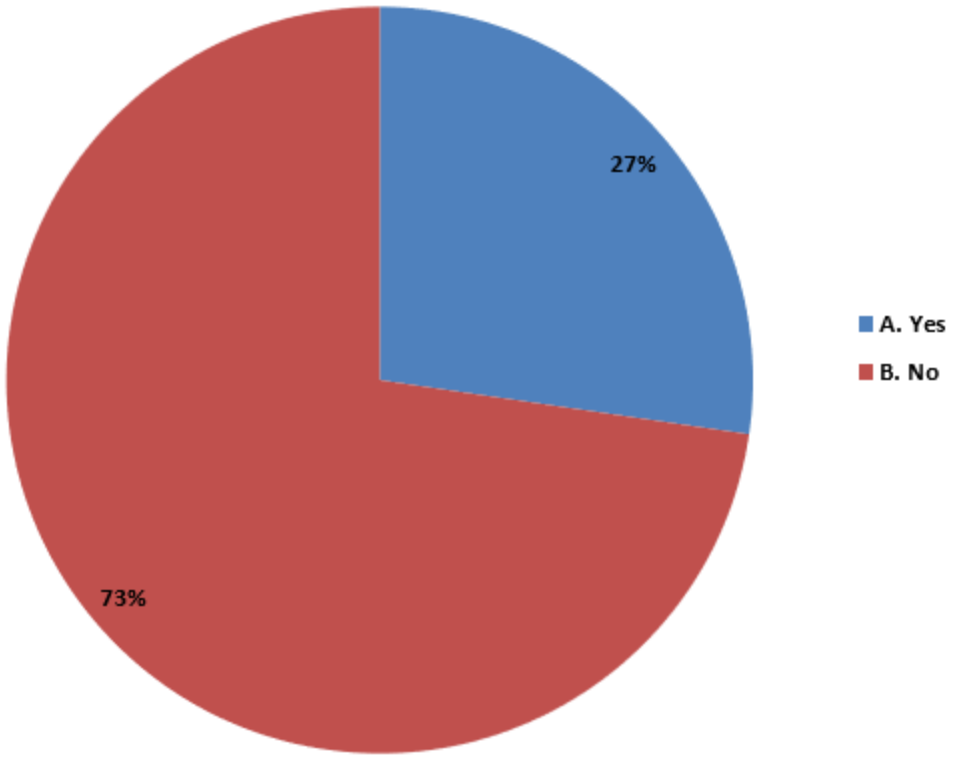
This question was required for all RCs, BAs and TOPs responding to this Alert. Most entities left this field blank, including no other explanation, or referenced other fields where the entity had a different registration class (e.g., Question 47 as a PC). Some entities mentioned that they have limited visibility of "retail loads" that may be sizable and fall into a large load definition.

71. In the free text field, describe your process or needs to include Large Loads into Undervoltage Load Shed, Underfrequency Load Shed, and Manual Load Shed plans. Indicate in this response how you have communicated this need and associated capability to TOs and DPs in your footprint. Enter "No shedding" if you do not see a need to include Large Loads into these programs. - RC, BA, TOP

This question was required for all RCs, BAs and TOPs responding to this Alert. Nearly all entities indicated that large loads are not included in automatic load-shedding programs. Some indicated that their manual load shedding schemes may consider large loads, but they are weighted against all industrial-level loads and depend on various real-time conditions before shedding the load. Roughly half of entities also reported that their load-shedding schemes are based on studies to prove their effectiveness, including underfrequency load shedding (UFLS) and undervoltage load shedding (UVLS). In these studies, the entities reported that the large load is evaluated for potential inclusion or exclusion. Entities have also reported that they follow NERC Reliability Standards for coordination and communication to the TO or DP for these study results and potential inclusion of large load entities in automatic or manual load shedding schemes.

72. Are you coordinating with TOs to integrate operational requirements in the TO interconnection requirements that need to be met by the Large Load to maintain reliability? [Yes/No] - RC, BA, TOP

This question was required for all RCs, BAs and TOPs responding to this Alert. Nearly three quarters of all reporting entities stated that they do not coordinate with TOs to integrate operational requirements into the TO interconnection requirements.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	27.3%	28.9%	14.3%	44.4%	25.5%	35.0%	22.8%
B. No	72.7%	71.1%	85.7%	55.6%	74.5%	65.0%	77.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

73. Describe the operational load ramp limits. Include in this response any post-Disturbance recovery load ramp limits and their values. Enter "No limits" if these limits do not exist. - RC, BA, TOP

This question was required for the 53 entities that answered "Yes" to Question 72. Most entities reported that no limit exists. However, the entities that do have limits mirror those found in Question 10 and Question 11.

74. Describe how these limits are imposed when the Large Loads enters service, exits service, or operates during normal operations. Enter "No limits" if these limits do not exist. - RC, BA, TOP

This question was required for the 53 entities that answered "Yes" to Question 72. Nearly all entities reported that no limit exists. Where this limit does exist, the entity indicated that it is either operator-initiated when necessary or via a formal contractual limit (e.g., an operation agreement) set in place prior to operations.

75. Describe how these limits are shared to TOs within your footprint. Enter "Not shared" if these limits are not shared to TOs. - RC, BA, TOP

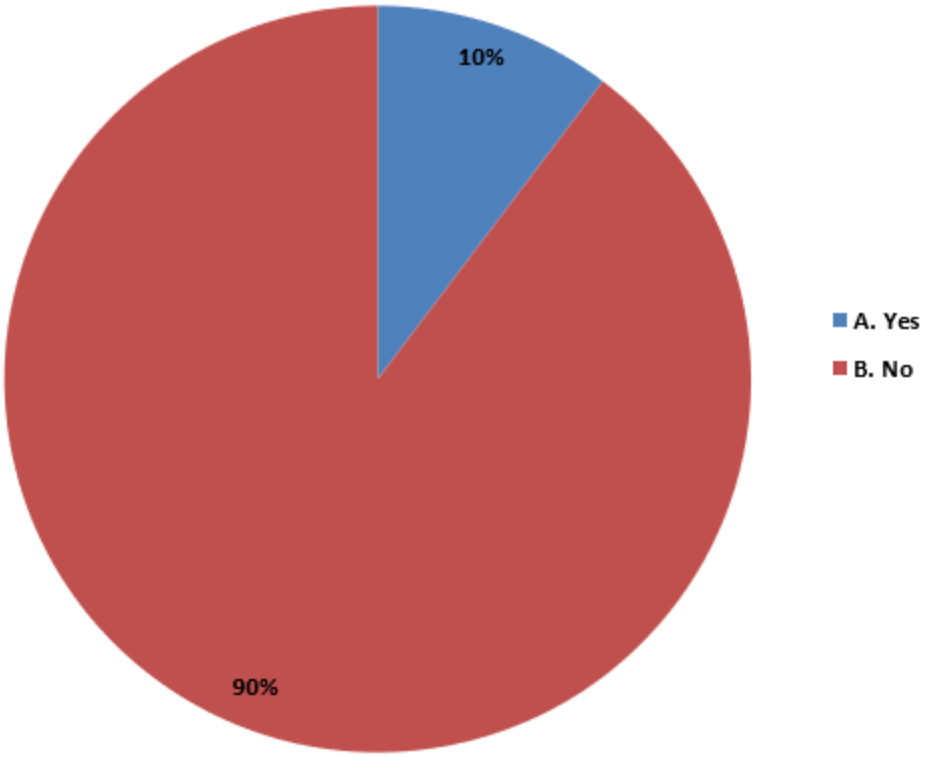
This question was required for the 53 entities that answered "Yes" to Question 72. Nearly all entities reported that no limits are shared to the TOs as nearly all entities did not have a limit to share. Of the limited entities that share these values, the primary method the RC, BA, or TOP uses is the same as Question 74 or the entity indicated that they also perform the TO role. These processes include operating calls in real time or set in place via a formal contractual means.

76. Describe how these limits are shared to DPs within your footprint. Enter "Not shared" if these limits are not shared to DPs. - RC, BA, TOP

This question was required for the 53 entities that answered "Yes" to Question 72. Nearly all entities reported that no limits are shared to the DPs as nearly all entities did not have a limit to share. Of the limited entities that share these values, the primary method the RC, BA, or TOP uses is the same as Question 74 or the entity indicated that they also perform the DP role. The number of reporting entities that also perform the DP role, however, is less than the number of reporting entities that also perform the TO role. Some entities emphasized the role of contractual limits shared ahead of operations for this question or the need for public posting to distribute to DPs.

77. Do you have limitations on the maximum amount of load that could be disconnected (e.g., through tripping or customer-initiated reduction) or reconnected for a single System Disturbance from a reserve standpoint? [Yes/No] - RC, BA, TOP

This question was required for all RCs, BAs and TOPs responding to this Alert. Roughly 90% of all entities indicated that they have no limitations on the maximum amount of load that could be disconnected or reconnected for a single system disturbance when viewed from their reserves standpoint. When considering RC-only entities, there is a greater likelihood the entity has defined this limit over other types of entities.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	10.3%	5.3%	0.0%	11.1%	19.1%	15.0%	7.0%
B. No	89.7%	94.7%	100.0%	88.9%	80.9%	85.0%	93.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

78. Describe how these disconnection or reconnection limits are imposed when the Large Loads enters service, exits service, or operates during normal operations. Enter "No limits" if these limits do not exist. - RC, BA, TOP

This question was required for the 20 entities that answered "Yes" to Question 77. Nearly all entities reported that these limits do not exist for normal operations. Some entities that do impose these limits indicated that this is worked out through the contractual agreements with the large loads during interconnection and imposed via operating instructions in real time. Some entities (of which not all were required to respond to this question) also shared that they are looking for their ISO or RTO to implement or impose these limitations. Some entities mentioned that their ISO or RTO has two different load disconnection limits: one for any given P1–P7 contingency as part of the TPL-001 process (e.g., 1,000 MW per Point of Interconnection), and the second one is a system operating limit based on frequency stability (e.g., 2,600 MW of aggregate loss). The second limit for frequency stability considers all load in an area that may disconnect from a transmission fault in a dynamic simulation.

79. Describe how these limits are shared to TOs within your footprint. Enter "Not shared" if these limits are not shared to TOs. - RC, BA, TOP

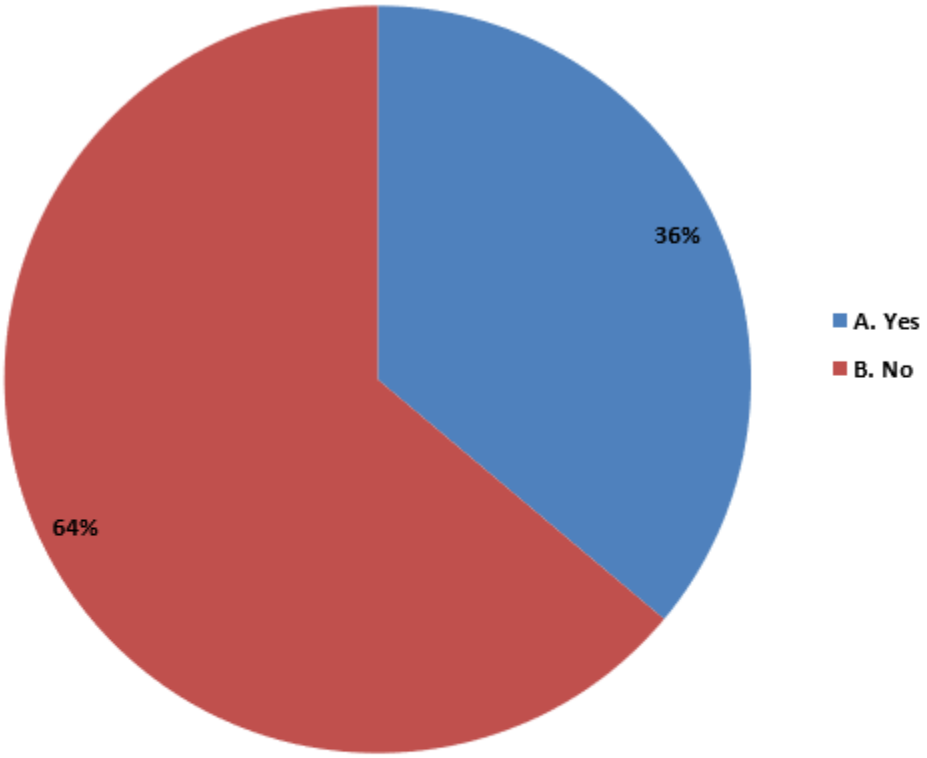
This question was required for the 20 entities that answered "Yes" to Question 77. Nearly all entities reported that these limits are not shared to the TOs in their area. Where they are shared, most entities reported that they provide user manuals, operational guides, tariff language, or other instructions. Some entities also indicated that they are the same company as the TO and share internally. Some entities (of which not all were required to respond to this question) also shared that they are looking for their ISO or RTO to implement or impose these limitations. One ISO/RTO company mentioned that it also discusses these limits and any updates to the studies that inform the limits at a regular stakeholder meeting.

80. Describe how these limits are shared to DPs within your footprint. Enter "Not shared" if these limits are not shared to DPs. - RC, BA, TOP

This question was required for the 20 entities that answered "Yes" to Question 77. Nearly all entities reported that these limits are not shared to the DPs in their area. Where they are shared, most entities reported that they provide user manuals, operational guides, tariff language, or other instructions. Some entities also indicated they are the same company as the DP and share internally, but this is a significantly fewer number of entities than in Question 79. Some entities (of which not all were required to respond to this question) also shared that they are looking for their ISO or RTO to implement or impose these limitations.

81. Do you have processes in place with TOs to ensure Large Loads are properly accounted for in operational modeling, forecasting, or other operational requirements prior to energization and commercial operations? [Yes/No] - RC, BA, TOP

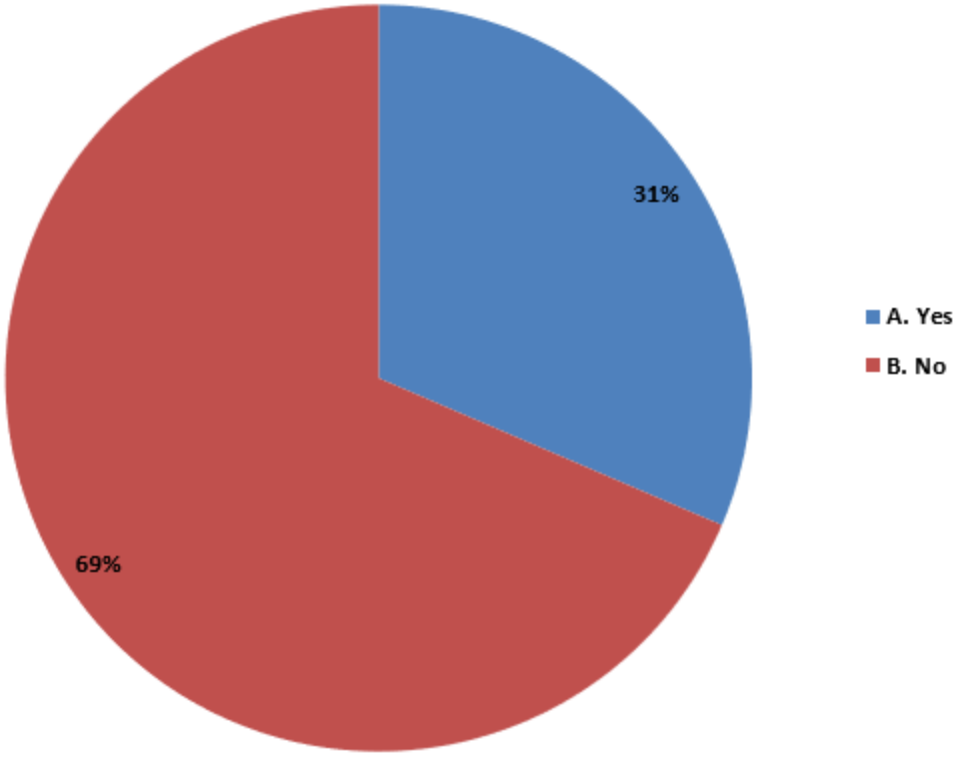
This question was required for all RCs, BAs, and TOPs responding to this Alert. Roughly one-third of entities indicated that they have a process in place with TOs to ensure that large loads are accounted for in operational modeling, forecasting, or other needed requirements prior to energization and commercial operations.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	36.1%	44.7%	7.1%	66.7%	27.7%	45.0%	31.6%
B. No	63.9%	55.3%	92.9%	33.3%	72.3%	55.0%	68.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

82. Do you have processes in place with DPs to ensure Large Loads are properly accounted for in operational modeling, forecasting, or other operational requirements prior to energization and commercial operations? [Yes/No] - RC, BA, TOP

This question was required for all RCs, BAs, and TOPs responding to this Alert. Roughly one-third of entities indicated that they have a process in place with DPs to ensure large loads are accounted for in operational modeling, forecasting, or other needed requirements prior to energization and commercial operations.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	31.4%	34.2%	7.1%	44.4%	29.8%	40.0%	29.8%
B. No	68.6%	65.8%	92.9%	55.6%	70.2%	60.0%	70.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

83. If the answer to Question 81 or 82 is yes, describe how you account for Large Loads in your operational modeling, forecasting, or other requirements prior to Large Load energization and commercial operations. - RC, BA, TOP

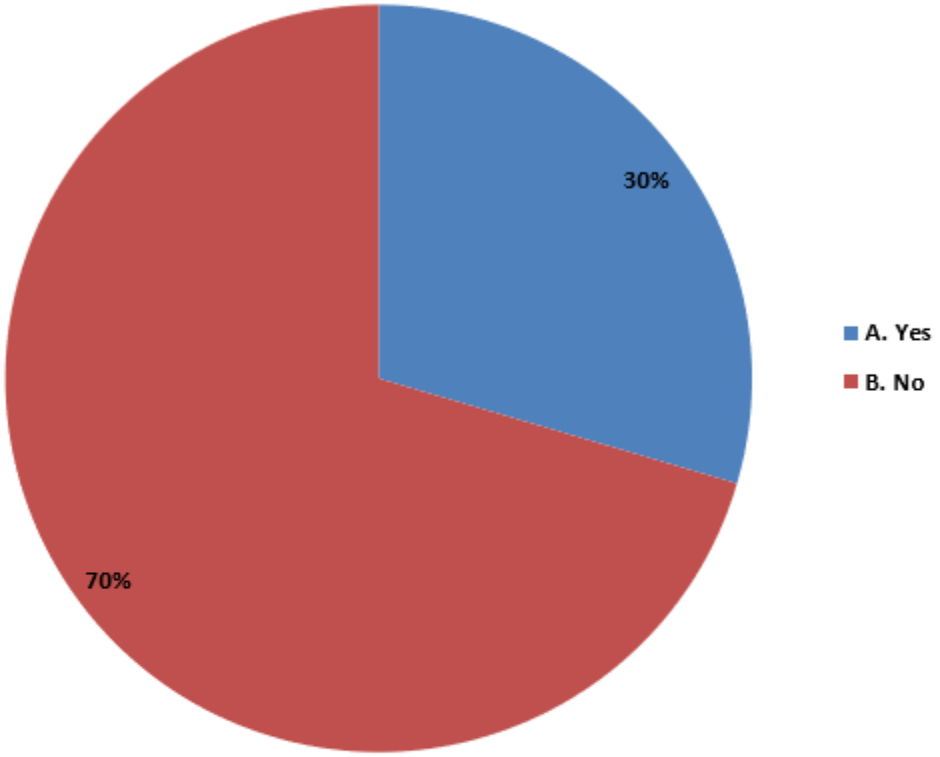
This question was required for the 61 entities that selected "Yes" to either Questions 81 or 82. Most entities indicated that they account for all operational modeling, forecasting, and other requirements through their SCADA or EMS platforms. Other entities also reported that they coordinate with large load control centers or through their TOs to develop long- and short-term forecasts. Many also indicated that this process is the same for all loads in their area, including large loads.

84. Describe any plans you have within 2 years to include changes intended to address the issues raised in Recommendation 3. - RC, BA, TOP

This question was required for all RCs, BAs, and TOPs responding to this Alert. Roughly one-third of entities indicated that they have no plans to address the issues raised in Recommendation 3. Many of the entities that indicated that they have some plan to address the issues within two years also indicated that they are closely monitoring or actively working with others to address the issues raised in Recommendation 3. Some entities further indicated that they are waiting on another's process (primarily their ISO or RTO) before implementing their own.

85. Are you consulting with or have you consulted with TOs and DPs to establish operating protocols for Large Loads? [Yes/No] - RC, BA, TOP

This question was required for all RCs, BAs, and TOPs responding to this Alert. Roughly three quarters of entities indicated that they do not consult with TOs and DPs to establish operating protocols for large loads.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	29.5%	35.1%	7.1%	66.7%	27.7%	30.0%	21.1%
B. No	70.5%	64.9%	92.9%	33.3%	72.3%	70.0%	78.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

86. Include the list of common Real-Time communication protocols used for Large Loads. Enter "N/A" if none exist. - RC, BA, TOP

This question was required for the 57 entities that selected "Yes" for Question 85. This question held a variety of nearly equal shares of categories of responses. Some entities listed their real-time communication protocols used, such as ICCP/SCADA/EMS systems. Other entities listed that they perform this real-time communication through operator calls, SCADA, or similar hybrid methods. Not all entities indicated that operator voice calls were part of this real-time communication, as was anticipated by NERC staff for Recommendation 4.

87. Describe the method used by the Large Load entities to provide operational load forecasts. Enter "N/A" if this does not exist. - RC, BA, TOP

This question was required for the 57 entities that selected "Yes" for Question 85. Most entities indicated that this method does not exist. Where this process does exist, responding entities indicated that large load entities were submitting hourly profiles to the operating desk via email or similar mechanisms. Some entities also indicated that they receive their forecasts from customer surveys, account managers, or scheduling coordinators for the customer.

88. Describe the method used to collect disturbance recordings or other data to aid in post-hoc event analysis. Enter "N/A" if this does not exist. - RC, BA, TOP

This question was required for the 57 entities that selected "Yes" for Question 85. Entities were nearly evenly split between online versus offline methods. Entities reported collecting the disturbance recordings through an application programming interface (API) remotely for most of the online methods. Other online methods included phasor measurement unit (PMU) streaming or other telemetry values. Offline methods were primarily focused on sending in a technician for download of the data to mobile storage.

89. Describe the coordination process Large Loads will follow in normal operating conditions (e.g., telemetry via SCADA). Enter "N/A" if this does not exist. - RC, BA, TOP

This question was required for the 57 entities that selected "Yes" for Question 85. Most entities indicated that most of the coordination will come through telemetered values through SCADA or other ICCP value. Some entities indicated that they do not have specific large load processes or data streams, but their generic items are applicable to large loads. Some entities indicated that they host operator calls to coordinate between large load entities.

90. Describe the coordination process Large Loads will follow in System Emergency operating conditions with you (e.g., telemetry via SCADA or operator calls). Enter "N/A" if this does not exist. - RC, BA, TOP

This question was required for the 57 entities that selected "Yes" for Question 85. Half of the entities reporting indicated that they directly coordinate with the large load entity during system emergency operating conditions. The other half indicated that no such coordination exists. Some shared that this coordination is done through a customer accounts manager for certain system emergencies (e.g., day-ahead energy deficiencies).

91. Describe the coordination process Large Loads will follow with you in the post-Disturbance period following a Contingency (e.g., System Operator calls). Enter "N/A" if this does not exist. - RC, BA, TOP

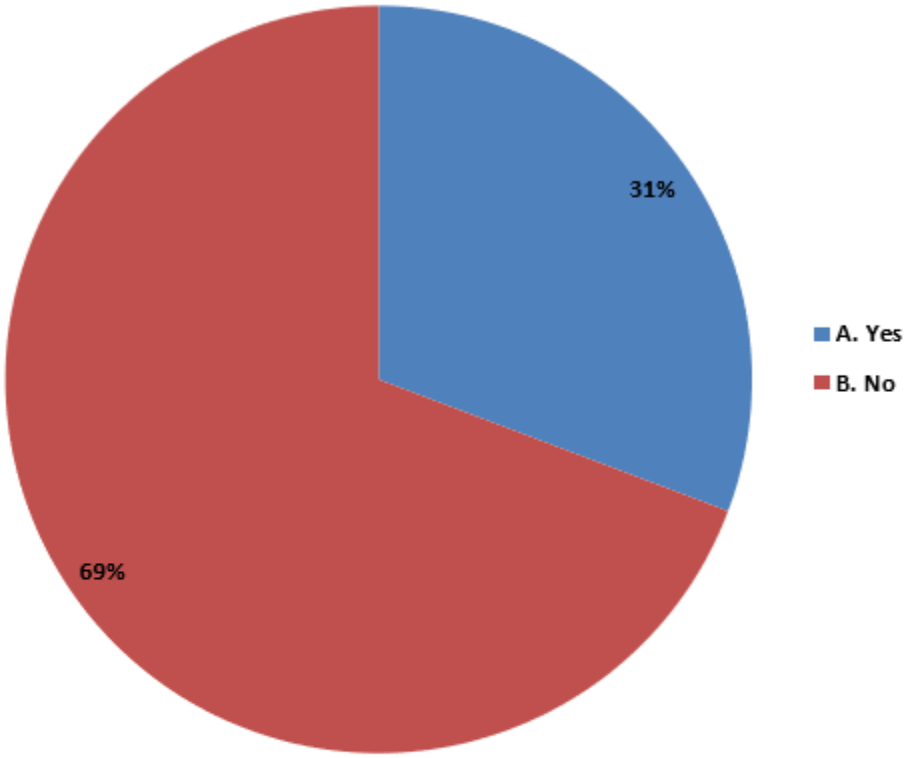
This question was required for the 57 entities that selected "Yes" for Question 85. Most of the entities indicated that this coordination for post-disturbance following a contingency does not occur. Where this coordination occurs, some entities reported that direct operator calls and coordination are expected prior to reconnection of the large load to the system. Some entities also indicated that this coordination is done through a customer account manager or done on a case-by-case basis as not all contingencies are the same.

92. Describe the process by which a Large Load notifies you of a major equipment status change. Enter "N/A" if this does not exist. - RC, BA, TOP

This question was required for the 57 entities that selected "Yes" for Question 85. Most of the entities indicated that large loads are expected to perform direct operator calls or follow the defined procedure that was put in place during the interconnection process. Some entities also indicated that this status update needs to be shared with other utilities (and the entities share the procedure for following this sharing with the affected other utilities with the large load) as well as through other key accounts management processes or systems. Some entities indicated that large loads do not notify them of a major equipment status change.

93. Are you consulting with or have you consulted with TOs and DPs to ensure the necessary Real-Time communication infrastructure and monitoring capabilities are in place? [Yes/No] - RC, BA, TOP

This question was required for all RCs, BAs, and TOPs responding to this Alert. Roughly two-thirds of entities indicated that they are not consulting with or have not consulted with TOs and DPs to ensure necessary communication infrastructure and monitoring capabilities are in place for large load entities.



Answer	Percentage	MRO	NPCC	RF	SERC	TRE	WECC
A. Yes	30.7%	34.2%	28.6%	55.6%	21.3%	35.0%	27.3%
B. No	69.3%	65.8%	71.4%	44.4%	78.7%	65.0%	72.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

94. If the answer to Question 93 is yes, describe Real-Time communication infrastructure and monitoring capabilities. Include details for the device types, electrical locations (including any phase-to-phase differences), and sample rates. Enter "N/A" if this does not exist. - RC, BA, TOP

This question was required for the 59 entities that selected "Yes" for Question 93. Most entities indicated that some form of online telecommunication infrastructure architecture is established at the point of interconnection. Some entities pointed to their facility requirements or other metering standards that share the exact specifications. Very few entities provided phase-to-phase differences in these requirements, leading NERC staff to conclude that these standards are applicable regardless of phase configuration or facility design. Some entities indicated that while they currently have typical SCADA or billing architecture for low-resolution data, advanced metering is planned for future interconnections.

95. Describe any plans you have within 2 years to include revisions to address the issues raised in Recommendation 4. - RC, BA, TOP

This question was required for all RCs, BAs, and TOPs responding to this Alert. Most entities indicated that they have no plan or mentioned no specific plans to change their processes to address the issues raised in Recommendation 4. Most that do have plans indicated that they will be able to implement these plans or expect to implement these plans within the two-year time frame in Question 95. Some entities indicated that they are waiting on a separate entity, primarily their ISO or RTO, to decide before implementing their own revisions.

96. In the free text field provide your definition of Large Loads including any MW or kV threshold or other operational characteristics about the load profile. Also indicate in this response other registered entities (e.g., BA, TOP, TP, or similar) that were consulted when defining Large Loads in your footprint. Enter "None" if your organization has not formally defined Large Loads. - RP

This is the same as Question 1 except answered by the RPs. See Question 1 for analysis of this response.

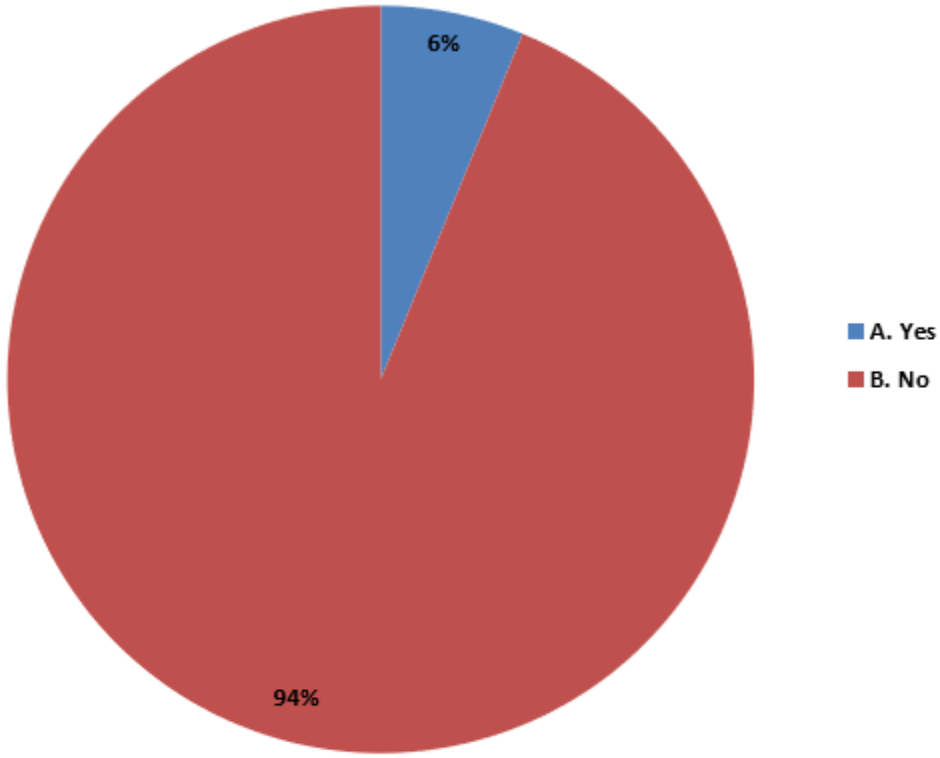
97. In the free text field provide your experience in integrating Large Loads. Include in this response the number of years of experience in integrating Large Loads and other highlights or lessons learned as part of this experience. - RP

This is the same as Question 2 except answered by the RPs. See Question 2 for analysis of this response.

98. Do your reserve margin/energy adequacy studies account for the intra-minute variability or ramping of Large Loads? [Yes/No] - RP

This question was required for all RPs responding to this Alert. Nearly all (over 90%) of entities indicate that their reserve margin or energy adequacy studies do not account for intra-minute variability or ramping of large loads.

While the models surrounding reserve margins or energy adequacy studies may be different than Interconnection-wide models, the intra-minute active power consumption or ramping of large loads has shown to be a risk in the NERC LLWG's *Characteristics and Risks of Emerging Large Loads*.[15]



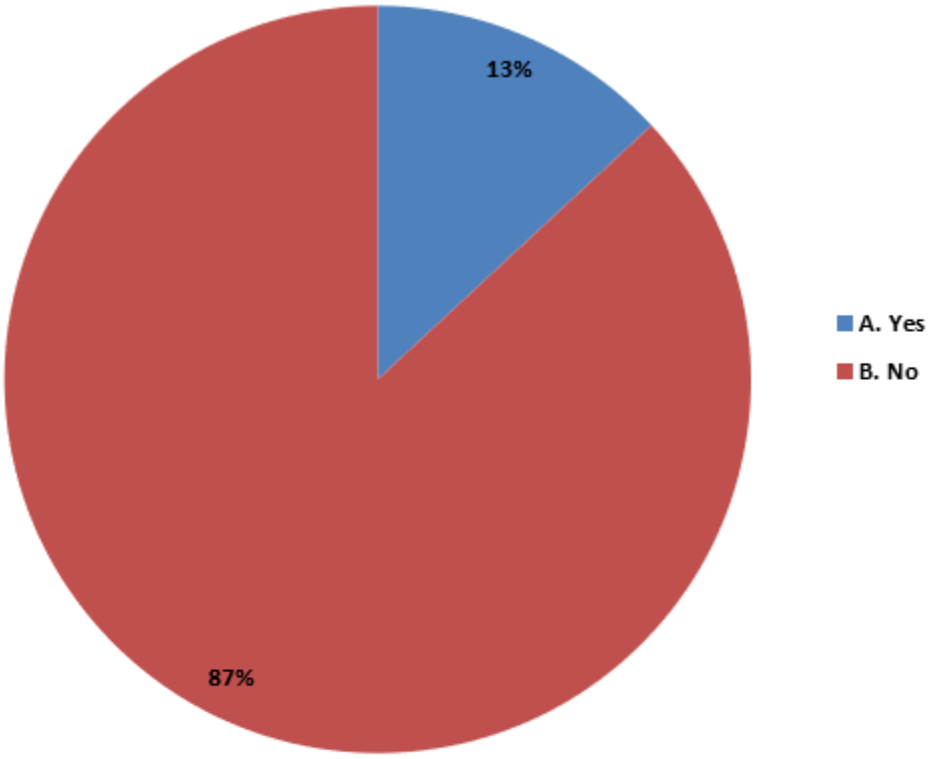
Answer	Percentage
A. Yes	6.2%
B. No	93.8%
Total	100.0%

[15] Available here: https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf

99. Do your reserve margin/energy adequacy studies account for the loss (and delayed reconnect) of aggregate load under the most severe Contingency? [Yes/No] - RP

This question was required for all RPs responding to this Alert. Most entities indicated that their reserve margin or energy adequacy studies do not account for the loss of aggregate load under the most severe contingency.

Downward regulating reserves are an important piece of the Interconnection's ability to maintain energy adequacy as highlighted in the NERC LLWG's *Characteristics and Risks of Emerging Large Loads*.[16]



Answer	Percentage
A. Yes	13.1%
B. No	86.9%
Total	100.0%

[16] Available here: https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf

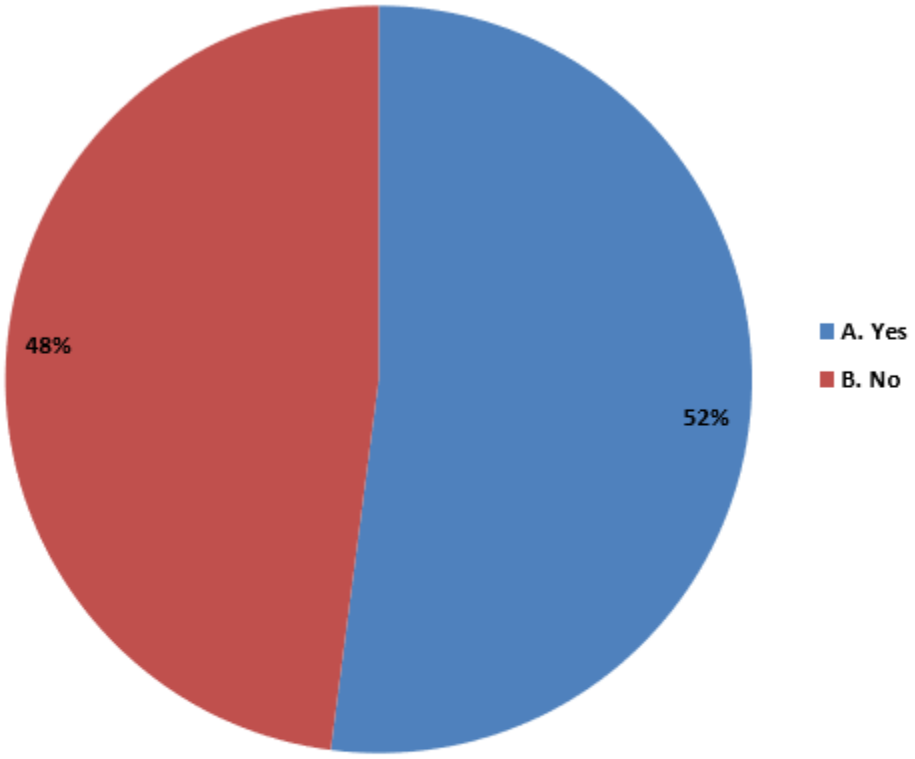
100. In the free text field provide any comments you wish to provide to help explain your answers to these questions. - RP

This question was for all RPs responding to this Alert but was only required if they had additional comments to explain their answers. Most RPs used this field to highlight concerns with how large loads are impacting their processes. These included the following:

- Large load variability is not accounted for generally.
- Another entity is contracted with or performs their energy adequacy assessments on their behalf.
- The reserve margin/energy adequacy assessments are done via a working group and are not readily applicable for individual study.
- The RP does not determine the capacity needs of the organization.
- The studies to assess reserve margin or energy adequacy use highly probabilistic methods to capture a range of anticipated or possible outcomes.
- Load contingencies are not typically studied as part of the established reserve margin requirements.

101. Are you identifying and implementing a process to include Large Loads into your Near-Term Planning Horizon Demand forecasts? [Yes/No] - RP

This question was required for all RPs responding to this Alert. Roughly half of all RPs are identifying and implementing a process to include large loads in their near-term transmission planning horizon. While the word "transmission" was excluded in the question, entities that reached out for clarification interpreted the question to refer to the term used in the *NERC Glossary of Terms*,[17] which was the intent of Question 101. This roughly equates to the same percentage of TPs and PCs that were asked a similar question.

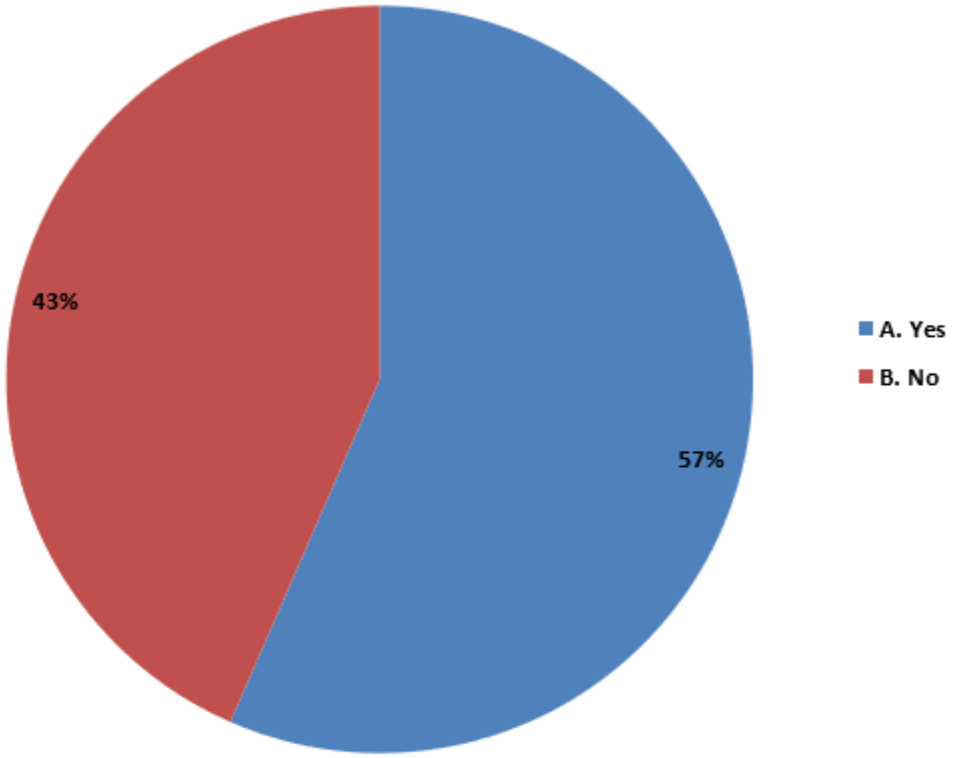


Answer	Percentage
A. Yes	52.1%
B. No	47.9%
Total	100.0%

[17] Available here: https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf

102. Are you identifying and implementing a process to include Large Loads into your Long-Term Planning Horizon Demand forecasts? [Yes/No] - RP

This question was required for all RPs responding to this Alert. Roughly half of all RPs are identifying and implementing a process to include large loads in their long-term transmission planning horizon. While the word "Transmission" was excluded in the question, entities that reached out for clarification interpreted the question to refer to the term used in the *NERC Glossary of Terms*,[18] which was the intent of Question 102. This roughly equates to the same percentage of TPs and PCs that were asked a similar question.



Answer	Percentage
A. Yes	56.6%
B. No	43.4%
Total	100.0%

[18] Available here: https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf

103. If your answer to Question 101 or 102 is yes, describe your method of including Large Loads into your Near-Term Planning Horizon and Long-Term Planning Horizon Demand forecasts. Enter "N/A" if this process does not exist. - RP

This question was required for the 76 entities responding "Yes" to Question 101 or Question 102. Many entities highlighted that there is no firm way to account for large loads during the near- or long-term horizons but that they track various milestones to assess the potential for a large load to energize during a given year in the two different horizons. Some entities reported that they use customer-provided data (e.g., a forecast for load expansion over multiple years), and some entities reported that they use construction milestones to adjust this process. Some entities run this process through annualized studies, while others include large loads on given contractual steps. A few entities reported that they estimate a fraction of the "queue" of loads based on the historic amount of load that has materialized from long- or near-term planning horizons and use that value for including large loads into their processes.

104. If your answer to Question 101 or 102 is yes, describe how you validate your demand projections annually, or more frequently, for Large Loads. Enter "No validation" if this process does not exist. - RP

This question was required for the 76 entities responding "Yes" to Question 101 or Question 102. Roughly half of the entities report not being able to validate demand projections through their mechanisms. The other half of entities indicated that they do have a process to track large load entities on an annual, monthly, or daily basis. A few entities use alternative methods like satellite imagery to validate the data center's progress for their demand projections. Entities that have a process to validate their demand projections highlighted that there is no firm way to approach this validation.

105. If the answer to Question 101 or 102 is no, describe any plans you have within 2 years to include revisions to address the issues raised in Recommendation 5. - RP

This question was required for the 70 entities responding "No" to Question 101 or Question 102. Most entities that do not have ways to include large loads into their near- or long-term horizons indicated that they do not have plans to include large loads into these processes. Some of these entities also shared they are relying on others before implementing changes to their processes, which could include process changes in industry working groups.

Conclusions and Next Steps

From the responses to the Recommendations in the Alert, NERC has found a few key principles that demonstrate how industry is responding to reliability concerns with interconnecting, commissioning, studying, and operating large loads. These key findings are as follows:

- Many entities at the time of this Alert do not have specific procedures to handle the unique challenges associated with large loads. Some do not plan to implement changes to address the risks associated with the Recommendations in this Alert. Entities that are creating requirements are mostly coordinating with higher-level entities like PCs and RCs in stakeholder processes.
  - For entities that do have strong interconnection requirements for large loads, these interconnection requirements adequately address most reliability concerns with large loads.
  - Some evidence exists that entities were unable to report consistent numerical load capacities as indicated in the Alert worksheet. For example, some load forecasts for in-service by year end of 2025 did not equal the sum of all reported in-service large loads (within a margin of acceptable error).
  - Some entities do not have or do not plan to have large loads interconnecting to their system, which explains this type of entities' lack of plans to address the Recommendations in this Alert.
- Many entities do not have a process to coordinate with TOs and DPs to establish protection coordination requirements for large loads.
- Many entities do not have a process to coordinate with TOs and DPs to establish post-disturbance recovery requirements.
- Many entities report waiting on or coordinating with a separate entity, primarily their ISO or RTO, before changing their procedures to address the reliability concerns in the Recommendations of this Alert.
- Many entities have not developed a list of detailed modeling data, settings, and parameters needed from large loads.
- Entities did not contact their large load entities to respond to this Alert even if they have established strong contacts with the large load customer.
  - Typically, this coordination was performed through the TO and the associated LSE for the large load, if not done directly.
  - Many entities that did contact their large load entities used customer account managers to coordinate and communicate.
- Entities do not have a standardized requirement for operational ramp limits in a post-disturbance state to address the reliability concerns raised in Recommendation 1.
- Entities report not being able to gather modeling information to represent large loads as raised in Recommendation 1 and 2.
  - Many entities report not having the authority to gather the modeling information.

  - Some entities report a lack of knowledge on what modeling information to gather to represent the large load facility.
- Entities generally do not have a commissioning process to address the concerns discussed in Recommendation 3.
  - Most entities do not have processes to require large loads to provide and update modeling data based on design changes, upgrades, and disturbance-based model validation.
  - Entities that do have a commissioning practice do not include model verification or model validation to support BPS reliability.
  - Many entities report not coordinating the findings of the commissioning to other entities.
- Entities broadly do not have a direct level of coordination with large load entities as they either do not have large load entities, or a problem arose that prevented communication in their established process. These are issues that are addressed in Recommendation 4.
- Entities do not have a good way to capture large loads in near-term or long-term transmission planning horizons as recommended in Recommendation 5.
  - Some evidence in the data shows that RPs are not themselves determining the capacity needs for their area.

The data collected in this Alert underscores the importance of recognizing the reliability concerns around large loads and proactively addressing the associated challenges. NERC recommends continuing collaboration with industry to drive a continued focus on these risks.

To do so, NERC recommends taking targeted actions, including the following:

- Issue a Level 3 NERC Alert by June 2026 with essential actions that address the most significant gaps and concerns identified from this Level 2 Alert analysis.
- Explore and draft starting in the second quarter of 2026:
  - Registry criteria updates to address the integration of computational load and
  - Develop new and update existing Reliability Standards applicable to new registrants and existing registered entities.
- Release a reliability guideline mid-2026 to share best practices. This guidance as well as the Level 3 Alert will be crucial for entities as they will share methods to improve reliability.

Attachment 1-D

Incident Reviews

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.

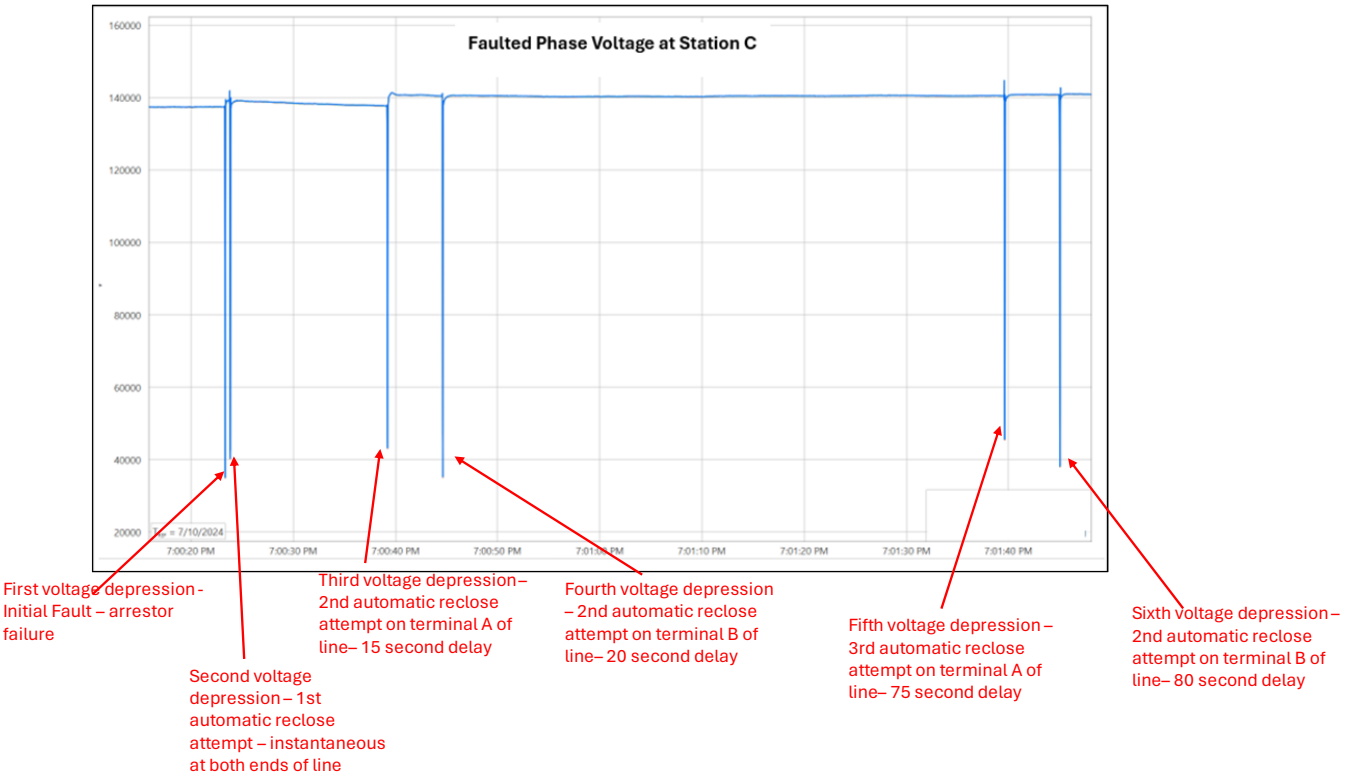


Figure 1: Faulted Phase Voltage

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.

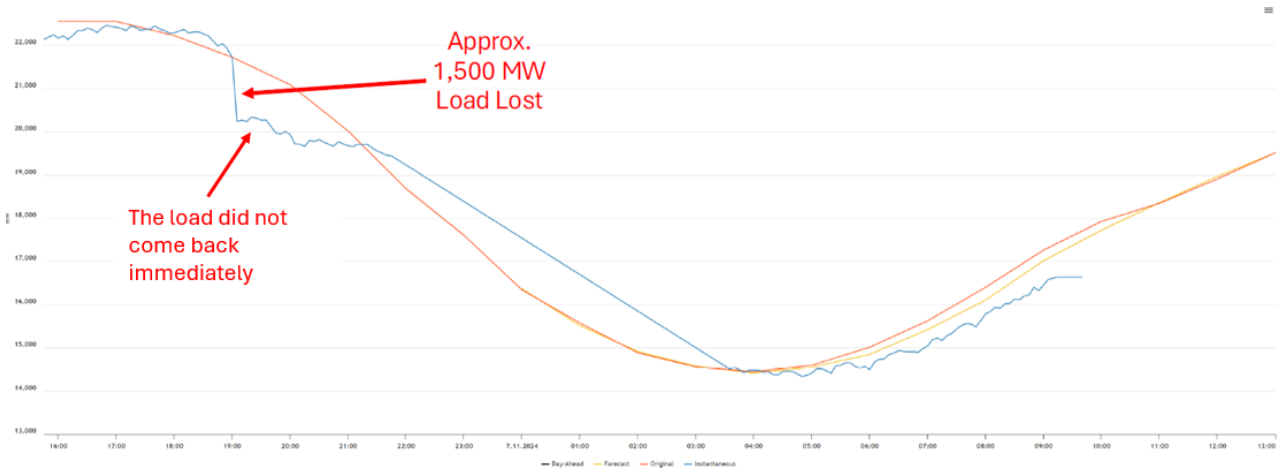


Figure 2: System Load Chart

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.

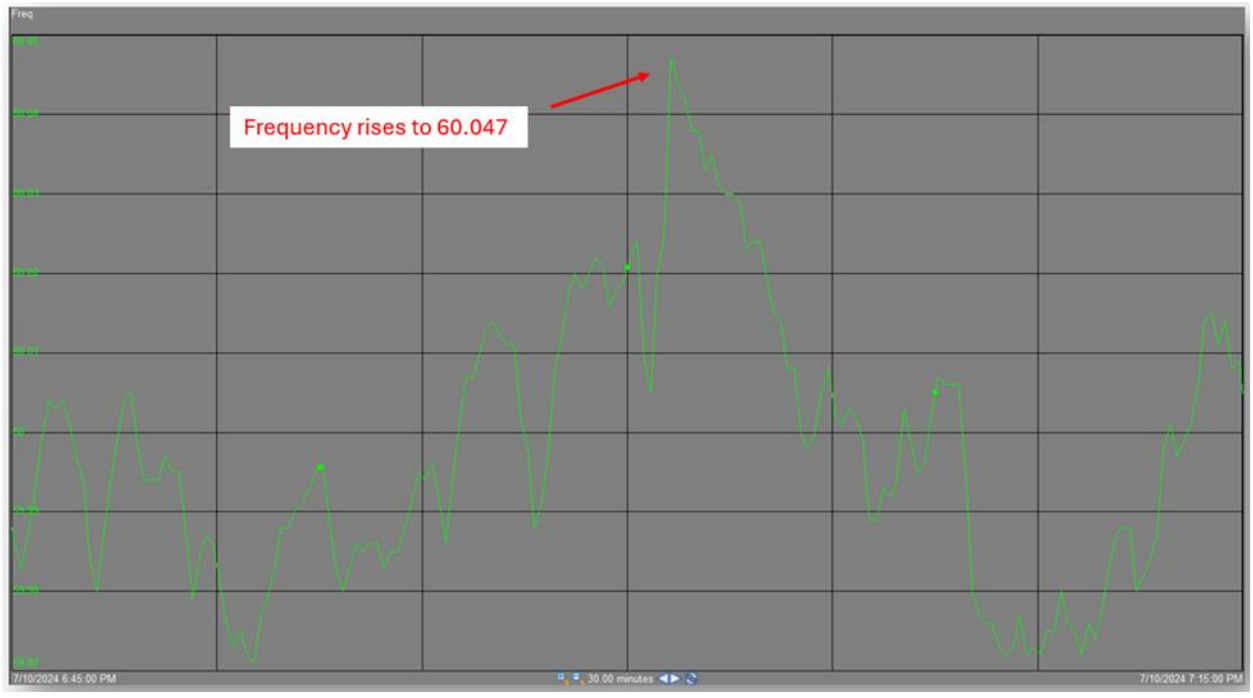


Figure 3: Frequency at Time of Load Loss

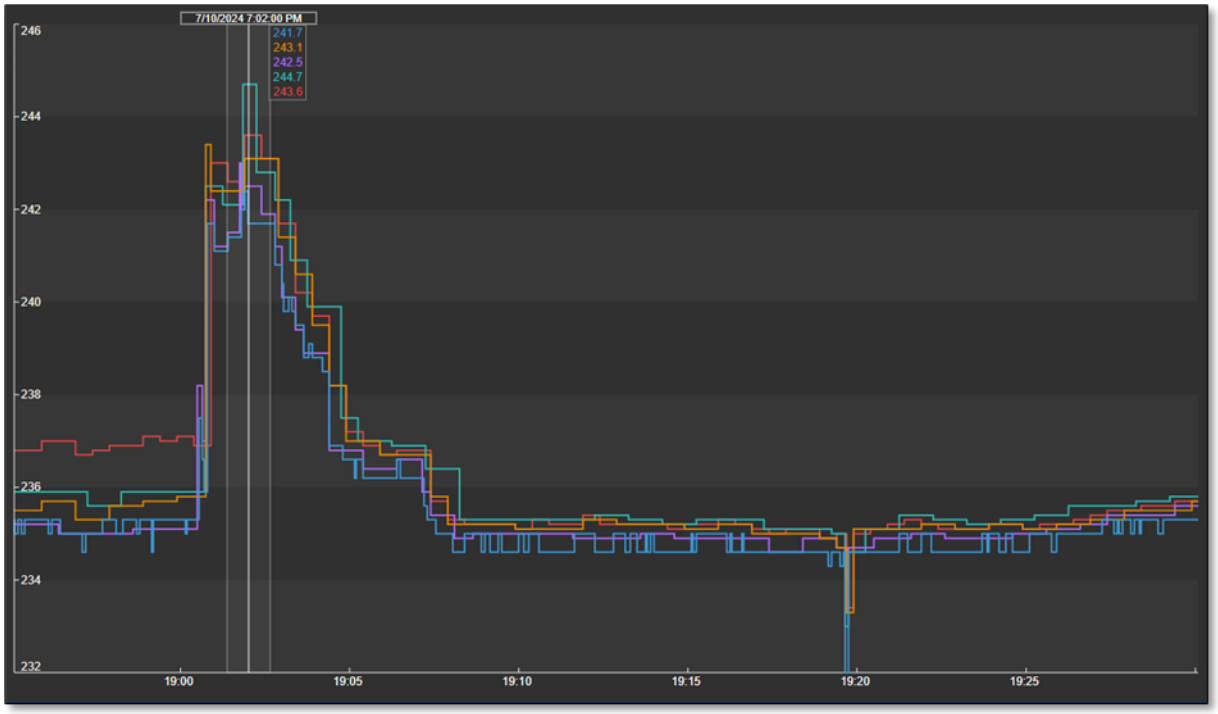


Figure 4: 230 kV Voltages

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.

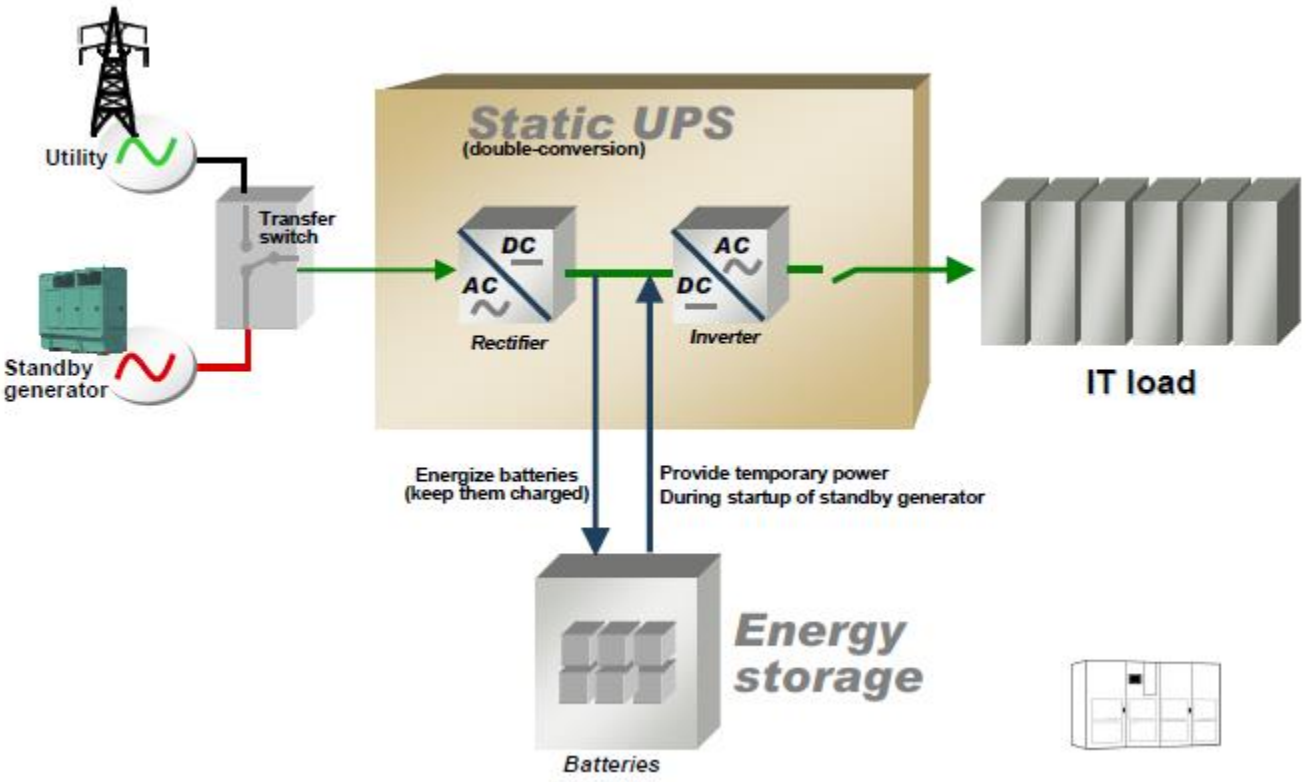


Figure 5: Static Centralized UPS
[Source: Schneider Electric White Paper 92]

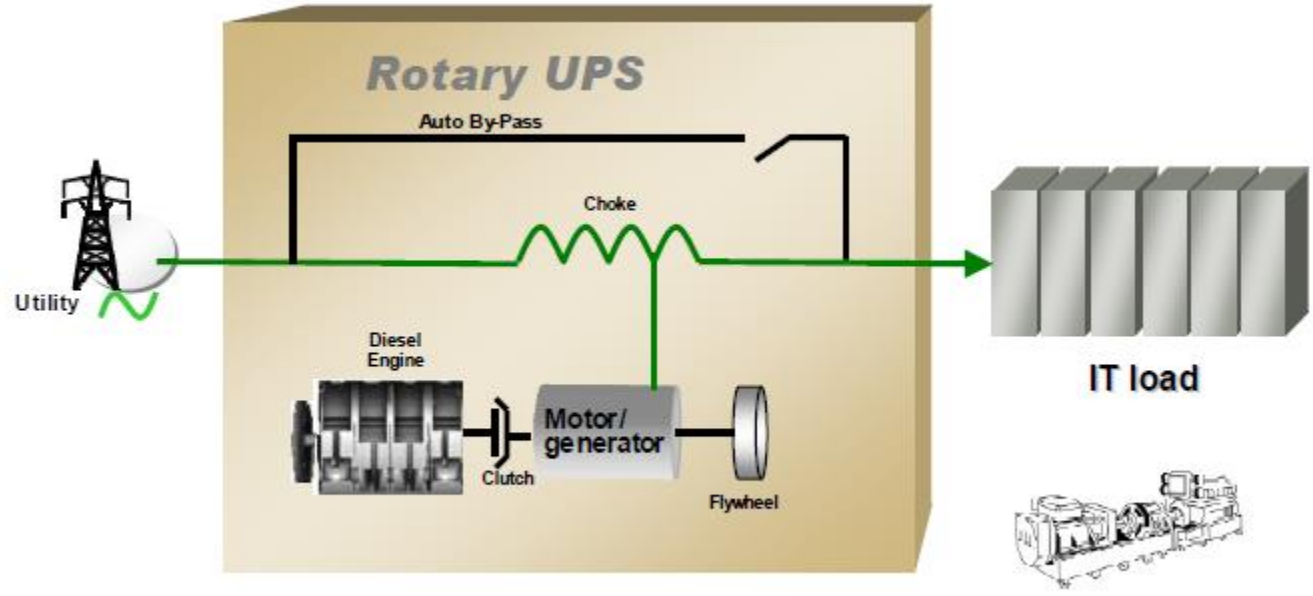


Figure 6: DRUPS
[Source: Schneider Electric White Paper 92]

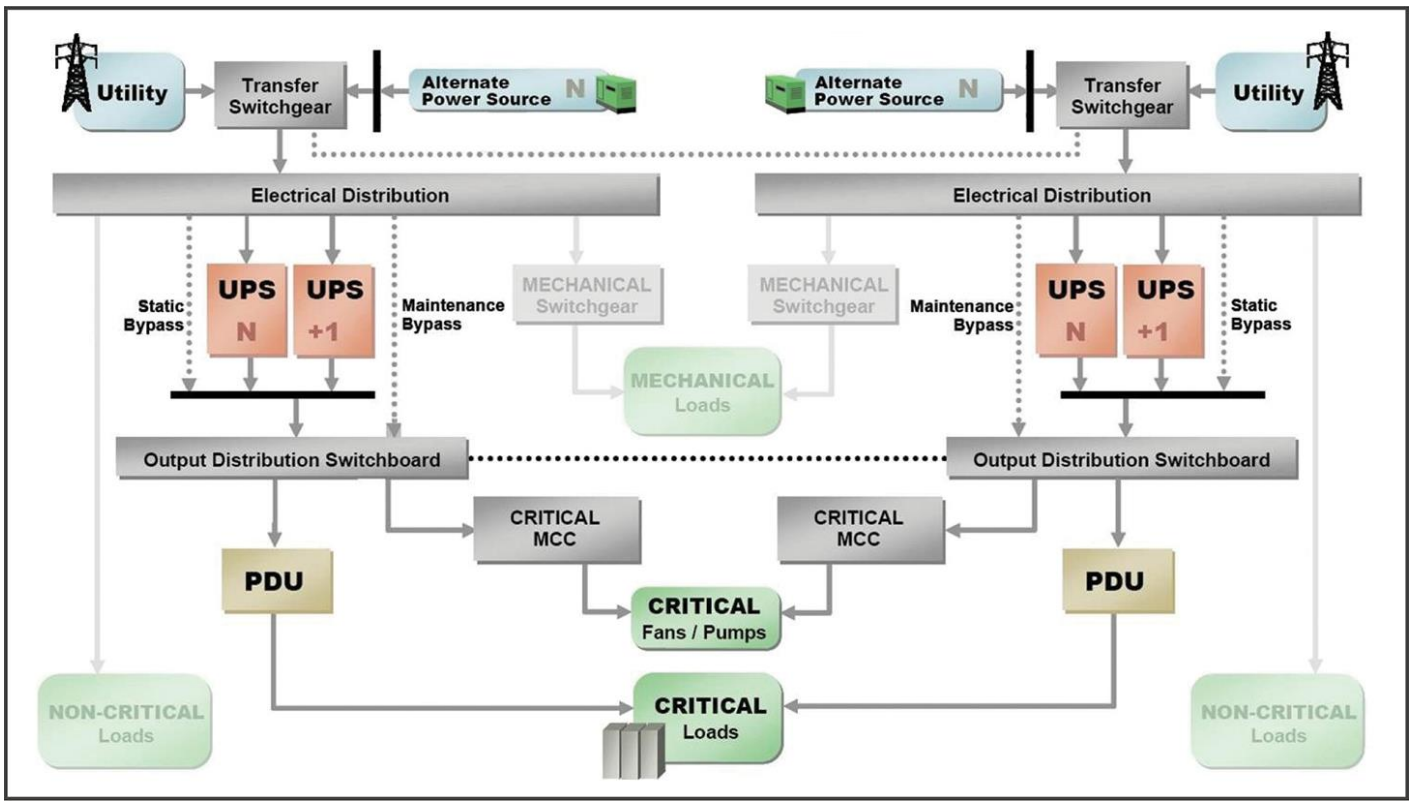


Figure 7: Typical Centralized UPS Power Distribution
[Source: Uptime Institute Journal]

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.

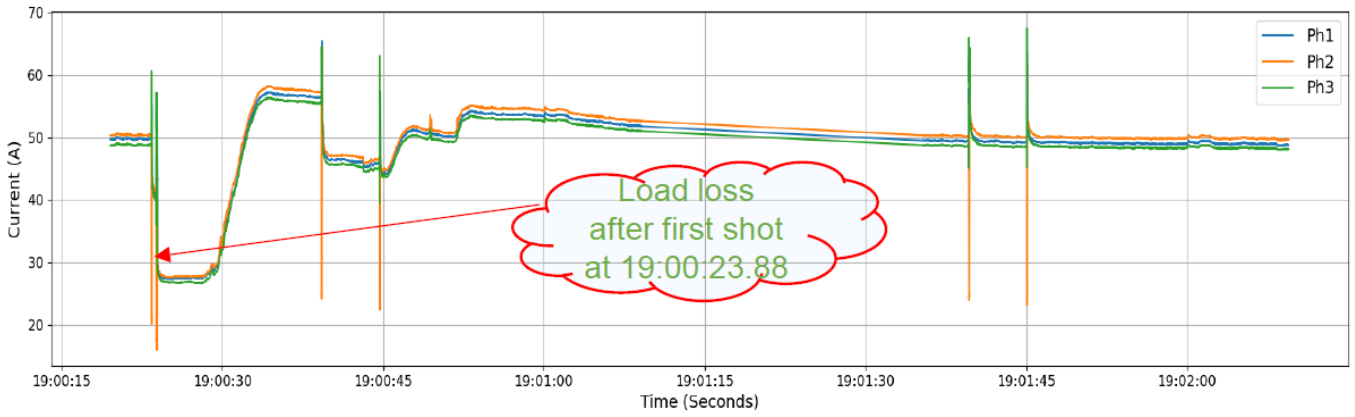


Figure 8: Static UPS Load Characteristic



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**.

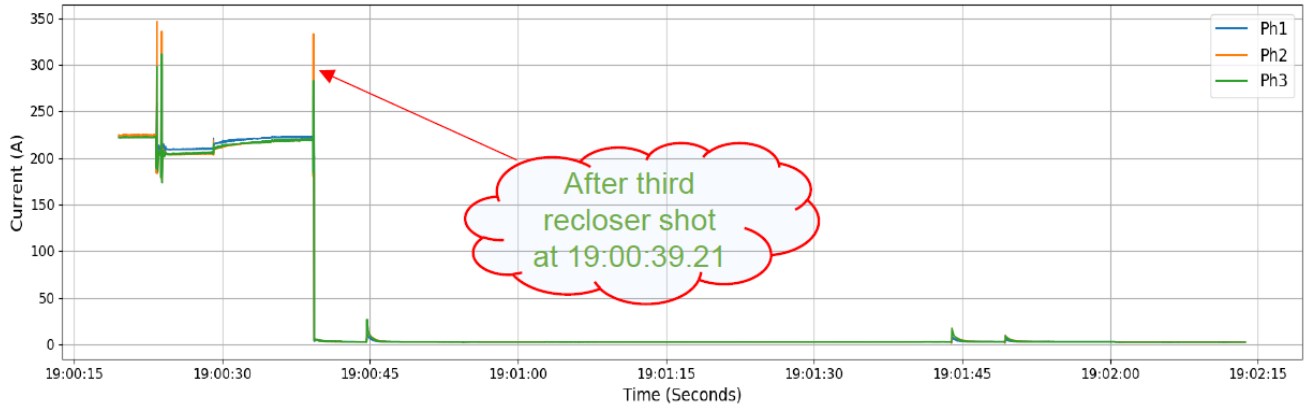


Figure 10: Voltage Disturbance Counting Scheme Load Characteristic

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Incident Review

Voltage-Sensitive Crypto Load Reductions

Primary Takeaways

Recent Electric Reliability Council of Texas (ERCOT) load-loss events highlight the unique and sensitive ride-through characteristics of crypto-mining facilities. As these facilities rely heavily on constant-power electronic supplies, cooling equipment, and single-phase devices that respond to normally cleared transmission faults, they experience load drops within milliseconds of a voltage sag. Restoration times vary widely depending on equipment configuration and the level of manual intervention required.

Understanding these behaviors is essential for assessing grid impacts, interpreting event data, and developing appropriate ride-through expectations and mitigation strategies for large electronic loads (LEL) operating in the bulk power system (BPS).

Overview of Crypto-Mining Facility

Crypto-mining facilities are specialized, industrial-scale data centers that house powerful computers (miners) for the purpose of solving complex problems. Solving these problems may then produce new digital tokens that are distributed per the protocols used by that currency.

The facilities differ from other data center facilities, such as cloud computing and AI data centers, in that they typically do not have uninterruptible power supply (UPS) systems or backup generators. As a result, crypto facilities have different ride-through characteristics than other types of data centers.

Crypto-mining facilities depend on a large number of constant-power electronic power supplies that are highly sensitive to voltage drops. When the voltage dips below a certain threshold, the miners shut down almost instantly, causing a rapid loss of load. During a voltage depression or sag, the nature of the constant power supply means that, during a voltage depression, the amount of current drawn will be inversely proportional to the reduction in voltage. For example, if the voltage dropped to 0.8 per unit (p.u.), the current would need to increase by 1.25 p.u. Depending on how heavily loaded the circuits are, the voltage depression could result in overloads and possible protective actions and potentially trigger local protection systems.

Once the voltage recovers, crypto-mining facilities go through a multistage restoration process, which includes stabilizing the power supply, booting the operating system, initializing the mining software, recognizing hash boards, and normalizing the cooling system. Consequently, restoration times can vary greatly—from just a few minutes to significantly longer—depending on the type of equipment, the cooling system, and whether manual resets are required. Unlike traditional data centers, crypto-mining facilities do not return to full load almost immediately; instead, their ramp-up process is gradual and predictable, reducing the chances of rapid spikes in demand on the grid.

Summary of Incidents

Over the last several years, ERCOT has experienced indirect load[1] loss in response to normally cleared transmission line faults on the system. This load loss has been attributed to blockchain/crypto-mining facilities not riding through the temporary voltage depressions during the faults. If blockchain/crypto-mining load continues to grow in the ERCOT Interconnection, this load loss could grow to a level that would threaten the reliability of the Interconnection. To understand the ride-through characteristics of these blockchain/crypto-mining facilities, discussions were held with the facility owners and operators. The information gathered from those discussions is included in this report.

Incident Details

ERCOT identified 26 LEL ride-through events involving indirect load loss greater than 100 MW from one or more crypto facilities between January 2023 and September 2025. These events primarily occurred in Central Texas, far West Texas, the Panhandle, and the North Zone.

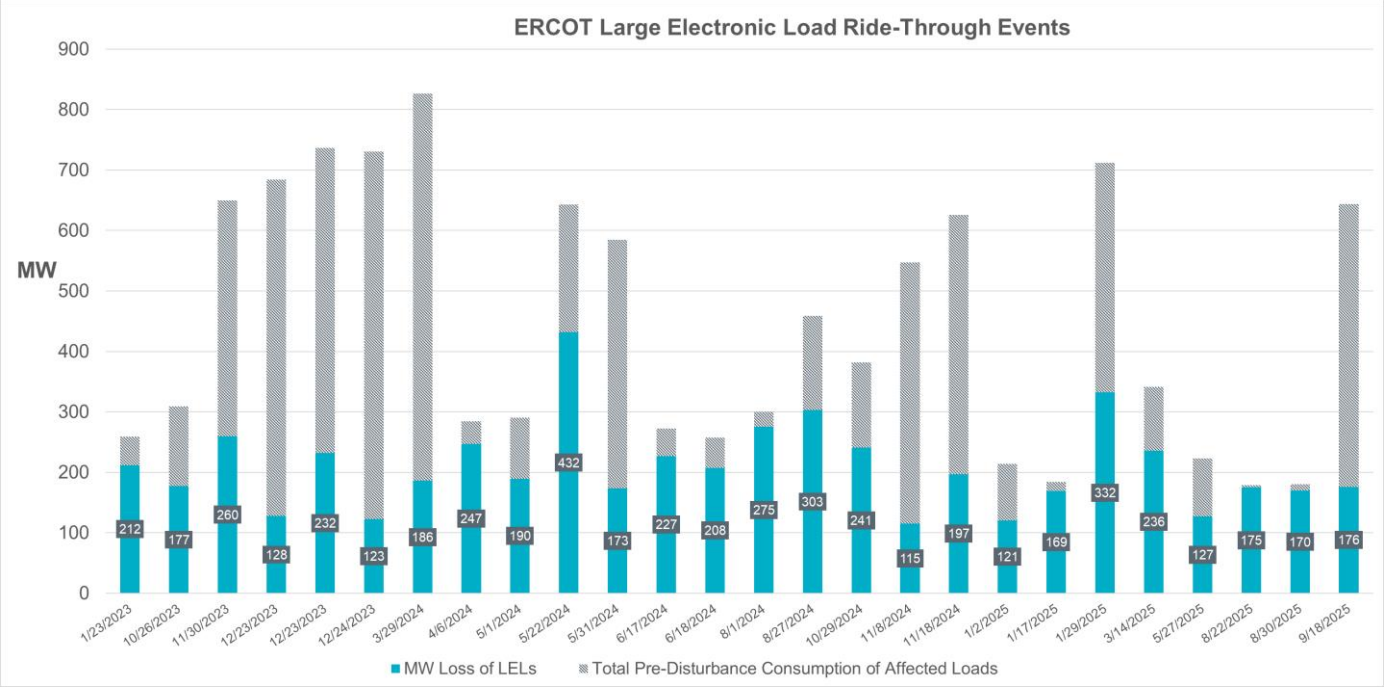


Figure 1: ERCOT LEL Ride-Through Events (January 2023 and September 2025)

Figure 1 shows a wide range of load reductions during voltage disturbance events; impacts varied from approximately 17% to 95% of pre-disturbance consumption, with several events exceeding 50% loss and occasional events approaching near-total load dropout. The magnitude of reduction was closely tied to the type and severity of the fault. Three line-to-ground faults produced the largest reductions, averaging around 65%, while single line-to-ground faults resulted in more moderate reductions of 17% to 40%. Notably, even relatively mild disturbances triggered measurable responses: One event showed a 19% reduction in consumption due to a shallow single-phase voltage dip to 0.844 p.u.

[1] Indirect load loss: Load loss not directly attributable to the outage of the electrically connecting line during the fault, arising instead from system or grid effects.

The events varied in severity but consistently demonstrated that LELs—specifically crypto-mining facilities—experience significant active-power reductions when exposed to even shallow voltage depressions. All events confirmed low voltage at the point of interconnection (POI) and verified that crypto facilities exhibit sensitive ride-through behavior, reducing consumption rapidly in response to voltage dips, particularly when single-phase voltage falls below approximately 0.7 p.u.

Technical Observations

This section consolidates technical observations from multiple ERCOT load-loss events involving crypto-mining facilities. It provides an overview of how these facilities respond to voltage depressions, why their behavior often deviates from standard Information Technology Industry Council (ITIC) ride-through assumptions, and how factors such as cooling-system performance, transformer configuration, neutral overcurrent protection, and constant-power equipment influence both the magnitude of load loss and the speed of recovery.

This section is intended to frame the underlying mechanisms that drive observed disturbance patterns and to support a deeper understanding of how crypto-mining loads interact with the BPS during and after normally cleared faults.

ITIC Curve

The performance of crypto-mining facilities during power disturbances largely depends on the design of the installed equipment. Typically, the ride-through performance of computer-based equipment adheres to the ITIC curve (see **Figure 2**), which was formerly published by the Computer and Business Equipment Manufacturers Association (CBEMA). This curve defines the ac voltage limits that most information technology equipment (ITE) can endure without experiencing unexpected shutdowns or malfunctions.

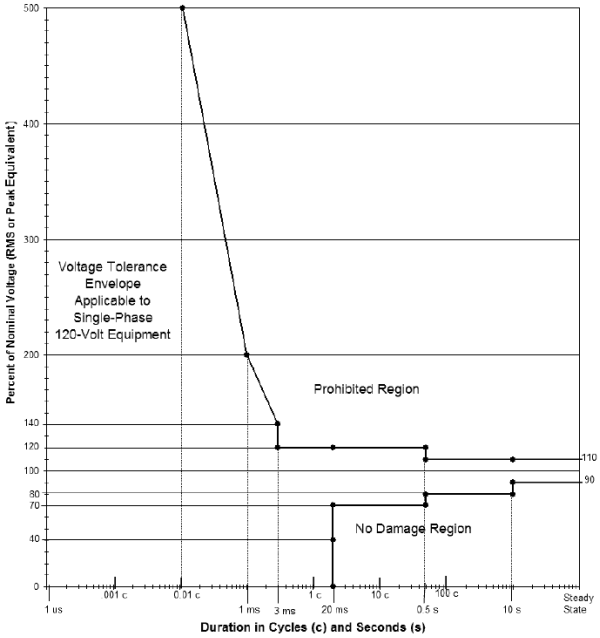


Figure 2: ITIC Curve

Most modern ITE devices are powered by switched-mode power supplies. The front end of these power supplies contains a bridge rectifier that converts incoming ac voltage to dc voltage. This rectified dc voltage

is stored in a bus capacitor and subsequently converted to the required voltage to power various subsystems within the ITE equipment.

During power disturbances, such as voltage sags, swells, or transients, the dc bus voltage may fluctuate significantly, which can affect the reliable operation of the ITE equipment. The ITIC curve serves as a performance plot that illustrates the relationship between input voltage and duration for different types of power disturbances, including sags, swells, transients, interruptions, and steady-state voltage variations at the input terminals of the ITE equipment.

The ITIC curve indicates that voltage sags down to 70% of the root mean square (RMS) nominal voltage are acceptable if the duration does not exceed 0.5 seconds. Meanwhile, sags that drop to 80% of the RMS nominal voltage are permissible for up to 10 seconds. A dropout event, which causes equipment to stop functioning, occurs when the sag falls below 70% of the RMS nominal voltage. If this dropout lasts longer than one ac cycle, it enters what is known as the "no damage region" of the ITIC curve. As the power supplies cannot provide sufficient power to the ITE during low-voltage conditions, the ITE shuts down.

However, event analysis has shown that tripping of equipment according to the CBEMA/ITIC curve is not precise for the equipment. For a voltage depression that is close to the boundaries of the CBEMA/ITIC curve at the POI/utility connection, multiple instances of partial loss of load have been observed. This has been attributed to the equipment not operating precisely according to the CBEMA/ITIC curve.

For example, a load-reduction event occurred due to a line-line-to-ground fault caused by a lightning strike on 138 kV lines that was cleared within approximately five cycles. Two crypto facilities (A and B) were affected.

At crypto facility A, a multi-phase voltage depression reduced both A-phase and B-phase voltages below 0.7 p.u. for more than 20 milliseconds. Consequently, the reduction in active power for A-phase and B-phase accounted for 80% of the total reduction. During the disturbance, current levels rose to approximately 160% of the pre-fault magnitude. The facility required nearly two hours to return to normal consumption.

For crypto facility B, a less severe but still impactful voltage sag affected only the A-phase, which dipped slightly below 0.7 p.u. for over 20 milliseconds. Consequently, the reduction in active power for the A-phase accounted for 70% of the total reduction. Current increased to approximately 150% of pre-fault levels. Load was fully restored in approximately five minutes.

Table 1 below shows that these facilities experienced a partial loss of load rather than a complete loss despite both facilities experiencing low voltages below 0.7 p.u.

Table 1: A Crypto Load Reduction Event

Load Identifier	Pre-fault Consumption	Post-fault consumption	Consumption Loss	% Loss	Low Voltage at POI	Load Type
Crypto Facility A	112.3	60.6	51.7	46.0	0.535 pu	Crypto
Crypto Facility B	157.0	119.3	37.7	24.0	0.670 pu	Crypto

Neutral Overcurrent Protection

Installed equipment in a crypto-mining facility is largely single-phase. If single-phase equipment experiences a voltage depression, load will drop/decrease on that single phase and remain the same on the unaffected phases. This leads to unbalanced current flowing on the three phases, which results in increased neutral current in the facility. In multiple instances, neutral overcurrent protection (see **Figure 3**) has tripped the entire facility because of unbalanced phase current due to a temporary single-phase voltage depression during a normally cleared transmission system fault.

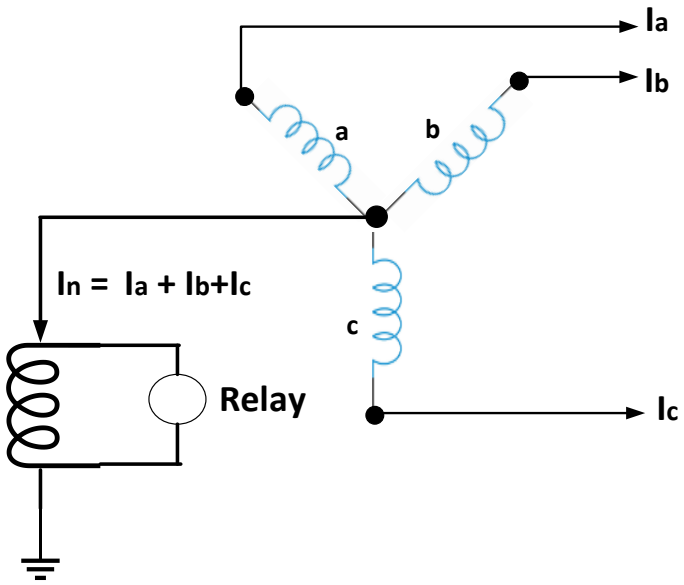


Figure 3: Neutral Overcurrent Protection

Ground overcurrent protection is effective in addressing the issue of neutral overcurrent protection (see **Figure 4**), as it can differentiate between a true ground fault and a temporary phase imbalance caused by one or two phases of equipment (most of which operate on a single phase), temporarily reducing their load in response to a voltage sag.

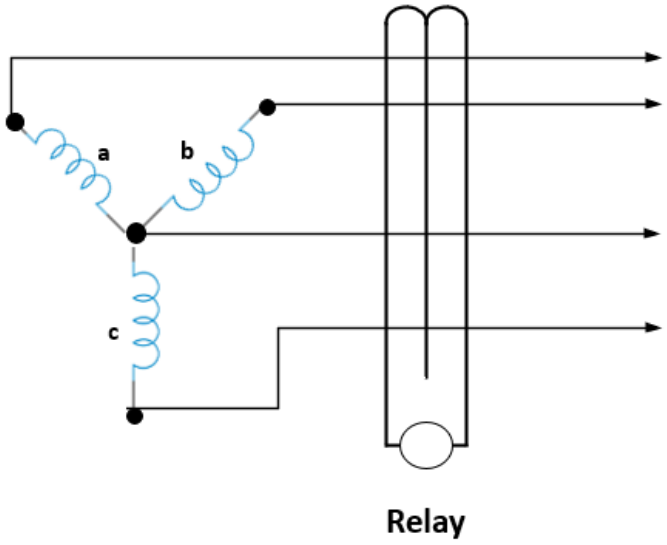


Figure 4: Ground Overcurrent Protection

Ground overcurrent protection typically employs a single zero-sequence current transformer (CT) that encircles all phase conductors as well as the neutral conductor. In a healthy system, even if there is some imbalance, all current flows within this boundary, resulting in a net magnetic field of zero. However, when a true ground fault occurs, some current takes an unintended path to ground (such as through equipment casing, conduit, or the earth), thus bypassing the neutral return path and the zero-sequence CT. This creates a measurable imbalance in the current passing through the CT, leading to a non-zero sum of currents.

The ground overcurrent protection is specifically designed to respond only to the current that returns through the ground. It is inherently insensitive to phase unbalanced currents that remain within the normal phase/neutral return path.

Voltage Transformer Winding Configuration

A delta-wye transformer winding somewhere in the voltage transformation between the utility connection and the facility loads "tempers" the voltage depression seen by the equipment. This can decrease the magnitude of voltage depressions for normally cleared single-phase transmission system faults seen by the load.

A delta-wye transformer (see **Figure 5**) connects a delta-configured primary winding to a wye-configured secondary winding, which creates a voltage transformation while also introducing a 30° phase shift.

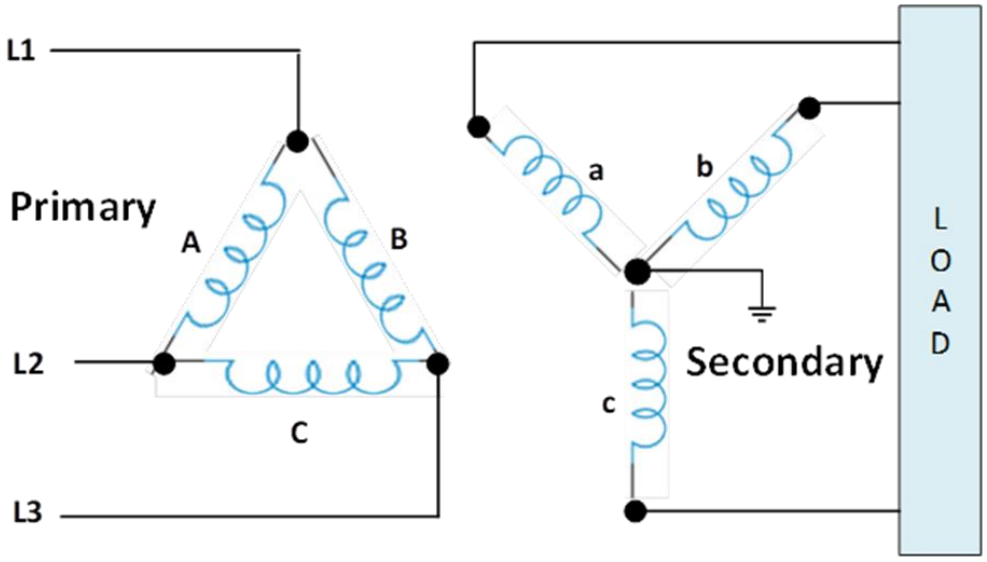


Figure 5: Delta-Wye Transformer Connects

When a single-phase fault occurs, the primary delta connection allows circulating currents to flow among the remaining healthy phases. These circulating currents help maintain magnetic balance within the transformer core and support the secondary voltage, even when one primary phase experiences a voltage drop.

As a result, all three secondary phase voltages remain present—though unbalanced—with one phase retaining nearly its full voltage and the other two experiencing moderate reductions. This ability to sustain

partial voltage across all secondary phases reduces the magnitude and duration of voltage depression seen by the load, improving voltage stability and power continuity during fault clearance.

A wye-wye transformer connects both the primary and secondary windings in a wye configuration. In a wye-wye transformer with ***grounded*** primary windings (see **Figure 6**), the loss of one primary phase removes a complete magnetic path for one core leg. Consequently, one secondary phase collapses entirely, while the other two might remain relatively unchanged in magnitude. However, in a wye-wye transformer with ***ungrounded*** primary windings, the loss of one primary phase leads to the complete collapse of one secondary phase and the other two secondary phases drop to approximately half of their nominal voltages. This situation results in significant and disruptive voltage depression.

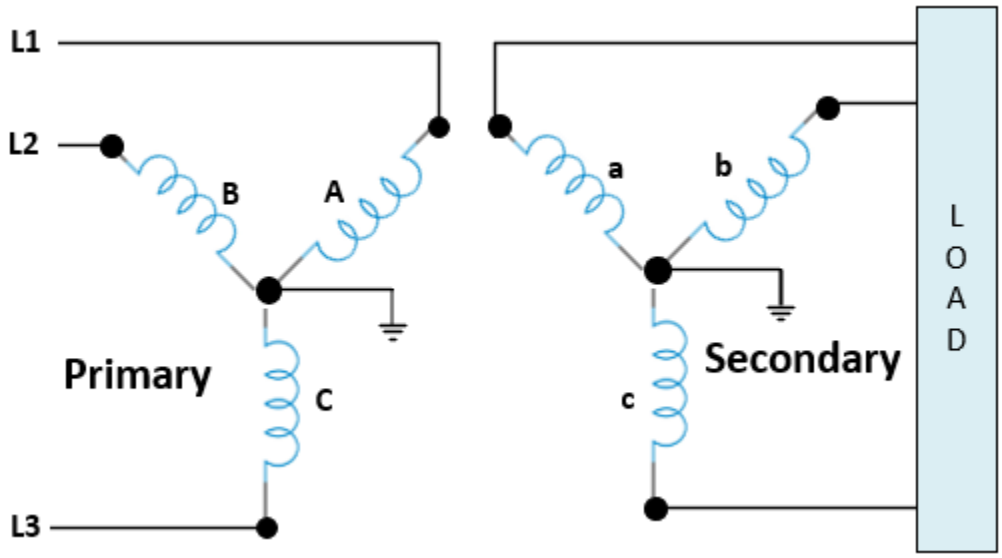


Figure 6: Wye-Wye Transformer with Grounded Primary Windings

As mentioned in the previous section, 0.7 p.u. is a critical point because the ITIC curve allows equipment to disconnect within 20 milliseconds at that voltage level. In the case of a single-phase transmission system fault that results in a 0.7 p.u. voltage on the faulted phase at the POI, using a delta winding results in a voltage of 0.85 p.u. on the two non-faulted phases on the secondary side of a delta-wye transformation. To achieve a 0.7 p.u. voltage on those two phases on the secondary side, a 0.35 p.u. faulted phase voltage at the POI would be necessary. However, the geographic area associated with a 0.35 p.u. voltage is significantly smaller than that of a 0.7 p.u. voltage. Therefore, incorporating a delta-wye configuration in voltage transformers damps the voltage sag induced by transient single-phase faults, providing enhanced voltage ride-through capability and improved system robustness against single-phase loss events.

Overcurrent Tripping

The power supplies that provide power to the computer-based equipment in a crypto-mining facility are constant power devices, which attempt to maintain constant power to the computer equipment during depressions of the supply voltage. To maintain constant power, if a voltage depression occurs, the current will ***increase*** proportionally to the voltage decrease. Event analysis has revealed that some facilities have tripped main power distribution breakers via overcurrent protection in response to this increase in current during a very short duration (50 milliseconds) voltage depression.

Figure 7 shows that current increases proportionally with a decrease in voltage during a voltage depression. The facility in question experienced a momentary single-phase voltage drop originating from the external transmission system, with the A-phase voltage falling to approximately 0.08 p.u.

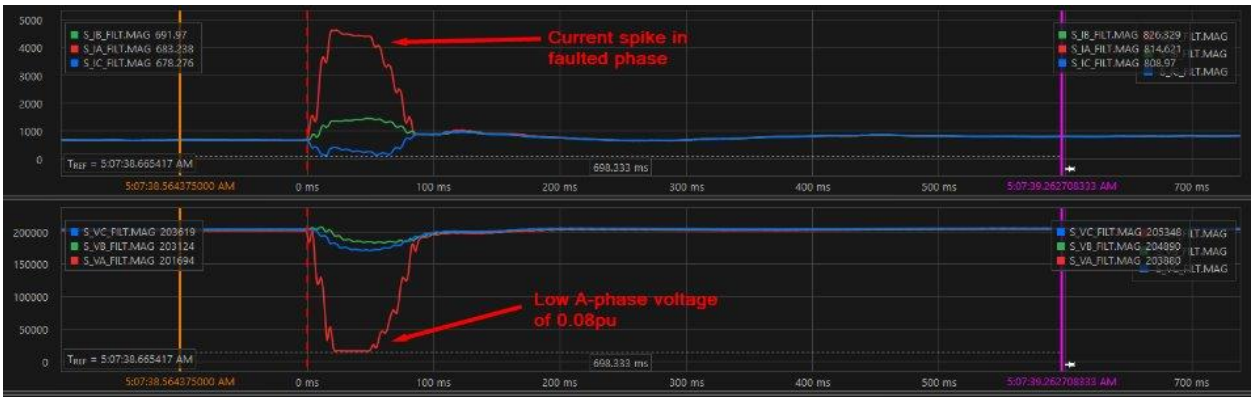


Figure 7: Voltage and Current

During this same period, the A-phase current spiked sharply, while the currents in the B and C phases remained relatively stable. This pattern is indicative of a typical single-line-to-ground fault on the utility side. The fault was quickly cleared by upstream protection, and the voltage on all phases returned to normal levels shortly thereafter.

The current spike observed in the faulted A phase was influenced by the behavior of the constant-power supplies used throughout the facility. These supplies, which support the computer-based crypto-processing equipment, automatically increase their current draw to maintain a constant power output during a voltage sag. As a result, the voltage drops on the A phase caused a proportional increase in current on that phase, leading to unbalanced three-phase loading.

Cooling System Load

The ride-through characteristics of cooling equipment in cryptocurrency facilities significantly impact the overall ride-through performance of these facilities. Much of the cooling load employs variable frequency drive (VFD)/variable speed drive (VSD) equipment, which includes low-voltage protection to safeguard its internal components. Analysis of events has demonstrated that a loss of cooling load can lead to the complete shutdown of cryptocurrency facilities during normally cleared transmission system faults. In one instance, the undervoltage trip thresholds of the VFD/VSD equipment were set as high as 0.96 p.u. As a result, even a brief voltage drop lasting just 50 milliseconds, caused by a typically cleared transmission system fault, led to the loss of the cooling equipment load. Once cooling is lost, the cryptocurrency facility can rapidly overheat, ultimately forcing a complete shutdown.

Given the critical role of ride-through requirements, ERCOT is planning to introduce such requirements related to cooling system load, as cooling system load response must be explicitly addressed to ensure facility-wide resilience. The following recommendations should be considered:

- Review and verify manufacturer default undervoltage settings on VFDs/VSDs to ensure that they are not overly sensitive

- Adjust protection thresholds or implement UPS on control circuits and drives to maintain operation during brief voltage sags
- Ensure that ride-through coordination between IT and mechanical systems is part of the facility's reliability design

Crypto-Mining Facility Recovery

Based on observed disturbance events, restoration times across crypto facilities vary significantly. Some facilities recover quickly through automated restart sequences, while others experience slower recovery due to manual processes, equipment resets, or complex coordination steps.

In general, crypto-mining facilities recover through a restart sequence following the return of normal power. Depending on facility configuration, mining equipment may begin restarting automatically when power is restored or may require manual initiation. As systems come back on-line, they initially operate at a reduced level before mining operations resume and power draw gradually ramps back to normal operating levels.

Observed events indicate that restoration can be delayed if cooling systems fail to restart, power systems within the data center (such as breakers or distribution units) require manual intervention, or environmental conditions slow down equipment stabilization.

Regardless of whether restoration is immediate or delayed, observed events show that the increase in power draw follows a gradual ramp-up from minimal load to full capacity. In no recorded instance has a crypto facility's power draw surged instantaneously—such as within a few cycles or seconds—because recovery occurs through a restarting process, not from instantaneous transfer via UPS as seen in traditional data centers.

Future Considerations

The following future considerations highlight key areas where additional analysis, equipment adjustments, and operational improvements may be needed to enhance the ride-through performance and reliability of crypto-mining facilities. These points stem from observed system behaviors that collectively influence how LELs interact with the BPS. As these facilities evolve and potentially transition to new computational applications, understanding and addressing these technical gaps will be essential for maintaining grid stability and ensuring that new and existing installations meet reliability expectations.

- **Neutral overcurrent protection schemes should be reviewed.** Single-phase voltage depressions create significant current imbalance, causing neutral overcurrent relays to trip entire facilities. Transitioning to ground overcurrent protection may help distinguish true ground faults from temporary phase imbalance events.
- **Transformer winding configurations influence voltage sag severity.** Delta-wye transformer stages help "temper" single-phase voltage depressions, reducing load-loss risk. The effectiveness of transformer configuration should be considered in future facility designs and interconnection reviews.
- **Constant-power device behavior must be incorporated into event modeling.** Crypto-mining power supplies increase current during voltage depressions, contributing to overcurrent trips. Future

system models and protection studies need to reflect this constant-power response during grid faults. Crypto facility owners should account for this increase in current during system fault-induced voltage depressions to avoid overcurrent tripping of facility devices during normally cleared system faults.

- **Cooling-load ride-through coordination must be strengthened.** VFD/VSD-driven cooling equipment has shown overly sensitive undervoltage trip settings (e.g., 0.96 p.u.), causing entire facilities to drop for faults that clear normally within milliseconds. Facilities should reassess protection settings and consider UPS support for cooling controls.
- **Restoration-time variability should be studied and tracked.** Crypto-mining facilities recover through staged boot processes rather than instantaneous UPS-backed restoration.
- **Interconnection requirements may need updates for evolving load types.** As some crypto facilities transition toward AI or cloud workloads, load behavior, ride-through characteristics, and use of UPS systems may change.
- **Enhancements are unlikely to address multi-phase fault conditions**. Some crypto-mining facilities in ERCOT have significantly improved their ability to withstand single-phase transmission faults, primarily due to equipment upgrades and operational adjustments. However, these enhancements are unlikely to address multi-phase fault conditions, which can lead to deeper and more prolonged voltage depressions that most installed systems cannot handle. New requirements for submitting facility data and models before interconnection have slowed the rate of new crypto connections but also highlight the need for greater transparency in the process.
  - Proposals[2] have been introduced to include voltage and frequency ride-through requirements for LELs into ERCOT's regional operating guides and protocols. These rule changes are undergoing the ERCOT stakeholder process.
  - ERCOT has also conducted studies to identify the worst-case LEL loss in geographic areas with large concentrations of these loads based on existing voltage and frequency ride-through limitations.

For more information, please contact:
NERC – Event Analysis

Date of Publication: January 9, 2026

[2] https://www.ercot.com/mktrules/issues/NOGRR282#keydocs

Attachment 1-E

Technical Reasoning

Technical Reasoning Update

Proposed Computational Load Owner and Computational Load Operator
August 19, 2026

Background

NERC has been actively assessing the impact of large loads on the reliability of the Bulk Power System (BPS) since March of 2024 by engaging relevant stakeholders to understand risks and appropriate mitigations. In March 2024, the Reliability and Security Technical Committee (RSTC) hosted a panel to discuss the impact of large loads originating from data centers and cryptocurrency mining centers. By Summer of 2024, the RSTC had launched what is today the Large Load Working Group (LLWG). The LLWG has been instrumental in helping to gauge the scope of risk, gaps, and next steps in NERC's response. Additional work by NERC and the Regional Entities, including, the January 2025 incident review on a large load loss event in the Eastern Interconnection, and the January 2026 incident review of voltage-sensitive crypto load reductions in Texas Interconnection, also continues.

Through these events, NERC identified the unique electrical behaviors, composition, and aggregate impacts that increase risk when large amounts of computational load are connected to the BPS. To ensure these loads that pose an increased risk when connected to the BPS have specific requirements, NERC determined it should modify its Registry Criteria to require computational loads (i.e., "users") to register with NERC. The NERC Registry Criteria prescribe the threshold(s) for which users, owners, and operators of the BPS must register with NERC. At a minimum, an entity registered by NERC will be subject to at least one NERC Reliability Standard requirement (to be determined through the NERC Standards development process). For a thorough technical discussion of the impacts and risks of large loads, please refer to the source material provided on the Large Loads Action Plan web page.

On April 1, 2026, NERC proposed revisions to its Rules of Procedure (ROP) to require registration of Computational Load Entities that contribute to an aggregate capability of 20 megawatt (MW) connected at a BPS voltage greater than or equal to 60 kilovolts (kV), with 1 MW or greater of Computational Load. NERC posted these proposed ROP revisions for a public comment period that ended on May 15, 2026. Based on the comments received, NERC has revised its proposed ROP revisions, as described in the next section.

In addition, on July 16, 2026, FERC issued an Order directing NERC to file Reliability Standards pertaining to computational load integration. The Order also directed NERC to develop revisions to its ROP necessary for the registration of computational load entities and to submit the proposed revisions by December 31, 2026.

Changes to ROP Revisions

NERC received 32 sets of comments from 44 commenters regarding the April 1 posting of proposed ROP revisions. The major themes of stakeholder comments include:

- General support in addressing the risk while more explicit justification is needed
- Change Computational Load Entity to Computational Load Owner and Computational Load Operator functions
- Proposed 20 MW and/or 60 kV is too low or includes unintended entities
- Remove 1 MW "de minimis" criteria
- Suggested definition of "Computational Load Facility" for greater clarity
- Need clarification on the point of interconnection

During and following the April 1 ROP posting, NERC registration staff have been collaborating with the Project 2026-02 Standard Drafting Team (SDT) to ensure alignment with common terms and definitions, as well as understanding of proposed ROP Registry Criteria revisions. Based on the stakeholder comments and coordination with the SDT, as well as addition analysis performed by NERC registration, the proposed ROP revisions have been changed as follows:

- Replace the single Computational Load Entity function with two functions, Computational Load Owner (CLO) and Computational Load Operator (CLOP), to better represent the structure of the industry:[1]

  Computational Load Owner means the entity that owns and maintains a Computational Load Site.

  Computational Load Operator means the entity that operates a Computational Load Site.

- Increase the registry criteria threshold to 50 MW and 100 kV and update the point of interconnection language to better align with BPS reliability risk:

  Computational Load Owner of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection.

  Computational Load Operator of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection.

- Remove the 1 MW "de minimis" Computational Load criteria, and
- Replace the Computational Load definition with a Computations Load Site definition to clarify what loads are subject to the proposed criteria:

  Computational Load Site means one or more buildings, structures, or installations at a single location that

  1. Primarily contains information technology infrastructure used for:
     - creating, executing, and delivering software applications and services;
     - artificial intelligence training, deployment, and delivery;
     - cryptocurrency mining; or
     - other computational activities at a data center; and
  2. Is supplied through electrical equipment that is connected to the BPS.

NERC registration staff in collaboration with the SDT developed a Frequently Asked Questions (FAQ) document that addresses certain questions related to the application of this proposed registry criteria. For example, the FAQ includes Computational Load Site configuration scenarios that are evaluated against the proposed criteria, provides guidance to identify the connection point(s) to the BPS, and contains factors that define a Computational Load Site boundary, as well as several other issues.

[1] This framework is also consistent with other existing NERC Registry functions, such as Generator Owners and Operators and Transmission Owners and Operators.

Thresholds

NERC's proposed criteria for CLO and CLOP are based on their aggregate impact to the BPS.[2] It is important to note that aggregate impact, in this case, is a different arrangement than the aggregate Computational Load Site capability of an individual registration candidate as outlined in the proposed ROP Registry Criteria. Specifically, aggregate impact refers to the impact of several Computational Load Sites connecting to the BPS in a similar manner where their aggregate characteristics impact BPS reliability collectively.

NERC's initial analysis and threshold recommendation of 20 MW and 60 kV was based on data provided from responses to the Level 2 Alert. Data NERC received regarding the interconnection of large loads and other efforts of the NERC LLWG are summarized in the public Level 2 Alert report posted on March 17, 2026.[3] Existing registered functional entities (e.g., Transmission Owners, Distribution Providers, etc.) were requested to provide the total capacity of large loads on their system that are currently operational and expected to be in-service by the end of 2027, including the voltage level at the interconnecting point. The report concluded that large load is expected to change its composition dramatically, moving from a split between industrial and computational load to almost entirely computational. The Alert worksheet information further indicated that load may increase by 300 GW between 2028 and 2030, with the bulk of this increase represented by data centers. A large share of the expected load growth will come from the "Traditional Data Center," "AI Data Center," and "Cryptocurrency Mining" categories (or a combination of the three). In general, the Alert data provided valuable insight into BPS-connected large load risks; however, NERC was concerned that further analysis was warranted given the large share of this expected load growth.

As a result, NERC has performed additional research on Computational Load Site development which has resulted in updating the proposed NERC Registry Criteria threshold to 50 MW and 100 kV. The analysis was conducted using comprehensive data collected by a third-party who tracks existing and future data center activity.[4] The data is consistently updated with NERC's additional analysis based on June 2026 data. Data includes individual building, campus, their locations, electric utility information, and load estimates. NERC used its internal analysis tools to complement the Alert worksheet data voltage and interconnection information that was used to propose the initial NERC Registry Criteria threshold. The additional analysis led to a more refined understanding of the aggregate risks associated with data center clusters connected throughout the BPS.

NERC's additional analysis revealed there is 41,827 MW of active data center load (at all voltages) as of June 2026 and an additional 37,675 MW under construction and expected to be in-service by the end of 2027, for an overall total of approximately 79,502 MW by year end 2027. NERC estimates that the proposed 50 MW and 100 kV threshold should lead to the registration of approximately 68,288 MW of Computational Load Site owners and operators. This amount equals approximately 86% of the overall total (all sizes and voltages) and captures the vast majority of computational load entities that pose aggregate risks to the BPS. The threshold encompasses those Computational Load Sites that are of the size and connected voltage that can create unforeseen and difficult-to-explain dynamic behaviors when connected to the BPS. NERC determined the 100 kV voltage criteria is an appropriate threshold based on its interconnection voltage analysis. At the 50 MW threshold, there was a small difference of only 2% of the overall total load comparing 100 kV to the previously proposed 60 kV threshold. The 2% of load represents those Computational Load Sites which are generally smaller than 50 MW, dispersed across the BPS, and represent a smaller fraction of the collective load where they are

[2] North American Electric Reliability Corporation, 150 FERC ¶ 61,213 at P 58 (2015) (stating, "Registry Criteria provide that a class of entities, each of which would be individually excluded, may nevertheless be registered based on their aggregate impact on Bulk-Power System reliability.")

[3] See NERC Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations, at https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/aggregated-report-level-2-large-load-interconnection-study-commissioning-and-operations.pdf. For additional information, please see the NERC Large Loads Action Plan web page at https://www.nerc.com/initiatives/large-loads-action-plan.

[4] NERC has a license with Aterio to access its "US Data Center Locations and Power Demand" data set which "provides a comprehensive inventory of data centers across the United States, including those currently operational, under development, and planned for future construction."

located, thus representing less aggregate risk. In addition, the proposed 50 MW and 100 kV threshold ensures BPS-connected entities are subject to registration while excluding entities that have not been seen to negatively impact BPS reliability and removes confusion about whether a Computational Load Site is served by what may be considered local distribution. Further, NERC estimated that increasing the threshold to 75 MW would lower the amount of Computational Load Site owners and operators subject to registration to approximately 63,960 MW, or 80% of the total, which NERC asserts would not be sufficient to address the aggregate risk to the BPS. NERC will continue to monitor computational total connected Load and connection voltage with respect to the aggregate risks and reserves the right to propose additional ROP Registry Criteria changes in the future to address any risks to the BPS.

Attachment 2

Clean Proposed Revisions

Attachment 2-A

Appendix 2 Clean



NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DEFINITIONS USED IN THE RULES OF PROCEDURE

APPENDIX 2 TO THE RULES OF PROCEDURE

Effective: TBD

General

For purposes of the NERC Rules of Procedure, including all Appendices, the terms defined in this Appendix shall have the meanings set forth herein. For convenience of reference to the user, definitions of terms that are used in a particular Appendix may be repeated in that Appendix.

Where used in the Rules of Procedure, a defined term will be capitalized. Where a term defined in this Appendix appears in the Rules of Procedure but is not capitalized, the term is there being used in its ordinary and commonly understood meaning and not as defined in this Appendix (if different). Other terms that are not defined terms, such as the names of entities, organizations, committees, or programs; position titles; titles of documents or forms; section headings; geographic locations; and other terms commonly presented as proper nouns, may also be capitalized in the Rules of Procedure without being defined in this Appendix.

Definitions of terms in this Appendix that are marked with asterisks (**) are taken from the NERC *Glossary of Terms Used in Reliability Standards*. Definitions of terms in this Appendix that are marked with "pluses" (++) are taken from Section 215 of the Federal Power Act or the Commission's regulations at 18 C.F.R. Part 39 or Part 388.

Other terms used in the Rules of Procedure but not defined in this Appendix that have commonly understood and used technical meanings in the electric power industry, including applicable codes and standards, shall be construed in accordance with such commonly understood and used technical meanings.

Specific Definitions

"Acceptance of the Exception Request" or "Acceptance" means the determination that an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) contains all the Required Information so that it can undergo substantive review.

"Adjacent Balancing Authority" means a Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**

"Adjusted Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as determined based on application of the adjustment factors identified in Section 4.3 of the *Sanction Guidelines* to the Base Penalty Amount.

"Advisories" or "Level 1 (Advisories)" is a notification issued by NERC in accordance with Section 810.3.1 of the Rules of Procedure.

"Alleged Violation" means a potential noncompliance for which the Compliance Enforcement Authority has determined, based on an assessment of the facts and circumstances surrounding the potential noncompliance, that evidence exists to indicate a Registered Entity has violated a Reliability Standard and such violation will be resolved outside of the Compliance Exception or FFT processes.

"Annual Report" means the annual report to be filed by NERC with FERC and other Applicable Governmental Authorities in accordance with Section 13.0 of Appendix 4D.

"Applicable Governmental Authority" means the FERC within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability in Canada and Mexico.

"Applicable Requirement" means a Requirement or a Requirement Part of a CIP Standard that (i) expressly provides that compliance with the terms of the Requirement or Requirement Part is required where technically feasible or (ii) is subject to Appendix 4D by FERC directive.

"Approval of the Exception Request" or "Approval" means the determination by NERC that an Exception Request meets the criteria to receive the requested Exception.

"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**

"Balancing Authority Area" means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.**

"Base Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as initially determined pursuant to Sections 4.1 and 4.2 of the NERC *Sanction Guidelines*, before application of any adjustment factors.

"BES Cyber Asset" means a Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.**

"BES Cyber System" means one or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.**

"BES Definition" means the NERC definition of the Bulk Electric System as set forth in the NERC *Glossary of Terms Used in Reliability Standards.*

"Blackstart Resource" means a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the

Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.**

"Board" or "Board of Trustees" means the Board of Trustees of NERC.

"Board of Trustees Compliance Committee," "BOTCC" or "Compliance Committee" means the Compliance Committee of the NERC Board of Trustees, or its successor.

"Bulk Electric System" or "BES" means unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.

- **I2** - Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
    a) Gross individual nameplate rating greater than 20 MVA. Or,
    b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.

- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
    a) The individual resources, and
    b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

- **I5** - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

    a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

  b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

  c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4** - Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.**

"Bulk Power System" means, depending on the context:
(i) (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and
(B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.)
(ii) Solely for purposes of Appendix 4E, Bulk Electric System.

"Canadian" means one of the following: (a) a company or association incorporated or organized under the laws of Canada, or its designated representative(s) irrespective of nationality; (b) an agency of a federal, provincial, or local government in Canada, or its designated representative(s) irrespective of nationality; or (c) a self-representing individual who is a Canadian citizen residing in Canada.

"Canadian Entity" means a Registered Entity (or, solely for purposes of Appendix 4D, a Responsible Entity) that is organized under Canadian federal or provincial law.

"Cascading" means the uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.**

"CCC" means the NERC Compliance and Certification Committee.

"Certification" means, depending on the context, (i) the process undertaken by NERC and a Regional Entity to verify that an entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator and/or Reliability Coordinator; such Certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure; or (ii) for purposes of Section 600 of the Rules of Procedure, an official recognition that indicates the recipient has passed a NERC exam or completed a specified number of Continuing Education Hours.

"Certification Staff" means individuals employed or contracted by NERC who have the authority to make initial determinations of Certification of entities performing reliability functions.

"Certification Team" means a team assembled by a Regional Entity that will be responsible for performing the activities included in the Certification process for an entity pursuant to Appendix 5A.

"CIP Senior Manager" means a single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC CIP Standards.**

"Classified National Security Information" means Required Information that has been determined to be protected from unauthorized disclosure pursuant to Executive Order No. 12958, as amended,

and/or the regulations of the NRC at 10 C.F.R. §95.35; or pursuant to any comparable provision of Canadian federal or provincial law.

"Clerk" means an individual assigned by the Compliance Enforcement Authority or NERC to perform administrative tasks relating to the conduct of hearings as described in Attachment 2, Hearing Procedures, to Appendix 4C.

"Commission" means the Federal Energy Regulatory Commission or FERC.

"Complaint" means an allegation that a Registered Entity violated a Reliability Standard.

"Compliance and Certification Manager" means individual/individuals within the Regional Entity that is/are responsible for monitoring compliance of entities with applicable NERC Reliability Standards.

"Compliance Audit" means a systematic, objective review and examination of records and activities to determine whether a Registered Entity meets the Requirements of applicable Reliability Standards.

"Compliance Audit Participants" means Registered Entities scheduled to be audited and the audit team members.

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

"Compliance Enforcement Authority's Area of Responsibility" means the Compliance Enforcement Authority's Region. If a Regional Entity is the Compliance Enforcement Authority, the Compliance Enforcement Authority's Area of Responsibility is shown in Exhibit A to the delegation agreement between the Regional Entity and NERC.

"Compliance Exception" means a noncompliance that is addressed in Appendix 4C and is not pursued through an enforcement action under Section 5.0 of Appendix 4C to these Rules of Procedure by a Compliance Enforcement Authority.

"Compliance Investigation" means a comprehensive investigation, which may include an on-site visit with interviews of the appropriate personnel, to determine if a violation of a Reliability Standard has occurred.

"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC *Compliance Monitoring and Enforcement Program* (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

"Compliant Date" means the date by which a Responsible Entity is required to be in compliance with an Applicable Requirement of a CIP Standard.

"Computational Load Operator" means the entity that operates a Computational Load Site.

"Computational Load Owner" means the entity that owns and maintains a Computational Load Site.

"Computational Load Site" means one or more buildings, structures, or installations at a single location that

1) Primarily contains information technology infrastructure used for:
   - creating, executing, and delivering software applications and services;
   - artificial intelligence training, deployment, and delivery;
   - cryptocurrency mining; or
   - other computational activities at a data center; and
2) is supplied through electrical equipment that is connected to the BPS.

"Confidential Business and Market Information" means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

"Confidential Information" means (i) Confidential Business and Market Information; (ii) Critical Electric Infrastructure Information; (iii) Critical Energy Infrastructure Information; (iv) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (v) work papers, including any records produced for or created in the course of an evaluation or audit; (vi) investigative files, including any records produced for or created in the course of an investigation; or (vii) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition; or (vii) for purposes of Appendix 4D, any other information that is designated as Confidential Information in Section 11.0 of Appendix 4D.

"Confirmed Violation" means an Alleged Violation for which (1) the Registered Entity has accepted or not contested the Notice of Alleged Violation and Penalty or Sanction or other notification of the Alleged Violation, or (2) there has been the issuance of a final order from NERC or a Hearing Body finding a violation, Penalty or sanction, or (3) the period for requesting a hearing or an appeal has expired, or (4) the Registered Entity has executed a settlement agreement pursuant to Section 5.6.

"Consolidated Hearing Process" means the process pursuant to Section 403.15B used to conduct hearings and issue decisions concerning disputed compliance matters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

"Continuing Education Hour" or "CE Hour" means based on sixty clock minutes, and includes at least fifty minutes of participation in a group or self-study learning activity that meets the criteria of the NERC Continuing Education Program.

"Continuing Education Program Provider" or "Provider" means the individual or organization offering a learning activity to participants and maintaining documentation required by Section 600 of the Rules of Procedure.

"Coordinated Functional Registration" means where two or more entities (parties) agree in writing upon a division of compliance responsibility among the parties for one or more Reliability Standard(s) applicable to a particular function, and/or for one or more Requirement(s)/sub-Requirement(s) within particular Reliability Standard(s).

"Covered Asset" means any BES Cyber Asset, BES Cyber System, Protected Cyber Asset, Electronic Access Control or Monitoring System, or Physical Access Control System that is subject to an Applicable Requirement.

"Credential" means a NERC designation that indicates the level of qualification achieved (i.e., reliability operator; balancing, interchange, and transmission operator; balancing and interchange operator; and transmission operator).

"Critical Electric Infrastructure" means a system or asset of the bulk power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters.

"Critical Electric Infrastructure Information" means information related to proposed or existing Critical Electric Infrastructure. Such term includes information that qualifies as Critical Energy Infrastructure Information as defined herein.

"Critical Energy Infrastructure Information" means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.++

"Critical Infrastructure" means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.++

"Critical Infrastructure Protection Standard" or "CIP Standard" means any of NERC Reliability Standards included in the Critical Infrastructure Protection group of Reliability Standards that is adopted by the NERC Board of Trustees according to the NERC *Bylaws* and *Rules of Procedure* and approved by Applicable Governmental Authorities.

"Cross-Border Regional Entity" means a Regional Entity that encompasses a part of the United States and a part of Canada or Mexico.++

"Cyber Assets" means programmable electronic devices, including hardware, software, and data in those devices.**

"Cyber Security Incident" means any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.++

"Cyber Security Incident Information" means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

"Days", as used in Appendix 5A with respect to the Registration and Certification processes, means calendar days.

"Deactivation," as used in Appendix 5A with respect to the Registration processes, refers to removal of an entity from the NCR for a specific functional category. As a result of deactivation, the entity is no longer subject to any prospective compliance obligations with respect to Reliability Standards applicable to that functional category.

"Delegate" means a person to whom the CIP Senior Manager of a Responsible Entity has delegated authority pursuant to Requirement R4 of CIP Standard CIP-003 (or any successor provision).

"Director of Compliance" means the Director of Compliance of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority who is responsible for the management and supervision of Compliance Staff, or his or her designee.

"Director of Enforcement" means the Director of Enforcement of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority who is responsible for the management and supervision of Enforcement Staff, or his or her designee.

"Disapproval of the Exception Request" or "Disapproval" means the determination by NERC that an Exception Request does not meet the criteria to receive the requested Exception.

"Distribution Factor" means the portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).**

"Distribution Provider" means the entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**

"Document" means, in addition to the commonly understood meaning of the term as information written or printed on paper, any electronically stored information, including writings, drawings, graphs, charts, photographs, sound recordings, images and other data or data compilations stored

in any medium from which information can be obtained, and shall be translated by the producing party into reasonably usable form.

"Electric Reliability Organization" or "ERO" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the Bulk Power System in the United States, subject to Commission review. The organization may also have received recognition by Applicable Governmental Authorities in Canada and Mexico to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries.

"Electronic Access Control or Monitoring Systems" means Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.**

"Electronic Access Point" means a Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.**

"Electronic Security Perimeter" means the logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.**

"Element" means any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.**

"Eligible Reviewer" means a person who has the required security clearances or other qualifications, or who otherwise meets the applicable criteria, to have access to Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information, as applicable to the particular information to be reviewed.

"End Date" means the last date of the period to be covered in a Compliance Audit.

"Essential Actions" or "Level 3 (Essential Actions)" is a notification issued by NERC in accordance with Section 810.3.3 of the Rules of Procedure.

"Evidentiary Hearing" means a hearing at which one or more Participants submits evidence for the record. A Testimonial Hearing is an Evidentiary Hearing, but an Evidentiary Hearing does not necessarily include the presentation of testimony by witnesses in person.

"Exception" means either an Inclusion Exception or an Exclusion Exception.

"Exception Procedure" means the procedure set forth in Appendix 5C.

"Exception Request" means a request made by a Submitting Entity in accordance with Appendix 5C for an Exception.

"Exception Request Form" means the form adopted by each Regional Entity, in accordance with a template provided by NERC, for use by Submitting Entities in submitting Exception Requests; provided, that the Exception Request Form must include Section III.B as adopted by NERC.

"Exclusion Exception" means a determination that an Element that falls within the BES Definition should be excluded from the BES.

"Facility" means a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)**

"FERC" means the United States Federal Energy Regulatory Commission.

"Final Penalty Amount" means the final, proposed Penalty for violation of a Reliability Standard, determined in accordance with the *Sanction Guidelines*.

"Find, Fix, Track and Report" or "FFT" means a streamlined process, addressed in Appendix 4C, to resolve minimal or moderate risk, remediated noncompliance that are not assessed a financial penalty.

"Flowgate" means 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.**

"FOIA" means the U.S. Freedom of Information Act, 5 U.S.C. §552.

"Footprint" means the geographical or electric area served by an entity.

"Frequency Response Sharing Group" means a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.**

"Functional Entity" means an entity responsible for a function that is required to ensure the Reliable Operation of the electric grid as identified in the NERC Reliability Standards.

"Generator Operator" means the entity that: 1) operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services (Category 1 GOP); or 2) operates non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV (Category 2 GOP).

"Generator Owner" means an entity that: 1) owns and maintains generating Facility(ies) (Category 1 GO); or 2) owns and maintains non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected

through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV(Category 2 GO).

"Hearing Body" means the body designated by the Compliance Enforcement Authority to conduct hearings and issue decisions concerning disputed compliance matters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

"Hearing Officer" means, depending on the context, (i) an individual employed or contracted by the Compliance Enforcement Authority or NERC to preside over hearings conducted pursuant to Attachment 2, Hearing Procedures, of Appendix 4C; the Hearing Officer shall not be a member of the Hearing Body, or (ii) solely for hearings conducted pursuant to Appendix 4E, (A) a CCC member or (B) an individual employed or contracted by NERC, as designated and approved by the CCC to preside over hearings conducted pursuant to the Hearing Procedures in Appendix E; the Hearing Officer shall not be a member of the Hearing Panel.

"Hearing Panel" means the five person hearing body established as set forth in the CCC Charter on a case by case basis and that is responsible for adjudicating a matter as set forth in Appendix 4E.

"Hearing Procedures" means, depending on the context, (i) Attachment 2 to the NERC or a Regional Entity CMEP, as applicable, or (ii) the hearing procedures of the NERC Compliance and Certification Committee in Appendix 4E.

"Inclusion Exception" means a determination that an Element that falls outside the BES Definition should be included in the BES.

"Inherent Risk Assessment" or "IRA" means a review by the Compliance Enforcement Authority of potential risks posed by an individual Registered Entity to the reliability of the Bulk Power System. An IRA considers factors such as, but is not limited to, assets, system, geography, interconnectivity, prior compliance history and factors unique to the Registered Entity. The results of an entity-specific IRA may result in the scope of compliance monitoring for a particular Registered Entity to include more, fewer, or different Reliability Standards than those contained in the annual ERO CMEP Implementation Plan.

"Interactive Remote Access" means user-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point. Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.**

"Interchange" means energy transfers that cross Balancing Authority boundaries.**

"Interchange Authority" means the responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.**

"Interchange Distribution Calculator" means the mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.**

"Interchange Schedule" means an agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.**

"Interchange Transaction" means an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.**

"Interconnected Operations Service" means a service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.**

"Interconnection" means a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++ When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.**

"Interconnection Reliability Operating Limit" means a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.**

"Intermediate System" means a Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.**

"Internal Control Evaluation" or "ICE" means a review by the Compliance Enforcement Authority of a Registered Entity's internal controls. The ICE may further refine the compliance oversight plan, including the scope of an audit, the type and application of compliance monitoring tools, the depth and breadth of a particular area of review.

"Interpretation" means an addendum to a Reliability Standard, developed in accordance with the NERC *Standard Processes Manual* and approved by the Applicable Governmental Authority(ies), that provides additional clarity about one or more Requirements in the Reliability Standard.

"ISO/RTO" means an independent transmission system operator or regional transmission organization approved by the FERC or the Public Utility Commission of Texas.

"Joint Registration Organization" means two or more entities (the parties) agree in writing upon a division of compliance responsibility where an entity registers in the Compliance Registry for one or more function type(s) for itself and on behalf of one or more other parties to such agreement for function type(s) for which such parties would otherwise be required to register.

"Lead Entity" means (1) within the meaning of Appendices 5A and 5B, the entity identified in a Joint Registration Organization or Coordinated Functional Registration agreement as the primary Point of Contact that administers that agreement with NERC and the applicable Regional Entity(ies), and (2) within the meaning of Appendix 5C, the entity that submits the Exception Request information that is common to a group of Submitting Entities that are submitting Exception Requests jointly.

"Lead Mediator" means a member of a mediation team formed pursuant to Appendix 4E who is selected by the members to coordinate the mediation process and serve as the mediation team's primary contact with the Parties.

"Load" means an end-use device or customer that receives power from the electric system.**

"Load-Serving Entity" means an entity that secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.**

"Mapping" means the process of determining whether a Regional Entity's Footprint is being served by Registered Entities.

"Material Change" means a change in facts that modifies Required Information in connection with an approved TFE. Examples of a Material Change could include, but are not limited to an increase in device count (but not a decrease), change in compensating measures, change in statement of basis for approval for the TFE, a change in the TFE Expiration Date, or a Responsible Entity achieving Strict Compliance with the Applicable Requirement.

"Material Change Report" means a report submitted by the Responsible Entity to the Regional Entity in the event there is a Material Change to the facts underlying an approved TFE pursuant to Section 4.0 of Appendix 4D.

"Mediation Settlement Agreement" means a written agreement entered into by the Parties to a mediation pursuant to Appendix 4E that resolves the dispute.

"Member" means a member of NERC pursuant to Article II of its Bylaws.

"Member Representatives Committee" or "MRC" means the body established pursuant to Article VIII of the NERC Bylaws.

"Mexican Entity" means a Registered Entity that is organized under Mexican law.

"Mitigating Activities" means actions taken by a Registered Entity to correct and prevent recurrence of a noncompliance, whether or not the actions are embodied in a Mitigation Plan.

"Mitigation Plan" means an action plan developed by the Registered Entity to (1) correct a noncompliance with a Reliability Standard and (2) prevent re-occurrence of the violation.

"NERC-Approved Learning Activity" means training that maintains or improves professional competence and has been approved by NERC for use in its Continuing Education Program.

"NERC Compliance Monitoring and Enforcement Program Implementation Plan," "NERC Implementation Plan" or "ERO Compliance Monitoring and Enforcement Program (CMEP) Implementation Plan" means the annual ERO CMEP Implementation Plan that identifies the risk elements to prioritize risks to the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements become inputs for Regional Entities in their compliance oversight for individual Registered Entities. The ERO CMEP Implementation Plan may be updated more often than annually as needed.

"NERC Compliance Registry," "Compliance Registry" or "NCR" means a list, maintained by NERC pursuant to Section 500 of the NERC Rules of Procedure and Appendix 5B, the NERC *Statement of Compliance Registry Criteria*, of the owners, operators and users of the Bulk Power System, and the entities registered as their designees, that perform one or more functions in support of reliability of the Bulk Power System and are required to comply with one or more Requirements of Reliability Standards.

"NERC Identification Number" or "NERC ID" means a number given to NERC Registered Entities that will be used to identify the entity for certain NERC activities. Corporate entities may have multiple NERC IDs to show different corporate involvement in NERC activities.

"NERC Organization Certification" or "Organization Certification" means the process undertaken by NERC and a Regional Entity to verify that a new entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator, and/or Reliability Coordinator; such certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure.

"Net Energy for Load" or "NEL" means net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.

"Notice of Alleged Violation and Proposed Penalty or Sanction" means a notice issued by the Compliance Enforcement Authority to a Registered Entity pursuant to Section 5.3 of Appendix 4C.

"Notice of Completion of Enforcement Action" means a notice issued by the Compliance Enforcement Authority to a Registered Entity, pursuant to Section 5.10 of Appendix 4C, stating than an enforcement action is closed.

"Notice of Confirmed Violation" means a notice issued by the Compliance Enforcement Authority to a Registered Entity confirming the violation of one or more Reliability Standards.

"Notice of Penalty" means a notice prepared by NERC and filed with FERC, following approval by NERC of a Notice or other notification of Confirmed Violation or a settlement agreement, stating the Penalty or sanction imposed or agreed to for the Confirmed Violation or as part of the settlement.

"Notice of Preliminary Screen" means a notice issued by the Compliance Enforcement Authority to a Registered Entity that (1) states a potential noncompliance has been identified, (2) provides a brief description of the potential noncompliance, including the Reliability Standard Requirement(s) and the date(s) involved, and (3) instructs the Registered Entity to retain and preserve all data and records relating to the potential noncompliance.

"NRC" means the United States Nuclear Regulatory Commission.

"NRC Safeguards Information" means Required Information that is subject to restrictions on disclosure pursuant to 42 U.S.C. §2167 and the regulations of the NRC at 10 C.F.R. §73.21-73.23; or pursuant to comparable provisions of Canadian federal or provincial law.

"Open Access Transmission Tariff" means an electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.**

"Owner" means the owner(s) of an Element or Elements that is or may be determined to be part of the BES as a result of either the application of the BES Definition or an Exception, or another entity, such as an operator, authorized to act on behalf of the owner of the Element or Elements in the context of an Exception Request.

"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Body or by FERC to participate as an intervenor in a proceeding conducted pursuant to the Hearing Procedures, and as used in the Hearing Procedures shall include, depending on the context, the members of the Compliance Staff that participate in a proceeding or the members of the Certification Staff that participate in a proceeding pursuant to Appendix 4E.

"Party" or "Parties" means a Person or the Persons participating in a mediation pursuant to Appendix 4E.

"Penalty" means and includes all penalties and sanctions, including but not limited to a monetary or non-monetary penalty; a limitation on an activity, function, operation or other appropriate sanction; or the addition of the Registered Entity or Respondent to a reliability watch list composed of major violators. Penalties must be within the range set forth in the NERC *Sanction Guidelines* approved by FERC pursuant to 18 C.F.R. Section 39.7(g)(2), and shall bear a reasonable relation to the seriousness of a Registered Entity's or Respondent's violation and take into consideration any timely efforts made by the Registered Entity or Respondent to remedy the violation.

"Periodic Data Submittals" means modeling, studies, analyses, documents, procedures, methodologies, operating data, process information or other information to demonstrate compliance with Reliability Standards and provided by Registered Entities to the Compliance Enforcement Authority on a time frame required by a Reliability Standard or an ad hoc basis.

"Person" means any individual, partnership, corporation, limited liability company, governmental body, association, joint stock company, public trust, organized group of persons, whether incorporated or not, or any other legal entity.

"Planning Authority" means the responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.**

"Physical Access Control Systems" means Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.**

"Physical Security Perimeter" means the physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.**

"Point of Delivery" means a location that a Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.**

"Point of Receipt" means a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.**

"Potential Noncompliance" means the identification, by the Compliance Enforcement Authority, of a possible failure by a Registered Entity to comply with a Reliability Standard that is applicable to the Registered Entity.

"Preliminary Screen" means an initial evaluation of evidence indicating potential noncompliance with a Reliability Standard has occurred or is occurring, conducted by the Compliance Enforcement Authority, and consisting of an evaluation of whether (1) the entity allegedly involved in the potential noncompliance is registered, (2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to a reliability function for which the entity is registered, and (3) if known, the potential noncompliance is not a duplicate of one that is currently being processed.

"Probation" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is still valid. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

"Protected Cyber Asset" means one or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same Electronic Security Perimeter.**

"Protected FOIA Information" means Required Information, held by a governmental entity, that is subject to an exemption from disclosure under FOIA (5 U.S.C. §552(e)), under any similar state or local statutory provision, or under any comparable provision of Canadian federal or provincial law, which would be lost were the Required Information to be placed into the public domain.

"Protection System" means protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**

"Purchasing-Selling Entity" means the entity that purchases, or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.**

"Reactivation" refers to re-registration pursuant to the NERC Rules of Procedure Section 500 and Appendices 5A and 5B of an entity to the NCR for a specific functional category or the revocation of, or additions to, a sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements) that has been granted to an entity. Reactivation may be initiated by NERC, a Regional Entity or an entity with respect to such entity's own functional categories or sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements).

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

"Real Power" means the portion of electricity that supplies energy to the Load.**

"Receiving Entity" means NERC or a Regional Entity receiving Confidential Information from an owner, operator, or user of the Bulk Power System or from any other party.

"Recommendation" for purposes of Appendix 5C means the report to NERC containing the evaluation prepared in accordance with section 5.2 of Appendix 5C concerning whether or to what extent an Exception Request should be approved.

"Recommendations" or "Level 2 (Recommendations)" is a notification issued by NERC in accordance with Section 810.3.2 of the Rules of Procedure.

"Region" means the geographic area, as specified in a Regional Entity's delegation agreement with NERC, within which the Regional Entity is responsible for performing delegated functions.

"Regional Criteria" means reliability requirements developed by a Regional Entity that are necessary to implement, to augment, or to comply with Reliability Standards, but which are not Reliability Standards. Such Regional Criteria may be necessary to account for physical differences in the Bulk Power System but are not inconsistent with Reliability Standards nor do they result in lesser reliability. Such Regional Criteria are not enforceable pursuant to NERC-delegated authorities, but may be enforced through other available mechanisms. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents.

"Regional Entity" means an entity having enforcement authority pursuant to 18 C.F.R. § 39.8.++

"Regional Reliability Standard" means a type of Reliability Standard that is applicable only within a particular Regional Entity or group of Regional Entities. A Regional Reliability Standard may augment, add detail to, or implement another Reliability Standard or cover matters not addressed by other Reliability Standards. Regional Reliability Standards, upon adoption by NERC and approval by the Applicable Governmental Authority(ies), shall be Reliability Standards and shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Registered Ballot Body" means that aggregation of all entities or individuals that qualify for one of the Segments approved by the Board of Trustees, and are registered with NERC as potential ballot participants in the voting on proposed Reliability Standards.

"Registered Entity" means an owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry.

"Registration" or "Organization Registration" means the processes undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region.

"Regulation Reserve Sharing Group" means a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.**

"Rejection of the Exception Request" or "Rejection" means the determination that an Exception Request is not an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) or does not contain all the Required Information in accordance with section 4.5 of Appendix 5C in order to be reviewed for substance.

"Reliability Coordinator" means the entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.**

"Reliability Coordinator Area" means the collection of generation, transmission and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.**

"Reliability Standard" means a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk Power System. The term includes requirements for the operation of existing Bulk Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.++ (In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions.)

"Reliability Standards Development Plan" means the forward-looking plan developed by NERC on an annual basis setting forth the Reliability Standards development projects that are scheduled to be worked on during the ensuing three-year period, as specified in Section 310 of the Rules of Procedure.

"Reliable Operation" means operating the elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.++

"Remedial Action Directive" means an action (other than a Penalty or sanction) required by a Compliance Enforcement Authority that (1) is to bring a Registered Entity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat.

"Reporting Entity" means an entity required to provide data or information requested by NERC or a Regional Entity in a request for data or information pursuant to Section 1600 of the Rules of Procedure.

"Requirement" means an explicit statement in a Reliability Standard that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement with which compliance is mandatory.

"Required Date" means the date given a Registered Entity in a notice from the Compliance Enforcement Authority by which some action by the Registered Entity is required.

"Required Information" means, as applicable, either (i) the information required to be provided in a TFE Request, as specified in Section 4.0 of Appendix 4D; or (ii) the information required to be provided in an Exception Request, as specified in section 4.0 of Appendix 5C.

"Requirement Part" means a component of a Requirement that is designated by a decimal number (e.g., Requirement R1 could have Requirement Parts 1.1, 1.2 and 1.3).

"Reserve Sharing Group" means a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply Operating Reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in more quickly (e.g., between zero and ten minutes) then, for the purposes of recovery from a Reportable Balancing Contingency Event, the areas become a Reserve Sharing Group.**

"Resource Planner" means the entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.**

"Respondent" means, depending on the context, the Registered Entity, who is the subject of the Notice of Alleged Violation, contested Mitigation Plan or contested Remedial Action Directive that is the basis for the proceeding, whichever is applicable, or the Registered Entity that is the subject of the Certification decision that is the basis for a proceeding under Appendix 4E.

"Responsible Entity" means an entity that is registered for a reliability function in the NERC Compliance Registry and is responsible for complying with any Requirement, or Requirement Part.

"Revoked" means a NERC certificate that has been suspended for more than twelve months. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified. The certificate holder will be required to pass an exam to be certified again. Any CE Hours accumulated prior to or during the revocation period will not be counted towards Credential Maintenance.

"Revoke for Cause" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is no longer valid and requiring successfully passing an exam to become certified. However, an exam will not be authorized until the revocation period expires. CE Hours earned before or during this revocation period will not be counted for maintaining a Credential.

"Scope of Responsibility" means the registered functions of a Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority and the geographical or electric region in which the Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority operates to perform its registered functions, or with respect to a Regional Entity, its Regional Entity Region.

"Section I Required Information" means Required Information that is to be provided in Section I of a Submitting Entity's Exception Request.

"Section II Required Information" means Required Information that is to be provided in Section II of a Submitting Entity's Exception Request.

"Section III Required Information" means Required Information that is to be provided in Section III of a Submitting Entity's Exception Request.

"Sector" means a group of Members of NERC that are Bulk Power System owners, operators, or users or other persons and entities with substantially similar interests, including governmental entities, as pertinent to the purposes and operations of NERC and the operation of the Bulk Power System, as defined in Article II, Section 4 of the NERC Bylaws. Each Sector shall constitute a class of Members for purposes of the New Jersey Nonprofit Corporation Act.

"Segment" means one of the subsets of the Registered Ballot Body whose members meet the qualification criteria for the subset.

"Self-Certification" means an attestation by a Registered Entity that it is compliant or non-compliant with a Reliability Standard Requirement that is the subject of the Self-Certification, or that it does not own Facilities that are subject to the Reliability Standard Requirement, or that the Reliability Standard Requirement is not applicable to the Registered Entity.

"Self-Logging" means a process by which Registered Entities found to be eligible by a Compliance Enforcement Authority, after a formal review of internal controls, record potential noncompliance on a log, in accordance with Appendix 4C, in lieu of individually submitted Self-Reports of each potential noncompliance.

"Self-Report" means a report by a Registered Entity stating that the Registered Entity believes it has, or may have, violated a Reliability Standard.

"Sink Balancing Authority" means the Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.**

"Source Balancing Authority" means the Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.**

"Special Protection System" means an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system

stability, acceptable voltage, or power flows. A Special Protection System does not include (a) underfrequency or undervoltage Load shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a Special Protection System).**

"Spot Check" means a process in which the Compliance Enforcement Authority requests a Registered Entity to provide information (1) to support the Registered Entity's Self-Certification, Self-Report, or Periodic Data Submittal and to assess whether the Registered Entity complies with Reliability Standards, or (2) as a random check, or (3) in response to operating problems or system events.

"Staff" or "CMEP Staff" means individuals employed or contracted by NERC or the Compliance Enforcement Authority who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties and Mitigation Plans.

"Strict Compliance" means compliance with the terms of an Applicable Requirement without reliance on a Technical Feasibility Exception.

"Submitting Entity" means (i) an owner, operator, or user of the Bulk Power System or any other party that submits information to NERC or a Regional Entity that it reasonably believes contains Confidential Information or, (ii) solely for purposes of Appendix 5C, the entity that submits an Exception Request in accordance with section 4.0 of Appendix 5C.

"Suspended" means certificate status due to an insufficient number of CE Hours being submitted prior to the expiration of a certificate. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified.

"System" means a combination of generation, transmission and distribution components.**

"System Operating Limit" means the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- facility ratings (applicable pre- and post-contingency equipment ratings or facility ratings)
- transient stability ratings (applicable pre- and post-contingency stability limits)
- voltage stability ratings (applicable pre- and post-contingency voltage stability)
- system voltage limits (applicable pre- and post-contingency voltage limits).**

"Technical Advisor" means any Staff member, third-party contractor, or industry stakeholder who satisfies NERC's or the Compliance Enforcement Authority's (as applicable) conflict of interest policy and is selected to assist in a proceeding by providing technical advice to the Hearing Officer and/or the Hearing Body or Hearing Panel.

"Technical Feasibility Exception" or "TFE" means an exception from Strict Compliance with the terms of an Applicable Requirement on grounds of technical feasibility or technical limitations in accordance with one or more of the criteria in section 3.0 of Appendix 4D.

"Technical Review Panel" means a panel established pursuant to section 5.3 of Appendix 5C.

"Termination of Credential" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure whereby a Credential is permanently Revoked.

"Testimonial Hearing" means an Evidentiary Hearing at which the witness or witnesses on behalf of one or more Participants appears in person to present testimony and be subject to cross-examination.

"TFE Expiration Date" means the date on which an approved TFE expires.

"TFE Request" means a request submitted by a Responsible Entity in accordance with Appendix 4D for an exception from Strict Compliance with an Applicable Requirement.

"TFE Termination Date" means the date, as specified in a notice disapproving a TFE Request or terminating an approved TFE, on which the disapproval or termination becomes effective.

"Transmission" means an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.**

"Transmission Customer" means 1. any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can and does receive Transmission Service. 2. Any of the following entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.

"Transmission Operator" means the entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.**

"Transmission Owner" means the entity that owns and maintains transmission Facilities.**

"Transmission Planner" means the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.**

"Transmission Service" means services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.**

"Transmission Service Provider" means the entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.**

"Variance" means an aspect or element of a Reliability Standard that applies only within a particular Regional Entity or group of Regional Entities, or to a particular entity or class of entities. A Variance allows an alternative approach to meeting the same reliability objective as the Reliability Standard, and is typically necessitated by a physical difference. A Variance is

embodied within a Reliability Standard and as such, if adopted by NERC and approved by the Applicable Governmental Authority(ies), shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Violation Risk Factor" or "VRF" means a factor (lower, medium or high) assigned to each Requirement of a Reliability Standard to identify the potential reliability significance of noncompliance with the Requirement.

"Violation Severity Level" or "VSL" means a measure (lower, moderate, high or severe) of the degree to which compliance with a Requirement was not achieved.

"Wide Area" means the entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.**

Attachment 2-B

Appendix 5A Clean

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix 5A

Organization Registration and Certification Manual

Effective Date: TBD

RELIABILITY | RESILIENCE | SECURITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Section I — Executive Summary 1
Section II — Introduction to Organization Registration and Organization Certification Processes 4
Section III — Organization Registration Process 7
Section IV — Organization Certification Process 13
Section V — Organization Certification Review Process 20
Section VI — NERC Organization Registration Appeals Process 26
Section VII — NERC Organization Certification Appeals Process 28
Definitions 30

Public

Section I — Executive Summary

Overview

The purpose of this document is twofold: (1) to define the process utilized in the North American Electric Reliability Corporation (NERC) Organization Registration Program for identifying which functional entities must register as owners, operators, and users of the Bulk Power System (BPS) for compliance with Reliability Standards; and (2) to define the process utilized in the Organization Certification Program for certifying the following entities: Reliability Coordinator (RC), Balancing Authority (BA), and Transmission Operator (TOP).

To Whom Does This Document Apply?

All industry participants responsible for or intending to be responsible for, the following functions must register with NERC through the Organization Registration process. The entities are defined in the NERC *Statement of Compliance Registry Criteria*, set forth in **Appendix 5B** to the NERC Rules of Procedure (ROP), with responsibilities designated by the individual Reliability Standards or by a sub-set list of the otherwise applicable Reliability Standards determined in accordance with this **Appendix 5A**, Section III(D) to the NERC ROP.

	Entities that Must Register	Entities that Need to be Certified
Reliability Coordinator (RC)	√	√
Transmission Operator (TOP)	√	√
Balancing Authority (BA)	√	√
Planning Authority/Planning Coordinator (PA/PC)	√	
Transmission Planner (TP)	√	
Transmission Service Provider (TSP)	√	
Transmission Owner (TO)	√	
Resource Planner (RP)	√	
Distribution Provider (DP)	√	
Generator Owner (GO)	√	
Generator Operator (GOP)	√	
Reserve Sharing Group (RSG)	√	
Frequency Response Sharing Group (FRSG)	√	
Regulation Reserve Sharing Group (RRSG)	√	
Computational Load Owner (CLO)	√	
Computational Load Operator (CLOP)	√	

When did These Processes Begin?

The initial Registration process began in January of 2006. Registration of new entities is an ongoing process. If a Registered Entity's information changes, these changes must be submitted to the applicable Regional Entity(ies).

Certification is ongoing for entities in accordance with Sections IV and V of this manual.

Where to Access and Submit Form(s)?

Certification forms are provided on each Regional Entity's website. Completed forms are to be sent electronically to the Compliance and Certification Manager of the applicable Regional Entity(ies). Registration information is submitted electronically via an online application that is hosted on the NERC website. If an entity operates in more than one Region, separate Registration applications must be completed and submitted to each of the Regional Entities.

NERC will coordinate process execution when an entity is registering or certifying with multiple Regional Entities.

Roles and Responsibilities

The following is a high-level overview of the roles and responsibilities in the Registration and Certification processes:

NERC

1. Oversight of entity processes performed by the Regional Entities, including:
   a. Governance per the Regional Entity's delegation agreement with NERC.
   b. Coordination of process execution when an entity is registering and/or certifying with multiple Regional Entities.
2. Manage each entity's NERC Compliance Registry identification number (NERC ID) including:
   a. Sending a Registration or Certification letter that contains the NERC ID to the applicable Regional Entity(ies) for review and approval. If the Regional Entity(ies) agrees with all the information provided, it will notify NERC to issue the NERC ID to the Registered Entity and will send a copy of the notification being provided to the Regional Entity(ies).
   b. Ensuring each Registered Entity has only one NERC ID for all Regional Entities in which registered.
3. RESERVED
4. Maintain accurate Registration and Certification records including granting Certification certificates for the Registered Entity(ies) responsible for compliance (including Joint Registration Organization (JRO)/Coordinated Functional Registration (CFR)).
5. Maintain published up-to-date list of Registered Entities (i.e. the NERC Compliance Registry (NCR)) on the NERC website. NERC maintains the NCR, which identifies each Registered Entity and the applicable functional categories for which it is registered.
6. Lead panel reviews in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III(D).

Regional Entity

1. Performs data collection and mapping of BPS facilities and those facilities that have a material impact on the BPS within its Regional Entity defined reliability Region boundaries.
2. Approves or disapproves entity Registration applications.
3. Reviews entity Certification applications for completeness.
4. Notifies NERC of entities registered with the Regional Entity.
5. Approves or denies Certification Team (CT) recommendations and notifies the entity and NERC of the decision.
6. Provides leadership to the CT throughout the Certification process.

Entity Submitting the Application

1. Completes and submits Registration and/or Certification application.
2. Submits updates to Registration and/or Certification information as necessary and/or requested.
3. Responds to Regional Entity and/or NERC questions pertaining to Registration and/or Certification.

4. Provides documentation or other evidence requested or required to verify compliance with Certification requirements.

Section II — Introduction to Organization Registration and Organization Certification Processes

The processes utilized to implement the Organization Registration and Organization Certification Programs are administered by each Regional Entity. Pursuant to its delegation agreement with NERC, each Regional Entity is responsible for registering and certifying industry participants within its Regional Entity reliability Region boundaries. Each Regional Entity must use the following NERC processes.

Organization Registration — Entities Required to Register

All industry participants responsible for one or more of the functions below must register for each function through the Organization Registration Program. These entities are defined in the NERC *Statement of Compliance Registry Criteria*.

- RC
- TOP
- BA
- PA/PC
- TP
- TSP
- TO
- RP
- DP
- GO
- GOP
- RSG
- FRSG
- RRSG
- CLO
- CLOP

The Registration procedure is in Section III of this manual.

Organization Certification

Prospective and existing Registered Entities intending to perform or performing the RC, TOP, and/or BA functions shall achieve and/or maintain certification to operate one or more RC, TOP, and/or BA Areas. Every RC, TOP, and BA Area shall have a certified RC, TOP, and BA responsible for performing the duties and tasks identified in and required by the Reliability Standards.

Certification is required prior to the start of, and during the operation of a RC, TOP, or BA Area, subject to exception in NERC's sole discretion (conditional Certification). In such exceptions, the Registered Entity must satisfy conditions imposed according to an implementation plan agreed to by NERC to continue or discontinue operating its Area(s).

The activities of the program are designed to identify issues that, if not closed, could lead to unacceptable performance of the duties and responsibilities applicable to the certified function. The absence of a certified RC,

TOP, and/or BA for any Area jeopardizes the functional relationships within and between Areas specified by the Reliability Standards, and may lead to the inability of Registered Entities to maintain compliance with standards requiring performance with respect to those relationships.

The Certification/Review Team (CRT) works to establish one of the two findings below, utilizing Open Issues and Areas of Concern derived from an in-depth review and well-documented assessment of an entity's capability to perform the tasks of the certifiable function. Open Issues are items that must be closed before (continued) Certification is recommended.

- Certification/Review Team (CRT) recommends (initial or continued) certification contingent upon resolution of specified Open Issues (if any)
- Certification/Review Team (CRT) cannot recommend (initial or continued) certification. (Usually where the applicant contests Open Issues. The applicant has remedy in the appeal process of Section VII.)

This Certification process is described in Section IV of this manual. Certification reviews are conducted according to Section V. The Registered Entity is required to start operation of its Area within 12 months of being NERC certified.

Section III — Organization Registration Process

Purpose and Scope

The purpose and scope of this process is to provide guidance on how a user, owner, and/or operator of the BPS should be registered in the NCR.

Overview

Section 39.2 of the Commission's regulations, 18 C.F.R. § 39.2, requires each owner, operator, and user of the BPS to be registered with NERC and to comply with approved Reliability Standards.

Owners, operators, and users of the BPS will be registered by function(s) and are:

1. Responsible for compliance with all applicable Requirements/sub-Requirements within Reliability Standards approved by Applicable Governmental Authorities, for the applicable functions for which the Registered Entity is registered, except to the extent that an entity is granted a sub-set list of applicable Reliability Standards, which specifies the Reliability Standards and may specify Requirements/sub-Requirements by NERC, in which case the entity will be responsible for compliance with only such sub-set list; and
2. Subject to the compliance monitoring and enforcement requirements of Section 400 of the ROP.

If an entity does not agree with a Registration determination, it may request a NERC-led Registration Review Panel evaluation in accordance with Section III(D) of Appendix 5A. Entities should seek a determination from the NERC-led Registration Review Panel prior to making an appeal to the BOTCC in accordance with NERC ROP Section 500 and Section VI of Appendix 5A.

For Registration determinations dependent on application of the BES Definition, NERC has established a procedure to determine Inclusion and Exclusion Exceptions to the BES Definition (Appendix 5C). Appendix 5A relates to Registered Entity status whereas Appendix 5C relates to an Element's BES status. In cases where a BES Exception determination pursuant to Appendix 5C directly impacts an entity's functional registration requirements, the entity must initiate the BES Exceptions process prior to requesting a Registration change in status, and should be aware that the determination in that proceeding may be necessary prior to reaching a final decision by the NERC-led Registration Review Panel. This situation is dependent on facts and circumstances.

A. Organization Registration Application Process

1. This procedure applies to the following applicable entities: 1) those entities to be registered for the first time and 2) currently registered or previously registered entities for which registration changes are sought. Deactivation, Reactivation, and registration for a sub-set list of Reliability Standards are subject to the procedures in this subsection III(A). Additional procedures applicable to Deactivation and Reactivation are contained in subsections III(B) and III(C), respectively. Applicable entities shall begin the Registration process by submitting a completed Registration application to the Regional Entity(ies) of the reliability Region(s) where the entity performs or intends to perform its function(s).
    a. At any time, an entity may recommend in writing, with supporting documentation, to the Regional Entity(ies) that an entity be added to or removed from the Compliance Registry.
    b. If an entity does not have a NERC ID, NERC shall assign one.
    c. An entity responsible for more than one function will use a single NERC ID.
    d. The Registration process for an entity may also be initiated by a Regional Entity, NERC, or Applicable Governmental Authority.

e. At any time, an entity whose registration is at issue may request expedited treatment and waiver of applicable timelines. NERC, in its sole discretion, shall determine if such a request will be granted and alternative timelines. NERC's decision is not a final decision that is subject to appeal.

f. The following issues require determination by a NERC-led Registration Review Panel:

i. If, based on the entity's materiality to BPS reliability, the Regional Entity proposes to register an entity that does not meet the criteria set forth in Appendix 5B, Statement of Compliance Registry Criteria, the Regional Entity will submit a request for a determination by a NERC-led Registration Review Panel in accordance with Appendix 5A, Section III(D).

ii. If, based on the entity's lack of materiality to BPS reliability, an entity that meets the criteria set forth in Appendix 5B, Statement of Compliance Registry Criteria, believes that it should not be registered, the entity may submit a request for a determination by a NERC-led Registration Review Panel in accordance with Appendix 5A, Section III(D).

iii. If an entity disputes a Regional Entity determination that the entity meets the criteria set forth in Appendix 5B, Statement of Compliance Registry Criteria, the entity may submit a request for determination by a NERC-led Registration Review Panel in accordance with Appendix 5A, Section III(D).

iv. An entity seeking to be registered for a sub-set list of Reliability Standards may submit a request for a determination by a NERC-led Registration Review Panel in accordance with Appendix 5A, Section III(D).[1]

2. NERC shall coordinate Registration of entities that are required to register with multiple Regional Entities in order to ensure consistency of the Registration process.

3. For entities applying for the RC, TOP, and BA functions, Certification and Registration processes should be initiated concurrently using the applicable processes set forth in this manual. The entity should initiate the Certification process per Section IV of this manual.

4. Regional Entities shall evaluate the submitted information and determine if the information is complete/correct. If the information is not complete/correct, the entity will be notified to complete/correct or clarify the Registration information.

5. A single entity must register for all function type(s) that it performs itself. Provided that, an entity may execute an agreement to register as a Lead Entity of a JRO on behalf of one or more of its parties to the JRO agreement for one or more function type(s) for which the parties would have otherwise been required to register. The Lead Entity thereby, accepts on the parties' behalf compliance responsibility for all Requirements/sub-Requirements of Reliability Standards applicable to that function or those functions including reporting requirements. (ROP Section 507)

6. Multiple entities may each register for a function and delineate compliance responsibility for that function using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function type. (ROP Section 508)

7. In completing the Regional Entity responsibilities for the Registration process, the following are key items the Regional Entity must verify:

a. That function registrations are consistent with the requirements contained in ROP Section 501(1.4).

[1] If NERC has established clearly defined criteria for eligibility for a sub-set list of applicable Reliability Standards and has identified the sub-set list that may apply to similarly situated entities, such criteria shall govern the applicability of such sub-set list and such a matter shall not proceed to the NERC-led review panel, unless there is a dispute by the entity whose sub-set list treatment is at issue.

b. The Registration submission includes all data requested by NERC that is necessary for accurately identifying and contacting the Registered Entity.

8. The Regional Entity shall forward all Registration information to NERC for inclusion of an entity on the NCR:

   a. Within five business Days of a Registration determination by NERC or the NERC-led Registration Review Panel, as applicable, NERC will forward the proposed additions or changes to the NCR to the Regional Entity for review and comment.

   b. The Regional Entity has five business Days to respond to the proposed changes.

   c. If NERC does not receive any comments, the NCR will be revised. If NERC does receive comments, NERC will work with the Regional Entity to the extent changes are needed to the NCR and will revise the NCR accordingly.

9. NERC updates the NCR and notifies the applicable Registered Entity(ies) within five business Days of the update.

10. The Registered Entity may appeal the final registration determination by NERC in accordance with the ROP Section 500 and Section VI of **Appendix 5A**.

11. The NCR shall be dynamic and will be revised as necessary to take account of changing circumstances. Per the Regional Entity's delegation agreement, the Regional Entity will take any recommendation received under Section 1.a, and other applicable information, under advisement as it determines whether an entity should be on the NCR.

    a. Each Registered Entity identified in the NCR shall notify its corresponding Regional Entity and/or NERC of any corrections, revisions, deletions, changes in ownership, changes in corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards.[2] Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards. (ROP Section 400)

    b. Each Regional Entity has an independent obligation, even in the absence of a notification by an entity, to review and submit updates to the NCR to NERC, consistent with the procedures in this Section III, with appropriate notification to the affected entities, to the extent the Regional Entity is aware of, or possesses information that the NCR should be updated. These updates include, but are not limited to: 1) conditions on which the sub-set list are no longer applicable; 2) where a new and emerging risk to reliability is identified that changes the basis: a) upon which the entity was deactivated or deregistered; or b) upon which a sub-set list of requirements was made applicable; or 3) deactivation of entities that no longer meet the applicable registration thresholds. This does not excuse the Registered Entity from its obligation to provide such required notifications.

12. NERC may extend the timelines for processing Registration matters for good cause shown. Requests should be sent to the Registration email address, found on the Registration and Certification page of the NERC website. NERC shall notify the Registered Entity and the Regional Entity of such time extensions.

B. Deactivation Process

1. The term Deactivation refers to removal of an entity from the NCR for a specific functional category.

2. As a result of Deactivation, the entity is no longer subject to any prospective compliance obligations with respect to Reliability Standards applicable to that functional category.

[2] This includes changes in ownership of BPS facilities, changes in the applicability of the BES Definition to a Facility, and newly installed BPS facilities.

3. If all functional categories have been deactivated for a given entity, such entity would be deregistered and removed from the NCR. However, the entity's compliance history will be retained. In its letter notifying the entity of its Deactivation or deregistration, as applicable, NERC will notify the entity of the required retention period, in accordance with the NERC ROP.
4. An entity seeking Deactivation of RC, TOP, or BA registrations shall demonstrate to the satisfaction of its Regional Entity and NERC through the Certification review process, described in **Appendix 5A** Section V, that the duties and tasks identified in and required by the Reliability Standards either have properly been transferred to another Certified and Registered Entity or the Area has ceased to operate.
5. A Registered Entity may submit a request for Deactivation and supporting information to the Regional Entity at any time. Such information shall include:
    a. Entity name and NCR ID number;
    b. Functions for which Deactivation is requested; and
    c. The basis on which Deactivation is requested, including supporting documentation, which may be limited to an attestation, if appropriate.
6. The Regional Entity shall request any additional information from the Registered Entity within 10 Days of receipt of the request for Deactivation.
7. The Registered Entity shall provide the additional information within 20 Days of its request for Deactivation.
8. The Regional Entity will issue a decision within 50 Days of the date of receipt of all requested information from the Registered Entity.
9. If the Regional Entity approves the request for Deactivation, it shall forward its Deactivation determination to NERC within five business Days of issuance of the decision.
10. If NERC approves the Deactivation determination and the Registered Entity agrees with the determination, NERC will forward within five business Days of receipt of the Deactivation determination from the Regional Entity, the proposed additions or changes to the NCR to the Regional Entity for review and comment.
    a. The Regional Entity has five business Days to respond to the proposed changes.
    b. If NERC does not receive any comments, the NCR will be revised. If NERC receives comments, NERC will work with the Regional Entity to the extent changes are needed to the NCR and will revise the NCR accordingly.

C. Reactivation Process

1. NERC maintains the NCR, which identifies each Registered Entity and the applicable functional categories for which it is registered.
2. The term Reactivation refers to re-registration of an entity to the NCR for a specific functional category or the revocation of, or additions to, a sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements) that has been granted to an entity. Reactivation may be initiated by NERC, a Regional Entity or an entity with respect to such entity's own functional categories or sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements).
3. As a result of Reactivation, and consistent with the implementation plan to be developed pursuant to this paragraph, the entity shall prospectively comply with all Reliability Standards applicable to that functional category, or with the sub-set list specified in the Reactivation determination, unless otherwise notified. Within 30 days of a final Reactivation determination, the entity shall submit a proposed implementation plan to the Regional Entity detailing the schedule for complying with any Reliability Standards applicable to the

Reactivation. The Regional Entity and Registered Entity shall confer to agree upon such schedule. If the Regional Entity and Registered Entity are unable to agree on the implementation plan, the Regional Entity shall notify NERC via the Registration email address, found on the Registration and Certification page of the NERC website, of the disagreement, and shall provide statements of the Regional Entity's and the Registered Entity's positions, and NERC shall specify a reasonable implementation schedule.

4. The entity's prior compliance history will be retained and shall apply with respect to the Reactivation. In its letter notifying the entity of its Reactivation, NERC will notify the entity of its registration in accordance with the NERC ROP.

D. NERC-led Registration Review Panel

1. NERC shall establish a NERC-led Registration Review Panel (Panel) comprised of a NERC lead with Regional Entity participants, to evaluate: 1) Registered Entity requests for Deactivation of, or decisions not to register, an entity that meets Sections I through IV of the Registry Criteria, 2) requests to add an entity that does not meet (i.e., falls below) Sections I through IV of the Registry Criteria, 3) disputes regarding the application of Sections I through IV of the Registration Criteria, and/or requests for a sub-set list of applicable Reliability Standards (which may specify the Requirements/sub-Requirements).

    a. The Panel will be comprised of a standing pool of individuals with relevant expertise from NERC and each of the Regional Entities. Individuals with relevant expertise shall be appointed by the Regional Entity senior executive (CEO, President, General Manager, etc.) and individuals with relevant expertise shall be appointed by the NERC senior executive (CEO, President, General Manager, etc.). NERC shall select the Panel members for a given matter from the standing pool.

    b. Panel members for a given matter shall comply with Subsection 7 of Section 403 of the NERC ROP, shall not be employed by the Regional Entity whose determination is being reviewed or have otherwise participated in the review of the registration matter, and shall have the required technical background to evaluate registration matters.

2. An applicant requests a Panel review by completing an application using the **NERC-led Review Request Form** (Request Form) available on the NERC website (www.nerc.com)

    a. The Request Form provides instruction for submittal of documentation and data associated with the request.

    b. The applicant[3] should include an evaluation of materiality,[4] a description of the applicability of Sections I through IV, of the Registration Criteria, and/or an assessment of the impact of a sub-set of reliability standards, as appropriate.

    c. The burden of proof is on the applicant that makes the request for a Panel review, except in two instances where the burden of proof is on the applicable Regional Entity. These two instances include: 1) disputes regarding application of Sections I through IV of Registry Criteria for registration, and 2) disputes where NERC has (i) established clearly defined criteria for eligibility for a sub-set of applicable Reliability Standards (which may specify Requirements/sub-Requirements) and (ii) identified similarly situated entities that the sub-set list may apply to.

    d. For the purpose of this Panel process, the parties are the applicable Regional Entity(ies), RC, BA, TOP, and PC and the entity whose registration status is at issue.

[3] Applicants can either be a Regional Entity or an entity whose registration or sub-set list status is at issue.

[4] The evaluation of materiality should include the relevant "materiality test" factors listed in the "Determination of Material Impact" section of Appendix 5B, and/or any other factors that may be considered relevant to the request for Panel review.

e. Parties are to upload any documents, data, and/or information related to the Panel request to the secure location established by NERC for the Panel review.[5] When materials are uploaded to this location by a party, that party will provide notice to all other parties via email.

3. NERC will review the submitted documentation and determine if the application is valid within 30 days of receipt.
4. If the application is deemed not valid, NERC will send a written notification to the applicant via email with a reason the application was rejected.
5. If the application is deemed valid, NERC will send a written notice of NERC's acceptance of a valid Panel request to the applicant and the parties via email.
   a. Unless informed otherwise in NERC's notice of a valid request, the entity whose status at issue will have their current responsibilities for compliance with approved Reliability Standards in effect until the issue at hand has a final determination.
6. The Regional Entity(ies) or the entity whose registration status is as issue, as appropriate, will provide a written assessment of the Panel request to NERC, as described in step 2(e), within 20 days of NERC's acceptance of a valid Panel request.
   a. The RC, BA, TOP, and PC are also requested to provide a written assessment to NERC, as described in step 2(e), within 30 days of NERC's acceptance of a valid Panel request.
   b. The Regional Entity, or entity whose registration status is at issue, as appropriate, can provide a written response to NERC, as described in step 2(e), of any party's assessment within 40 days of NERC's acceptance of a valid Panel request.
7. The standard of proof in any proceeding under these procedures shall be by a preponderance of the evidence. The Panel will evaluate all documentation, assessments, and responses submitted to determine whether the weight of the evidence supports the Registration action under review more than it does not support the action. The Panel may issue a request for information to the applicant or any of the parties and will copy all parties on any such correspondence. The Panel will render its decision within 60 Days of the final submission to the panel or relevant correspondence is received related to the request from any party.
8. In reaching a decision, the Panel will apply the materiality test and other criteria, as applicable, set forth in the "Determination of Material Impact" section of Appendix 5B, Statement of Compliance Registry Criteria and any applicable guidance. The Panel shall also include a review of individual and aggregate system-wide risks to, and considerations of, reliability of the BPS, as well as the BES Definition, as applicable.
9. NERC may use its discretion to extend the timelines of the Panel process for good cause. Any party may also request to extend the timelines by sending an email to the Registration email address, found on the Registration and Certification page of the NERC website. NERC shall notify all parties of such time extensions.
10. The Panel decision will be issued to the applicant with a copy to all parties via email. The decision (including its basis) will also be posted on the NERC website,[6] with confidential information redacted in accordance with Section 1500 of the NERC ROP.
11. Any required changes to the NCR resulting from the Panel decision will be initiated by the Regional Entity in accordance with the Organization Registration Process of this manual. An entity may file an appeal with the BOTCC, in accordance with NERC ROP Section 500 and **Appendix 5A,** Section VI, if it wishes to dispute the Registration determination of the Panel.

[5] NERC will provide instructions to each party regarding how to request access to the secure location.

[6] A Panel decision subject to appeal will not be posted prior to the 21 day appeal window closing (in accordance with **Appendix 5A**, Section VI), which begins when the decision is issued to the parties. If no appeal is received, the decision will be posted and the Federal Energy Regulatory Commission will be notified.

Section IV — Organization Certification Process

Purpose and Scope

Reliability Coordinators, Transmission Operators, and Balancing Authorities take actions in Real-time that impact the reliable operation of the Bulk Power System. Certification activities assess the processes, procedures, tools, and training these organizations use in performing these functions and provide a prospective level of assurance that the organization has the capacity to meet the reliability obligations of its registration. The Certification will adhere to the following process to the extent allowed by the circumstances.

Organization Certification Process

Initiation

1. Certification processes shall begin upon the Regional Entity's receipt of a certification application for a Registered Entity or prospective Registered Entity; or when an entity has been registered by NERC for the functions of RC, TOP, and BA.
    a. An entity in a single Regional Entity reliability region shall initiate the Certification process by completing a Certification application (Certification applications are provided on each Regional Entity's website) and sending it to that Regional Entity which will manage the Certification process.
    b. An entity in multiple Regional Entity reliability regions shall initiate the Certification process by completing a Certification application (Certification applications are provided on each Regional Entity's website) and sending it to each Regional Entity. Each Regional will inform NERC of request with a recommendation for which Regional Entity will provide the leadership to manage the Certification process. NERC will determine which Regional Entity shall lead review of the application.
    c. The Regional Entity leading the review of the application shall review the application, and respond and acknowledge receipt or submit requests for more information within 30 days of its receipt of the application.
        i. If the application is not complete or accurate, the Regional Entity will notify the entity to revise the application as needed.
        ii. As part of such review, the Regional Entity may propose to issue a determination rejecting an application on a procedural basis. The applicant will be given 15 days to resolve the reason for rejection. If the Regional Entity and NERC determine that the applicant would fail to meet Registry Criteria or would otherwise not be able to competently perform the duties and responsibilities required under relevant Reliability Standards for the applicable Area, then a rejection notice will be sent to the applicant. Thereafter, the applicant may file an appeal of the rejection in accordance with Appendix 5A, Section VII.
    d. With the agreement of the Registered Entity, the Regional Entity or NERC may initiate certification processes based on documented conversations or other communications with a Registered Entity that contain information equivalent to that of the application.
2. The Regional Entity shall identify a team lead (CTL) for the certification activity.
3. The CTL shall notify NERC of the request for certification, and the following will take place:
    a. The CTL and NERC will review the request for Certification and concur on acceptance. When the application is deemed complete and accurate, it will be accepted.

b. If accepted, the CTL will inform the Registered Entity of the decision to initiate certification activities.

   i. The entity and the Regional Entity shall agree to a timeline including specific milestones for the Certification process. The proposed schedule for the Certification Process shall be submitted to NERC for approval. NERC shall review the draft final schedule and will (i) approve; (ii) modify; or (iii) reject the final schedule within 45 days of receipt from the CTL.

   ii. Certification activities are expected to be completed, allowing sufficient time to correct any Open Issues noted in the entity's preparedness, prior to the effective date of an entity's Registration.

c. In the case when an entity has been registered by NERC on behalf of the entity for the functions of RC, TOP, or BA, Certification activities will be concurrent with the entity's Registration implementation plan.

4. The following subsections detail which entities are required to be certified if they are a party to a JRO, CFR, or other delegation agreement.

   a. Each entity that has taken responsibility for Reliability Standards and/or Requirements/sub-Requirements applicable to the certifiable functions by virtue of being a member of a JRO, CFR, or other agreement shall be the entity NERC certifies to operate their portion of the RC, TOP, or BA Area(s).

   b. For all other entities that perform tasks related to the RC, TOP, or BA functions within a JRO or other agreement, the Regional Entity(ies) shall, based on a review of the JRO or other agreement, identify and notify such entities of the need for an evaluation and determination of the applicability of a "capability verification" or "readiness evaluation"[7] for those tasks.

Planning

1. The CTL shall form the team that will be responsible for performing the activities included in the Certification process.

   a. Participants shall adhere to NERC's confidentiality requirements for any data or information made available through the Certification process. Participants shall not be employees of or have a direct financial interest in the entity or any of its affiliates.

   b. Certification teams (CT) shall consist of the following:

      i. For BA certifications, the CT shall have representation from an existing BA, the entity's proposed RC, TOP, each affected Regional Entity, and NERC.

      ii. For RC certifications, the CT shall have representation from an existing RC, a BA and a TOP in the proposed Reliability Coordinator Area, each affected Regional Entity, and NERC.

      iii. For TOP certifications, the CT shall have representation from an existing TOP, the entity's proposed BA(s) and RC, each affected Regional Entity, and NERC.

      iv. Additional CT members with expertise in any of the NERC registry functional areas may be added as necessary (i.e., NERC, Regional Entity staff).

   c. If the entity objects to any member of the CT, the entity must make that known, in writing, to the Regional Entity listing the reasons for the objection. The Regional Entity will either replace the team member or respond with written justification for keeping the member on the team.

   d. Entities such as government representatives or other stakeholders may be observers in the Certification process. Any Confidential Information will be handled in accordance with Section 1500 of the NERC ROP.

2. CT members shall have the necessary diversity in their technical training and experience to collectively represent the subject matter competencies needed to perform the evaluation of the specific function being

[7] A "capability verification" or "readiness evaluation" is a review of the duties and tasks of the Registered Entity that it has delegated to another entity through an agreement.

certified. Previous experience as a System Operator, Operations Support Personnel, or management of a Control Center is desired for CT members performing the on-site visit.

3. The CTL shall ensure all CT members have completed the following:
   a. Certification team member training requirements as established by NERC
   b. Non-ERO employees shall also complete the following:
      i. Certification team member training record form
      ii. Certification team conflict of interest form
      iii. An ERO confidentiality agreement form
4. The CTL shall review the certification application (and Entity information available through other ERO programs) with NERC to determine the scope of the assessment. The CTL shall identify the competency areas to be evaluated based on the function(s) for which the entity is to be certified and the method(s) for their evaluation.
5. The CTL shall utilize a secured server to distribute and house all relevant certification activity documents, including but not limited to the following:
   a. The application or other documented correspondence with the Registered Entity initiating the certification activity
   b. All relevant correspondence between the CTL and the applicant, including the certification packet (as described in step 6 below)
   c. All relevant correspondence between the CTL and the CT members
   d. The work papers used to evaluate the entity during the process
   e. The overall process schedule
   f. The agenda for the on-site visit
   g. The final certification report
   h. The Regional Entity certification process check sheet indicating the completion of certain process check-points
6. A Certification packet shall be developed and sent to the entity at least ninety (90) days prior to an on- site visit. It shall contain the following:
   a. Notification of the certification process
   b. Logistic information request
   c. The tentative overall process schedule and on-site agenda
   d. The CT roster and member biographies
   e. Request of confirmation of no objections to CT members
   f. Pre-certification survey that must be returned to the CTL within fifteen (15) days of receipt
   g. Any initial requests for information
7. CTL shall contact the entity within one week of submitting the packet to confirm receipt of the package and discuss any concerns the entity may have.
8. The entity shall complete and return the requested information and supporting documentation no later than four (4) weeks prior to the on-site visit.
9. The CTL and CT shall review the logistic information request response, in order to do the following:

a. Understand the entity's expectations of the CT when on site

b. Make all travel arrangements

10. If the CT is to be broken into smaller groups, the CTL shall identify sub-teams and assign a scribe(s) to document the assessment:

    a. For complex Certifications, the CTL may assign members of the CT to different focus areas. For example:

        i. Facilities: Examples may include the physical cyber assets against the CIP standards, the cyber training, the maintenance contracts and records for the facilities, the electrical system and uninterruptible power supply (UPS), the cybersecurity of servers, passwords, etc., per the CIP standards, and the physical installation of data and voice equipment.

        ii. EMS/SCADA: Interview the EMS/SCADA SMEs to ensure that the tools will provide adequate situational awareness against the NERC standards. Ensure adequate change control of the EMS/SCADA. Review the data transfer, server, applications, and redundancy configuration of the core tools including EMS, OSI-PI, ICCP, outage scheduling, scheduling, map-board displays, communication systems, etc.

        iii. Operator Preparedness: Interview the operators at their workstations and ask them to present the tools, procedures, and job aids in use for normal day-to-day and emergency operations. This could include cyber intrusion detection and real-time assessment. Interview the training staff regarding initial training needed to support the transition to the new responsibilities and continuing training to the NERC standards.

        iv. Critical Infrastructure Preparedness: Interview the CIP staff to understand how critical infrastructure protections are being utilized.

    b. The CTL shall ensure documentation used to substantiate the conclusions of the Certification (Review) is collected from each sub-team.

Fieldwork

1. Areas of capability to be evaluated by the certification activity shall be tailored to the situation and matched with appropriate assessment methods (e.g., validation of legacy information, review of entity responses, document review, direct observation, or personnel interview, etc.)
2. The CTL shall schedule a document review(s) with the CT prior to the on-site visit. Document reviews could take place face-to-face or via teleconference.
3. During document reviews, the CT shall note all the following:

    a. Follow-up or corroborating questions for the entity's management, SMEs, and system operators based upon the review of supporting documentation

    b. Additional requests for information (to be submitted to the entity prior to the on-site visit.)

    c. Comments during the document review that support the entity's abilities to perform the function for which the entity applied and indicate items which do not need further review

    d. Issues that need to be addressed prior to certification being granted

4. The CTL shall provide the entity a final schedule and agenda for the on-site visit based upon the results of the document review.
5. The CT on-site visit to the entity's location where operational functionality is performed shall include the following:

    a. Opening presentation

b. At a minimum, the team will:

   i. Review with the entity the data that is available only on-site;

   ii. Interview the operations, management, and training personnel;

   iii. Inspect the Facilities and equipment associated with the function being certified;

   iv. Request demonstration of all tools identified in the scope of the Certification;

   v. Review documents and data including agreements, processes, and procedures identified in the document review;

   vi. Verify operating personnel Certification credentials and proposed work schedules; and

   vii. Review any additional documentation resulting from inquiries arising during the on-site visit.

c. The CT shall interview other entity personnel as required to clarify responses covered in the document review.

d. At the end of each day, the CT will meet for the debriefing. The CTL shall lead a daily debriefing with the entity in order to do the following:

   i. Identify the status of the assessment

   ii. Identify any items of concern that need to be addressed

   iii. Provide an update to the schedule

e. The CTL shall provide an exit briefing at the end of the on-site visit in order to do the following:

   i. Identify any Open Issues that need to be addressed, and identify a timeline for follow-up to closure

   ii. Discuss the reporting process

   iii. Discuss the next steps in the certification process, including any Areas of Concern and the schedule of a post-onsite visit, if required.

   iv. Convey that entity feedback forms will be sent to allow the entity to resolve any open with a request for candid feedback.

Reporting

1. The CTL will provide the CT and entity with feedback forms, and request that they are returned within five (5) calendar days with a copy to the Certification email address, found on the Registration and Certification page of the NERC website.
2. After completion of the on-site visit, the CTL shall develop a draft final report, in coordination with input from the CT, which presupposes all Open Issues are closed. The format for the report shall conform to the template posted on the NERC website, generally containing:

   - Title page
   - Table of Contents
   - Introduction – A brief discussion on the Regional Entity(ies) involved, the entity being certified, a description of the function the entity(ies) are being certified for, and a brief timeline of the Certification project.
   - CT – Provide the CT makeup.
   - Objective and Scope – Discussion on entity application (who, what, when, & how).
   - Overall Conclusion – finding of the CT.

- Open Issues - Any item(s) that must be closed prior to going operational and within 180 days of conclusion of the on-site visit.
- Positive Observations.
- Company History – Discussion on the applicant's company history.
- Company Details – Specific details regarding the Reliability Coordinator, Transmission Operator or Balancing Authority Areas to be operated and the entity's relationship with other entities (RCs, TOPs, and BAs etc.).
- Documentation List – Provide a list of critical documentation reviewed by the CT used to make the CT's conclusion and the documentation retention requirements.
- Attachments – Describe those attachments that are for public viewing and those that are separated from the report due to confidentiality issues such as Critical Infrastructure documentation.

3. The CTL shall transmit the draft final report to the CT requesting final comments within five (5) business days, unless agreed to otherwise.
4. After the CT has completed their review of the draft report, the CTL shall transmit the draft final report to the entity, requesting return with comments within fourteen (14) calendar days, unless agreed to otherwise.
5. Entity comments will be given due consideration and incorporated in the final report at the discretion of the CTL and the input of the CT. The CTL and CT will review the completed final report.
6. When all Open Issues are satisfactorily closed, the CTL will submit the final report to Regional Entity(ies) management for consideration and approval. CT minority opinions and areas where CT consensus was not reached will be communicated to Regional Entity(ies) management prior to approval, but will not be included in the final report nor in the Regional Entity recommendation to NERC.
    a. If Regional Entity management contradicts the CT finding, the CTL will work with the CT the entity to resolve any issues.
    b. The Regional Entity CEO (or a designee) will transmit to NERC and copy the entity the final CT report with a recommendation regarding NERC's certification of the entity.
7. If NERC approves the entity for certification, NERC shall email confirmation to the entity and post the final report on NERC's public website. Attached to the email will be the formal certification letter and NERC certificate. Any Confidential Information will be redacted in accordance with Section 1500 of the NERC ROP.
8. The entity may appeal NERC's decision in accordance with the Rules of Procedure and Section VII of this manual.
9. The certification process shall be completed within nine (9) months unless agreed to by all parties involved in the process
10. Operational responsibility for RC, TOP, or BA Areas shall not begin prior to the entity's registration effective date. Trial operations, conducted in parallel with an incumbent RC, TOP, or BA who retains responsibility, shall be coordinated to ensure operational authority for an Area is clear at all times.
11. The applicant must commence operations for its RC, TOP, or BA Areas within twelve (12) months of being certified by NERC. If the applicant fails to commence operation within twelve (12) months, the certification process must be repeated.
    a. During the pendency of the certification process, NERC may use its discretion to issue conditional Certification to ensure that the entity can be Registered, and no areas of the BPS are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical.

i. Conditional Certification will include an implementation plan which provides qualifications or criteria that NERC and the Regional Entity have determined necessary to address the risk of an entity failing to be certified or to be certified when needed.

ii. The entity subject to conditional Certification shall create an implementation plan that establishes how delayed or failed certification is mitigated so that no gaps in reliability occur. The implementation plan would also detail potential impacts both to the applicant and to any affected entities, and discuss how those impacts would be mitigated, how required functions would be served, and how other affected entities within its prospective footprint would meet their compliance responsibilities if certification is failed or delayed.

iii. NERC and the Regional Entity will work with the applicant to develop the implementation plan. If the parties are unable to agree upon an implementation plan, NERC will issue an implementation plan.

Data Retention

1. Documentation used to substantiate the conclusions of the Certification (Review) must be retained by the Regional Entity for six (6) years.
2. Documentation used to substantiate program oversight of the Certification processes must be retained by NERC for six (6) years.

NERC will maintain and post all Certification Final Reports on its website. Any Confidential Information will be redacted in accordance with Section 1500 of the NERC ROP.

Section V — Organization Certification Review Process

Purpose and Scope

Certification review provides reasonable assurance an already certified and operational Registered Entity will continue to support reliable operations of the BPS after initiating a material change. The review will seek assurance that the entity has addressed personnel training and qualifications, facilities, and equipment needed to perform and maintain the reliability functions in accordance with the applicable Requirements of Reliability Standards, considering among others the following:

- BPS reliability impacts of the change
- Critical Infrastructure Protection implications of the change
- Operator training in support of the change
- Data collection, sharing, and facilities monitoring and control necessary for Real-time Assessments, as well as next-day and longer-term planning
- Coordination of normal and emergency operations

Overview

Certification review activities, including the checks and balances of reporting and documenting those activities, should take place in advance of the change. Functional operations and compliance to the Standards remain the responsibility of the applicable Registered Entity. Certification is of the organization performing the function—not of a facility or system of equipment. Every RC, TOP, and BA Area shall have a certified RC, TOP, and BA registered as responsible for performing the duties and tasks identified in and required by the Reliability Standards. Entities seeking Deactivation of BA, TOP, or RC registrations shall demonstrate to the satisfaction of their Regional Entity and NERC through the Certification review process that the duties and tasks identified in and required by the Reliability Standards either have properly been transferred to another Certified and Registered Entity or the Area has ceased to operate. An entity remains certified during the review activities and subject to all applicable requirements of Reliability Standards, unless conditional Certification is granted by NERC providing qualifications or criteria that NERC and the Regional Entity have determined necessary to address the risk of an entity failing to be certified or to be certified when needed.

Items that are to be considered for a Certification review include one or more of the following non- exhaustive list of changes from an entity's prior certification assessments.

a. Changes to Registered Entity's footprint[8] (including de-certification changes to existing JRO/CFR assignments or sub-set list of requirements):

   i. The review of changes to an already registered and operational Entity's footprint is primarily concerned with ensuring the gaining functional entity has the tools, training, and security in place to reliably operate with new responsibilities. Changes to an entity's footprint can be characterized by new metered boundaries associated with the integration or dis-association of existing electrical areas of the BPS (Reliability Coordinator Area, Transmission Operator Area, or Balancing Authority Area).

b. Relocation of the Control Center:

   i. Fundamental to the reliable operation of the interconnected transmission network are the control centers that continuously monitor, assess, and control the generation and transmission power flows on the BES. Of interest are impacts to the functionality provided within these facilities for continued reliable operations of the BES that affect:

[8] This includes changes in ownership of BPS facilities, changes in the applicability of the BES Definition to a Facility, and newly installed BPS facilities.

- Tools and applications that System Operators use for situational awareness of the BES
- Data exchange capabilities
- Interpersonal (and alternate) Communications capabilities
- Power source(s)
- Physical and cyber security

ii. The impact of the relocation of the Control Center on the entity's ability to perform the functions for which the entity is registered under normal and emergency conditions should be explored and documented to understand the manner in which the Control Center continues to support the reliable operations of the BES.

c. Modification of the Energy Management System (EMS) which is expected to materially affect CIP security perimeters or the System Operator's: 1) situational awareness tools, 2) functionality, or 3) machine interfaces.

NERC may revoke an entity's certification and de-certify that entity if NERC determines that the entity is no longer performing the responsibilities that are associated with the function for which it is certified. Revocation shall be posted to the NERC website. The entity will remain registered and subject to compliance for the function, unless it has gone through the deactivation or deregistration process for the applicable function. NERC's revocation may be appealed in accordance with **Appendix 5A**, Section VII.

Organization Certification Review Process

Initiation

1. A Registered Entity that requires a review of the conditions upon which their certification was granted shall complete the appropriate form and submit it to the applicable Regional Entity. Informal dialogue on potential certification activity is encouraged as far in advance as possible.
   a. An entity in a single Regional Entity reliability region shall initiate the Certification review process by completing an application (Certification review applications are provided on each Regional Entity's website) and sending it to the Regional Entity that will manage the Certification review process.
   b. An entity in multiple Regional Entity reliability regions shall initiate the certification process by completing a certification application (certification applications are provided on each Regional Entity's website) and sending it to each Regional Entity. Each Regional Entity will inform NERC of the request with a recommendation for which Regional Entity will provide leadership to manage the certification process. NERC will determine which Regional Entity shall lead review of the application.
   c. The Regional Entity leading the review of the application shall review the application and respond with either acceptance or a request for more information within 30 days of the receipt of the request.
2. Upon receipt of the request for Certification review, the Regional Entity(ies) shall evaluate as follows:
   a. If the application is not complete or accurate, the Regional Entity will notify the entity to revise the application as needed.
   b. For an entity that is not required to be certified but performs tasks associated with a RC, TOP, or BA in accordance with Section IV, the Regional Entity shall consult with the Registered Entity regarding the applicability of a "capability verification" or "readiness evaluation" regarding those tasks.
   c. The Regional Entity or NERC may initiate the Certification review processes based on documented conversations or other communications with a Registered Entity that contain information equivalent to that of the application.

d. The decision to certify changes to an already operating and certified Registered Entity is a collaborative decision between the affected Regional Entity(ies) and NERC. The decision may be to conduct a review under this Certification review process or engage in any lesser activity necessary to understand changes that are material to an entity's operations or inherent risk.

3. When the decision is made to initiate a Certification review, the Regional Entity shall identify a team lead (CRTL) for the Certification review activity and the following will take place:

   a. The CRTL will inform the Registered Entity of the decision to initiate Certification review activities.

   b. The CRTL shall tailor the scope of the Certification review to evaluate those capabilities that are affected as a direct result of the reason for the review.

   c. The Regional Entity and NERC will determine if an on-site visit is required or if off-site review is sufficient. NERC has the final authority in this decision.

   d. The entity and the Regional Entity shall agree to a timeline including specific milestones for the Certification review process. The proposed schedule for the Certification review process shall be submitted to NERC for approval. NERC shall review the draft final schedule and will (i) approve; (ii) modify; or (iii) reject the final schedule within 45 days of receipt from the CRTL.

   e. Certification review activities are expected to be completed allowing sufficient time to address the risk of an entity failing to be certified or to be certified when needed prior to the effective date of any registration changes

Planning

1. The CRTL shall form the team (CRT) that will be responsible for performing the activities included in the Certification review process.

   a. The CRTL shall review the request (and entity information available through other ERO programs) with NERC to identify the competency areas to be evaluated and the method(s) for their evaluation (entity/neighbor questionnaire, request documents for review, on-site demonstration, personnel interview, etc.)

   b. The CRT participants shall adhere to NERC's confidentiality requirements under Section 1500 for any data or information made available through the Certification review process. Participants shall not be employees of or have a direct financial interest in the entity or any of its affiliates.

   c. CRT Composition:

      i. The CRT shall have the necessary diversity in their technical training and experience to collectively represent the subject matter competencies needed to perform the evaluation of the specific function being certified. Previous experience as a System Operator, Operations Support Personnel, or management of a Control Center is desired for CRT members performing the on-site visit.

      ii. Entities such as government representatives or other stakeholders may be observers in the Certification review process.

   d. If the entity objects to any member of the CRT, the entity must make that known, in writing, to the Regional Entity, listing the reasons for the objection. The Regional Entity will either replace the team member or respond with written justification for keeping the member on the team.

2. The CRTL shall ensure all CRT members have completed the following:

   a. Certification team member training requirements as established by NERC

   b. Team Member profile documenting technical training and experience of team members

c. For non-ERO employees they shall also complete the following:

3. The CRTL shall utilize a secured server to distribute and house all relevant Certification review activity documents, including but not limited to the following:
   a. The application or other documented correspondence with the Registered Entity initiating the certification activity
   b. All relevant correspondence between the CRTL and the applicant, including the certification packet (as described in step 4 below)
   c. All relevant correspondence between the CRTL and the CRT members
   d. The work papers used to evaluate the entity during the process
   e. The overall process schedule
   f. The agenda for the on-site visit, if required
   g. The final Certification review summary report
   h. The Regional Entity certification process check sheet indicating the completion of certain process check-points
4. A Certification review packet shall be developed and sent to the entity at least ninety (90) days prior to an on-site visit. It shall contain the following:
   a. Notification of the Certification review process
   b. Logistic information request
   c. The tentative overall process schedule and tentative on-site agenda
   d. The CRT roster and member biographies
   e. Request of confirmation of no-objections to CRT members
   f. Pre-certification survey that must be returned to the CRTL within fifteen (15) days of receipt
   g. Any initial requests for information
5. The CRTL shall contact the entity within one week of submitting the packet to confirm receipt of the package and discuss any concerns the entity may have.
6. The entity shall complete and return the requested information no later than four (4) weeks prior to the on-site visit.
7. The CRTL and CRT shall review the logistic information request, in order to do the following:
   a. Understand the entity's expectations of the CRT when on site
   b. Make travel arrangements

Fieldwork

1. Areas of capability to be evaluated by the Certification review activity shall be tailored to the situation and matched with appropriate assessment methods (e.g., validation of legacy information, review of questionnaire responses, document review, direct observation, or personnel interview, etc.)
2. The CRTL shall schedule a document review(s) with the CRT prior to the on-site visit. Document reviews could take place face-to-face or via teleconference.
3. During document reviews, the CRT shall note all the following:

a. Follow-up or corroborating questions for the entity's management, SMEs, and system operators based upon the review of supporting documentation

b. Additional requests for information (to be submitted to the entity)

c. Comments during the document review that support the entity's abilities to perform the function for which the entity applied and items which do not need further review

d. Issues that need to be addressed prior to continued certification being recommended

4. The CRTL shall provide the entity a final schedule and agenda for the on-site visit (if applicable) based upon the results of the document review.

5. As appropriate, the CRT shall conduct interviews at the entity's facilities or via teleconference. The team will:

   a. Review with the entity any data or information requiring clarification

   b. Interview operations, management, and training personnel

   c. During on-site visits:

      i. Inspect the facilities and equipment associated with the applicable Reliability Standards referenced in the questionnaire;

      ii. Request demonstration of all tools affected by the change;

   d. Review documents and data including agreements, processes, and procedures identified by CRT

   e. Review any additional documentation resulting from inquiries arising during the interview

6. At the end of each on-site day, the CRT will meet for debriefing. The CRTL shall lead a daily debriefing with the entity in order to do the following:

   a. Identify the status of the assessment

   b. Identify any items of concern that need to be addressed

   c. Provide an update to the schedule

7. The CRTL shall provide an exit briefing at the end of the on-site visit in order to do the following:

   a. Identify any Open Issues that need to be addressed, and identify a timeline for follow-up to closure

   b. Discuss the reporting process

   c. Discuss the next steps in the Certification review process, including any areas of concern and the schedule of a post-onsite visit, if required

   d. Convey that entity feedback forms will be sent to the entity

Reporting

1. The CRTL will provide the CRT and entity with feedback forms, and request that they are returned within five (5) calendar days with a copy to the Certification email address, found on the Registration and Certification page of the NERC website.

2. After completion of the on-site visit, the CRTL shall develop a draft summary report, in coordination with input from the CRT, which presupposes all Open Issues are closed. The format for the report shall conform to the template posted on the NERC website.

3. The entity, in conjunction with the CRT, shall attempt to resolve any Open Issues prior to issuance of the draft summary report.

4. The CRTL shall transmit the draft final report to the CRT requesting final comments within five (5) business days, unless agreed to otherwise.
5. After the CRT has completed their review of the draft report, the CRTL shall transmit the draft final report to the entity, requesting return with comments within fourteen (14) calendar days, unless agreed to otherwise.
6. At the discretion of the CRT and NERC, the entity may be permitted to implement the change at any point in time after the exit briefing. Trial operations, if used, shall be coordinated to ensure operational authority for an Area is clear at all times.
7. Entity comments will be given due consideration and incorporated into the summary report at the discretion of the CRTL and the input of the CRT. The CRTL will review the completed summary report with the CRT.
8. When all Open Issues are satisfactorily closed, the CRTL will submit the summary report to Regional Entity(ies) management for consideration and approval. CRT minority opinions and areas where CRT consensus was not reached will be communicated to Regional Entity(ies) management prior to approval but will not be included in the final report nor in the Regional Entity recommendation to NERC.
    a. If Regional Entity management contradicts the CRT finding, the CRTL will work with the CRT and the entity to resolve any issues.
    b. The Regional Entity CEO (or a designee) will transmit to NERC and copy the entity the final CRT report with a recommendation regarding NERC's certification of the entity.
9. If NERC approves continued certification for the entity, NERC shall email confirmation to the entity.
10. If NERC declines continued certification for the entity, NERC shall make available to the entity Hearing Procedures for use in Appeals of Certification Matters, CCCPP-005 contained in Appendix 4E.

Data Retention

1. Documentation used to substantiate the conclusions of the Certification review must be retained by the Regional Entity for six (6) years.
2. Documentation used to substantiate program oversight of the certification processes must be retained by NERC for six (6) years.

Section VI — NERC Organization Registration Appeals Process

Purpose and Scope

This section describes the process that any organization must use to seek review of its listing and functional assignment on the NCR.

Overview

NERC has established documented procedures to ensure a fair and impartial appeals process. No one with a direct interest in a dispute may participate in the appeals process except as a party or witness.

Organization Registration Appeals Procedure

1. Any Registered Entity included on the NCR may challenge final decisions regarding its listing, functional assignments, and determinations regarding the applicability of a sub-set of Reliability Standards (which specifies the specific Reliability Standards and may specify Requirements/sub-Requirements).
2. All registration appeals must be filed in writing to NERC, via electronic and registered mail. Appeals are sent to:

   Organization Registration and Certification
   Main: (404) 446-2560
   Facsimile: (404) 446-2595
   Email: Communications@NERC.net
   Address: As posted on NERC.com
3. Each party in the appeals process shall pay its own expenses for each step in the process.
4. A stipulation of invoking the appeals process is that the Regional Entity or Registered Entity requesting the appeal agrees that NERC (its Members, Board, committees, subcommittees, and staff), any person assisting in the appeals process, and any company employing a person assisting in the appeals process, shall not be liable for, and shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.
5. Parties retain the right to seek further review of a decision in whatever regulatory agency or court that may have jurisdiction.
6. All appeals must be received within 21 Days of receipt of the NERC determination that is being appealed. The appeal must state why the Registered Entity believes it should not be registered or should be deactivated based on the NERC ROP and the *NERC Statement of Compliance Registry Criteria* or why its compliance obligations should be limited only to a sub-set list of otherwise applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements). A copy of the appeal must be concurrently served on the Regional Entity.
7. After receipt of the appeal, the Registered Entity has a 30 day period to work with the Regional Entity to resolve the appeal, if possible. NERC may extend such deadline in its sole discretion. If the appeal is resolved, the Regional Entity will notify NERC with the details of the resolution and NERC will close the appeal.
8. At any time through this appeals process, a Registered Entity may agree with the decision and/or agree to close the appeal. NERC shall notify the involved parties and the NERC BOTCC that the appeal is resolved and update the NCR as applicable.

9. NERC will notify the Registered Entity and the applicable Regional Entity(ies) regarding the appeal with the following expectations:

    a. The Registered Entity will provide NERC and the applicable Regional Entity(ies) any additional data supporting its appeal within 10 Days of the date of the NERC appeal notification.

    b. The applicable Regional Entity(ies) will provide a copy of its assessment directly to the Registered Entity, as well as to NERC, within 20 Days of the date of the NERC appeal notification.

    c. The Registered Entity may submit a response to the Regional Entity(ies) assessment, with copies to the Regional Entity(ies) and NERC, within 30 Days of the date of the NERC appeal notification.

    d. To ensure there is no confusion with respect to the rights and responsibilities of the Registered Entity during the appeal process, the notification will confirm whether the Registered Entity will remain on the NERC Compliance Registry and will be responsible for compliance with approved Reliability Standards applicable to the function under appeal during the appeal.

    e. NERC may extend the timelines for good cause shown. Requests should be sent to the Registration email address, found on the Registration and Certification page on the NERC website. NERC shall notify the Registered Entity and the Regional Entity of such time extensions.

10. Hearing and Ruling by the BOTCC

    a. The BOTCC will resolve Registration disputes and apply a *de novo* review.

    b. The BOTCC may request additional data from NERC, the relevant Regional Entity(ies) or the Registered Entity, and prescribe the timeframe for the submitting the requested data.

    c. The BOTCC will provide a written decision regarding any appeals, along with the basis for its decision.

    d. If the BOTCC upholds the appeal, NERC will:

        - Notify the Registered Entity and Regional Entity(ies) that the appeal was granted.
        - Update the NCR.

    e. If the BOTCC does not uphold the appeal, NERC will:

        - Notify the Registered Entity and the Regional Entity(ies) that the appeal was denied.
        - The Registered Entity may appeal to Federal Energy Regulatory Commission (FERC) or another Applicable Governmental Authority within 21 Days of the notification of the decision.

    f. A record of the appeals process shall be maintained by NERC. Confidentiality of the record of the appeal will be based on the NERC ROP Section 1500.

Section VII — NERC Organization Certification Appeals Process

Purpose and Scope

This section describes the process for an organization to appeal the Certification decision that was determined in the Certification process.

Overview

The NERC Organization Certification Program provides a key means to fulfill NERC's mission. In conducting this program, NERC has established documented procedures to ensure a fair and impartial appeals process. No one with a direct interest in a dispute may participate in the appeals process except as a party or witness.

Organization Certification Appeals Procedure

1. Appeal for an Organization Certification finding.
2. Any entity can appeal an Organization Certification decision issued as a result of the Certification process.
3. Requirements and Conditions for Appeals.
    a. For all appeals under the NERC Organization Certification Program, the appeals process begins when an entity notifies the NERC via the Certification email address, found on the Registration and Certification page of the NERC website that it wishes to use the NERC appeals process.
        - The Director of Compliance is the main contact for all parties in all steps of the appeals process.
        - If an appeal is not filed within 21 Days of the date that the Certification report or finding is issued, or the final Regional Entity appeals process ruling is made, the finding shall be considered final and un-appealable.
    b. Each party in the appeals process shall pay its own expenses for each step in the process.
    c. A stipulation of invoking the appeals process is that the Regional Entity or entity requesting the appeal agrees that NERC (its Members, Board, committees, subcommittees, and staff), any person assisting in the appeals process, and any company employing a person assisting in the appeals process, shall not be liable, and shall be held harmless against the consequences of any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.
    d. Parties retain the right to seek further review of a decision in whatever regulatory agency or court that may have jurisdiction.
4. At any time through this appeals process, an entity may withdraw its appeal.
5. Hearing and Ruling by the Compliance and Certification Committee.
    a. Within 28 Days of receiving notice from the NERC Director of Compliance, the CCC will conduct a hearing where all the parties or representatives of the disputing parties will present the issue in question, in accordance with CCC procedure CCCPP-005, *Hearing Procedures for Use in Appeals of Certification Matters*, which is incorporated in **Appendix 4E** of the ROP.
    b. If the appeal is upheld, NERC notifies the entity and Regional Entity(ies), updates the NCR, and issues any appropriate letter and certificate to the entity.
    c. If the appeal is denied, NERC notifies the entity and Regional Entity(ies).
6. Hearings and Ruling by the BOTCC.

a. The BOTCC will be asked to resolve a dispute related to the NERC Organization Certification Program if any party to the appeal contests the CCC final order.

b. The BOTCC may request additional data from NERC, Regional Entity(ies) or the entity and prescribe the timeframe for submitting the requested data.

c. At the next regularly scheduled BOTCC meeting, or at a special meeting if the Board determines it is necessary, the Chair of the CCC will present a summary of the dispute and the actions taken to the BOTCC.

- Each party will have an opportunity to state its case.
- The BOTCC will then rule on the dispute.

d. If the BOTCC upholds the appeal, NERC will:

- Notify the entity and the Regional Entity(ies) that the appeal was upheld.
- Update the NCR.
- Issue a Certification letter and a certificate to the entity as applicable.

e. If the BOTCC does not uphold the appeal, NERC will notify the entity and the Regional Entity(ies) that the appeal was denied.

- The entity may appeal to Applicable Governmental Authorities within 21 Days of the issuance of the decision.

f. A record of the appeals process shall be maintained by NERC and available upon request. Confidentiality of the record of the appeal will be based on the NERC ROP Section 1500.

Definitions

Capitalized terms used in this Appendix shall have the definitions set forth in Appendix 2 of the ROP. For convenience of reference, definitions used in this Appendix are also set forth below:

NERC Organization Certification	The process undertaken by NERC and a Regional Entity to verify that a new entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator, and/or Reliability Coordinator.
Compliance and Certification Manager	The individual/individuals within the Regional Entity that is/are responsible for monitoring compliance of entities with applicable NERC Reliability Standards.
Days	Days as used in the Registration and Certification processes are defined as calendar days.
Footprint	The geographical or electric area served by an entity.
Functional Entity	An entity responsible for a function that is required to ensure the Reliable Operation of the electric grid as identified in the NERC Reliability Standards.
Mapping	The process of determining whether a Regional Entity's Footprint is being served by Registered Entities.
NERC Identification Number (NERC ID)	A number given to NERC Registered Entities that will be used to identify the entity for certain NERC activities. Corporate entities may have multiple NERC IDs to show different corporate involvement in NERC activities.
Regional Entity	An entity having enforcement authority pursuant to 18 C.F.R. § 39.8.
Registration	Processes undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region.
Coordinated Functional Registration (CFR)	Where two or more entities (parties) agree in writing upon a division of compliance responsibility among the parties for one or more Reliability Standard(s) applicable to a particular function, and/or for one or more Requirement(s)/sub-Requirement(s) within particular Reliability Standard(s).

Attachment 2-C

Appendix 5B Clean

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix 5B

Statement of Compliance Registry Criteria
Revision 9

Effective: TBD

RELIABILITY | RESILIENCE | SECURITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Statement of Compliance Registry Criteria (Revision 9) 1
Summary 1
Background 2
Statement of Issue 2
Resolution 2
Registry Criteria 2
Determination of Material Impact 6
Limitation of responsibilities to a sub-set of Reliability Standards 7

Public

Statement of Compliance Registry Criteria (Revision 9)

Summary

This document describes how the North American Electric Reliability Corporation (NERC) will identify organizations that may be candidates for Registration and assign them to the Compliance Registry.

NERC and the Regional Entities[1] have the obligation to identify and register all entities that meet the criteria for inclusion in the Compliance Registry, as further explained in the balance of this document.

Organizations will be responsible to register and to comply with approved Reliability Standards to the extent that they are owners, operators, and users of the Bulk Power System (BPS), perform a function listed in the functional types identified in Section II of this document, and are material to the Reliable Operation of the interconnected BPS as defined by the criteria and sections set forth in this document. NERC will apply the following principles to the Compliance Registry:

- In order to carry out its responsibilities related to enforcement of Reliability Standards, NERC must identify the owners, operators, and users of the BPS who have a material impact[2] on the BPS through a Compliance Registry. NERC and the Regional Entities will make their best efforts to identify all owners, users and operators who have a material impact on the BPS in order to develop a complete and current Compliance Registry list. The Compliance Registry will be updated as required and maintained on an on-going basis.
- Organizations listed in the Compliance Registry are responsible and will be monitored for compliance with applicable mandatory Reliability Standards. They will be subject to NERC's and the Regional Entities' Compliance Monitoring and Enforcement Programs.
- NERC and Regional Entities will not monitor nor hold those not in the Compliance Registry responsible for compliance with the Reliability Standards. An entity which is not initially placed on the Compliance Registry, but which is identified subsequently as having a material impact on the BPS, will be added to the Compliance Registry. Such entity will not be subject to a sanction or Penalty by NERC or the Regional Entity for actions or inactions prior to being placed on the Compliance Registry, but may be required to comply with a Remedial Action Directive or Mitigation Plan in order to become compliant with applicable Reliability Standards. After such entity has been placed on the Compliance Registry, it shall be responsible for complying with Reliability Standards and may be subject to sanctions or Penalties as well as any Remedial Action Directives and Mitigation Plans required by the Regional Entities or NERC for future violations, including any failure to follow a Remedial Action Directive or Mitigation Plan to become compliant with Reliability Standards.
- Required compliance by a given organization with the Reliability Standards will begin the later of (i) inclusion of that organization in the Compliance Registry and (ii) approval by the Applicable Governmental Authority of mandatory Reliability Standards applicable to the registered entity.

Entities responsible for funding NERC and the Regional Entities have been identified in the budget documents filed with FERC.[3] Presence on or absence from the Compliance Registry has no bearing on an entity's independent responsibility for funding NERC and the Regional Entities.

---

[1] The term "Regional Entities" includes Cross-Border Regional Entities that have footprints in the U.S., Canada, and Mexico, as applicable. Applicable Governmental Authorities in Canadian jurisdictions may have adopted their own Rules of Procedure and Compliance Registry requirements. Registered Entities may be subject to the Compliance Monitoring and Enforcement Programs (CMEP) in their respective jurisdictions, in accordance with applicable laws and regulations.

[2] The criteria for determining whether an entity will be placed on the Compliance Registry are set forth in the balance of this document. At any time a person may recommend in writing, with supporting reasons, to the Director of Compliance (or an equivalent position) that an organization be added to or removed from the Compliance Registry, pursuant to NERC Rules of Procedure Section 501.1.3.5.

[3] Budget documents are submitted to Applicable Governmental Authorities in Canada for information.

Background

The initial Registration process began in January of 2006. Registration of new entities is an ongoing process. If a Registered Entity's information changes, these changes must be submitted to the applicable Regional Entity(ies). Based on selection as the ERO, NERC's Organization Registration program[4] is the means by which NERC and the Regional Entities plan, manage, and execute Reliability Standard compliance oversight of owners, operators, and users of the BPS. Organizations listed in the Compliance Registry are subject to NERC's and the Regional Entities' Compliance Monitoring and Enforcement Programs.

Statement of Issue

As the ERO, NERC intends to comprehensively and thoroughly protect the reliability of the grid. To support this goal NERC will include in its Compliance Registry each entity that NERC concludes can materially impact the reliability of the BPS.

NERC will identify those entities that may need to be listed in its Compliance Registry. Identifying these organizations is necessary and prudent for the purpose of determining resource needs, both at the NERC and Regional Entity level, and for communicating with these entities regarding their potential responsibilities and obligations. Candidate entities can be identified at any time, as and when needed. The Compliance Registry is available on NERC's website.

Resolution

The potential costs and effort of registering every organization potentially within the scope of "owner, operator, and user of the BPS," while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so.

NERC and the Regional Entities have identified two principles they believe are key to the entity selection process. These are:

1. There needs to be consistency between Regions and across the continent with respect to which entities are registered; and
2. Any entity reasonably deemed material to the reliability of the BPS will be registered, irrespective of other considerations.

To address the second principle the Regional Entities, working with NERC, will identify and register any entity they deem material to the reliability of the BPS.

Registry Criteria

In order to promote consistency, NERC and the Regional Entities use the following criteria as the basis for determining whether particular entities should be identified as candidates for Registration. All organizations meeting or exceeding the criteria will be identified as candidates.

The following criteria (Sections I-V) plus the statement in Section VI will provide guidance regarding an entity's Registration status:

I. Owners, operators, or users of the BPS are candidates for Registration.[5]

[4] See NERC ERO Application; Exhibit C; Section 500 – Organization Registration and Certification.

[5] See NERC Rules of Procedure Section 501.1 NERC Compliance Registry — NERC shall establish and maintain the NCR of the BPS owners, operators, and users that are subject to approved Reliability Standards. For purposes of this Section I, users, owners, and operators of the BPS includes: 1) entities that use, own, or operate Elements of the Bulk Electric System (BES) as defined in Appendix 2 of the NERC Rules of Procedure and NERC Glossary of Terms; as well as 2) entities otherwise defined in the Registry Criteria in this Appendix 5B.

II. Entities identified in Section I above will be categorized as Registration candidates who may be subject to Registration under one or more appropriate Functional Entity types based on a comparison of the functions the entity normally performs against the following function type definitions.[6]

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time.
Computational Load Operator	CLOP	The entity that operates a Computational Load Site.
Computational Load Owner	CLO	The entity that owns and maintains a Computational Load Site.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage. Note: As provided in Section III.b.1 below, a Distribution Provider entity shall be an Underfrequency Load Shedding (UFLS)-Only Distribution Provider if it is the responsible entity that owns, controls or operates UFLS Protection System(s) needed to implement a required UFLS program designed for the protection of the BES, but does not meet any of the other registration criteria for a Distribution Provider.
Frequency Response Sharing Group	FRSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Generator Operator	GOP	The entity that: 1) operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services (Category 1 GOP); or 2) operates non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV (Category 2 GOP).

[6] Exclusion: An entity will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, including bilateral agreements and Sections 501, 507, and 508 of the NERC Rules of Procedure.

Function Type	Acronym	Definition/Discussion
Generator Owner	GO	The entity that: 1) owns and maintains generating Facility(ies) (Category 1 GO); or 2) owns and maintains non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV (Category 2 GO).
Planning Authority/ Planning Coordinator	PA/PC	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the Reliable Operation of the BES, has the Wide Area view of the BES, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Regulation Reserve Sharing Group	RRSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply Operating Reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in more quickly (e.g., between zero and ten minutes), then, for the purposes of recovery from a Reportable Balancing Contingency Event, the areas become a Reserve Sharing Group.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific Loads (customer demand and energy requirements) within a Planning Authority area.
Transmission Owner	TO	The entity that owns and maintains transmission Facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.

Function Type	Acronym	Definition/Discussion
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.

III. Entities identified in Section II above as being subject to Registration as a Distribution Provider, Computational Load Operator, or Computational Load Owner should be included in the Compliance Registry for these functions only if they meet any of the criteria listed below:

III(a) Distribution Provider:

III.a.1 Distribution Provider system serving >75 MW of peak Load that is directly connected to the BES;[7] or

III.a.2 Distribution Provider is the responsible entity that owns, controls, or operates Facilities that are part of any of the following Protection Systems or programs designed, installed, and operated for the protection of the BES:[8]

- a required Undervoltage Load Shedding (UVLS) program and/or
- a required Special Protection System or Remedial Action Scheme and/or
- a required transmission Protection System; or

III.a.3 Distribution Provider that is responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs) pursuant to an executed agreement; or

III.a.4 Distribution Provider with field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks.

III(b) Distribution Provider with UFLS-Only assets (referred to as "UFLS-Only Distribution Provider")

III.b.1 UFLS-Only Distribution Provider does not meet any of the other registration criteria in Sections III(a)(1)-(4) for a Distribution Provider; and

III.b.2 UFLS-Only Distribution Provider is the responsible entity that owns, controls, or operates UFLS Protection System(s) needed to implement a required UFLS Program designed for the protection of the BES.

The Reliability Standards applicable to UFLS-Only Distribution Providers are: (1) any version of PRC-005 and PRC-006 applicable to UFLS-Only Distribution Providers, (2) any regional Reliability Standard whose purpose is to develop or establish a UFLS Program, and (3) any Reliability Standard that lists UFLS-Only Distribution Provider in the applicability section. Reliability Standards that apply to Distribution Providers will not apply to UFLS-Only Distribution Providers, unless explicitly stated in the applicability section of these Reliability Standards and in future revisions and/or versions.

[7] Ownership, control or operation of UFLS Protection System(s) needed to implement a required UFLS Program designed for the protection of the BES does not affect an entity's eligibility for registration pursuant to III.a.1.

[8] As used in Section III.a.2, "protection of the Bulk Electric System" means protection to prevent instability, Cascading, or uncontrolled separation of the BES and not for local voltage issues (UVLS) or local line loading management (Special Protection System) that are demonstrated to be contained within a local area.

III(c) Computational Load Owner or Operator:

III.c.1 Computational Load Owner of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection.

III.c.2 Computational Load Operator of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection.

IV. Joint Registration Organization, Coordinated Functional Registration and applicable Member Registration.

Pursuant to FERC's directive in paragraph 107 of Order No. 693, NERC's rules pertaining to joint Registrations and Joint Registration Organizations, as well as Coordinated Functional Registrations, are now found in Section 501, 507, and 508 of the NERC Rules of Procedure.

V. If NERC or a Regional Entity encounters an organization that is not listed in the Compliance Registry, but which should be subject to the Reliability Standards, NERC or the Regional Entity is obligated and will initiate actions to add that organization to the Compliance Registry, subject to that organization's right to challenge as provided in Section 500 of NERC's Rules of Procedure.

Determination of Material Impact[9]

An entity that does not meet (i.e., falls below) the criteria may nevertheless be registered if it can be demonstrated that the entity has a material impact on the reliability of the BPS. Similarly, an entity that meets the criteria may be excluded if it can be demonstrated to NERC that the entity does not have a material impact on the reliability of the BPS. Such Registration decisions regarding materiality must be made by the NERC-led Registration Review Panel in accordance with Section III(D) of Appendix 5A to the NERC Rules of Procedure. In order to ensure a consistent approach to assessing materiality, a non-exclusive set of factors ("materiality test") for consideration is identified below; however, only a sub-set of these factors, or other additional factors, may be applicable to a particular functional registration category or specific entity, as appropriate:

1. Is the entity specifically identified in the emergency operation plans and/or restoration plans of an associated Reliability Coordinator, Balancing Authority, Generator Operator or Transmission Operator?
2. Will intentional or inadvertent removal of an Element owned or operated by the entity, or a common mode failure of two Elements as identified in the Reliability Standards (for example, loss of two Elements as a result of a breaker failure), lead to a reliability issue on another entity's system (such as a neighboring entity's Element exceeding an applicable rating, or loss of non-consequential load due to a single contingency)? Conversely, will such contingencies on a neighboring entity's system result in issues for Reliability Standards compliance on the system of the entity in question?
3. Can the normal operation, misoperation or malicious use of the entity's cyber assets cause a detrimental impact (e.g., by limiting the operational alternatives) on the operational reliability of an associated Balancing Authority, Generator Operator or Transmission Operator?
4. Can the normal operation, misoperation, or malicious use of the entity's Protection Systems (including UFLS, UVLS, Special Protection System, Remedial Action Schemes and other Protection Systems protecting BES Facilities) cause an adverse impact on the operational reliability of any associated Balancing Authority,

[9] The Determination of Material Impact applies when an entity seeks a NERC-led Registration Review Panel to review its request for examination of registration based on material impact. As stated in Appendix 5A, "[t]he Panel shall also include a review of individual and aggregate system-wide risks to, and considerations of, reliability of the BPS, as well as the BES Definition, as applicable." Appendix 5A, Section III(D). Any such request will be reviewed on a case by case basis in accordance with the Panel procedures set forth in Appendix 5A.

Generator Operator or Transmission Operator, or the automatic load shedding programs of a PC or TP (UFLS, UVLS)?

Limitation of responsibilities to a sub-set of Reliability Standards

NERC may limit the compliance obligations of (1) a given entity registered for a particular function or (2) a similarly situated class of entities, as warranted based on the particular facts and circumstances, to a sub-set list of Reliability Standards (which may specify Requirements/sub-Requirements). If NERC establishes a sub-set list for similarly situated class of entities, NERC will post the eligibility criteria and sub-set list of applicable Reliability Standards to the Registration and Certification page of the NERC Website.

Attachment 3

Redline Proposed Revisions

Attachment 3-A

Appendix 2 Redline

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DEFINITIONS USED IN THE RULES OF PROCEDURE

APPENDIX 2 TO THE RULES OF PROCEDURE

Effective: ~~June 27, 2024~~TBD

General

For purposes of the NERC Rules of Procedure, including all Appendices, the terms defined in this Appendix shall have the meanings set forth herein. For convenience of reference to the user, definitions of terms that are used in a particular Appendix may be repeated in that Appendix.

Where used in the Rules of Procedure, a defined term will be capitalized. Where a term defined in this Appendix appears in the Rules of Procedure but is not capitalized, the term is there being used in its ordinary and commonly understood meaning and not as defined in this Appendix (if different). Other terms that are not defined terms, such as the names of entities, organizations, committees, or programs; position titles; titles of documents or forms; section headings; geographic locations; and other terms commonly presented as proper nouns, may also be capitalized in the Rules of Procedure without being defined in this Appendix.

Definitions of terms in this Appendix that are marked with asterisks (**) are taken from the NERC *Glossary of Terms Used in Reliability Standards*. Definitions of terms in this Appendix that are marked with "pluses" (++) are taken from Section 215 of the Federal Power Act or the Commission's regulations at 18 C.F.R. Part 39 or Part 388.

Other terms used in the Rules of Procedure but not defined in this Appendix that have commonly understood and used technical meanings in the electric power industry, including applicable codes and standards, shall be construed in accordance with such commonly understood and used technical meanings.

Specific Definitions

"Acceptance of the Exception Request" or "Acceptance" means the determination that an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) contains all the Required Information so that it can undergo substantive review.

"Adjacent Balancing Authority" means a Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**

"Adjusted Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as determined based on application of the adjustment factors identified in Section 4.3 of the *Sanction Guidelines* to the Base Penalty Amount.

"Advisories" or "Level 1 (Advisories)" is a notification issued by NERC in accordance with Section 810.3.1 of the Rules of Procedure.

"Alleged Violation" means a potential noncompliance for which the Compliance Enforcement Authority has determined, based on an assessment of the facts and circumstances surrounding the potential noncompliance, that evidence exists to indicate a Registered Entity has violated a Reliability Standard and such violation will be resolved outside of the Compliance Exception or FFT processes.

"Annual Report" means the annual report to be filed by NERC with FERC and other Applicable Governmental Authorities in accordance with Section 13.0 of Appendix 4D.

"Applicable Governmental Authority" means the FERC within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability in Canada and Mexico.

"Applicable Requirement" means a Requirement or a Requirement Part of a CIP Standard that (i) expressly provides that compliance with the terms of the Requirement or Requirement Part is required where technically feasible or (ii) is subject to Appendix 4D by FERC directive.

"Approval of the Exception Request" or "Approval" means the determination by NERC that an Exception Request meets the criteria to receive the requested Exception.

"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**

"Balancing Authority Area" means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.**

"Base Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as initially determined pursuant to Sections 4.1 and 4.2 of the NERC *Sanction Guidelines*, before application of any adjustment factors.

"BES Cyber Asset" means a Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.**

"BES Cyber System" means one or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.**

"BES Definition" means the NERC definition of the Bulk Electric System as set forth in the NERC *Glossary of Terms Used in Reliability Standards.*

"Blackstart Resource" means a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the

Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.**

"Board" or "Board of Trustees" means the Board of Trustees of NERC.

"Board of Trustees Compliance Committee," "BOTCC" or "Compliance Committee" means the Compliance Committee of the NERC Board of Trustees, or its successor.

"Bulk Electric System" or "BES" means unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.

- **I2** - Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
    a) Gross individual nameplate rating greater than 20 MVA. Or,
    b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.

- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
    a) The individual resources, and
    b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

- **I5** - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

    a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

  b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

  c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4** - Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.**

"Bulk Power System" means, depending on the context:
(i) (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and
(B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.)
(ii) Solely for purposes of Appendix 4E, Bulk Electric System.

"Canadian" means one of the following: (a) a company or association incorporated or organized under the laws of Canada, or its designated representative(s) irrespective of nationality; (b) an agency of a federal, provincial, or local government in Canada, or its designated representative(s) irrespective of nationality; or (c) a self-representing individual who is a Canadian citizen residing in Canada.

"Canadian Entity" means a Registered Entity (or, solely for purposes of Appendix 4D, a Responsible Entity) that is organized under Canadian federal or provincial law.

"Cascading" means the uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.**

"CCC" means the NERC Compliance and Certification Committee.

"Certification" means, depending on the context, (i) the process undertaken by NERC and a Regional Entity to verify that an entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator and/or Reliability Coordinator; such Certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure; or (ii) for purposes of Section 600 of the Rules of Procedure, an official recognition that indicates the recipient has passed a NERC exam or completed a specified number of Continuing Education Hours.

"Certification Staff" means individuals employed or contracted by NERC who have the authority to make initial determinations of Certification of entities performing reliability functions.

"Certification Team" means a team assembled by a Regional Entity that will be responsible for performing the activities included in the Certification process for an entity pursuant to Appendix 5A.

"CIP Senior Manager" means a single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC CIP Standards.**

"Classified National Security Information" means Required Information that has been determined to be protected from unauthorized disclosure pursuant to Executive Order No. 12958, as amended,

and/or the regulations of the NRC at 10 C.F.R. §95.35; or pursuant to any comparable provision of Canadian federal or provincial law.

"Clerk" means an individual assigned by the Compliance Enforcement Authority or NERC to perform administrative tasks relating to the conduct of hearings as described in Attachment 2, Hearing Procedures, to Appendix 4C.

"Commission" means the Federal Energy Regulatory Commission or FERC.

"Complaint" means an allegation that a Registered Entity violated a Reliability Standard.

"Compliance and Certification Manager" means individual/individuals within the Regional Entity that is/are responsible for monitoring compliance of entities with applicable NERC Reliability Standards.

"Compliance Audit" means a systematic, objective review and examination of records and activities to determine whether a Registered Entity meets the Requirements of applicable Reliability Standards.

"Compliance Audit Participants" means Registered Entities scheduled to be audited and the audit team members.

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

"Compliance Enforcement Authority's Area of Responsibility" means the Compliance Enforcement Authority's Region. If a Regional Entity is the Compliance Enforcement Authority, the Compliance Enforcement Authority's Area of Responsibility is shown in Exhibit A to the delegation agreement between the Regional Entity and NERC.

"Compliance Exception" means a noncompliance that is addressed in Appendix 4C and is not pursued through an enforcement action under Section 5.0 of Appendix 4C to these Rules of Procedure by a Compliance Enforcement Authority.

"Compliance Investigation" means a comprehensive investigation, which may include an on-site visit with interviews of the appropriate personnel, to determine if a violation of a Reliability Standard has occurred.

"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC *Compliance Monitoring and Enforcement Program* (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

"Compliant Date" means the date by which a Responsible Entity is required to be in compliance with an Applicable Requirement of a CIP Standard.

"Computational Load Operator" means the entity that operates a Computational Load Site.

"Computational Load Owner" means the entity that owns and maintains a Computational Load Site.

"Computational Load Site" means one or more buildings, structures, or installations at a single location that

1) Primarily contains information technology infrastructure used for:
   - creating, executing, and delivering software applications and services;
   - artificial intelligence training, deployment, and delivery;
   - cryptocurrency mining; or
   - other computational activities at a data center; and
2) is supplied through electrical equipment that is connected to the BPS.

"Confidential Business and Market Information" means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

"Confidential Information" means (i) Confidential Business and Market Information; (ii) Critical Electric Infrastructure Information; (iii) Critical Energy Infrastructure Information; (iv) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (v) work papers, including any records produced for or created in the course of an evaluation or audit; (vi) investigative files, including any records produced for or created in the course of an investigation; or (vii) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition; or (vii) for purposes of Appendix 4D, any other information that is designated as Confidential Information in Section 11.0 of Appendix 4D.

"Confirmed Violation" means an Alleged Violation for which (1) the Registered Entity has accepted or not contested the Notice of Alleged Violation and Penalty or Sanction or other notification of the Alleged Violation, or (2) there has been the issuance of a final order from NERC or a Hearing Body finding a violation, Penalty or sanction, or (3) the period for requesting a hearing or an appeal has expired, or (4) the Registered Entity has executed a settlement agreement pursuant to Section 5.6.

"Consolidated Hearing Process" means the process pursuant to Section 403.15B used to conduct hearings and issue decisions concerning disputed compliance matters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

"Continuing Education Hour" or "CE Hour" means based on sixty clock minutes, and includes at least fifty minutes of participation in a group or self-study learning activity that meets the criteria of the NERC Continuing Education Program.

"Continuing Education Program Provider" or "Provider" means the individual or organization offering a learning activity to participants and maintaining documentation required by Section 600 of the Rules of Procedure.

"Coordinated Functional Registration" means where two or more entities (parties) agree in writing upon a division of compliance responsibility among the parties for one or more Reliability Standard(s) applicable to a particular function, and/or for one or more Requirement(s)/sub-Requirement(s) within particular Reliability Standard(s).

"Covered Asset" means any BES Cyber Asset, BES Cyber System, Protected Cyber Asset, Electronic Access Control or Monitoring System, or Physical Access Control System that is subject to an Applicable Requirement.

"Credential" means a NERC designation that indicates the level of qualification achieved (i.e., reliability operator; balancing, interchange, and transmission operator; balancing and interchange operator; and transmission operator).

"Critical Electric Infrastructure" means a system or asset of the bulk power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters.

"Critical Electric Infrastructure Information" means information related to proposed or existing Critical Electric Infrastructure. Such term includes information that qualifies as Critical Energy Infrastructure Information as defined herein.

"Critical Energy Infrastructure Information" means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.++

"Critical Infrastructure" means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.++

"Critical Infrastructure Protection Standard" or "CIP Standard" means any of NERC Reliability Standards included in the Critical Infrastructure Protection group of Reliability Standards that is adopted by the NERC Board of Trustees according to the NERC *Bylaws* and *Rules of Procedure* and approved by Applicable Governmental Authorities.

"Cross-Border Regional Entity" means a Regional Entity that encompasses a part of the United States and a part of Canada or Mexico.++

"Cyber Assets" means programmable electronic devices, including hardware, software, and data in those devices.**

"Cyber Security Incident" means any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.++

"Cyber Security Incident Information" means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

"Days", as used in Appendix 5A with respect to the Registration and Certification processes, means calendar days.

"Deactivation," as used in Appendix 5A with respect to the Registration processes, refers to removal of an entity from the NCR for a specific functional category. As a result of deactivation, the entity is no longer subject to any prospective compliance obligations with respect to Reliability Standards applicable to that functional category.

"Delegate" means a person to whom the CIP Senior Manager of a Responsible Entity has delegated authority pursuant to Requirement R4 of CIP Standard CIP-003 (or any successor provision).

"Director of Compliance" means the Director of Compliance of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority who is responsible for the management and supervision of Compliance Staff, or his or her designee.

"Director of Enforcement" means the Director of Enforcement of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority who is responsible for the management and supervision of Enforcement Staff, or his or her designee.

"Disapproval of the Exception Request" or "Disapproval" means the determination by NERC that an Exception Request does not meet the criteria to receive the requested Exception.

"Distribution Factor" means the portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).**

"Distribution Provider" means the entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**

"Document" means, in addition to the commonly understood meaning of the term as information written or printed on paper, any electronically stored information, including writings, drawings, graphs, charts, photographs, sound recordings, images and other data or data compilations stored

in any medium from which information can be obtained, and shall be translated by the producing party into reasonably usable form.

"Electric Reliability Organization" or "ERO" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the Bulk Power System in the United States, subject to Commission review. The organization may also have received recognition by Applicable Governmental Authorities in Canada and Mexico to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries.

"Electronic Access Control or Monitoring Systems" means Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.**

"Electronic Access Point" means a Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.**

"Electronic Security Perimeter" means the logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.**

"Element" means any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.**

"Eligible Reviewer" means a person who has the required security clearances or other qualifications, or who otherwise meets the applicable criteria, to have access to Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information, as applicable to the particular information to be reviewed.

"End Date" means the last date of the period to be covered in a Compliance Audit.

"Essential Actions" or "Level 3 (Essential Actions)" is a notification issued by NERC in accordance with Section 810.3.3 of the Rules of Procedure.

"Evidentiary Hearing" means a hearing at which one or more Participants submits evidence for the record. A Testimonial Hearing is an Evidentiary Hearing, but an Evidentiary Hearing does not necessarily include the presentation of testimony by witnesses in person.

"Exception" means either an Inclusion Exception or an Exclusion Exception.

"Exception Procedure" means the procedure set forth in Appendix 5C.

"Exception Request" means a request made by a Submitting Entity in accordance with Appendix 5C for an Exception.

"Exception Request Form" means the form adopted by each Regional Entity, in accordance with a template provided by NERC, for use by Submitting Entities in submitting Exception Requests; provided, that the Exception Request Form must include Section III.B as adopted by NERC.

"Exclusion Exception" means a determination that an Element that falls within the BES Definition should be excluded from the BES.

"Facility" means a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)**

"FERC" means the United States Federal Energy Regulatory Commission.

"Final Penalty Amount" means the final, proposed Penalty for violation of a Reliability Standard, determined in accordance with the *Sanction Guidelines*.

"Find, Fix, Track and Report" or "FFT" means a streamlined process, addressed in Appendix 4C, to resolve minimal or moderate risk, remediated noncompliance that are not assessed a financial penalty.

"Flowgate" means 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.**

"FOIA" means the U.S. Freedom of Information Act, 5 U.S.C. §552.

"Footprint" means the geographical or electric area served by an entity.

"Frequency Response Sharing Group" means a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.**

"Functional Entity" means an entity responsible for a function that is required to ensure the Reliable Operation of the electric grid as identified in the NERC Reliability Standards.

"Generator Operator" means the entity that: 1) operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services (Category 1 GOP); or 2) operates non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV (Category 2 GOP).

"Generator Owner" means an entity that: 1) owns and maintains generating Facility(ies) (Category 1 GO); or 2) owns and maintains non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected

through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV(Category 2 GO).

"Hearing Body" means the body designated by the Compliance Enforcement Authority to conduct hearings and issue decisions concerning disputed compliance matters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

"Hearing Officer" means, depending on the context, (i) an individual employed or contracted by the Compliance Enforcement Authority or NERC to preside over hearings conducted pursuant to Attachment 2, Hearing Procedures, of Appendix 4C; the Hearing Officer shall not be a member of the Hearing Body, or (ii) solely for hearings conducted pursuant to Appendix 4E, (A) a CCC member or (B) an individual employed or contracted by NERC, as designated and approved by the CCC to preside over hearings conducted pursuant to the Hearing Procedures in Appendix E; the Hearing Officer shall not be a member of the Hearing Panel.

"Hearing Panel" means the five person hearing body established as set forth in the CCC Charter on a case by case basis and that is responsible for adjudicating a matter as set forth in Appendix 4E.

"Hearing Procedures" means, depending on the context, (i) Attachment 2 to the NERC or a Regional Entity CMEP, as applicable, or (ii) the hearing procedures of the NERC Compliance and Certification Committee in Appendix 4E.

"Inclusion Exception" means a determination that an Element that falls outside the BES Definition should be included in the BES.

"Inherent Risk Assessment" or "IRA" means a review by the Compliance Enforcement Authority of potential risks posed by an individual Registered Entity to the reliability of the Bulk Power System. An IRA considers factors such as, but is not limited to, assets, system, geography, interconnectivity, prior compliance history and factors unique to the Registered Entity. The results of an entity-specific IRA may result in the scope of compliance monitoring for a particular Registered Entity to include more, fewer, or different Reliability Standards than those contained in the annual ERO CMEP Implementation Plan.

"Interactive Remote Access" means user-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point. Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.**

"Interchange" means energy transfers that cross Balancing Authority boundaries.**

"Interchange Authority" means the responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.**

"Interchange Distribution Calculator" means the mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.**

"Interchange Schedule" means an agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.**

"Interchange Transaction" means an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.**

"Interconnected Operations Service" means a service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.**

"Interconnection" means a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++ When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.**

"Interconnection Reliability Operating Limit" means a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.**

"Intermediate System" means a Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.**

"Internal Control Evaluation" or "ICE" means a review by the Compliance Enforcement Authority of a Registered Entity's internal controls. The ICE may further refine the compliance oversight plan, including the scope of an audit, the type and application of compliance monitoring tools, the depth and breadth of a particular area of review.

"Interpretation" means an addendum to a Reliability Standard, developed in accordance with the NERC *Standard Processes Manual* and approved by the Applicable Governmental Authority(ies), that provides additional clarity about one or more Requirements in the Reliability Standard.

"ISO/RTO" means an independent transmission system operator or regional transmission organization approved by the FERC or the Public Utility Commission of Texas.

"Joint Registration Organization" means two or more entities (the parties) agree in writing upon a division of compliance responsibility where an entity registers in the Compliance Registry for one or more function type(s) for itself and on behalf of one or more other parties to such agreement for function type(s) for which such parties would otherwise be required to register.

"Lead Entity" means (1) within the meaning of Appendices 5A and 5B, the entity identified in a Joint Registration Organization or Coordinated Functional Registration agreement as the primary Point of Contact that administers that agreement with NERC and the applicable Regional Entity(ies), and (2) within the meaning of Appendix 5C, the entity that submits the Exception Request information that is common to a group of Submitting Entities that are submitting Exception Requests jointly.

"Lead Mediator" means a member of a mediation team formed pursuant to Appendix 4E who is selected by the members to coordinate the mediation process and serve as the mediation team's primary contact with the Parties.

"Load" means an end-use device or customer that receives power from the electric system.**

"Load-Serving Entity" means an entity that secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.**

"Mapping" means the process of determining whether a Regional Entity's Footprint is being served by Registered Entities.

"Material Change" means a change in facts that modifies Required Information in connection with an approved TFE. Examples of a Material Change could include, but are not limited to an increase in device count (but not a decrease), change in compensating measures, change in statement of basis for approval for the TFE, a change in the TFE Expiration Date, or a Responsible Entity achieving Strict Compliance with the Applicable Requirement.

"Material Change Report" means a report submitted by the Responsible Entity to the Regional Entity in the event there is a Material Change to the facts underlying an approved TFE pursuant to Section 4.0 of Appendix 4D.

"Mediation Settlement Agreement" means a written agreement entered into by the Parties to a mediation pursuant to Appendix 4E that resolves the dispute.

"Member" means a member of NERC pursuant to Article II of its Bylaws.

"Member Representatives Committee" or "MRC" means the body established pursuant to Article VIII of the NERC Bylaws.

"Mexican Entity" means a Registered Entity that is organized under Mexican law.

"Mitigating Activities" means actions taken by a Registered Entity to correct and prevent recurrence of a noncompliance, whether or not the actions are embodied in a Mitigation Plan.

"Mitigation Plan" means an action plan developed by the Registered Entity to (1) correct a noncompliance with a Reliability Standard and (2) prevent re-occurrence of the violation.

"NERC-Approved Learning Activity" means training that maintains or improves professional competence and has been approved by NERC for use in its Continuing Education Program.

"NERC Compliance Monitoring and Enforcement Program Implementation Plan," "NERC Implementation Plan" or "ERO Compliance Monitoring and Enforcement Program (CMEP) Implementation Plan" means the annual ERO CMEP Implementation Plan that identifies the risk elements to prioritize risks to the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements become inputs for Regional Entities in their compliance oversight for individual Registered Entities. The ERO CMEP Implementation Plan may be updated more often than annually as needed.

"NERC Compliance Registry," "Compliance Registry" or "NCR" means a list, maintained by NERC pursuant to Section 500 of the NERC Rules of Procedure and Appendix 5B, the NERC *Statement of Compliance Registry Criteria*, of the owners, operators and users of the Bulk Power System, and the entities registered as their designees, that perform one or more functions in support of reliability of the Bulk Power System and are required to comply with one or more Requirements of Reliability Standards.

"NERC Identification Number" or "NERC ID" means a number given to NERC Registered Entities that will be used to identify the entity for certain NERC activities. Corporate entities may have multiple NERC IDs to show different corporate involvement in NERC activities.

"NERC Organization Certification" or "Organization Certification" means the process undertaken by NERC and a Regional Entity to verify that a new entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator, and/or Reliability Coordinator; such certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure.

"Net Energy for Load" or "NEL" means net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.

"Notice of Alleged Violation and Proposed Penalty or Sanction" means a notice issued by the Compliance Enforcement Authority to a Registered Entity pursuant to Section 5.3 of Appendix 4C.

"Notice of Completion of Enforcement Action" means a notice issued by the Compliance Enforcement Authority to a Registered Entity, pursuant to Section 5.10 of Appendix 4C, stating than an enforcement action is closed.

"Notice of Confirmed Violation" means a notice issued by the Compliance Enforcement Authority to a Registered Entity confirming the violation of one or more Reliability Standards.

"Notice of Penalty" means a notice prepared by NERC and filed with FERC, following approval by NERC of a Notice or other notification of Confirmed Violation or a settlement agreement, stating the Penalty or sanction imposed or agreed to for the Confirmed Violation or as part of the settlement.

"Notice of Preliminary Screen" means a notice issued by the Compliance Enforcement Authority to a Registered Entity that (1) states a potential noncompliance has been identified, (2) provides a brief description of the potential noncompliance, including the Reliability Standard Requirement(s) and the date(s) involved, and (3) instructs the Registered Entity to retain and preserve all data and records relating to the potential noncompliance.

"NRC" means the United States Nuclear Regulatory Commission.

"NRC Safeguards Information" means Required Information that is subject to restrictions on disclosure pursuant to 42 U.S.C. §2167 and the regulations of the NRC at 10 C.F.R. §73.21-73.23; or pursuant to comparable provisions of Canadian federal or provincial law.

"Open Access Transmission Tariff" means an electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.**

"Owner" means the owner(s) of an Element or Elements that is or may be determined to be part of the BES as a result of either the application of the BES Definition or an Exception, or another entity, such as an operator, authorized to act on behalf of the owner of the Element or Elements in the context of an Exception Request.

"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Body or by FERC to participate as an intervenor in a proceeding conducted pursuant to the Hearing Procedures, and as used in the Hearing Procedures shall include, depending on the context, the members of the Compliance Staff that participate in a proceeding or the members of the Certification Staff that participate in a proceeding pursuant to Appendix 4E.

"Party" or "Parties" means a Person or the Persons participating in a mediation pursuant to Appendix 4E.

"Penalty" means and includes all penalties and sanctions, including but not limited to a monetary or non-monetary penalty; a limitation on an activity, function, operation or other appropriate sanction; or the addition of the Registered Entity or Respondent to a reliability watch list composed of major violators. Penalties must be within the range set forth in the NERC *Sanction Guidelines* approved by FERC pursuant to 18 C.F.R. Section 39.7(g)(2), and shall bear a reasonable relation to the seriousness of a Registered Entity's or Respondent's violation and take into consideration any timely efforts made by the Registered Entity or Respondent to remedy the violation.

"Periodic Data Submittals" means modeling, studies, analyses, documents, procedures, methodologies, operating data, process information or other information to demonstrate compliance with Reliability Standards and provided by Registered Entities to the Compliance Enforcement Authority on a time frame required by a Reliability Standard or an ad hoc basis.

"Person" means any individual, partnership, corporation, limited liability company, governmental body, association, joint stock company, public trust, organized group of persons, whether incorporated or not, or any other legal entity.

"Planning Authority" means the responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.**

"Physical Access Control Systems" means Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.**

"Physical Security Perimeter" means the physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.**

"Point of Delivery" means a location that a Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.**

"Point of Receipt" means a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.**

"Potential Noncompliance" means the identification, by the Compliance Enforcement Authority, of a possible failure by a Registered Entity to comply with a Reliability Standard that is applicable to the Registered Entity.

"Preliminary Screen" means an initial evaluation of evidence indicating potential noncompliance with a Reliability Standard has occurred or is occurring, conducted by the Compliance Enforcement Authority, and consisting of an evaluation of whether (1) the entity allegedly involved in the potential noncompliance is registered, (2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to a reliability function for which the entity is registered, and (3) if known, the potential noncompliance is not a duplicate of one that is currently being processed.

"Probation" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is still valid. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

"Protected Cyber Asset" means one or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same Electronic Security Perimeter.**

"Protected FOIA Information" means Required Information, held by a governmental entity, that is subject to an exemption from disclosure under FOIA (5 U.S.C. §552(e)), under any similar state or local statutory provision, or under any comparable provision of Canadian federal or provincial law, which would be lost were the Required Information to be placed into the public domain.

"Protection System" means protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**

"Purchasing-Selling Entity" means the entity that purchases, or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.**

"Reactivation" refers to re-registration pursuant to the NERC Rules of Procedure Section 500 and Appendices 5A and 5B of an entity to the NCR for a specific functional category or the revocation of, or additions to, a sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements) that has been granted to an entity. Reactivation may be initiated by NERC, a Regional Entity or an entity with respect to such entity's own functional categories or sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements).

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

"Real Power" means the portion of electricity that supplies energy to the Load.**

"Receiving Entity" means NERC or a Regional Entity receiving Confidential Information from an owner, operator, or user of the Bulk Power System or from any other party.

"Recommendation" for purposes of Appendix 5C means the report to NERC containing the evaluation prepared in accordance with section 5.2 of Appendix 5C concerning whether or to what extent an Exception Request should be approved.

"Recommendations" or "Level 2 (Recommendations)" is a notification issued by NERC in accordance with Section 810.3.2 of the Rules of Procedure.

"Region" means the geographic area, as specified in a Regional Entity's delegation agreement with NERC, within which the Regional Entity is responsible for performing delegated functions.

"Regional Criteria" means reliability requirements developed by a Regional Entity that are necessary to implement, to augment, or to comply with Reliability Standards, but which are not Reliability Standards. Such Regional Criteria may be necessary to account for physical differences in the Bulk Power System but are not inconsistent with Reliability Standards nor do they result in lesser reliability. Such Regional Criteria are not enforceable pursuant to NERC-delegated authorities, but may be enforced through other available mechanisms. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents.

"Regional Entity" means an entity having enforcement authority pursuant to 18 C.F.R. § 39.8.++

"Regional Reliability Standard" means a type of Reliability Standard that is applicable only within a particular Regional Entity or group of Regional Entities. A Regional Reliability Standard may augment, add detail to, or implement another Reliability Standard or cover matters not addressed by other Reliability Standards. Regional Reliability Standards, upon adoption by NERC and approval by the Applicable Governmental Authority(ies), shall be Reliability Standards and shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Registered Ballot Body" means that aggregation of all entities or individuals that qualify for one of the Segments approved by the Board of Trustees, and are registered with NERC as potential ballot participants in the voting on proposed Reliability Standards.

"Registered Entity" means an owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry.

"Registration" or "Organization Registration" means the processes undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region.

"Regulation Reserve Sharing Group" means a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.**

"Rejection of the Exception Request" or "Rejection" means the determination that an Exception Request is not an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) or does not contain all the Required Information in accordance with section 4.5 of Appendix 5C in order to be reviewed for substance.

"Reliability Coordinator" means the entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.**

"Reliability Coordinator Area" means the collection of generation, transmission and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.**

"Reliability Standard" means a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk Power System. The term includes requirements for the operation of existing Bulk Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.++ (In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions.)

"Reliability Standards Development Plan" means the forward-looking plan developed by NERC on an annual basis setting forth the Reliability Standards development projects that are scheduled to be worked on during the ensuing three-year period, as specified in Section 310 of the Rules of Procedure.

"Reliable Operation" means operating the elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.++

"Remedial Action Directive" means an action (other than a Penalty or sanction) required by a Compliance Enforcement Authority that (1) is to bring a Registered Entity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat.

"Reporting Entity" means an entity required to provide data or information requested by NERC or a Regional Entity in a request for data or information pursuant to Section 1600 of the Rules of Procedure.

"Requirement" means an explicit statement in a Reliability Standard that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement with which compliance is mandatory.

"Required Date" means the date given a Registered Entity in a notice from the Compliance Enforcement Authority by which some action by the Registered Entity is required.

"Required Information" means, as applicable, either (i) the information required to be provided in a TFE Request, as specified in Section 4.0 of Appendix 4D; or (ii) the information required to be provided in an Exception Request, as specified in section 4.0 of Appendix 5C.

"Requirement Part" means a component of a Requirement that is designated by a decimal number (e.g., Requirement R1 could have Requirement Parts 1.1, 1.2 and 1.3).

"Reserve Sharing Group" means a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply Operating Reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in more quickly (e.g., between zero and ten minutes) then, for the purposes of recovery from a Reportable Balancing Contingency Event, the areas become a Reserve Sharing Group.**

"Resource Planner" means the entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.**

"Respondent" means, depending on the context, the Registered Entity, who is the subject of the Notice of Alleged Violation, contested Mitigation Plan or contested Remedial Action Directive that is the basis for the proceeding, whichever is applicable, or the Registered Entity that is the subject of the Certification decision that is the basis for a proceeding under Appendix 4E.

"Responsible Entity" means an entity that is registered for a reliability function in the NERC Compliance Registry and is responsible for complying with any Requirement, or Requirement Part.

"Revoked" means a NERC certificate that has been suspended for more than twelve months. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified. The certificate holder will be required to pass an exam to be certified again. Any CE Hours accumulated prior to or during the revocation period will not be counted towards Credential Maintenance.

"Revoke for Cause" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is no longer valid and requiring successfully passing an exam to become certified. However, an exam will not be authorized until the revocation period expires. CE Hours earned before or during this revocation period will not be counted for maintaining a Credential.

"Scope of Responsibility" means the registered functions of a Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority and the geographical or electric region in which the Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority operates to perform its registered functions, or with respect to a Regional Entity, its Regional Entity Region.

"Section I Required Information" means Required Information that is to be provided in Section I of a Submitting Entity's Exception Request.

"Section II Required Information" means Required Information that is to be provided in Section II of a Submitting Entity's Exception Request.

"Section III Required Information" means Required Information that is to be provided in Section III of a Submitting Entity's Exception Request.

"Sector" means a group of Members of NERC that are Bulk Power System owners, operators, or users or other persons and entities with substantially similar interests, including governmental entities, as pertinent to the purposes and operations of NERC and the operation of the Bulk Power System, as defined in Article II, Section 4 of the NERC Bylaws. Each Sector shall constitute a class of Members for purposes of the New Jersey Nonprofit Corporation Act.

"Segment" means one of the subsets of the Registered Ballot Body whose members meet the qualification criteria for the subset.

"Self-Certification" means an attestation by a Registered Entity that it is compliant or non-compliant with a Reliability Standard Requirement that is the subject of the Self-Certification, or that it does not own Facilities that are subject to the Reliability Standard Requirement, or that the Reliability Standard Requirement is not applicable to the Registered Entity.

"Self-Logging" means a process by which Registered Entities found to be eligible by a Compliance Enforcement Authority, after a formal review of internal controls, record potential noncompliance on a log, in accordance with Appendix 4C, in lieu of individually submitted Self-Reports of each potential noncompliance.

"Self-Report" means a report by a Registered Entity stating that the Registered Entity believes it has, or may have, violated a Reliability Standard.

"Sink Balancing Authority" means the Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.**

"Source Balancing Authority" means the Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.**

"Special Protection System" means an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system

stability, acceptable voltage, or power flows. A Special Protection System does not include (a) underfrequency or undervoltage Load shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a Special Protection System).**

"Spot Check" means a process in which the Compliance Enforcement Authority requests a Registered Entity to provide information (1) to support the Registered Entity's Self-Certification, Self-Report, or Periodic Data Submittal and to assess whether the Registered Entity complies with Reliability Standards, or (2) as a random check, or (3) in response to operating problems or system events.

"Staff" or "CMEP Staff" means individuals employed or contracted by NERC or the Compliance Enforcement Authority who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties and Mitigation Plans.

"Strict Compliance" means compliance with the terms of an Applicable Requirement without reliance on a Technical Feasibility Exception.

"Submitting Entity" means (i) an owner, operator, or user of the Bulk Power System or any other party that submits information to NERC or a Regional Entity that it reasonably believes contains Confidential Information or, (ii) solely for purposes of Appendix 5C, the entity that submits an Exception Request in accordance with section 4.0 of Appendix 5C.

"Suspended" means certificate status due to an insufficient number of CE Hours being submitted prior to the expiration of a certificate. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified.

"System" means a combination of generation, transmission and distribution components.**

"System Operating Limit" means the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- facility ratings (applicable pre- and post-contingency equipment ratings or facility ratings)
- transient stability ratings (applicable pre- and post-contingency stability limits)
- voltage stability ratings (applicable pre- and post-contingency voltage stability)
- system voltage limits (applicable pre- and post-contingency voltage limits).**

"Technical Advisor" means any Staff member, third-party contractor, or industry stakeholder who satisfies NERC's or the Compliance Enforcement Authority's (as applicable) conflict of interest policy and is selected to assist in a proceeding by providing technical advice to the Hearing Officer and/or the Hearing Body or Hearing Panel.

"Technical Feasibility Exception" or "TFE" means an exception from Strict Compliance with the terms of an Applicable Requirement on grounds of technical feasibility or technical limitations in accordance with one or more of the criteria in section 3.0 of Appendix 4D.

"Technical Review Panel" means a panel established pursuant to section 5.3 of Appendix 5C.

"Termination of Credential" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure whereby a Credential is permanently Revoked.

"Testimonial Hearing" means an Evidentiary Hearing at which the witness or witnesses on behalf of one or more Participants appears in person to present testimony and be subject to cross-examination.

"TFE Expiration Date" means the date on which an approved TFE expires.

"TFE Request" means a request submitted by a Responsible Entity in accordance with Appendix 4D for an exception from Strict Compliance with an Applicable Requirement.

"TFE Termination Date" means the date, as specified in a notice disapproving a TFE Request or terminating an approved TFE, on which the disapproval or termination becomes effective.

"Transmission" means an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.**

"Transmission Customer" means 1. any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can and does receive Transmission Service. 2. Any of the following entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.

"Transmission Operator" means the entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.**

"Transmission Owner" means the entity that owns and maintains transmission Facilities.**

"Transmission Planner" means the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.**

"Transmission Service" means services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.**

"Transmission Service Provider" means the entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.**

"Variance" means an aspect or element of a Reliability Standard that applies only within a particular Regional Entity or group of Regional Entities, or to a particular entity or class of entities. A Variance allows an alternative approach to meeting the same reliability objective as the Reliability Standard, and is typically necessitated by a physical difference. A Variance is

embodied within a Reliability Standard and as such, if adopted by NERC and approved by the Applicable Governmental Authority(ies), shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Violation Risk Factor" or "VRF" means a factor (lower, medium or high) assigned to each Requirement of a Reliability Standard to identify the potential reliability significance of noncompliance with the Requirement.

"Violation Severity Level" or "VSL" means a measure (lower, moderate, high or severe) of the degree to which compliance with a Requirement was not achieved.

"Wide Area" means the entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.**

Attachment 3-B

Appendix 5A Redline

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix 5A

Organization Registration and Certification Manual

Effective Date: ~~June 27, 2024~~TBD

RELIABILITY | RESILIENCE | SECURITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Section I — Executive Summary 1
Section II — Introduction to Organization Registration and Organization Certification Processes ..... 4~~3~~
Section III — Organization Registration Process ..... 7~~5~~
Section IV — Organization Certification Process ..... 13~~11~~
Section V — Organization Certification Review Process ..... 20~~18~~
Section VI — NERC Organization Registration Appeals Process ..... 26~~24~~
Section VII — NERC Organization Certification Appeals Process ..... 28~~26~~
Definitions ..... 30~~28~~

Public

Section I — Executive Summary

Overview

The purpose of this document is twofold: (1) to define the process utilized in the North American Electric Reliability Corporation (NERC) Organization Registration Program for identifying which functional entities must register as owners, operators, and users of the Bulk Power System (BPS) for compliance with Reliability Standards; and (2) to define the process utilized in the Organization Certification Program for certifying the following entities: Reliability Coordinator (RC), Balancing Authority (BA), and Transmission Operator (TOP).

To Whom Does This Document Apply?

All industry participants responsible for or intending to be responsible for, the following functions must register with NERC through the Organization Registration process. The entities are defined in the NERC *Statement of Compliance Registry Criteria*, set forth in **Appendix 5B** to the NERC Rules of Procedure (ROP), with responsibilities designated by the individual Reliability Standards or by a sub-set list of the otherwise applicable Reliability Standards determined in accordance with this **Appendix 5A**, Section III(D) to the NERC ROP.

	Entities that Must Register	Entities that Need to be Certified
Reliability Coordinator (RC)	√	√
Transmission Operator (TOP)	√	√
Balancing Authority (BA)	√	√
Planning Authority/Planning Coordinator (PA/PC)	√	
Transmission Planner (TP)	√	
Transmission Service Provider (TSP)	√	
Transmission Owner (TO)	√	
Resource Planner (RP)	√	
Distribution Provider (DP)	√	
Generator Owner (GO)	√	
Generator Operator (GOP)	√	
Reserve Sharing Group (RSG)	√	
Frequency Response Sharing Group (FRSG)	√	
Regulation Reserve Sharing Group (RRSG)	√	
Computational Load Owner (CLO)	√	
Computational Load Operator (CLOP)	√	

When did These Processes Begin?

The initial Registration process began in January of 2006. Registration of new entities is an ongoing process. If a Registered Entity's information changes, these changes must be submitted to the applicable Regional Entity(ies).

Certification is ongoing for entities in accordance with Sections IV and V of this manual.

Where to Access and Submit Form(s)?

Certification forms are provided on each Regional Entity's website. Completed forms are to be sent electronically to the Compliance and Certification Manager of the applicable Regional Entity(ies). Registration information is submitted electronically via an online application that is hosted on the NERC website. If an entity operates in more than one Region, separate Registration applications must be completed and submitted to each of the Regional Entities.

NERC will coordinate process execution when an entity is registering or certifying with multiple Regional Entities.

Roles and Responsibilities

The following is a high-level overview of the roles and responsibilities in the Registration and Certification processes:

NERC

1. Oversight of entity processes performed by the Regional Entities, including:
   a. Governance per the Regional Entity's delegation agreement with NERC.
   b. Coordination of process execution when an entity is registering and/or certifying with multiple Regional Entities.
2. Manage each entity's NERC Compliance Registry identification number (NERC ID) including:
   a. Sending a Registration or Certification letter that contains the NERC ID to the applicable Regional Entity(ies) for review and approval. If the Regional Entity(ies) agrees with all the information provided, it will notify NERC to issue the NERC ID to the Registered Entity and will send a copy of the notification being provided to the Regional Entity(ies).
   b. Ensuring each Registered Entity has only one NERC ID for all Regional Entities in which registered.
3. RESERVED
4. Maintain accurate Registration and Certification records including granting Certification certificates for the Registered Entity(ies) responsible for compliance (including Joint Registration Organization (JRO)/Coordinated Functional Registration (CFR)).
5. Maintain published up-to-date list of Registered Entities (i.e. the NERC Compliance Registry (NCR)) on the NERC website. NERC maintains the NCR, which identifies each Registered Entity and the applicable functional categories for which it is registered.
6. Lead panel reviews in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III(D).

Regional Entity

1. Performs data collection and mapping of BPS facilities and those facilities that have a material impact on the BPS within its Regional Entity defined reliability Region boundaries.
2. Approves or disapproves entity Registration applications.
3. Reviews entity Certification applications for completeness.
4. Notifies NERC of entities registered with the Regional Entity.
5. Approves or denies Certification Team (CT) recommendations and notifies the entity and NERC of the decision.
6. Provides leadership to the CT throughout the Certification process.

Entity Submitting the Application

1. Completes and submits Registration and/or Certification application.
2. Submits updates to Registration and/or Certification information as necessary and/or requested.
3. Responds to Regional Entity and/or NERC questions pertaining to Registration and/or Certification.

4. Provides documentation or other evidence requested or required to verify compliance with Certification requirements.

Section II — Introduction to Organization Registration and Organization Certification Processes

The processes utilized to implement the Organization Registration and Organization Certification Programs are administered by each Regional Entity. Pursuant to its delegation agreement with NERC, each Regional Entity is responsible for registering and certifying industry participants within its Regional Entity reliability Region boundaries. Each Regional Entity must use the following NERC processes.

Organization Registration — Entities Required to Register

All industry participants responsible for one or more of the functions below must register for each function through the Organization Registration Program. These entities are defined in the NERC *Statement of Compliance Registry Criteria*.

- RC
- TOP
- BA
- PA/PC
- TP
- TSP
- TO
- RP
- DP
- GO
- GOP
- RSG
- FRSG
- RRSG
- CLO
- CLOP

The Registration procedure is in Section III of this manual.

Organization Certification

Prospective and existing Registered Entities intending to perform or performing the RC, TOP, and/or BA functions shall achieve and/or maintain certification to operate one or more RC, TOP, and/or BA Areas. Every RC, TOP, and BA Area shall have a certified RC, TOP, and BA responsible for performing the duties and tasks identified in and required by the Reliability Standards.

Certification is required prior to the start of, and during the operation of a RC, TOP, or BA Area, subject to exception in NERC's sole discretion (conditional Certification). In such exceptions, the Registered Entity must satisfy conditions imposed according to an implementation plan agreed to by NERC to continue or discontinue operating its Area(s).

The activities of the program are designed to identify issues that, if not closed, could lead to unacceptable performance of the duties and responsibilities applicable to the certified function. The absence of a certified RC,

TOP, and/or BA for any Area jeopardizes the functional relationships within and between Areas specified by the Reliability Standards, and may lead to the inability of Registered Entities to maintain compliance with standards requiring performance with respect to those relationships.

The Certification/Review Team (CRT) works to establish one of the two findings below, utilizing Open Issues and Areas of Concern derived from an in-depth review and well-documented assessment of an entity's capability to perform the tasks of the certifiable function. Open Issues are items that must be closed before (continued) Certification is recommended.

- Certification/Review Team (CRT) recommends (initial or continued) certification contingent upon resolution of specified Open Issues (if any)
- Certification/Review Team (CRT) cannot recommend (initial or continued) certification. (Usually where the applicant contests Open Issues. The applicant has remedy in the appeal process of Section VII.)

This Certification process is described in Section IV of this manual. Certification reviews are conducted according to Section V. The Registered Entity is required to start operation of its Area within 12 months of being NERC certified.

Section III — Organization Registration Process

Purpose and Scope

The purpose and scope of this process is to provide guidance on how a user, owner, and/or operator of the BPS should be registered in the NCR.

Overview

Section 39.2 of the Commission's regulations, 18 C.F.R. § 39.2, requires each owner, operator, and user of the BPS to be registered with NERC and to comply with approved Reliability Standards.

Owners, operators, and users of the BPS will be registered by function(s) and are:

1. Responsible for compliance with all applicable Requirements/sub-Requirements within Reliability Standards approved by Applicable Governmental Authorities, for the applicable functions for which the Registered Entity is registered, except to the extent that an entity is granted a sub-set list of applicable Reliability Standards, which specifies the Reliability Standards and may specify Requirements/sub-Requirements by NERC, in which case the entity will be responsible for compliance with only such sub-set list; and
2. Subject to the compliance monitoring and enforcement requirements of Section 400 of the ROP.

If an entity does not agree with a Registration determination, it may request a NERC-led Registration Review Panel evaluation in accordance with Section III(D) of Appendix 5A. Entities should seek a determination from the NERC-led Registration Review Panel prior to making an appeal to the BOTCC in accordance with NERC ROP Section 500 and Section VI of Appendix 5A.

For Registration determinations dependent on application of the BES Definition, NERC has established a procedure to determine Inclusion and Exclusion Exceptions to the BES Definition (Appendix 5C). Appendix 5A relates to Registered Entity status whereas Appendix 5C relates to an Element's BES status. In cases where a BES Exception determination pursuant to Appendix 5C directly impacts an entity's functional registration requirements, the entity must initiate the BES Exceptions process prior to requesting a Registration change in status, and should be aware that the determination in that proceeding may be necessary prior to reaching a final decision by the NERC-led Registration Review Panel. This situation is dependent on facts and circumstances.

A. Organization Registration Application Process

1. This procedure applies to the following applicable entities: 1) those entities to be registered for the first time and 2) currently registered or previously registered entities for which registration changes are sought. Deactivation, Reactivation, and registration for a sub-set list of Reliability Standards are subject to the procedures in this subsection III(A). Additional procedures applicable to Deactivation and Reactivation are contained in subsections III(B) and III(C), respectively. Applicable entities shall begin the Registration process by submitting a completed Registration application to the Regional Entity(ies) of the reliability Region(s) where the entity performs or intends to perform its function(s).
    a. At any time, an entity may recommend in writing, with supporting documentation, to the Regional Entity(ies) that an entity be added to or removed from the Compliance Registry.
    b. If an entity does not have a NERC ID, NERC shall assign one.
    c. An entity responsible for more than one function will use a single NERC ID.
    d. The Registration process for an entity may also be initiated by a Regional Entity, NERC, or Applicable Governmental Authority.

e. At any time, an entity whose registration is at issue may request expedited treatment and waiver of applicable timelines. NERC, in its sole discretion, shall determine if such a request will be granted and alternative timelines. NERC's decision is not a final decision that is subject to appeal.

f. The following issues require determination by a NERC-led Registration Review Panel:

i. If, based on the entity's materiality to BPS reliability, the Regional Entity proposes to register an entity that does not meet the criteria set forth in Appendix 5B, Statement of Compliance Registry Criteria, the Regional Entity will submit a request for a determination by a NERC-led Registration Review Panel in accordance with Appendix 5A, Section III(D).

ii. If, based on the entity's lack of materiality to BPS reliability, an entity that meets the criteria set forth in Appendix 5B, Statement of Compliance Registry Criteria, believes that it should not be registered, the entity may submit a request for a determination by a NERC-led Registration Review Panel in accordance with Appendix 5A, Section III(D).

iii. If an entity disputes a Regional Entity determination that the entity meets the criteria set forth in Appendix 5B, Statement of Compliance Registry Criteria, the entity may submit a request for determination by a NERC-led Registration Review Panel in accordance with Appendix 5A, Section III(D).

iv. An entity seeking to be registered for a sub-set list of Reliability Standards may submit a request for a determination by a NERC-led Registration Review Panel in accordance with Appendix 5A, Section III(D).[1]

2. NERC shall coordinate Registration of entities that are required to register with multiple Regional Entities in order to ensure consistency of the Registration process.

3. For entities applying for the RC, TOP, and BA functions, Certification and Registration processes should be initiated concurrently using the applicable processes set forth in this manual. The entity should initiate the Certification process per Section IV of this manual.

4. Regional Entities shall evaluate the submitted information and determine if the information is complete/correct. If the information is not complete/correct, the entity will be notified to complete/correct or clarify the Registration information.

5. A single entity must register for all function type(s) that it performs itself. Provided that, an entity may execute an agreement to register as a Lead Entity of a JRO on behalf of one or more of its parties to the JRO agreement for one or more function type(s) for which the parties would have otherwise been required to register. The Lead Entity thereby, accepts on the parties' behalf compliance responsibility for all Requirements/sub-Requirements of Reliability Standards applicable to that function or those functions including reporting requirements. (ROP Section 507)

6. Multiple entities may each register for a function and delineate compliance responsibility for that function using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function type. (ROP Section 508)

7. In completing the Regional Entity responsibilities for the Registration process, the following are key items the Regional Entity must verify:

a. That function registrations are consistent with the requirements contained in ROP Section 501(1.4).

[1] If NERC has established clearly defined criteria for eligibility for a sub-set list of applicable Reliability Standards and has identified the sub-set list that may apply to similarly situated entities, such criteria shall govern the applicability of such sub-set list and such a matter shall not proceed to the NERC-led review panel, unless there is a dispute by the entity whose sub-set list treatment is at issue.

b. The Registration submission includes all data requested by NERC that is necessary for accurately identifying and contacting the Registered Entity.

8. The Regional Entity shall forward all Registration information to NERC for inclusion of an entity on the NCR:

   a. Within five business Days of a Registration determination by NERC or the NERC-led Registration Review Panel, as applicable, NERC will forward the proposed additions or changes to the NCR to the Regional Entity for review and comment.

   b. The Regional Entity has five business Days to respond to the proposed changes.

   c. If NERC does not receive any comments, the NCR will be revised. If NERC does receive comments, NERC will work with the Regional Entity to the extent changes are needed to the NCR and will revise the NCR accordingly.

9. NERC updates the NCR and notifies the applicable Registered Entity(ies) within five business Days of the update.

10. The Registered Entity may appeal the final registration determination by NERC in accordance with the ROP Section 500 and Section VI of **Appendix 5A**.

11. The NCR shall be dynamic and will be revised as necessary to take account of changing circumstances. Per the Regional Entity's delegation agreement, the Regional Entity will take any recommendation received under Section 1.a, and other applicable information, under advisement as it determines whether an entity should be on the NCR.

    a. Each Registered Entity identified in the NCR shall notify its corresponding Regional Entity and/or NERC of any corrections, revisions, deletions, changes in ownership, changes in corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards.[2] Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards. (ROP Section 400)

    b. Each Regional Entity has an independent obligation, even in the absence of a notification by an entity, to review and submit updates to the NCR to NERC, consistent with the procedures in this Section III, with appropriate notification to the affected entities, to the extent the Regional Entity is aware of, or possesses information that the NCR should be updated. These updates include, but are not limited to: 1) conditions on which the sub-set list are no longer applicable; 2) where a new and emerging risk to reliability is identified that changes the basis: a) upon which the entity was deactivated or deregistered; or b) upon which a sub-set list of requirements was made applicable; or 3) deactivation of entities that no longer meet the applicable registration thresholds. This does not excuse the Registered Entity from its obligation to provide such required notifications.

12. NERC may extend the timelines for processing Registration matters for good cause shown. Requests should be sent to the Registration email address, found on the Registration and Certification page of the NERC website. NERC shall notify the Registered Entity and the Regional Entity of such time extensions.

B. Deactivation Process

1. The term Deactivation refers to removal of an entity from the NCR for a specific functional category.

2. As a result of Deactivation, the entity is no longer subject to any prospective compliance obligations with respect to Reliability Standards applicable to that functional category.

[2] This includes changes in ownership of BPS facilities, changes in the applicability of the BES Definition to a Facility, and newly installed BPS facilities.

3. If all functional categories have been deactivated for a given entity, such entity would be deregistered and removed from the NCR. However, the entity's compliance history will be retained. In its letter notifying the entity of its Deactivation or deregistration, as applicable, NERC will notify the entity of the required retention period, in accordance with the NERC ROP.
4. An entity seeking Deactivation of RC, TOP, or BA registrations shall demonstrate to the satisfaction of its Regional Entity and NERC through the Certification review process, described in **Appendix 5A** Section V, that the duties and tasks identified in and required by the Reliability Standards either have properly been transferred to another Certified and Registered Entity or the Area has ceased to operate.
5. A Registered Entity may submit a request for Deactivation and supporting information to the Regional Entity at any time. Such information shall include:
    a. Entity name and NCR ID number;
    b. Functions for which Deactivation is requested; and
    c. The basis on which Deactivation is requested, including supporting documentation, which may be limited to an attestation, if appropriate.
6. The Regional Entity shall request any additional information from the Registered Entity within 10 Days of receipt of the request for Deactivation.
7. The Registered Entity shall provide the additional information within 20 Days of its request for Deactivation.
8. The Regional Entity will issue a decision within 50 Days of the date of receipt of all requested information from the Registered Entity.
9. If the Regional Entity approves the request for Deactivation, it shall forward its Deactivation determination to NERC within five business Days of issuance of the decision.
10. If NERC approves the Deactivation determination and the Registered Entity agrees with the determination, NERC will forward within five business Days of receipt of the Deactivation determination from the Regional Entity, the proposed additions or changes to the NCR to the Regional Entity for review and comment.
    a. The Regional Entity has five business Days to respond to the proposed changes.
    b. If NERC does not receive any comments, the NCR will be revised. If NERC receives comments, NERC will work with the Regional Entity to the extent changes are needed to the NCR and will revise the NCR accordingly.

C. Reactivation Process

1. NERC maintains the NCR, which identifies each Registered Entity and the applicable functional categories for which it is registered.
2. The term Reactivation refers to re-registration of an entity to the NCR for a specific functional category or the revocation of, or additions to, a sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements) that has been granted to an entity. Reactivation may be initiated by NERC, a Regional Entity or an entity with respect to such entity's own functional categories or sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements).
3. As a result of Reactivation, and consistent with the implementation plan to be developed pursuant to this paragraph, the entity shall prospectively comply with all Reliability Standards applicable to that functional category, or with the sub-set list specified in the Reactivation determination, unless otherwise notified. Within 30 days of a final Reactivation determination, the entity shall submit a proposed implementation plan to the Regional Entity detailing the schedule for complying with any Reliability Standards applicable to the

Reactivation. The Regional Entity and Registered Entity shall confer to agree upon such schedule. If the Regional Entity and Registered Entity are unable to agree on the implementation plan, the Regional Entity shall notify NERC via the Registration email address, found on the Registration and Certification page of the NERC website, of the disagreement, and shall provide statements of the Regional Entity's and the Registered Entity's positions, and NERC shall specify a reasonable implementation schedule.

4. The entity's prior compliance history will be retained and shall apply with respect to the Reactivation. In its letter notifying the entity of its Reactivation, NERC will notify the entity of its registration in accordance with the NERC ROP.

D. NERC-led Registration Review Panel

1. NERC shall establish a NERC-led Registration Review Panel (Panel) comprised of a NERC lead with Regional Entity participants, to evaluate: 1) Registered Entity requests for Deactivation of, or decisions not to register, an entity that meets Sections I through IV of the Registry Criteria, 2) requests to add an entity that does not meet (i.e., falls below) Sections I through IV of the Registry Criteria, 3) disputes regarding the application of Sections I through IV of the Registration Criteria, and/or requests for a sub-set list of applicable Reliability Standards (which may specify the Requirements/sub-Requirements).

    a. The Panel will be comprised of a standing pool of individuals with relevant expertise from NERC and each of the Regional Entities. Individuals with relevant expertise shall be appointed by the Regional Entity senior executive (CEO, President, General Manager, etc.) and individuals with relevant expertise shall be appointed by the NERC senior executive (CEO, President, General Manager, etc.). NERC shall select the Panel members for a given matter from the standing pool.

    b. Panel members for a given matter shall comply with Subsection 7 of Section 403 of the NERC ROP, shall not be employed by the Regional Entity whose determination is being reviewed or have otherwise participated in the review of the registration matter, and shall have the required technical background to evaluate registration matters.

2. An applicant requests a Panel review by completing an application using the **NERC-led Review Request Form** (Request Form) available on the NERC website (www.nerc.com)

    a. The Request Form provides instruction for submittal of documentation and data associated with the request.

    b. The applicant[3] should include an evaluation of materiality,[4] a description of the applicability of Sections I through IV, of the Registration Criteria, and/or an assessment of the impact of a sub-set of reliability standards, as appropriate.

    c. The burden of proof is on the applicant that makes the request for a Panel review, except in two instances where the burden of proof is on the applicable Regional Entity. These two instances include: 1) disputes regarding application of Sections I through IV of Registry Criteria for registration, and 2) disputes where NERC has (i) established clearly defined criteria for eligibility for a sub-set of applicable Reliability Standards (which may specify Requirements/sub-Requirements) and (ii) identified similarly situated entities that the sub-set list may apply to.

    d. For the purpose of this Panel process, the parties are the applicable Regional Entity(ies), RC, BA, TOP, and PC and the entity whose registration status is at issue.

[3] Applicants can either be a Regional Entity or an entity whose registration or sub-set list status is at issue.

[4] The evaluation of materiality should include the relevant "materiality test" factors listed in the "Determination of Material Impact" section of Appendix 5B, and/or any other factors that may be considered relevant to the request for Panel review.

e. Parties are to upload any documents, data, and/or information related to the Panel request to the secure location established by NERC for the Panel review.[5] When materials are uploaded to this location by a party, that party will provide notice to all other parties via email.

3. NERC will review the submitted documentation and determine if the application is valid within 30 days of receipt.
4. If the application is deemed not valid, NERC will send a written notification to the applicant via email with a reason the application was rejected.
5. If the application is deemed valid, NERC will send a written notice of NERC's acceptance of a valid Panel request to the applicant and the parties via email.
   a. Unless informed otherwise in NERC's notice of a valid request, the entity whose status at issue will have their current responsibilities for compliance with approved Reliability Standards in effect until the issue at hand has a final determination.
6. The Regional Entity(ies) or the entity whose registration status is as issue, as appropriate, will provide a written assessment of the Panel request to NERC, as described in step 2(e), within 20 days of NERC's acceptance of a valid Panel request.
   a. The RC, BA, TOP, and PC are also requested to provide a written assessment to NERC, as described in step 2(e), within 30 days of NERC's acceptance of a valid Panel request.
   b. The Regional Entity, or entity whose registration status is at issue, as appropriate, can provide a written response to NERC, as described in step 2(e), of any party's assessment within 40 days of NERC's acceptance of a valid Panel request.
7. The standard of proof in any proceeding under these procedures shall be by a preponderance of the evidence. The Panel will evaluate all documentation, assessments, and responses submitted to determine whether the weight of the evidence supports the Registration action under review more than it does not support the action. The Panel may issue a request for information to the applicant or any of the parties and will copy all parties on any such correspondence. The Panel will render its decision within 60 Days of the final submission to the panel or relevant correspondence is received related to the request from any party.
8. In reaching a decision, the Panel will apply the materiality test and other criteria, as applicable, set forth in the "Determination of Material Impact" section of Appendix 5B, Statement of Compliance Registry Criteria and any applicable guidance. The Panel shall also include a review of individual and aggregate system-wide risks to, and considerations of, reliability of the BPS, as well as the BES Definition, as applicable.
9. NERC may use its discretion to extend the timelines of the Panel process for good cause. Any party may also request to extend the timelines by sending an email to the Registration email address, found on the Registration and Certification page of the NERC website. NERC shall notify all parties of such time extensions.
10. The Panel decision will be issued to the applicant with a copy to all parties via email. The decision (including its basis) will also be posted on the NERC website,[6] with confidential information redacted in accordance with Section 1500 of the NERC ROP.
11. Any required changes to the NCR resulting from the Panel decision will be initiated by the Regional Entity in accordance with the Organization Registration Process of this manual. An entity may file an appeal with the BOTCC, in accordance with NERC ROP Section 500 and **Appendix 5A,** Section VI, if it wishes to dispute the Registration determination of the Panel.

[5] NERC will provide instructions to each party regarding how to request access to the secure location.

[6] A Panel decision subject to appeal will not be posted prior to the 21 day appeal window closing (in accordance with **Appendix 5A**, Section VI), which begins when the decision is issued to the parties. If no appeal is received, the decision will be posted and the Federal Energy Regulatory Commission will be notified.

Section IV — Organization Certification Process

Purpose and Scope

Reliability Coordinators, Transmission Operators, and Balancing Authorities take actions in Real-time that impact the reliable operation of the Bulk Power System. Certification activities assess the processes, procedures, tools, and training these organizations use in performing these functions and provide a prospective level of assurance that the organization has the capacity to meet the reliability obligations of its registration. The Certification will adhere to the following process to the extent allowed by the circumstances.

Organization Certification Process

Initiation

1. Certification processes shall begin upon the Regional Entity's receipt of a certification application for a Registered Entity or prospective Registered Entity; or when an entity has been registered by NERC for the functions of RC, TOP, and BA.
    a. An entity in a single Regional Entity reliability region shall initiate the Certification process by completing a Certification application (Certification applications are provided on each Regional Entity's website) and sending it to that Regional Entity which will manage the Certification process.
    b. An entity in multiple Regional Entity reliability regions shall initiate the Certification process by completing a Certification application (Certification applications are provided on each Regional Entity's website) and sending it to each Regional Entity. Each Regional will inform NERC of request with a recommendation for which Regional Entity will provide the leadership to manage the Certification process. NERC will determine which Regional Entity shall lead review of the application.
    c. The Regional Entity leading the review of the application shall review the application, and respond and acknowledge receipt or submit requests for more information within 30 days of its receipt of the application.
        i. If the application is not complete or accurate, the Regional Entity will notify the entity to revise the application as needed.
        ii. As part of such review, the Regional Entity may propose to issue a determination rejecting an application on a procedural basis. The applicant will be given 15 days to resolve the reason for rejection. If the Regional Entity and NERC determine that the applicant would fail to meet Registry Criteria or would otherwise not be able to competently perform the duties and responsibilities required under relevant Reliability Standards for the applicable Area, then a rejection notice will be sent to the applicant. Thereafter, the applicant may file an appeal of the rejection in accordance with Appendix 5A, Section VII.
    d. With the agreement of the Registered Entity, the Regional Entity or NERC may initiate certification processes based on documented conversations or other communications with a Registered Entity that contain information equivalent to that of the application.
2. The Regional Entity shall identify a team lead (CTL) for the certification activity.
3. The CTL shall notify NERC of the request for certification, and the following will take place:
    a. The CTL and NERC will review the request for Certification and concur on acceptance. When the application is deemed complete and accurate, it will be accepted.

b. If accepted, the CTL will inform the Registered Entity of the decision to initiate certification activities.

   i. The entity and the Regional Entity shall agree to a timeline including specific milestones for the Certification process. The proposed schedule for the Certification Process shall be submitted to NERC for approval. NERC shall review the draft final schedule and will (i) approve; (ii) modify; or (iii) reject the final schedule within 45 days of receipt from the CTL.

   ii. Certification activities are expected to be completed, allowing sufficient time to correct any Open Issues noted in the entity's preparedness, prior to the effective date of an entity's Registration.

c. In the case when an entity has been registered by NERC on behalf of the entity for the functions of RC, TOP, or BA, Certification activities will be concurrent with the entity's Registration implementation plan.

4. The following subsections detail which entities are required to be certified if they are a party to a JRO, CFR, or other delegation agreement.

   a. Each entity that has taken responsibility for Reliability Standards and/or Requirements/sub-Requirements applicable to the certifiable functions by virtue of being a member of a JRO, CFR, or other agreement shall be the entity NERC certifies to operate their portion of the RC, TOP, or BA Area(s).

   b. For all other entities that perform tasks related to the RC, TOP, or BA functions within a JRO or other agreement, the Regional Entity(ies) shall, based on a review of the JRO or other agreement, identify and notify such entities of the need for an evaluation and determination of the applicability of a "capability verification" or "readiness evaluation"[7] for those tasks.

Planning

1. The CTL shall form the team that will be responsible for performing the activities included in the Certification process.

   a. Participants shall adhere to NERC's confidentiality requirements for any data or information made available through the Certification process. Participants shall not be employees of or have a direct financial interest in the entity or any of its affiliates.

   b. Certification teams (CT) shall consist of the following:

      i. For BA certifications, the CT shall have representation from an existing BA, the entity's proposed RC, TOP, each affected Regional Entity, and NERC.

      ii. For RC certifications, the CT shall have representation from an existing RC, a BA and a TOP in the proposed Reliability Coordinator Area, each affected Regional Entity, and NERC.

      iii. For TOP certifications, the CT shall have representation from an existing TOP, the entity's proposed BA(s) and RC, each affected Regional Entity, and NERC.

      iv. Additional CT members with expertise in any of the NERC registry functional areas may be added as necessary (i.e., NERC, Regional Entity staff).

   c. If the entity objects to any member of the CT, the entity must make that known, in writing, to the Regional Entity listing the reasons for the objection. The Regional Entity will either replace the team member or respond with written justification for keeping the member on the team.

   d. Entities such as government representatives or other stakeholders may be observers in the Certification process. Any Confidential Information will be handled in accordance with Section 1500 of the NERC ROP.

2. CT members shall have the necessary diversity in their technical training and experience to collectively represent the subject matter competencies needed to perform the evaluation of the specific function being

[7] A "capability verification" or "readiness evaluation" is a review of the duties and tasks of the Registered Entity that it has delegated to another entity through an agreement.

certified. Previous experience as a System Operator, Operations Support Personnel, or management of a Control Center is desired for CT members performing the on-site visit.

3. The CTL shall ensure all CT members have completed the following:
   a. Certification team member training requirements as established by NERC
   b. Non-ERO employees shall also complete the following:
      i. Certification team member training record form
      ii. Certification team conflict of interest form
      iii. An ERO confidentiality agreement form
4. The CTL shall review the certification application (and Entity information available through other ERO programs) with NERC to determine the scope of the assessment. The CTL shall identify the competency areas to be evaluated based on the function(s) for which the entity is to be certified and the method(s) for their evaluation.
5. The CTL shall utilize a secured server to distribute and house all relevant certification activity documents, including but not limited to the following:
   a. The application or other documented correspondence with the Registered Entity initiating the certification activity
   b. All relevant correspondence between the CTL and the applicant, including the certification packet (as described in step 6 below)
   c. All relevant correspondence between the CTL and the CT members
   d. The work papers used to evaluate the entity during the process
   e. The overall process schedule
   f. The agenda for the on-site visit
   g. The final certification report
   h. The Regional Entity certification process check sheet indicating the completion of certain process check-points
6. A Certification packet shall be developed and sent to the entity at least ninety (90) days prior to an on- site visit. It shall contain the following:
   a. Notification of the certification process
   b. Logistic information request
   c. The tentative overall process schedule and on-site agenda
   d. The CT roster and member biographies
   e. Request of confirmation of no objections to CT members
   f. Pre-certification survey that must be returned to the CTL within fifteen (15) days of receipt
   g. Any initial requests for information
7. CTL shall contact the entity within one week of submitting the packet to confirm receipt of the package and discuss any concerns the entity may have.
8. The entity shall complete and return the requested information and supporting documentation no later than four (4) weeks prior to the on-site visit.
9. The CTL and CT shall review the logistic information request response, in order to do the following:

a. Understand the entity's expectations of the CT when on site

b. Make all travel arrangements

10. If the CT is to be broken into smaller groups, the CTL shall identify sub-teams and assign a scribe(s) to document the assessment:

    a. For complex Certifications, the CTL may assign members of the CT to different focus areas. For example:

        i. Facilities: Examples may include the physical cyber assets against the CIP standards, the cyber training, the maintenance contracts and records for the facilities, the electrical system and uninterruptible power supply (UPS), the cybersecurity of servers, passwords, etc., per the CIP standards, and the physical installation of data and voice equipment.

        ii. EMS/SCADA: Interview the EMS/SCADA SMEs to ensure that the tools will provide adequate situational awareness against the NERC standards. Ensure adequate change control of the EMS/SCADA. Review the data transfer, server, applications, and redundancy configuration of the core tools including EMS, OSI-PI, ICCP, outage scheduling, scheduling, map-board displays, communication systems, etc.

        iii. Operator Preparedness: Interview the operators at their workstations and ask them to present the tools, procedures, and job aids in use for normal day-to-day and emergency operations. This could include cyber intrusion detection and real-time assessment. Interview the training staff regarding initial training needed to support the transition to the new responsibilities and continuing training to the NERC standards.

        iv. Critical Infrastructure Preparedness: Interview the CIP staff to understand how critical infrastructure protections are being utilized.

    b. The CTL shall ensure documentation used to substantiate the conclusions of the Certification (Review) is collected from each sub-team.

Fieldwork

1. Areas of capability to be evaluated by the certification activity shall be tailored to the situation and matched with appropriate assessment methods (e.g., validation of legacy information, review of entity responses, document review, direct observation, or personnel interview, etc.)
2. The CTL shall schedule a document review(s) with the CT prior to the on-site visit. Document reviews could take place face-to-face or via teleconference.
3. During document reviews, the CT shall note all the following:

    a. Follow-up or corroborating questions for the entity's management, SMEs, and system operators based upon the review of supporting documentation

    b. Additional requests for information (to be submitted to the entity prior to the on-site visit.)

    c. Comments during the document review that support the entity's abilities to perform the function for which the entity applied and indicate items which do not need further review

    d. Issues that need to be addressed prior to certification being granted

4. The CTL shall provide the entity a final schedule and agenda for the on-site visit based upon the results of the document review.
5. The CT on-site visit to the entity's location where operational functionality is performed shall include the following:

    a. Opening presentation

b. At a minimum, the team will:

   i. Review with the entity the data that is available only on-site;

   ii. Interview the operations, management, and training personnel;

   iii. Inspect the Facilities and equipment associated with the function being certified;

   iv. Request demonstration of all tools identified in the scope of the Certification;

   v. Review documents and data including agreements, processes, and procedures identified in the document review;

   vi. Verify operating personnel Certification credentials and proposed work schedules; and

   vii. Review any additional documentation resulting from inquiries arising during the on-site visit.

c. The CT shall interview other entity personnel as required to clarify responses covered in the document review.

d. At the end of each day, the CT will meet for the debriefing. The CTL shall lead a daily debriefing with the entity in order to do the following:

   i. Identify the status of the assessment

   ii. Identify any items of concern that need to be addressed

   iii. Provide an update to the schedule

e. The CTL shall provide an exit briefing at the end of the on-site visit in order to do the following:

   i. Identify any Open Issues that need to be addressed, and identify a timeline for follow-up to closure

   ii. Discuss the reporting process

   iii. Discuss the next steps in the certification process, including any Areas of Concern and the schedule of a post-onsite visit, if required.

   iv. Convey that entity feedback forms will be sent to allow the entity to resolve any open with a request for candid feedback.

Reporting

1. The CTL will provide the CT and entity with feedback forms, and request that they are returned within five (5) calendar days with a copy to the Certification email address, found on the Registration and Certification page of the NERC website.
2. After completion of the on-site visit, the CTL shall develop a draft final report, in coordination with input from the CT, which presupposes all Open Issues are closed. The format for the report shall conform to the template posted on the NERC website, generally containing:

   - Title page
   - Table of Contents
   - Introduction – A brief discussion on the Regional Entity(ies) involved, the entity being certified, a description of the function the entity(ies) are being certified for, and a brief timeline of the Certification project.
   - CT – Provide the CT makeup.
   - Objective and Scope – Discussion on entity application (who, what, when, & how).
   - Overall Conclusion – finding of the CT.

- Open Issues - Any item(s) that must be closed prior to going operational and within 180 days of conclusion of the on-site visit.
- Positive Observations.
- Company History – Discussion on the applicant's company history.
- Company Details – Specific details regarding the Reliability Coordinator, Transmission Operator or Balancing Authority Areas to be operated and the entity's relationship with other entities (RCs, TOPs, and BAs etc.).
- Documentation List – Provide a list of critical documentation reviewed by the CT used to make the CT's conclusion and the documentation retention requirements.
- Attachments – Describe those attachments that are for public viewing and those that are separated from the report due to confidentiality issues such as Critical Infrastructure documentation.

3. The CTL shall transmit the draft final report to the CT requesting final comments within five (5) business days, unless agreed to otherwise.
4. After the CT has completed their review of the draft report, the CTL shall transmit the draft final report to the entity, requesting return with comments within fourteen (14) calendar days, unless agreed to otherwise.
5. Entity comments will be given due consideration and incorporated in the final report at the discretion of the CTL and the input of the CT. The CTL and CT will review the completed final report.
6. When all Open Issues are satisfactorily closed, the CTL will submit the final report to Regional Entity(ies) management for consideration and approval. CT minority opinions and areas where CT consensus was not reached will be communicated to Regional Entity(ies) management prior to approval, but will not be included in the final report nor in the Regional Entity recommendation to NERC.
    a. If Regional Entity management contradicts the CT finding, the CTL will work with the CT the entity to resolve any issues.
    b. The Regional Entity CEO (or a designee) will transmit to NERC and copy the entity the final CT report with a recommendation regarding NERC's certification of the entity.
7. If NERC approves the entity for certification, NERC shall email confirmation to the entity and post the final report on NERC's public website. Attached to the email will be the formal certification letter and NERC certificate. Any Confidential Information will be redacted in accordance with Section 1500 of the NERC ROP.
8. The entity may appeal NERC's decision in accordance with the Rules of Procedure and Section VII of this manual.
9. The certification process shall be completed within nine (9) months unless agreed to by all parties involved in the process
10. Operational responsibility for RC, TOP, or BA Areas shall not begin prior to the entity's registration effective date. Trial operations, conducted in parallel with an incumbent RC, TOP, or BA who retains responsibility, shall be coordinated to ensure operational authority for an Area is clear at all times.
11. The applicant must commence operations for its RC, TOP, or BA Areas within twelve (12) months of being certified by NERC. If the applicant fails to commence operation within twelve (12) months, the certification process must be repeated.
    a. During the pendency of the certification process, NERC may use its discretion to issue conditional Certification to ensure that the entity can be Registered, and no areas of the BPS are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical.

i. Conditional Certification will include an implementation plan which provides qualifications or criteria that NERC and the Regional Entity have determined necessary to address the risk of an entity failing to be certified or to be certified when needed.

ii. The entity subject to conditional Certification shall create an implementation plan that establishes how delayed or failed certification is mitigated so that no gaps in reliability occur. The implementation plan would also detail potential impacts both to the applicant and to any affected entities, and discuss how those impacts would be mitigated, how required functions would be served, and how other affected entities within its prospective footprint would meet their compliance responsibilities if certification is failed or delayed.

iii. NERC and the Regional Entity will work with the applicant to develop the implementation plan. If the parties are unable to agree upon an implementation plan, NERC will issue an implementation plan.

Data Retention

1. Documentation used to substantiate the conclusions of the Certification (Review) must be retained by the Regional Entity for six (6) years.
2. Documentation used to substantiate program oversight of the Certification processes must be retained by NERC for six (6) years.

NERC will maintain and post all Certification Final Reports on its website. Any Confidential Information will be redacted in accordance with Section 1500 of the NERC ROP.

Section V — Organization Certification Review Process

Purpose and Scope

Certification review provides reasonable assurance an already certified and operational Registered Entity will continue to support reliable operations of the BPS after initiating a material change. The review will seek assurance that the entity has addressed personnel training and qualifications, facilities, and equipment needed to perform and maintain the reliability functions in accordance with the applicable Requirements of Reliability Standards, considering among others the following:

- BPS reliability impacts of the change
- Critical Infrastructure Protection implications of the change
- Operator training in support of the change
- Data collection, sharing, and facilities monitoring and control necessary for Real-time Assessments, as well as next-day and longer-term planning
- Coordination of normal and emergency operations

Overview

Certification review activities, including the checks and balances of reporting and documenting those activities, should take place in advance of the change. Functional operations and compliance to the Standards remain the responsibility of the applicable Registered Entity. Certification is of the organization performing the function—not of a facility or system of equipment. Every RC, TOP, and BA Area shall have a certified RC, TOP, and BA registered as responsible for performing the duties and tasks identified in and required by the Reliability Standards. Entities seeking Deactivation of BA, TOP, or RC registrations shall demonstrate to the satisfaction of their Regional Entity and NERC through the Certification review process that the duties and tasks identified in and required by the Reliability Standards either have properly been transferred to another Certified and Registered Entity or the Area has ceased to operate. An entity remains certified during the review activities and subject to all applicable requirements of Reliability Standards, unless conditional Certification is granted by NERC providing qualifications or criteria that NERC and the Regional Entity have determined necessary to address the risk of an entity failing to be certified or to be certified when needed.

Items that are to be considered for a Certification review include one or more of the following non- exhaustive list of changes from an entity's prior certification assessments.

a. Changes to Registered Entity's footprint[8] (including de-certification changes to existing JRO/CFR assignments or sub-set list of requirements):

   i. The review of changes to an already registered and operational Entity's footprint is primarily concerned with ensuring the gaining functional entity has the tools, training, and security in place to reliably operate with new responsibilities. Changes to an entity's footprint can be characterized by new metered boundaries associated with the integration or dis-association of existing electrical areas of the BPS (Reliability Coordinator Area, Transmission Operator Area, or Balancing Authority Area).

b. Relocation of the Control Center:

   i. Fundamental to the reliable operation of the interconnected transmission network are the control centers that continuously monitor, assess, and control the generation and transmission power flows on the BES. Of interest are impacts to the functionality provided within these facilities for continued reliable operations of the BES that affect:

[8] This includes changes in ownership of BPS facilities, changes in the applicability of the BES Definition to a Facility, and newly installed BPS facilities.

- Tools and applications that System Operators use for situational awareness of the BES
- Data exchange capabilities
- Interpersonal (and alternate) Communications capabilities
- Power source(s)
- Physical and cyber security

ii. The impact of the relocation of the Control Center on the entity's ability to perform the functions for which the entity is registered under normal and emergency conditions should be explored and documented to understand the manner in which the Control Center continues to support the reliable operations of the BES.

c. Modification of the Energy Management System (EMS) which is expected to materially affect CIP security perimeters or the System Operator's: 1) situational awareness tools, 2) functionality, or 3) machine interfaces.

NERC may revoke an entity's certification and de-certify that entity if NERC determines that the entity is no longer performing the responsibilities that are associated with the function for which it is certified. Revocation shall be posted to the NERC website. The entity will remain registered and subject to compliance for the function, unless it has gone through the deactivation or deregistration process for the applicable function. NERC's revocation may be appealed in accordance with **Appendix 5A**, Section VII.

Organization Certification Review Process

Initiation

1. A Registered Entity that requires a review of the conditions upon which their certification was granted shall complete the appropriate form and submit it to the applicable Regional Entity. Informal dialogue on potential certification activity is encouraged as far in advance as possible.
   a. An entity in a single Regional Entity reliability region shall initiate the Certification review process by completing an application (Certification review applications are provided on each Regional Entity's website) and sending it to the Regional Entity that will manage the Certification review process.
   b. An entity in multiple Regional Entity reliability regions shall initiate the certification process by completing a certification application (certification applications are provided on each Regional Entity's website) and sending it to each Regional Entity. Each Regional Entity will inform NERC of the request with a recommendation for which Regional Entity will provide leadership to manage the certification process. NERC will determine which Regional Entity shall lead review of the application.
   c. The Regional Entity leading the review of the application shall review the application and respond with either acceptance or a request for more information within 30 days of the receipt of the request.
2. Upon receipt of the request for Certification review, the Regional Entity(ies) shall evaluate as follows:
   a. If the application is not complete or accurate, the Regional Entity will notify the entity to revise the application as needed.
   b. For an entity that is not required to be certified but performs tasks associated with a RC, TOP, or BA in accordance with Section IV, the Regional Entity shall consult with the Registered Entity regarding the applicability of a "capability verification" or "readiness evaluation" regarding those tasks.
   c. The Regional Entity or NERC may initiate the Certification review processes based on documented conversations or other communications with a Registered Entity that contain information equivalent to that of the application.

d. The decision to certify changes to an already operating and certified Registered Entity is a collaborative decision between the affected Regional Entity(ies) and NERC. The decision may be to conduct a review under this Certification review process or engage in any lesser activity necessary to understand changes that are material to an entity's operations or inherent risk.

3. When the decision is made to initiate a Certification review, the Regional Entity shall identify a team lead (CRTL) for the Certification review activity and the following will take place:

   a. The CRTL will inform the Registered Entity of the decision to initiate Certification review activities.

   b. The CRTL shall tailor the scope of the Certification review to evaluate those capabilities that are affected as a direct result of the reason for the review.

   c. The Regional Entity and NERC will determine if an on-site visit is required or if off-site review is sufficient. NERC has the final authority in this decision.

   d. The entity and the Regional Entity shall agree to a timeline including specific milestones for the Certification review process. The proposed schedule for the Certification review process shall be submitted to NERC for approval. NERC shall review the draft final schedule and will (i) approve; (ii) modify; or (iii) reject the final schedule within 45 days of receipt from the CRTL.

   e. Certification review activities are expected to be completed allowing sufficient time to address the risk of an entity failing to be certified or to be certified when needed prior to the effective date of any registration changes

Planning

1. The CRTL shall form the team (CRT) that will be responsible for performing the activities included in the Certification review process.

   a. The CRTL shall review the request (and entity information available through other ERO programs) with NERC to identify the competency areas to be evaluated and the method(s) for their evaluation (entity/neighbor questionnaire, request documents for review, on-site demonstration, personnel interview, etc.)

   b. The CRT participants shall adhere to NERC's confidentiality requirements under Section 1500 for any data or information made available through the Certification review process. Participants shall not be employees of or have a direct financial interest in the entity or any of its affiliates.

   c. CRT Composition:

      i. The CRT shall have the necessary diversity in their technical training and experience to collectively represent the subject matter competencies needed to perform the evaluation of the specific function being certified. Previous experience as a System Operator, Operations Support Personnel, or management of a Control Center is desired for CRT members performing the on-site visit.

      ii. Entities such as government representatives or other stakeholders may be observers in the Certification review process.

   d. If the entity objects to any member of the CRT, the entity must make that known, in writing, to the Regional Entity, listing the reasons for the objection. The Regional Entity will either replace the team member or respond with written justification for keeping the member on the team.

2. The CRTL shall ensure all CRT members have completed the following:

   a. Certification team member training requirements as established by NERC

   b. Team Member profile documenting technical training and experience of team members

c. For non-ERO employees they shall also complete the following:

3. The CRTL shall utilize a secured server to distribute and house all relevant Certification review activity documents, including but not limited to the following:
   a. The application or other documented correspondence with the Registered Entity initiating the certification activity
   b. All relevant correspondence between the CRTL and the applicant, including the certification packet (as described in step 4 below)
   c. All relevant correspondence between the CRTL and the CRT members
   d. The work papers used to evaluate the entity during the process
   e. The overall process schedule
   f. The agenda for the on-site visit, if required
   g. The final Certification review summary report
   h. The Regional Entity certification process check sheet indicating the completion of certain process check-points
4. A Certification review packet shall be developed and sent to the entity at least ninety (90) days prior to an on-site visit. It shall contain the following:
   a. Notification of the Certification review process
   b. Logistic information request
   c. The tentative overall process schedule and tentative on-site agenda
   d. The CRT roster and member biographies
   e. Request of confirmation of no-objections to CRT members
   f. Pre-certification survey that must be returned to the CRTL within fifteen (15) days of receipt
   g. Any initial requests for information
5. The CRTL shall contact the entity within one week of submitting the packet to confirm receipt of the package and discuss any concerns the entity may have.
6. The entity shall complete and return the requested information no later than four (4) weeks prior to the on-site visit.
7. The CRTL and CRT shall review the logistic information request, in order to do the following:
   a. Understand the entity's expectations of the CRT when on site
   b. Make travel arrangements

Fieldwork

1. Areas of capability to be evaluated by the Certification review activity shall be tailored to the situation and matched with appropriate assessment methods (e.g., validation of legacy information, review of questionnaire responses, document review, direct observation, or personnel interview, etc.)
2. The CRTL shall schedule a document review(s) with the CRT prior to the on-site visit. Document reviews could take place face-to-face or via teleconference.
3. During document reviews, the CRT shall note all the following:

a. Follow-up or corroborating questions for the entity's management, SMEs, and system operators based upon the review of supporting documentation

b. Additional requests for information (to be submitted to the entity)

c. Comments during the document review that support the entity's abilities to perform the function for which the entity applied and items which do not need further review

d. Issues that need to be addressed prior to continued certification being recommended

4. The CRTL shall provide the entity a final schedule and agenda for the on-site visit (if applicable) based upon the results of the document review.

5. As appropriate, the CRT shall conduct interviews at the entity's facilities or via teleconference. The team will:

   a. Review with the entity any data or information requiring clarification

   b. Interview operations, management, and training personnel

   c. During on-site visits:

      i. Inspect the facilities and equipment associated with the applicable Reliability Standards referenced in the questionnaire;

      ii. Request demonstration of all tools affected by the change;

   d. Review documents and data including agreements, processes, and procedures identified by CRT

   e. Review any additional documentation resulting from inquiries arising during the interview

6. At the end of each on-site day, the CRT will meet for debriefing. The CRTL shall lead a daily debriefing with the entity in order to do the following:

   a. Identify the status of the assessment

   b. Identify any items of concern that need to be addressed

   c. Provide an update to the schedule

7. The CRTL shall provide an exit briefing at the end of the on-site visit in order to do the following:

   a. Identify any Open Issues that need to be addressed, and identify a timeline for follow-up to closure

   b. Discuss the reporting process

   c. Discuss the next steps in the Certification review process, including any areas of concern and the schedule of a post-onsite visit, if required

   d. Convey that entity feedback forms will be sent to the entity

Reporting

1. The CRTL will provide the CRT and entity with feedback forms, and request that they are returned within five (5) calendar days with a copy to the Certification email address, found on the Registration and Certification page of the NERC website.

2. After completion of the on-site visit, the CRTL shall develop a draft summary report, in coordination with input from the CRT, which presupposes all Open Issues are closed. The format for the report shall conform to the template posted on the NERC website.

3. The entity, in conjunction with the CRT, shall attempt to resolve any Open Issues prior to issuance of the draft summary report.

4. The CRTL shall transmit the draft final report to the CRT requesting final comments within five (5) business days, unless agreed to otherwise.
5. After the CRT has completed their review of the draft report, the CRTL shall transmit the draft final report to the entity, requesting return with comments within fourteen (14) calendar days, unless agreed to otherwise.
6. At the discretion of the CRT and NERC, the entity may be permitted to implement the change at any point in time after the exit briefing. Trial operations, if used, shall be coordinated to ensure operational authority for an Area is clear at all times.
7. Entity comments will be given due consideration and incorporated into the summary report at the discretion of the CRTL and the input of the CRT. The CRTL will review the completed summary report with the CRT.
8. When all Open Issues are satisfactorily closed, the CRTL will submit the summary report to Regional Entity(ies) management for consideration and approval. CRT minority opinions and areas where CRT consensus was not reached will be communicated to Regional Entity(ies) management prior to approval but will not be included in the final report nor in the Regional Entity recommendation to NERC.
    a. If Regional Entity management contradicts the CRT finding, the CRTL will work with the CRT and the entity to resolve any issues.
    b. The Regional Entity CEO (or a designee) will transmit to NERC and copy the entity the final CRT report with a recommendation regarding NERC's certification of the entity.
9. If NERC approves continued certification for the entity, NERC shall email confirmation to the entity.
10. If NERC declines continued certification for the entity, NERC shall make available to the entity Hearing Procedures for use in Appeals of Certification Matters, CCCPP-005 contained in Appendix 4E.

Data Retention

1. Documentation used to substantiate the conclusions of the Certification review must be retained by the Regional Entity for six (6) years.
2. Documentation used to substantiate program oversight of the certification processes must be retained by NERC for six (6) years.

Section VI — NERC Organization Registration Appeals Process

Purpose and Scope

This section describes the process that any organization must use to seek review of its listing and functional assignment on the NCR.

Overview

NERC has established documented procedures to ensure a fair and impartial appeals process. No one with a direct interest in a dispute may participate in the appeals process except as a party or witness. ~~See Figure 3, *Organization Registration Appeals Process Overview*.~~

Organization Registration Appeals Procedure

1. Any Registered Entity included on the NCR may challenge final decisions regarding its listing, functional assignments, and determinations regarding the applicability of a sub-set of Reliability Standards (which specifies the specific Reliability Standards and may specify Requirements/sub-Requirements).
2. All registration appeals must be filed in writing to NERC, via electronic and registered mail. Appeals are sent to:

   Organization Registration and Certification
   Main: (404) 446-2560
   Facsimile: (404) 446-2595
   Email: Communications@NERC.net
   Address: As posted on NERC.com
3. Each party in the appeals process shall pay its own expenses for each step in the process.
4. A stipulation of invoking the appeals process is that the Regional Entity or Registered Entity requesting the appeal agrees that NERC (its Members, Board, committees, subcommittees, and staff), any person assisting in the appeals process, and any company employing a person assisting in the appeals process, shall not be liable for, and shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.
5. Parties retain the right to seek further review of a decision in whatever regulatory agency or court that may have jurisdiction.
6. All appeals must be received within 21 Days of receipt of the NERC determination that is being appealed. The appeal must state why the Registered Entity believes it should not be registered or should be deactivated based on the NERC ROP and the *NERC Statement of Compliance Registry Criteria* or why its compliance obligations should be limited only to a sub-set list of otherwise applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements). A copy of the appeal must be concurrently served on the Regional Entity.
7. After receipt of the appeal, the Registered Entity has a 30 day period to work with the Regional Entity to resolve the appeal, if possible. NERC may extend such deadline in its sole discretion. If the appeal is resolved, the Regional Entity will notify NERC with the details of the resolution and NERC will close the appeal.

8. At any time through this appeals process, a Registered Entity may agree with the decision and/or agree to close the appeal. NERC shall notify the involved parties and the NERC BOTCC that the appeal is resolved and update the NCR as applicable.
9. NERC will notify the Registered Entity and the applicable Regional Entity(ies) regarding the appeal with the following expectations:
    a. The Registered Entity will provide NERC and the applicable Regional Entity(ies) any additional data supporting its appeal within 10 Days of the date of the NERC appeal notification.
    b. The applicable Regional Entity(ies) will provide a copy of its assessment directly to the Registered Entity, as well as to NERC, within 20 Days of the date of the NERC appeal notification.
    c. The Registered Entity may submit a response to the Regional Entity(ies) assessment, with copies to the Regional Entity(ies) and NERC, within 30 Days of the date of the NERC appeal notification.
    d. To ensure there is no confusion with respect to the rights and responsibilities of the Registered Entity during the appeal process, the notification will confirm whether the Registered Entity will remain on the NERC Compliance Registry and will be responsible for compliance with approved Reliability Standards applicable to the function under appeal during the appeal.
    e. NERC may extend the timelines for good cause shown. Requests should be sent to the Registration email address, found on the Registration and Certification page on the NERC website. NERC shall notify the Registered Entity and the Regional Entity of such time extensions.
10. Hearing and Ruling by the BOTCC
    a. The BOTCC will resolve Registration disputes and apply a *de novo* review.
    b. The BOTCC may request additional data from NERC, the relevant Regional Entity(ies) or the Registered Entity, and prescribe the timeframe for the submitting the requested data.
    c. The BOTCC will provide a written decision regarding any appeals, along with the basis for its decision.
    d. If the BOTCC upholds the appeal, NERC will:
        - Notify the Registered Entity and Regional Entity(ies) that the appeal was granted.
        - Update the NCR.
    e. If the BOTCC does not uphold the appeal, NERC will:
        - Notify the Registered Entity and the Regional Entity(ies) that the appeal was denied.
        - The Registered Entity may appeal to Federal Energy Regulatory Commission (FERC) or another Applicable Governmental Authority within 21 Days of the notification of the decision.
    f. A record of the appeals process shall be maintained by NERC. Confidentiality of the record of the appeal will be based on the NERC ROP Section 1500.

Section VII — NERC Organization Certification Appeals Process

Purpose and Scope

This section describes the process for an organization to appeal the Certification decision that was determined in the Certification process.

Overview

The NERC Organization Certification Program provides a key means to fulfill NERC's mission. In conducting this program, NERC has established documented procedures to ensure a fair and impartial appeals process. No one with a direct interest in a dispute may participate in the appeals process except as a party or witness. ~~See Figure 4 *Organization Certification Appeals Process Overview.*~~

Organization Certification Appeals Procedure

1. Appeal for an Organization Certification finding.
2. Any entity can appeal an Organization Certification decision issued as a result of the Certification process.
3. Requirements and Conditions for Appeals.
    a. For all appeals under the NERC Organization Certification Program, the appeals process begins when an entity notifies the NERC via the Certification email address, found on the Registration and Certification page of the NERC website that it wishes to use the NERC appeals process.
        - The Director of Compliance is the main contact for all parties in all steps of the appeals process.
        - If an appeal is not filed within 21 Days of the date that the Certification report or finding is issued, or the final Regional Entity appeals process ruling is made, the finding shall be considered final and un-appealable.
    b. Each party in the appeals process shall pay its own expenses for each step in the process.
    c. A stipulation of invoking the appeals process is that the Regional Entity or entity requesting the appeal agrees that NERC (its Members, Board, committees, subcommittees, and staff), any person assisting in the appeals process, and any company employing a person assisting in the appeals process, shall not be liable, and shall be held harmless against the consequences of any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.
    d. Parties retain the right to seek further review of a decision in whatever regulatory agency or court that may have jurisdiction.
4. At any time through this appeals process, an entity may withdraw its appeal.
5. Hearing and Ruling by the Compliance and Certification Committee.
    a. Within 28 Days of receiving notice from the NERC Director of Compliance, the CCC will conduct a hearing where all the parties or representatives of the disputing parties will present the issue in question, in accordance with CCC procedure CCCPP-005, *Hearing Procedures for Use in Appeals of Certification Matters*, which is incorporated in **Appendix 4E** of the ROP.
    b. If the appeal is upheld, NERC notifies the entity and Regional Entity(ies), updates the NCR, and issues any appropriate letter and certificate to the entity.
    c. If the appeal is denied, NERC notifies the entity and Regional Entity(ies).

6. Hearings and Ruling by the BOTCC.

   a. The BOTCC will be asked to resolve a dispute related to the NERC Organization Certification Program if any party to the appeal contests the CCC final order.

   b. The BOTCC may request additional data from NERC, Regional Entity(ies) or the entity and prescribe the timeframe for submitting the requested data.

   c. At the next regularly scheduled BOTCC meeting, or at a special meeting if the Board determines it is necessary, the Chair of the CCC will present a summary of the dispute and the actions taken to the BOTCC.

      - Each party will have an opportunity to state its case.
      - The BOTCC will then rule on the dispute.

   d. If the BOTCC upholds the appeal, NERC will:

      - Notify the entity and the Regional Entity(ies) that the appeal was upheld.
      - Update the NCR.
      - Issue a Certification letter and a certificate to the entity as applicable.

   e. If the BOTCC does not uphold the appeal, NERC will notify the entity and the Regional Entity(ies) that the appeal was denied.

      - The entity may appeal to Applicable Governmental Authorities within 21 Days of the issuance of the decision.

   f. A record of the appeals process shall be maintained by NERC and available upon request. Confidentiality of the record of the appeal will be based on the NERC ROP Section 1500.

Definitions

Capitalized terms used in this Appendix shall have the definitions set forth in Appendix 2 of the ROP. For convenience of reference, definitions used in this Appendix are also set forth below:

NERC Organization Certification	The process undertaken by NERC and a Regional Entity to verify that a new entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator, and/or Reliability Coordinator.
Compliance and Certification Manager	The individual/individuals within the Regional Entity that is/are responsible for monitoring compliance of entities with applicable NERC Reliability Standards.
Days	Days as used in the Registration and Certification processes are defined as calendar days.
Footprint	The geographical or electric area served by an entity.
Functional Entity	An entity responsible for a function that is required to ensure the Reliable Operation of the electric grid as identified in the NERC Reliability Standards.
Mapping	The process of determining whether a Regional Entity's Footprint is being served by Registered Entities.
NERC Identification Number (NERC ID)	A number given to NERC Registered Entities that will be used to identify the entity for certain NERC activities. Corporate entities may have multiple NERC IDs to show different corporate involvement in NERC activities.
Regional Entity	An entity having enforcement authority pursuant to 18 C.F.R. § 39.8.
Registration	Processes undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region.
Coordinated Functional Registration (CFR)	Where two or more entities (parties) agree in writing upon a division of compliance responsibility among the parties for one or more Reliability Standard(s) applicable to a particular function, and/or for one or more Requirement(s)/sub-Requirement(s) within particular Reliability Standard(s).

Attachment 3-C

Appendix 5B Redline

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix 5B

Statement of Compliance Registry Criteria

Revision ~~8~~9

Effective: ~~June, 27 2024~~TBD

RELIABILITY | RESILIENCE | SECURITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Statement of Compliance Registry Criteria (Revision 9) 1
Summary 1
Background 2
Statement of Issue 2
Resolution 2
Registry Criteria 2
Determination of Material Impact 6
Limitation of responsibilities to a sub-set of Reliability Standards ..... 7~~6~~

Statement of Compliance Registry Criteria (Revision ~~8~~9)

Summary

This document describes how the North American Electric Reliability Corporation (NERC) will identify organizations that may be candidates for Registration and assign them to the Compliance Registry.

NERC and the Regional Entities[1] have the obligation to identify and register all entities that meet the criteria for inclusion in the Compliance Registry, as further explained in the balance of this document.

Organizations will be responsible to register and to comply with approved Reliability Standards to the extent that they are owners, operators, and users of the Bulk Power System (BPS), perform a function listed in the functional types identified in Section II of this document, and are material to the Reliable Operation of the interconnected BPS as defined by the criteria and sections set forth in this document. NERC will apply the following principles to the Compliance Registry:

- In order to carry out its responsibilities related to enforcement of Reliability Standards, NERC must identify the owners, operators, and users of the BPS who have a material impact[2] on the BPS through a Compliance Registry. NERC and the Regional Entities will make their best efforts to identify all owners, users and operators who have a material impact on the BPS in order to develop a complete and current Compliance Registry list. The Compliance Registry will be updated as required and maintained on an on-going basis.
- Organizations listed in the Compliance Registry are responsible and will be monitored for compliance with applicable mandatory Reliability Standards. They will be subject to NERC's and the Regional Entities' Compliance Monitoring and Enforcement Programs.
- NERC and Regional Entities will not monitor nor hold those not in the Compliance Registry responsible for compliance with the Reliability Standards. An entity which is not initially placed on the Compliance Registry, but which is identified subsequently as having a material impact on the BPS, will be added to the Compliance Registry. Such entity will not be subject to a sanction or Penalty by NERC or the Regional Entity for actions or inactions prior to being placed on the Compliance Registry, but may be required to comply with a Remedial Action Directive or Mitigation Plan in order to become compliant with applicable Reliability Standards. After such entity has been placed on the Compliance Registry, it shall be responsible for complying with Reliability Standards and may be subject to sanctions or Penalties as well as any Remedial Action Directives and Mitigation Plans required by the Regional Entities or NERC for future violations, including any failure to follow a Remedial Action Directive or Mitigation Plan to become compliant with Reliability Standards.
- Required compliance by a given organization with the Reliability Standards will begin the later of (i) inclusion of that organization in the Compliance Registry and (ii) approval by the Applicable Governmental Authority of mandatory Reliability Standards applicable to the registered entity.

Entities responsible for funding NERC and the Regional Entities have been identified in the budget documents filed with FERC.[3] Presence on or absence from the Compliance Registry has no bearing on an entity's independent responsibility for funding NERC and the Regional Entities.

---

[1] The term "Regional Entities" includes Cross-Border Regional Entities that have footprints in the U.S., Canada, and Mexico, as applicable. Applicable Governmental Authorities in Canadian jurisdictions may have adopted their own Rules of Procedure and Compliance Registry requirements. Registered Entities may be subject to the Compliance Monitoring and Enforcement Programs (CMEP) in their respective jurisdictions, in accordance with applicable laws and regulations.

[2] The criteria for determining whether an entity will be placed on the Compliance Registry are set forth in the balance of this document. At any time a person may recommend in writing, with supporting reasons, to the Director of Compliance (or an equivalent position) that an organization be added to or removed from the Compliance Registry, pursuant to NERC Rules of Procedure Section 501.1.3.5.

[3] Budget documents are submitted to Applicable Governmental Authorities in Canada for information.

Background

The initial Registration process began in January of 2006. Registration of new entities is an ongoing process. If a Registered Entity's information changes, these changes must be submitted to the applicable Regional Entity(ies). Based on selection as the ERO, NERC's Organization Registration program[4] is the means by which NERC and the Regional Entities plan, manage, and execute Reliability Standard compliance oversight of owners, operators, and users of the BPS. Organizations listed in the Compliance Registry are subject to NERC's and the Regional Entities' Compliance Monitoring and Enforcement Programs.

Statement of Issue

As the ERO, NERC intends to comprehensively and thoroughly protect the reliability of the grid. To support this goal NERC will include in its Compliance Registry each entity that NERC concludes can materially impact the reliability of the BPS.

NERC will identify those entities that may need to be listed in its Compliance Registry. Identifying these organizations is necessary and prudent for the purpose of determining resource needs, both at the NERC and Regional Entity level, and for communicating with these entities regarding their potential responsibilities and obligations. Candidate entities can be identified at any time, as and when needed. The Compliance Registry is available on NERC's website.

Resolution

The potential costs and effort of registering every organization potentially within the scope of "owner, operator, and user of the BPS," while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so.

NERC and the Regional Entities have identified two principles they believe are key to the entity selection process. These are:

1. There needs to be consistency between Regions and across the continent with respect to which entities are registered; and
2. Any entity reasonably deemed material to the reliability of the BPS will be registered, irrespective of other considerations.

To address the second principle the Regional Entities, working with NERC, will identify and register any entity they deem material to the reliability of the BPS.

Registry Criteria

In order to promote consistency, NERC and the Regional Entities use the following criteria as the basis for determining whether particular entities should be identified as candidates for Registration. All organizations meeting or exceeding the criteria will be identified as candidates.

The following criteria (Sections I-V) plus the statement in Section VI will provide guidance regarding an entity's Registration status:

I. Owners, operators, or users of the BPS are candidates for Registration.[5]

[4] See NERC ERO Application; Exhibit C; Section 500 – Organization Registration and Certification.

[5] See NERC Rules of Procedure Section 501.1 NERC Compliance Registry — NERC shall establish and maintain the NCR of the BPS owners, operators, and users that are subject to approved Reliability Standards. For purposes of this Section I, users, owners, and operators of the BPS includes: 1) entities that use, own, or operate Elements of the Bulk Electric System (BES) as defined in Appendix 2 of the NERC Rules of Procedure and NERC Glossary of Terms; as well as 2) entities otherwise defined in the Registry Criteria in this Appendix 5B.

II. Entities identified in Section I above will be categorized as Registration candidates who may be subject to Registration under one or more appropriate Functional Entity types based on a comparison of the functions the entity normally performs against the following function type definitions.[6]

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time.
Computational Load Operator	CLOP	The entity that operates a Computational Load Site.
Computational Load Owner	CLO	The entity that owns and maintains a Computational Load Site.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage. Note: As provided in Section III.b.1 below, a Distribution Provider entity shall be an Underfrequency Load Shedding (UFLS)-Only Distribution Provider if it is the responsible entity that owns, controls or operates UFLS Protection System(s) needed to implement a required UFLS program designed for the protection of the BES, but does not meet any of the other registration criteria for a Distribution Provider.
Frequency Response Sharing Group	FRSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Generator Operator	GOP	The entity that: 1) operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services (Category 1 GOP); or 2) operates non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV (Category 2 GOP).

[6] Exclusion: An entity will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, including bilateral agreements and Sections 501, 507, and 508 of the NERC Rules of Procedure.

Function Type	Acronym	Definition/Discussion
Generator Owner	GO	The entity that: 1) owns and maintains generating Facility(ies) (Category 1 GO); or 2) owns and maintains non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV (Category 2 GO).
Planning Authority/ Planning Coordinator	PA/PC	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the Reliable Operation of the BES, has the Wide Area view of the BES, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Regulation Reserve Sharing Group	RRSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply Operating Reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in more quickly (e.g., between zero and ten minutes), then, for the purposes of recovery from a Reportable Balancing Contingency Event, the areas become a Reserve Sharing Group.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific Loads (customer demand and energy requirements) within a Planning Authority area.
Transmission Owner	TO	The entity that owns and maintains transmission Facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.

Function Type	Acronym	Definition/Discussion
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.

III. Entities identified in Section II above as being subject to Registration as a Distribution Provider, Computational Load Operator, or Computational Load Owner should be included in the Compliance Registry for these functions only if they meet any of the criteria listed below:

III(a) Distribution Provider:

III.a.1 Distribution Provider system serving >75 MW of peak Load that is directly connected to the BES;[7] or

III.a.2 Distribution Provider is the responsible entity that owns, controls, or operates Facilities that are part of any of the following Protection Systems or programs designed, installed, and operated for the protection of the BES:[8]

- a required Undervoltage Load Shedding (UVLS) program and/or
- a required Special Protection System or Remedial Action Scheme and/or
- a required transmission Protection System; or

III.a.3 Distribution Provider that is responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs) pursuant to an executed agreement; or

III.a.4 Distribution Provider with field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks.

III(b) Distribution Provider with UFLS-Only assets (referred to as "UFLS-Only Distribution Provider")

III.b.1 UFLS-Only Distribution Provider does not meet any of the other registration criteria in Sections III(a)(1)-(4) for a Distribution Provider; and

III.b.2 UFLS-Only Distribution Provider is the responsible entity that owns, controls, or operates UFLS Protection System(s) needed to implement a required UFLS Program designed for the protection of the BES.

The Reliability Standards applicable to UFLS-Only Distribution Providers are: (1) any version of PRC-005 and PRC-006 applicable to UFLS-Only Distribution Providers, (2) any regional Reliability Standard whose purpose is to develop or establish a UFLS Program, and (3) any Reliability Standard that lists UFLS-Only Distribution Provider in the applicability section. Reliability Standards that apply to Distribution Providers will not apply to UFLS-Only Distribution Providers, unless explicitly stated in the applicability section of these Reliability Standards and in future revisions and/or versions.

[7] Ownership, control or operation of UFLS Protection System(s) needed to implement a required UFLS Program designed for the protection of the BES does not affect an entity's eligibility for registration pursuant to III.a.1.

[8] As used in Section III.a.2, "protection of the Bulk Electric System" means protection to prevent instability, Cascading, or uncontrolled separation of the BES and not for local voltage issues (UVLS) or local line loading management (Special Protection System) that are demonstrated to be contained within a local area.

III(c) Computational Load Owner or Operator:

III.c.1 Computational Load Owner of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection.

III.c.2 Computational Load Operator of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection.

IV. Joint Registration Organization, Coordinated Functional Registration and applicable Member Registration.

Pursuant to FERC's directive in paragraph 107 of Order No. 693, NERC's rules pertaining to joint Registrations and Joint Registration Organizations, as well as Coordinated Functional Registrations, are now found in Section 501, 507, and 508 of the NERC Rules of Procedure.

V. If NERC or a Regional Entity encounters an organization that is not listed in the Compliance Registry, but which should be subject to the Reliability Standards, NERC or the Regional Entity is obligated and will initiate actions to add that organization to the Compliance Registry, subject to that organization's right to challenge as provided in Section 500 of NERC's Rules of Procedure.

Determination of Material Impact[9]

An entity that does not meet (i.e., falls below) the criteria may nevertheless be registered if it can be demonstrated that the entity has a material impact on the reliability of the BPS. Similarly, an entity that meets the criteria may be excluded if it can be demonstrated to NERC that the entity does not have a material impact on the reliability of the BPS. Such Registration decisions regarding materiality must be made by the NERC-led Registration Review Panel in accordance with Section III(D) of Appendix 5A to the NERC Rules of Procedure. In order to ensure a consistent approach to assessing materiality, a non-exclusive set of factors ("materiality test") for consideration is identified below; however, only a sub-set of these factors, or other additional factors, may be applicable to a particular functional registration category or specific entity, as appropriate:

1. Is the entity specifically identified in the emergency operation plans and/or restoration plans of an associated Reliability Coordinator, Balancing Authority, Generator Operator or Transmission Operator?
2. Will intentional or inadvertent removal of an Element owned or operated by the entity, or a common mode failure of two Elements as identified in the Reliability Standards (for example, loss of two Elements as a result of a breaker failure), lead to a reliability issue on another entity's system (such as a neighboring entity's Element exceeding an applicable rating, or loss of non-consequential load due to a single contingency)? Conversely, will such contingencies on a neighboring entity's system result in issues for Reliability Standards compliance on the system of the entity in question?
3. Can the normal operation, misoperation or malicious use of the entity's cyber assets cause a detrimental impact (e.g., by limiting the operational alternatives) on the operational reliability of an associated Balancing Authority, Generator Operator or Transmission Operator?
4. Can the normal operation, misoperation, or malicious use of the entity's Protection Systems (including UFLS, UVLS, Special Protection System, Remedial Action Schemes and other Protection Systems protecting BES Facilities) cause an adverse impact on the operational reliability of any associated Balancing Authority,

[9] The Determination of Material Impact applies when an entity seeks a NERC-led Registration Review Panel to review its request for examination of registration based on material impact. As stated in Appendix 5A, "[t]he Panel shall also include a review of individual and aggregate system-wide risks to, and considerations of, reliability of the BPS, as well as the BES Definition, as applicable." Appendix 5A, Section III(D). Any such request will be reviewed on a case by case basis in accordance with the Panel procedures set forth in Appendix 5A.

Generator Operator or Transmission Operator, or the automatic load shedding programs of a PC or TP (UFLS, UVLS)?

Limitation of responsibilities to a sub-set of Reliability Standards

NERC may limit the compliance obligations of (1) a given entity registered for a particular function or (2) a similarly situated class of entities, as warranted based on the particular facts and circumstances, to a sub-set list of Reliability Standards (which may specify Requirements/sub-Requirements). If NERC establishes a sub-set list for similarly situated class of entities, NERC will post the eligibility criteria and sub-set list of applicable Reliability Standards to the Registration and Certification page of the NERC Website.

Attachment 4

Comments and Consideration of Comments

Attachment 4-A

August 2026 Posting

Comments Submitted on Proposed Revisions to the NERC Rules of Procedure

NERC Rules of Procedure Appendix 2 (Definitions Used in the Rules of Procedure); Appendix 5A (Organization Registration and Certification Manual); and Appendix 5B (Statement of Compliance Registry Criteria)

NERC posted proposed revisions to its Rules of Procedure to develop new registered entity types, called Computational Load Owner and Computational Load Operator, for comment from August 19, 2026 to September 18, 2026. The entities in the following table responded during the comment period, either submitting comments or indicating support of other entities' comments. This pdf package includes the comments received during this posting period.

List of Responding Entities

	Entity
1	Ameren
2	American Chemistry Council***
3	American Electric Power
4	ATC
5	Bonneville Power Administration
6	CenterPoint Energy Houston Electric, LLC
7	Constellation
8	Corscale*
9	Danovo Energy Solutions
10	Data Center Coalition
11	Dru Dunton
12	Duke Energy
13	EdgeConneX
14	ELCON
15	ERCOT
16	Google*
17	Industrial Energy Consumers of America
18	Invenergy

19	ISO/RTO Council Standards Review Committee
20	ITC
21	LADWP
22	Microsoft*
23	MISO**
24	National Association of Regulatory Utility Commissioners
25	National Electrical Manufacturers Association
26	National Rural Electric Cooperative Association
27	nationalgrid
28	NERC MRC Sector 9
29	PG&E
30	Prologis
31	QTS Data Centers*+
32	Real Estate Roundtable
33	Sierra Club
34	TVA
35	Union of Concerned Scientists

*supports DCC

**supports ISO/RTO SRC

***supports ELCON

+means support and additional comments

September 18, 2026

Ms. Laura Anderson, Senior Standards Developer
North American Electric Reliability Corporation

Re: Project 2026-02 Computational Loads (CLO-002 Standard) Definitions

Dear Ms. Anderson:

The American Chemistry Council (ACC) appreciates the opportunity to comment on the North American Electric Reliability Corporation's (NERC) proposed Rules of Procedure revisions, specifically the definitions of "Computational Load Owner," "Computational Load Operator," and "Computational Load Site" associated with the CLO-002 Standard.

ACC represents a diverse group of companies engaged in the business of chemistry, a $673 billion enterprise. The energy-intensive and trade-exposed chemical manufacturing industry is a cornerstone of American competitiveness, national security, and technological innovation. Chemical manufacturing accounts for approximately 40 percent of industrial-sector energy consumption, including 20 percent of electricity, 42 percent of natural gas, and 56 percent of purchased steam.

ACC comments in this proceeding are limited to an endorsement of the comments submitted by the Electricity Consumers Resource Council (ELCON), dated September 18, regarding the need for specific, narrowly tailored definitions of "Computational Load Owner," "Computational Load Operator," and "Computational Load Site" in Appendix 2. We would welcome the opportunity to discuss these comments or provide further information relevant to the chemical sector at your convenience.

Sincerely,

/s/

Charles Franklin
Senior Director, Energy, Climate and Environment
Regulatory and Scientific Affairs
American Chemistry Council

American Electric Power's Comments on Proposed Revisions to NERC Rules of Procedure for Computational Load

American Electric Power (AEP) appreciates the opportunity to provide comments on the proposed revisions to the NERC Rules of Procedure (ROP) pertaining to Computational Load. AEP supports NERC's objective of safeguarding the reliability of the Bulk Power System (BPS) from risks associated with large Computational Loads and recognizes the importance of establishing Registration Criteria for entities that own or operate such sites.

AEP appreciates NERC's consideration of stakeholder feedback throughout this initiative and acknowledges the revisions made in response to prior comments. AEP believes these revisions reflect a thoughtful effort to address stakeholder concerns while advancing NERC's reliability objectives.

AEP Proposes the Following Modifications:

Appendix 2 (Definitions Used in the Rules of Procedure)

The proposed definition updates provide important clarity and consistency for the Computational Load framework. NERC's efforts to better define key terms strengthen the foundation for the associated Registration Criteria and support a common understanding across stakeholders. AEP appreciates the thoughtful approach taken to improve clarity within the Rules of Procedure and supports the proposed revisions.

Appendix 5A (Organization Registration and Certification Manual)

The revisions to Appendix 5A are a constructive enhancement to the registration process for Computational Loads. The proposed updates improve transparency and provide useful guidance on how the registration requirements will be applied.

Appendix 5B (Statement of Compliance Registry Criteria)

AEP supports the proposed Registration Criteria and appreciates NERC's efforts to establish a clear framework for identifying Computational Load facilities that may present reliability risks to the Bulk Power System (BPS). AEP believes the proposed revisions provide a practical path forward and supports their adoption.

Ameren comments on the Proposed Computational Load ROP Revisions

Ameren supports the proposed revisions to the NERC Rules of Procedure to incorporate computational loads into the registration and reliability framework. Ameren also recommends that NERC consider whether future revisions should address large loads more broadly, including MW, interconnection voltage, and load type, because aggregated emerging large-load categories may present similar reliability considerations.

From:
To:
Subject: Comments for Computational Load ROP Revisions
Date: Friday, September 18, 2026 6:59:40 PM

Definitions in Appendix 2:
ATC feels that the definition for Computational Load Site (CLS) may be too broad since "One or more buildings, structures, or installations **at a single location**" may not appropriately represent every CLS. For example, a single campus with multiple interconnections evaluated separately may not be classified as one CLS as some may interpret "a single location" as one POI or substation which can be too limiting.

There are also concerns for coordinated multi-sites that are separate CLS under different CLOs that are operated as one aggregate computation load. For example, data center owners have stated that a single" job" can be run on multiple data centers with different owners. This job will act in synchronism at the different locations so that load characteristics, such as variability, ride-through, etc. will affect the system the same as if they had been at one location with a single owner. The job could even be terminated for job-related reasons, affecting all sites involved simultaneously. This would be very difficult to monitor and audit for compliance.

Additionally, the definitions for Computational Load Owner and Computational Load Operator, when used in conjunction with CLS, is too simplistic a definition that does not clearly establish the responsible entity for a campus served through multiple substations or POIs.

Criteria in Appendix 5B:
ATC believes that the Computational Load Sites definition should **apply to a voltage level greater than or equal to 60 kV** as even these locations with a high enough load could easily impact the BES/BPS.

Thank you,

Amy Wilke
Reliability Standards Compliance Analyst | PWK |

From:
To: ROPComments (SM)
Cc:
Subject: BPA Comments on Computational Load ROP Revisions
Date: Thursday, September 17, 2026 11:56:09 AM
Attachments: E1-E3-LN_Example.pdf
Proposed Solution to Modify Appendix 2_Definition of BES_For Computational Loads_BPA Comments.docx

Hello,

Please see below BPA's comments on the Computational Load ROP Revisions. We appreciate the opportunity to provide feedback.

Note: BPA has also shared these comments (including attachments) with the NERC Project 2026-02 Drafting Team.

BPA believes the NERC Rules of Procedure definitions must be strengthened to ensure Registered Entities such as Transmission Owners (TO), or currently non-registered entities that have computational loads on their systems, would not be able to apply Bulk Electric System (BES) exclusions E1 or E3 to areas that contain Computational Load Site(s) (CLS). If the CLS or Computational Load Owner (CLO) is interconnected to the Bulk Power System (BPS), and for that portion of the BPS the TO uses BES exclusions such as E1 or E3, the Transmission Planner would not receive modeling data for that portion of the TO system under the exclusion. In the model, this would create an island for CLS data. BPA recommends exclusions E1 and E3 not be allowed when there is embedded CLS within such networks. Please see the attached document (E1-E3-LN Example.pdf), which helps clarify our concerns in a visual format.

BPA suggests two potential solutions for consideration:

1. (Preferred solution) Revise the current definition of Bulk Electric System (BES) in Appendix 2 to include a new I6 specific to Computational Load Site and conforming revisions to Exclusions E1 and E3 (see attached Word Doc 'Proposed Solution to Modify Appendix 2_Definition of BES_For Computational Loads_BPA Comments). Or,

2. Modify MOD-032 to allow for data gathering to be applied for all BES and

   BPS elements connected to Computational Load Sites.

Additionally, BPA recommends Appendix 5B be revised to align with language used in Appendix 2, as show below.

- **Appendix 5B (Statement of Compliance Registry Criteria):**
- Computational Load Owner or Operator of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through

electrical equipment that is connected ~~at a voltage level greater than or equal to 100 kV from one or more points of connection~~ to the BPS.

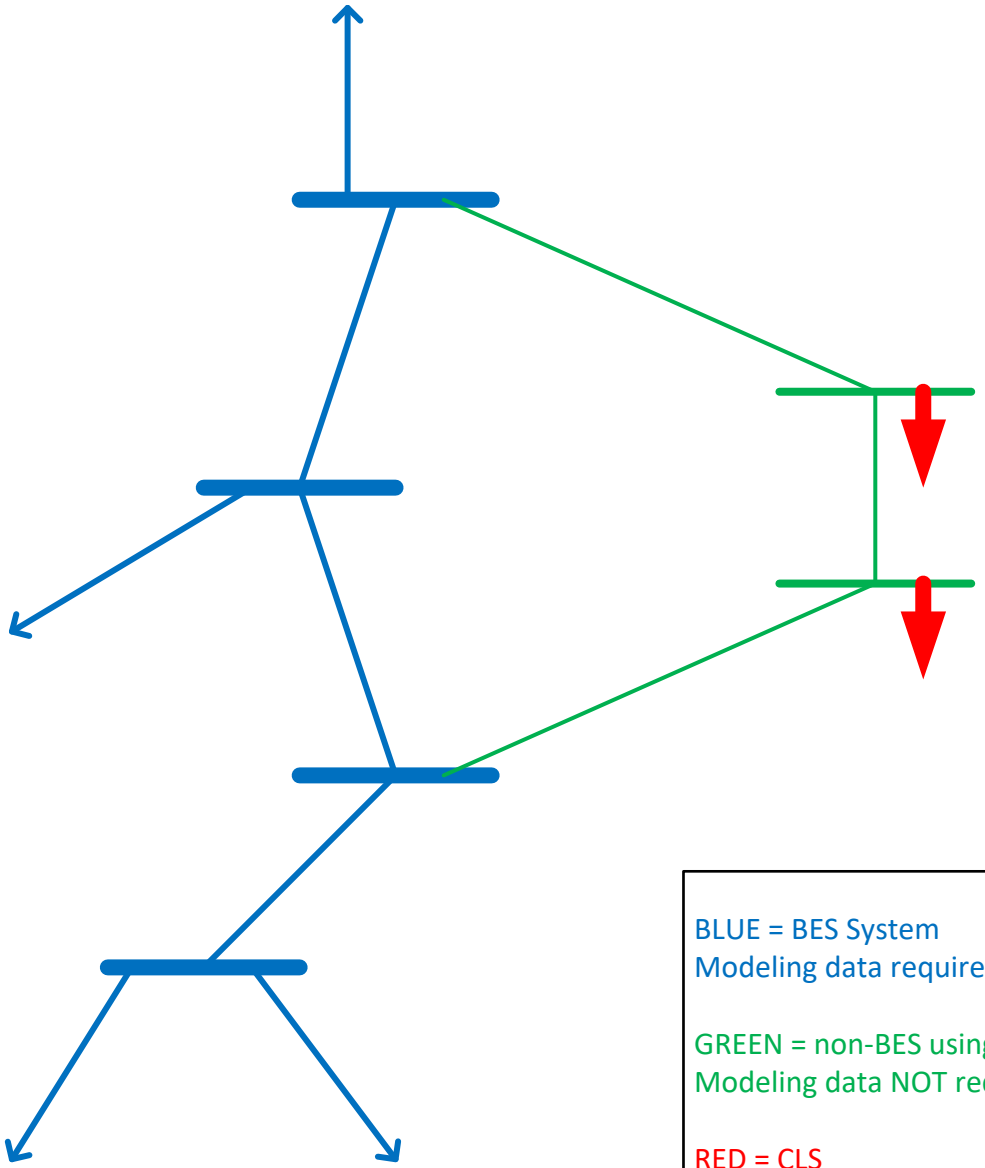
- **Appendix 2 (Definitions Used in the Rules of Procedure):**

  "Computational Load Site" means one or more buildings, structures, or installations at a single location that

  1. Primarily contains information technology infrastructure used for:
     - creating, executing, and delivering software applications and services;
     - artificial intelligence training, deployment, and delivery;
     - cryptocurrency mining; or
     - other computational activities at a data center; and
  2. is supplied through electrical equipment that is connected to the BPS.

Thank you,

Cain Braveheart
BONNEVILLE POWER ADMINISTRATION
DEPARTMENT OF ENERGY
Public Utilities Specialist (Reliability Standards Specialist) | Transmission Business Operations | TAB



BLUE = BES System
Modeling data required to be shared via MOD-032 R2.

GREEN = non-BES using E3 Local Network Exclusion
Modeling data NOT required to be shared.

RED = CLS
Modeling data required to be shared via CLO-001 R9.

By allowing E1 or E3 BES Exclusions then this can create a gap in the model. It is suggested that E1 and E3 Exclusions are not allowed when there is embedded qualifying Computational Load Sites.

Appendix 2

"Bulk Electric System" or "BES" means unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1 -** Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.

- **I2 -** Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
    a) Gross individual nameplate rating greater than 20 MVA. Or,
    b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

- **I3 -** Blackstart Resources identified in the Transmission Operator's restoration plan.

- **I4 -** Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
    a) The individual resources, and
    b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

- **I5 -** Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

- **I6 -** Computational Load Site(s) with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment that is connected to the BPS.

Exclusions:

- **E1 -** Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
    a) Only serves Load, not identified in Inclusion I6. Or,
    b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
    c) Where the radial system serves Load, not identified in Inclusion I6, and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

  Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
  Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- **E2 -** A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3 -** Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load, not identified in Inclusion I6, rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
    a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
    b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).
d) Limits on connected loads: The LN and its underlying Elements do not include Computational Loads identified in Inclusions I6.

- **E4 -** Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.**

CenterPoint Energy Houston Electric, LLC (CEHE) Comments on NERC Rules of Procedure Revisions for Computational Load Registration

To whom it may concern,

CenterPoint Energy Houston Electric, LLC (CEHE) is supportive of the registration effort for computational loads. The Computational Load "Owner" and "Operator" structure that NERC proposed is appropriate and echoes tried-and-tested registration frameworks (such as the Transmission "Owner" and "Operator" structure). CEHE also agrees with the expanded narrative definition of a Computational Load Site, as proposed in the changes to Appendix 2 of the NERC Rules of Procedure, but supports EEI's recommendation that guidance is provided clarifying that cloud storage sites are intended to be included under the definition.

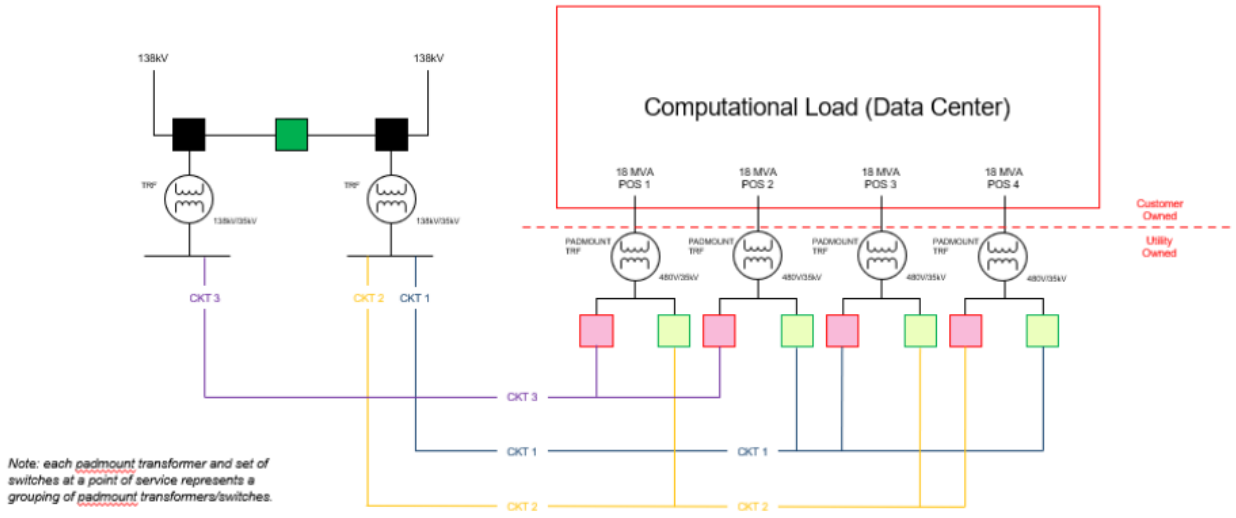
CEHE does recommend that NERC provide additional guidance on the types of Computational Load Site configurations that would be subject to registration requirements.

Many Computational Load Sites in excess of 50 MW are interconnected via fully-fledged breakered customer substations. At said customer substations, the voltage is stepped down to distribution level voltages, such as 35 kV, before Computational Load Site padmount transformers further reduce the voltage to a level appropriate for computational equipment (e.g. 480 V). Because the customer-owned substation takes transmission service, it is unambiguously part of the BPS per the registration criteria.

However, in other cases, a utility may interconnect a Computational Load Site in excess of 50 MW via a dedicated distribution feed and own the padmount transformers on the outside of the Computational Load Site. The utility thereby provides 480 V distribution service to the Site. Would the registration criteria in such instances be applied to the point of connection at the primary transformers feeding the site (the distribution padmount transformers), or the transformer(s) that the dedicated feed comes from? Figure 1 below illustrates such an example.

Figure 1

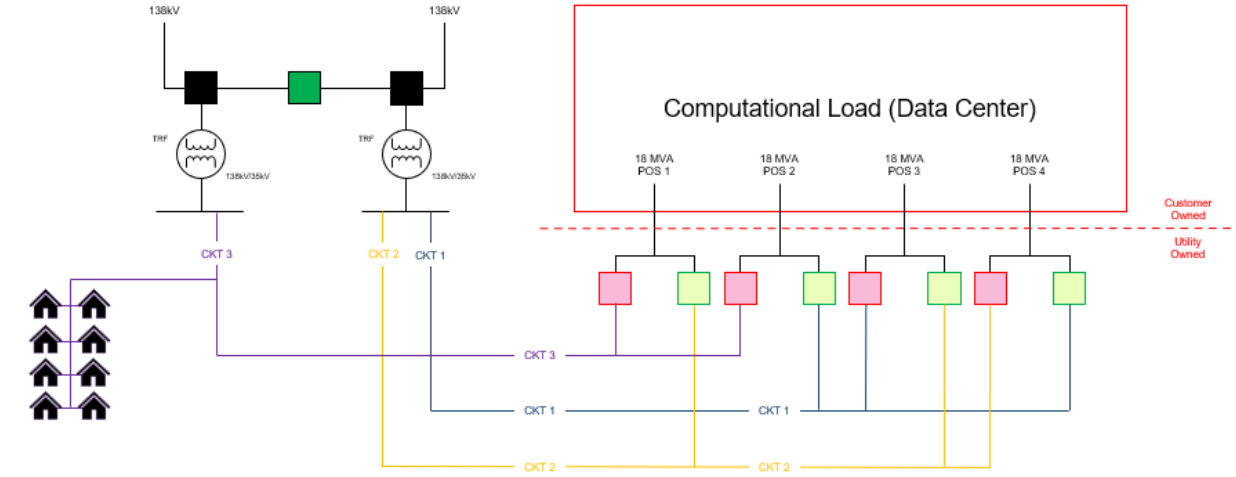
Computational Load served with 480 volts, drawn from a utility owned padmount transformer with a high-side of 35 kV



Additionally, some Computational Load Sites in excess of 50 MW may be interconnected on radial distribution feeds, as illustrated in Figure 2 below. In such instances, would the radial nature of the point of connection preclude registration (per the 7-Part Test established in FERC Order 888), or would the proposed registration criteria still apply?

Figure 2

Computational Load served with 35 kV, drawn from a utility owned transformer with a high-side of 138 kV, with residential customers served of the same feed



Guidance and/or a NERC registration webinar to answer these questions would help reduce ambiguity for both Computational Load Site Owners/Operators and interconnecting Utilities.

Constellation Energy Generation, LLC Comments on NERC ROP Changes associated with NERC Project 2026-02 Computational Loads

Proposed Changes to Rules of Procedure

NOTE: Comments are to be submitted via email and not through the SBS System by ***9/18/26***

ROPcomments@nerc.net.

Constellation Comments on Proposed Revisions to the NERC Rules of Procedure NERC Rules of Procedure Appendix 2 (Definitions Used in the Rules of Procedure); Appendix 5A (Organization Registration and Certification Manual); and Appendix 5B (Statement of Compliance Registry Criteria):

While Constellation supports the creation of two new functions, Computational Load Owner (CLO) and Computational Load Operator (CLOP), further clarification is needed on the intent and scope of the CLOP. The FAQ document developed to provide additional guidance on connection point(s) to the BPS and examples of defining a Computational Load Site boundary does not provide enough clarity on what "operational" activities could be performed by the CLOP. Without revision, it is not clear what reliability functions will apply to the connecting Transmission Owner, Distribution Provider or Generator Owner serving the Computational Load or what reliability functions would apply to the CLOP. For example, in the case of a GO/GOP that connects to a Computational Load directly or via a Co-Located Load arrangement, if the GO/GOP operates the breakers supplying the Computational Load in response to an Operational Instruction to divorce the load it could inadvertently and unnecessarily require the GO/GOP d to register as a CLOP.

Per the revised definition of an Operating Instruction:

(Modified) Operating Instruction:
A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, **output, or input** of an Element of the Bulk Electric System or Facility of the Bulk Electric System or a Computational Load Site. ***[emphasis added]***

The Technical Rationale for CLO-003-1 does provide some example scenarios on the potential ownership of the main power transformer(s) of the Computational Load Site and additional clarity on how the CLOP may be applied; however, Technical Rationale documents are informational only and not submitted to the FERC for approval. The drafting team should remove ambiguity regarding the assumed demarcation between the CLOP and the GO, DP and/or TO because it is not clearly described within the definition of the CLOP or the associated draft CLOP Standards.

From:
To:
Subject: Comments on Computational Load ROP Revisions – Corscale Data Centers
Date: Friday, September 18, 2026 7:30:02 PM

Corscale Data Centers supports and concurs with the comments submitted by the Data Center Coalition regarding the proposed revisions to the NERC Rules of Procedure for Computational Load Owners and Operators.

Best Regards,

Dan Vanderplas
Data Center Campus Director



13760 University Blvd.
Gainesville, VA 20155

CORSCALE.COM

From:
To: ROPComments (SM)
Subject: Comments on Computational Load Entity ROP Revisions
Date: Wednesday, September 16, 2026 3:38:03 PM
Attachments: image.png

1. Some computational load owners are not experts in utility-grade maintenance and operations of infrastructure. Will the enforcement and registration come with associated guidebooks and training on the new roles and expectations for load owners? We may want to add some clarity on this in Page 3A by adding a check against "Entities that need to be certified"

2. Who is responsible for establishing POI operating rules where there is common infrastructure between utility and CLO?
   The wording for determination of material impact, could we modify the criteria "Is the entity specifically identified in the emergency operation plans and/or restoration plans of an associated Reliability Coordinator, Balancing Authority, Generator Operator or Transmission Operator?" to

"Is the entity specifically identified and reached mutual agreement in the emergency operation plans and/or restoration plans of an associated Reliability Coordinator, Balancing Authority, Generator Operator or Transmission Operator?"

Vidya

VIDYA VANKAYALA. PhD, PEng
Executive Advisor
Danovo Energy Solutions
Industry leaders. Trusted advisors.

Web https://www.DanovoEnergy.com
LinkedIn https://www.linkedin.com/company/danovoenergy/

DANOVO
ENERGY SOLUTIONS
A QUANTA SERVICES COMPANY

From:
To: ROPComments (SM)
Cc:
Subject: Data Center Coalition comments on NERC Proposed Rules of Procedure and Registry Criteria
Date: Friday, September 18, 2026 4:31:23 PM

Good Afternoon,

See below, the Data Center Coalition (DCC's) comments on NERC's proposed Rules of Procedure and Registry Criteria, due today. Please confirm receipt of our comments as appropriate.

DCC Comments on the NERC Rules of Procedure Updates
On the Computational Load Definitions/Registration Criteria
Submitted 9/17/2026

The Data Center Coalition (DCC) is pleased to submit these comments on NERC's updated proposed Rules of Procedure definitions and registration criteria for Computational Loads.
Like all customers, the data center industry depends on a reliable electricity grid in order to fulfill its role as a vital backbone of our modern economy. In turn, data centers offer a number of reliability benefits to the grid, including significant investments in new energy resources and next-generation technologies. Data centers can also serve as grid assets that help promote reliability during energy emergencies caused by extreme weather.
It is critical to ensure proposed definitions and registration criteria by NERC are based on complete evidence, the technical capabilities and specifications of data center equipment, and do not disregard important developments or information from the industry. The DCC's comments below aim to provide the challenges and concerns with the proposed definitions and registration criteria in applying accurately and fairly across the country, while also giving recommendations to improve the definitions and criteria to address the stated issues.

Proposed ROP Definition

- DCC requests that NERC confirm that it intended to use the term "BPS" in defining Computational Load Site as "supplied through electrical equipment that is connected to the BPS." The NERC registration model has historically been based on the BES definition, as NERC/REs determine whether or not entities are "Users, Owners, and Operators" of the BES for purposes of registration. Yet Section 215 of the FPA uses the term "BPS," not BES. FERC has said that, even though NERC

uses BES, the fact that FPA Section 215 uses BPS is evidence that Congress actually intended to give FERC authority beyond NERC's BES definition. See, e.g., Mandatory Reliability Standards for the Bulk Power System, 118 FERC P 61,218 at P 76 (2007) ("Therefore, the Commission confirms its statements in the NOPR that the Bulk-Power System reaches farther than those facilities that are included in NERC's definition of the bulk electric system."). DCC requests clarity on the intent and purpose of using BPS, and how this use relates to the exclusion in FPA Section 215–namely that the BPS "does not include facilities used in the local distribution of electric energy."

- DCC is particularly concerned about the potential for confusion regarding the definition of "Computational Load Operator" as the entity that "operates" a Computational Load Site, and the definition of Computational Load Owner as the entity that "maintains" a Computational Load Site. Given the diversity of business models and responsibility configurations among distinct legal entities that may exist at a given Computational Load Site, it may be unclear where one entity's "operation" of a site ends, and where another's "maintenance" begins. DCC suggests striking the phrase "or maintains" from the definition of Computational Load Owner to avoid this potential confusion. In addition, the use of the word "owns" in the Computational Load Owner definition should also be clarified that this is the owner of the physical equipment of the site (UPS, cooling systems, electrical infrastructure, controls/relays, etc.), rather than say owners of the real estate/land.
- The Computational Load Site definition covers one or more buildings, structures, or installations at a "single location, " and how that term and the term "one or more buildings" are read decides whether a phased campus generates one registration or several. The term should be defined to track how campuses are actually built, since buildings may be separated by roads or parcel lines, energized years apart, and fed from different stations while sharing cooling and auxiliary load. If it stays undefined as it currently is in the proposed definition, the same physical campus can be read as one location or several depending on the reviewer, and each reading carries a different registration count and compliance cost, which is the highest leverage cost driver in the package. DCC asks NERC to either define single location by reference to the published factors, or to replace it with new text such as the following: "buildings, structures, or installations that share common electrical infrastructure or a coordinated operating function constitute a single Computational Load Site, without regard to parcel boundaries or phased in service dates."

Proposed MW Threshold Criteria

- DCC recommends NERC increase the proposed registration threshold from 50 MW to 75 MW while retaining the 100 kV criterion. NERC's own technical analysis provided with the ROP changes shows that a 75 MW threshold would still capture approximately 63,960 MW, or 80%, of current/forecasted computational load, compared to 68,288 MW, or 86%, under the proposed 50 MW threshold. The proposed 50 MW threshold therefore captures only approximately 4.3 GW of additional load nationwide, representing less than 6% of total current/forecasted computational load. DCC does not believe this incremental increase in coverage materially changes aggregate BPS reliability risk, and a 75 MW threshold would provide a more appropriate balance between reliability and regulatory burden.
- In addition, the term “connected Load” in the CLO/CLOP registration criteria should also be clarified to ensure it is the contracted load identified/agreed upon in the interconnection agreements such that any behind-the-meter generation is accounted for that impacts the total load seen by the grid.

Clarification of the term “Primarily”

- NERC should revise the proposed Computational Load Site definition to replace the subjective term "primarily" with a measurable threshold. Unlike other jurisdictions, the proposed definition does not specify what percentage of facility demand must be attributable to computational load activities. For example, ERCOT defines a Large Computational Load as a facility where 50% or more of demand consists of computational load, while MISO uses a threshold based on at least 25 MW of IT equipment demand (essentially the same as a 50% threshold). Establishing a clear percentage or MW-based criterion would improve consistency of the registration criteria across Regional Entities.

Proposed Voltage Threshold Boundary Concerns

- NERC should clarify the application of the 100 kV criterion by establishing a clear boundary for when a Computational Load Site is considered to be "supplied through" electrical equipment connected at or above 100 kV. As currently drafted, it is unclear whether a facility interconnected at 34.5 kV remains subject to registration simply because the serving distribution circuit ultimately traces back to a 100 kV or higher transmission source (all distribution eventually traces back to a transmission source). Additional guidance is needed to distinguish between facilities served by dedicated feeders directly connected to a neighboring transmission substation and facilities served through traditional distribution systems with many customers.
- The proposed ≥100 kV criterion creates ambiguous and inequitable outcomes for

data centers connected at distribution voltages. Many facilities take service at sub-100 kV (e.g., 34.5 kV) through Distribution Provider infrastructure that connects upstream to the transmission network at 100 kV or above. In these configurations, the Computational Load Owner has no control over, and often no visibility into, how the Distribution Provider connects to the transmission system or what other loads share the same bus. The NERC FAQ diagrams suggest that registration may hinge on whether other loads happen to be connected to the same distribution bus, yet Distribution Providers routinely move loads, open bus ties, and swap feeders without notifying connected customers. A facility's registration status could therefore change overnight through no action of its own. DCC requests that NERC clarify: (1) how applicability is determined when the distribution bus serving a data center also serves other customers; (2) what notification obligations the Distribution Provider has when network changes affect a facility's registration status; and (3) whether the FERC Order 773 seven-factor test for local distribution exclusion applies to large loads consuming power at distribution voltage, given that the only sub-100 kV inclusion precedent in that order was for generation injecting power, not load withdrawing it. DCC also asks NERC to further clarify and define the phrase “common point of connection,” which Figures 2 and 3 in the FAQ both use and treat as distinct from the point of connection to the BPS without defining either.

Co-located Campuses & Buildings

- NERC should clarify how registration applies to campus developments with multiple Computational Load Owners. Under the proposed framework, it is unclear whether registration is assessed at the Computational Load Site level, the individual owner level, or both. For example, if a campus exceeds 50 MW in aggregate but consists of multiple building owners, including some responsible for less than 50 MW of load, it is unclear whether all owners would be required to register.
- The industry needs clarity up front prior to these new definitions and registration criteria getting approved in place, as the industry and future registered entities need to understand exactly how these roles and responsibilities will apply to their facilities and existing commercial agreements such that flexibility and appropriate planning of these compliance responsibilities can be made well in advance of the official NERC registration dates.
- Similarly, many Computational Loads operate in a co-located tenant model. It is unclear whether tenants are CLOPs in all circumstances or only when they exercise operational control over computational equipment. As an example, if a 300 MW Computational Load Site contains ten Computational Load Operators,

including operators responsible for less than 50 MW each, it is unclear whether all ten operators would be required to register or whether registration would apply only to those entities with a material ownership or operational role at the site. Any compliance framework should align responsibilities with the entity that owns or controls the relevant equipment and data. NERC should also recognize that colocation providers are often subject to confidentiality and commercial agreements that limit their ability to obtain, verify, or disclose tenant-specific operational information, and should avoid imposing compliance obligations that require one entity to report information controlled by another.

- To illustrate the range of delivery models the registration criteria must accommodate, DCC offers the following to NERC staff:
    - DCC's members develop power infrastructure using the delivery model best suited for each location. On some campuses, the serving utility owns and operates the substation and provides medium voltage service (typically 34.5 kV or 12.5 kV) directly to the owner's facilities. On other campuses, particularly large hyperscale developments requiring significant capacity, the owner takes service at transmission voltage (typically 100 kV and above) and owns the high voltage substation that transforms power to medium voltage for campus distribution. In these cases, the owner owns and manages the transmission interconnection, substation assets, and medium voltage distribution infrastructure. Power is delivered to the tenants at low voltage (typically 480 V), and each tenant controls only their own computational workload.

Single Registration Language in ROP

- NERC should clarify the treatment of multi-tenant facilities and expressly identify when a single entity may serve as the accountable Computational Load Operator for an entire Computational Load Site in the ROP. While NERC has indicated that a centralized or shared operating function may serve as the single accountable Computational Load Operator at a multi-tenant site, that concept is not reflected in the proposed registration criteria or supporting definitions.
    - This matters because a campus is typically owned by one legal entity, operated by staff or an affiliate or a shared services entity, and leased to tenants who control only their own workloads, so without a stated rule, affiliates or tenants risk being pulled onto the Compliance Registry alongside the owner. Left as drafted, a registrant cannot tell a tenant with confidence that the tenant is outside the registry, which complicates leasing. DCC requests that NERC clarify where owner and operator functions are split, when a single accountable operator may register as CLO for the entire site,

and provide confirmation that a tenant controlling only its own workload is or is not itself a Computational Load Operator where a shared operating function has registered

Phased Campus Buildouts

- NERC should also clarify how these requirements apply to phased campus developments. Registration obligations should be clarified on how current energized and operational capacity may be phased over time leading to the ultimate buildout capacity, as campuses are commonly developed and placed into service over multiple phases and years. Clear guidance is needed to ensure consistent treatment of multi-owner campuses while allowing registration and compliance obligations to align with the actual load that is in service.

Making the FAQ Document Binding Text

- NERC's FAQ says helpful things, that two or more sites can sit behind the same supply equipment, that a single site can be fed from separate stations, and that there can be more than one owner and more than one operator of a single site, but an FAQ is not enforceable and can be revised or ignored by whoever runs a given registration review. For an owner and operator, that means the difference between one registration and several registrations for a phased campus is based on informal guidance rather than on the criteria themselves, and registration is the gateway to every obligation in all three proposed Reliability Standards. If the draft stays as written, each campus gets reviewed on its own facts with no binding text to point to, so outcomes vary region to region. DCC recommends NERC to convert the FAQ answers into binding text in Appendix 5B or some other enforceable document to keep consistency across the entire ERO.
- NERC has identified factors – such as ownership, shared or common infrastructure, and coordinated use of the computing infrastructure – that bear on how a site is delineated, but they currently function as informal guidance rather than as a published test. A published test is what lets an owner model registration outcomes at the design stage, when it is deciding whether phases share a substation, share cooling, or are separately metered. Without it, the registrant has no certainty in advance and invites inconsistent results across regions. DCC asks that the factors NERC lists be published as the governing test for site delineation, with the further point on how the connected load is measured at the site compared against the future maximum build out of load studied in the interconnection process, and how those differences will apply for registration and NERC requirements while the projects are built out over time.

FAQ Expansion

- DCC requests that NERC add various campus examples to the FAQ illustrating how the proposed registration criteria would apply to phased, multi-building, and multi-tenant Computational Load Sites. Building on the existing Figures 2 and 3, NERC should illustrate a campus with multiple phases energized over time, shared substations and cooling infrastructure, separate parcel boundaries, multiple points of connection and the voltages of the connecting equipment, and tenants that control only their own computational workloads. The examples should identify the expected registration outcomes and clarify whether connected load is evaluated at the site level or by individual phase, owner, operator, or tenant. Such examples would provide meaningful implementation guidance and help ensure consistent application of the criteria across a range of common data center development and ownership structures.

Sincerely,

Morgan A. Sipple
Director, Energy Policy - FERC and RTOs
Data Center Coalition

https://www.datacentercoalition.org

From:
To:
Subject: Comments on the Proposed Computational Load ROP Revisions
Date: Friday, September 18, 2026 11:42:34 PM

Hello,
I appreciate the opportunity to comment on the Proposed Computational Load ROP Revisions. I am filing my comments as an individual member of the public.

My comments are as follows:
1. Appendix 2 to the Rules of Procedure, Definitions, should include the threshold values defined in Appendix 5B at page 8. Some definitions, but not all, include threshold values. Appendix 2 is likely to be the first place interested parties would look for threshold values.

2. Appendix 5B, Statement of Compliance Registry Criteria, includes a section on "Determination of Material Impact" at page 8, which states, "An entity that does not meet (i.e., falls below) the criteria may nevertheless be registered if it can be demonstrated that the entity has a material impact on the reliability of the BPS." Given the robust debate over thresholds, it would seem prudent for NERC to actively engage stakeholders in reviewing these threshold values in a public process going forward.

3. Proposed registered entities CLO and CLOP represent a major conceptual departure from the traditional NERC registration framework characteristics of the load itself. Footnote 5 on page 4 expressly broadens “users, owners, and operators of the BPS” to include not only entities using, owning, or operating BES Elements, but also entities “otherwise defined in the Registry Criteria in this Appendix 5B."

There is no policy discussion here explaining the historical significance, no comparison with prior registration practice, and no discussion of why direct regulation of an electricity consumer is institutionally different from registering utilities, generators, transmission owners, planners, or reliability coordinators.

Including a direct acknowledgement and explanation of this shift in policy seems reasonable.

Thank you again for the opportunity to review these well-crafted documents.
Dru Dunton
Individual Commenter

From:
To:
Cc:
Subject: Comments on Computational Load ROP Revisions - Due 9/18/2026
Date: Tuesday, September 15, 2026 5:00:32 PM

INTERNAL

Duke Energy Comments on Computational Load ROP Revisions

General Comment
NERC and the Regional Entities should ensure a mechanism is in place to inform BAs, TOPs, and RCs when new Computational Load Owners and Computational Load Operators are Registered with sufficient lead time for BAs/TOPs/RCs to comply with CLO Standards. Throughout the development of the CL Standards it has been stated by participants that there may be multiple Computational Load Operators associated with a Computational Load Owner / Computational Load Site, and that these Operators may change at various time intervals depending on short-term 'lease' agreements. For BAs/TOPs/RCs to distribute data specifications per CLO-002-1 and have successful 'day one' compliance, for example, there should be prior notice given for Registration of CL Owners/Operators to the BAs/TOPs/RCs. During CAT2 IBR Registration some Regional Entities declined to provide a list of forthcoming CAT2 IBR GO/GOPs to their 'mapped' BAs/TOPs/RCs to facilitate this compliance coordination, and that information is not available to BAs/TOPs/RCs in the NERC CORES tool. A mechanism should be developed going forward, prior to the implementation of these CLO Standards, so that proper coordination can be accomplished prior to the effective Registration date for new CL Entities.

Appendix 2
Section: Specific Definitions
Consider changing: "Computational Load Operator" means ~~the~~ "any" entity that operates a Computational Load Site.
Basis For Change: Because of the high likelihood that more than one Computational Load Operator will be located at a single Computational Load Site, Duke Energy proposes the above change to the definition of Computational Load Operator in Appendix 2.

Appendix 5B
Section: Statement of Compliance Registry Criteria – Registry Criteria, Section II, Table of Definitions
Consider changing: "Computational Load Operator" means ~~the~~ "any" entity that operates a Computational Load Site.
Bases For Change: 1- Because of the high likelihood that more than one Computational

Load Operator will be located at a single Computational Load Site, Duke proposes the above change to the definition of Computational Load Operator in Appendix 5B.

2-Appendix 2 uses the identical definitional language.

Regards,

Kim Thomas
Duke Energy – NERC O&P Standards

edgeconnex®

September 18, 2026

North American Electric Reliability Corporation
1401 H Street NW, Suite 410
Washington, DC 20005
ROPcomments@nerc.net

Re: Comments on the August 2026 Proposed Revisions to the NERC Rules of Procedure Concerning Computational Loads

To whom it may concern,

EdgeConneX ("ECX") respectfully files these comments in response to the August 19, 2026 notice as to proposed changes to NERC's Rules of Procedure. Those proposed changes include adding the terms "Computational Load Owner" and "Computational Load Operator," to Appendix 2. The definitions of those terms, however, are inadequate to allow implementation of the standards that NERC is contemplating.

The proposed definition of a Computational Load Owner is simply an "entity that owns and maintains a Computational Load Site." Similarly, a Computational Load Operator is proposed to be "an entity that operates a Computational Load Site." Neither definition is clear as to whether it includes collocated tenants that operate information technology at a Computational Load Site. This lack of clarity is significant because, if tenants are not included, it may well be the case that the entities that are covered by the proposed standards will not have the ability or information necessary to comply with many of those requirements.

For instance, proposed standard CLO-OO1 anticipates Computational Load Owners providing studies and modeling data. ECX, however, does not own or operate any servers that hold or manage computational data. Those are owned by its collocated tenants, so ECX does not have information necessary to create forecasts based on those parties' actual future behavior. Beyond that, under its lease agreements with all its tenants, ECX is often subject to strict confidentiality agreements that may well prevent it from sharing any information it does have as to future usage.

Similarly, for purposes of communicating real-time operational information under proposed CLO-002, ECX can provide information only at the level of the full data center, not that of any individual tenant. Any information that relates to tenant data must be released by the tenant, rather than ECX. Even where it has tenant-specific data, existing agreements often prevent ECX from releasing that information.

For these reasons, NERC should clarify whether tenants are Computational Load Operators. If they are not Computational Load Operators subject to the proposed reliability standards, NERC should either

add a definition of tenants and include those entities in its standards or revise those standards so that they do not inappropriately and unfairly impose obligations that regulated entities cannot satisfy.

Sincerely,

Lisa Youngers
Global Head of Public Policy & External Affairs

2201 Cooperative Way, Suite 400
Herndon, VA 20171

Proposed Changes to NERC Rules of Procedure
"Computational Load Owner"
"Computational Load Operator"
"Computational Load Site"

Comments of the Electricity Consumers Resource Council (ELCON)

The Electricity Consumers Resource Council (ELCON) respectfully submits these Comments in response to the National Electric Reliability Corporation's (NERC) proposed revisions to the NERC Rules of Procedure posted August 19, 2026[1] incorporating the terms "Computational Load Owner," "Computational Load Operator," and "Computational Load Site."

ELCON is the national association representing large industrial consumers of electricity. ELCON member companies create a wide range of products from virtually every segment of the industrial community—we own and operate hundreds of major facilities and are significant consumers of electricity throughout the United States. Reliable electricity supply at just and reasonable rates is essential to our members' operations.

ELCON appreciates NERC's careful consideration of the public comments and feedback to its April 1, 2026 posting proposing a newly defined "Computational Load Entity" for NERC registration. ELCON recognizes that NERC attempted to incorporate ELCON's feedback to add further clarification to the proposed definitions and criteria that directly tie the primary electrical operations of a facility or site to the risks posed to the bulk power system (BPS).

However, we remain concerned that the revised definitions and registration criteria, as written, could capture industrial and other large commercial loads rather than narrowly targeting data center and cryptocurrency loads identified in NERC's prior whitepapers as exhibiting behaviors that pose a risk to the BPS.[2]

---

[1] https://www.nerc.com/who-we-are/rules-of-procedure/proposed-changes-to-rules-of-procedure.

[2] *See* Characteristics and Risks of Emerging Large Loads (July 2025), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf; Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads (March 2026), https://www.nerc.com/globalassets/our-work/guidelines/reliability/white-paper---assessment-of-gaps.pdf.

Appendix 2 – Definitions Used in the Rules of Procedure

The August 19 proposed revisions to Appendix 2 of NERC's Rules of Procedure replace "Computational Load" and "Computational Load Entity" with three new terms that include "Computational Load Owner," "Computational Load Operator," and "Computational Load Site." The definition for "Computational Load Site" being:

> one or more buildings, structures, or installations at a single location that
>
> 1) Primarily contains information technology infrastructure used for:
>   - creating, executing, and delivering software applications and services;
>   - artificial intelligence training, deployment, and delivery;
>   - cryptocurrency mining; or
>   - other computational activities at a data center; and
>
> 2) is supplied through electrical equipment that is connected to the BPS.

The new definition attempts to capture the primary operations associated with data center, artificial intelligence, and cryptocurrency that encapsulates the majority of that facility or site's electrical usage and demand. ELCON is concerned that the first bullet "creating, executing, and delivering software applications and services" could be interpreted as extremely broad and could capture any large facility with a server room hosting communication processing, monitoring applications, or data storage. It is unclear whether all three actions in bullet one – creating, executing, **and** delivering – must occur at the site or if any one of those actions qualifies the building, structure, or installation as a Computational Load Site. For example, if the structure is only executing software applications that are ancillary to the electrical demand of the primary operations of the facility, those entities should not meet the definition of a Computational Load Site.

NERC's stated intent is to address the unique, highly variable, and unpredictable electrical dynamics associated with massive, dedicated data-processing clusters, not to register established commercial and industrial end-users whose load profiles and electrical demand are already well understood by their host utilities.

To reflect this intent without regulatory ambiguity, the definition must clearly evaluate whether a site is dedicated to the full operational cycle of creating, executing, and delivering computational services as its core purpose. The definition must explicitly exclude ancillary information technology usage, such as on-site server rooms hosting communication and other data processing applications, that is incidental to a facility's primary industrial or commercial operations.

ELCON recommends that NERC further refine the definition of Computational Load Site to specify:

> 1) Primarily contains information technology infrastructure used for:
>   - creating, executing, and delivering software applications and **their related** services**, not including electricity usage for information technology**

infrastructure that is secondary or incidental to a facility's primary electrical demand;

As another example, ERCOT's Large Computational Load definition includes a percentage of total demand to effectively carve out those loads whose information technology demand is incidental. ERCOT defines Large Computational Load as "A Large Load in which 50% or greater of the Demand at the site consists of power electronic based load, specifically computational load, such as data centers and cryptocurrency mining facilities."

With a similar clarification, ELCON is satisfied that large industrial and commercial loads will be appropriately excluded from the category of "Computational Load Site" and thus exempt from NERC registration and compliance with mandatory reliability standards.

Appendix 5B – Statement of Compliance Registry Criteria

In the August 19 posting, NERC raised the originally proposed thresholds for registering computational loads from 20 MW to 50 MW of total connected load at a single 100kv point, rather than 69kv. While the newly proposed 50 MW threshold of total connected load more appropriately reflects the risk impact of computational load sites, merely raising the MW threshold does not shield large industrial loads from registration requirements on its own. Without the recommended clarifications to the definition, the registration criteria presents a similar broad stroke without addressing the operational characteristics unique to data center and crypto loads.

Should NERC reject the recommended clarifications to the definition of Computation Load Site, ELCON recommends adding similar revised language to the Registration Criteria such that "a site with a total connected load of 50 MW or higher**, of which 50% or more is attributable to information technology demand,**" or "**not including electricity usage for information technology infrastructure that is secondary or incidental to a facility's primary electrical demand**" is effectively differentiated from other large loads.

With the qualifying language applied either to the Computational Load Site definition or the Computational Load Owner/Operator registration criteria, ELCON has no specific comment as to the appropriateness of the 50 MW or 100kv thresholds other than to recognize FERC's responsiveness to ELCON's recommendations to the April 1st proposal.

ELCON strongly recommends that whatever criteria is ultimately approved to be filed with FERC, there is a coordinated effort among FERC, NERC, RTOs/ISOs, and the states to develop consistent terms, conditions, and guidelines around large load interconnection and integration that recognizes the potential risk impact of certain large loads. Absent such coordination, we run the risk of a patchwork of regulations rife with inconsistencies and conflicting obligations. The reliability of an interconnected BPS relies on consistent, predictable, and technically grounded rules that reflect how power actually flows. Regulatory thresholds must logically align with operational performance and the physical impact on the bulk electric system. Without a cohesive, coordinated effort across federal

and state jurisdictions, the industry faces an uncoordinated compliance regime that creates jurisdictional confusion, inflates consumer costs, and distracts from addressing genuine reliability risks.

ELCON appreciates the extensive outreach and analysis devoted to ensuring our grid can meet the challenges of integrating computational loads and large load technologies. ELCON looks forward to continuing our engagement with NERC as we address large load operations and the criticality of reliable electricity.

/s/ Karen Onaran
Karen Onaran
President & CEO
Electricity Consumers Resource Council (ELCON)

September 18, 2026

September 18, 2026

ERCOT Comments on Proposed Revisions to Rules of Procedure Relating to Computational Loads.

Electric Reliability Council of Texas, Inc. (ERCOT) provides the following comments in response to the August 19, 2026 posting of proposed revisions to Appendices 2, 5A, and 5B of the NERC Rules of Procedure, relating to the registration of Computational Loads.

ERCOT has concerns that the proposed definition of "Computational Load Site" lacks sufficient clarity to provide clear, objective guidance regarding which locations will be subject to the proposed standards. This lack of clarity could substantially complicate the application of the proposed standard, which requires Planning Coordinators, Transmission Planners, Generator Owners, Transmission Owners, and Distribution Providers—and developers of Computational Load Sites—to know which entities must be subject to the required interconnection study processes. As written, the proposed definition leaves room for significant debate about whether a given site with computational load should be regarded as a Computational Load Site. The definition of that term refers to "one or more buildings, structures, or installations at a single location that . . . Primarily contains information technology infrastructure . . . ." Because the phrase "primarily contains information technology infrastructure" is presumed to modify the word "location" due to subject-verb agreement rules, the essence of this first half of the definition is whether a "location . . . primarily contains" IT infrastructure. If "location" is reasonably understood to refer to the entirety of the site that contains all of the customer's grid-connected infrastructure, which ERCOT presumes is the intent, it must then be understood what it means for that site to "primarily contain" IT infrastructure. On its face, this appears to require a spatial determination that raises many questions, such as: Is the calculation based on square footage of buildings or square footage of IT equipment inside those buildings? Does it consider volume of either of those? Are items like cooling equipment, UPS, and dedicated backup generation included?

Apart from the lack of clarity in scope, a spatial approach likely presents a problem in the case of co-located generation. For example, if a 1,000 MW data center co-locates with a 2,000 MW generating facility that has a larger total footprint, one might reasonably conclude that the location primarily contains generating infrastructure, and not IT infrastructure. Yet it would make little sense to exempt data centers from these standards simply because they are co-locating with generation facilities. Given the growing interest and incidence of co-location of computational loads with generation (whether existing or new generation), ERCOT believes it is important to avoid any room for debate under this definition.

Consistent with NERC's original draft proposal in April 2026, ERCOT recommends that NERC establish the regulatory scope based on the amount of computational load at the site—ideally establishing scope based on the percentage of computational load

relative to the total site load, so long as total site load meets a minimum MW threshold. This approach would better align with the underlying reliability interest because it would focus on the MW size of the computational load, which is the most significant factor for reliability, as opposed to spatial aspects of the facility, which are less relevant to BPS reliability. While the proposed registry criteria would impose a 50 MW minimum size threshold, the use of "primarily located" in the Computational Load Site definition introduces ambiguity as to which locations will be subject to registration in the first place. ERCOT encourages NERC to reconsider this approach.

Relatedly, ERCOT also has concerns with the 100kV threshold in the Compliance Registry Criteria for Computational Load Owners and Computational Load Operators. Larger loads can connect at voltages lower than 100kV. As noted above, the MW size of the load should be the critical factor for determining impact to the BPS. Introducing a voltage threshold serves no reliability purpose and creates room for creative arrangements designed to circumvent these requirements. ERCOT recommends removing this threshold.

Regarding the definition of "Computational Load Owner," requiring that the entity both "owns and maintains" the Computational Load Site introduces unnecessary ambiguity due to the uncertain meaning of "maintains." In ERCOT's view, ownership should be the only material factor to defining a Computational Load Owner. Whatever "maintain" is understood to mean, if an entity that owns the facility arguably does not "maintain" the facility, this would create a gap where there is no Computational Load Owner for a given Computational Load Site. Since a Computational Load Owner is necessary for each Computational Load Site, the drafting team should delete the reference to "maintains" to ensure at least one entity meets the definition in each case.

As a more general matter, ERCOT anticipates that it may be difficult to ascertain which entity is the Computational Load Operator in some cases. For example, in some situations, an entity that owns a large data center may lease out space to multiple entities, each of which may be considered an operator of computational load equipment. Having multiple entities responsible for compliance at a single site would create uncertainty regarding allocation of responsibility for complying with operational requirements and could require Reliability Coordinators, Balancing Authorities, and other entities to coordinate with multiple entities, creating unnecessary confusion. In addition, the entity that operates the data center location may differ from the entity responsible for the operational behavior of the IT equipment (e.g., real power oscillation). Which of them truly "operates" the IT equipment at the location may not be not facially clear. One way to address these concerns may be to create a single term—perhaps "Computational Load Customer"—that subsumes both the ownership and operator obligations and that could be used throughout the standards in lieu of the CLO/CLOP terms. This would more clearly assign responsibility to the entity connecting the computational load to the BPS, and that responsibility could then be assigned through contractual allocation of liability to any third-party tenants or other actors at the site whose activities might implicate NERC Reliability Standard requirements. This approach would avoid complications that might

arise from attempting to determine which entity is truly the operator in each case and would ensure a single entity is responsible for each computational load facility.

From:
To:
Cc:
Subject: Google comments on NERC"s definition of computational loads
Date: Friday, September 18, 2026 10:00:19 AM

Hello NERC,

Google fully supports the DCC's comments on the updated proposed Rules of Procedure definitions and registration criteria for Computational Loads. Please see below.

Mike

*****

The Data Center Coalition (DCC) is pleased to submit these comments on NERC's updated proposed Rules of Procedure definitions and registration criteria for Computational Loads.

Like all customers, the data center industry depends on a reliable electricity grid in order to fulfill its role as a vital backbone of our modern economy. In turn, data centers offer a number of reliability benefits to the grid, including significant investments in new energy resources and next-generation technologies. Data centers can also serve as grid assets that help promote reliability during energy emergencies caused by extreme weather.

It is critical to ensure proposed definitions and registration criteria by NERC are based on complete evidence, the technical capabilities and specifications of data center equipment, and do not disregard important developments or information from the industry. The DCC's comments below aim to provide the challenges and concerns with the proposed definitions and registration criteria in applying accurately and fairly across the country, while also giving recommendations to improve the definitions and criteria to address the stated issues.

Proposed ROP Definition

- DCC requests that NERC confirm that it intended to use the term "BPS" in defining Computational Load Site as "supplied through electrical equipment that is connected to the BPS." The NERC registration model has historically been based on the BES definition, as NERC/REs determine whether or not entities are "Users, Owners, and Operators" of the BES for purposes of registration. Yet Section 215 of the FPA uses the term "BPS," not BES. FERC has said that, even though NERC uses BES, the fact that FPA Section 215 uses BPS is evidence that Congress actually intended to give FERC authority beyond NERC's BES definition. See, e.g., Mandatory Reliability Standards for the Bulk Power System, 118 FERC P 61,218 at P 76 (2007) ("Therefore, the Commission confirms its statements in the NOPR that the Bulk-Power System reaches farther than those facilities that are included in NERC's definition of the bulk electric system."). DCC requests clarity on the intent and purpose of using BPS, and how this use relates to the exclusion in FPA Section 215–namely that the BPS "does not include

facilities used in the local distribution of electric energy."

- DCC is particularly concerned about the potential for confusion regarding the definition of "Computational Load Operator" as the entity that "operates" a Computational Load Site, and the definition of Computational Load Owner as the entity that "maintains" a Computational Load Site. Given the diversity of business models and responsibility configurations among distinct legal entities that may exist at a given Computational Load Site, it may be unclear where one entity's "operation" of a site ends, and where another's "maintenance" begins. DCC suggests striking the phrase "or maintains" from the definition of Computational Load Owner to avoid this potential confusion. In addition, the use of the word "owns" in the Computational Load Owner definition should also be clarified that this is the owner of the physical equipment of the site (UPS, cooling systems, electrical infrastructure, controls/relays, etc.), rather than say owners of the real estate/land.

- The Computational Load Site definition covers one or more buildings, structures, or installations at a "single location, " and how that term and the term "one or more buildings" are read decides whether a phased campus generates one registration or several. The term should be defined to track how campuses are actually built, since buildings may be separated by roads or parcel lines, energized years apart, and fed from different stations while sharing cooling and auxiliary load. If it stays undefined as it currently is in the proposed definition, the same physical campus can be read as one location or several depending on the reviewer, and each reading carries a different registration count and compliance cost, which is the highest leverage cost driver in the package. DCC asks NERC to either define single location by reference to the published factors, or to replace it with new text such as the following: "buildings, structures, or installations that share common electrical infrastructure or a coordinated operating function constitute a single Computational Load Site, without regard to parcel boundaries or phased in service dates."

Proposed MW Threshold Criteria

- DCC recommends NERC increase the proposed registration threshold from 50 MW to 75 MW while retaining the 100 kV criterion. NERC's own technical analysis provided with the ROP changes shows that a 75 MW threshold would still capture approximately 63,960 MW, or 80%, of current/forecasted computational load, compared to 68,288 MW, or 86%, under the proposed 50 MW threshold. The proposed 50 MW threshold therefore captures only approximately 4.3 GW of additional load nationwide, representing less than 6% of total current/forecasted computational load. DCC does not believe this incremental increase in coverage materially changes aggregate BPS reliability risk, and a 75 MW threshold would provide a more appropriate balance between reliability and regulatory burden.

- In addition, the term "connected Load" in the CLO/CLOP registration criteria should also be

clarified to ensure it is the contracted load identified/agreed upon in the interconnection agreements such that any behind-the-meter generation is accounted for that impacts the total load seen by the grid.

Clarification of the term "Primarily"

- NERC should revise the proposed Computational Load Site definition to replace the subjective term "primarily" with a measurable threshold. Unlike other jurisdictions, the proposed definition does not specify what percentage of facility demand must be attributable to computational load activities. For example, ERCOT defines a Large Computational Load as a facility where 50% or more of demand consists of computational load, while MISO uses a threshold based on at least 25 MW of IT equipment demand (essentially the same as a 50% threshold). Establishing a clear percentage or MW-based criterion would improve consistency of the registration criteria across Regional Entities.

Proposed Voltage Threshold Boundary Concerns

- NERC should clarify the application of the 100 kV criterion by establishing a clear boundary for when a Computational Load Site is considered to be "supplied through" electrical equipment connected at or above 100 kV. As currently drafted, it is unclear whether a facility interconnected at 34.5 kV remains subject to registration simply because the serving distribution circuit ultimately traces back to a 100 kV or higher transmission source (all distribution eventually traces back to a transmission source). Additional guidance is needed to distinguish between facilities served by dedicated feeders directly connected to a neighboring transmission substation and facilities served through traditional distribution systems with many customers.

- The proposed ≥100 kV criterion creates ambiguous and inequitable outcomes for data centers connected at distribution voltages. Many facilities take service at sub-100 kV (e.g., 34.5 kV) through Distribution Provider infrastructure that connects upstream to the transmission network at 100 kV or above. In these configurations, the Computational Load Owner has no control over, and often no visibility into, how the Distribution Provider connects to the transmission system or what other loads share the same bus. The NERC FAQ diagrams suggest that registration may hinge on whether other loads happen to be connected to the same distribution bus, yet Distribution Providers routinely move loads, open bus ties, and swap feeders without notifying connected customers. A facility's registration status could therefore change overnight through no action of its own. DCC requests that NERC clarify: (1) how applicability is determined when the distribution bus serving a data center also serves other customers; (2) what notification obligations the Distribution Provider has when network changes affect a facility's registration status; and (3) whether the FERC Order 773 seven-factor test for local distribution exclusion applies to large loads consuming power at distribution voltage, given that the only sub-100 kV inclusion precedent in that order was for generation injecting power, not load withdrawing it. DCC also asks NERC to further clarify and define the

phrase “common point of connection,” which Figures 2 and 3 in the FAQ both use and treat as distinct from the point of connection to the BPS without defining either.

Co-located Campuses & Buildings

- NERC should clarify how registration applies to campus developments with multiple Computational Load Owners. Under the proposed framework, it is unclear whether registration is assessed at the Computational Load Site level, the individual owner level, or both. For example, if a campus exceeds 50 MW in aggregate but consists of multiple building owners, including some responsible for less than 50 MW of load, it is unclear whether all owners would be required to register.

- The industry needs clarity up front prior to these new definitions and registration criteria getting approved in place, as the industry and future registered entities need to understand exactly how these roles and responsibilities will apply to their facilities and existing commercial agreements such that flexibility and appropriate planning of these compliance responsibilities can be made well in advance of the official NERC registration dates.

- Similarly, many Computational Loads operate in a co-located tenant model. It is unclear whether tenants are CLOPs in all circumstances or only when they exercise operational control over computational equipment. As an example, if a 300 MW Computational Load Site contains ten Computational Load Operators, including operators responsible for less than 50 MW each, it is unclear whether all ten operators would be required to register or whether registration would apply only to those entities with a material ownership or operational role at the site. Any compliance framework should align responsibilities with the entity that owns or controls the relevant equipment and data. NERC should also recognize that colocation providers are often subject to confidentiality and commercial agreements that limit their ability to obtain, verify, or disclose tenant-specific operational information, and should avoid imposing compliance obligations that require one entity to report information controlled by another.

- To illustrate the range of delivery models the registration criteria must accommodate, DCC offers the following to NERC staff:

    - DCC’s members develop power infrastructure using the delivery model best suited for each location. On some campuses, the serving utility owns and operates the substation and provides medium voltage service (typically 34.5 kV or 12.5 kV) directly to the owner’s facilities. On other campuses, particularly large hyperscale developments

requiring significant capacity, the owner takes service at transmission voltage (typically 100 kV and above) and owns the high voltage substation that transforms power to medium voltage for campus distribution. In these cases, the owner owns and manages the transmission interconnection, substation assets, and medium voltage distribution infrastructure. Power is delivered to the tenants at low voltage (typically 480 V), and each tenant controls only their own computational workload.

Single Registration Language in ROP

- NERC should clarify the treatment of multi-tenant facilities and expressly identify when a single entity may serve as the accountable Computational Load Operator for an entire Computational Load Site in the ROP. While NERC has indicated that a centralized or shared operating function may serve as the single accountable Computational Load Operator at a multi-tenant site, that concept is not reflected in the proposed registration criteria or supporting definitions.

    - This matters because a campus is typically owned by one legal entity, operated by staff or an affiliate or a shared services entity, and leased to tenants who control only their own workloads, so without a stated rule, affiliates or tenants risk being pulled onto the Compliance Registry alongside the owner. Left as drafted, a registrant cannot tell a tenant with confidence that the tenant is outside the registry, which complicates leasing. DCC requests that NERC clarify where owner and operator functions are split, when a single accountable operator may register as CLO for the entire site, and provide confirmation that a tenant controlling only its own workload is or is not itself a Computational Load Operator where a shared operating function has registered

Phased Campus Buildouts

- NERC should also clarify how these requirements apply to phased campus developments. Registration obligations should be clarified on how current energized and operational capacity may be phased over time leading to the ultimate buildout capacity, as campuses are commonly developed and placed into service over multiple phases and years. Clear guidance is needed to ensure consistent treatment of multi-owner campuses while allowing registration and compliance obligations to align with the actual load that is in service.

Making the FAQ Document Binding Text

- NERC's FAQ says helpful things, that two or more sites can sit behind the same supply equipment, that a single site can be fed from separate stations, and that there can be more than one owner and more than one operator of a single site, but an FAQ is not enforceable and can be revised or ignored by whoever runs a given registration review. For an owner and

operator, that means the difference between one registration and several registrations for a phased campus is based on informal guidance rather than on the criteria themselves, and registration is the gateway to every obligation in all three proposed Reliability Standards. If the draft stays as written, each campus gets reviewed on its own facts with no binding text to point to, so outcomes vary region to region. DCC recommends NERC to convert the FAQ answers into binding text in Appendix 5B or some other enforceable document to keep consistency across the entire ERO.

- NERC has identified factors – such as ownership, shared or common infrastructure, and coordinated use of the computing infrastructure – that bear on how a site is delineated, but they currently function as informal guidance rather than as a published test. A published test is what lets an owner model registration outcomes at the design stage, when it is deciding whether phases share a substation, share cooling, or are separately metered. Without it, the registrant has no certainty in advance and invites inconsistent results across regions. DCC asks that the factors NERC lists be published as the governing test for site delineation, with the further point on how the connected load is measured at the site compared against the future maximum build out of load studied in the interconnection process, and how those differences will apply for registration and NERC requirements while the projects are built out over time.

FAQ Expansion

- DCC requests that NERC add various campus examples to the FAQ illustrating how the proposed registration criteria would apply to phased, multi-building, and multi-tenant Computational Load Sites. Building on the existing Figures 2 and 3, NERC should illustrate a campus with multiple phases energized over time, shared substations and cooling infrastructure, separate parcel boundaries, multiple points of connection and the voltages of the connecting equipment, and tenants that control only their own computational workloads. The examples should identify the expected registration outcomes and clarify whether connected load is evaluated at the site level or by individual phase, owner, operator, or tenant. Such examples would provide meaningful implementation guidance and help ensure consistent application of the criteria across a range of common data center development and ownership structures.

Mike Della Penna | Global Infrastructure & Energy |

Industrial Energy Consumers of America (IECA)
The Voice of the Industrial Energy Consumers

1050 Connecticut Avenue, NW, Suite 500 • Washington, D.C. 20036
• www.ieca-us.org

September 18, 2026

North American Electric Reliability Corporation (NERC)
1401 H Street NW
Suite 410
Washington, DC 20005
ROPcomments@nerc.net

Re: Proposed Changes to NERC Rules of Procedure, Computational Load Owner, Computational Load Operator, Computational Load Site

On behalf of the member companies of the Industrial Energy Consumers of America (IECA), we submit the following input. We are grateful for the opportunity to provide comments.

IECA is a nonpartisan association of leading manufacturing companies with $1.3 trillion in annual sales, over 12,000 facilities nationwide, and with more than 1.9 million employees. One hundred percent of IECA members are manufacturing companies whose competitiveness is largely determined by the cost and reliability of natural gas and electricity. IECA membership represents a diverse set of industries including chemicals, plastics, steel, iron ore, aluminum, national defense industries, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, consumer goods, building products, automotive, independent oil refining, and cement.

We remain very concerned that manufacturing companies will be captured by the proposed NERC definitions.[1] Doing so could be costly to energy price sensitive non-computational load industries that compete globally, thereby possibly impacting competitiveness, investments and jobs.

IECA recomends a fail safe approach to excluding manufacturing industries from computational loads as you address important regulatory issues. We recommend

[1] Proposed Changes to Rules of Procedure, NERC, https://www.nerc.com/who-we-are/rules-of-procedure/proposed-changes-to-rules-of-procedure

that NERC use the North American Industry Classification System (NAICS), which is the U.S. Census Bureau's standard for classifying business establishments.[2]

The NAICS code for "computational loads" falls under NAICS 541513 "Data Processing, Hosting, and Related Services," with related codes in 541511 "Computer Systems Design Services" and 517210 "Data Processing, Hosting, and Related Services."

There is no manufacturing sectors included in those NAICS codes. Therefore, specifically stating that the new NERC definitions would only apply to those NAICS codes would not subject our industries to the new NERC rules.

Finally, we would like to reinforce the differences between data centers and manufacturers. Unlike data centers, manufacturing demand and how we operate do not increase costs to other ratepayers nor do our operations impact the reliability of the grid.

- Our electricity demand is barely increasing. According to the U.S. Energy Information Administration (EIA), in the last ten years U.S. manufacturing electricity demand increased by only 0.067 percent, while gross output increased by 32.2 percent.[3] A tremendous success story. Because we face extreme competition, we are price sensitive and drive down the use of electricity and that is not going to change in the future.

- Manufacturing reduces electricity costs to other ratepayers. When there is high peak demand periods many implement demand response to reduce consumption. This results in lower prices to other ratepayers.

- We invest capital to generate power via combined heat and power, waste heat to power, wind, solar, and batteries. By doing so, it avoids the need for the utility to build generation capacity, thereby reducing costs to other ratepayers.

- Finally, many manufacturing facilities operate day and night, 365 days per year. Many facilities with CHP generation provide valuable balancing benefits to the grid by producing less power at night and buying power from the grid when demand from the residential and commercial sectors is low. This predictable behavior supports grid balancing and frequency stability through continuous operation that differs fundamentally from data center loads. Our electric generating units are also called upon to provide power or curtail load in times of

[2] North American Industry Classification System, https://www.census.gov/naics/
[3] Manufacturing Electricity Demand is Flat, https://www.ieca-us.org/wp-content/uploads/Electricity-slide.pdf

grid system stress or shortages, thereby supporting grid reliability. There is not a single example nationwide that a manufacturing facility has caused a grid reliability problem.

The manufacturing sector are the supply chain for the entire U.S. economy including to data centers and our national defense industries. Thank you for your support.

Sincerely,

Paul N. Cicio
Paul N. Cicio
President & CEO

Invenergy

One South Wacker Drive | Suite 1500 | Chicago, Illinois 60606

September 18, 2026

Invenergy Comments on Proposed Computational Load Entity RoP Revisions

NERC,

Invenergy is grateful for the opportunity to provide comments on NERC's proposed Rules of Procedure revisions, which seek to establish two new functional entity types, Computational Load Owner and Computational Load Operator. Invenergy is supportive of these efforts as well as the parallel efforts under NERC's Large Loads Action Plan to mitigate risks to the BPS posed by the rapid interconnection of large computational loads.

Invenergy previously provided comments on this matter during the April 2026 posting and we appreciate NERC's responses to those comments. Specifically, we find the increased registry criteria threshold of 50 MW and 100 kV and removal of the 1 MW de minimis criteria to be positive changes that better align the registry criteria with BPS risks and other regional definitions for large loads.

Sincerely,
Rhonda Jones
Vice President of Reliability Compliance, Invenergy
Member, Reliability and Security Technical Committee

From:
To: ROPComments (SM)
Subject: RE: [EXT] Notice of Proposed Revisions to the NERC Rules of Procedure and Request for Comments – Computational Loads
Date: Friday, September 18, 2026 4:47:47 PM
Attachments: image005.png
image006.png
image002.png

Hello,

ITC supports the proposed changes to the NERC Rules of Procedure regarding Computational Loads.

Please let me know if you have any questions.

Thank you!
Allie

Allie Gavin
Pr. Reliability Assurance Analyst
Reliability Policy and Strategy

www.itc-holdings.com
~~27175 Energy Way | No~~vi, MI 48377



From:
Sent: Wednesday, August 19, 2026 9:59 AM
To:
Subject: [EXT] Notice of Proposed Revisions to the NERC Rules of Procedure and Request for Comments – Computational Loads



Notice of Proposed Revisions to the NERC Rules of Procedure and Request for Comments – Computational Loads

NERC Rules of Procedure Appendix 2 (Definitions Used in the Rules of Procedure); Appendix 5A (Organization Registration and Certification Manual); and Appendix 5B (Statement of Compliance

Registry Criteria)

Proposed Changes to Rules of Procedure
Appendix 2 Clean | **Redline to Last Posted** | **Redline to Last Approved**
Appendix 5A Clean | **Redline to Last Posted** | **Redline to Last Approved**
Appendix 5B Clean | **Redline to Last Posted** | **Redline to Last Approved**
Summary of Changes
Response to Comments
Technical Reasoning

Proposed Revisions to Rules of Procedure – NERC is proposing revisions to its Rules of Procedure to develop new registered entity types, called Computational Load Owner and Computational Load Operator. In response to comments received on its initial posting, NERC is posting proposed revisions to NERC Rules of Procedure Appendix 2, Appendix 5A, and Appendix 5B for an additional public comment period for 30 days from **August 19, 2026** to **September 18, 2026**. Comments must be submitted electronically to **ROPcomments@nerc.net**.

The proposed revisions address recommendations from the NERC Large Loads Working Group (a subgroup of the NERC Reliability and Security Technical Committee) whitepaper "***Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads***" and are further supported by the findings in the "***NERC Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations***" analyzing responses to a **Level 2 Alert** on the interconnection of large loads. The recommendations and findings indicate a need for new registered entity types to comply with Reliability Standards (currently under development in **Project 2026-02 – Computational Loads**) to reduce risks to the reliability of the Bulk Power System.

In pursuing its mission to assure the effective and efficient reduction of risks to the reliability and security of the grid, NERC works with owners, operators, users, and consumers as well as federal, state, and provincial regulators across North America. To that end, NERC welcomes input from all stakeholders on the proposed revisions and values the opportunity to engage with stakeholders on how the proposed revisions can contribute to the reliability of the Bulk Power System.

For more information or assistance, please contact **Marisa Hecht** via email.

COMMENTS FROM THE LOS ANGELES DEPARTMENT OF WATER AND POWER
ON PROPOSED REVISIONS TO NERC RULES OF PROCEDURE AND ASSOCIATED APPENDICES
POSTED AUGUST 19, 2026

Dated: September 16, 2026

The Los Angeles Department of Water and Power (LADWP) appreciates the opportunity to provide comments on the Proposed Revisions to the NERC Rules of Procedure (ROP) and associated Appendices posted for comment on August 19, 2026.

The City of Los Angeles is a municipal corporation and charter city organized under the provisions set forth in the California Constitution. LADWP is a department of the City of Los Angeles, pursuant to the Los Angeles City Charter, whose governing structure includes a mayor, a fifteen-member City Council, and a five-member Board of Water and Power Commissioners. LADWP is the third largest electric utility in the state, one of five California Balancing Authorities, and the nation's largest municipal utility, serving a population of over four million people within a 465 square mile service territory that covers the City of Los Angeles and portions of the Owens Valley. LADWP's mission is to provide its customers and the communities it serves safe, reliable, and cost-effective water and power in a customer-focused and environmentally responsible manner.

LADWP supports NERC's objective to revise Appendix 2 (Definitions Used in the Rules of Procedure), Appendix 5A (Organization Registration and Certification Manual), Appendix 5B (Statement of Compliance Registry Criteria) and requests NERC to further clarify some of the proposed changes.

1. **Appendix 2 (Definitions Used in the Rules of Procedure)**

   LADWP recommends

   ii) Clarification regarding which software applications and services to consider. For example, blockchain technology would fall under the intended scope for the proposed definition of "Computational Load Site", whereas an antivirus software service would not fall under the intended scope of the proposed definition.

   iii) LADWP requests clarification on the meaning of "at a single location". The current definition could be interpreted to mean at a single physical location, or at a single electrical connection which can potentially lead to all the CLO standards being applicable beyond the intended facilities.

2. **Appendix 5A (Organization Registration and Certification Manual)**

   LADWP supports NERC's revisions to Appendix 5A of the Rules of Procedure – Organization Registration and Certification Manual.

3. **Appendix 5B (Statement of Compliance Registry Criteria)**

   The proposed registry criteria for Computational Load Owners (CLOs) and Computational Load Operators (CLOPs) are ambiguous regarding the point of connection. The Frequently Asked Questions (FAQ) include example diagrams illustrating scenarios that are intended to be within and outside the scope of the proposed criterion. However, based solely on the proposed applicability language, it is not apparent why certain Computational Load Sites are excluded. In particular, the proposed language appears broad enough that all of the example configurations in Figures 1 through 7 could reasonably be interpreted as satisfying the criterion that the Computational Load Site is "supplied through the electrical equipment connected at a voltage level greater than or equal to 100kV."

   For example, in Figure 3, if a Computational Load Site is electrically supplied through multiple

transformation stages (e.g., 230 kV to 69 kV to 34.5 kV), the proposed language does not clearly identify what makes Figure 3 non-applicable. It is unclear whether the disqualification is based on multiple voltage transformation levels considering that some utilities only have a single transformation level, or if it is the TO or DP serving non-computational load (the example in Figure 3 includes "Local Distribution Load"), or some other criteria. **Does the inclusion of the "Local Distribution Load" in Figure 3 have a material impact on the evaluation for registering?**

Because the language is open to interpretation with or without the use of diagrams, LADWP recommends NERC to provide additional clarity on the distinctions revolving around the common point of connection at the distribution level (e.g. 34.5 kV) by adding specificity to the registry criteria for CLOs and CLOPs. Alternately or in conjunction, NERC should provide a comprehensive set of diagrams via the FAQ to encompass varying configurations seen across different utilities.

4. Additional Comments

LADWP requests NERC to confirm that the responsibility remains with the Computational Load Sites to register as a CLO/CLOP upon notification from the TO and DP that their equipment connects to the BPS at 100 kV or greater.

Dated: September 16, 2026

Respectfully Submitted,

North American Electric Reliability Corporation

Digitally signed by North American Electric Reliability Corporation
Date: 2026.10.21 14:30:25 -04'00'

Alex Geronilla
Manager of Operations & Planning Compliance
111 North Hope Street, Room 1246
Los Angeles, CA 90012

North American Electric Reliability Corporation

Digitally signed by North American Electric Reliability Corporation
Date: 2026.10.21 14:30:43 -04'00'

Daniel A. Baker
Interim Director of Regulatory Compliance
111 North Hope Street, Room 1514
Los Angeles, CA 90012

From:
To: ROPComments (SM)
Subject: Microsoft Corporation Comments on Computational Load ROP and Registry Criteria Revisions
Date: Friday, September 18, 2026 6:16:37 PM
Attachments: image.png

Good Afternoon,
Microsoft Corporation would like to state our support for the comments submitted by the Data Center Coalition regarding NERC's proposed August 2026 revisions to Rules of Procedure Appendices 2, 5A, and 5B addressing Computational Load Owners, Computational Load Operators, and associated registry criteria.

Thank you,

John Greene
he/him
Sr. Energy Regulatory Program Manager - Data Center Energy
Cloud Operations + Innovation

Microsoft

From:
To: ROPComments (SM)
Subject: NERC ROP Revisions
Date: Friday, September 18, 2026 5:18:42 PM

To whom it may concern,

MISO has elected to sign on to the SRC comments in our Responses.

MEMORANDUM

TO: NERC

FROM: Michael Moody and Darryl Lawrence – MRC Sector 9 Small End-Use Electricity Customer Representatives

DATE: September 18, 2026

SUBJECT: Small End-Use Sector (9) Response to Proposed Computational Load Rules of Procedure Revisions

The representatives to the NERC Member Representatives Committee for the Small End-Use Customer Sector (9) provide these comments in response to the Proposed Computational Load Rules of Procedure Revisions.

We appreciate the work of the NERC Large Load Working Group (LLWG), NERC Staff, and the commenters who have shaped these proposed revisions to the NERC Rules of Procedure. Large computational loads are being proposed across the country, and the need to consider the reasonableness of integrating them into the bulk electric system is real. NERC's Level 2 Industry Recommendation and the LLWG whitepaper advance a schedule that looks to proactively address any current barriers to entry for these entities prior to them receiving their first electric bill. By moving these efforts through the current system, we are undoubtedly shifting the make-ready costs of the grid and the processes that govern its operation to current ratepayers, to the benefit of an unproven and highly speculative industries.

NERC does not set retail rates or render bills, but its compliance, reporting, and planning requirements create substantial unfunded mandates for Transmission Owners, Planners and Coordinators, Operators, Distribution Providers, and Reliability Coordinators. Those costs are passed through to retail bills of existing customers often when they are incurred. The September 2025 NERC Alert gave entities four months to develop large load integration policies and procedures, diverting labor, time, and capital from local system improvements that would have delivered reliability benefits to existing customers. Because this work is driven entirely by a potential future ratepayer, rather than an existing one, there is no feasible way to recover the costs from future large loads entities at the retail level. The only real option for recovery of NERC compliance costs, which are difficult to argue are not prudent, is to subsidize them across the current customer base.

The proactive elimination of barriers for future large loads is not speculative; it is intentional and mentioned throughout the Level 2 and Level 3 recommendations and the Proposed Rules of Procedure Revision summary.

- "enhance their load commissioning activities to establish a comprehensive commissioning process that ensures operational readiness for large loads."
- "establish operating protocols and the necessary communication infrastructure to support reliable ongoing operations after large load facilities enter into commercial operations."
- "The goal is to ensure that as more industrial-scale consumers connect to the grid, they actively participate in practices that protect grid stability. These steps highlight that proactive planning and participation can enable even more of these facilities to come online reliably and quickly."
- To expeditiously address these risks, NERC initiated the Large Loads Action Plan.

These enhancements may be sound planning and engineering principles, but they will be at the cost of current customers. This conflicts with a national and many state level goals to require large energy users to cover the full cost of their grid integration, which must include overhauls to the regulatory, planning, and compliance environments to accommodate their entry to the BES.

Registering Large Computational Loads without strong ratepayer protections as proposed in these revisions gives deep-pocketed tech firms direct influence over NERC standards development and balloting, allowing them to potentially shift market entry costs onto households in a forum where small customers and customer advocates have been disenfranchised because of their lack of adequate resources to participate fully.

While we welcome thoughtful economic growth, large loads must not access the Bulk Electric System until NERC, FERC, and state regulators can ensure computational loads bear 100% of their costs, including every network upgrade, administrative mandate, and resource expansion.

From:	
To:	ROPComments (SM)
Cc:	
Subject:	Comments of NARUC to NERC"s revisions to its Rules of Procedure to develop new registered entity types known as Computational Load Owners and Computational Load Operators.
Date:	Thursday, September 17, 2026 9:50:09 PM

Comments by National Association of Regulatory Utility Commissioners

On May 15, 2026, the National Association of Regulatory Utility Commissioners (NARUC) joined several other trade groups to provide comments to NERC on the draft proposed revisions to the North American Electric Reliability Corporation's (NERC) Rules of Procedure (ROP) on the registration of large computational loads. On August 19, 2026, NERC responded to comments and provided amendments to the draft proposed revisions. The deadline for comments to the proposed amendments is September 18, 2026.

NARUC appreciates NERC's updated revisions to the draft proposed ROP on the registration of large computational loads, as well as the opportunity for further comment. NARUC submits this addition comment to reiterate its position on the definition of large competitional load. In response to comments indicating that the connection criteria at 60 kilovolts (kV) is too low and may capture sites that could be considered only local distribution, NERC determined that this threshold could be raised from 60 kV to 100 kV. NARUC continues to propose that NERC define computational load facilities as facilities connected at higher than 115 kV, due to the fact that under certain circumstances, with specific technical exclusions, 115 kV lines can be considered only local distribution and excluded from the bulk electric system.

From:
To: ROPComments (SM)
Cc:
Subject: Comments on Computational Load ROP Revisions
Date: Friday, September 18, 2026 10:58:14 AM

Good day,

We would like to submit the following comment for consideration regarding the definition of Computational Load Site.

The proposed Computational Load Site definition might not provide sufficient clarity regarding all entities we believe should be subject to the CLO Standards, such as Computational Load Sites handling data storage and cloud storage. Adding these to the facilities listed under Computational Load Site would help provide greater clarity regarding the types of computational activities intended to be within scope and promote more consistent interpretation and application of the definition across industry stakeholders. Explicitly referencing data storage and cloud storage would help reduce potential ambiguity during implementation and future applicability determinations of facilities we believe should be captured under the term Computational Load Site.

Thank you,

Trishona Manganiello
Senior Program Manager, Standards Development & Compliance Readiness
Reliability Compliance & Policy | Critical Infrastructure Risk Management
nationalgrid | 55 Bearfoot Road Northborough, MA 01532

1812 N. Moore Street, Suite 2200
Arlington, VA 22209
703.841.3200

September 18, 2026
North American Electric Reliability Corporation

Re: Comments on Project 2026-02 Computational Loads

The National Electrical Manufacturers Association (NEMA) appreciates the opportunity to comment on Project 2026-02 Computational Loads. NEMA represents more than 300 electrical equipment manufacturers that make safe, reliable, and efficient products and technologies that power, connect, and light our world. Together, our members contribute a full 1% of U.S. GDP and directly provide more than 590,000 American jobs, adding over $375 billion to the U.S. economy.

Of particular importance to Project 2026-02 Computational Loads, NEMA members produce technologies supporting the generation, transmission, distribution, control, and end use of electricity throughout North America, including critical infrastructure deployed in data centers and other large computational load facilities.

NEMA supports NERC's efforts to address emerging reliability risks associated with the growth of computational loads. We are also aligned with the staged approach NERC has outlined: first establishing the registration, modeling, data exchange, and monitoring framework, and then focusing on dynamic performance, power quality, and ride-through requirements. Clarifying the modeling, data submission, disturbance monitoring, and event reporting obligations in CLO-001 and CLO-003 can help support smoother compliance with technical standards later.

As NERC advances this initiative, NEMA encourages continued engagement with the electrical manufacturing industry to ensure that future Reliability Standards are informed by evolving equipment capabilities, facility design practices, manufacturing considerations, and technology trends.

NEMA's 2026 update to A Reliable Grid for an Electric Future projects that U.S. electricity demand will increase by more than 55 percent by 2050, with data centers accounting for approximately 38 percent of net electricity consumption growth through 2037. These trends underscore the importance of developing durable, practical reliability requirements that support both system reliability and the timely deployment of critical electrical infrastructure.

General Comments

NEMA appreciates NERC's responsiveness to stakeholder feedback since its April 2026 proposal. The transition from the proposed “Computational Load Entity” concept to a more targeted “Computational Load Owner” and “Computational Load Operator” framework, together with revisions to the proposed registration criteria, represents a meaningful refinement of the proposal and provides a stronger foundation for future standards development.

As computational load facilities, power architectures, and supporting technologies continue to evolve, NEMA encourages NERC to maintain ongoing engagement with electrical manufacturers throughout future phases of this initiative. Manufacturers possess unique expertise regarding

equipment design, testing, production, deployment, and operational capabilities that can help inform both standards development and implementation considerations. Overall, we support the upward revision to a 50 MW connected-load threshold at 100 kV and above, which we believe better focuses the framework on facilities with meaningful bulk power system impacts.

However, as this process moves forward, it is important to continue examining varying thresholds and remain flexible as they evolve. For instance, ERCOT's Large Load Interconnection Process uses a 75 MW threshold with its own study, model, and performance expectations. Other regions differ as well. As a result, the same facility may face multiple applicability triggers and overlapping submission requirements.

Recognizing that these thresholds will evolve as more experience is gained and lessons are learned, NEMA members recommend that NERC develop and publish a crosswalk identifying where NERC, regional, Planning Coordinator, and Transmission Owner requirements overlap; how conflicts are escalated; and when a single study, model, test, or report satisfies equivalent obligations. Manufacturers and other providers supplying equipment into multiple regions would find value in requirements strategically converging rather than multiplying.

Definitions and Applicability

NEMA supports NERC's efforts to establish clear definitions and applicability criteria for computational load entities. As definitions and future Reliability Standards evolve, NEMA encourages NERC to preserve clear distinctions among:

- Information technology (IT), operational technology (OT), industrial control systems (ICS), and other connected management systems that facilitate the operation and administration of computing loads throughout the grid;
- Facility infrastructure supporting those loads, including electrical distribution systems, backup power systems, cooling systems, and related equipment; and
- Utility-owned and utility-operated assets interconnected with the Bulk Power System.

Maintaining these distinctions will help ensure that reliability obligations are assigned appropriately and that future standards accurately reflect the operational responsibilities of the relevant entities.

CLO-001: Computational Load Interconnection, Studies, and Modeling Data

NEMA supports efforts to improve planning and operational visibility through enhanced modeling and data exchange requirements.

At the same time, computational load technologies and the electrical infrastructure supporting artificial intelligence and high-performance computing applications continue to evolve rapidly. NEMA therefore encourages NERC to focus on the performance objectives and reliability information needed to support planning and operations while avoiding technology-specific requirements that may become outdated as computing architectures and facility designs change. As it looks to strengthen reliability performance, NERC could examine areas such as fault and

1812 N. Moore Street, Suite 2200
Arlington, VA 22209
703.841.3200

voltage ride-through, managed load recovery following a disturbance, load ramp-rate management, disturbance monitoring, and operational communications.

Ultimately, performance-based and technology-neutral requirements are more likely to remain effective over time while supporting innovation and maintaining reliability objectives.

Additionally, the drafting team should consider clarifying that the model verification requirements in R11.2.2 apply to changes that materially affect a site's aggregate dynamic response at the point of interconnection. For large facilities subject to routine hardware, software, firmware, and settings updates, applying verification requirements to every individual change may not provide additional reliability value where there is no material impact on aggregate electrical performance.

We also encourage NERC to consider documented change-management processes and periodic review for routine changes that do not materially affect electrical performance. Representative verification approaches may likewise be appropriate for equipment with materially identical configurations and operating characteristics.

More broadly, firmware and controls updates are a routine part of the equipment lifecycle and, by themselves, may not materially affect reliability-relevant electrical behavior. Similarly, the determination of a "qualified change" under R7 should focus on changes to a facility's electrical characteristics and performance rather than the specific computational workload being performed.

CLO-002: Operational Data and Communications

NEMA supports efforts to improve operational visibility and communications between computational load facilities and reliability entities and appreciates NERC's recognition of their importance. As these requirements are developed, NEMA encourages NERC to consider establishing common baseline expectations for operational data, communications, and information exchange where practical.

Consistent approaches to data definitions, timing conventions, quality requirements, and secure communications can promote interoperability, reduce implementation complexity, and support efficient deployment of communications and monitoring technologies across jurisdictions. NEMA also encourages implementation schedules that appropriately reflect the time required to engineer, procure, deploy, and validate new communications and monitoring infrastructure.

CLO-003: Computational Load Protection Coordination and Disturbance Monitoring

NEMA supports NERC's focus on protection coordination, controls, disturbance monitoring, and the reliability impacts associated with rapid load changes.

As standards development progresses, NEMA appreciates NERC’s effort to broaden engagement with electrical manufacturers and original equipment manufacturers, in addition to traditional utility and operating stakeholders. Manufacturers have substantial technical expertise related to

protection systems, communications technologies, power electronics, controls, and integrated facility equipment that can help inform practical and effective reliability requirements.

We continue to encourage NERC to prioritize performance-based requirements over prescriptive technology selections or specific protection schemes. Such an approach allows flexibility as technologies evolve while continuing to support the desired reliability outcomes.

As NERC further develops disturbance monitoring requirements, NEMA believes it should continue evaluating whether the proposed requirements will provide sufficient visibility into the behavior of rapidly evolving computational load facilities during system disturbances. NERC should also consider practical implementation factors, including equipment capabilities and the collection, storage, and management of disturbance data.

Implementation Considerations

As NERC advances future standards and implementation plans, it is important that compliance schedules and implementation expectations recognize the realities associated with equipment engineering, manufacturing, procurement, testing, and deployment.

The electrical manufacturing industry is experiencing significant transformation as digitalization, advanced automation, artificial intelligence, and increasing demand for grid infrastructure reshape production and deployment practices. At the same time, the entire electric sector—utilities, operators, and suppliers—is responding to unprecedented growth in electricity demand and data center development.

Since grid impacts are often driven by aggregate electrical behavior at the point of interconnection, NEMA members encourage reliability measurement and accountability to be addressed generally at the interconnected site or campus level. NERC's standards development process will benefit from continued dialogue with manufacturers regarding equipment capabilities, supply chain considerations, and implementation timelines. We also encourage continued consideration of the cumulative burden of evolving or new requirements to avoid creating misaligned incentives for computational loads to move toward fully islanded operation. The standards should recognize grid-tied facilities that invest in visibility, controllability, storage, advanced energy management, and flexible load capabilities in a way that values the broader system reliability benefits these enhancements can provide.

In June 2026, NEMA, ASHRAE, and Pacific Northwest National Laboratory (PNNL) released the *AI Data Center Energy Performance Framework* (Framework), which provides guidance for the planning, design, operation, and modernization of next-generation data centers. The Framework reflects the industry's ongoing efforts to support resilient, reliable, and efficient computational load infrastructure and may serve as a useful resource as NERC's work in this area continues. It also references more than ten data center design consideration documents that NEMA developed on technologies such as energy storage, switchgear, and microgrids.

Conclusion

1812 N. Moore Street, Suite 2200
Arlington, VA 22209
703.841.3200

NEMA appreciates the opportunity to provide comments on Project 2026-02 Computational Loads. We look forward to continued engagement with NERC and other industry stakeholders as this effort progresses and stand ready to provide technical expertise regarding electrical equipment, infrastructure deployment, manufacturing considerations, and emerging technology trends relevant to computational load integration and reliability.



Bridget Bartol, Executive Director, Grid, Regulatory and Industry Affairs
National Electrical Manufacturers Association (NEMA)
www.makeitelectric.org.

From:
To:
Subject: Comments on Computational Load ROP Revisions - Cooperative Sector Comments
Date: Monday, September 14, 2026 1:13:07 PM

The Cooperative Sector appreciates the opportunity to review and comments on the proposed revisions to the ROP to address the integration of Computational Loads. In general, we agree with the proposed revisions and only pose the following for clarification and possible revisions based on the intent of the “and” statement.

RoP Registration Criteria and Definitions for CLO

- Computational Load Owner – the definition states “The entity that owns and maintains a Computational Load Site.” The issue is with the word ‘and’. If the entity doesn’t own and maintain the site, does it still apply?

Patti Metro
Senior Director, Grid Operations & Reliability
Business & Technology Strategies | National Rural Electric Cooperative Association

Pacific Gas and Electric Company
300 Lakeside Drive
Oakland, CA 94612

To the North American Electric Reliability Commission:

PG&E wishes to provide the following comments on the Rules of Procedure posting regarding the registration thresholds and aggregation matters for Computational Load Owners and Computational Load Operators.

PG&E is concerned about potential load aggregation impacts. Under the proposed criteria, several computational load facilities below the registration threshold could be interconnected to a common bus, common point of interconnection, or common supplying facility and collectively exhibit behavior comparable to a single registrable Computational Load Site. Because the proposed registration criteria are applied on a site-by-site and owner-by-owner basis, these aggregated configurations may fall outside the registration framework despite presenting material reliability impacts to the Bulk-Power System.

To address this concern, PG&E recommends that NERC explicitly clarify the availability and application of the existing materiality pathway contained in Appendix 5A, Section III(D). Specifically, PG&E requests that NERC state in Appendix 5B or the ERO Registration Reference Document that:

1. Regional Entities may consider the aggregate reliability impact of computational load connected to a common point of interconnection, common bus, or common supplying facility, including individual sites that fall below the Appendix 5B registration thresholds;
2. Transmission Owners and Distribution Providers may bring potential aggregation concerns to the attention of their Regional Entity, along with guidance concerning the information necessary to support such a review;
3. Registration determinations involving Computational Load Sites are communicated to the interconnecting Transmission Owner or Distribution Provider, in addition to the affected entity; and
4. A target timeframe is established for Registration Review Panel determinations.

The reliability basis for this recommendation is that multiple sub-threshold computational load facilities are increasingly developed in close electrical proximity and may collectively produce reliability impacts similar to those of a single large Computational Load Site. PG&E does not recommend expanding the registration criteria themselves to capture every such configuration. Rather, PG&E believes the existing materiality process is the appropriate mechanism for addressing these situations, but that the circumstances under which it may be invoked should be more clearly articulated.

September 18, 2026

Mr. Jim Robb
President and CEO
North American Electric Reliability Corporation (NERC)
1401 H Street NW, Suite 410
Washington, DC 20005
Attn: Project 2026-02

Prologis Comments on Computational Load Definitions and Registration Criteria for Proposed Rules of Procedure Revisions

Prologis appreciates the opportunity to provide comments on the NERC's Computational Load Definitions and Registration Criteria, and we acknowledge the significant amount of work and attention that went in to developing definitions that will allow NERC to address reliability concerns connected to computational load facilities. However, at this time, Prologis does not believe that the proposed definitions are sufficiently clear, and we recommend several changes to avoid potential confusion in the implementation of these requirements.

Specifically, defining a Computational Load Owner (CLO) as the entity that "owns and maintains" a Computational Load Site implies that the owner of a site is always the same entity that maintains the site. In practice, these are often different entities. For example, as a real estate provider, Prologis may own the land and building that houses computational load equipment, but the operator of the equipment may be responsible for maintenance of the site and associated infrastructure. In this respect, the entity that "maintains" the site may actually be the Computational Load Operator, creating overlap between these two definitions that may lead to confusion as to which entity is responsible for a particular requirement in NERC's standards. Prologis recommends striking the word "maintains" from the definition to avoid confusion.

In addition, NERC should provide more clarity around what scale and level of ownership is needed to establish an entity as a CLO. Is a CLO the entity that owns the land, the building, or the computational load equipment in the building? These could be different entities, as real estate companies like Prologis may own the land/building while their tenants may own, install, and maintain the associated equipment within the building. Prologis recommends clarifying this definition to identify that the CLO is the owner of the land/building rather than the equipment, and that "ownership" means an ownership stake (i.e. >50% equity) to avoid having minority owners identified as CLOs. Finally, NERC should clarify how these definitions will apply in situations where multiple buildings or facilities are located on the same site or within the same load pocket on the grid but are owned and/or operated by different entities.

Respectfully submitted,

Collin Smith
Energy Policy Manager
Prologis
Pier 1, Bay 1
San Francisco, CA 94111

From:	
To:	ROPComments (SM)
Cc:	
Subject:	Comments of QTS Data Centers on Proposed Revisions to Rules of Procedure Appendices 2, 5A, and 5B (Computational Loads), posted August 19, 2026
Date:	Friday, September 18, 2026 2:39:28 PM
Attachments:	image.png

To the North American Electric Reliability Corporation:

QTS Data Centers develops, owns, and operates data center campuses across the United States and participates in the Registered Ballot Body in Segment 7. QTS owns the electrical infrastructure at its campuses, provides a shared operating function for them, and expects to register under the criteria NERC adopts.

QTS supports registration and supports a definition of Computational Load Site broad enough to capture the aggregate behavior that drives the risk NERC has identified. These comments address six provisions where the text would produce different registration outcomes for identical electrical facts. QTS files separately from the Data Center Coalition and supports the Coalition's filing.

1. Appendix 2: the extent of a Computational Load Site

Provision at issue: the phrase "at a single location" in the proposed definition of Computational Load Site.

Position: NERC should state the electrical and operating facts that place buildings at a single location, and should state that total connected Load aggregates across every building and every point of connection at that site.

Reason: The extent of a site determines both who registers and whether the 50 MW threshold is met, and the current text answers neither question for a campus built in phases. A campus reaches full build over several years. Its buildings may sit on separate parcels, energize years apart, and draw from more than one point of connection while sharing one substation and one auxiliary system.

Read narrowly, the phrase divides that campus. A 300 MW campus served through four points of connection reads as four sites of 75 MW, or as twelve buildings each below the threshold, and the aggregate behavior NERC's technical work identifies as the risk driver

falls outside the criteria entirely. Read broadly, the same campus registers once. Both readings are available on the current text.

The result matters to the Transmission Planner as much as to the Computational Load Owner. The Transmission Planner models the campus at its points of connection as one electrical entity. A criterion that fragments it produces several partial models of that entity, and leaves the largest single contributor to the planning case unregistered.

The factors NERC has already identified – ownership, shared or common infrastructure, and coordinated use of the computing infrastructure – resolve this without narrowing NERC's judgment on application. The proposed text below requires shared electrical infrastructure in every case, so buildings that share only a cooling system but connect separately are not aggregated. Appendix 5A leaves every determination reviewable by the Registration Review Panel.

Proposed redline to Appendix 2, definition of Computational Load Site:

> "Computational Load Site" means one or more buildings, structures, or installations at a single location that 1) Primarily contains information technology infrastructure used for: creating, executing, and delivering software applications and services; artificial intelligence training, deployment, and delivery; cryptocurrency mining; or other computational activities at a data center; and 2) is supplied through electrical equipment that is connected to the BPS. **Buildings, structures, or installations are at a single location where they share common electrical infrastructure and are under common ownership or a common operating function. Parcel boundaries, public rights of way, separate metering, and differing in service dates do not place them at separate locations.**

Proposed redline to Appendix 5B, Section III, Computational Load Owner or Operator criterion:

> Computational Load Owner or Operator of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection. **Total connected Load is the sum of the connected Load of all electrical equipment at the Computational Load Site, aggregated across all buildings, structures, and installations at the site and across all points of connection serving the site.**

2. Appendix 5B: registration of a site that energizes in phases

Provision at issue: the same criterion, applied to a campus that reaches full build over several years.

Position: NERC should state that a Computational Load Site is registered once, and that placing a later phase in service does not create an additional registration where the site continues to meet the Appendix 2 definition.

Reason: The consequence of the alternative falls on the operating entities. Registering each phase produces several registrants behind one point of connection, several annual data submissions describing one electrical facility, and several sets of protection settings coordinated against one another rather than against the system. During an event, the Transmission Operator issuing an instruction to that campus would need to identify which of several registrants controls which portion of the load.

Registration attaches to the site as Appendix 2 defines it. The threshold in Section 1 above continues to operate on the site as a whole, so a campus that grows beyond the shared infrastructure defining it is assessed against the criteria as it then exists. What the text below prevents is a second registration for the same electrical facility, not a registration for a facility that has changed.

Proposed redline to Appendix 5B, Section III, Computational Load Owner or Operator criterion, second added sentence:

> **A Computational Load Site is registered once. Placing additional buildings, structures, or installations in service at a registered Computational Load Site does not create an additional Computational Load Site or an additional registration, provided the site continues to meet the definition in Appendix 2.**

3. Appendix 2: the Computational Load Operator at a site with divided operating functions

Provision at issue: "Computational Load Operator" means the entity that operates a Computational Load Site.

Position: NERC should state that where operating functions are divided, the entity that controls the electrical demand at the site's points of connection is the Computational

Load Operator for the site.

Reason: The obligations that attach to this function are operational. A Computational Load Operator receives an Operating Instruction and changes demand at the points of connection within the time the instruction allows. The entity able to perform that function is the one holding the equipment that changes demand, which at a campus with divided functions is the shared operating function rather than a party controlling a workload behind low voltage distribution.

The current text does not say this. Read to reach every party that operates equipment at a site, it registers entities that cannot perform the function the registration exists to secure, and it leaves the Transmission Operator without a single accountable contact during an event. NERC replaced "end user or the entity that hosts end users" with two functions in order to address differing organizational arrangements more clearly. Tying the operator function to control of demand at the points of connection completes that work, and it produces the correct answer under any arrangement: where a party does control demand at a point of connection, it is the operator for that site regardless of how the campus is leased.

Proposed redline to Appendix 2, definition of Computational Load Operator:

> "Computational Load Operator" means the entity that operates a Computational Load Site. **Where operating functions at a Computational Load Site are divided among more than one party, the Computational Load Operator is the entity that controls the electrical demand of the site at its point or points of connection.**

4. Appendix 2: the Computational Load Owner where the serving utility owns the substation

Provision at issue: "Computational Load Owner" means the entity that owns and maintains a Computational Load Site.

Position: NERC should replace the conjunctive test with ownership of the site's electrical infrastructure.

Reason: Campuses take service under two models. On some, the serving utility owns and operates the substation and delivers medium voltage service to the owner's buildings. On others, the owner takes service at transmission voltage and owns the high

voltage substation that transforms power for campus distribution.

The conjunctive "owns and maintains" resolves the second model and not the first. Where the utility owns and maintains the substation, the entity that maintains the supplying equipment is not the entity that owns the site. Read to reach the utility, the criterion registers a Transmission Owner a second time for one asset. Read to reach neither, a 300 MW campus has no registered Computational Load Owner and no entity holds the data submission, modeling, and protection coordination duties the proposed Reliability Standards assign to that function.

Ownership of the site's electrical infrastructure produces the assignment the standards use. CLO-003 assigns monitoring and protection duties to whichever entity owns the equipment on which each duty operates, and a criterion tied to the same fact produces one consistent answer under either service model.

Proposed redline to Appendix 2, definition of Computational Load Owner:

"Computational Load Owner" means the entity that owns and maintains **the electrical infrastructure of** a Computational Load Site.

5. Appendix 5B: the point at which the voltage criterion is measured

Provision at issue: "supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection."

Position: NERC should state that the voltage is measured where the equipment supplying the site connects to the BPS.

Reason: The criterion does not say where the measurement is taken, and the answer determines whether a site registers at all. Consider two 50 MW sites drawing from the same 230 kV system. One connects at 230 kV. The other sits behind a utility owned 230 to 69 kV transformer and connects at 69 kV. The load behaves identically at both. The first registers and the second does not.

The difference rests on the serving utility's upstream configuration, which the site owner does not control and which the utility may change after the site is built. A site can therefore move onto or off the Compliance Registry without any change to its own facilities or its own behavior.

NERC retained the voltage criterion because voltage identifies the most impactful connections to the BPS. That purpose requires a stated measuring point, because the criterion otherwise produces different answers for the same equipment depending on how far upstream the reviewer looks. The text below measures at the connection to the BPS, which is the point NERC's Frequently Asked Questions diagrams use, and it does so without regard to the voltage recited in a service or interconnection agreement.

Proposed redline to Appendix 5B, Section III, Computational Load Owner or Operator criterion, third added sentence:

> **The voltage level is the voltage at which the electrical equipment supplying the Computational Load Site connects to the BPS, without regard to the voltage recited in any service or interconnection agreement.**

6. Appendix 2: the measure of "primarily"

Provision at issue: "Primarily contains information technology infrastructure."

Position: NERC should state how "primarily" is measured, and should use connected Load.

Reason: "Primarily" can be measured by floor area, by equipment count, or by load, and the three produce different answers at the same site. Connected Load is the quantity the rest of the criterion already uses, and it is the quantity that bears on the reliability question, since floor area devoted to information technology infrastructure tells the planner nothing about the demand the site places on the system. Measuring against connected Load keeps one denominator throughout the criterion.

Proposed redline to Appendix 2, definition of Computational Load Site, clause 1:

Primarily contains information technology infrastructure**, meaning information technology infrastructure accounting for more than 50 percent of the connected Load at the site,** used for:

Thank you for your consideration of the foregoing.

Respectfully submitted,

Jeremy Stout
Senior Manager, Regulatory Compliance

6000 Technology Blvd. Sandston, VA 23150

Home - QTS Data Centers



Board of Directors

Chair
Owen D. Thomas
Chairman & CEO
BXP

President and CEO
Jeffrey D. DeBoer

Treasurer
Michelle Herrick
Managing Director, Head of CRE
J.P. Morgan

Secretary
Geordy Johnson
CEO
The Johnson Group

Thomas J. Baltimore, Jr.
Chairman & CEO
Park Hotels & Resorts

Jeff T. Blau
CEO
Related Companies

Ben Brown
Managing Partner
Brookfield Properties

Sean Burton
Chairman and CEO
Cityview

Michael A. Covarrubias
Chairman and Co-CEO
TMG Partners

Giovanni Cutaia
President of Blackstone Real Estate
Blackstone

John F. Fish
Chairman & CEO
SUFFOLK
Immediate Past Chair
The Real Estate Roundtable

Conor Flynn
Chief Executive Officer
Kimco Realty Corporation
Immediate Past Chair, Nareit

Leslie D. Hale
President & CEO
RLJ Lodging Trust

Harrison T. LeFrak, Esq.
Vice Chairman
LeFrak

Dan Letter
Chief Executive Officer
Prologis

Michael H. Lowe
Co-CEO
Lowe

Anthony E. Malkin
Chairman and CEO
Empire State Realty Trust, Inc.

Roy Hilton March
Executive Chairman
Eastdil Secured

Kara McShane
Head of Commercial Real Estate
Wells Fargo

Ross Perot, Jr.
Chairman
The Perot Companies and Hillwood

Andrew P. Power
President & CEO
Digital Realty

Scott Rechler
Chairman & CEO
RXR

Benjamin Schall
CEO & President
Vivmark Residential

Rob Speyer
President and CEO
Tishman Speyer

Barry Sternlicht
Chairman and CEO
Starwood Capital Group

Leslie Teskey
Managing Principal/Tenant Representative
Cresa
2026 President, CREW Network

Kenneth J. Valach
CEO
Trammell Crow Residential
Past Chair
National Multifamily Housing Council

Willy Walker
Chairman & CEO
Walker & Dunlop
Representative
Mortgage Bankers Association

The Real Estate Roundtable

September 17, 2026

Mr. Jim Robb
President and CEO
North American Electric Reliability Corporation (NERC)
1401 H Street NW, Suite 410
Washington, DC 20005

Re: ***Project 2026-02 – Comments on Computational Load Definitions (Appendix 2) and Registration Criteria (Appendix 5B)***

Dear Mr. Robb:

The Real Estate Roundtable (www.rer.org) ("RER")[1] appreciates this opportunity to comment on NERC's Definitions and Registration Criteria proposed on August 19 as part of Project 2026-02. We commend NERC's external engagement and "Large Computational Loads" teams for their proactive, excellent outreach to many stakeholders, including RER, throughout the process.

Summary of Comments

We support NERC's objective of addressing grid reliability impacts of Large Computational Loads. NERC's new regulatory framework should reflect how data centers are actually owned and operated in the real estate marketplace—particularly at colocation and other leased facilities, where ownership of the site is typically separate from control over the computational equipment and its electrical load. Our comments recommend that NERC better clarify:

- The distinction between Computational Load Owners ("CLOs") and Computational Load Operators ("CLOPs") in the Appendix 2 definitions considering their respective ownership, control, leasing arrangements, activities, responsibilities, and operational functions at data centers.

[1] The last page of the Addendum to this letter provides more information on RER and real estate's impact to the U. S. economy.

- What constitutes a "Computational Load Site" in the first instance. Our recommended definition would clarify that a property may use a lot of electricity (≥ 50MW) – but may not be a "Computational Load Site" and thus fall outside of NERC's registration regime. We suggest that only properties "***primarily used by IT infrastructure to process, store, transmit, or manipulate digital information"*** for computer-based activities (like creating software applications, delivering cloud services, training AI models, and mining crypto assets) should qualify as "Computational Load Sites" for purposes of NERC registration.

- The amount of a Site's "***Total Connected*** Load" (≥ 50MW) as critical to determine whether a CLO and/or CLOP must register with NERC. We recommend a separate Appendix 2 definition of the term "Total Connected Load" as the amount of electricity that includes computational load – ***plus*** the rest of a facility's electrical consumption needed to run HVAC, lighting, non-computer equipment and appliance plug loads, and loads to support other non-computational building systems like elevators, security, and fire/safety.

- The term "Single Location" as necessary to establish the physical boundaries of a "Computational Load Site." A separate Appendix 2 definition of "Single Location" will guide CLOs and CLOPs in determining when they must aggregate "Total Connected Loads" from individual buildings and leased spaces at the Site, for purposes of meeting the 50-MW registration threshold.

- How Appendix 5B's Registration Criteria apply to various data center leasing scenarios. A CLO may lease an entire Site and all of its power capacity to a single hyperscaler-CLOP tenant. Or, at a colocation Site, a CLO may lease physical space and allocate contracted amounts of MW usage to numerous tenant CLOPs each consuming relatively smaller amounts of electricity. There are many variations of site ownership and tenant operational arrangements in between. NERC should provide a range of hypothetical examples to illustrate how CLOs, CLOPs, and other stakeholders should apply the Registration Criteria in practice to various owner-landlord/operator-tenant arrangements.

- Offer an objective physical point where voltage should be measured to meet the 100-kV Registration Criterion. We defer to NERC, and Transmission Owners and Generator Owners, as to where that precise point should be. As a guiding principle, we think that point should be reasonably attributable to electricity usage ***by*** the Site, as opposed to a point too far "upstream" along the transmission pathway from the Bulk Power System to the Site.

Ideally, the refinements we suggest to the Appendix 2 Definitions and Appendix 5B Registration Criteria may encourage NERC to establish reciprocal, two-way data and information sharing responsibilities among CLOs and CLOPs. In this manner, responsibilities to comply with Standards CLO-001, -002, and -003 (and future Computational Load Standards) should follow the entity that controls the relevant equipment, activity, and information.

Importantly, NERC should avoid imposing compliance responsibilities on one entity where another party possesses the information or operational capability needed to satisfy that obligation. Where a CLO's compliance depends on information or actions within a CLOP's possession or control – and vice versa – the Reliability Standards should impose a corresponding affirmative obligation for each party to share with the other necessary data and information in a timely and confidential manner. This principle is particularly important at colocation Sites, and should provide the foundation for NERC's treatment of data centers as definitions and standards evolve—including any future "ride-through" performance requirements for data centers to remain connected to the BPS through grid disturbances and voltage oscillations.

We believe our recommendations will help preserve clear regulatory accountability while also ensuring that NERC receives the ownership and operational cooperation necessary to protect the U.S. electric grid. More detailed comments are provided in the attached Addendum. For further information regarding these comments, please contact Duane J. Desiderio, Senior Vice President and Counsel with The Real Estate Roundtable.

Sincerely,



Jeffrey D. DeBoer
President and Chief Executive Officer



The Real Estate Roundtable

Comments on Definition of Computational Load Owner ("CLO)"

(Appendix 2 Definitions)

- ***NERC Proposed Definition:*** "The entity that owns and maintains a Computational Load Site."

- ***RER Recommended Definition:***

  "Computational Load Owner (CLO) means a corporation, limited liability company, partnership, or other legal entity organized under applicable State, Tribal, or other law that directly owns the real property at a Computational Load Site, including the land and building(s). Ownership of stock, partnership interests, beneficial interests, or other equity or financial interests in such legal entity shall not, by itself, constitute direct ownership of the Computational Load Site.

  "A CLO may: (1) also qualify as a Computational Load Operator (CLOP); or (2) lease or otherwise provide physical space, equipment, and/or load capacity through contractual agreement(s) with one or more unrelated CLOP tenant(s)."

- ***Explanation:***

  - Stating that a CLO "owns" a Computational Load Site is circular. NERC should clarify that "owns" refers solely to the particular business entity that directly owns the real estate – that is, land and buildings – at the Computational Load Site. NERC should make clear that "owns" does not reach businesses, shareholders, and investors that simply have an equity stake or other financial interest in the CLO entity holding title to the Site's real property. Much like office buildings, hotels, apartments, warehouses and other types of commercial buildings, data centers may be held through special purpose entities – such as project-level LLCs, subsidiaries, joint ventures, and other multi-tiered property ownership structures. Because CLO status triggers registration and mandatory Reliability Standard compliance, NERC's definition should cover only the particular project-level legal entity that directly owns the Site's real property.

  - NERC should avoid the term "owns and maintains" in defining a CLO. A facility-owning entity may satisfy its maintenance responsibilities through a separate property management contractor or other service provider. Thus, the entity that "maintains" the property may be different from the entity that "owns" the property. The fact that the Site owner does not itself employ the personnel performing maintenance work should not negate its status or obligation to register as a CLO. In fact, in many cases, the entity that ***maintains*** the facility may also be the one that ***operates*** it. Thus, the phrase "owns and maintains" should not be used to avoid overlap between the CLO and CLOP definitions,

and minimize confusion where NERC's Reliability Standards direct the CLO to fulfill a requirement that should fall to the CLOP instead.

- The CLO definition should expressly recognize distinct "ownership" and "operation" entities may own different equipment at a Computational Load Site, particularly in the property leasing context. A CLO may own the underlying land and building(s) at the Site, as well as HVAC and mechanical, electrical, and plumbing equipment and systems in common service to the Site's separate buildings. Meanwhile, individual tenant(s) may own servers, racks, processing units, UPS equipment, batteries, and other equipment within the leased spaces where they operate.

- Just because a CLO may lease space to data center tenants, or a tenant owns and controls its own computing systems at the Site, should not make it difficult to readily identify the CLO – or result in each tenant becoming an additional CLO merely because it owns equipment located within the Site's boundaries. We believe our recommendations can provide a clearer foundation for allocating separate obligations to CLOs – distinguished from CLOP tenant(s) that lease space – with definitional reference to "who controls what" functions, systems, equipment, information, and data within lessors' and lessees' respective spheres of possession and control.

Comments on Definition of Computational Load Operator ("CLOP")

(Appendix 2 Definitions)

- ***NERC Proposed Definition:*** "The entity that operates a Computational Load Site."

- ***RER Recommended Definition:***

"Computational Load Operator ("CLOP") means a corporation, limited liability company, partnership, or other legal entity organized under applicable State, Tribal, or other law that exercises day-to-day control and decision-making authority over the use, management, and functioning of computers, processing units, servers, and other information technology equipment and systems that consume electric power and contribute to the computational load at the Computational Load Site.

"A CLOP may: (1) also qualify as a Computational Load Owner ("CLO"); or (2) lease or otherwise obtain, through contractual agreement(s) with an unrelated CLO, physical space, equipment and/or load capacity to perform computational load activities and functions."

Explanation:

- Stating that a CLOP is the "entity that operates" a Site is circular. Given that CLOP registration would carry mandatory Reliability Standard obligations distinct from a CLO's compliance responsibilities, businesses should be able to determine with reasonable certainty which particular legal entity(ies) perform independent functions unique to CLOP status.

- NERC can improve definitional clarity if it states that CLOPs possess day-to-day control and decision-making authority to use, program and configure the servers, processing units, microchips, batteries, networking equipment, and other IT infrastructure whose electricity consumption constitutes the Site's computational load.

- Our recommended phrase – "exercises day-to-day control and decision-making authority" – draws from an analogous context to help define CLOP status. The U.S. Supreme Court emphasized that an "operator" for purposes of Superfund sites is "someone who directs the workings of, manages, or conducts the affairs of a facility." *United States v. Bestfoods*, 524 U.S. 51, 66 (1998). The Court tailored that inquiry ***to the particular regulated activity***—in that case, focusing on the "operator" as the party that controls the day-to-day management, direction, and conduct of business operations specifically related to hazardous waste management:

  > To sharpen the definition for purposes of [the Superfund law's] concern with environmental contamination, an operator must manage, direct, or conduct operations specifically related to pollution, that is, operations having to do with the leakage or disposal of hazardous waste, or decisions about compliance with environmental regulations.

  Id. at 66–67. See also *id.* at 72 (evidence that the facility's operator "actively participated in," "exerted control over," and "issued directives regarding," the facility's environmental impacts).

- NERC should apply the reasoning from *Bestfoods* and adopt a similar control-based approach here, tailored to a CLOP's actions affecting grid reliability. Accordingly, an "operator" is not determined by "ownership" of the real estate or data center building(s) within a Site's boundaries. CLOP responsibilities should rest instead with the entity that manages, directs, or controls activities specifically related to the electrical loads from **"**computers, processing units, servers, batteries, and other information technology equipment and systems," as we propose.

- Our suggested CLOP definition is phrased in a manner to encompass wide varieties of leasing arrangements that occur at data centers. For example, a CLO may lease the entire Site and all of its electrical load to a single unrelated hyperscaler tenant that also owns its own computing equipment. Or, a CLO may lease square footage, equipment, and electrical capacity to many unrelated "smaller" tenants at a colocation site.

- Whatever the scenario (or some variation in between), we believe it is important for NERC to contemplate data center leasing arrangements where CLOs may have limited or no control over CLOP tenants' energy consumption activities, especially regarding computer use. Because the CLO may be responsible for the building while lacking control over the equipment driving a significant portion of its energy consumption, we recommend that the CLOP definition incorporate similar language that mirrors our proposed CLO definition – to acknowledge that a data center owner and a data center operator could be the same entity, but are commonly separate entities with different regulatory obligations and responsibilities.

Comments on Definition of "Computational Load Site"

(Appendix 2 Definitions)

- ***NERC Proposed Definition:*** "[O]ne or more buildings, structures, or installations at a single location that:
  "(1) Primarily contains information technology infrastructure used for:
    - creating, executing, and delivering software applications and services;
    - artificial intelligence training, deployment, and delivery;
    - cryptocurrency mining; or
    - other computational activities at a data center; and

  "(2) Is supplied through electrical equipment that is connected to the BPS."

- ***RER Recommended Definition:*** " 'Computational Load Site' means one or more buildings, structures, or installations at a single location that **is**:
  (1) Primarily ~~contains~~ ***used by*** information technology infrastructure ***to process, store, transmit, or manipulate digital information, including:***
    - creating, executing, and delivering software applications and ***cloud*** services;
    - artificial intelligence training, deployment, and delivery; ***and***
    - cryptocurrency mining; ***and***
    - ~~other computational activities at a data center; and~~

  "(2) Supplied through electrical equipment that is connected to the BPS."

- ***Add a new Appendix 2 definition for "Single Location":***

"The term 'Single Location' includes separate buildings, structures, or installations that—

(1) Are located on the same parcel of land, or adjacent or contiguous parcels of land, as recorded with the relevant local government authority; and

(2) Meet any of the following criteria:

(a) owned by the same CLO;

(b) operated by the same CLOP;

(c) have the same street address;

(d) developed pursuant to a common land-use or master construction plan;

(e) share significant electrical integration to the BPS, such as receipt of electricity from the same step-down transformer that reduces transmission-level voltage for delivery to the Site; or

(f) are served by the same cooling, water, or other site-level infrastructure.

RER Comments:

- ***NERC should separately define the term, "Single Location," in Appendix 2.***

  - CLO and CLOP registrants will benefit from greater clarity as to what constitutes a "Single Location" under the "Computational Load Site" definition. As discussed below regarding the 50-MW threshold in the "Registration Criteria," NERC intends that electric loads of individual buildings – at a "Single Location" – will be aggregated at campuses or similar properties where separate structures are integrated in terms of their ownership, operations, management, and receipt of electricity from the grid. "Single Location" should be defined with objective and consistently applicable criteria to guide when CLOs and CLOPs may need to add the loads of physically separate buildings at a Computational Load Site that are nonetheless related by ownership or function.

  - The U.S. Department of Treasury, through the Internal Revenue Service ("IRS"), provides helpful guidance. For purposes of a 1-MW threshold that determines qualification for energy project tax incentives, IRS Notice 2018-59 lists relevant factors to determine when multiple energy properties "are operated as part of a ***single project***."[2] Treasury and the IRS have consistently relied on these same criteria to define a "single project."[3]

[2] Section 7.01(2)-(4) of Notice 2018-59 (at pp. 21-24) discusses when multiple energy properties are treated as a "single project" to determine the "start of construction" for federal renewable energy tax credit purposes. Section 7.01(2) sets forth eight criteria based on whether separate energy properties: (1) are owned by a single legal entity; (2) are constructed on contiguous pieces of land; (3) are described in a common power purchase agreement(s); (4) have a common intertie; (5) share a common substation; (6) are described in one or more common environmental or other regulatory permits; (7) constructed pursuant to a master construction contract; or (8) are financed pursuant to the same construction loan agreement.

[3] Treasury Department regulation, 26 C.F.R. 1.48-13(d)(1); IRS Notice 2025-42 (August 20, 2025).

- Our recommended definition here parallels factors in the Treasury/IRS criteria – namely, common ownership, operations, addresses, master development plans, and receipt of electricity from the same step-down transformer – to assist NERC's definitional exercise for a "Computational Load Site." The IRS's Guidance may inform a more predictable framework from NERC to help registered CLOs and CLOPs decide when they must combine electric loads from separate buildings located at a "master" Site.

- ***NERC should avoid describing a Computational Load Site as one that "primarily contains" IT infrastructure – and instead define the Site as one that "primarily uses" IT infrastructure to perform various computational activities.***

  - NERC's use of the phrase "primarily contains" is ambiguous. It is not clear what must "primarily contain" IT infrastructure – the Computational Load Site as a whole, or each individual building at the Site? It is also unclear what "primarily" measures: Square footage? "Computational" load? "Total" load? Equipment count?

  - We thus recommend that NERC should instead employ a more functional test regarding IT infrastructure ***used*** at the Site for computational activities– as opposed to whether the Site "***contains***" IT infrastructure.

  - Our recommended definition of "Computational Load Site" encourages NERC to illustrate – but not prescribe – the types of computer-based functions performed by IT equipment including (but not limited to) activities like processing software, providing cloud services, developing and training AI models, and mining crypto assets. Our suggested text expresses these activities as non-exhaustive types of computational functions that "process, store, transmit, or manipulate digital information." We aim to reflect the wording and spirit of NERC's Level 3 "Action Alert" which immediately presaged the proposed Reliability Standards at issue for Large Computational Loads.[4]

Comments on New Compliance Registry Threshold Criteria

for CLOs and CLOPs (Section III(c), Appendix 5B)

- ***NERC Proposal:*** Computational Load Owners and Operators must register with NERC, regarding a Computational Load Site:
  - With a "Total Connected Load" greater than or equal to 50 MW;
  - That is supplied through electrical equipment; and

[4] NERC's Level 3 "Action Alert" (May 4, 2026), is aimed to remedy "specific deficiencies with the treatment of computational loads. ***Examples of this load include*** artificial intelligence training, cryptocurrency mining, and traditional data center uses" (emphasis added).

- Connected at a voltage level greater than or equal to "100 kV from one or more points" of connection.

RER Comments:

- ***NERC should add a new Appendix 2 definition for the term, "Total Connected Load," as follows:***

  " 'Total Connected Load' means 'Computational Load' plus electricity used for HVAC, lighting, non-computer equipment and appliance plug loads, and loads to support other non-computational building systems like elevators, security, and fire/safety equipment at a Computational Load Site."

  - A separate glossary definition of "Total Connected Load" will be helpful to CLO and CLOP registrants. Defining the term independently will make clear that "Total Connected Load" is the relevant metric of magnitude for purposes of the 50-MW Registration Criterion. It will help property owners understand what types of real estate facilities NERC intends to reach through its Registration Criteria and Reliability Standards.

  - At this juncture, NERC does not intend to impose standards on large loads ***per se*** – but only on owners and operators of "Large ***Computational*** Loads," considering their impacts on grid reliability.[5]

    - ✓ E.g.: A factory, hospital campus, large office park, laboratory complex, or casino may each consume a lot of energy and individually exceed 50 MW per property. But they may not need to register with NERC because they may not qualify as a "Computational Load Site."

    - ✓ We urge NERC to state this point clearly as it finalizes the Registration Criteria.

[5] "NERC is proposing foundational Reliability Standards with accompanying glossary updates that align with updates to the registry criteria to support ***computational load integration*** while maintaining reliability of the bulk power system." NERC website, *"Large Load Action Plan"*. NERC's Level 3 "Action Alert" (May 4, 2026), presaging the development of the Reliability Standards at issue, intends to remedy "***specific deficiencies with the treatment of computational loads.*** Examples of this load include artificial intelligence training, cryptocurrency mining, and traditional data center uses." The Level 3 Alert "was issued as NERC observed customer-initiated large load reductions and significant oscillations that occur in seconds, leaving little or no room for real-time responses, threatening BPS reliability." NERC press release (May. 4, 2026). See also NERC, *Reliability Insights*, "Large Computational Load Risks Due to Voltage Sensitivity" (Sept. 2026) ("[I][nterconnection of large computational loads has implications for BPS reliability," as "several incidents involving computational loads … have been shown to impact BPS operations when the loads remove themselves from the system during disturbances").

- ***NERC should provide hypothetical scenarios to distinguish between CLO/CLOP "registration" and Total Connected Load "aggregation." For example:***

  - Data center owner delivers and interconnects a facility with 70 MW of "Total Connected Load." A single hyperscaler leases the entire facility.
    - ✓ The owner must register as a CLO because the site connects at a capacity ≥ 50 MW.
    - ✓ The hyperscaler tenant must register as a CLOP because its operations use ≥ 50 MW.

  - Data center owner delivers and interconnects a colocation facility with 70 MW of "Total Connected Load." Seven (7) different tenants each use 10 MW in the spaces they lease in multiple buildings across the Site.
    - ✓ The owner must register as a CLO because the data center site in aggregate exceeds the 50-MW threshold.
    - ✓ None of the tenants need to register as CLOPs. None of their contracted electricity usage is ≥ 50 MW.

  - Data center owner delivers and interconnects a facility with 70 MW of "Total Connected Load." Tenant A uses 50 MW. Tenant B uses 14 MW. Tenants C and D each use 3 MW.
    - ✓ The owner must register as a CLO because the data center in aggregate exceeds the 50-MW threshold.
    - ✓ Tenant A must register as a CLOP. Its contracted electricity usage pursuant to its lease with the CLO is equal to NERC's 50-MW registration threshold.
    - ✓ Tenants B, C, and D do not need to register as CLOPs. None of their contracted electricity usage pursuant to their distinct leases meets the 50-MW threshold.

  - Data center owner delivers and interconnects a facility with 70 MW of "Total Connected Load." Tenant A uses 30 MW in Building X, and 20 MW in Building Y at the Site. Tenant B uses 10 MW in Building X, and 20 MW in Building Y.
    - ✓ The owner must register as a CLO because "Total Connected Load" in aggregate at the Computational Load Site exceeds the 50-MW registration threshold.
    - ✓ Tenant A must register as a CLOP. Its aggregate energy usage in both buildings at the Site, as contracted with the CLO through a lease, equals 50MW – at NERC's threshold.
    - ✓ Tenant B does not need to register as a CLOP. Its aggregate energy usage in both buildings at the Site is 30MW – under NERC's threshold.

- ***NERC should clarify how far "upstream" on the electrical path, between the BPS and the Computational Load Site, the 100 kV level should be measured.***

- The proposed Registration Criteria apply to a Computational Load Site with 50 MW "Total Connected Load" – that is "supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection." While the 50-MW threshold addresses ***magnitude***, the separate 100-kV criterion serves another screening function to support NERC registration, by establishing a sufficiently close electrical ***nexus*** along the transmission route between the BPS and the Site.

- We encourage NERC to specify the voltage measurement point as one reasonably attributable to electricity usage ***by*** the Computational Load Site, rather than remote upstream points on the grid that distribute electricity to customers and properties unrelated to the CLO.

- When the CLO applies for interconnection, the Transmission Owner and applicable Generator Owners (longstanding registrants in NERC's regime) are likely the best entities to identify for the CLO the specific voltage measurement point to ascertain whether the 100-kV criterion is satisfied.[6]

- We urge NERC to adopt a reasonable limiting principle to the 100-kV threshold in identifying a point along the BPS's transmission route that is proximate to the Computational Load Site. Furthermore, our intent is not to allow CLOs (and CLOPs) posing grid reliability impacts to evade registration with NERC. Our recommendation is intended to appropriately balance grid reliability concerns with the need for an objective and administrable registration criterion that considers the Site's actual relationship to and receipt of electricity from the BPS.

Impacts of Our Recommended Definition and Registration Criteria Refinements on Proposed Reliability Standards CLO-001-1, -002-1, and -003-1

- Ideally, the revisions we propose to the Definitions and Registration Criteria will avoid potential regulatory mismatch whereby one entity bears responsibility for compliance with a Standard, but another entity possesses the information or functional capacity to achieve it.

- Clearly delineating compliance responsibilities is especially relevant at leased data centers. A CLO-landlord may know what is occurring at the site and interconnection level**,** while individual CLOP-tenant(s) may know what is occurring with the computational equipment and operational load**.** Neither necessarily has the complete picture. NERC should not assume

[6] Reliability Standard FAC-001-05, regarding "Facility Interconnection Requirements," states as its "Purpose": "To avoid adverse impacts on the reliability of the Bulk Electric System, ***Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information."*** (Emphasis supplied.)

that information automatically flows between them merely because they own and operate at the same Site.

- Thus, where a CLO bears the compliance obligation – but satisfaction depends upon information within the possession or control of a CLOP(s) – then NERC should impose a corresponding affirmative obligation on the CLOP(s) to timely provide the CLO with all information and data necessary to meet the pertinent Standard.

- Likewise, CLOP(s) should bear compliance responsibilities where a Reliability Standard imposes an obligation directly concerning information, equipment, or operations regarding computational load functions and activities that ***it*** controls and manages on a day-to-day basis.

- Applying these principles to the proposed Reliability Standards:

  - Standard CLO-001-1 should require CLOPs to provide CLOs with equipment data, operating characteristics, modeling information, model-verification information, and notice of potentially material changes within CLOPs' possession or control – so a CLO can discharge its own responsibilities under the Standard. At least some of the modeling, change-notification, verification, and study-coordination duties logically belong on the CLOP—because the operator-tenant(s) may control the very equipment and operating practices that determine how the facility behaves electrically.

  - Standard CLO-002-1 addresses the operational data, communications, and instructions necessary to support reliable operation of Computational Load Sites and the BPS. It imposes obligations on both CLOs and CLOPs. It requires each to share operational data with grid entities, comply with operating instructions, maintain lines of communication, provide notification of specified changes in load or operations, and implement instructions from grid operators to address BPS reliability needs. NERC should expressly require CLOs and CLOPs at the same Site to confidentially share ***with each other*** the information necessary to satisfy their respective compliance responsibilities. NERC should establish reciprocal compliance obligations on CLOs and CLOPs to confidentially exchange data and information as needed for each to meet their respective CLO-002 responsibilities.

  - Standard CLO-003-1 lays the foundation for eventual, substantive "ride-through" performance requirements. At this juncture, NERC should impose an affirmative reporting obligation on the CLOP operating the electrical equipment. A CLO might own a substation and lease it to tenants, in which case the CLO may not have direct access to the information NERC needs. In addition, NERC's Standard should direct CLOs and CLOPs to confidentially exchange and provide relevant protection and disturbance data with each other, rather than assuming one possesses the other's information essential for compliance. It will be critical to get the monitoring and information-sharing architecture correct now—

because NERC will eventually regulate how CLOs and CLOPs must actually perform during "ride-through" events.

* * *

For more information regarding these comments, please contact Duane J. Desiderio, Senior Vice-President and Counsel with The Real Estate Roundtable.

The Real Estate Roundtable

ADDENDUM

About The Real Estate Roundtable

www.rer.org

The Real Estate Roundtable is an invitation-only organization whose members are the Chairs, Presidents, and CEOs of top public and privately-owned real estate entities and trade associations, across every segment of the commercial real estate industry – as well as the Managing Directors of major national and international financial, pension, and lending entities. Roundtable members also include significant local and regional real estate leaders and advisors, along with the elected leaders of 18 national real estate trade associations.

Members of The Real Estate Roundtable work closely with Washington lawmakers and regulators to produce meaningful results on key national issues that affect the industry. The organization is committed to fact-based analysis of issues and sound, asset-related policies that have a positive impact on economic growth, job-creation, and local communities.

Real Estate's Impact on the U.S. economy:

(*See* Commercial Real Estate by the Numbers: 2026)

- **$26.8 trillion:** Total value of investable commercial real estate in the U.S.
- **$2.5 trillion:** Real estate's contribution to U.S. GDP
- **14.2 million:** U.S. jobs directly supported by real estate
- **$630 billion:** Yearly property taxes paid by CRE owners to local governments
- **$900 billion:** Amount invested in U.S. real estate by pension funds, educational endowments, and charitable foundations

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

18 September 2026

Thank you for the opportunity to provide feedback on the draft language to the NERC Rules of Procedures.

Before articulating the individual comments to the various appendices included within the NERC Rules of Procedure that will be updated as a result of this process, we felt it important to outline the principles by which NERC should evaluate success in drafting forthcoming reliability standards for large computational users. While these five principles are relevant to the drafted ROP language, they also transcend that change and should be applied wherever NERC is establishing regulatory, procedural, or policy structures to address and respond to computational load entities.

Principles for Evaluating NERC Draft Reliability Standards and Related Revisions for Large Computational Loads

1. Forthcoming Reliability Standards (inclusive of the Registry Criteria) must comprehensively address the nature of the risk that computational loads pose.
NERC remains tasked with the singular responsibility of developing, implementing, and enforcing reliability standards for computational loads like data centers that pose unique risks to the bulk power system. This should be done carefully and comprehensively upfront. Articulating the balance between protecting existing systems and fostering an environment of innovation is challenging, yet we are confident that NERC is up to the challenge and is poised to develop standards that meaningfully address the unprecedented nature of the risk.

2. While the need for reliability requirements is undeniable, NERC must ensure that proposed requirements are robust and fully vetted through the stakeholder process.
Despite claims of urgency from both industry and political stakeholders, the "need for speed" cannot undermine the imperative for quality. Stakeholders can and consistently have demonstrated the ability to adapt; developing comprehensive standards correctly is more important than doing so quickly. The NERC staff, stakeholder bodies, and volunteer contributors are working incredibly quickly, and that initiative should be lauded. But compromising the quality of the standards to satisfy demands for speed undermines the role of NERC as the entity responsible for developing standards to mitigate reliability risks.

3. First movers in AI data center development must not be rewarded with exemption from forthcoming requirements. The risk of being an early adopter is just that - higher risk; this remains true across the technological innovation spectrum. Technology companies and innovators understand this, and it is not NERC's responsibility to mitigate that risk. Technology companies who had (and have) the capital and appetite to pursue rapid development of hyperscale data centers did so with knowledge that there could be forthcoming Reliability Standards. This should not grant them exemption from the requirements necessary to protect the reliability of the bulk power system. Weak retroactivity provisions or broad exemptions cannot be used to avoid or delay compliance.

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Instead, NERC and ERO-designated entities have clear procedures for updating, revisiting, and evaluating standards in response to ongoing and evolving industry needs. If the need arises to evaluate the impact of the standards, such processes can be utilized. Codifying legacy exemption or acquired rights does not meaningfully address the concerns raised by industry stakeholders about the significant impacts computational loads can have on the bulk power system. **To manage a period of dramatic change with responsible regulation, NERC must propose universally applicable standards.**

4. Greater transparency throughout the standards development process is required for successful, long-term reliability. Transparency requires clear signposting of standards development to utilities, states, and the broader stakeholder community. Many entities including RTOs, state regulatory commissions, and utilities are developing large load regulations, tariff provisions, and operational policies while NERC is still developing computational load reliability standards. NERC clarity regarding expected standard topics and finalization timelines is critical to enabling regulators, policy makers, and asset owners to adapt to eventual NERC regulation quickly and seamlessly. **While NERC must not shy away from a necessary standard if it diverges from a previously posted roadmap, clear signposting can help mitigate friction associated with these concurrent processes.** NERC should also make clear which stakeholders are providing what feedback to support a more open and transparent stakeholder process. What NERC is already rolling out with public comment period(s), and use of broader communication channels, demonstrates what this can look like in practice.

5. Reliability Standards must support sensible cost allocation. While NERC's focus for Reliability Standards is–and must continue to be–ensuring reliability, *how* reliability standards are set can impact the ability to cleanly allocate costs associated with risk mitigation to the cost-causers. In plain language, outages cost money, and mitigating the risk imposed by large loads has a meaningful impact on long-term cost. NERC should focus standards on how large loads can mitigate their reliability risks, and ensure operational actions that other load and unaffiliated generation can take to mitigate computational load risk are clearly noted as secondary mitigation strategies.

Utilization of these principles throughout the LLWG and associated processes will ensure that the output of the NERC working groups meaningfully and thoroughly addresses and creates responsive guardrails to the nature of the risks posed by these system users. To demonstrate the gravity of this effort, an additional 313 individual Sierra Club members signed onto these principles to demonstrate the importance of NERC's role in ensuring that standards for large computational loads meaningfully address the risks posed (see Signatories at end of Comments).

Sincerely,
Jessi Eidbo, Senior Advisor,
Sierra Club

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Comments on Updates to the NERC Rules of Procedure

We applaud the care of the Large Loads Working Group to treat the inclusion of Computational Loads within the Rules of Procedure (ROP) with the gravity it merits, and appreciate the attention being taken to respond to stakeholder concerns throughout the process. We spent time reviewing the draft materials and now offer the following for consideration. Our comments are organized by Appendix. It's helpful to note at the onset that three values underpin our comments: clarity, consistency with the existing ROP, and reliability as a foundational metric to evaluate appropriateness of the proposed changes to the ROP.

Appendix 2 (Definitions Used in the Rules of Procedure)

We support the updated definitions in Appendix 2. With regard to the specific definitions:

- **"Computational Load Operator" and "Computational Load Owner"** are helpful to keep distinct, appreciating that there are likely to be many instances where they are distinct actors, though there could be instances where they are the same. When we seek to find precedent in the existing NERC Rules of Procedure, we appreciate that this definition retains consistency with the definition for Generation Owner and Generation Operator. However, there is departure from precedent in that the classification for Generation Owner immediately incorporates a size classification (20 MW and connected at a common point of connection greater than or equal to 60 kV). The decision to treat the size threshold for Computational Load Sites outside of the actor (CL Operator or CL Owner) creates inconsistency with how this is handled within the ROP for generation. **We recommend including the size threshold in the definition(s) for both the definition of CL Operator and CL Owner for consistent treatment.**

- **Computational Load Site.** The clarity that the new definition offers is incredibly helpful and will ensure that ambiguity is mitigated in the compliance and enforcement down the road. However, the introduction of the word "primarily" in the term "computational load site" regarding what the site contains *could* introduce ambiguity. To address this, it may be helpful to either expound how "primarily" is measured, or change the language to "the majority of the site's load consists of information technology infrastructure used for…" We recognize that the use of the term "primarily" is common in the Rules of Procedure, and so while this may not be something that NERC can address via these comments alone, it should be considered in the long-term.

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Appendix 5A (Organization Registration and Certification Manual)

We support the inclusion of the two entity types (Computational Load Owner and Computational Load Operator) to the list of functional entity types to which mandatory and enforceable Reliability Standards apply.

Appendix 5B (Statement of Compliance Registry Criteria)

1. The determination of whether a Computational Load Site (CLS) is or is not beholden to the NERC Reliability Standards must consider more than the size and voltage at interconnection of the site.

The use of size and voltage at interconnection is a somewhat crude delineation of true risk posed by a CLS (and relatedly, from multiple CLS) to the BPS.[1] An expanded set of holistic criteria should be used to determine if a CLS should be subject to the reliability standards. Such expansion must address the actual electrical behavior of CLS and the risk profile they present to the bulk power system.

We propose the following characterization schema for criteria registry that builds on the Idaho National Lab evaluation of large load risk behavior variables:[2]

- **Load size.** Metrics used to define load size should be expanded and include:
  - Minimum absolute amount based on peak demand (not cumulative, can be applicable to *only* IT equipment).
  - Monthly total consumption (cumulative, inclusive of all metered load at Computational Load Site, not just IT equipment).

- **Load variability.** This could be measured in a number of ways:
  - Maximum ramp rate. For example, the Long Island Power Authority evaluates the amplitude variation at various frequencies and defines an angle under which large load operations must remain.[3]
  - Frequency of instances of ramp by category (for example, number of daily instances of ramps exceeding 10 MW/min).

---

[1] Characteristics and Risks of Emerging Large Loads, NERC Large Load Task Force, July 2025, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf

[2] Idaho National Laboratory, Characterizing Large Loads, A Taxonomy to Support Large Load Integration (INL/RPT-25-88356, Revision 0, Grid Deployment Office), October 2025, https://inl.gov/content/uploads/2023/07/Characterizing-Large-Loads-A-Taxonomy-to-Support-Large-Load-Integration.pdf

[3] PSEG and Long Island, PERFORMANCE REQUIREMENTS FOR LARGE LOADS CONNECTED TO THE LIPA SYSTEM, February 18, 2026, https://www.psegliny.com/aboutpseglongisland/-/media/BB34AE143811453B8F5923C8E7C234BC.ashx

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

- **Load flexibility.** This should include both technical ability to be flexible, and elective flexibility (i.e., when CLS elect to participate in curtailment product offerings within an RTO).

- **Presence of co-located generation.** Both the size and the ramping capability of co-located generation should be considered, as both influence how rapidly a facility could elect to switch power source(s).

- **CLO/CLS' purchase bid mechanism**. This metric should evaluate when a CLO elects to participate in, for example, a price-adaptive power purchase program. In Southwest Power Pool (SPP), the regional grid operator is currently outlining provisions for a Price Adaptive Load (PAL) scheme that would allow customers to only procure power through the bulk power system when prices are above or below a certain value.[4] The participation in this type of a program could meaningfully impact the behavior of the facility as it interfaces with the bulk power system.

2. If a site undergoes significant change (i.e., material modification), the applicability of the reliability standards must be re-evaluated.

The current language simply reads: "An entity which is not initially placed on the Compliance Registry, but which is identified subsequently as having a material impact on the BPS, will be added to the Compliance Registry." [5] Even clearer guidance on what constitutes a change significant enough to merit notifying the regional entity should be spelled out. This is especially critical given the possibility for certain computational loads to be exempted from the requirements.

While we feel strongly that there should be no wholesale retroactive exemptions (i.e., no legacy exemptions or grandfathering provisions), we recognize that in some past instances, NERC has adopted legacy exemptions for other entities as they begin participation in the registry process. However, we submit any exemptions should be (a) time limited and (b) designed to account for legitimate logistical constraints that would impede the facility meeting the new standards.

Further, if exemptions are offered (i.e., legacy exemption or retroactive status provision), then it must be made clear when a change to an existing site is sufficient to merit (a) notification of the change, and (b) change in compliance status from exempt to no longer exempt. The criteria for material modification should include the following. Note that these characteristics are coincident with the expanded registry criteria introduced above.

---

[4] SPP Document and Filings, Large Load Integration: Price Adaptive Load stakeholder forum, meeting materials July 2026, available at https://spp.org/spp-documents-filings?id=540506, including "SPP Initiative Submission Form: 786, Price Adaptive Load service" https://spp.org/documents/74785/sir796%20price%20adaptive%20load%20service.pdf

[5] Appendix 5B Clean, August 2026 posting, available at https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/appendix-5b-clean---august-2026-posting.pdf

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

- **Any change to load size.** Metrics for characterizing change in load size should include at least:
    - A minimum absolute amount, i.e., 10 MW by peak (not cumulative, can be applicable to *only* IT equipment).
    - Change in monthly **total** consumption (cumulative, inclusive of all metered load at Computational Load Site, not just IT equipment).
    - Change in monthly **peak** consumption (cumulative, inclusive of all metered load at Computational Load Site, not just IT equipment).

- **Change to load variability.** This could be measured in a number of ways:
    - Change in maximum ramp rate. As discussed above, the Long Island Power Authority methodology could serve as a basis for this standard.[6]
    - Changes in frequency of instances of ramp by category (for example, an increase in the number of daily instances of ramps exceeding 10 MW/min).

- **Change to load flexibility.** This should include both technical ability to be flexible, and elective flexibility (i.e., when CLS elect to participate in curtailment product offerings within an RTO).

- **Change to co-located generation assets.** Changes to both the size and the ramping capability of co-located generation should be considered, as both influence how rapidly a facility could elect to switch power source(s).

- **Change to a CLO/CLS' purchase bid mechanism**. This should include changes to the bid parameters if the market mechanism has not changed, and a reassessment of bids if the market mechanism has changed.

3. We do not support the updated threshold size minimums. As long as size alone is being used to evaluate requirements for site compliance, we suggest a reversion to the original size threshold for the registry criteria.

Many would argue there is a need for simplicity in reporting which dictates the use of simplified metrics to evaluate the risk that a CLS poses to the bulk electric system.[7] However, the criteria used to evaluate the true risk of a CLS should be expansive to represent the behavioral profile of the load, not just its size, as we argue in (1) above. But we acknowledge that when seeking which characteristics offer the most meaningful insight into what degree of risk a CLS introduces, size and voltage at interconnection are often the easiest variables to quantify. Therefore, should NERC opt to use simpler metrics at the expense of comprehensive metrics, the original threshold of 20 MW and 60 kV should be used for the following reasons:

---

[6] *See supra*, fn 3.

[7] Characteristics and Risks of Emerging Large Loads, NERC Large Load Task Force, July 2025, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

A. Part of the justification for the change to 50 MW and 100 kW was that "unintended entities were included." [8] But the number of impacted entities is not a useful metric when considering reliability impacts to the BPS. While the August 19th update offered justification for the change based on the number of entities that would or would not be affected, *this does not meaningfully measure the change in system impact* from the revised size and kV threshold definition.[9] This importance of mitigating risk associated with load size is underscored in the current draft NERC white paper, "Large Load Disturbance Performance – Impact Analysis and Ride-Through Recommendations," in which authors acknowledge that: "*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*."

B. The change to 50 MW and 100 kV introduces a departure from the standards that already exist for generation, where 20 MW is the current threshold for standard applicability (see PRC-029). As a result, some elements of PRC-029-1, such as the defaults for FRT and RoCoF criteria, *were* extended to large computational loads, while other parts of PRC-029-1 were not (i.e., size threshold minimums). The departure from PRC-029 for minimum size threshold is as yet unsubstantiated.

C. Because size and voltage at interconnection are such crude determinants of true risk to the system, using more conservative thresholds is necessary to protect the integrity and reliability of the bulk power system. Lowering the thresholds captures the risk which smaller, lower voltage systems pose to BPS reliability as a function of their behavior, even if their size alone does not pose a risk. Thus, a more comprehensive and responsive standard reliant on size alone must revert to the 20 MW and 60 kV threshold.

To further support lower thresholds, we look to the precedent set by Southwest Power Pool, in their recently FERC-approved definition of High-Impact Large Loads (HILL):

> *"(1) 10 MW or more if connected to the Transmission System at a voltage level less than or equal to 69 [kilovolts (kV)];*
> *or (2) 50 MW or more if connected to the Transmission System at a voltage level greater than 69 kV."*

SPP's approved definition therefore goes one step further than the original NERC draft threshold, by requiring a 10 MW minimum size threshold under certain voltage ratings at point of

---

[8] NERC, Technical Reasoning Update Proposed Computational Load Owner and Computational Load Operator August 19, 2026, at https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/august-posting-technical-reasoning.pdf

[9] Technical Reasoning Update Proposed Computational Load Owner and Computational Load Operator August 19, 2026, https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/august-posting-technical-reasoning.pdf

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

interconnect. Given that this has already been approved at FERC, there is clear support for more conservative thresholds to mitigate potential risk.

4. If lower thresholds are not restored, then CLS in the 20 MW to 50 MW range and those connected below 100 kV must be further screened to ensure they do not pose meaningful risks.

If necessary, the criteria could allow for sites between 20 MW and 50 MW or below 100 kV to apply for a waiver if they feel they should not be included in the registry. In other words, this would allow the "unintended facilities" to apply for exemption. We are supportive of the language spelled out under "Determination of Material Impact" in the Statement of Compliance Registry Criteria (Revision 9)," but feel that additional information could be helpful. Examples of the type of information that could further be evaluated in the wavier:

- EMT models showing detailed risk analysis.
- In the interim as EMT modeling of data center risk is being developed, a proxy metric for risk could be proximity to other CLS. NERC should work with industry to determine a reasonable threshold for proximity that would indicate that the site seeking waiver does or does not present a material risk.

However, because these EFT models require further refinement to offer value, it is difficult to articulate ways to evaluate risk beyond just requiring compliance. We offer this comment insofar as we cognizant that the current draft is preferred by some. This does not change our preference to require that 20MW serve as the threshold, and therefore that these sites are simply beholden to the standards and registered.

Finally, if no change is made to the thresholds, additional detail (beyond the technical reasoning currently provided) around the modeling and inputs used in the decision-making process by NERC to justify the change should be made available to all stakeholders and relevant parties. This should include model validation and assurance that detailed thought was given to the implication of the change on reliability risks, and not just the number of entities impacted.

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Additional Signatories

Tony Usibelli, Olympia, WA, 98501

Rebecca Dien-Johns, Indianapolis, IN, 46219

Bill Sabey, Plymouth Meeting, PA, 19462

Cecilia Garcia-Linz, Lansing, MI, 48917

Sarah Garcia-Linz, Lansing, MI, 48917

Anne Woiwode, OKEMOS, MI, 48864

Bari Levinson, Reno, NV, 89519

Rita Mitchell, Ann Arbor, MI, 48103

James Kotcon, Morgantown, WV, 26508

Lisa Di Bartolomeo, Morgantown, WV, 26501

Patricia Libbey, Phila., PA, 19128

Betsy Lawson, Morgantown, WV, 26501

Jim Vallem, Ann Arbor, MI, 48105

Rita Caruso, Ann Arbor, MI, 48103

Edward Steinman, Ann Arbor, MI, 48103

Roberta Duda RN, Ann Arbor, MI, 48104

elizabeth hunter, ann arbor, MI, 48103

Anne Bannister, Ann Arbor, MI, 48104

Amy Bokser, Ann Arbor, MI, 48103

Diane Blumson, Ann Arbor, MI, 48104

ROBIN Everett, Seattle, WA, 98115

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Rex Riddle, Indianapolis, IN, 46219

Kaylee Howard, Leon, WV, 25123

Michael Dadamo, New Hope, PA, 18938

Daria Jones, Morgantown, WV, 26508

Daniella Parent, Charleston, WV, 25301

Linda Berauer, Ann Arbor, MI, 48103

A Giatas, ANN ARBOR, MI, 48103

Irene Bayer, Ann Arbor, MI, 48103

Donald Danyko, Ann Arbor, MI, 48105

Ellen Ramsburgh, Ann Arbor, MI, 48104

Laura Hannah, Minneapolis, MN, 55407

Tamara Horne, Whitehall, MI, 49461

Briana Kouma, Omaha, NE, 68164

Anita Manning, Wilmington, DE, 19809

Dorothy Reader, Wilmington, DE, 19808

David Wiesler, Newark, DE, 19713

Bryanna Vacca, Frankford, DE, 19945

SANDRA DOBBS, WILMINGTON, DE, 19810

Raymond Majewski, NEW CASTLE, DE, 19720

Diane Faircloth, Hartly, DE, 19953

Lisa Portale, Wilmington, DE, 19809

Iris Patty Yermak, Wilmington, DE, 19809

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Zona Lindsay, Greenville, DE, 19807

Jen Emerle-Sifuentes, Hockessin, DE, 19707

Joan Schrider, Newark, DE, 19711

RAE C, Wilmington, DE, 19805

Cynthia Opderbeck, Lewes, DE, 19958

MIKE KELLY, Newark, DE, 19702

Jesse Browne, Ashland, OR, 97520

Dorothy Dobbyn, Millsboro, DE, 19966

Katie Hasty, Lawrence, KS, 66049

Ty Gorman, Kansas City, KS, 66104

Emma Pabst, Pflugerville, TX, 78660

Margo Praus, Stockton, CA, 95203

Arthur Brosius, Magnolia, DE, 19962

Ann Bornholdt, Castle Rock, CO, 80104

Marc Moccia, Newark, DE, 19711

Stacey Eichman, Olathe, KS, 66063

Carolyn Ryan, St. Louis, MO, 63146

Joseph Mihalko, Ronan, MT, 59864

Lauren Houskeeper, Reno, NV, 89521

Judith Mercer, ROSEBURG, OR, 97471

Angela Greear, Rome, GA, 30165

Debra Miller, Rego Park, NY, 11374

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Wendi Cohen, Ossining, NY, 10562

SONJA LAUNSPACH, POCATELLO, ID, 83201

John Prybylski, Buffalo, NY, 14227

Ralph James, Madison, WI, 53705

Jerome Moses, Madisonville, TN, 37354

Ruthann Fudacz, Whitsett, NC, 27377

Sylvia Tolley, Taunton, MA, 2780

Katherine Plosky, Winchester, MA, 1890

Susan Ramser, Sausalito, CA, 94966

David Harbeitner, St Petersburg, FL, 33701

Dominic Percopo, West Haven, CT, 6516

Gwen Demitria-De Leeuw, Kaneohe, HI, 96744

Guillemette Epailly, Santa Monica, CA, 90404

Laura Ng, New York, NY, 10024

Dorothy C Sawyer, Cleveland, OH, 44112

Joan Parker-Roach, Groton, MA, 1450

Carole Childs, Klamath Falls, OR, 97601

Connie Ball, Tucson, AZ, 85737

chessa johnson, Fishers, IN, 46037

Cheryl Walsh, Eugene, OR, 97402

Alex Fierro-Clarke, Los Angeles, CA, 90026

Karen Hoover, Bremerton, WA, 98312

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Nick Jenkins, Bristol, NH, 3222

Jane Beene, Phoenix, AZ, 85015

Bruce Hlodnicki, INDIANAPOLIS, IN, 46226

Tim Brennan, Narvon, PA, 17555

Cathy Anderson, NAMPA, ID, 83651

Steven Korson, Riverside, CA, 92505

Vicky Rey, Hudson, FL, 34667

Mark Goodman, Dallas, TX, 75248

Kevin Goodwin, Bakersfield, CA, 93308

Robin Aeschliman, PACIFIC GROVE, CA, 93950

Cynthia Key, Alachua, FL, 32615

E Scantlebury, Hereford, AZ, 85615

Lynn Hoang, Fullerton, CA, 92833

Beverly Hoff, Albuquerque, NM, 87112

Bridget Clark-Cooper, Phoenix, AZ, 85023

Bleibe Lereei, Chicago, IL, 60617

REGINA HUNI, Debary, FL, 32713

Daniel Burval, Santa Cruz, NM, 87567

Maureen Sundberg, Andover, MA, 1810

Mary Hayes, Kenosha, WI, 53142

John Fields, Portland, IN, 47371

Sarah Smithy, Orland Hills, IL, 60487

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Scott Chapman, San Luis Obispo, CA, 93406

Marcia Kellam, Pensacola, FL, 32506

David Scheer, Bellingham, WA, 98225

Logan Miller, Edwardsville, IL, 62025

Gene McGill, Boise, ID, 83705

Keri Zacher, Kaunakakai, HI, 96748

Michael O Johnson, Ruther Glen, VA, 22546

Michael O. Johnson, Ruther Glen, VA, 22546

Claire Lawrence, Fort Worth, TX, 76244

Jennifer Marinilli, Wayland, NY, 14572

Denise Cameron, Bronx, NY, 10470

Adrianne Micco, Vacaville, CA, 95687

Barbara Tewart-Darwin, Columbus, OH, 43214

Susan Asbury Holley, Marshall, IN, 47859

Peter Burval, Hillside, NJ, 7205

Martha Yeager, Windsor Heights, IA, 50324

Helgaleena Healingline, Madison, WI, 53716

Emily Sparks, New Palestine, IN, 46163

Lynn Walston, Marietta, GA, 30062

Doug Goodall, Ogden, UT, 84412

Lisa Reutter, Los Angeles, CA, 90019

Vanja Hathcock, Sacramento, CA, 95820

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Loisann Sciarrillo, Schertz, TX, 78108

Chiwah Slater, Oceanside, CA, 92058

Denise Marlowe, Inver Grove Heights, MN, 55076

Deb Federin, Monterey, CA, 93940

Maureen Ouellette, Greenfield, WI, 53220

Jamie Clark, San Francisco, CA, 94114

Karen Rudy, New Cumberland, PA, 17070

Linda Huggins, Leavenworth, KS, 66043

Norma Buckley, Vacaville, CA, 95688

Kristin Konstanty, Columbus, IN, 47203

D. Spaulding, Fort Collins, CO, 80521

Cecelia Furman, Holly Springs, NC, 27540

Judith Clarity, Midlothian, VA, 23112

Art Hanson, East Lansing, MI, 48823

Sheryl Stephens, Derby, KS, 67037

Lynne Taylor, Gaston, OR, 97119

Debbie Blair, Boca Raton, FL, 33428

Carol Lux, Vashon, WA, 98070

First_minnesota Last_minnesota, San Mateo, CA, 94303

Susan Childress, Grovetown, GA, 30813

Virginia Manuel, Houston, TX, 77027

Mia Lee, Tucson, AZ, 85712

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Janet Geren, Shasta Lake, CA, 96089

Jackie Gray, Carrboro, NC, 27510

Cheri Carlson, Browns Point, WA, 98422

Holly Foster, Poway, CA, 92064

Kristin Womack, San Anselmo, CA, 94960

Brian Duea, Seattle, WA, 98109

Stephen Craven, Athens, GA, 30606

Joseph Kratky, Sierra Vista, AZ, 85650

John Pearce, Charlotte, NC, 28226

Cydney Siri, Cimarron, CO, 81220

Jennifer Salhus, Norfolk, MA, 2056

Eric Dickey, Long Beach, CA, 90803

Janet Falcone, Louisville, KY, 40207

Jan Novak, Santa Fe, NM, 87501

Barry Zuckerman, Middletown, NY, 10940

Elaina Valzania, Greenland, NH, 3840

Vianne Crouse, Boulder, CO, 80301

Judith Schlacter, Eugene, OR, 97440

Lori Esposito, Annandale, VA, 22003

Van Christiansen, Jacksonville, FL, 32209

Vanessa Gonzalez-Green, Towson, MD, 21286

Ann Leslie Uzdavinis, West Hollywood, CA, 90069

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

D. Feagin, Spring, TX, 77373

Nellie Medlin, Holly Springs, MS, 38635

Donald Schwartz, Baltimore, MD, 21209

Sheila Cooley, Duluth, GA, 30096

Carol Maghakian, Myrtle Beach, SC, 29588

Marquita Tanner, Corpus Christi, TX, 78411

Tony Bell, Austin, TX, 78731

kathy JENSEN, Roy, UT, 84067

Mary Drake, Springfield, MO, 65809

Barbara Bollmann, Roundup, MT, 59072

Salome Reis, Goldsboro, NC, 27534

Iris Devlin, South Fork, CO, 81154

Jeffrey Wilson, Matthews, NC, 28105

Elisabeth Carroll, Indian Shores, FL, 33785

Barbara Fontana, Wading River, NY, 11792

Virginia Leslie, Milpitas, CA, 95035

Thomas Mariconda, Shelton, CT, 6484

Stephanie Poletis, Egg Harbor Township, NJ, 8234

Carolyn De Mirjian, Van Nuys, CA, 91401

Carol Thompson, Lorain, OH, 44053

Patricia Adamo, Staten Island, NY, 10306

Linda Remy, Belvedere, CA, 94920

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Dawn Hitchens, Tumwater, WA, 98511

Erh-Yen To, Sacramento, CA, 95835

Donna Edwards, Plainfield, NJ, 7063

Jackie Lowell, San Diego, CA, 92117

Michael Earney, Utopia, TX, 78884

David Beauvais, San Francisco, CA, 94122

Levi Nyberg, Bellingham, WA, 98228

Finch Serra, Brevard, NC, 28712

Lonnette Prather, Aloha, OR, 97078

Linda Ricks, Beaufort, NC, 28516

Ernest Lee, Lebanon, NH, 3766

David Kruchkow, Ocala, FL, 34476

Ysan Reischke, Marmora, NJ, 8223

Susan Green, Rochester, NY, 14610

Jillian Shea, Port Ludlow, WA, 98365

Laurel Facey, Millers Falls, MA, 1349

Linda Reilly, Olympia, WA, 98502

Rosalyn Haram, Martinsburg, WV, 25404

Nick Beck, Chicago, IL, 60612

Frances Palacio, Saint Augustine, FL, 32095

Simon Kugucki, La Grange Highlands, IL, 60525

Julia Bototm, Longmont, CO, 80503

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Mary Ann Till, Denver, NC, 28037

Diane Nowak, Cottonwood, AZ, 86326

Robin Devaney, Middletown, PA, 17057

Stephanie Rogers, Hillsborough, NC, 27278

Ruth Clarke-Smith, Hudson, MA, 1749

Steve Jarocki, Eau Claire, WI, 54701

Mae Basye, Fuquay Varina, NC, 27526

Deb Hausler, Sheboygan, WI, 53081

Casey Simmons, Sheboygan, WI, 53083

Rebecca Glass, Shoreline, WA, 98133

Charlotte Alexandre, Thornton, CO, 80229

Marion Tidwell, Merrillville, IN, 46410

Kay Miller, Martinsville, IN, 46151

Jim Miller, Martinsville, IN, 46151

Jean Cameron, Tallahassee, FL, 32309

Nicholas Sherman, Shelburne, VT, 5482

Scott Bates, Pittsboro, NC, 27312

Jerry Eldredge, Wilmington, OH, 45177

Sadie Sarkissian, Kailua, HI, 96734

Bonnie Worden, Charlevoix, MI, 49720

Patricia Alonso, Pembroke Pines, FL, 33029

Jo Mandrell, Upland, CA, 91784

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Joan Angelosanto, Melrose, MA, 2176

Kirsten Wolner, Henderson, NV, 89074

Jeanette Copeland, Missoula, MT, 59801

Adam Schwartz, Harriman, NY, 10926

L Zelling, Bainbridge Island, WA, 98110

Barbara Hoffmann, Pike Road, AL, 36064

Doug Ruth, La Mesa, CA, 91942

Dian Campbell, Las Vegas, NV, 89117

Megan Lear, Nevada City, CA, 95959

Ashleigh Long, Peru, IN, 46970

barbara kemp, boise, ID, 83706

Tabby Smith, Richwood, WV, 26261

Teresa Wright, New Buffalo, MI, 49117

Robert Moore, Wake Forest, NC, 27587

Emily Brown Eudy, charlotte, NC, 28262

Sarah Gregg, Albuquerque, NM, 87110

Ron Broschart, Ventura, CA, 93001

Jessica Forrest, Concord, NH, 3301

James Mulcare, Clarkston, WA, 99403

Lakshmi Banerjee, Brooklyn, NY, 11220

Cheryl Patil, Centreville, VA, 20121

Kimberly Powers, Albany, CA, 94611

SIERRA CLUB

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Donna Foster, Claremont, NH, 3743

Christy A Morris, Lufkin, TX, 75901

Robert D Kohlenberg, Louisburg, KS, 66053

Anne Greene, Maidens, VA, 23102

Ralph Rogers, Olathe, KS, 66062

Roger Vannoy, Lewisburg, WV, 24901

Larissa Barnes, Franklin, NH, 3235

Rhonda Obert, Birmingham, AL, 35208

Sophia Bello, San Diego, CA, 92154

Deanna Johnson, Davis, CA, 95618

Casey swallow, Cheyenne, WY, 82007

Bart Poste, Suquamish, WA, 98392

Laura Borst, Houston, TX, 77042

Laurie Lagoe, Alexandria, VA, 22309

Ellen Mitrov, Charlotte, NC, 28216

Venesa Winegardner, New Lexington, OH, 43764

Henry Faryna, Painted Post, NY, 14870

Lenora O'Neill, Toledo, WA, 98591

Lola Schiefelbein, Richland, WA, 99352

Elizabeth Gailius, Raynham, MA, 2767

Bonnie Bodolus, Berlin, MD, 21811

Patrice Kiezer, Sunrise, FL, 33313

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Patty Weyhrich, Carbondale, IL, 62903

Carol Book, York, PA, 17406

John Rand, Tehachapi, CA, 93561

Nicolas Argueta-Vasquez, Alexandria, VA, 22310

Marjorie Browning, Benson, AZ, 85602

Samuel Durkin, Fairfield, CA, 94534

Kristin Powers, Aurora, IL, 60502

Virginia Collins, San Leandro, CA, 94577

Cara Schmidt, yellville, AR, 72687

Dawn Moreno, San Antonio, TX, 78253

Alyson Perkins, Falls Church, VA, 22042

Gracie Rives, Haslet, TX, 76052

Lenora Young, Jamaica, NY, 11434

Mishea Dempsey, Concord, NC, 28027

Shawna Reed, Wheatfield, IN, 46392

Randall Bash, Scottsdale, AZ, 85260

Gaurav Singh, El Paso, TX, 79922

Sharon Mylott, Charlestown, NH, 3603

Mary Keller, Grand Rapids, MI, 49594

Alyson Iovacchini, Philadelphia, PA, 19131

Richard Presnell, Morganton, NC, 28655

Laronda Clark-patten, Belmont, NH, 3220

2101 Webster St.
Suite 1300
Oakland, CA 94612

SierraClub.org

Bryan Knower, East Elmhurst, NY, 11370

Margo Wyse, Mimbres, NM, 88049

Kellie Evilsizer, Austin, TX, 78759

Flo Cole-baker, Bend, OR, 97702

Mary Wright, Rancho Cordova, CA, 95670

Darrel Rose, tehachapi, CA, 93561

ISO/RTO Council Standard Review Committee's Comments on Proposed Computational Load Entity ROP Revisions

September 18, 2026

The ISO/RTO Council (IRC) Standards Review Committee[1] (SRC) offers the following comments on the proposed revisions to the NERC Rules of Procedure (ROP) to define Computational Load and register Computational Load Owner (CLO), Computational Load Operators (CLOP), and Computational Load Sites (CLS), released on August 19, 2026. The SRC appreciates this opportunity to provide feedback on the proposed ROP revisions.

Summary of SRC Comments

- Incorporate clearer requirements for registration to address distributed Computational Load Sites.
- Utilize "and/or" in the enumerated list under Computational Load Site to address potential hybrid implementations.
- Provide examples for entities and scenarios that would require registration.
- Complete CORES updates to enable notification to Distribution Providers, Reliability Coordinators, Planning Coordinators, Transmission Planners, and Transmission Operators to inform them that a CLO/CLOP has notified the RE of the designation.
- Formalize criteria for commissioning and interconnection registration requirements that occur before the CLOP is operational.

SRC Comments

Clearer registration requirements

The new and revised definitions are necessary to reduce the reliability risks that large computational loads pose to the Bulk Power System. The SRC sees value in the inclusion of the 50MW threshold.

However, the SRC recommends removing the voltage threshold for registration because retaining the threshold could:

- Create confusion among tariff requirements, local state requirements, and others.
- Prevent the inclusion of distributed (meshed) computational loads that utilize unused electrical capacity across residential circuits to power discrete nodes at scale, achieving performance and load sizes analogous to larger, consolidated data centers.

[1] For purposes of these comments, the SRC comprises the California Independent System Operator Corporation (California ISO), ISO New England Inc. (ISO-NE), PJM Interconnection, L.L.C. (PJM), Midcontinent Independent System Operator, Inc., (MISO), New York Independent System Operator, Inc. (NYISO), and Southwest Power Pool, Inc. (SPP).

- Prevent identification of distributed networks with a potential for gigawatt-scale load growth creating risk that could be hidden through jointly defined MW thresholds and defined voltage levels.

The 50 MW threshold provides a clear delineation for assets that must meet NERC standards and allows for the flexibility of the other jurisdictions to manage thresholds for interconnecting. Alternatively, the ROP could utilize a lower interconnection voltage of 60kV, rather than 100kV. Per NERC's Technical Reasoning[2] changing the threshold from 100kV to 60kV would only result in a two percent increase in the computational loads identified. Based on this, setting the threshold to 60kV will not cause additional burden on existing computational loads and prevents future computational loads from opting to connect at a lower voltage level and bypassing compliance and oversight. Also, remaining at 60kV aligns with the current Category 2 Generator Owners/Operators which ensures NERC registration due to the increasing prevalence of inverter-based resources connected at a lower voltage level. PJM is requesting the same oversight and registration as the proliferation of computational loads continues.

Computational Load Site (CLS) definition

The currently proposed CLS definition may limit the applicability to a narrower set of resources than intended based upon incorrect interpretation to the reference to a "single location." As business models evolve, the limitation of a single point may obfuscate the actual impact that a distributed resource could have. These evolving applications[3] are demonstrating a common CLOP controlling smaller computational loads, potentially in gigawatts, that are distributed across multiple lower voltage interconnections. The net result from the CLS is an equally impactful load to frequency. To avoid excluding materially impactful distributed deployments, replace 'single location' with 'single location or served by a single transmission bus or electrically contiguous bus configuration,' ensuring resources distributed across lower-voltage interconnections that present aggregate frequency impact are appropriately captured.

The SRC also recommends modifying the list of computational activities associated with a Computational Load Site which should use "and/or" instead of "or". As written, it appears a facility could have 20MW for cryptocurrency mining and 30MW designated as artificial intelligence training, thus not containing 50MW of one or the other. This enables hybrid facilities performing multiple tasks to claim the definition does not apply to them. Furthermore, the phrase "primarily contains IT infrastructure" is vague for co-located sites; the drafting team should clarify how to handle edge cases, such as a site that is 51% generation and 49% data center.

[2] https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/august-posting-technical-reasoning.pdf
[3] SPAN® Blog | SPAN Announces XFRA, a Distributed Data Center Solution to Close the Speed-to-Power Ga…

Provide examples and model the Category 2 Generator Owner/Operators process

Registration Implementation should be modeled after Category 2 Generator Owner (GO) and Generator Operator (GOP) registrations with industry outreach and education for these new and existing Registered Entities, new NERC Reliability Standards, and new NERC/modified Glossary Terms remains paramount to achieving the reliability objective of such efforts. It is essential to publish numerous scenarios illustrating Computational Load deployments and registrations to educate industry on how to apply these new criteria. These would include scenarios that identify configurations and deployments to ensure various approaches used by industry would clearly define which entities would need to be included in the registration process.

Complete CORES updates

The confusion regarding registration has become increasingly apparent, especially during the introduction of the new Category 2 GO/GOP functions, where some entities claiming others to serve in roles where no formal agreement between both parties exist. This is occurring more frequently as the newer entities are registering with NERC; therefore, declaration of the relationship to the Regional Entities during the registration process should include notification reflexively to all entities under such declaration to serve in a role under the standards. For instance, a CLO may declare a certain entity to be their Reliability Coordinator (RC). This creates obligations under the standards to perform certain functions or communications that the RC may not be aware of without notification by NERC and the respective CLO that an entity is claiming to perform its RC function. The declaration of one party alone should not be sufficient to create obligations unless all entities affirm their respective functions.

Formalize criteria for activity before CLO/CLOP operations

Lastly, upon registration of a CLO/CLOP, the CLO/CLOP must include an affirmation that the CLO/CLOP has provided (as requested) the necessary data and information to its host Balancing Authority (BA), Transmission Operator (TOP), and Reliability Coordinator (RC). Coordination between the CLO/CLOP and its host BA, TOP, RC is needed prior to registration to ensure reliable operations and compliance to the proposed CLO Standards. Nothing in the registration process should preclude Balancing Authorities, Transmission Operators, and Reliability Coordinators from obtaining all necessary information and adopting additional requirements on computational loads through their own processes.

Conclusion

The SRC appreciates the opportunity to comment on the proposed ROP revisions. The SRC would welcome the opportunity to further discuss these comments or other Computational Load-related topics with NERC as appropriate and looks forward to engaging in the remainder of the ROP revision process.

From:
To:
Subject: Comments for Proposed Revisions to the NERC Rules of Procedure – Computational Loads
Date: Monday, September 14, 2026 12:13:34 PM

Good afternoon,

TVA recommends publishing additional guidance similar to the BES Reference Document or ERO Enterprise CMEP Practice Guide: Application of the Registration Criteria for Category 2 Generator Owner and Generator Operator Inverter-Based Resources to clarify scenarios for meeting the Computational Load Owner and Operator registration requirements. There could be interpretations that allow for total load at a site at multiple voltage level connections or collocated generation producing a "net" total connected load under 50MW. This could also be clarified in a footnote to the definition of Computational Load Site.

Thank you for your time and consideration.

Jonathan Prater, PE
Sr Program Manager
NERC Regulatory Compliance & Support

TVA TENNESSEE VALLEY AUTHORITY

Union of Concerned Scientists

ucs.org

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1350 I St NW, Suite 400,
Washington, DC 20005-7201
202-223-6133

West Coast
2001 Addison St., Suite 200
Berkeley, CA 94704
510-843-1872

Midwest
200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

18 September 2026

Thank you for the opportunity to provide feedback on the draft language to the NERC Rules of Procedures.

Before articulating the individual comments to the various appendices included within the NERC Rules of Procedure that will be updated as a result of this process, we felt it important to outline the principles by which NERC should evaluate success in drafting forthcoming reliability standards for large computational users. While these five principles are relevant to the drafted ROP language, they also transcend that change and should be applied wherever NERC is establishing regulatory, procedural, or policy structures to address and respond to computational load entities.

Principles for Evaluating NERC Reliability Standard Revisions for Large Computational Loads

1. Forthcoming Reliability Standards (inclusive of the Registry Criteria) must comprehensively address the nature of the risk that computational loads pose. NERC remains tasked with the singular responsibility of developing, implementing, and enforcing reliability standards for computational loads like data centers that pose unique risks to the bulk power system. This should be done carefully and comprehensively upfront. Articulating the balance between protecting existing systems and fostering an environment of innovation is challenging, yet we are confident that NERC is up to the challenge and is poised to develop standards that meaningfully address the unprecedented nature of the risk.

2. While the need for reliability requirements is undeniable, NERC must ensure that proposed requirements are robust and fully vetted through the stakeholder process. Despite claims of urgency from both industry and political stakeholders, the "need for speed" cannot undermine the imperative for quality. Stakeholders can and consistently have demonstrated the ability to adapt; developing comprehensive standards correctly is more important than doing so quickly. The NERC staff, stakeholder bodies, and volunteer contributors are working incredibly quickly, and that initiative should be lauded. But compromising the quality of the standards to satisfy demands for speed undermines the role of NERC as the entity responsible for developing standards to mitigate reliability risks.

3. First movers in AI data center development must not be rewarded with exemption from forthcoming requirements. The risk of being an early adopter is just that - higher risk; this remains true across the technological innovation spectrum. Technology companies and innovators understand this, and it is not NERC's responsibility to mitigate that risk. Technology companies who had (and have) the capital and appetite to pursue rapid development of hyperscale data centers did so with knowledge that there could be forthcoming Reliability Standards. This should not grant them exemption from the requirements necessary to protect the reliability of the bulk power system. Weak retroactivity provisions or broad exemptions cannot be used to avoid or delay compliance.

Instead, NERC and ERO-designated entities have clear procedures for updating, revisiting, and evaluating standards in response to ongoing and evolving industry needs. If the need arises to evaluate the impact of the standards, such processes can be utilized. Codifying legacy exemption or acquired rights does not meaningfully address the concerns raised by industry stakeholders about the significant impacts computational loads can have on the bulk power system. **To manage a period of dramatic change with responsible regulation, NERC must propose universally applicable standards.**

4. Greater transparency throughout the standards development process is required for successful, long-term reliability. Transparency requires clear signposting of standards development to utilities, states, and the broader stakeholder community. Many entities including RTOs, state regulatory commissions, and utilities are developing large load regulations, tariff provisions, and operational policies while NERC is still developing computational load reliability

standards. NERC clarity regarding expected standard topics and finalization timelines is critical to enabling regulators, policy makers, and asset owners to adapt to eventual NERC regulation quickly and seamlessly. **While NERC must not shy away from a necessary standard if it diverges from a previously posted roadmap, clear signposting can help mitigate friction associated with these concurrent processes.** NERC should also make clear which stakeholders are providing what feedback to support a more open and transparent stakeholder process. What NERC is already rolling out with public comment period(s), and use of broader communication channels, demonstrates what this can look like in practice.

5. Reliability Standards must support sensible cost allocation. While NERC's focus for Reliability Standards is–and must continue to be–ensuring reliability, *how* reliability standards are set can impact the ability to cleanly allocate costs associated with risk mitigation to the cost-causers. In plain language, outages cost money, and mitigating the risk imposed by large loads has a meaningful impact on long-term cost. NERC should focus standards on how large loads can mitigate their reliability risks, and ensure operational actions that other load and unaffiliated generation can take to mitigate computational load risk are clearly noted as secondary mitigation strategies.

Utilization of these principles throughout the LLWG and associated processes will ensure that the output of the NERC working groups meaningfully and thoroughly addresses and creates responsive guardrails to the nature of the risks posed by these system users. To demonstrate the gravity of this effort, an additional 10,979 individual Union of Concerned Scientists supporters signed onto these principles to demonstrate the importance of NERC's role in ensuring that standards for large computational loads meaningfully address the risks posed (see attached signatories).

Comments on Updates to the NERC Rules of Procedure

We applaud the care of the Large Loads Working Group to treat the inclusion of Computational Loads within the Rules of Procedure (ROP) with the gravity it merits, and appreciate the attention being taken to respond to stakeholder concerns throughout the process. We spent time reviewing the draft materials and now offer the following for consideration. Our comments are organized by Appendix. It's helpful to note at the onset that three values underpin our comments: clarity, consistency with the existing ROP, and reliability as a foundational metric to evaluate appropriateness of the proposed changes to the ROP.

Appendix 2 (Definitions Used in the Rules of Procedure)

We support the updated definitions in Appendix 2. With regard to the specific definitions:

"Computational Load Operator" and "Computational Load Owner" are helpful to keep distinct, appreciating that there are likely to be many instances where they are distinct actors, though there could be instances where they are the same. When we seek to find precedent in the existing NERC Rules of Procedure, we appreciate that this definition retains consistency with the definition for Generation Owner and Generation Operator. However, there is departure from precedent in that the classification for Generation Owner immediately incorporates a size classification (20 MW and connected at a common point of connection greater than or equal to 60 kV). The decision to treat the size threshold for Computational Load Sites outside of the actor (CL Operator or CL Owner) creates inconsistency with how this is handled within the ROP for generation. **We recommend including the size threshold in the definition(s) for both the definition of CL Operator and CL Owner for consistent treatment.**

Computational Load Site. The clarity that the new definition offers is incredibly helpful and will ensure that ambiguity is mitigated in the compliance and enforcement down the road. However, the introduction of the word "primarily" in the term "computational load site" regarding what the site contains *could* introduce ambiguity. To address this, it may be helpful to either expound how "primarily" is measured, or change the language to "the majority of the site's load consists of information technology infrastructure used for…" We recognize that the use of the term "primarily" is common in the Rules of Procedure, and so while this may not be something that NERC can address via these comments alone, it should be considered in the long-term.

Appendix 5A (Organization Registration and Certification Manual)

We support the inclusion of the two entity types (Computational Load Owner and Computational Load Operator) to the list of functional entity types to which mandatory and enforceable Reliability Standards apply.

Appendix 5B (Statement of Compliance Registry Criteria)

1. The determination of whether a Computational Load Site (CLS) is or is not beholden to the NERC Reliability Standards must consider more than the size and voltage at interconnection of the site.

The use of size and voltage at interconnection is a somewhat crude delineation of true risk posed by a CLS (and relatedly, from multiple CLS) to the BPS.[1] An expanded set of holistic criteria should be used to determine if a CLS should be subject to the reliability standards. Such expansion must address the actual electrical behavior of CLS and the risk profile they present to the bulk power system. We propose the following characterization schema for criteria registry that builds on the Idaho National Lab evaluation of large load risk behavior variables:[2]

Load size. Metrics used to define load size should be expanded and include:

- Minimum absolute amount based on peak demand (not cumulative, can be applicable to *only* IT equipment).
- Monthly total consumption (cumulative, inclusive of all metered load at Computational Load Site, not just IT equipment).

Load variability. This could be measured in a number of ways:

- Maximum ramp rate. For example, the Long Island Power Authority evaluates the amplitude variation at various frequencies and defines an angle under which large load operations must remain.[3]
- Frequency of instances of ramp by category (for example, number of daily instances of ramps exceeding 10 MW/min).

Load flexibility. This should include both technical ability to be flexible, and elective flexibility (i.e., when CLS elect to participate in curtailment product offerings within an RTO).

- **Presence of co-located generation.** Both the size and the ramping capability of co-located generation should be considered, as both influence how rapidly a facility could elect to switch power source(s).
- **CLO/CLS' purchase bid mechanism**. This metric should evaluate when a CLO elects to participate in, for example, a price-adaptive power purchase program. In Southwest Power Pool (SPP), the regional grid operator is currently outlining provisions for a Price Adaptive Load (PAL) scheme that would allow customers to only procure power through the bulk power system when prices are above or below a certain value.[4] The participation in this type of a program could meaningfully impact the behavior of the facility as it interfaces with the bulk power system.

2. If a site undergoes significant change (i.e., material modification), the applicability of the reliability standards must be re-evaluated.

The current language simply reads: "An entity which is not initially placed on the Compliance Registry, but which is identified subsequently as having a material impact on the BPS, will be added to the Compliance Registry." [5] Even clearer

---

[1] Characteristics and Risks of Emerging Large Loads, NERC Large Load Task Force, July 2025, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf

[2] Idaho National Laboratory, Characterizing Large Loads, A Taxonomy to Support Large Load Integration (INL/RPT-25-88356, Revision 0, Grid Deployment Office), October 2025, https://inl.gov/content/uploads/2023/07/Characterizing-Large-Loads-A-Taxonomy-to-Support-Large-Load-Integration.pdf

[3] PSEG and Long Island, PERFORMANCE REQUIREMENTS FOR LARGE LOADS CONNECTED TO THE LIPA SYSTEM, February 18, 2026, https://www.psegliny.com/aboutpseglongisland/-/media/BB34AE143811453B8F5923C8E7C234BC.ashx

[4] SPP Document and Filings, Large Load Integration: Price Adaptive Load stakeholder forum, meeting materials July 2026, available at https://spp.org/spp-documents-filings?id=540506, including "SPP Initiative Submission Form: 786, Price Adaptive Load service" https://spp.org/documents/74785/sir796%20price%20adaptive%20load%20service.pdf

[5] Appendix 5B Clean, August 2026 posting, available at https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/appendix-5b-clean---august-2026-posting.pdf

guidance on what constitutes a change significant enough to merit notifying the regional entity should be spelled out. This is especially critical given the possibility for certain computational loads to be exempted from the requirements.

While we feel strongly that there should be no wholesale retroactive exemptions (i.e., no legacy exemptions or grandfathering provisions), we recognize that in some past instances, NERC has adopted legacy exemptions for other entities as they begin participation in the registry process. However, we submit any exemptions should be (a) time limited and (b) designed to account for legitimate logistical constraints that would impede the facility meeting the new standards.

Further, if exemptions are offered (i.e., legacy exemption or retroactive status provision), then it must be made clear when a change to an existing site is sufficient to merit (a) notification of the change, and (b) change in compliance status from exempt to no longer exempt.

The criteria for material modification should include the following. Note that these characteristics are coincident with the expanded registry criteria introduced above.

Any change to load size. Metrics for characterizing change in load size should include at least:

- A minimum absolute amount, i.e., 10 MW by peak (not cumulative, can be applicable to *only* IT equipment).
- Change in monthly **total** consumption (cumulative, inclusive of all metered load at Computational Load Site, not just IT equipment).
- Change in monthly **peak** consumption (cumulative, inclusive of all metered load at Computational Load Site, not just IT equipment).

Change to load variability. This could be measured in a number of ways:

- Change in maximum ramp rate. As discussed above, the Long Island Power Authority methodology could serve as a basis for this standard.[6]
- Changes in frequency of instances of ramp by category (for example, an increase in the number of daily instances of ramps exceeding 10 MW/min).

Change to load flexibility. This should include both technical ability to be flexible, and elective flexibility (i.e., when CLS elect to participate in curtailment product offerings within an RTO).

- **Change to co-located generation assets.** Changes to both the size and the ramping capability of co-located generation should be considered, as both influence how rapidly a facility could elect to switch power source(s).
- **Change to a CLO/CLS' purchase bid mechanism**. This should include changes to the bid parameters if the market mechanism has not changed, and a reassessment of bids if the market mechanism has changed.

3. We do not support the updated threshold size minimums. As long as size alone is being used to evaluate requirements for site compliance, we suggest a reversion to the original size threshold for the registry criteria.

Many would argue there is a need for simplicity in reporting which dictates the use of simplified metrics to evaluate the risk that a CLS poses to the bulk electric system.[7] However, the criteria used to evaluate the true risk of a CLS should be expansive to represent the behavioral profile of the load, not just its size, as we argue in (1) above. But we acknowledge that when seeking which characteristics offer the most meaningful insight into what degree of risk a CLS introduces, size and voltage at interconnection are often the easiest variables to quantify. Therefore, should NERC opt to use simpler metrics at the expense of comprehensive metrics, the original threshold of 20 MW and 60 kV should be used for the following reasons:

---

[6] *See supra*, fn 3.
[7] Characteristics and Risks of Emerging Large Loads, NERC Large Load Task Force, July 2025, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf

1. Part of the justification for the change to 50 MW and 100 kW was that "unintended entities were included."[8] But the number of impacted entities is not a useful metric when considering reliability impacts to the BPS. While the August 19th update offered justification for the change based on the number of entities that would or would not be affected, *this does not meaningfully measure the change in system impact* from the revised size and kV threshold definition.[9] This importance of mitigating risk associated with load size is underscored in the current draft NERC white paper, "Large Load Disturbance Performance – Impact Analysis and Ride-Through Recommendations," in which authors acknowledge that: "*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.*" [10]

2. The change to 50 MW and 100 kV introduces a departure from the standards that already exist for generation, where 20 MW is the current threshold for standard applicability (see PRC-029).[11] As a result, some elements of PRC-029-1, such as the defaults for FRT and RoCoF criteria, *were* extended to large computational loads, while other parts of PRC-029-1 were not (i.e., size threshold minimums). The departure from PRC-029 for minimum size threshold is as yet unsubstantiated.[12]

3. Because size and voltage at interconnection are such crude determinants of true risk to the system, using more conservative thresholds is necessary to protect the integrity and reliability of the bulk power system. Lowering the thresholds captures the risk which smaller, lower voltage systems pose to BPS reliability as a function of their behavior, even if their size alone does not pose a risk. Thus, a more comprehensive and responsive standard reliant on size alone must revert to the 20 MW and 60 kV threshold.

To further support lower thresholds, we look to the precedent set by Southwest Power Pool, in their recently FERC-approved definition of High-Impact Large Loads (HILL): "(1) 10 MW or more if connected to the Transmission System at a voltage level less than or equal to 69 [kilovolts (kV)]; or (2) 50 MW or more if connected to the Transmission System at a voltage level greater than 69 kV." [13]

SPP's approved definition therefore goes one step further than the original NERC draft threshold, by requiring a 10 MW minimum size threshold under certain voltage ratings at point of interconnect. Given that this has already been approved at FERC, there is clear support for more conservative thresholds to mitigate potential risk.

4. If lower thresholds are not restored, then CLS in the 20 MW to 50 MW range and those connected below 100 kV must be further screened to ensure they do not pose meaningful risks.

If necessary, the criteria could allow for sites between 20 MW and 50 MW or below 100 kV to apply for a waiver if they feel they should not be included in the registry. In other words, this would allow the "unintended facilities" to apply for exemption. We are supportive of the language spelled out under "Determination of Material Impact" in the Statement of Compliance Registry Criteria (Revision 9)," but feel that additional information could be helpful. Examples of the type of information that could further be evaluated in the wavier:

- EMT models showing detailed risk analysis.

---

[8] NERC, Technical Reasoning Update Proposed Computational Load Owner and Computational Load Operator August 19, 2026, at https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/august-posting-technical-reasoning.pdf

[9] Technical Reasoning Update Proposed Computational Load Owner and Computational Load Operator August 19, 2026, https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/august-posting-technical-reasoning.pdf

[10] NERC "Large Load Disturbance Performance – Impact Analysis and Ride-Through Recommendations," draft version for public comment, accessed on Sept. 1, 2026. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/draft_llwg_white_paper_large_load_disturbance_performance_tosubmit.pdf

[11] NERC, PRC-029-1 – Frequency and Voltage Ride-through Requirements for Inverter-based Resources, https://www.nerc.com/globalassets/standards/reliability-standards/prc/prc-029-1.pdf

[12] NERC, "Large Load Disturbance Performance – Impact Analysis and Ride-Through Recommendations," draft version for public comment, specifically: *"Recommendation 2: NERC Reliability Standards should use the IEEE 280084 and PRC-029-185 FRT and RoCoF criteria, possibly modified to prevent simultaneous load and generation tripping for high frequency excursions, as requirements for computational loads." (Page 44)*

[13] Docket No.ER26-247-000, Order Accepting Tariff Revisions, Subject to Condition re Southwest Power Pool, Inc. under ER26-247. Commissioner Rosner is concurring with a separate statement attached, available for download at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260114-3109&optimized=false&sid=996f1bcc-9ce4-47bf-9778-4eff9a5968b1

- In the interim as EMT modeling of data center risk is being developed, a proxy metric for risk could be proximity to other CLS. NERC should work with industry to determine a reasonable threshold for proximity that would indicate that the site seeking waiver does or does not present a material risk.

However, because these EFT models require further refinement to offer value, it is difficult to articulate ways to evaluate risk beyond just requiring compliance. We offer this comment insofar as we cognizant that the current draft is preferred by some. This does not change our preference to require that 20MW serve as the threshold, and therefore that these sites are simply beholden to the standards and registered.

Finally, if no change is made to the thresholds, additional detail (beyond the technical reasoning currently provided) around the modeling and inputs used in the decision-making process by NERC to justify the change should be made available to all stakeholders and relevant parties. This should include model validation and assurance that detailed thought was given to the implication of the change on reliability risks, and not just the number of entities impacted.

NERC

Consideration of Comments

Rules of Procedure (ROP) Revisions to Appendices 2, 5A, and 5B (Computational Load Owner and Computational Load Operator)

September 30, 2026

Table of Contents

Introduction iii
List of Commenters iv
Summary of Proposed Revisions Posted for Comment 1
NERC Rules of Procedure Appendix 2 – Definitions Used in the Rules of Procedure 1
NERC Rules of Procedure Appendix 5A – Organization Registration and Certification Manual 1
NERC Rules of Procedure Appendix 5B – Statement of Compliance Registry Criteria 1
Comments 1
Support for the Proposed Revisions 1
Clarifications and Guidance 2
Computational Load Owner and Operator Definitions 3
Computational Load Site Definition 8
Thresholds 14
Other 18

Introduction

NERC thanks all commenters who submitted comments on the proposed changes to the Rules of Procedure. NERC posted the proposed changes for public comment from August 19, 2026 through September 18, 2026. NERC received 30 sets of comments from 35 commenters, as shown in the table on the following pages.

NERC has posted submitted comments on the Proposed Changes to Rules of Procedure page.

List of Commenters

	Entity
1	Ameren
2	American Chemistry Council (ACC)***
3	American Electric Power (AEP)
4	ATC
5	Bonneville Power Administration (BPA)
6	CenterPoint Energy Houston Electric, LLC (Centerpoint)
7	Constellation
8	Corscale*
9	Danovo Energy Solutions (Danovo)
10	Data Center Coalition (DCC)
11	Dru Dunton
12	Duke Energy (Duke)
13	EdgeConneX
14	Electricity Consumers Resource Council (ELCON)
15	Electric Reliability Council of Texas (ERCOT)
16	Google*
17	Industrial Energy Consumers of America (IECA)
18	Invenergy
19	ISO/RTO Council Standards Review Committee (IRC SRC)
20	ITC
21	Los Angeles Department of Water and Power (LADWP)
22	Microsoft*
23	Midcontinent Independent System Operator (MISO)**
24	National Association of Regulatory Utility Commissioners (NARUC)
25	National Electrical Manufacturers Association (NEMA)
26	National Rural Electric Cooperative Association (NRECA)
27	nationalgrid
28	NERC Member Representatives Committee Sector 9 (MRC-9)

29	Pacific Gas & Electric Company (PG&E)
30	Prologis
31	QTS Data Centers (QTS)*+
32	Real Estate Roundtable (RER)
33	Sierra Club
34	Tennessee Valley Authority (TVA)
35	Union of Concerned Scientists (UCS)

*supports DCC

**supports IRC SRC

***supports ELCON

+means support and additional comments

Summary of Proposed Revisions Posted for Comment

The following section summarizes the proposed revisions to the NERC Rules of Procedure posted for comment from August 19 - September 18, 2026 regarding registry criteria for computational loads.

NERC Rules of Procedure Appendix 2 – Definitions Used in the Rules of Procedure

Appendix 2 to the NERC Rules of Procedure includes defined terms used throughout the Rules of Procedure. The proposed revisions add the following three terms:

- "Computational Load Operator" means the entity that operates a Computational Load Site.
- "Computational Load Owner" means the entity that owns and maintains a Computational Load Site.
- "Computational Load Site" means one or more buildings, structures, or installations at a single location that
  1) Primarily contains information technology infrastructure used for:
     - creating, executing, and delivering software applications and services;
     - artificial intelligence training, deployment, and delivery;
     - cryptocurrency mining; or
     - other computational activities at a data center; and
  2) is supplied through electrical equipment that is connected to the BPS.

NERC Rules of Procedure Appendix 5A – Organization Registration and Certification Manual

Appendix 5A contains the process used by NERC and the Regional Entities to register certain functional entity types to which mandatory and enforceable Reliability Standards apply. The proposed revisions to Appendix 5A add "Computational Load Owner (CLO)" and "Computational Load Operator (CLOP)"as types of entities that are required to register on the NERC Compliance Registry. In addition, proposed revisions to Appendix 5A include minor administrative corrections.

NERC Rules of Procedure Appendix 5B – Statement of Compliance Registry Criteria

Appendix 5B contains the specific criteria NERC and the Regional Entities use to identify which organizations may be candidates for registration for functional entity types. In accordance with the Federal Power Act, NERC must identify the owners, operators, and users of the Bulk Power System (BPS) who have a material impact on the BPS. To that end, the proposed revisions in Appendix 5B add threshold criteria to identify those organizations that should be registered as Computational Load Owners and Operators, summarized below:

- Computational Load Owner or Operator of a Computational Load Site with a total connected Load greater than or equal to 50 MW that is supplied through electrical equipment connected at a voltage level greater than or equal to 100 kV from one or more points of connection.

Candidates must meet all the criteria in the proposed revisions in Appendix 5B to be registered as a Computational Load Owner or Computational Load Operator.

Comments

The following section provides a summary of issues raised in stakeholder comments on the proposed Rules of Procedure revisions along with NERC's response. For responses to comments on the proposed CLO Reliability Standards, interested stakeholders may view them on the Project 2026-02 Computational Loads standard drafting team's web page.

As further summarized in the following tables, comments on the proposed Rules of Procedure revisions included the following: support for the proposals, requests for additional guidance or clarification, questions on the application of the criteria to specific scenarios, and some proposed revisions to the language.

Support for the Proposed Revisions

Entity	Summary of Stakeholder Comments	Response
AEP Ameren Invenergy ITC	Several commenters expressed support for the proposed language and appreciated that the revisions addressed comments on the first posting.	NERC appreciates commenters noting support of the proposed revisions.

Clarifications and Guidance

Entity	Summary of Stakeholder Comments	Response
TVA DCC QTS Corscale Google Microsoft NEMA Centerpoint RER IRC SRC MISO	Several commenters requested more guidance on the application of the registry criteria to scenarios, particularly in reference to specific configurations, fact patterns, and various owner-landowner/operator-tenant arrangements.	While the proposed registry criteria provide the generally applicable criteria necessary for identifying entities that should be registered as a CLO or CLOP, NERC understands that each entity and Computational Load Site may have unique characteristics and that entities want to understand how the criteria apply in these specific circumstances. NERC and the Regional Entities recognize the need for consistency among regions and across the continent with respect to which entities are subject to registration. To promote this consistency in applying the NERC Registry Criteria, the ERO Enterprise develops "Registration Reference" documents that provide guidance to ERO Enterprise staff in applying criteria to scenarios. NERC will develop a registration reference for the CLO and CLOP functions and will update as needed or appropriate. Several of the examples provided in the standard drafting team's FAQ document, as well as examples provided in these comments, will be considered for inclusion in the reference document. As an example, NERC developed a registration reference document that provides examples of how the Generator Owner and Generator Operator criteria applies to Category 2 inverter-based generating resources that are not Bulk Electric System (BES) resources, available at https://www.nerc.com/globalassets/programs/registration/registration-documentation/application-of-the-registration-criteria-for-category-2-generator-owner-and-generator-operator-inverter-resources.pdf.

Entity	Summary of Stakeholder Comments	Response
LADWP Danovo IRC SRC MISO	Commenters had questions on compliance responsibilities, who is responsible for initiating registration, the registration process, and the compliance monitoring process. Some commenters suggested modeling the outreach after the Inverter-Based Resources Registration Initiative.	Upon Board approval and filing of the proposed registry criteria with FERC, NERC and the Regional Entities will engage in outreach and education on the NERC Organization Registration and Certification Program as well as the Compliance Monitoring and Enforcement Program. Similar to the approach with Category 2 GO/GOP non-BES inverter-based generating resources, NERC plans to provide opportunities for CLO/CLOP registration candidates to interact with NERC and Regional Entity staff in various settings to help entities prepare for the upcoming Reliability Standards. Inherent to the registration process is a concerted effort by Regional Entities to establish contacts with each entity and understand its organization and system to appropriately register the responsible party and to initiate contact with compliance staff at NERC and the Regional Entities. NERC proactively will seek to reach out to entities to help them start the registration process, but NERC encourages possible CLO/CLOP candidates, or those who are unsure whether their site may qualify them as CLO/CLOP, to engage early with NERC and the Regional Entities for the best outcomes. The ERO Enterprise Registration Procedure includes contact information for registration staff at the Regional Entities. ERO Enterprise Registration Procedure is available at https://www.nerc.com/globalassets/programs/registration/registration-documentation/ero-enterprise-registration-procedure.pdf. The NERC Registration web page includes contact information for registration staff at NERC, which is NERC.Registration@nerc.net. The NERC Registration web page is available at https://www.nerc.com/programs/registration.

Computational Load Owner and Operator Definitions

Entity	Summary of Stakeholder Comments	Response
DCC Corscale Google Microsoft QTS	Commenters questioned how the CLO and CLOP registry criteria apply in scenarios where there may be multiple owners, operators, or tenants; where there are tenants who may have the necessary data, information, or operational capability; or where	NERC recognizes entities may have differing organizational structures and business relationships that may impact who owns or operates a Computational Load Site. In these situations, such as multiple owners, operators, or tenants, the NERC registration process provides flexibility in how organizations would like to handle registration and compliance.

Entity	Summary of Stakeholder Comments	Response
Duke EdgeConneX ERCOT RER	campus developments have multiple owners or operators. Some commenters asked for clarification if they could register more than one CLO or CLOP for a Computational Load Site.	To that end, there are several mechanisms within the NERC registration process available to accommodate these different constructs and ensure responsibility for applicable requirements is assigned to the appropriate entity or entities, such as Joint Registration Organizations, Coordinated Functional Registration, or use of third-party agreements to explicitly assign responsibility. NERC clarifies that a Computational Load Site could have multiple CLOs or CLOPs, although the various mechanisms described below can help an entity to assign responsibility for compliance to one or more entities when there may be tenants or multiple owners or operators. In Section II of the NERC Registry Criteria Appendix 5B, which includes the proposed CLO and CLOP definitions, Footnote 6 reads as follows: "Exclusion: An entity will not be registered based on [Section II] criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, including bilateral agreements and Sections 501, 507, and 508 of the NERC Rules of Procedure." As an example of how this language could apply, an entity that may own a Computational Load Site but contracts out its maintenance, and that contractor would more appropriately be responsible for the applicable requirements, may instead have that contractor register as the CLO of the Computational Load Site by demonstrating the responsibility for the Reliability Standards requirements has been transferred via a bilateral agreement that explicitly transfers such responsibility. Such an agreement may also be appropriate for CLOs with tenants who may take on the responsibility for all or some of the functional requirements. While there may be various types of agreements that achieve the intended result, an entity may consider a Joint Registration Organization (JRO) relationship (section 507 of the Rules of Procedure) or a Coordinated Functional Registration (CFR) relationship (section 508 of

Entity	Summary of Stakeholder Comments	Response
		the Rules of Procedure). A JRO is when parties agree that a lead entity takes full responsibility for a particular function (e.g., Computational Load Operator) for itself and the agreement parties. A CFR is when a lead entity takes full responsibility for one or more Reliability Standards for a particular function. These mechanisms and types of acceptable agreements may vary for entities depending on facts and circumstances, but Regional Entities during the registration process will assist candidate Computational Load Owners on the appropriate registration structure for their particular circumstance so that the entities on the NERC Compliance Registry are those that will be responsible for the applicable NERC Reliability Standards requirements. The NERC Rules of Procedure and ERO Enterprise Registration Procedure provide more information on available options to entities. The ERO Enterprise Registration Procedure is available at https://www.nerc.com/globalassets/programs/registration/registration-documentation/ero-enterprise-registration-procedure.pdf.

NRECA RER DCC Corscale Google Microsoft QTS Prologis ERCOT EdgeConneX	Commenters questioned the use of "owns and maintains" as part of the Computational Load Owner definition. Some commented that maintenance and operation may be difficult to distinguish in the data center context. Others questioned how it applies to entities who may own a site, but other entities maintain the site or may have the information needed to comply with applicable standards. Some suggested to remove "and maintains" from the definition.	NERC acknowledges that the business structures and relationships within computational loads are varied or multi-layered and that compliance responsibilities should fall on those who have the authority or capability to carry them out. However, NERC declines to further revise the Computational Load Owner language because commenters suggested inclusion of such a function during the first set of comments, and the "owns and maintains" language is consistent with other owner functions on the NERC Compliance Registry. In comments on the April 1st posting, commenters recommended the proposed criteria use the same "Owner" and "Operator" Model for Computational Loads to remain consistent with the registration criteria currently in the NERC Rules of Procedure for Transmission Owner (TO), Transmission Operator (TOP), Generator Owner (GO), and Generator Operator (GOP). Commenters stated that this structure is in place because for Transmission and Generation facilities, there are often situations that occur where the owner of the facilities is different from the operator of the facilities. This registration criteria structure allows the different entities to be responsible only for the activities that they are contractually set up for as the owner or operator. NERC has been applying the "owns and maintains" language to the Transmission Owner and Generator Owner functions, and the various organizational structures of those entities, for many years. Accordingly, within the NERC registration process, there are mechanisms available to help those generation or transmission projects, for example, understand which entity should be registered as a Generator Owner or Transmission Owner. Under the existing registration construct, entities may wish to establish bilateral contracts with other entities to take responsibility for the requirements applicable to the GO function, as appropriate. Chapter 2 of the ERO Enterprise Registration Procedure provides the options for a registered entity in using third-party agreements. The ERO Enterprise Registration Procedure is available at https://www.nerc.com/globalassets/programs/registration/registration-documentation/ero-enterprise-registration-procedure.pdf.

Entity	Summary of Stakeholder Comments	Response
		In the context of computational loads, the Computational Load Owner who "owns and maintains" the Computational Load Site helps establish that it is intended to be the entity that plays a more active role in ownership rather than a passive role. Specifically, the inclusion of "maintains" helps better define the role of the entity that will be considered as a candidate for registration so that NERC is not registering every passive owner with only a small financial interest in a CLS.
QTS Constellation	Commenters requested clarity on the operational activities for a CLOP.	NERC developed Computational Load Owner and Computational Load Operator functions based off comments from the first posting that two functions better reflected the structure of the industry and who should be responsible for applicable requirements. While entities will need to work with Regional Entities to ultimately determine the appropriate entity to place on the NERC Compliance Registry, generally speaking a CLOP can impact the day-to-day control of the CLS's electrical operations or has communications capabilities with their transmission or reliability entities, as appropriate, or both, among other considerations as to operations.
DCC Corscale Google Microsoft QTS Sierra Club UCS	Commenters requested clarification on how the registry criteria apply to phased campus developments or sites that energize in phases, particularly those that reach full build over several years. Some commenters requested more clarity on what constitutes a change significant enough to merit notifying the Regional Entity regarding registration.	NERC registers entities, not facilities or sites. Accordingly, NERC will register an entity that is responsible for the CLO as well as the CLOP functions, as appropriate. For phased projects, NERC and the Regional Entities will register a CLO and a CLOP as soon as the site, regardless of whether there will be future phases, meets the Computational Load Site definition and the registry criteria thresholds for that site. Then, should that site continue to expand, the CLO and CLOP would not need to register again, only update their registration information with the Regional Entity. To do so, the CLO and CLOP must notify the Regional Entities of changes to its site for compliance purposes or if those changes could lead to de-registration or other appropriate changes. Once an entity is initially registered as a CLO and CLOP for one site, any additional Computational Load Sites only requires the CLO and CLOP to notify the Regional Entity of such additions.

Computational Load Site Definition

Entity	Summary of Stakeholder Comments	Response
LADWP RER nationalgrid IRC SRC MISO	Commenters requested clarity on the types of computational activities that are included in the definition of Computational Load Site.	The definition of Computational Load Site provides a list of the types of computational activities as well as a "catch all" category intended to capture those activities that would be performed at a data center, which inherently includes data storage, transmitting/delivering data, or data manipulation. The list of activities within the CLS definition clarifies that the purpose of the buildings, etc. are for housing IT infrastructure used in computational activities, but it is not intended to include a server room or building that may be part of a large industrial worksite. The list of the activities is intended to be illustrative but is not exhaustive for every case should a computational activity present an impact to the BPS but is not otherwise defined in the list. Further, these activities are not treated separately. Any computational type activities, including the non-computational ancillary loads (e.g., air conditioning, lighting, network switches, etc.), contribute toward the CLS total connected Load. In NERC documents, the use of "or" includes "and/or."
DCC QTS Corscale Google Microsoft Sierra Club UCS IRC SRC MISO ERCOT	Commenters requested clarification on the term "primarily" when used in the context of the IT infrastructure at a Computational Load Site. Some commenters requested a more quantitative measure for the amount of IT infrastructure, such as 50% or more.	While several commenters suggest more quantitative measures of how much IT infrastructure is part of a site, the use of "primarily" is intended to indicate that entities with the infrastructure performing computational activities that contribute to the unique impacts to the BPS are registration candidates, whereas load that is more industrial or manufacturing but may have large IT infrastructure is excluded. NERC declines to impose a numerical threshold as that may arbitrarily exclude entities with the same reliability impact based on a percentage despite the entities performing the same computational activities that pose an impact to the BPS. NERC does not anticipate the lack of a numerical threshold will indicate an issue in defining Computational Load Sites. for instance, the LLWG Whitepaper #1 identified that data centers and other computational loads' IT-related equipment that consists of servers, storage, and networking gear driven by power electronics, "generally comprise at least half of the data center's energy consumption. Data center

Entity	Summary of Stakeholder Comments	Response
		industry experts state that IT-related equipment may make up 60–95% of a data center's total energy demand." *See* Whitepaper #1 at page 4, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf. Regarding the question on Computational Load Sites co-located with generation, the use of "primarily" is not considered in the context of on-site generation next to the buildings, structures, or installations at a single location. For instance, in the example provided by ERCOT regarding the 1,000 MW data center co-located with the 2,000 MW generating facility, the buildings, structures, or installations that comprise the computational load would be considered in the context of the Computational Load Site definition as well as the additional registry criteria of the applicable MW and kV thresholds, not the generation which could require its owner and operator to register with NERC as a Generator Owner or Generator Operator. To that end, as entities are registered, the site associated with their functions would be considered on a case-by-case basis such that Regional Entities reviewing each site would not look to register manufacturing facilities or generating facilities that may have certain computational equipment that helps run their manufacturing processes or generating operations. Rather, the Regional Entities would look to whether the buildings, structures, or installations on the site primarily contain IT infrastructure, which has been a driver of the unique characteristics of computational load with a reliability impact on the BPS.

Entity	Summary of Stakeholder Comments	Response
IECA ELCON ACC	Commenters recommended that NERC further clarify that industrial and manufacturing are excluded from the definition of Computational Load Site, with commenters emphasizing the differences between industrial/manufacturing sites and sites performing computational activities. Some suggested that North American Industry Classification System (NAICS) codes should be used to identify the types of computational activities.	NERC points to the use of "primarily" which is intended to indicate that entities with the infrastructure performing computational activities that contribute to the unique impacts to the BPS are registration candidates, whereas load that is industrial or manufacturing but may have large IT infrastructure is excluded. As noted in response to comments in the first posting, while NERC recognizes the LLWG efforts reviewed other large loads in addition to computational loads, NERC determined that the most immediate risk is appropriately addressed by focusing on computational loads due to their aggregate and operational impacts on the BPS. NERC considered incorporating the NAICS codes as a qualifier in determining registry criteria; however, NERC declined to use these codes as they are developed outside the NERC stakeholder processes and subject to change without ERO Enterprise and its stakeholders' input.

LADWP RER DCC QTS Corscale Google Microsoft IRC SRC MISO ERCOT ATC	Commenters requested clarification on the meaning of "single location" in the Computational Load Site definition, including the factors used in establishing what is a single location. Some commenters suggested providing the factors in the proposed registry criteria.	NERC developed the Computational Load Site definition in response to comments from the first comment period requesting clarity on the site boundaries or definition to determine who owned or operated the site and how to calculate the total connected Load. While a load site is different than generation in many ways, the "single location" concept has been used in other regulatory contexts, such as PURPA, where FERC may consider certain physical or ownership characteristics of generation facilities to determine separate sites for Qualifying Facilities purposes. While NERC does not borrow all regulatory concepts from PURPA given the distinctions between load sites and generation, NERC determined that the use of "single location" in this instance was appropriate to convey that the 50 MW was not aggregating possibly geographically close but unrelated sites that share CLS characteristics. As noted in the standard drafting team's FAQ document, as part of the NERC registration process for CLOs and CLOPs, each Computational Load Site will be reviewed based on its specific factors to determine applicability. The registration process may consider many factors pertaining to the buildings, structures, or installations; including, but not limited to ownership, shared or common infrastructure (e.g., auxiliary or cooling load), or coordinated use across the information technology infrastructure to perform its computational activities. In addition, NERC clarifies that single location does not necessarily refer to real estate boundaries such as parcels, etc. For example, in the standing drafting team FAQ document, it states that it is possible to have two or more Computational Load Sites connected to the same source equipment because they represent distinct sets of buildings, structures, or installations at a single location. In that instance, both owners and operators of two Computational Load Sites would be subject to registration and be applicable to one or more NERC Reliability Standards. In that instance, the two sites could sit on the same real estate parcel, but they would be deemed two sites based on other operating factors. NERC is retaining the existing language as the Computational Load Site definition reasonably characterizes one or more buildings, structures,

Entity	Summary of Stakeholder Comments	Response
		or installations at a single location as the first condition of registration without limiting factors related to land parcel, address assignment, roads or rights-of-way, selected site name (e.g., a campus), shared utility or other infrastructure, interconnection, etc. Furthermore, while NERC appreciates that some commenters may want more specificity in the criteria on "single location," such as the factors NERC may consider in determining a Computational Load Site for purposes of identifying Computational Load Owners and Computational Load Operators, NERC notes that these factors would not be exclusive because of the differing site characteristics, ownership structures, topologies, etc. of Computational Load Sites. NERC plans to develop a Registration Reference document that addresses examples of how the registry criteria apply to certain scenarios. The Registration Reference document NERC will develop will include examples of the application of single location.

Entity	Summary of Stakeholder Comments	Response
DCC QTS Corscale Google Microsoft	Commenters requested confirmation that NERC intended to use "BPS" and not "BES" and how that relates to the exclusion from the BPS of facilities used in the local distribution of electric energy.	NERC confirms its intentional use of the term "BPS" instead of "BES" in the proposed Computational Load Site definition. NERC's reliability authority as the ERO under the Federal Power Act extends to all users, owners, and operators of the BPS. NERC's registry criteria identify the appropriate users, owners, and operators subject to Reliability Standards based on their potential material impact to the BPS. The proposed registry criteria are designed to regulate users with an impact on BPS reliability and are not designed to regulate users to ensure the reliability of local distribution facilities. In this instance, the impacts of computational loads as assessed by the LLWG and NERC engineering staff are not limited to those solely connected to the BES Facilities; rather, as load, the size of the large load, unique characteristics of the computational activity, and the number of these large loads contribute to the material impact identified on the BPS. Accordingly, BES was not an appropriate measure for determining which Computational Load Sites would lead to registration for entities. Nevertheless, the 50 MW and 100 kV thresholds ensure BPS-connected entities are subject to registration while excluding entities that have not been seen to negatively impact BPS reliability. These thresholds are also intended to remove confusion about whether a Computational Load Site is served by what may be considered "local distribution".
BPA	Under a specific scenario, the commenter suggested that some Computational Load Sites would be connected to elements excluded from the BES under E1 or E3. The commenter suggested that the BES should be revised to not permit use of E1 or E3 if a Computational Load Site is connected to it.	At this time, NERC has not identified a need to revise the Bulk Electric System definition. To the extent a need is identified in the future, revisions to the BES definition would be considered through NERC's open and transparent standards development process.

Thresholds

Entity	Summary of Stakeholder Comments	Response
DCC QTS Corscale Google Microsoft Sierra Club UCS Dru Dunton NEMA	Some commenters suggest raising the MW threshold to 75 MW while some support lowering to 20 MW. Others encouraged NERC to consider more than size or voltage. Some suggested if no change, additional justification beyond the technical reasoning provided be made available to stakeholders. Others encouraged NERC to continue to monitor how thresholds in regional interconnection processes may relate to the NERC Reliability Standards.	As noted in the response to comments in the first posting and the technical reasoning accompanying the second posting, NERC determined the 50 MW threshold appropriately addressed the risk identified while ensuring smaller, less impactful entities were excluded. Based on comments and ongoing analysis during and after the April 1-May 15, 2026 posting, NERC was able to refine its understanding of the aggregate risks associated with data center sites and clusters connected throughout the BPS. Further analysis was expanded to sites planned to be operational by the end of 2027. From the ongoing and expanded analysis, NERC determined that the threshold could be raised to 50 MW (from the first posting's 20 MW) while still addressing the risks. In addition, NERC reviewed Regional Transmission Organizations (RTO) and Independent System Operator (ISO) definitions of large loads and considered whether those would be appropriate for continent-wide reliability purposes. NERC found that 50 MW is generally in alignment with some RTO/ISO large load definitions. The threshold analysis considered available CLS information and their association with BPS facilities and encompassed those CLS of the size and connected voltage that can create unforeseen and difficult-to-explain dynamic behaviors impacting the BPS. The analysis further determined that CLS less than 50 MW and under 100 kV are generally smaller, dispersed across the BPS, and would contribute less aggregate risk. While there are locations under 50 MW and 100 kV, these locations have not been seen to negatively impact BPS reliability. Also, by not including these CLS removes confusion about what may be considered being connected to local distribution. NERC will continue to monitor the aggregate risks of applicable CLS and reserves the right to propose additional ROP Registry Criteria changes in the future to address any risks to the BPS. Lastly, NERC further concluded that increasing the threshold to 75 MW would decrease the number of CLS that are similar in size that have been seen to create unforeseen and

Entity	Summary of Stakeholder Comments	Response
		difficult-to-explain dynamic behaviors impacting the BPS and declines to increase the threshold to 75 MW. Should commenters want more information on the thresholds beyond the technical reasoning, NERC directs commenters to review the resources on NERC's Large Load Action Plan web page that provides the underlying analysis on the risk posed to the BPS that led to this action. In addition, NERC determined that the Computational Load Site definition does not need the numerical thresholds for MW and kV because those will be in the registry criteria only (Appendix 5B), whereas the Computational Load Site definition can also be used by the standard drafting team in the proposed Reliability Standards. This ensures alignment across ROP terms and NERC Glossary terms while maintaining registry thresholds in the ROP only. In addition, should a standard drafting team determine future requirements should apply to higher thresholds of CLS, that team can specify the specific threshold in the Facilities section of any proposed Reliability Standard. As part of the LLWG, NERC and stakeholders will continue to monitor whether computational load connected at different voltages may also pose impacts to the BPS that should be further considered.
RER DCC QTS Corscale Google Microsoft	Commenters requested clarification on the term "connected Load" in the registry criteria.	In response to comments on the first posting, NERC revised the registry criteria to refer to "total connected Load", which refers to all the electrical equipment at a Computational Load Site, to help clarify how the MW threshold should be calculated. While NERC declines to further define "total connected Load" in the ROP because the term "total" indicates all the Load at the site, NERC confirms that such a calculation would include the rest of a site's electrical connected load needed to run HVAC, lighting, non-computer equipment and defined plug-in type loads, and loads to support other non-computational building systems like elevators, security, and fire/safety. The "total connected Load" language, in conjunction with the "single location" language, helps clarify that NERC is not aggregating small but discrete

Entity	Summary of Stakeholder Comments	Response
		sites that may be close together that do not share CLS characteristics for purposes of calculating the MW, but that entities are required to include ancillary systems that are part of the site in determining its "total connected Load." The future Registration Reference document can provide further examples of this calculation to the extent it is helpful in assisting consistent calculations, although each site may vary in the types of electrical equipment at a Computational Load Site.
DCC Corscale Google Microsoft QTS	Commenters requested clarification on where the 100 kV is calculated and whether it is the kV listed in the entity's interconnection agreement with a utility. One commenter requested that NERC clarify: (1) how applicability is determined when the distribution bus serving a data center also serves other customers; (2) what notification obligations the Distribution Provider has when network changes affect a facility's registration status; and (3) whether the FERC Order 773 seven-factor test for local distribution exclusion applies to large loads consuming power at distribution voltage, given that the only sub-100 kV inclusion precedent in that order was for generation injecting power, not load withdrawing it.	As noted in the standard drafting team FAQ document, the focus of the criterion is not on the common point of connection, as may be typically defined in an interconnection agreement, but rather the kV level to which the electrical equipment supplying the Computational Load Site is connected to the BPS. In other words, this would typically be the high-side voltage level of the electrical equipment connected to the BPS that is supplying the Computational Load Site, which may or may not be the documented point of interconnection in an interconnection agreement. As CLO and CLOP candidate entities go through the registration process, the applicable Regional Entities will assess the BPS kV connection level of the Computational Load Site to determine whether registration is required or not. As for specific configurations suggested by commenters, NERC notes that the Registration Reference may address these scenarios to provide greater clarity to potential registrants. As for the 7-factor test, NERC recognizes that determinations of whether a facility is used in local distribution are made by FERC, and that Order No. 773 at P 72 stated, "while the starting point for the Commission's analysis will be an analysis based on the Seven Factor Test, the Commission will consider other factors that should be taken into account in particular situations." As the Commission reviews local distribution on a case-by-case basis and a variety of factors, NERC cannot speak as to how the Commission will consider the application of precedent regarding generation versus load and their reliability impacts. That being said, NERC confirms that the proposed registry criteria are designed to regulate users with an impact on BPS reliability

Entity	Summary of Stakeholder Comments	Response
		and are not designed to regulate solely for the reliability of local distribution facilities, consistent with section 215 of the Federal Power Act.
IRC SRC MISO ERCOT BPA	Commenters suggested either removing the kV or lowering it to 60 kV.	NERC determined that including voltage in the registry criteria ensures registration of entities with the most impactful connection to the BPS. As each candidate goes through the registration process, Regional Entity staff will assist candidates in assessing the applicable voltage threshold or connection configuration. As noted in the technical reasoning document, NERC determined the 100 kV voltage criteria is an appropriate threshold based on its interconnection voltage analysis. At the 50 MW threshold, there was a small difference of only 2% of the overall total load comparing 100 kV to the previously proposed 60 kV threshold.
NARUC	The commenter suggested the voltage level be raised to higher than 115 kV to account for certain 115 kV lines that are excluded from the BES as local distribution.	The voltage threshold at or above 100 kV is for registry criteria only. It has no bearing here on BES inclusions or exclusions. The definition of Computational Load Sites and corresponding registry criteria for CLO and CLOP are intentionally distinct from the BES and Facility definitions. Therefore, any BPS or Computational Load Site equipment that does not explicitly meet the existing BES or Facility definitions, including inclusions or exclusions, would not be subject to NERC Reliability Standard requirements that refer to the BES or Facility defined terms. The proposed registry criteria are designed to regulate users with an impact on BPS reliability and are not designed to regulate users to ensure the reliability of local distribution facilities.
LADWP RER DCC QTS Corscale Google Microsoft	Commenters requested clarification on “point of connection” language. One commenter suggested that the point should be reasonably attributable to electricity usage by the Computational Load Site. Another commenter asked NERC to further clarify and define the phrase “common point of connection,” which Figures 2 and 3 in the FAQ both use and treat as distinct from the point of connection to the BPS without defining either.	NERC revised the registry criteria from “point of interconnection” to “one or more points of connection” to the BPS based on comments in the first comment period requesting clarification. The use of points of connection better distinguishes between the interconnection agreements entities may have with a utility and is intended to capture the high-side voltage level of the electrical equipment connected to the BPS that is supplying the Computational Load Site. As commenters note, examples in the standard drafting team FAQ document provide some indication of possible different configurations of points of

Entity	Summary of Stakeholder Comments	Response
		connection. As NERC and the Regional Entities develop the Registration Reference document, it will include additional examples to assist entities in understanding how various configurations may be considered.

Other

Entity	Summary of Stakeholder Comments	Response
Dru Dunton	The commenter suggested that registering load was a major conceptual departure from other entities under the NERC registration framework.	NERC recognizes that this marks the first instance in which NERC has determined to register end users of the BPS for compliance with mandatory Reliability Standards. While NERC's statutory authority expressly provides that NERC may register users, owners, and operators of the BPS, NERC has not heretofore identified a specific reliability need to register end users. The rapid growth of computational end users, the unique way in which such end users interact with the BPS, and multiple system incidents involving such end users have caused NERC to reevaluate. Further, FERC has directed NERC to register such users. While the proposed registry criteria itself may not further discuss the differences of Load from other existing functional entity types, throughout NERC's Large Load Action Plan, such discussions have occurred through various forums and written material. For instance, NERC's Large Loads Working Group (LLWG) Whitepaper #2 discusses how existing registered entities cannot address the gaps identified and that a new function for Load should be developed. In addition, NERC has filed comments in the FERC ANOPR docket discussing that users of the BPS have rarely been identified on the NERC compliance registry, but it is within NERC's authority to register users of the BPS and FERC has contemplated in the past that a large load could be such a user of the BPS.

Entity	Summary of Stakeholder Comments	Response
Danovo Dru Dunton	A commenter suggested revisions to the factors in considering materiality in Appendix 5B. Another suggested the NERC-led Registration Review Panel process to review case-by-case materiality be public.	The assessment of material impact for entities that may either be excluded or included from the NERC Compliance Registry is completed by a NERC-led Registration Review Panel, which consists of NERC staff and Regional Entity staff. Should a panel review such a request, decisions are posted on the NERC web site for entities to review, providing the necessary level of transparency while protecting confidentiality of the materials that may be provided to assess materiality. In addition, the non-exclusive factors included in assessing materiality are based on certain activities that may or may not be applicable to a certain function. These factors help ensure a consistent approach to assessing materiality; however, only a sub-set of these factors, or other additional factors, may be applicable to a particular functional registration category or specific entity. Accordingly, NERC declines to further revise Appendix 5B factors that would apply to other functions.
Sierra Club UCS	Commenters noted that there should be no wholesale retroactive exemptions for in-service units.	The implementation plans for each Reliability Standard applicable to CLO and CLOP provide the timelines when requirements become effective and are developed under Project 2026-02 in an open and transparent NERC standards development process. As such, the standard drafting team can more appropriately address when entities would be expected to comply with requirements. However, NERC notes that while there may be different timelines for entities depending on in-service or new loads, there are not planned blanket exceptions for entities that are registered as CLO and CLOP based on whether they are already in-service. Changes in a Computational Load Site that affect an entity's registration status or factors used in its registration determination (e.g., change in total connected Load, connection voltage, etc.) are handled through Regional Entity processes.

Entity	Summary of Stakeholder Comments	Response
Duke IRC SRC MISO	Commenters noted that BAs, RCs, and TOPs need time to coordinate with CLO and CLOP entities to comply with CLO Reliability Standards. Some commenters suggested notification to all entities designated a role under a registration to affirm respective functions.	NERC recognizes the need for RCs, BAs, and TOPs to coordinate with CLOs and CLOPs before and during the registration process. In addition, NERC recognizes the impacts of CLO/CLOP registration on the compliance obligations for RCs, BAs, and TOPs. As NERC initiates the registration process for CLO/CLOP prior to the effective date of applicable Reliability Standards, the proposed implementation plans for the proposed CLO-001, -002, and -003 Reliability Standards provide the timing of associated compliance obligations affecting the new registrants and existing registered entities.
Sierra Club UCS	Commenters noted that transparency and a robust stakeholder process is required even in projects moving quickly to address reliability risks.	NERC appreciates the recognition of its transparency in stakeholder processes and coordination with other regulatory, policy, or reliability-focused entities while addressing computational loads expediently. NERC plans to continue extensive engagement and outreach to stakeholders to ensure appropriate entities provide input into any future computational load projects. NERC also asserts that any speed with which it has moved comports with its regulatory process, and that NERC has used its consensus-building processes to develop quality products.
Sierra Club UCS MRC-9	Stakeholders commented on the impact of reliability actions on cost allocation. Some commenters indicated that actions to mitigate risk have a meaningful impact on cost allocation due to the cost of outages. Other commenters indicated that the costs of Reliability Standards will be at the cost of current customers.	While setting rates and cost allocation are outside of NERC's purview, comments on cost considerations for standards may be submitted to any standards development project for consideration in assisting NERC to achieve its reliability goal effectively and efficiently, although, consistent with FERC Order No. 672, such proposed standards should not achieve less than excellence in system reliability solely to protect against reasonable expenses for supporting the grid.

Entity	Summary of Stakeholder Comments	Response
PG&E	The commenter requested clarification that the NERC-led Registration Review Panel assessments of materiality in Appendix 5A, Section III(D) are applicable to CLO and CLOP that may fall below the registry criteria threshold but may have similar impacts to entities that meet CLO and CLOP criteria. The commenter requested clarity on the factors considered in aggregate reliability impact, that TOs or DPs may bring their concerns to Regional Entities, that registration determinations will be communicated to relevant entities, and that a target timeframe is established for panel decisions.	For entities that fall below registry criteria, NERC confirms that the NERC-led Registration Review Panel under Appendix 5A, Section III(D) could assess the materiality of an entity for purposes of registering the entity as a CLO or CLOP. While Appendix 5B lists factors for consideration in materiality, NERC notes that the factors are non-exclusive, and the panel could consider the aggregate reliability impact of computational load. NERC publicly posts the decisions of the panel. NERC can consider whether target timeframes on decisions may be set but declines to set timeframes other than those listed in the Rules of Procedure at this time. Finally, NERC confirms that an entity may submit a request regarding another entity.

Attachment 4-B

April 2026 Posting

Comments Submitted on Proposed Revisions to the NERC Rules of Procedure

NERC Rules of Procedure Appendix 2 (Definitions Used in the Rules of Procedure); Appendix 5A (Organization Registration and Certification Manual); and Appendix 5B (Statement of Compliance Registry Criteria)

NERC posted proposed revisions to its Rules of Procedure to develop a new registered entity type, called Computational Load Entity, for comment from April 1, 2026 to May 15, 2026. The entities in the following table responded during the comment period, either submitting comments or indicating support of other entities' comments. This pdf package includes the comments received during this posting period, with personal contact information removed.

List of Responding Entities

	Entity
1	Industrial Energy Consumers of America
2	Microsoft
3	ISO/RTO Council Standards Review Committee
4	Electricity Customer Alliance, Electricity Consumers Resource Council, and Industrial Energy Consumers of America
5	American Electric Power
6	Alphataraxia Management LP
7	Ameren*
8	ATC*+
9	AZPS*+
10	City of Santa Clara (dba Silicon Valley Power)*+
11	Southwest Power Pool
12	Equinix
13	Dominion Energy*
14	Corscale Data Centers**
15	AIONTRACKS, Inc.
16	Crusoe Technologies LLC
17	DC Energy Management, LP
18	Digital Power Network

19	Electricity Consumers Resource Council
20	Entergy
21	Arkansas Electric Cooperative Corporation
22	Edison Electric Institute, American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, Transmission Access Policy Study Group, and National Association of Regulatory Utility Commissioners (Trade Associations)
23	FirstEnergy*
24	Google**
25	Independent Electricity System Operator
26	Invenergy
27	Midcontinent Independent System Operator
28	Data Center Coalition
29	Bonneville Power Administration
30	Arevon Energy, Inc.
31	New York Power Authority*
32	Oracle**
33	Persistence Analytics Group LLC
34	PJM Interconnection
35	Eversource*+
36	CenterPoint Energy Houston Electric, LLC*
37	Consumers Energy
38	PacifiCorp
39	Southern Company*
40	Solar Energy Industries Association
41	Sacramento Municipal Utility District and Balancing Authority of Northern California*
42	Salt River Project*
43	American Chemistry Council

*supports Trade Associations

**supports Data Center Coalition

+means support and additional comments

Industrial Energy Consumers of America (IECA)
The Voice of the Industrial Energy Consumers

1050 Connecticut Avenue, NW, Suite 500 • Washington, D.C. 20036
Telephone (202) 223-1420 • www.ieca-us.org

May 15, 2026

North American Electric Reliability Corporation
1401 H Street NW, Suite 410
Washington, DC 20005
ROPcomments@nerc.net

Re: Proposed Computational Load Entity Registry

On behalf of the Industrial Energy Consumers of America (IECA), we urge you not to move forward with the proposed Computational Load Entity Registry. Manufacturing self-generation units (CHP/WHP) operate as stable, predictable resources that do not present the reliability risks this proposal is intended to address. There is no evidence to suggest that these units are a threat to the grid.

The proposed rule is intended to address reliability gaps associated with emerging computational loads but does not identify a demonstrated reliability gap for CHP/WHP resources. We are not data centers. We do not operate like data centers and we should not be treated like them under contemplated regulations.

The proposed criteria appropriately focus on large, high-density computational loads comprised of information technology equipment with distinctive and less predictable electrical behavior, which is not characteristic of CHP/WHP facilities driven by thermal and industrial processes. Unlike computational loads, which can fluctuate rapidly, CHP/WHP units are thermal-following and operate with stable, continuous output that supports grid stability. Industrial facilities typically fall within conventional load profiles and may only include de minimis levels of information technology equipment, consistent with NERC's distinction based on differing electrical behavior. The proposed changes unnecessarily increase our costs and economic and regulatory uncertainty.

One hundred percent of IECA's members are manufacturing companies from every industry. Many of these companies have been generating their own power and steam since the late 1970s, using CHP and/or heat to power systems.

According to EIA there are over 900 CHP units across the U.S. that have a rated capacity of about 60,000 MW. They have operated successfully day and night without any negative impacts to grid reliability. Some of them provide valuable balancing benefits to the grid by producing less at night and buying power from the grid when demand by other sectors are low. This predictable behavior supports grid balancing and supports frequency stability through continuous operation that differs fundamentally from the volatility of data center loads.

Importantly, some of these units have a history of being called upon to provide power in times of power shortages, thereby supporting grid reliability.

Existing NERC reliability standards and interconnection requirements, including FAC-001 and FAC-002, already provide appropriate oversight and study requirements for industrial facilities and their interaction with the Bulk Power System. No additional regulatory gap has been identified that would justify expanding registration to CHP/WHP under a new functional entity classification.

We are a resource and we look forward to working with you to help ensure any new registry is appropriately scoped to address emerging, high-variability computational loads while avoiding unintended inclusion of stable, conventional industrial generation.

Sincerely,

Paul N. Cicio
Paul N. Cicio
President & CEO

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.3 trillion in annual sales, over 12,000 facilities nationwide, and with more than 1.9 million employees. One hundred percent of IECA members are manufacturing companies whose competitiveness is largely determined by the cost and reliability of natural gas and electricity. IECA's sole mission is to reduce and avoid energy costs and increase energy reliability through advocacy in Congress and regulatory agencies, such as the Federal Energy Regulatory Commission (FERC). IECA membership represents a diverse set of industries including chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, consumer goods, building products, automotive, independent oil refining, and cement.

ELECTRICITY CUSTOMER ALLIANCE

To: North American Electricity Reliability Council
ROPComments@nerc.com

Re: Comments on Proposed Computational Load Entity Rules of Procedure Revisions

The Electricity Customer Alliance (ECA), on behalf of itself and the undersigned customer groups, is pleased to submit comments on NERC's proposed changes to its Rules of Procedure to create a new functional entity type, called "Computational Load Entity", and define the criteria that will require such entities to register with NERC and comply with current or future mandatory and enforceable Reliability Standards. ECA appreciates the opportunity to submit these comments and the efforts that NERC and its staff have made to engage with customers through the course of its analysis of the impacts of emerging large loads on bulk power system reliability. **For the reasons discussed below, ECA asks that NERC decline to move forward with the proposal at this time and instead conduct further examination of the most cost-effective and efficient means of addressing the reliability risks it has identified with respect to emerging large loads.**

ECA is a growing national coalition dedicated to advancing customer-centric solutions that modernize the grid, support economic growth and the development of digital infrastructure and advanced manufacturing, and keep electricity affordable and reliable for all users. Members and participants in ECA include a diverse range of customers and customer groups, from large customers in the technology, industrial, and manufacturing segments, to smaller commercial customers and residential ratepayer advocates. ECA works to elevate customer perspectives and coalesce and align customer segments to identify and advance common ground approaches to the challenges of load growth, grid expansion and modernization, electricity market governance and accountability, and rising electricity affordability concerns.

Creating the proposed new functional entity type, "Computational Load Entity," would mark a dramatic departure from historic practice by, for the first time, subjecting end use customers to mandatory and enforceable reliability standards. To date, the mandatory and enforceable reliability standards framework has focused on the planning and operational activities of entities that generate, transmit, or deliver electricity to end use customers to ensure that these activities support reliable operation of the bulk power system. This includes, among other things, planning, operational practices, communications, training, and system protection standards that these entities must individually and collectively perform to ensure reliable operations in accordance with the requirements of Section 215 of the Federal Power Act. In short, the existing reliability standards framework is focused on the entities that have operational control of the bulk power system and that regularly engage in coordinated planning and communications protocols to ensure reliable operations.

NERC has not demonstrated why bringing end use customers into this framework for the first time would be the most effective and efficient means of solving the emerging reliability challenges it has identified. NERC's Large Load Working Group (LLWG) has found that emerging large loads (which it proposes to define as "Computational Loads" like data centers or cryptocurrency operations) may pose certain new risks to reliable operations, including operational risks from sudden load drops, ramping characteristics, and inability to ride through disturbances. In addition, the LLWG identified gaps in existing reliability standards and requirements that do not account for the unique characteristics of these emerging loads, such as planning and interconnection obligations and modeling and study requirements. With respect to large load interconnection processes, the LLWG identified the lack of consistent interconnection requirements among current registered entities to ensure the identification of potential impacts to the bulk power system, such as requirements related to voltage/frequency disturbance ride-through, sensitive protection settings, ramping, power quality, and oscillation. The LLTF also noted gaps in the assignment of responsibility among existing registered entities for assessing and mitigating these potential risks.

NERC has not fully explained why an unprecedented expansion of registration requirements to end use customers is the most effective strategy for filling these gaps in requirements and assignments of responsibility. The LLTF's gap assessment's first recommendation notes that "[t]here are multiple high-impact risks to the [bulk power system] from large loads that NERC registered entities cannot adequately address," a statement followed by a stark conclusion that NERC should "pursue registration of a type of entity (or types of entities) that is able to perform specific functions to address the risks."[1] NERC repeats this conclusion in the "Technical Reasoning" document accompanying the proposed revisions to the Rules of Operating Procedure, stating that "[d]ue to the number of existing and anticipated large loads needing power to support computational processes and the unforeseen and difficult-to-explain dynamic electrical behavior of these users of the [bulk power system] as identified by the LLWG, NERC determined that it was appropriate to propose a new functional entity type that focuses on loads with these characteristics."[2]

These broad statements do not answer the fundamental question of why existing NERC registered entities could not adequately address these impacts with changes to the existing reliability standards, or the development of new reliability standards, to fill the information, modeling, study, and operational coordination gaps that have been identified. The two Large Load Task Force (LLTF) white papers that form the basis for the recommendation to create a new functional entity, and the

[1] NERC, "Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads: NERC Large Loads Working Group White Paper" at 53 (March 2026), *available at* https://www.nerc.com/globalassets/our-work/guidelines/reliability/white-paper---assessment-of-gaps.pdf.
[2] NERC, "Technical Reasoning: Proposed Computational Load Entity" at 2 (April 2, 2026), *available at* https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/cle-technical-reasoning-april-2026-posting.pdf.

other available evidence, including the two industry alerts NERC has issued urging existing registered entities to take additional steps to address large load impacts, likewise do not answer this question.

This fundamental question should be answered before taking the unprecedented step of expanding the universe of registered entities beyond those with direct operational control of the bulk power system. Adding end use customers to the NERC registry and the framework of mandatory and enforceable reliability standards would add new complexities to the compliance regime and could create unintended consequences for that regime. For example, end use customers do not have the same operational control over the bulk power system or visibility into operations that existing registered entities possess, nor are they integrated into the communications and protocols that have long existed between these entities. These realities will likely create added complications for end use customers in complying implementing operational controls in real-time when compared to existing registered entities. In addition, integrating an entirely new set of registered entities for the first time could result in new process or analysis gaps or require new modes of communication, requiring additional work that could detract from or stall progress in addressing the emergent reliability concerns identified by the LLWG. Moreover, deflecting a subset of reliability obligations to end use customers instead of the entities with direct bulk power system operational control could fragment and weaken existing accountability structures.

Reforming the existing reliability standards or developing new standards to fill the information, modeling, study, and operational coordination gaps that have been identified would not mean that emerging large loads are free of any responsibility for contributing to the reliable operation of the bulk power system. Load interconnection requirements and communication protocols implemented by registered entities would place appropriate obligations on those large load customers while retaining the focus of the NERC standards framework on those entities who have direct operational control of the bulk power system. The difficulty of defining "Computational Loads" and the fact that customer loads are not a monolith and have different operational profiles and potential grid impacts, both of which NERC has acknowledged, makes it all the more appropriate to focus on interconnection requirements implemented through existing registered entities rather than expanding the registered entities that must be involved.

In addition, before taking such a significant step to expand the universe of registered entities, NERC should solicit the views of the Federal Energy Regulatory Commission (FERC), states, and other key policymakers, and engage them in further examination of the most effective approach to address the identified reliability risks. FERC is ultimately responsible for implementation of the mandatory reliability standards framework envisioned by Congress in Section 215 of the Federal Power Act, including determining the jurisdictional reach of Section 215 to "users, owners and operators of the bulk-power system." NERC's proposed criteria directly implicate jurisdictional questions, particularly its proposal to apply registration requirements based on aggregated load at a single

point of interconnection at a voltage of 60 kV or higher, which is above the 100 kV threshold for determination of bulk power system facilities. FERC guidance on these questions before taking additional steps to extend the NERC compliance framework well beyond where it has been historically, and beginning the process of placing the obligations of that framework on end-use customers, is critical. Moreover, other federal and state policymakers likely have views on the efficacy of such a change and how it could impact consumer costs. Additional process (perhaps convened by FERC) is important to transparently address these issues before moving forward.

Finally, while NERC has identified important reliability considerations of emerging large loads that require immediate attention, it is not clear that expanding the universe of registered entities is necessary on the aggressive schedule NERC is pursuing. We understand that the initial reliability standards developed under the draft Standards Authorization Request issued in April will not apply to the proposed new Computational Load Entities. In addition, the Level 2 and 3 Alerts that NERC has issued in the past several months have identified important steps that existing registered entities should take now to address emergent reliability concerns identified by the LLWG. As a result, there is ample time to engage in additional examination and fact finding before finalizing a decision on registration of Computational Load Entities.

For these reasons, we urge NERC to reconsider adding additional registered entities at this time and instead examine whether reforming existing standards and the responsibilities placed on existing registered entities would be a more effective and efficient approach to address the identified gaps. We look forward to further engaging with NERC and stakeholders on these important reliability issues.

Sincerely,

Electricity Customer Alliance (ECA)
Electricity Consumers Resource Council (ELCON)
Industrial Energy Consumers of America (IECA)

American Electrics Power Comments on Proposed Revisions to NERC Rules of Procedure for Computational Load

American Electric Power (AEP) appreciates the opportunity to comment on the proposed revisions to the North American Electric Reliability Corporation (NERC) Rules of Procedure (ROP) related to Computational Load. AEP supports NERC's objective of protecting the Bulk Power System (BPS) from reliability risks associated with large Computational Loads and understands the need to develop registration criteria for owners and operators of Computational Load.

AEP offers the following comments and recommended modifications to help ensure the proposed changes are clear, consistent with existing NERC registration models, and appropriately focused on Computational Loads that pose a material risk to BPS reliability.

AEP Proposes the Following Modifications:

Appendix 2 (Definitions Used in the Rules of Procedure)

1. **Addition of New Definition Computational Load Facility (CLF)**

   AEP supports the Trade Associations' recommendation to add a new definition Computational Load Facility (CLF):

   > **"Computational Load Facility"** means a collection of electrical equipment located at one or more buildings, structures, or installations that is designed to receive power, has an aggregate connected maximum peak demand of Computational Load greater than or equal to 75 MW, and is served through electric facilities at a voltage level greater than or equal to 100 kV from one or more points of connection.

   A clear definition of a Computational Load *Facility* is essential to the success of Project 2026-02. Existing Standards that address similar types of essential actions being proposed for data centers but are applicable to other comparable equipment (like generators) consistently rely on a *Facility*-type definition. This is consistent with how Generator Owner/Operator and Generating Facility are treated, defined, and included in the registration criteria.

2. **AEP agrees with the Trade Associations' recommendation to replace CL Entity (CLE) with CL Operator (CLOP) and CL Owner (CLO):**

   "Computational Load Owner" means the end-user entity that owns and maintains a Computational Load Facility, **and/or** the entity that owns and maintains a Computational Load Facility that hosts end-users that receive electric power **at a** Computational Load **Facility**.

"Computational Load Operator" means the end-user entity that operates a Computational Load Facility, **and/or** the entity that operates a Computational Load Facility that hosts end-users that receive electric power **at a** Computational Load **Facility**.

AEP recommends the same "Owner" and "Operator" Model for Computational Loads to remain consistent with the registration criteria currently in the NERC Rules of Procedure for Transmission Owner (TO), Transmission Operator (TOP), Generator Owner (GO), and Generator Operator (GOP). This structure is in place because for Transmission and Generation facilities, there are often situations that occur where the owner of the facilities is different from the operator of the facilities. This registration criteria structure allows the different entities to be responsible only for the activities that they are contractually set up for as the owner and/or operator.

3. **AEP supports the Trade Associations' recommendation to clarify the Computational Load (CL) definition:**

   "Computational Load" means Load comprised **primarily** of electric power demand from **power electronic-based** information technology equipment.

Appendix 5A (Organization Registration and Certification Manual)

4. **As discussed in Comment 2 above, AEP agrees with the Trade Associations' recommendation to replace CL Entity (CLE) with CL Operator (CLOP) and CL Owner (CLO) to align with existing NERC Owner/Operator registration frameworks.**

Appendix 5B (Statement of Compliance Registry Criteria)

5. **AEP supports the Trade Associations' recommendation to either (a) increase the proposed Computational Load thresholds or (b) pursue an approach comparable to the Category 1/Category 2 registration structure currently used for Generation.**

   a. <u>Increase Computational Load Threshold</u>

      AEP recommends that NERC increase the proposed thresholds from 20 MW and 60 kV to 75 MW and 100 kV for Computational Load Facilities and eliminate the 1MW Computational Load criterion.

      The proposed thresholds are set unnecessarily low and would result in the registration of a substantial number of facilities that do not pose a material risk to the reliability of the Bulk Power System (BPS) and, thus, do not justify the burden of NERC registration. The current Rules of Procedure, Registration Criteria, and Standard Drafting efforts related to Computational Loads should focus on those loads that pose the most meaningful risk to the BPS.

Accordingly, AEP recommends establishing a threshold of greater than or equal to 75 MW connected at greater than or equal to 100 kV for Computational Load Facilities and elimination the 1MW Computational Load criterion.

b. Category 1/Category 2 Registration Approach

NERC should pursue a Category 1/Category 2 approach for Computational Loads.

If a threshold lower than 75 MW is deemed necessary, AEP recommends that NERC enhance the Technical Reasoning document to reflect the analysis and supporting evidence demonstrating the need for the lower facility threshold for BPS reliability. In addition, AEP recommends that NERC adopt the same registration criteria model that was developed for Inverter-Based Resources (IBRs) with the Category 1 GO/GOP and establish a new Category 1 and Category 2 structure with the proposed definitions:

- **"Computational Load Facility"** means a collection of electrical equipment located at one or more buildings, structures, or installations that is designed to receive power, is served through electric facilities from one or more points of connection **and meets the criteria in either Category 1 or Category 2 Computational Load Owner/Operator registration categories.**
- **"Category 1 CLO/CLOP"** should be aligned with the BES criteria, which would be entities who own/operate Computational Load Facilities (CLFs) that are **greater than or equal to 75 MW** of Computational Load connected at **greater than or equal to 100 kV**.
- **"Category 2 CLO/CLOP"** should be aligned with the lower threshold value supported by NERC and industry, which would be entities who own/operate Computational Load Facilities that are **greater than or equal to 20 MW** of Computational Load connected at **greater than or equal to 60 kV**.

This structure would allow the Electric Reliability Organization enterprise to focus its initial entity registration, Standards Development efforts, and compliance education activities on the highest-risk CLOs/CLOPs first. This framework also establishes a more manageable path to subsequently address lower-risk Category 2 CLOs/CLOPs in future work phases.

NERC Rules of Procedure Team —

AIONTRACKS, Inc. respectfully submits the following comments on the proposed Rules of Procedure changes establishing the Computational Load Entity (CLE) functional entity type and the registration criteria in proposed Appendix 5B.

Comment 1 — The proposed registration criteria are well-calibrated for the threshold class.

The proposed criteria — aggregate connected load capability ≥ 20 MW at a single point of interconnection at ≥ 60 kV, hosting ≥ 1 MW of computational load-appear well-aligned with the BPS-impact threshold for which mandatory Reliability Standards are appropriate. AIONTRACKS supports the proposed thresholds.

Comment 2 — The criteria may benefit from a class of-service descriptor captured at registration.

Computational loads vary substantially in workload composition. A facility hosting predominantly artificial intelligence training workloads has materially different electrical and operational characteristics from facility hosting predominantly inference workloads, or from a mixed-workload facility. The class of service hosted at the facility affects both the demand profile under normal conditions and the response capability during disturbances. NERC may wish to consider whether the registration form should capture a class-of-service descriptor (e.g., training-dominant, inference-dominant, mixed, batch-dominant, or other) to support downstream standard application and audit. Capturing this information at registration imposes minimal burden on the registrant and provides NERC and the Regional Entities with material context for compliance review.

Comment 3 — The criteria should anticipate facilities hosting computational loads on behalf of multiple end-users.

Some computational load facilities operate as multi-tenant infrastructure, hosting computational workloads on behalf of multiple end-user customers under contractual arrangements. The proposed criterion that the CLE must be "the end-user or the entity that hosts end-users that receives electric power" appropriately captures this case, but NERC may wish to clarify in guidance whether the multi-tenant facility operator is the registered CLE or whether each end-user is registered separately. Clarification of this point will reduce registration ambiguity for the operator class likely to host the largest aggregate computational load.

AIONTRACKS appreciates the opportunity to comment and offers to serve as a technical resource to NERC staff in finalizing the registration criteria.

Respectfully,

Praneet Sharma, M.D.
Founder and Chief Executive Officer
AIONTRACKS, Inc.
Phoenix, Arizona

Date: April 30, 2026

North American Electric Reliability Corporation
3353 Peachtree Road NE, Suite 600N
Atlanta, Georgia 30326

Re: Comments of Alphataraxia on Proposed Revisions to NERC Rules of Procedure Appendices 2, 5A, and 5B (Computational Load Entity Registry Criteria)

Dear NERC Staff:

Alphataraxia Management LP ("**ATX**") submits these comments on NERC's April 1, 2026 posting of proposed revisions establishing a "Computational Load Entity" ("**CLE**") functional entity type. ATX is engaged in energy trading in domestic ISO/RTO markets and, as a wholesale market participant, has a direct interest in the accuracy of load data and planning models that underpin locational marginal prices, congestion revenue rights, and reserve margin determinations. Accurate classification and registration of computational loads is not merely a technical compliance matter—as large-scale data center and AI infrastructure loads increasingly stress transmission systems and distort reserve margin calculations, failures to properly account for their magnitude and consumption profiles risk cascading reliability events that ultimately harm end-use consumers through price volatility, inadequate capacity procurement, and, in the most severe cases, supply shortfalls. ATX supports the CLE initiative and submits these comments to urge NERC to require, as a registration condition, transparency about load qualification criteria and disclosure of historical consumption data.

I. Background

In September 2025, NERC issued its Level 2 Industry Recommendation on Large Load Interconnection, Study, Commissioning, and Operations. The Level 2 Alert responded to a series of grid disturbances in which more than 1,000 MW of large-load output was unexpectedly reduced across multiple events in 2024 and 2025. NERC's Aggregated Report on the Level 2 Alert responses (the "**Aggregated Report**") identified a central, recurring deficiency: load data 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." The LLWG's March 2026 white paper confirmed that existing Reliability Standards and industry processes are inadequate for reliable large load integration. The proposed registry criteria represent the correct structural location to address this deficiency—before downstream standards development locks out a data-first approach.

II. Historical Consumption Data Must Be a Registration Condition

NERC has recognized that computational loads can exhibit electrical behavior that is "distinctive and often less predictable than conventional loads." The Aggregated Report confirmed that forward-looking projections submitted at interconnection bore little resemblance to actual operational profiles. AI training and high-

performance compute workloads have been specifically identified as among the load types most likely to introduce forced oscillations into the grid.

ATX recommends that the criteria require CLEs, as a condition of initial registration, to commit to submitting metered consumption data at hourly intervals, including observed peak demand, minimum demand, and average load factor. For newly commissioned facilities, the most complete available observed data plus a validated dynamic load model should be required, as well as a commitment to post metered consumption data to a nationwide database that is publicly available. Public posting of such data has huge value. There is already a nationwide database for generators posted by the US Energy Information Administration (available at https://www.eia.gov/electricity/data.php), which has supported significant analysis and research; a similar database for CLEs would add immense value to research into reliability and optimization.

III. Load Modeling and Market Integrity Require Actual Consumption Data

Level 2 Alert Recommendation 5 directed Transmission Planners, Resource Planners, and Planning Coordinators to incorporate large loads into near-term and long-term demand forecasts, accounting for intra-minute variability, cyclical ramping, and aggregate load disconnections during contingencies. That recommendation presupposes access to actual consumption data. Without it, the planning models that underpin wholesale market prices in PJM, MISO, SPP, and ERCOT will continue to degrade in accuracy as CLE penetration grows.

When load models do not reflect actual CLE consumption profiles, the resulting distortions affect locational marginal prices, create unanticipated transmission congestion, and affect the financial settlement of FTRs and virtual transactions. ATX accordingly recommends that the criteria explicitly require CLEs to provide historical consumption data to a nationwide database.

IV. Transparent Qualification Criteria Are Necessary to Prevent Registration Arbitrage

Opaque CLE qualification criteria create incentives for registration arbitrage. Entities with borderline facilities, like data centers co-located with conventional operations, multi-metering-point campuses, or facilities with significant on-site backup generation, have incentives to structure their operations to minimize reported interconnection load and avoid registration, reducing compliance costs while continuing to affect grid conditions. NERC should publish detailed guidance on how the 20 MW aggregate connected load threshold is measured across shared substations, co-located generation, and mixed-use facilities, and how “single point of interconnection” is applied to campus configurations. Consistent, data-grounded application across all Regional Entities is essential to preventing regulatory gaps and preserving the competitive integrity of wholesale markets.

As data centers are projected to be more than 10% of total U.S. electricity consumption by 2028, the aggregate market impact of unmodeled or under-modeled CLE consumption will be substantial. Wholesale market participants that hold financial transmission rights and manage load-serving obligations in CLE-concentrated load zones are entitled to rely on planning models that reflect actual CLE consumption behavior.

V. Conclusion

ATX urges NERC to strengthen the proposed CLE registry criteria by incorporating the idea of a nationwide database of CLEs. In particular, (i) requiring submission of consumption data at hourly intervals; (ii) defining load qualification criteria with sufficient specificity to enable consistent Regional Entity application and prevent registration arbitrage; and (iii) explicitly requiring that historical consumption data flow be provided so that it can be posted publicly (ideally, in a national database) so as to allow Transmission Planners, Planning Coordinators, Balancing Authorities, and RTOs/ISOs to incorporate into planning models. These measures are necessary to give practical effect to the Aggregated Report's findings, to enable existing registered entities to fulfill their planning standards obligations, and to preserve the competitive integrity of the wholesale markets NERC's reliability framework supports.

Respectfully submitted,

Brian Kozlowski
General Counsel
Alphataraxia Management LP

Ameren comments on the NERC Proposed Computational Load Entity ROP Revisions

Ameren agrees with EEI's comments on the revisions.

May 15, 2026

North American Electric Reliability Corporation
Rules of Procedure Comments

Via Electronic Submission: ROPcomments@nerc.net

Re: Comments on Proposed Revisions to NERC Rules of Procedure — Computational Load Entity (Appendices 2, 5A, and 5B)

I. Introduction

Arevon Energy, Inc. (Arevon) appreciates the opportunity to submit comments on the proposed revisions to the North American Electric Reliability Corporation ("NERC") Rules of Procedure ("RoP") establishing a new Computational Load Entity ("CLE") functional category and associated registration criteria in Appendices 2, 5A, and 5B. These comments are submitted in response to NERC's April 1, 2026 posting and the 45-day public comment period closing May 15, 2026.

Arevon recognizes that emerging large computational loads — including data centers, AI compute clusters, and cryptocurrency mining facilities — present genuine reliability challenges that require proactive action. While NERC's Large Loads Action Plan objectives are valid, we urge NERC to refine the proposed RoP revisions to ensure that (1) definitions are precise and risk-calibrated, (2) registration thresholds capture only those entities whose behavior drives the identified reliability risks, (3) the obligations that follow registration are proportionate and appropriately assigned, and (4) the implementation timeline is realistic for entities that are entirely new to NERC's compliance framework.

The comments included in this document are organized into four sections: Appendix 2 (Definitions), Appendix 5A (Registration Process), Appendix 5B (Registry Criteria), and Cross-Cutting Process and Implementation Considerations.

II. Appendix 2 — Definitions Used in the Rules of Procedure

A. The Proposed "Computational Load" Definition Requires Greater Precision

As proposed, "Computational Load means Load comprised of electric power demand from information technology equipment, such as servers, storage, and networking hardware." While we agree with NERC staff that a term other than "Large Load" is appropriate — since "Large Load" can connote many different types of loads on the Bulk Power System ("BPS"), such as large process facilities, education and medical campuses, pharmaceutical loads, and manufacturing loads — the proposed definition introduces several ambiguities that should be resolved before adoption.

1. The phrase "such as" is non-inclusive and open-ended. It creates uncertainty about what equipment falls within scope. Virtually all BPS-connected facilities may contain some information technology equipment (PLCs, RTUs, SCADA systems, routers, personal computers). Without a clear, inclusive list or a quantitative threshold tied to the proportion of IT-related demand, the definition risks capturing facilities that were never the intended subject of NERC's Large Load Action Plan. NERC should replace "such as" with "including, but not limited to" or provide a closed-form definition anchored to the types of facilities actually driving reliability risk (data centers, AI compute clusters, cryptocurrency mining).

2. "Storage" should be amended to "data storage." As drafted, "storage" is ambiguous and could be interpreted to include Battery Energy Storage Systems ("BESS"), which are separately governed under existing NERC registration criteria for inverter-based resources. The intent is clearly to reference Network Attached Storage ("NAS"), Hard Disk Drives ("HDDs"), and Solid-State Drives ("SSDs"). This clarification is essential to avoid unintended overlap with generation-side registration criteria.

3. The term "Computational" may be too narrow. Some referenced equipment — particularly networking hardware — has minimal computational capability compared to CPUs and GPUs. As power electronic equipment (e.g., solid-state transformers) is deployed at customer sites, the definition may become even more misaligned with the actual risk drivers. NERC should consider a broader term such as "Electronic Load," consistent with ERCOT's adoption of "Large Electronic Load" in NPRR 1308, which extends beyond purely computational activities and better captures the full spectrum of loads driving the identified reliability risks.

B. The Definition Excludes Non-IT Large Loads with Identical Reliability Risks

The proposed definition captures only loads from information technology equipment. Yet NERC's own Large Loads Working Group ("LLWG") reports identify hydrogen electrolyzers, industrial heat pumps, advanced manufacturing facilities, and other energy-intensive loads as posing identical reliability risks — rapid demand changes, voltage sensitivity, and forecasting difficulty.

By limiting the definition to "information technology equipment," NERC would need to repeat the entire RoP revision process when these load types reach scale — delaying the reliability protections that the Large Loads Action Plan was designed to deliver. NERC should either broaden the definition now to encompass all large loads exhibiting the identified risk behaviors, or explain in its technical reasoning why the identified reliability risks are unique to computational equipment and do not apply to other emerging large loads.

C. The "Computational Load Entity" Definition Has Structural Ambiguities

As proposed, "Computational Load Entity means the end-user or the entity that hosts end-users that receives electric power for Computational Load." This definition raises several structural concerns:

1. Owner/Operator Distinction. NERC's existing registration framework distinguishes between owners and operators (e.g., GO/GOP, TO/TOP). Many computational load facilities will have separate ownership and operating structures — particularly in the colocation and multi-tenant data center market. The proposed single "Computational Load Entity" functional type does not accommodate this reality and should adopt a parallel Owner/Operator structure (e.g., CLO/CLOP) to properly assign differentiated reliability responsibilities.

2. Ambiguity in "end-user or the entity that hosts end-users." Where both an end-user and a hosting entity exist at a single facility, the definition does not clarify which party bears registration obligations — or whether both must register. This is a critical gap given the prevalence of colocation and multi-tenant data center arrangements.

3. Potential Third-Party Registration Obligations. The use of "end-user" could introduce lessee or tenant entities as separately registrable parties, creating a three-tier registration structure (owner, operator, tenant) that is unprecedented in NERC's framework and operationally unworkable without further guidance. NERC should clarify whether registration follows facility ownership, operational control, or electrical metering boundaries. For example, if Company A and Company B lease a warehouse owned by Company C that hosts the equipment creating the demand for electricity (load), who should register? Company A, B, or C or all of them? There could be several permutations and combinations of such scenarios.

D. The "Users of the BPS" Legal Authority Does Not Compel Registration of All Load Customers

NERC's Technical Reasoning grounds the proposed CLE registration in the Federal Power Act's grant of authority over "users, owners, and operators of the Bulk Power System." 16 U.S.C. § 824o, Section 215(b); 18 C.F.R. § 39.2(c) (2026). However, the existence of jurisdictional authority does not, by itself, determine where the registration threshold should be set. NERC acknowledges this materiality principle by proposing thresholds rather than blanket registration of all BPS-connected loads. The critical question, therefore, is not whether NERC has authority to register computational load entities — it does — but whether the proposed thresholds are appropriately calibrated to capture entities whose behavior materially impacts BPS reliability. As discussed in Section IV below, the proposed 1 MW Computational Load threshold is set so low that it captures entities whose electrical behavior does not implicate the reliability risks identified in NERC's own technical analysis.

III. Appendix 5A — Organization Registration and Certification Manual

A. The Registration Process Requires a Reasonable Transition and Implementation Timeline

The addition of "Computational Load Entity (CLE)" as a registrable entity type represents a historic first. The registration process should include a reasonable implementation period and clear guidance on the registration workflow, particularly for entities that have no institutional familiarity with NERC's compliance obligations, audit expectations, or the ERO Enterprise framework. It is recommended that a clear communication be developed for outreach to entities that would potentially fall under this registration type, as well as the ecosystem supporting those entities.

B. Registration Must Be Coordinated with Project 2026-02 Standards Development

Registration should not outpace the development of applicable Reliability Standards. Registering CLEs before the standards they must comply with are finalized creates a compliance gap — entities would be on the NERC Compliance Registry with no clear obligations, or worse, subject to enforcement actions for standards still under development. NERC's Standards Committee accepted the Project 2026-02 SAR on March 18, 2026, and a Standards Drafting Team has been appointed. The current project timeline targets Board adoption in December 2026. Accordingly, the effective date for CLE registration should be no earlier than the effective date of the first mandatory Reliability Standard applicable to CLEs.

C. A Clear De-Registration Process Is Needed

The proposed criteria define when an entity must register but are silent on what happens when an entity falls below the threshold — e.g., a facility reduces IT load below 1 MW, or aggregate load drops below 20 MW due to decommissioning or facility reconfiguration.

Appendix 5A should include a clear de-registration process for CLEs that no longer meet the threshold criteria. The current RoP provisions for de-registration of other functional entities (e.g., GOs, TOPs) may not translate directly to CLEs, given the dynamic nature of computational load facilities. NERC should specify the evidentiary requirements, timeline, and Regional Entity review process for CLE de-registration to avoid indefinite registration of entities that no longer pose the identified reliability risks.

IV. Appendix 5B — Statement of Compliance Registry Criteria

A. Registration Thresholds Are Misaligned with Actual Reliability Risk

As proposed, the three-part threshold requires: (1) aggregate connected Load capability ≥ 20 MW; (2) at a single point of interconnection to the BPS at ≥ 60 kV; and (3) hosting ≥ 1 MW of Computational Load. This threshold captures facilities that do not present the reliability risks identified in NERC's own technical analysis. It also appears that these numbers have simply been adopted from the IBR registration initiative (aggregation and interconnection thresholds), rather than based on any solid engineering or technical analysis demonstrating risk to the BPS.

The 1 MW Computational Load threshold is disproportionately low. At 20 MW aggregate load, 1 MW of Computational Load represents just 5% of total facility demand. A 75 MW industrial facility with 1 MW of IT equipment for servers, PLCs, RTUs, routers, and personal computers would be required to register despite presenting none of the rapid load-swing, voltage stability, or protection coordination risks documented in the LLWG white papers and the Level 3 Alert. Additionally, current Registered Entities that may have 1 MW of computational load may also fall under this category – does that mean they would have to register as a CLE as well and have the additional administrative burden and cost of complying with standards that may be applicable to a CLE?

ERCOT's approach may better reflects risk. ERCOT's proposed NPRR 1308 definition requires that 50% or greater of site demand consist of power-electronic-based computational load, with a minimum aggregate peak demand of 75 MW. NERC's criteria, intended to establish the minimum acceptable continent-wide requirements, may conflict with ISO/RTO- has determined appropriate for its footprint.

Recommendation. NERC should consider surveying different markets or transmission organizations that are interconnecting such large loads to determine what the right threshold (e.g., Computational Load percentage of 25–50% of aggregate demand) for registration is to ensure only facilities whose electrical behavior genuinely poses BPS reliability risks — namely, those with high concentrations of power-electronic-based load capable of rapid, large-magnitude demand changes are registered. This approach would align with the LLWG's findings and permit transmission organizations to adopt more stringent criteria as appropriate for their systems.

The aggregate impact doctrine requires careful calibration for load entities. NERC's Technical Reasoning invokes the aggregate impact doctrine, citing 150 FERC ¶ 61,213 at P 58 (2015), which provides that "Registry Criteria provide that a class of entities, each of which would be individually excluded, may nevertheless be registered based on their aggregate impact on Bulk-Power System reliability." However, the aggregate impact doctrine was originally developed in the context of generation resources and was subsequently applied to inverter-based resources (IBRs) under the Category 2 GO/GOP registration initiative. Applying this doctrine to load entities requires careful calibration. The aggregate impact of a class of computational load entities may not justify registering individual entities within that class whose

own characteristics do not pose the identified reliability risks. A 20 MW mixed-use industrial facility with 1 MW of IT/computational load equipment may not exhibit the power electronic load ("PEL") behavior that NERC identifies as the risk driver — regardless of how many such facilities exist in aggregate.

The 1 MW threshold does not effectively serve as a de minimis filter. NERC's Technical Reasoning states that "the intent behind the '1 MW or greater' of Computational Load threshold is to distinguish that those entities, such as industrial manufacturers, with a 'de minimus' amount of Computational Load do not meet the criteria for registration as a Computational Load Entity." Howe4ver, 1 MW does not effectively serve this de minimis filtering function. Modern industrial facilities routinely may contain well over 1 MW of information technology equipment — including server rooms, SCADA systems, industrial automation platforms, edge computing infrastructure, and enterprise networking. A large petrochemical complex, steel mill, or semiconductor fabrication facility with 1–5 MW of IT equipment would be captured by the proposed criteria despite presenting none of the rapid load-swing or voltage sensitivity risks associated with data centers. A percentage-based threshold (e.g., 25–50% of aggregate demand consisting of Computational Load) would more effectively distinguish facilities whose primary function is computational from facilities that simply use computing equipment ancillary to their primary industrial process.

The registration criteria should align with NERC's own technical risk analysis. Notably, NERC's Technical Reasoning identifies power electronic load ("PEL") behavior as the actual technical risk driver, citing the LLWG's finding that "many new large loads are [power electronic loads] (PELs) that use software controls to manage the load behavior rather than the mechanical controls used by older motor loads" and that "PEL control systems enable loads to rapidly change electricity consumption, creating previously unseen load behavior that can cause BPS planning and operational challenges." Yet the proposed definition and registration thresholds are equipment-type-based, not behavior-based. NERC should align its registration criteria with its own technical reasoning by incorporating behavioral characteristics — such as the proportion of PEL-based load, rate-of-change capability, or voltage sensitivity — rather than simply counting megawatts of "information technology equipment." This approach would more precisely target the entities whose behavior drives the identified reliability risks.

B. A Tiered Registration Approach Should Reflect Non-Linear Risk Scaling

The LLWG's own analysis concluded that "the potential impact of several 100 MW loads may be less than the impact of a 500 MW load and may require different treatment" and that "the emergence of gigawatt-scale loads may create exponential complications for study, planning and operations." Yet the proposed criteria apply a single binary threshold — register or don't.

The registry criteria should support a tiered or graduated approach to compliance obligations, consistent with the LLWG's finding that risk scales non-linearly with load size. A 25 MW data center and a 500 MW hyperscale campus present fundamentally different risk profiles, yet the proposed criteria would subject both to the same registration status. Consider distinguishing between load sizes (e.g., 20–100 MW, 100–300 MW, >300 MW) to enable proportional obligations in the standards that follow.

C. NERC Should Explicitly Preserve Regional Flexibility — Floor vs. Ceiling

Multiple ISOs/RTOs are developing their own large load frameworks with materially different thresholds. The following table illustrates the divergence:

ISO/RTO	Threshold	Key Feature	Activity Level
ERCOT (NPRR 1308)	≥ 75 MW; ≥ 50% power-electronic load	Higher bar, behavior-based	High
SPP (HILL)	≥ 10 MW at ≤ 69 kV; ≥ 50 MW at > 69 kV	Voltage-tiered	High
PJM	Co-location order; CIFP underway	Service-type based	High
NERC (Proposed)	≥ 20 MW aggregate; ≥ 1 MW CL at ≥ 60 kV	Lowest threshold	—

NERC's proposed criteria establish a continent-wide floor, but they should explicitly state that Regional Entities and ISOs/RTOs retain the ability to adopt more stringent thresholds and additional criteria appropriate to their system conditions — consistent with NERC's traditional approach to registration. Without this clarification, the proposed criteria could be misinterpreted as preempting more tailored regional approaches like ERCOT's NPRR 1308 or SPP's HILL framework.

D. "Single Point of Interconnection" Requires Clarification for Co-Located Facilities

The criterion requiring connection "at a single point of interconnection to the Bulk Power System at a voltage greater than or equal to 60 kV" does not address facilities with multiple POIs, shared substations, or co-located generation. NERC should clarify:

- Whether aggregation occurs across multiple POIs at the same physical site;
- How co-located generation (solar, BESS) and computational load at a shared POI are treated for purposes of the 20 MW aggregate calculation;
- Whether behind-the-meter generation offsets are considered — i.e., whether a 30 MW data center with 15 MW of on-site solar has an "aggregate connected Load capability" of 30 MW or 15 MW; and
- How phased construction or modular expansion of computational load facilities affects the timing of registration obligations.

E. Registration Thresholds Should Align with the Level 3 Essential Action Alert

On May 4, 2026, NERC issued a Level 3 Essential Action Alert identifying seven essential actions that registered entities must take to address immediate risks posed by computational loads interfacing with the BPS:

1. Develop modeling requirements for computational loads;
2. Complete system studies and planning improvements;
3. Update definition of "qualified change";
4. Establish a commissioning process for computational loads;
5. Implement protection and coordination enhancements;
6. Install dynamic fault recording devices; and
7. Create Interpersonal Communication capabilities.

These seven essential actions provide the clearest preview yet of the obligations CLEs will face. NERC should explain how the proposed registration thresholds were calibrated to capture the entities whose behavior drives the need for these essential actions. If the thresholds capture entities whose facilities do not implicate these actions (e.g., a 20 MW mixed-use industrial facility with 1 MW of IT equipment), the criteria are overbroad and should be revised.

Notably, the two specific incidents that underpin NERC's urgency — the January 2025 Eastern Interconnection large load loss event and the January 2026 Texas Interconnection voltage-sensitive crypto load reductions — both involved facilities with high concentrations of computational load, not mixed-use facilities with incidental IT equipment. This further supports a higher percentage threshold that targets the facilities whose electrical behavior actually caused these events.

V. Cross-Cutting Process and Implementation Considerations

A. Protect Against Unintended Scope Creep to Generator Owners and Operators

Any new registration criteria and the reliability standards that follow must clearly delineate which risks are attributable to computational load behavior versus generation performance. Risks driven by computational load characteristics — volatility, forecasting uncertainty, rapid load changes, and protection coordination challenges — should be addressed through CLE-specific obligations, not through expanded requirements on Generator Owners or Generator Operators who do not control load behavior.

Furthermore, any new or revised Reliability Standards developed as a result of these RoP revisions should be applied prospectively and aligned with approved interconnection agreements, study

assumptions, and existing facility designs. Retroactive application would introduce compliance risk without corresponding reliability benefit, particularly for co-located generation and storage facilities.

B. Jurisdictional Coordination with FERC's ANOPR (Docket RM26-4-000)

NERC's proposed CLE registration criteria are advancing in parallel with FERC's Advanced Notice of Proposed Rulemaking ("ANOPR") under Docket RM26-4-000, initiated pursuant to DOE Secretary Wright's rare invocation of Section 403 authority. The ANOPR will establish its own federal large load interconnection framework, including standardized study procedures, cost allocation, and protection system requirements for loads greater than 20 MW connecting to transmission.

NERC should explain how CLE registration will coordinate with — and avoid conflicting with — FERC's emerging interconnection requirements. The ANOPR's > 20 MW threshold matches NERC's proposed aggregate load threshold, but FERC's scope extends to all large loads, not just computational loads. Entities may face overlapping, inconsistent, or duplicative obligations unless NERC and FERC explicitly coordinate these parallel proceedings. At minimum, NERC's filing with FERC for approval of the RoP revisions should address how the two frameworks will interact. Notably, NERC itself filed comments in Docket RM26-4-000 on November 21, 2025, acknowledging the need for coordination between NERC's reliability framework and FERC's interconnection requirements for large loads. The proposed RoP revisions should be consistent with the positions NERC articulated in those comments.

C. Data Confidentiality Protections for CLE Operational Data

Many CLEs — particularly hyperscale data centers — consider their power consumption, load profiles, demand forecasts, and facility configurations to be commercially sensitive and competitively valuable. The proposed RoP revisions do not address how CLE operational data will be protected under NERC's existing confidentiality framework.

The revisions should clarify how data submitted by CLEs will be treated under NERC's confidentiality classifications (Public, Limited Disclosure, Confidential, Restricted-Confidential). Without clear data protection commitments, entities may resist registration or provide incomplete data, undermining the reliability objectives of the Large Loads Action Plan. NERC should develop CLE-specific data handling protocols in coordination with the Regional Entities before the registration process begins.

D. NERC Should Publish a Clear Implementation Roadmap

The Level 3 Essential Action Alert (May 4, 2026), the Voluntary Reliability Guideline, the RoP registration criteria (comment period closing May 15, 2026), and the Phase 1 bridge standard from Project 2026-02 are all advancing in parallel on aggressive timelines. NERC should publish a clear implementation roadmap that sequences registration, standard development, and enforcement expectations to avoid confusion and premature compliance exposure.

Additionally, NERC and the Regional Entities should develop targeted onboarding materials, compliance workshops, and a reasonable ramp-up period before enforcement actions are pursued against newly

registered CLEs. These entities are, by definition, new to NERC's compliance framework and will require structured guidance to achieve meaningful compliance.

VI. Conclusion

The Large Loads Action Plan represents an important and timely initiative. However, the proposed RoP revisions require refinement in several critical areas to ensure that the new CLE registration framework achieves its intended reliability objectives without creating unintended consequences.

In summary, the comments are organized around four key themes:

1. **Definitional Precision:** The "Computational Load" and "Computational Load Entity" definitions require greater specificity to avoid overbroad application, resolve ambiguities regarding ownership/operating structures, and close gaps for non-IT large loads with identical reliability risk profiles.
2. **Risk-Calibrated Thresholds:** The Appendix 5B registration criteria should be revised to increase the Computational Load percentage threshold, adopt a tiered approach reflecting the LLWG's finding that risk scales non-linearly with load size, incorporate behavioral characteristics consistent with NERC's own PEL-based technical reasoning, and explicitly preserve regional flexibility for ISOs/RTOs to adopt more stringent criteria.
3. **Implementation Sequencing:** CLE registration should not outpace standards development or enforcement readiness. NERC should coordinate registration timing with Project 2026-02, FERC's ANOPR under Docket RM26-4-000, and the Level 3 Alert essential actions to avoid overlapping or conflicting obligations.
4. **Scope Protection:** Risks attributable to computational load behavior should be addressed through CLE-specific obligations — not through expanded requirements on Generator Owners or Generator Operators who do not control load behavior.

Comments on
Proposed Revisions to NERC ROP: Computational Loads

NERC

Notice of Proposed Revisions to the NERC Rules of Procedure and Request for Comments – Computational Load Entity
NERC Rules of Procedure Appendix 2 (Definitions Used in the Rules of Procedure); Appendix 5A (Organization Registration and Certification Manual); and Appendix 5B (Statement of Compliance Registry Criteria)

Proposed Changes to Rules of Procedure
Appendix 2 Clean | **Redline**
Appendix 5A Clean | **Redline**
Appendix 5B Clean | **Redline**
Summary of Changes

Proposed Revisions to Rules of Procedure – NERC is proposing revisions to its Rules of Procedure to develop a new registered entity type, called Computational Load Entity. NERC is posting the proposed revisions to NERC Rules of Procedure Appendix 2, Appendix 5A, and Appendix 5B for public comment for 45 days from **April 1, 2026** to **May 15, 2026**. Comments must be submitted electronically to ROPcomments@nerc.net.

The proposed revisions address recommendations from the NERC Large Loads Working Group (a subgroup of the NERC Reliability and Security Technical Committee) whitepaper "***Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads***" and are further supported by the findings in the "***NERC Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations***" analyzing responses to a Level 2 Alert on the interconnection of large loads. The recommendations and findings indicate a need for a new registered entity to comply with Reliability Standards (currently under development in Project 2026-02 – Computational Loads) to reduce risks to the reliability of the Bulk Power System.

In pursuing its mission to assure the effective and efficient reduction of risks to the reliability and security of the grid, NERC works with owners, operators, users, and consumers as well as federal, state, and provincial regulators across North America. To that end, NERC welcomes input from all stakeholders on the proposed revisions and values the opportunity to engage with stakeholders on how the proposed revisions can contribute to the reliability of the Bulk Power System.

For more information or assistance, please contact **Marisa Hecht** via email or at **404-446-9620**.

RELIABILITY | RESILIENCE | SECURITY **www.nerc.com**

POWERING TODAY. PROTECTING TOMORROW.

Comments on
Proposed Revisions to NERC ROP: Computational Loads

ATC generally supports the comments presented by the Trade Associations (APPA, EEI, LPPC, NRECA, TAPS, and NARUC) including the Section 1 'Overarching Principles'; maintaining consistency with other NERC Registration Categories; defining Computational Load to avoid inadvertent inclusion of previously stable large loads like industrial and commercial processes; and Section 4 'Comments on NERC's Proposed Revisions'.

Additional comments are provided below.

ATC Proposed Modifications

1. **Add a new definition Computational Load Facility (CLF):**

   "Computational Load Facility" means a collection of electrical equipment located at one or more buildings, structures, or installations that is designed to receive power, has an aggregate connected maximum peak demand greater than or equal to 20 MVA, hosts 50% or greater of the peak demand load as Computational Load, and is served through electric facilities at a voltage level greater than or equal to 60 kV from one or more points of connection.

   A clear definition of a Computational Load Facility is essential for Project 2026-02 success. Existing standards that currently address the same types of essential actions being proposed for data centers but are applicable to other comparable equipment (like generators) consistently rely on a Facility-type definition. This is consistent with how Generator Owner/Operator and Generating Facility are treated, defined, and included in the registration criteria.

   *Data center sites can have a significant number of physical and electrical configurations. For example, many data center sites can consist of one or more buildings, with each building having one or more connections to the Bulk Power System at the same location. In some cases, data center owners may consider that each building is an individual data center, while in other cases the collection of buildings connected to the grid is viewed as the data center. The risk to the BES comes from the aggregate load behavior of facilities at a single site. This was emphasized in NERC's "Characteristics and Risks of Emerging Large Loads" whitepaper that, while specific load types and thresholds to define Large Loads could not be defined across industry at that time, all agreed that any such definition should include "aggregation of load facilities **at a single site** behind one or more point(s) of interconnection that can pose reliability risks to the BPS."*

2. **Replace CL Entity (CLE) with CL Operator (CLOP) and CL Owner (CLO)**

   "Computational Load Operator": means the end-user entity that operates a Computational Load Facility, **and/or** the entity that operates a Computational Load Facility that hosts end-users that receives electric power **at a** Computational Load **Facility**.

"Computational Load Owner": means the end-user entity that owns and maintains a Computational Load Facility, **and/or** the entity that owns and maintains a Computational Load Facility that hosts end-users that receives electric power **at a** Computational Load **Facility**.

The risk to the BPS and the gaps in NERC reliability standards, as noted in NERC's "Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads" is driven by Computational Load impacts and behavior, not other type of load, and Computational Load Entity should focus only on the amount of data-centric/information technology type of load.

3. **Clarify the Computational Load (CL) definition:**

"Computational Load" means Load comprised **primarily** of electric power demand from **power electronic-based** information technology equipment.

4. **Modify Computational Load criteria thresholds in Appendix 5B**

ATC is concerned that NERC's Appendix 5B definition and criteria for Computational Load Entity is too broad and could unintendedly include larger loads that do not pose the same reliability risks as data centers. These existing non-data center facilities are not the target of these to address the most critical reliability issues associated with integrating these large loads onto the BPS in the near-term. It is inefficient to require all facilities 20 MW and greater with 1 MW of computation load to register, and difficult to then depend on the standard to further delineate between hospitals and data centers for requirements in new or existing standards.

Therefore, ATC proposes that the criteria and definition for Computational Load Entity be modified to "1) contributes to an aggregate connected maximum peak demand greater than or equal to 20 MVA; 2) hosts 50% or greater of the peak demand load as Computational Load; and 3) is served through electric facilities at a voltage level greater than or equal to 60 kV from one or more points of connection"

ATC also recommends that NERC considers requiring each applicable Transmission Operator and Transmission Owner to perform an entity specific study to determine the MW threshold at which a computational load presents reliability risk within its system.

ATC would consider supporting the Category 1/Category 2 designations proposed by the Trade Associations as long as both categories are subject to the same requirements and both categories are implemented without delay between them.

AZPS Comments on Proposed Revisions to NERC ROP: Computational Load Entity

May 8, 2026



Notice of Proposed Revisions to the NERC Rules of Procedure and Request for Comments – Computational Load Entity
NERC Rules of Procedure Appendix 2 (Definitions Used in the Rules of Procedure); Appendix 5A (Organization Registration and Certification Manual); and Appendix 5B (Statement of Compliance Registry Criteria)

Proposed Changes to Rules of Procedure
Appendix 2 Clean | **Redline**
Appendix 5A Clean | **Redline**
Appendix 5B Clean | **Redline**
Summary of Changes

Proposed Revisions to Rules of Procedure – NERC is proposing revisions to its Rules of Procedure to develop a new registered entity type, called Computational Load Entity. NERC is posting the proposed revisions to NERC Rules of Procedure Appendix 2, Appendix 5A, and Appendix 5B for public comment for 45 days from **April 1, 2026** to **May 15, 2026**. Comments must be submitted electronically to ROPcomments@nerc.net.

The proposed revisions address recommendations from the NERC Large Loads Working Group (a subgroup of the NERC Reliability and Security Technical Committee) whitepaper "***Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads***" and are further supported by the findings in the "***NERC Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations***" analyzing responses to a Level 2 Alert on the interconnection of large loads. The recommendations and findings indicate a need for a new registered entity to comply with Reliability Standards (currently under development in Project 2026-02 – Computational Loads) to reduce risks to the reliability of the Bulk Power System.

In pursuing its mission to assure the effective and efficient reduction of risks to the reliability and security of the grid, NERC works with owners, operators, users, and consumers as well as federal, state, and provincial regulators across North America. To that end, NERC welcomes input from all stakeholders on the proposed revisions and values the opportunity to engage with stakeholders on how the proposed revisions can contribute to the reliability of the Bulk Power System.

For more information or assistance, please contact **Marisa Hecht** via email or at **404-446-9620**.

RELIABILITY | RESILIENCE | SECURITY **www.nerc.com**

POWERING TODAY. PROTECTING TOMORROW.

AZPS Comments on Proposed Revisions to NERC ROP: Computational Load Entity

May 8, 2026

AZPS appreciates the opportunity to provide comments on the draft proposed revisions to the NERC Rules of Procedure: Computational Loads. AZPS respectfully requests additional clarification to ensure the computational load definition and registration criteria appropriately include all applicable entities, including owners, operators of large loads, and host-end users.

AZPS supports EEI's comments with the following exceptions and proposed modifications:

- AZPS agrees with EEI that a Computational Load Facility definition is needed and supports EEI's proposal with the caveat that AZPS believes the voltage should be 60kV.
    - **"Computational Load Facility"** means a collection of electrical equipment located at one or more buildings, structures, or installations that is designed to receive power, has an aggregate connected maximum peak demand of Computational Load greater than or equal to 75 MW, and is served through electric facilities at a voltage level greater than or equal to **60 kV** from one or more points of connection.

- AZPS agrees with EEI that a Computational Load Owner and Computational Load Operator definition is needed to clearly define ownership and responsibilities.

- AZPS is of the position that clarity is needed in the registry criteria language to ensure that Large Load entities that are embedded in small distribution entities such as a cooperative, municipal or other retail service utilities that serve Computational Load Entities should be applicable to registration criteria and not be excluded from Reliability requirements. All entities (including small distribution entities such as cooperatives, municipalities or other retail service utilities) with computational loads should be required to meet the established thresholds.

- AZPS is of the opinion that the proposed Statement of Compliance Registry Criteria for Computational Load Entity for hosts be increased from 1MW to 20MW or greater of Computational. AZPS submits the following proposed modification: A Computational Load Entity that 1) contributes to an aggregate connected Load capability greater than or equal to 20 MW; 2) at a single point of interconnection to the Bulk Power System at a voltage greater than or equal to 60 kV; and 3) hosts 20MW or greater of Computational Load.

AZPS supports the following comments submitted by EEI on behalf of their members:

<u>The Trades propose the following modifications:</u>

1. **Add a new definition Computational Load Facility (CLF):**

AZPS Comments on Proposed Revisions to NERC ROP: Computational Load Entity

May 8, 2026

> **"Computational Load Facility"** means a collection of electrical equipment located at one or more buildings, structures, or installations that is designed to receive power, has an aggregate connected maximum peak demand of Computational Load greater than or equal to 75 MW, and is served through electric facilities at a voltage level greater than or equal to 100 kV from one or more points of connection.

A clear definition of a Computational Load *Facility* is essential for Project 2026-02 success. Existing standards that currently address the same types of essential actions being proposed for data centers but are applicable to other comparable equipment (like generators) consistently rely on a *Facility*-type definition. This is consistent with how Generator Owner/Operator and Generating Facility are treated, defined, and included in the registration criteria.

Data center sites can have a significant number of physical and electrical configurations. For example, many data center sites can consist of one or more buildings, with each building having one or more connections to the Bulk Power System at the same location. In some cases, data center owners may consider that each building is an individual data center, while in other cases the collection of buildings connected to the grid is viewed as the data center. The risk to the BES comes from the aggregate load behavior of facilities *at a single site*. This was emphasized in NERC's "Characteristics and Risks of Emerging Large Loads" whitepaper that, while specific load types and thresholds to define Large Loads could not be defined across industry at that time, all agreed that any such definition should include "aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS."

2. **Replace CL Entity (CLE) with CL Operator (CLOP) and CL Owner (CLO)**

The Trades recommend that the Computational Load Entity definition be replaced with new definitions that align with the "Owner" and "Operator" Model currently in place in the NERC Rules of Procedure for registration criteria. Today we have registration criteria for Transmission Owner (TO), Transmission Operator (TOP), Generator Owner (GO), and Generator Operator (GOP). This structure is in place because for Transmission and Generation facilities, there are often situations that occur where the owner of the facilities is different from the operator of the facilities. This registration criteria setup allows for the different entities to be responsible only for the activities that they are contractually setup for as the owner and/or operator.

For Computational Load Facilities, these facilities have the same type of structure. There are many cases where the owner is different from the operator. Therefore, because of the actual structure of the facilities and to align with existing NERC registration criteria, the

AZPS Comments on Proposed Revisions to NERC ROP: Computational Load Entity

May 8, 2026

Trades recommend replacing of the Computational Load Entity definition with Computational Load Owner and Computational Load Operator, with proposed definitions for each included below.

"Computational Load Owner" means the end-user entity that owns and maintains a Computational Load Facility, **and/or** the entity that owns and maintains a Computational Load Facility that hosts end-users that receives electric power **at a** Computational Load **Facility**.

"Computational Load Operator" means the end-user entity that operates a Computational Load Facility, **and/or** the entity that operates a Computational Load Facility that hosts end-users that receives electric power **at a** Computational Load **Facility**.

However, if NERC staff retains only one Registered entity, the Trades suggest the following modifications to the Computational Load Entity definition:

"Computational Load Entity" means the end-user **and/or** the entity that hosts end-users that receives electric power ~~for~~ **at a** Computational Load **Facility**.

The risk to the BPS and the gaps in NERC reliability standards, as noted in NERC's "Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads" is driven by Computational Load impacts and behavior, not *other type* of load, and Computational Load Entity should focus only on the amount of data-centric/information technology type of load.

3. **Clarify the Computational Load (CL) definition:**

The Trade Associations recommend that the proposed Computational Load definition focus on the power electronic-based information technology equipment, which is the focus of the risks to the BPS as documented by NERC's Large Loads Task Force and Large Loads Working Group.

NERC's "Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads" identifies risks associated with the behavior and impacts of computational loads. Those risks arise from the data-centric and information technology characteristics of the load, not from unrelated load at the same site. The definition should therefore focus only on the amount of computational load and should not sweep in other types of loads that do not raise the same reliability concerns.

"Computational Load" means Load comprised **primarily** of electric power demand from **power electronic-based** information technology equipment.

AZPS Comments on Proposed Revisions to NERC ROP: Computational Load Entity

May 8, 2026

4. **Either (a) increase Computational Load thresholds <u>or</u> (b) pursue an approach comparable to the Category 1/Category 2 designations for Generation.**

   a. **<u>NERC should increase its 20 MW and 60 kV Thresholds</u>**

   The Trades recommend NERC reconsider the registration thresholds proposed in Appendix 5B. The proposed 20 MW/60 kV threshold with the 1MW Computational Load criteria is set unnecessarily low and sweeps in a substantial number of facilities that pose no material impact to the reliability of the Bulk-Power System and, thus, does not justify the burden of NERC registration. The current Rules of Procedure, Registration, and Standard Drafting efforts related to Computational Loads should focus on those loads that pose the most meaningful risk to the Bulk Power System. The threshold criteria (20 MW, 60 kV) is too low and we recommend the threshold be set to 75 MW connected at >= 100kV for Computational Load Facilities, consistent with the NERC Bulk Electric System definition for dispersed power producing resources (i.e., inverter-based resources) – where the current criteria is greater than 75 MVA at a common point of connection at >= 100kV is utilized.

   Although NERC has developed a Technical Reasoning Proposed Computational Load document, it does not provide sufficient explanation or practical examples to justify the selected thresholds in the proposed registration criteria. The Trades are concerned that NERC's proposed approach could inadvertently create compliance obligations for Distribution Provider (DP) entities by effectively deeming them Transmission Owners (TO) or Transmission Operators (TOP). It is critical to ensure that DPs do not lose the radial system exemption when solely serving load and not operating transmission facilities. Clear justification and refinement of the proposed thresholds are required to demonstrate that there are identifiable and material risks to the BES.

   In addition, NERC's "Characteristics and Risks of Emerging Large Loads" indicated that "most of the survey respondents qualified 'large' as greater than 50 MW, and the single size number most commonly suggested was 75 MW," and the NERC Alert 2 results confirmed this. NERC's "Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads" refers back to the first Whitepaper and in the definition section, and focuses on really large loads and how several smaller loads (still much bigger than 20 MW) are not as big of a risk.

"The potential impact of several 100 MW loads may be less than the impact of a 500 MW load and may require different treatment."

Furthermore, the NERC "Ten benchmarks of an Effective Reliability Standard" white paper emphasizes that "each [NERC reliability standard] requirement is 'not a lowest common denominator' exercise but instead achieves an objective that is the best approach for bulk power system reliability." The same applies to definitions and reliability criteria. NERC's decision to select 20 MW appears to be a "lowest common denominator" choice, instead of a higher value that the majority of the industry agrees with.

The Trades recommend NERC adopt an initial threshold of 75 MW at a common point of connection of 100 kV or higher. This pairing adheres to the current Bulk Electric System definition and appropriately balances reliability risk to compliance burden. A 75 MW/100 kV starting point focuses computational load entity registration on the facilities most likely to have a material impact on Bulk-Power System reliability. It would also give NERC and the Regional Entities time to identify entities for registration, develop Reliability Standards, and gain compliance oversight experience with a manageable population. Further, it avoids imposing new obligations on facilities whose individual contribution to reliability risk is limited.

b. <u>NERC should pursue a Category 1/Category 2 approach for Computational Loads</u>

If a threshold lower than 75 MW is deemed necessary by NERC staff, the Trades recommend that NERC staff enhance the Technical Reasoning document to reflect the analysis/evidence demonstrating the lower facility threshold is needed for BPS reliability. In addition, in this scenario the Trades also recommend that NERC staff adopt the same registration criteria model that was developed for IBRs with the Category 1 GO/GOP and Category 2 GO/GOP. NERC should create a new Category 1 Computational Load Owner/Operator (CLO/CLOP) and Category 2 CLO/CLOP definitions, and structure the MW and voltage criteria for each to align with the Category 1 GO/GOP and Category 2 GO/GOP. The Category 1/Category 2 approach to address the different security requirements needed for each categories. To create this structure, the following definitions are proposed:

- **"Computational Load Facility"** means a collection of electrical equipment located at one or more buildings, structures, or installations that is designed to receive power, is served through electric facilities from one or more points

of connection **and meets the criteria in either Category 1 or Category 2 Computational Load Owner/Operator registration categories.**

- **"Category 1 CLO/CLOP"** should be aligned with the BES criteria, which would be entities who own/operate Computational Load Facilities (CLFs) that are **>= 75 MW** of Computational Load connected at **>= 100kV**.

- **"Category 2 CLO/CLOP"** should be aligned with the lower threshold value supported by NERC and industry, which would be entities who own/operator Computational Load Facilities that are **>= 20 MW** of Computational Load connected at **>= 60kV**.

With NERC expected to address computational load risk on an accelerated timeline by the end of 2026, this structure would allow the entire ERO to focus its initial entity registration, standards development efforts, and compliance education activities on the highest-risk CLOs/CLOPs first. This framework also establishes a more manageable path to subsequently address lower-risk Category 2 CLOs/CLOPs in future work phases. Finally, this structure would enable a risk-based compliance approach by allowing more stringent reliability and security requirements to be applied to Category 1 CLOs/CLOPs compared to Category 2 CLOs/CLOPs.

5. Additional Comments

The draft Computational Load Entity registry criteria uses the word "capability" which can be interpreted as the maximum load of a Computational Load Facility (CLF). For example, if the CLF facility has a maximum possible load demand of 100 MW, then this is the Load "capability" of the CLF. However, this "capability" term as used with Load is likely not widely understood or utilized today. We recommend an alternative to the use of "capability" such as "**maximum peak demand**" of a Facility to be clearer. In addition, evaluating a CLF's impact on the BES should not rely solely on its size. Incorporating operational characteristics such as interruptibility, load flexibility, and the availability of on-site or contracted backup generation will provide a more comprehensive and accurate assessment of system impacts.

Additionally, the proposed registration criteria includes reference to a "point of interconnection" at 60 kV. "Point of interconnection" is primarily a term referring to generation interconnections – interconnections that most often rely on one generating tie-

line. Data centers often have many connections to the Bulk Power System at the same location. The ownership of equipment can also vary site to site, in which some connect to utilities directly at the high voltage kV bus by owning the high-voltage transformation, while others do not own the transformation or equipment greater than 60 kV.

In NERC's current proposed Computational Load Entity registration criteria, it states "contributes to an aggregate connected Load capability." How will NERC determine the amount of Computational Load or the amount of aggregate connected load thresholds? Will it be based on the "nameplate" of the various racks in a data center warehouse or some other methodology? Regardless of the method(s) for determining these values, the Trades recommend that this should be confirmed between the CLE and its Regional Entity and NERC should not be dependent on other registered entities for providing this information to Regional Entities. Critically this criteria states Load, not Computational Load. We believe this is incorrect and should be updated to state "Computational Load capability." In our proposed Computational Load Facility definition, we have included the use of Computational Load in the definition so that the focus is only on data-centric/information technology load. The Trades ask "How is a Computational Load fundamentally different from other large traditional loads such as steel mills, food processors, or automobile manufacturers? All large loads must be studied to ensure their interconnection and operation do not create grid reliability issues. There is concern that, as written, it may capture facilities that are not data centers or cryptocurrency mining operations, which are the business types that NERC has identified as potentially impacting the reliability of the BES. For example, many industrial and commercial facilities may operate more than 1 MW of information technology equipment (either now or in the future) such as servers, storage, and networking hardware to control and support processes, yet these are not solely or primarily computational in nature. In addition, it seems unreasonable that the loss of a 1 MW load, regardless of load type, would have a significant impact on the BES, therefore including a de minimis criteria of 1 MW of Computational Load drives significant confusion, pulls in a significant number of entities unnecessarily and has no justification pertaining to actual risk to the BPS. The 1 MW de minimis threshold conflicts with the material impact standard applied throughout Appendix 5B and would expand registration beyond entities capable of materially impacting BPS reliability. The 1 MW de minimis threshold should be removed from the Computational Load threshold.

To build on the concerns shared and the alternatives provided the Trades ask the following questions.

- "How will a Computational Load Entity(ies) be identified for registration under the proposed framework?"

- Will the Transmission Owner (TO), Transmission Operator (TOP), or Transmission Planner (TP) be responsible for identifying this Load(s) and sharing that information with their Regional Entity?
- Additionally, will responses to the NERC Level 3 Alert on Computational Loads be used to inform or determine registration requirements?

In addressing these questions, the Trades recommend that the identification CLEs for potential registration should be the responsibility of the Regional Entity and NERC should not be dependent on other registered entities for providing this information to Regional Entities.

Appendix B

It is unclear on how large load facility topology/interconnection configurations may impact the applicability of the proposed registration criteria. Recommend that the NERC/ERO quickly develop a CMEP Practice Guide on this new registration criteria for review by industry and DT to ensure no unintended consequences from this new criteria.

The Trades also note that NERC's document "Summary of Revisions" states candidates for CL registration must meet all the criteria in the proposed revisions in Appendix 5B in order to be registered as a Computational Load Entity, however, that is not explicitly stated in the proposed changes in Appendix 5B and should be stated.

Bright-line Criteria

Computational Load Entity (CLE) registration should be based on clear, bright-line criteria coupled with a formal exception process similar to the BES definition framework. Such an approach would allow an entity to demonstrate, through documented technical justification, that its facilities do not have a material impact on the Bulk Electric System (BES). This balance is necessary to ensure that registration and compliance obligations are applied only where there is a substantiated reliability risk, while avoiding unnecessary regulatory burden for entities whose operations do not pose a material threat to BES reliability.

NERC ROP Revisions: Computational Loads and Computational Load Entity – BPA Comments

Appendix 5B

BPA understands NERC's ROP revisions proposal has the following registration qualifiers for a Computational Load Entity:

1) contributes to an aggregate connected Load capability greater than or equal to 20 MW;

2) at a single point of interconnection to the Bulk Power System at a voltage greater than or equal to 60 kV; and

3) hosts 1 MW or greater of Computational Load.

In BPA's experience, data center interconnections vary.

Many large data centers interconnect at High Voltage (HV) level, 230-kV or 115-kV, and own step-down transformers and Medium Voltage (MV) equipment, usually 34.5-kV and 12.5-kV). BPA believes these will clearly fit into the proposed NERC ROP registration criteria.

However, BPA also sees large data centers that interconnect at the MV level, as illustrated below for a 200 MW data center. BPA understands that an interconnecting utility will own and operate HV to MV step-down transformers and MV substation and the change of ownership between a utility and a data center occurs at 34.5-kV level. BPA recommends the definition clarify that the described interconnection meets the NERC definition.

To achieve BPA's recommendation regarding the Computational Load Entity (CLE) definition, BPA suggests revising the language listed below:

III(c) Computational Load Entity:

III.c.1 Computational Load Entity that encompasses all of the following:

1) One or more facilities at a single site that contribute~~s~~ to an aggregate connected Load capability greater than or equal to 20 MW;

2) ~~at a single point of interconnection to the Bulk Power System at a voltage greater than or equal to 60 kV; and~~

Connects to the Bulk Power System (BPS) operated at a voltage greater than or equal to 60kV on the high side and behind one or more common Points of Interconnection (POIs) or Service Delivery Points; and

BPA believes 3MW is appropriate and should be the lowest MW value, as this is currently identified for AGC. BPA understands this to be the threshold for modeling and operational monitoring. BPA recommends revising the language to:

3) hosts ~~1~~ 3MW or greater of Computational Load.

Appendix 2:

Accompanied by BPA proposed revisions for Computational Load Entity, BPA recommends revising the BES definition to include 'Computational Loads'.

BES Definition:

"Bulk Electric System" or "BES" means unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher, Computational Loads, and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

BPA recommends adding a new 'Inclusion', proposed I6.

Inclusions:

I6 - Computational Loads, and the associated system(s) that connects it to the BES network for a Computational Load Entity.

Exclusions:

BPA recommends the following 'Exclusions' language revisions to accompany BPA's recommended I6 'Inclusion' language above.

- **E1 -** Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
    d) Only serves Load, not identified in Inclusion I6. Or,
    e) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
    f) Where the radial system serves Load, not identified in Inclusion I6, and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

- **E3 -** Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load, not identified in Inclusion I6, rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

BPA proposes a new bullet ‘d’ in ‘E3’ to not allow exclusions for Computational Loads, using the same concept as bullet ‘a’ for connected Generation.

> d) Limits on connected loads: The LN and its underlying Elements do not include Computational Loads identified in Inclusions I6.

BPA appreciates the compressed timeline NERC working under to address reliability risks posed by computational loads, and the necessary focus on the most critical actions to take in 2026 to address them. If this means the BES definition revisions are not incorporated now, BPA requests NERC open the BES definition for revision in early 2027 to account for Computational Loads and other changes to the nature of the BES that may warrant revision to its definition. This will address the risk that a CLE won’t have BES equipment using the existing BES definition. BPA believes BES definition clarity is an important step so the standard(s) being developed by Project 2026-02 are capturing the correct BES equipment before their implementation phase.

CenterPoint Energy Houston Electric, LLC (CEHE) is grateful for the opportunity to review and comment on the NERC proposed revisions to the NERC Rules of Procedure (ROP) to integrate Computational Loads as a registered Entity class.

CEHE is supportive of the attached comments submitted by the Trade Associations to NERC. The Trade Associations are the: American Public Power Association (APPA), Edison Electric Institute (EEI), Large Public Power Council (LPPC), National Rural Electric Cooperative Association (NRECA), and the Transmission Access Policy Study Group (TAPS).

CEHE looks forward to continuing to collaborate with NERC via the Project 2026-02 Computational Loads Standard Drafting Team and the NERC LLWG on these ongoing efforts to design risk-based reliability requirements for Computational Loads.

Thank you.

Leo McAfee Jr.
Senior NERC Policy and Compliance Consultant

CenterPoint Energy | CEHE Policy and Compliance
CenterPointEnergy.com

In addition to supporting the comments submitted by APPA, SVP provides the following comments on the Computational Loads SAR and proposed ROP revisions which include a new definition for "Computational Load Entity" and registration criteria for CLEs.

- **COMPUTATIONAL LOAD ENTITY "CLE" REGISTRATION**

SVP agrees that registration of Computational Load Entities is necessary to help ensure that interconnecting entities commit to meeting baseline reliability expectations, and SVP supports the registration criteria proposed in the Rules of Procedure, Appendix 5b **[1)load capability greater than or equal to 20M; 2) at a single point of interconnection to the Bulk Power System at a voltage greater than or equal to 60kV; and 3) hosts 1MW or greater of Computational Load.]**

- **CLE DEFINITION**

SVP considers the proposed definition of ***Computational Load Entity***, "the end user or the entity that hosts end-users that receives power for Computational Load," to be unnecessarily broad and more likely to result in conflicting accountability and strain any coordination efforts between TOPs and the CLEs within their system. SVP recommends that the Computational Load Entity be identified as the host/facility owner; this will streamline any coordination or Interpersonal Communication requirements that evolve from the Large Loads Bridge Standard project. (e.g.: Level 3 NERC Alert, Essential Action #7 – "TOPs, RCs, and BAs should establish Interpersonal Communication capabilities with computational loads to improve their situational awareness and joint operating procedures to ensure the reliability operation of the BPS. . .")

- **SCOPE of STANDARD AUTHORIZATION REQUEST**

While the purpose of the Standard Authorization request is generally understood by the industry, the SAR itself lacks enough specificity about the reliability risks it intends to address. SVP recommends that the SAR identify the risks the Essential Actions are meant to mitigate, using the "Essential Actions" in the May 4th Level 3 NERC Alert pertaining to Computational Loads as guidance. This will assist both the drafting team and voting entities determine whether the initial bridge standard meets the purpose of the SAR.

Sincere Regards,

Val

Valentina Guzman Ridad
Division Manager, Compliance | Electric Department
881 Martin Avenue | Santa Clara, CA 95050

Concern Regarding 1 MW Minimum Computational Threshold

The proposed 1 MW computational load threshold may be too low to reliably indicate the presence of system-relevant computational behavior. A facility with 1 MW of computational load within a 20MW aggregated load is unlikely to exhibit the characteristics that NERC is intending to address. We suggest evaluating whether a higher threshold or ratio-based threshold would better reflect reliability risk.

SPP recommend NERC evaluate whether**:**

- A higher computational load minimum (for example, 3–5 MW) better reflects the threshold at which computational characteristics materially impact system stability, or
- Additional technical justifications are provided to support the 1 MW cutoff.

Need Precise Definition of "Point of Interconnection at ≥60 kV"

We request clarification on how the point of interconnection at 60 kV or above is to be determined. This is critical for distinguishing true transmission-connected computational loads from distribution-fed commercial or mixed-use facilities. A defined measurement methodology would help ensure consistent registration and audit application.

Alan Wahlstrom N.C.S.O
Lead Engineer
Reliability Standards Development Group
Southwest Power Pool

To whom it may concern,

Please find the following suggested change for Appendix 5B - Statement of Compliance Registry Criteria - Revision 9:

> Registration Criteria:
> III(c) Computational Load Entity:
> III.c.1 Computational Load Entity that 1) contributes to an aggregate connected Load capability greater than or equal to 20 MW of Computational Load; and 2) at a single point of interconnection to the Bulk Power System at a voltage greater than or equal to 60 kV.~~; and 3) hosts 1 MW or greater of Computational Load.~~

The reasoning for this is that with the currently proposed definition (hosting 1MW of greater of Computational Load), a large number of facilities may be pulled into the registration criteria that are not AI data centers. 1MW of computational load may inadvertently require office buildings, university campuses, research centers, etc. to register as a Computational Load Entity.

By amending the first item to focus on the required amount of computational load, and not an aggregate load plus a relatively small portion of computational load, the definition becomes more salient and succinct.

Thank you,

Eric Mannarino
Global Design & Construction
Design Delivery Principal, Electrical Engineering

EQUINIX | 1 Lagoon Dr, Redwood City, CA 94065

EQUINIX	

Sylvia and/or NERC Representative Responsible for Obtaining Industry Comments,

I am submitting comments for a for all 4 sectors 1,3,5, and 6 for the Computational Load Entity ROP Revisions solicitation.

Dominion Energy supports EEI comments with no additional comments.

Matt Bullard
NERC Reliability Compliance Consultant
Dominion Energy

Corscale Data Centers agrees with the comments submitted by the Data Center Coalition.

Best Regards,

Dan Vanderplas
Data Center Campus Director



13760 University Blvd.
Gainesville, VA 20155

CORSCALE.COM

Dear NERC,

Corscale Data Centers agrees with and support the comments submitted by the Data Center Coalition.

Regards,

Ludo Hintos, PE

Vice President, Infrastructure Planning & Development



13760 University Blvd.
Gainesville, VA 20155

CORSCALE.COM

To whom it may

concern,

I am writing to provide comments on the proposed updates to the Rules of Procedure regarding the inclusion of Computational Load Entities.

The initiative to address risks associated with large and rapidly scaling computational loads is both timely and necessary. As these loads increasingly influence system planning and reliability considerations, establishing a clear framework is critical.

One consideration that may be worth incorporating into both the ROP and related standards discussions is how underlying demand is characterized.

Not all large computational loads are equally durable. A portion of projected demand may be conditional on evolving factors such as:

compute architecture and efficiency improvements siting and co-location decisions operational strategies and workload distribution underlying technology changes

As a result, treating all projected load as structurally fixed may introduce risk into planning and standard-setting processes.

In particular, there may be value in distinguishing between:

structural (persistent) load
conditional or transient load
load that may be reduced or eliminated through technological or operational changes

Incorporating this type of differentiation could help ensure that standards are aligned not only with current demand projections, but also with how those demands may evolve over time.

This consideration has implications for:

long-term reliability planning
infrastructure investment efficiency
risk assessment associated with large load integration

Appreciate the opportunity to provide input on this important topic.

Best regards,
Neil P. Osnato

Neil P. Osnato
Founder

Persistence Analytics Group LLC

Regarding the Rules of Procedure revisions relative to Computational Load (comments due May 15), the Large Public Power Council (LPPC) supports the comments submitted by the Trade Associations. Thanks.

Joe McClung
JEA Electric Compliance Program Manager

Dear NERC,

After reivew Corscale Data Centers agrees with and support the comments submitted by the Data Center Coalition.

Thank you,

Tyler Kent, P.E.
Project Director, Infrastructure Delivery



9830 Colonnade Blvd., Suite 405
San Antonio, TX 78230

CORSCALE.COM

May 12, 2026 | Via Electronic Filing: ROPcomments@nerc.net

Comments of Crusoe Technologies LLC

NERC Rules of Procedure Revision — Computational Load Entity Registration Criteria (Appendix 5B)

45-Day Comment Period | April 1 – May 15, 2026 | Project 2026-02

I. Introduction

Crusoe Technologies LLC ("Crusoe") submits these comments on NERC's proposed Appendix 5B registration criteria for a new functional entity type — the Computational Load Entity (CLE). Crusoe operates large-scale artificial intelligence compute infrastructure interconnected to the bulk power system (BPS) and participates actively in ERCOT's Batch Zero large load interconnection proceeding.

Crusoe supports the CLE framework, with more specific definitions. NERC's May 4, 2026 Level 3 Alert documented widespread, simultaneous load reductions exceeding 1,000 MW from computational facilities — events that create real BPS stability exposure. A registration and compliance framework with mandatory Reliability Standards is the right response. That said, any definitions and registration criteria should be grounded in load size and grid impact, applicable to all large load facilities regardless of industry type — not targeted at a specific end use of electricity. Crusoe's comments address two specific issues: the 20 MW threshold is too low and will not accomplish what NERC intends, and the proposed definitions are overbroad and require refinement.

II. The 20 MW Threshold Is Too Low — 75 MW Is the Right Number

The proposed criteria require registration where a facility contributes to aggregate connected load capability of ≥ 20 MW at ≥ 60 kV and hosts ≥ 1 MW of computational load. The 20 MW floor does not reflect large load impacts on the BPS.

A 20 MW load tripping offline — even instantly — creates an immeasurable frequency deviation on the Eastern or Western Interconnection. Automatic generation control and governor response absorb events of this size routinely without any reliability consequence. NERC's own Level 3 Alert identified the reliability problem as large-scale, simultaneous drops from clusters of computational facilities — not from individual 20 MW sites. Registering 20 MW facilities does not solve that problem. It creates an enormous administrative burden for the wrong population while diluting NERC's enforcement focus.

ERCOT — the RTO with the largest concentration of emerging computational load in North America — set its large load interconnection threshold at **75 MW**. This threshold reflects decades of ERCOT operational experience with the load size at which a single facility begins to affect transmission planning assumptions, SCED constraint dispatch, and reliability coordination. Crusoe respectfully urges NERC to adopt 75 MW as the CLE threshold and to explain, with technical justification, if it believes a different number better reflects BPS material impact.

III. The 1 MW Computational Load Sub-Criterion Sweeps In the Wrong Facilities

The proposed criteria require only that a qualifying facility 'hosts 1 MW or greater of Computational Load' — defined as load from servers, storage, and networking hardware. This definition is overly broad: it sweeps in hospitals, universities, corporate offices with modest server rooms, and industrial facilities like steel mills with incidental on-site IT equipment. None of these are the purpose-built, utility-scale infrastructure that prompted NERC's Level 3 Alert, and imposing full NERC compliance obligations on incidental IT users bears no relationship to the reliability risk NERC is managing

That is not the population that tripped 1,000 MW simultaneously and prompted NERC's Level 3 Alert. The Level 3 Alert, the Level 2 Alert before it, and the Large Loads Working Group white paper all focused on purpose-built, utility-scale AI and data center infrastructure. Imposing NERC Reliability Standards compliance — with audit obligations and civil penalty exposure up to $1 million per violation per day under FPA Section 215 — on incidental IT users bears no relationship to the reliability risk NERC is managing.Crusoe recommends that the computational load sub-criterion be set at 50 MW of dedicated computational load, or alternatively that computational load constitute at least 50% of the facility's aggregate connected load capability. Either formulation limits registration to purpose-built computational infrastructure — the actual source of BPS risk — and excludes conventional commercial and industrial facilities with incidental IT. As such, Crusoe recommends refining the definition of Computational Load to capture only loads that meet the MW threshold and are "predominantly comprised of" or where "the majority of electric power demand" comes from IT equipment.

IV. Proposed Revision to Appendix 5B Criterion 2

Current Language:

A Computational Load Entity that (1) contributes to an aggregate connected Load capability greater than or equal to 20 MW; (2) at a single point of interconnection to the BPS at a voltage ≥ 60 kV; and (3) hosts 1 MW or greater of Computational Load.

Crusoe's Recommended Language:

A Computational Load Entity that (1) contributes to an aggregate connected Load capability greater than or equal to 75 MW; (2) at a single point of interconnection to the BPS at a voltage ≥ 100 kV; and (3) hosts 50 MW or greater of Computational Load [alternative: for which Computational Load constitutes at least 50% of aggregate connected Load capability at that point of interconnection].

Crusoe also recommends a 100kv voltage threshold instead of the proposed 60kv. Transmission-level interconnection is a meaningful indicator of BPS exposure and should remain a necessary condition..

V. One Additional Issue: Co-Located Generation and Storage

The proposed CLE definition does not address facilities that combine computational load with co-located generation or energy storage — the BYOG (Bring Your Own Generation) model increasingly common in large AI infrastructure deployments. A facility that must register as a CLE, a Generator Owner, and an Energy Storage Resource Owner may face multi-entity compliance obligations that

have not been reconciled. Crusoe requests that NERC issue guidance on multi-functional entity registration for co-located configurations before the CLE criteria are finalized.

VI. Additional Recommendations

Crusoe supports the comments submitted by the Data Center Coalition (DCC). As an additional recommendation if NERC maintains the 20 MW/60kV thresholds, NERC should adopt the same registration criteria model that was developed for Inverter-Based Resources with the Category 1 and Category 2 GO/GOP definitions and criteria. This would enable NERC and the industry to focus initially on reliability issues created by the larger Category 1 Computational Load Owner/Computational Load Operator categories.

> Category 1 CLO/CLOP: Computational Load Facilities that are >= 75 MW of maximum peak demand of Computational Load connected at >= 100kV
>
> Category 2 CLO/CLOP: Computational Load Facilities that are >= 20 MW of maximum peak demand of Computational Load connected at >= 60 kV

VI. Summary of Recommendations

1. Raise the aggregate connected Load capability threshold from 20 MW to 75 MW.

2. Raise the Computational Load hosting sub-criterion from 1 MW to 50 MW — or require Computational Load to constitute at least 50% of aggregate connected load capability.

3. Raise the 60 kV voltage threshold to 100kv

4. Issue guidance on multi-functional entity registration for co-located generation and storage configurations before the CLE criteria are finalized.

Crusoe thanks NERC for its leadership in addressing the BPS reliability implications of large computational loads. The Level 3 Alert demonstrates that the urgency is real. Getting the threshold right — so that mandatory compliance obligations fall on the facilities that actually affect BPS reliability — is essential to making the CLE framework effective. Crusoe is available to provide additional technical input if that would assist NERC's deliberations.

Respectfully submitted,

Crusoe Technologies LLC

Contact: Bharath Ravulapati

May 15th, 2026

Filed electronically to: ROPcomments@nerc.net

NERC

Notice of Proposed Revisions to the NERC Rules of Procedure and Request for Comments – Computational Load Entity
NERC Rules of Procedure Appendix 2 (Definitions Used in the Rules of Procedure); Appendix 5A (Organization Registration and Certification Manual); and Appendix 5B (Statement of Compliance Registry Criteria)

Proposed Changes to Rules of Procedure
Appendix 2 Clean | **Redline**
Appendix 5A Clean | **Redline**
Appendix 5B Clean | **Redline**
Summary of Changes

Proposed Revisions to Rules of Procedure – NERC is proposing revisions to its Rules of Procedure to develop a new registered entity type, called Computational Load Entity. NERC is posting the proposed revisions to NERC Rules of Procedure Appendix 2, Appendix 5A, and Appendix 5B for public comment for 45 days from **April 1, 2026** to **May 15, 2026**. Comments must be submitted electronically to ROPcomments@nerc.net.

The proposed revisions address recommendations from the NERC Large Loads Working Group (a subgroup of the NERC Reliability and Security Technical Committee) whitepaper "***Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads***" and are further supported by the findings in the "***NERC Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations***" analyzing responses to a Level 2 Alert on the interconnection of large loads. The recommendations and findings indicate a need for a new registered entity to comply with Reliability Standards (currently under development in Project 2026-02 – Computational Loads) to reduce risks to the reliability of the Bulk Power System.

In pursuing its mission to assure the effective and efficient reduction of risks to the reliability and security of the grid, NERC works with owners, operators, users, and consumers as well as federal, state, and provincial regulators across North America. To that end, NERC welcomes input from all stakeholders on the proposed revisions and values the opportunity to engage with stakeholders on how the proposed revisions can contribute to the reliability of the Bulk Power System.

For more information or assistance, please contact **Marisa Hecht** via email or at **404-446-9620**.

RELIABILITY | RESILIENCE | SECURITY **www.nerc.com**

POWERING TODAY. PROTECTING TOMORROW.

Data Center Coalition Comments on Proposed Revisions to NERC ROP: Computational Loads 5/15/2026

The Data Center Coalition is pleased to submit these comments on NERC's proposed Rules of Procedure definitions and registration criteria for Computational Loads.

Like all customers, the data center industry depends on a reliable electricity grid in order to fulfill its role as a vital backbone of our modern economy. In turn, data centers offer a number of reliability benefits to the grid, including significant investments in new energy resources and next-generation technologies. As recently demonstrated during Winter Storm Fern, data centers can also serve as grid assets that help promote reliability during energy emergencies caused by extreme weather.

It is critical to ensure proposed definitions and registration criteria by NERC are based on complete evidence, the technical capabilities and specifications of data center equipment, and do not disregard important developments or information from key markets. In Virginia, improved communication between NERC, regional entities, utilities, and data center operators have greatly reduced — if not altogether eliminated in certain instances — load transfer events in Virginia. In Texas, DCC is unaware of any load transfer events that have been caused by data centers, based on ERCOT's reporting. This type of close collaboration, communication, and technical information sharing is essential to the upcoming work with NERC.

While NERC has elected to pursue a pathway that conflates and singles out "computational loads," we emphasize that any new definitions and registration criteria should be defined by any type of large load facility – and the corresponding load size, voltage level, and operational characteristics of any such large load facility - not simply by industry type or end use of electricity. With that fundamental concern noted, DCC is committed to leaning in as an engaged partner with NERC and transmission entities to help ensure a reliable grid for all customers and offers the following comments. In addition, while the DCC understands the urgency of the NERC computational load work, the recently released NERC Level 3 Alert on Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control is an important tool that should help get essential actions in place by the electric transmission industry. Given the scale and criticality of this Level 3 Alert, it would be prudent to wait for the industry response to this Level 3 Alert and corresponding essential action implementation before moving forward with the registration criteria and standard development for Computational Loads. The DCC also urges NERC to publicly release its legal analysis that NERC stated was ongoing throughout 2025, which we understand is supporting the conclusion that NERC has the authority under Section 215 of the Federal Power Act to register Computational Load Entities and impose mandatory reliability standards on them. This is a significant expansion of NERC's jurisdictional reach, and the data center industry, other computational load industries, and the electric industry all deserve to understand the legal reasoning before any registration framework or standard is advanced. Publishing this analysis would allow for informed stakeholder engagement, support a more defensible rulemaking record, and ensure that the process is lawful and reflects the transparency and due process the industry expects from NERC.

- Summary of RoP Changes

  - NERC has decided to target large computational loads, which appears to specifically exempt other types of large loads that also have a material impact on the bulk power system. Particularly with the relatively low thresholds proposed, it is unclear how a 20 MW data center would have a substantially greater impact to the BPS than, say, a multi-hundred MW mining load or manufacturing facility.

- Appendix 2
  - The definition for "Computational Load" is rather generic and may be difficult to implement and enforce due to the ambiguities it contains. Specifically, the terms say that "Load comprised of electric power demand from IT equipment…" Thus, if ANY portion of the load is IT-based equipment, then this would technically constitute as a Computational Load. For some examples:
    - A steel mill likely has some servers or computers on site that ultimately are IT equipment; however, the vast majority of the load is an industrial process and not intended to be captured by this definition.
    - Hospitals, large office buildings, colleges/universities are additional examples that all are large loads that will have plenty of IT equipment, including servers, storage systems, and networking equipment. But all of these facilities should not be intended to be captured by this definition.

    Therefore, NERC should consider some improvements to the definition to scope and refine it. One example would be to state "Load primarily comprised of electric power demand from IT…" or "Load where the majority of electric power demand from IT…". This captures the same intent but provides some clear specifications on how to apply it.
  - NERC should consider whether the "Computational Load Entity" ("CLE") is sufficient for the purposes of future standards applicability and registration. Does this refer to the owner or operator of the facility or the owner and operator of the computational load? Which is the main target of standards? What if the owner and operator are different entities, which is a common structure in the data center industry?
  - NERC may want to further clarify what "end-user or the entity that hosts end-users" means exactly, with some examples to support registration efforts. The industry generally believes this refers to, for example, data center locations that may have multiple tenants, but examples/confirmation from NEC on this is critical.

- Appendix 5B

- The criteria for CLE is generally missing the overall risks stated by NERC and industry in the various reports, as written. The criteria essentially states that a 50 MW load that has *only* 1 MW of Computational Load would then need to be registered as a CLE. A 1 MW threshold for registration and applicability to NERC standards seems very misaligned with the findings in NERC reports. We recommend that the 1 MW threshold requirement be removed entirely from the definition.
- In addition, a more straightforward definition would be: "contributes to aggregate connected ***Computational*** Load greater than 20 MW at a single point of interconnection to the BPS at a voltage greater than or equal to 60 kV." It is unclear why a definition such as something like this couldn't achieve the same outcome and be more aligned with other NERC registration efforts (e.g., Category 2 GO/GOPs) and general understanding of BPS impact/risks.

With those general comments provided, DCC would like to propose the following modifications to the proposed definitions and registration criteria, while also providing new definitions that provide better alignment with existing NERC registration criteria and definitions.

- Modify the new term, "Computational Load", to reference this load being primarily made up of power-electronic-based information technology equipment and remove any unnecessary examples of that equipment.
    - **"Computational Load":** Load comprised **primarily** of electric power demand from **power electronic-based** information technology equipment
- Create a new definition, "**Computational Load Facility**", to align with how existing NERC standards apply to Facilities (not entities) and include the updated registration criteria in this new definition. The registration criteria include updated MW threshold to 75 MW, updated voltage connection to 100kV, and changes the word "capability" to "maximum peak demand."
    - **Computational Load Facility ("CLF"):** a collection of electrical equipment located at one or more buildings, structures, or installations that is:

        (1) designed to receive power

        (2) has an aggregate connected maximum peak demand of Computational Load greater than or equal to **100 MW**

        (3) and is served through electric facilities at a voltage level greater than or equal to **100kV** from a single point of connection.
- Modify the new term, "Computational Load Entity", to reference the CLF definition and add some clarifying edits to the definition:

- **"Computational Load Entity":** the end-user **and/or** the entity that hosts end-users that receives electric power **at a** Computational Load **Facility**.
- Ideally, we would also like to propose that the Computational Load Entity definition turn into two separate Owner/Operator definitions, to align with the existing NERC registration criteria/definitions for Transmission Owners, Transmission Operators, Generation Owners, and Generation Operators. Updating CLE to CLO/CLOP is necessary as many data center facilities today have different owners and operators, just as occurs with Transmission and Generation facilities.
    - **"Computational Load Owner" (CLO):** the end-user entity that **owns and maintains** a Computational Load Facility, and/or the entity that **owns** a Computational Load Facility that hosts end-users that receives electric power at a Computational Load Facility.
    - **"Computational Load Operator" (CLOP):** the end-user entity that **operates** a Computational Load Facility, and/or the entity that **operates** a Computational Load Facility that hosts end-users that receives electric power at a Computational Load Facility.

- If NERC insists on keeping the 20 MW threshold of Computational Load, we ask that NERC provide a detailed explanation and evidence why such a low threshold is needed, as NERC's own reports and white papers do not align with this low threshold.
    - NERC's Large Load Task Force (LLTF) White Paper #1 (Characteristics and Risks of Emerging Large Loads) states that most survey respondents listed large loads to be in the range of at least 50 to 75 MW, and data center facility size is generally increasing.
    - NERC's LLTF White Paper #2 (Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads) states that "the potential impact of several 100 MW loads may be less than the impact of a 500 MW load and may require different treatment."
    - NERC's report on the Level 2 Alert responses ("Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations") also includes a figure of the aggregate responses to question on what is the current, or proposed, MW threshold for respondent's large load definition. The vast majority of responses were 50 MW or 75 MW. The report also stated that "the reporting [Distribution Providers] had thresholds typically below 20 MW."
    - All these reports and recommendations lead us to recommending that NERC increase the threshold to 100 MW connected at 100kV for the proposed Computational Load Facilities.

If NERC should continue to insist on a lower threshold being needed, we recommend that NERC adopt the same registration criteria model that was developed for Inverter-Based Resources with the Category 1 and Category 2 GO/GOP definitions and criteria. This would allow the industry to first focus our standard development efforts on the larger Category 1 CLO/CLOP Facilities, and then in time address the lower Category 2 CLO/CLOP Facilities. Below are the proposed Category 1 and Category 2 CLO/CLOP definitions that align with the current Category 1 and Category 2 GO/GOP thresholds/criteria.

- **Category 1 CLO/CLOP:**
  - Computational Load Facilities that are **>= 100 MW of maximum peak demand of Computational Load** connected at **>= 100kV**
- **Category 2 CLO/CLOP:**
  - Computational Load Facilities that are **>= 20 MW of maximum peak demand of Computational Load** connected at **>= 60 kV**

There are two primary types of data centers relevant to this discussion: (1) self-perform and enterprise data centers, in which the business owns and controls its servers and peripheral equipment and may or may not own the physical facility; and (2) multitenant and build-to-suit data centers, in which the facility owner leases space to one or more tenants, potentially encompassing both critical and non-critical load behind the same meter, where those tenants bear direct responsibility for the computational load activity occurring within their leased space. Reference the CIP-002-5.1a ERO Endorsed Implementation Guidance document that also defines Tenants and considers Tenants in the aspects of the standard.

Any attempt by NERC to define Computational Loads and Computational Entities must be cognizant of the complex and varied operational structures, agreements, contracts, and lease arrangements that currently exist between the owners, operators, and tenants of computational load facilities. These relationships were established under existing regulatory frameworks and commercial constructs that did not anticipate the definitional boundaries now being proposed. Accordingly, it is essential that NERC incorporate a clearly defined exception process to accommodate computational load facilities that were designed, contracted, and operationalized prior to the effective date of these rule changes; facilities that, through no fault of their own, may not align with new definitions or satisfy new requirements without significant operational or contractual disruptions and substantial retrofit costs. A blanket application of new definitions and requirements without such a process risks penalizing facilities for non-compliance with standards they had no reasonable basis to anticipate and could create unintended consequences for grid reliability if affected entities are forced into reactive operational changes.

Thank you for providing an opportunity to comment on the proposed Computational Load Entity Registry Criteria.

NERC should use the information it collects to provide greater transparency regarding large computational loads to the wider electricity market. Currently, market participants are struggling to understand where new large computational loads will interconnect, their size, and basic operational characteristics. Without this information, project developers, generators, power marketers and other electricity industry participants cannot forecast and plan for future grid conditions accurately and efficiently.

Large computational loads affect grid operations and locational electricity prices to a similar extent as generation resources of equivalent size. Yet, there is far less information available regarding large computational loads than there is for generation resources. For example, the Energy Information Administration publishes a public data base with basic information on the interconnection location and characteristics of generation resources (i.e., Form EIA-860 Data Base), but does not maintain an equivalent data base for large computational loads.

Private actors across the industry cannot make efficient investments in transmission and generation to serve the extraordinary demand forecasted from large computational loads without greater transparency, stifling investment and, ultimately, jeopardizing reliability. Electricity market participants should have access to certain information regarding each large computational load via a database of approved loads, their sizes, and the locations at which they plan to interconnect with the grid. In addition, market participants should have information regarding the portion of the load that will be firm or in another category. NERC should also provide basic information on the type of load, for instance, whether the studied load is for a data center or crypto mining, and whether the load will include new or existing co-located generation.

Justin R. Cockrell
Assistant General Counsel
DC Energy Management, LP

DIGITAL POWER NETWORK

DPN Comments on NERC Proposed Rules of Procedure Revision:

Computational Load Entities (CLEs)

As NERC considers revisions to the Rules of Procedure Appendix 2 (Definitions Used in the Rules of Procedure) to add new Computational Load Entities (CLEs), the Digital Power Network (DPN) offers the following comments and recommendations to ensure the continued operational viability of large, flexible computing loads as the standards are drafted.

DPN is the largest coalition of Bitcoin miners and digital infrastructure providers, representing facilities with a significant footprint in the grid and energy sector. Bitcoin mining facilities and data centers are increasingly critical components of modern infrastructure that support financing buildout and providing demand flexibility. Any standards framework should therefore balance reliability objectives with the need to support the safe, secure, and economically viable operation of these facilities.

I. Appendix 2 (Definitions Used in the Rules of Procedure) Comments

Ensure Clear Statutory Authority

NERC should clearly articulate the statutory basis for creating the Computational Load Entity (CLE) category and the proposed definition to ensure the framework remains legally grounded.

While Section 215 of the Federal Power Act (FPA) authorizes NERC to develop mandatory reliability standards for the Bulk-Power System (BPS), subject to FERC approval, that authority is not based on the identity of a particular industry or type of end-user. Rather, it is based on whether an entity materially affects the reliable operation of the BPS.

Accordingly, NERC should continue to focus on functional reliability impacts rather than establishing a fixed, industry-specific category of "Computational Load Entity." Historically, NERC registration and compliance obligations have been tied to reliability functions and material impacts on the BPS, rather than a facility's status as a particular type of electricity consumer.

Further, whether a computational load materially impacts BPS, reliability may need to be evaluated on a case-by-case basis given regional and operational differences. At the same

time, other non-CLE load entities may also materially affect BPS reliability but would not fall within the proposed definition.

NERC should also clarify its statutory basis for imposing direct reliability standards on "end-users" of the BPS. Section 215 applies to "users, owners, and operators" of the BPS, but NERC has historically applied registration and compliance obligations based on an entity's reliability function and material impact on BPS operations, rather than solely on its status as an electricity consumer.

Historically, crypto miners and data centers have generally been treated as end-users of electricity rather than entities directly subject to mandatory reliability standards. While NERC and applicable reliability entities may exercise indirect oversight through transmission operators, planners, balancing authorities, interconnection processes, and operating requirements, these facilities have not traditionally been subject to direct compliance obligations under the FPA solely by virtue of being large electricity consumers.

Further, NERC's jurisdiction extends only to entities and activities affecting the BPS and does not extend to purely local distribution facilities or other systems outside the statutory definition of the BPS.

While DPN supports NERC's mission to reduce risks to BPS reliability, expanding reliability standards through the BPS to directly regulate end-users raises broader legal and practical concerns that warrant careful consideration.

II. Foundational Principles for Initial Standards

Prioritize Coordination Before Compliance Requirements

The current standards drafting process appropriately emphasizes process-based standards. It is important that NERC promote coordination between large loads and relevant authorities.

Early and structured coordination will:

- Ensure stakeholder input is incorporated into standards development
- Reduce the risk of infeasible or misaligned requirements
- Improve overall implementation outcomes

Large loads should be active participants in the standards-setting process, not only subjects of compliance.

Streamline and Standardize Data Requests

As standards evolve, multiple entities (e.g., Transmission Planners, Planning Coordinators, Reliability Coordinators) may request similar data from large loads.

To avoid duplicative and burdensome requirements:

- Data requests should be standardized and streamlined across entities
- A coordinated framework should minimize repetitive submissions
- A lead authority or centralized process should be designated when possible

Protect Proprietary and Sensitive Information

Data centers and Bitcoin mining facilities frequently handle proprietary or third-party data. Energy usage and operational characteristics are integral to their business models and may be competitively sensitive.

NERC should incorporate clear data protection standards, including:

- Recognition of this data as Critical Energy Infrastructure Information (CEII)
- Robust protections for CEII
- Safeguards for commercially sensitive information such as:
    - Pricing strategies
    - Customer relationships
    - Capacity plans and expansion timelines
    - Technical specifications

Increased data-sharing requirements must be paired with equally strong data protections.

Stakeholder Process and Governance

To ensure operationally and economically viable compliance with the requirements of relevant authorities, NERC should:

- Require relevant authorities to engage directly with large load operators when developing standards
- Establish clear stakeholder participation processes that prioritize entities with direct operational relevance

III. Looking Ahead: Future (Technical) Standards

As NERC moves beyond initial "bridge" standards toward technical requirements, DPN emphasizes the importance of maintaining operational feasibility.

Voltage Ride-Through Standards

Future low-voltage ride-through (LVRT) requirements must be carefully designed to reflect current technological capabilities.

- Requirements that are too stringent could necessitate significant new technologies and impose substantial costs
- Poorly calibrated standards risk driving facilities out of certain markets

Ramp Rate Requirements

Ramp rate standards should account for real-world constraints, including:

- Supply chain limitations
- Permitting timelines

Overly rigid requirements could unintentionally limit deployment and flexibility

Preserve Operational Viability

Across all future standards should:

- Maintain flexibility for large loads to continue participating in demand response and curtailment programs
- Avoid requirements that undermine the economic or technical feasibility of operations
- Ensure standards are developed in partnership with industry
- Evaluate the impact of changing resource mixes and inverter-based resources on essential reliability services such as frequency response, voltage support, and system inertia

Conclusion

DPN supports NERC's efforts to improve coordination and visibility around large loads. However, the definition must only pertain to loads that have actual reliability impacts on the system rather than a targeted scope focused on industry rather than impact.

Beyond the definition, DPN recognizes that process-based standards are an appropriate first step.

However, success will depend on:

- Early and meaningful coordination with industry
- Streamlined and consistent data requirements
- Strong protections for sensitive information
- A continued focus on operational feasibility as standards evolve

A balanced approach will strengthen grid reliability while enabling the continued growth of critical digital infrastructure.

Proposed Changes to NERC Rules of Procedure "Computational Load Entity"

Comments of the Electricity Consumers Resource Council (ELCON)

The Electricity Consumers Resource Council (ELCON) respectfully submits these Comments in response to the National Electric Reliability Corporation's (NERC) proposed revisions to the NERC Rules of Procedure posted April 1, 2026[1] incorporating defined terms and registration criteria for "Computational Load Entities."

ELCON is the national association representing large industrial consumers of electricity. ELCON member companies create a wide range of products from virtually every segment of the industrial community—we own and operate hundreds of major facilities and are significant consumers of electricity throughout the United States. Reliable electricity supply at just and reasonable rates is essential to our members' operations.

ELCON has been engaged in the work of the NERC Large Load Task Force (now Large Load Working Group or LLWG) since its inception in August 2024 and appreciates the efforts of NERC staff and industry to quickly anticipate and mitigate emerging risks to the Bulk Power System (BPS) posed by massive new loads interconnecting to the BPS at speeds our current system was not designed for.

Following the completion of two whitepapers,[2] NERC determined that "unforeseen and difficult-to-explain dynamic electrical behavior" made it appropriate "to propose a new functional entity type that focuses on loads with these characteristics [and] further define the entities that will be subject to registration based on their individual characteristics as well as the aggregate impact of multiple Computational Loads meeting the Registry

[1] https://www.nerc.com/who-we-are/rules-of-procedure/proposed-changes-to-rules-of-procedure.

[2] Characteristics and Risks of Emerging Large Loads (July 2025), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf (Whitepaper #1); Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads (March 2026), https://www.nerc.com/globalassets/our-work/guidelines/reliability/white-paper---assessment-of-gaps.pdf (Whitepaper #2).

Criteria."[3] NERC further correctly identified the need to incorporate certain minimum thresholds "to distinguish [ ] those entities, such as industrial manufacturers, with a 'de minimus' [sic] amount of Computational Load do not meet the criteria for registration as a Computational Load Entity. This distinction is based on these entities' differing electrical behavior historically."[4]

As explained below, ELCON is concerned that, despite NERC's clear intent to register only those loads that exhibit certain behaviors that risk BPS stability and reliability, the proposed definitions in the Rules of Procedure and registration criteria in Section III of Appendix 5B (separately and jointly) could capture some traditional loads and, by requiring registration by end users, do not effectively target the entities responsible for ensuring reliable usage of the BPS.

In fact, nothing in the definition or registration criteria addresses the behaviors that introduce risk to the BPS, but rather focus on ancillary usage of a broad set of IT equipment that may or may not introduce those risks. Industrial and manufacturing large load customers are fundamentally different from the data center and computational facility activities that precipitated NERC's large load work. In contrast, traditional manufacturing and industrial customers operate predictable, process-driven load profiles; are already subject to existing power quality expectations under IEEE 519;[5] have decades-long interconnection histories with their host utilities; and do not exhibit the behaviors the LLWG identified as the primary drivers of BPS reliability risk. As proposed, the CLE definition and registration criteria do not adequately target those entities and behaviors identified in the whitepapers and the CLE Technical Reasoning.

Appendix 2 – Definitions Used in the Rules of Procedure

The proposed revisions to Appendix 2 of NERC's Rules of Procedure introduce two new terms:

> "Computational Load" means Load comprised of electric power demand from information technology equipment, such as servers, storage, and networking hardware.
>
> "Computational Load Entity" means the end-user or the entity that hosts end-users that receives electric power for Computational Load.

As an initial matter, both proposed definitions are anchored exclusively to equipment type—"information technology equipment, such as servers, storage, and networking hardware"—rather than to any of the behavioral characteristics that NERC's own LLWG analysis

[3] CLE Technical Reasoning, p. 2 (Apr. 2, 2026), https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/proposed/cle-technical-reasoning-april-2026-posting.pdf.

[4] *Id.*, p. 3 (emphasis added).

[5] IEEE Standard for Harmonic Control in Electric Power Systems.

identified as the source of BPS reliability risk.[6] NERC's technical work consistently grounds the large load reliability concern in specific operational behaviors: second-to-second demand oscillation tied to AI training workloads, voltage-sensitive customer-initiated load reductions (CILR), and synchronized cross-facility demand reductions. A definition anchored to equipment type rather than demonstrated or expected behavior cannot effectively distinguish load facilities that pose reliability risks from those that do not. ELCON urges NERC to anchor the definition to behavioral criteria, or at a minimum incorporate a substantial-proportion threshold as detailed below.

The "Computational Load Entity (CLE)" definition is independently problematic and overly broad. As worded, any user of electric power demand from information technology equipment satisfies this definition and is a candidate for registration. Taken to its extreme, anyone with a computer is a potential NERC registrant.

The phrase "the entity that hosts end-users" could capture a landlord or owner of a multi-tenant industrial park that has no direct control over individual tenants' electrical behavior. Similarly, an industrial manufacturer that operates a vendor-managed server room could be registered as a CLE even though it has zero operational control over that equipment's electrical behavior or demand variability. ELCON recommends that NERC revise the CLE definition to require that the entity have operational control over the computational load at the facility. An entity that passively receives electric power for use by a third-party operator of information technology equipment should not bear registration obligations arising from that operator's equipment and behaviors.

In addition to the overly broad nature of the proposed definitions, it is unclear whether the definition and registration criteria are to be considered separately or jointly. In other words, must an entity first meet the explicit definition of a (CLE) before applying the registration criteria to determine if they are subject to registration? Is there a scenario where a "computational load entity" would not meet the MW and voltage registration criteria as defined in Appendix 5B of NERC's Rules of Procedure?

For example, Company X manufacturers widgets with a load profile of 28 MW and uses 1.6 MW of that demand to power its internal communications server (email), file database, internal management systems, process controls, and onsite data processing. Based on the definition alone, Company X could be considered a "Computational Load Entity" as some of its demand is used to power its information technology equipment.

However, if NERC's intent is to directly tie the *characteristics* and *behaviors* of certain loads that pose a risk to the BPS and then apply the specific size and voltage thresholds to determine their registration eligibility, it is not entirely clear as written.

If NERC does not intend to capture traditional loads hosting informational technology that is ancillary to its primary industrial process, ELCON recommends that NERC modify the proposed definition of "Computational Load" to include the qualifying language "load comprised *primarily* of electric power demand from information technology equipment… ."

[6] *See* Whitepaper #2.

Alternatively, NERC could include a percentage threshold to the definition. For example, "Computational Load means Load comprised of at least 50% of total electric power demand coming from information technology equipment… ."

With the clarification proposed by ELCON, traditional loads such as large commercial and industrial loads would not qualify for registration as the first criteria, the CLE definition, is not applicable. Thus, the proposed registration criteria in Appendix 5B would be irrelevant.

Appendix 5B – Statement of Compliance Registry Criteria

If, however, NERC intended to cast a broad net initially, as currently proposed in the CLE definition, with the registration criteria being more narrowly targeted to size impacts, the low thresholds in the proposed revisions to Appendix 5B of NERC's Rules of Procedure would still inadvertently capture a wide swath of large loads that do not exhibit the characteristics and behaviors identified in the whitepapers and supporting documentation. Such broad implementation would be extremely inefficient and would distract industry from focusing on mitigating the behaviors that pose actual risk to BPS reliability.

Applying the proposed registration criteria in our Company X example, after meeting the broad criteria in the CLE definition of load with "electric power demand from information technology equipment," Company X would then apply the registration criteria proposed in the revisions to Appendix 5B which specifies that a CLE must contribute at least **20 MW** in aggregate load at a single point of interconnection at a voltage of **60 kV** or higher where it hosts at least **1 MW** of load attributable to information technology equipment.

Here again, Company X (28 MW load, connects at 60 kV, where 1.6 MW of its power demand is used for internal information technology equipment) would meet each of the proposed criteria merely because of its size, not its operational characteristics. According to NERC's Technical Reasoning supporting document, the 1 MW of computational load represents a de minimis amount that would distinguish traditional load "such as industrial manufacturers."[7] It is not clear how a facility with only 1 MW of computational load (defined only as "informational technology equipment") would exhibit any of the variable load patterns attributed to reliability risks that precipitated NERC's large load work. Even in aggregate where that 1 MW load was located with 19 other facilities with at least 1 MW of computational load (i.e. 20 MW in aggregate), there is no direct link that ties the risk of the behavior and the impact to the grid due to its size. This approach risks including traditional industrial, manufacturing, and commercial facilities—many of which utilize computational processes as an ancillary component of their operations—but whose load profiles, operating characteristics, and system impacts are well understood and already adequately addressed through existing planning, interconnection, and operational frameworks.

[7] CLE Technical Reasoning, p. 3.

Critically, the proposal does not establish a clear, evidence-based nexus between the mere presence of "computational" activity and an increased or unique reliability risk to the BPS. Absent such a showing, expanding mandatory registration to these facilities would impose significant compliance obligations without a commensurate reliability benefit. NERC's registration framework has historically been grounded in functional distinctions that align with demonstrated reliability impacts. Departing from that principle here could dilute the effectiveness of the registry by including entities that do not meaningfully affect system reliability.

Further, the 60 kV voltage threshold requires explicit legal and technical justification that NERC has not provided. FERC's definition of the Bulk Electric System establishes 100 kV as the general bright line, with narrow exceptions justified by specific demonstrated reliability impacts. NERC's prior extension to 60 kV for generator registration was grounded in documented technical analysis of sub-100 kV generation impacts on the BPS. NERC should be required to provide equivalent technical justification for applying load registration at 60 kV, and absent such justification, ELCON recommends the voltage threshold be set at 100 kV. Similarly, NERC should publish the reliability analysis, if any, that supports the 20 MW aggregate threshold, as the LLWG guideline itself explicitly states that no MW threshold is specified in that document. Registration thresholds must be grounded in demonstrated reliability impact, not arbitrary size proxies. Finally, the proposed aggregation approach—measuring load across a single point of interconnection—does not correspond to the actual reliability risk that NERC seeks to address. The LLWG's documented concern is with cross-facility synchronized demand reductions across geographically dispersed facilities. A single 28 MW industrial facility with 1.6 MW of internal IT equipment presents no such cross-facility synchronization risk regardless of its size, and the proposed criteria fail to make this distinction.

Should NERC reject the proposed qualifying language in Appendix 2 and adopt the CLE definition as written, ELCON requests that NERC adjust the MW and voltage thresholds proposed in Appendix 5B to more closely align with actual risk impact to the BPS.[8] Alternatively, the 1 MW "de minimis" criteria could be replaced with:

> and 3) at least 50% of that aggregated connected Load capability is attributable to powering Computational Load.[9]

This revision also recognizes that NERC's concern does not lie solely with the mere size of these loads and their variable behavior, but that the *proportion* of computational loads in relation to the entire system will significantly increase causing an even greater risk to the BPS.

[8] The proposed 20MW is entirely too low and fails to target the size impacts of actual observed behavior, such as the often-cited incidents in Virginia and Texas that each involved loads of over 1GW.

[9] ERCOT has recently recognized this distinction in its revised definition of "Large Computational Load" which includes the criteria that a 50% or greater portion of the demand at a site be attributable to electronic based load.

Finally, the breadth of the definition and registration criteria creates uncertainty for entities that may not reasonably have considered themselves subject to NERC jurisdiction, leading to potential over-reporting, administrative burden, and inefficient allocation of compliance resources—for both industry and NERC. Absent these refinements, the proposed criteria risk being both overinclusive and insufficiently tied to the reliability concerns it is intended to address. We respectfully urge NERC to revise the proposal to ensure that any expansion of the registration regime is targeted, justified, and proportionate to demonstrated risks to the BPS.

Registration of End-Users

NERC's jurisdiction over "users, owners and operators" was established by section 215 of the Federal Power Act as enacted through the Energy Policy Act of 2005. Since 2005, NERC has asserted that authority through its registration requirements, mandatory reliability standards, compliance and monitoring programs, and enforcement at the transmission level for those responsible for operating and planning the bulk power system. Although there has been some consideration of NERC's jurisdiction over certain distribution functions, there has never been an instance where NERC's authority over "users" has been challenged or more narrowly defined. Specifically, as "users" are typically under retail (state and local) jurisdiction, where does NERC's authority over "users" begin and end?

Size and voltage thresholds offer little protection when defining NERC jurisdiction as the end-user continues to evolve as does NERC's scope. The generally accepted bright-line for NERC jurisdiction has traditionally been 100 kV and above as memorialized in the Bulk Electric System definition in NERC's Rules of Procedure. With the introduction and increased penetration of variable resources, NERC determined that it needed to assert jurisdiction at the 60 kV in some instances[10].

Here again, NERC is proposing jurisdiction at the 60 kV level without addressing the retail v. wholesale, bulk electric system, transmission v. distribution divide. Further, it is questionable to what extent an entity whose chief function falls well outside of electric grid service should be required to manage grid operations and protocols. The reliability concerns cited in the proposal—such as large, rapidly changing load profiles or novel operational characteristics—can be more appropriately and lawfully addressed through entities that are already subject to NERC oversight. Transmission Owners, Transmission Operators, Balancing Authorities, and Load-Serving Entities are already responsible for planning,

[10] *See* NERC Rules of Procedure, Appendix 2 "'Generator Operator' means the entity that: 1) operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services (Category 1 GOP); or 2) operates non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to **60 kV** (Category 2 GOP)" (emphasis added).

interconnection oversight, operational coordination, and real-time balancing of load. These registered entities are well positioned to assess and manage the impacts of large or variable loads within their systems using existing or refined reliability standards, interconnection requirements, and operational tools. "Users" do not share the requisite expertise nor visibility and control into system operations. Their core mission is health care, manufacturing, chemical processing, mining, data processing, national security, logistics, etc. NERC must ensure that those entities with the technical expertise and responsibility for managing the grid are the entities responsible for ensuring responsible usage of the grid by their customers.

The existing NERC reliability framework places responsibility for BPS reliability squarely on registered entities—transmission owners, transmission operators, planning coordinators, balancing authorities, and distribution providers—who are professionally staffed, technically equipped, and legally obligated to manage BPS reliability. These entities already have the tools and authority to manage large load interconnections through FAC-001 interconnection requirements, qualified change triggers in interconnection agreements, and real-time operational coordination. The LLWG Reliability Guideline itself directs Transmission Owners to incorporate guideline recommendations into FAC-001 interconnection requirements; this mechanism can achieve the same reliability outcomes without the jurisdictional overreach of direct end-user registration. ELCON urges NERC to strengthen the obligations of existing registered entities rather than conscript retail customers into the NERC registry for purposes of addressing load behaviors that existing registered entities are already positioned and obligated to manage.

Reliability is essential to all of us and time is critical as our Nation's energy system evolves rapidly on both the user and producer side. To swiftly address the risks and regulatory gaps identified by the LLWG, the recommendations in the Level 2[11] and Level 3[12] alerts should be formalized through revisions to existing standards (bridge standard) with development of new standards to be applicable to current registered entities.

ELCON appreciates the extensive outreach and analysis devoted to ensuring our grid can meet the challenges of integrating emerging large loads and large load technologies. ELCON looks forward to continuing our engagement with NERC as we address large load operations and the criticality of reliable electricity.

[11] Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations (Sept. 9, 2025),

[12] Essential Action to Industry: Computational Load Modeling Studies, Instrumentation, Commissioning, Operations, Protection, and Control (May 4, 2026), https://www.nerc.com/globalassets/programs/bpsa/alerts/level-3-computational-load-alert.pdf.

/s/ Karen Onaran
Karen Onaran
President & CEO
Electricity Consumers Resource Council (ELCON)

May 15, 2026

Good afternoon,

For the proposed term, “Computational Load Entity”, the new entities should be designated as either a “Computational Load Owner” or “Computational Load Operator” like the existing functions of TO & TOP and GO & GOP. One organization can be registered as both, or multiple organization working on a project can register separately based on their scoped roles. This allows the appropriate reliability standard requirements to be assigned to an entity that owns and/or develops the project and to the entity that will be operating the Computation Load Facility.

Thank you,

Cassie Sims
Sr. Lead Analyst, Security & Reliability Programs

entergy.com



NERC Rules of Procedure Team –

Please see below for the comments from AECC's SMEs regarding the proposed revisions to the Rules of Procedure:

Computational Load Definition:

- The Standards Drafting Team should consider revising the definition of Computational Load to ensure it clearly reflects the explicit exclusion of equipment that is used by direct physical/local interaction (e.g., laptop computers).
- The Standards Drafting Team should consider revising the definition of Computational Load to ensure it is clearly restricted to server type hardware only (which would include "workstation" type hardware that is operated in a server mode or arrangement) whose power usage from the transmission system can be directly or indirectly controlled. This control can be due to the inherent processing source for the equipment between the transmission system and some other on-site source (e.g., generator, UPS, etc.). The ability to control the load seen by the transmission system will likely be an important component in future NERC Reliability Standards. If the owner cannot control the equipment, NERC will not be able to mandate any requirements that seek to control it.
- To summarize: Computational Loads should be non-portable, fixed, server type information technology equipment whose transmission system power usage can be controlled.

Other Thoughts:

- The Standards Drafting Team should reconsider the 1 MW threshold. 1 MW of load seems too low, and it may pull smaller data centers which do not pose a problem for the transmission system into scope. NERC should explain its reasoning and provide a justification for this specific threshold. The criteria should focus on the amount of computational load only, and not the amount of other traditional loads.
- Is NERC's intention to focus on the type of equipment or the type of load, and not the characteristics of the load? Are the concerns based more upon the fluctuations and fast ramp rates of loads regardless of load type? NERC should consider creating a "volatile loads" definition that is defined by the speed and degree to which the load magnitude changes instead of creating a "computational load" definition.

Thanks,

Ayslynn McAvoy

NERC Compliance Manager
Arkansas Electric Cooperative Corporation
Arkansas Electric Cooperatives, Inc.

To whom it may concern,

FirstEnergy will be supporting the comments generated by the Trade Association. They are attached to this email. We appreciate NERC taking our position into consideration.

Thank you,
Sarah Miller

Sarah Miller
Asst. Compliance Specialist

Hello NERC team,

Google agrees with the comments submitted by the Data Center Coalition (DCC) attached to this email.

Getting the definition details right is critical at this stage. The DCC has flagged several critical clarifications that will help NERC and industry ensure this effort is well targeted for the perceived risks.

Mike Della Penna | Global Infrastructure & Energy |

Dear NERC Team,

Thank you for the opportunity to provide stakeholder input on the Proposed Revisions to the Rules of Procedure and for NERC's continued efforts to address reliability considerations associated with emerging large/computational loads.

As outlined in the attached OEB–NERC MOU and IESO–NERC–NPCC MOU, these agreements define the framework for administering NERC reliability standards in Ontario, including clear roles and compliance accountabilities. Under this framework, the IESO is solely accountable to NERC, while Ontario market participants/entities comply through the IESO in accordance with the Market Rules rather than through direct registration with NERC. Given that changes to the Rules of Procedure may require direct registration in the NERC Compliance Registry, it is important that any revisions preserve this established compliance structure.

The following are our comments:

- Any revisions to NERC Registration Criteria to require registration of Computational Load Entities with NERC should respect existing jurisdictional registration frameworks for non-US entities.
- Clarification is needed regarding the meaning and intended application of "single point of interconnection," since a Computational Load Entity that receives multiple supplies from the BPS may not meet the definition.
- Further clarification would be helpful regarding registration of multi-tenant and colocation facilities where the host facility and end-use tenants may have different levels of control over IT load behavior, such as a data centre owner operating the electrical infrastructure while tenants control server dispatch or workload migration.
- It would be helpful to understand the technical and/or reliability rationale for the proposed registration thresholds, including the 20 MW aggregate connected load threshold and the 1 MW Computational Load criterion, and whether these values are based on BPS impact analysis, operational experience, historical disturbance data, alignment with existing registration thresholds, or specific reliability risks intended to be screened.
- Clarification would be helpful regarding applicability to distribution-connected computational loads, including cases where the IT load is connected below 60 kV but the distribution system is supplied from transmission at or above 60 kV; consideration

could be given to whether applicability should be based on the immediate customer connection point, the upstream transmission connection point, or demonstrated BPS impact.

- Additional clarity would be helpful on the treatment of behind-the-meter generation, self-supply, and export-capable facilities for registration purposes. Depending on whether registration is based on gross load, net load, maximum connected load capability, or another metric, registration criteria may or may not be met.
- Clearly defining registration boundaries between CLEs and existing registered entities would help avoid uncertainty, duplication, or conflicting obligations, including interactions with Transmission Planners, Transmission Operators, Distribution Providers, Planning Coordinators, and Load-Serving Entities.
- Looking beyond the current effort to revise the ROP, additional clarity would be helpful on registration timelines, transition periods, and expectations for existing versus new computational load facilities.

In closing, we thank NERC for its continued attention to these important matters. We welcome further discussion should any points require clarification or additional consideration.

Sincerely,
Independent Electricity System Operator (IESO)
Compliance Assurance

Pirouz Honarmand | **Specialist, Compliance Assurance | Legal Resources & Corporate Governance**
Independent Electricity System Operator (IESO) |

Invenergy

One South Wacker Drive | Suite 1500 | Chicago, Illinois 60606

May 15, 2026

Invenergy Comments on Proposed Computational Load Entity RoP Revisions

NERC,

Thank you for the opportunity to provide comments on this important matter. Invenergy believes the proposed registration criteria for Computational Load Entities is overly broad, and the low MW thresholds may unintentionally require industrial manufacturers or other non-data center loads with a de minimis amount of Computational Load to register with NERC. This will place an unnecessary burden on both the newly registered entities and the Regional Entities as critical resources are dedicated to smaller facilities that do not present the same risk to the Bulk Power System as larger data centers.

Invenergy recommends NERC revise the proposed registry criteria to better align with the existing, and in development, thresholds established by RTOs and ISOs. Their criteria better reflect the load capabilities that they consider impactful to their systems and will ensure that resources are not spread thin. If NERC is determined to include loads of 20 MW or greater, we recommend a ratio-based threshold for the Computational Load capability that limits registration to those entities whose primary purpose is Computational Load.

Sincerely,
Rhonda Jones
Vice President of Reliability Compliance, Invenergy
Member, Reliability and Security Technical Committee

ISO/RTO Council Standard Review Committee's Comments on Proposed Computational Load Entity ROP Revisions

May 15, 2026

The ISO/RTO Council (IRC) Standards Review Committee[1] (SRC) offers the following comments on the proposed revisions to the NERC Rules of Procedure (ROP) to define Computational Load and register Computational Load Entities (CLEs), released on April 1, 2026. The SRC appreciates this opportunity to provide feedback on the proposed ROP revisions.

Summary of SRC Comments

- Consider developing additional definitions for Bulk Electric System-level Computational Loads, analogous to Category 1 Generator Owners and Generator Operators.
- Increase the 1 MW Computational Load threshold in the CLE registration criteria or replace it with a threshold based on what percentage of the CLE's total Load is Computational Load.
- Align the Distribution Provider (DP) registration threshold with the CLE registration threshold.
- Evaluate the best way to ensure NERC-level obligations apply to the interconnection of a CLE that pushes a distribution entity above the DP registration threshold.
- Revise the Computational Load definition to read as follows: *"Computational Load" means Load that uses electric power for equipment needed for operation of computers or computer programs. Examples of such equipment include, but are not limited to, processors, memory, data storage devices, and networking equipment.*
- Revise the CLE definition as follows: *"Computational Load Entity" means the ~~end user or the entity~~ operator of a facility that ~~hosts end users that receives~~ uses electric power for Computational Load.*

SRC Comments

CLE Registration Threshold

The ROP revisions propose to require a CLE to register with NERC if the CLE contributes to an aggregate connected Load capability greater than or equal to 20 MW at a single 60 kV or greater point of interconnection to the Bulk-Power System and hosts 1 MW or more of Computational Load. The SRC offers no comment on the MW value used in the proposed 20 MW threshold, as a variety of thresholds exist in RTO/ISO-specific definitions of what constitutes a large load or CLE-type entity.

[1] For purposes of these comments, the SRC comprises the California Independent System Operator Corporation (California ISO), Electric Reliability Council of Texas, Inc. (ERCOT), ISO New England Inc. (ISO-NE), Midcontinent Independent System Operator, Inc., (MISO), New York Independent System Operator, Inc. (NYISO), PJM Interconnection, L.L.C. (PJM), and Southwest Power Pool, Inc. (SPP).

The SRC notes the proposed threshold appears to align with the threshold used for Category 2 Generator Owners and Generator Operators. Consequently, NERC may wish to consider whether it would be prudent to also establish a higher set of thresholds for CLEs that might be considered part of the Bulk Electric System, analogous to Category 1 Generator Owners and Generator Operators.

However, the SRC believes the 1 MW Computational Load threshold as proposed is too low and could result in registration requirements being imposed on entities that do not primarily perform Computational Load-type activities and cannot reasonably be considered Computational Loads (for example, a 200 MW manufacturing facility that happens to have 1.5 MW of on-site computing equipment). Establishing a higher threshold or a threshold based on a percentage of the total Load (e.g., more than 60% of the Load at the facility is Computational Load) would help prevent the definition from being overinclusive.

DP Registration Threshold

While the proposed ROP revisions do not presently address the DP registration threshold, the SRC recommends revising the DP threshold as part of this project. The original DP threshold was 25 MW, and the threshold was increased to 75 MW in 2015 to reduce the regulatory burden on smaller, lower-risk distribution systems. However, as the Standards Drafting Team in Project 2026-02 has recognized, DPs have an important role to play in reliably interconnecting CLEs to the Bulk-Power System. To avoid a scenario in which a CLE attempts to interconnect with an entity that is not registered as a DP and therefore has no NERC-level obligation to fulfill the DP's role in reliably interconnecting CLEs (for example, a 25 MW CLE seeking to interconnect with an entity that operates a 40 MW distribution system, resulting in a total system size of 65 MW, which is still below the current 75 MW DP threshold), the DP registration threshold should be revised to match the CLE registration threshold, regardless of whether that threshold is ultimately 20 MW or some other value.

Regardless of which registration thresholds are ultimately used for CLEs and DPs, NERC and the Project 2026-02 Standard Drafting Team will need to carefully consider the most effective way to address a scenario in which a CLE interconnection pushes a distribution system above the DP registration threshold (for example, under current thresholds, a 50 MW CLE seeking to interconnect with a 50 MW distribution system, resulting in a total system size of 100 MW). System reliability would be best served if the distribution entity were registered as a DP to fulfill the relevant NERC-level DP obligations before interconnecting the CLE. Achieving this result would likely require additional revisions to the DP registration criteria.

Computational Load Definition

The proposed Computational Load definition seem underinclusive and vulnerable to arguments about whether the examples provided (servers, storage, and networking hardware) limit the scope of the definition, thereby potentially excluding hardware used for advanced computing (such as computational accelerators or quantum computing hardware) or hardware that does not serve a traditional server-type role, such as hardware used in a peer-to-peer architecture instead of a server-client architecture. To better futureproof the definition and clarify the scope and role of any examples provided, the SRC recommends the Computational Load definition to be revised to read as follows:

> "Computational Load" means Load that uses electric power for equipment needed for operation of computers or computer programs. Examples of such equipment include, but are not limited to, processors, memory, data storage devices, and networking equipment.

CLE Definition[2]

In the proposed CLE definition, the phrase "entity that hosts end-users" is somewhat vague, and the phrase "end-user or the entity that hosts end-users" creates ambiguity as to whether the end user or the facility host would be the CLE for a given facility, which in turn creates ambiguity about who is required to register if the facility meets the applicable CLE registration thresholds. It would be less ambiguous to assign registration responsibility to the facility operator in all cases, since the operator is best situated to ensure the facility complies with all applicable Reliability Standards. Consequently, the SRC recommends revising the definition as follows:

> "Computational Load Entity" means the ~~end-user or the entity~~ operator of a facility that ~~hosts end-users that receives~~ uses electric power for Computational Load.

Conclusion

The SRC appreciates the opportunity to comment on the proposed ROP revisions. The SRC would welcome the opportunity to further discuss these comments or other Computational Load-related topics with NERC as appropriate and looks forward to engaging in the remainder of the ROP revision process.

[2] PJM is also submitting separate comments regarding the CLE definition and associated registration criteria.

Microsoft Comments on Proposed Revisions to NERC ROP: Computational Loads

5/15/2026

INTRODUCTION

Microsoft operates more than 400 data centers across North America and five continents. A reliable grid is essential to our ability to serve customers and support United States leadership in artificial intelligence. We welcome NERC's efforts to address the reliability risks posed by large computational loads and submit these comments to ensure the proposed framework is well-calibrated to that goal.

These comments build on Microsoft's prior submission on NERC's Standard Authorization Request for Project 2026-02, filed April 30, 2026, and focus specifically on whether the proposed definitions and registration criteria appropriately reflect system impact and reliability considerations.

COMMENTS

A. Existing Registered Entities Can Provide the Quickest Path to Mitigating Identified Risks

The existing reliability framework already provides effective tools for managing large load risks. Transmission Owners and Operators hold federal and state tariff authority that can be used to impose requirements on large load customers directly, i.e., no new registration category is required to close any accountability gap. Expanding the obligations of existing registered entities is faster to implement, avoids the complexity of bringing an entirely new class of entities into NERC compliance, and builds on processes that are already operational.

To make that approach effective, however, registered entities need to do their part. Microsoft recommends the drafting team establish clear expectations for existing entities to coordinate with large loads on telemetry standards, modeling data requirements, and grid-side monitoring—so that any compliance obligations placed on large loads are grounded in information that is available and actionable.

B. NERC Should Include All Large Loads That Impact the Bulk Power System, Not Only Computational Loads

Singling out "computational" load risks creating a framework that addresses one category of risk while leaving comparable risks from other large load types unaddressed. Large electrified industrial processes, battery manufacturing facilities, and similar loads can present the same reliability challenges—high ramp rates, concentrated interconnection, potential for correlated loss events—without falling within the proposed definition. A standard grounded in behavior and system impact rather than end-use would be more durable and more effective. At a minimum, NERC should commit to addressing other large load types in Phase 2.

C. The Definitions of "Computational Load" and "Computational Load Entity" Should Be Revised to Distinguish Between Differing Facility Operations and Load Behaviors

The definition of "Computational Load" as power demand from "information technology equipment, such as servers, storage, and networking hardware" is broad enough to capture hospitals,

universities, industrial facilities, and commercial buildings that use IT equipment as part of ordinary operations. These are stable, predictable loads that bear no resemblance to the reliability risks NERC has documented. The open-ended "such as" language compounds the problem by leaving the scope of the definition unclear for both registrants and auditors. NERC should ground the definition in the operational characteristics—load variability, ramp rate, power factor behavior—that actually drive reliability concerns and should include a clear exclusion for traditional loads that happen to use similar equipment.

The "Computational Load Entity" definition also does not reflect how data centers are actually structured. In many deployments, the entity that owns and finances the facility is entirely separate from the tenant that installs and operates the computational equipment, and it is the tenant's operational decisions that drive the load behavior of reliability concern. The single "CLE" designation obscures this distinction and risks misallocating compliance obligations between parties that have very different relationships to the grid.

Microsoft recommends that NERC establish separate Computational Load Owner ("CLO") and Computational Load Operator ("CLOP") functional entities, modeled on the existing Generator Owner/Operator and Transmission Owner/Operator frameworks.

For example, the CLO, the entity that owns and maintains the facility and its interconnection infrastructure, would bear responsibility for facility-level obligations: design specifications, interconnection compliance, and equipment standards. The CLOP: the entity that controls real-time load behavior, would bear responsibility for operational obligations: load ramp management, communications with the Transmission Operator and Balancing Authority. A single entity can hold both registrations where it owns and operates the same facility. Where ownership and operation are split, as is common in co-location and wholesale lease arrangements, each party's obligations would be delineated by function. This structure does not eliminate compliance responsibility for large load customers, but it ensures that each requirement attaches to the entity actually in a position to fulfill it, and creates a commercially workable framework for allocating grid compliance responsibilities between landlords and tenants.

D. The Aggregate Capacity and Load Thresholds Are Too Low and Risk Increasing Administrative Burden for Little Corresponding Reliability Benefit

The proposed 20 MW aggregate threshold captures a very wide range of facilities, many of which will have no meaningful impact on BPS reliability. NERC has not provided a technical basis for why a load at that level presents material risk, and the documented reliability incidents—involving load rejection events of 1,000 MW or more—do not support a 20 MW floor. The 1 MW computational load sub-threshold makes this worse: a facility with 1 MW of servers within a 20 MW footprint simply does not exhibit the characteristics NERC is trying to regulate. It is also important to note that what is observed at the point of interconnection is not the same as what is measured at the facility level. A load that appears behaviorally significant at the facility may present as routine variation at the POI on a larger system.

Microsoft recommends that NERC either raise the thresholds to levels supported by technical analysis and demonstrated material impact on the Bulk Power System or simplify to a single Computational Load threshold that directly reflects the characteristic driving reliability risk to the Bulk Power System. Registration thresholds should reflect what is observable and meaningful at the Bulk Power System level, not just the size of the facility.

E. Any New Category of Registered Entity Should Include Explicit Exclusions for Existing Facilities and Facilities in Advanced Design

Facilities that are already in service, under construction, or in advanced development were designed and financed without any expectation of NERC registration or technical requirements, which may have meaningful impacts on sites that are operational or in advanced design. Applying new requirements to them retroactively risks stranded investment and project disruption. Microsoft recommends that NERC includes a clear mechanism for requesting an exemption from reliability standards or clear grandfathering provisions covering facilities currently in service; facilities under active construction; facilities in design, permitting, or procurement; and facilities with executed interconnection or service agreements. Where new requirements do apply, compliance timelines should be developed in consultation with affected entities before they are finalized.

Microsoft recognizes that certain existing large computational loads may present genuine near-term reliability risks that NERC has a legitimate interest in addressing promptly. We do not categorically dispute that proposition. Our concern is with the remedy, not the risk assessment. The proposed framework applies registration and compliance obligations broadly, without distinguishing between facilities that present material BPS risk and those that do not. A 500 MW hyperscale AI training cluster interconnected directly to the transmission system presents a fundamentally different risk profile than a 25 MW colocation facility serving mixed commercial tenants. Applying the same retroactive compliance mandates to both, on the same timeline—is not proportionate to the actual reliability exposure involved.

The primary position is that any new registration requirements should apply prospectively, with existing and in-development facilities protected by clear grandfathering provisions. Facilities currently in service, under active construction, in design or procurement, or with executed interconnection or service agreements were designed and financed without any expectation of NERC registration; retroactive application risks significant stranded investment or substantive additional investment to bring facility into compliance.

In the alternative, if NERC determines that some existing facilities must be brought into compliance, Microsoft urges that the compliance pathway be tightly calibrated to the risk each facility actually poses to the Bulk Power System. Obligations and timelines should reflect the facility's size, interconnection voltage, load variability characteristics, and proximity to grid constraints - not a uniform mandate applied to every facility above a low MW threshold. This approach is consistent with the definitional precision we advocate in Sections B, C, and D: a framework that is appropriately scoped to the problem NERC has identified will be more durable, more defensible, and more likely to achieve its reliability objectives.

F. The "Point of Interconnection at ≥ 60 kV" Criterion Requires Clarification to Prevent Inconsistent Application

The proposed criterion—interconnection "at a single point to the Bulk Power System at a voltage ≥ 60 kV"—is ambiguous in common facility configurations where a step-down transformer sits between the load and the transmission system. A load entity could plausibly argue it interconnects at the lower secondary voltage and falls outside the registration threshold, even where the functional BPS connection is clear. NERC should close this gap by adopting language modeled on the existing Category 2 inverter-based resource definition, which captures facilities "connected through

a system designed primarily for delivering capacity to a common point of connection at a voltage ≥ 100 kV." That language is already accepted by industry and regulators and would apply straightforwardly here. A 100 kV threshold also aligns with NERC's existing Bulk Electric System definition framework and provides greater consistency across reliability registrations.

CONCLUSION

Microsoft appreciates NERC's consideration of our comments and a shared focus on addressing reliability issues in an expedited manner. Microsoft's recommendations are designed to encourage a framework that is based on material risk, existing regulatory structures, and technical rigor.

In summary, Microsoft respectfully recommends NERC:

- Maximize the use of existing Registered Entities to mitigate large load reliability risks, ensuring those entities provide the data, telemetry, and technical guidance that large load compliance will require;
- Expand the scope of the ROP revisions to address all large loads with material BPS impact, or commit to doing so in Phase 2;
- Revise the definitions of "Computational Load" and "Computational Load Entity" to reflect operational behavior and system impact rather than equipment type, and adopt a Computational Load Owner/Operator framework consistent with established NERC functional entity structures;
- Recalibrate the aggregate MW and Computational Load sub-thresholds upward, supported by clear technical analysis demonstrating material BPS impact at the selected levels;
- Include explicit grandfathering provisions covering in-service, in-construction, and in-design facilities, as well as those with executed agreements, with realistic compliance timelines developed in consultation with affected entities; and
- Clarify the "point of interconnection at ≥ 60 kV" criterion using language modeled on the existing Category 2 IBR definition to prevent inconsistent application and registration avoidance, while aligning the threshold with NERC's existing BES framework.

To who it may concern,

The proposed computational load definition would benefit from additional clarification in two areas. First, the reference to “storage” is unclear and should specify whether it refers to energy storage resources, data storage infrastructure (e.g., servers or hard drives), or another type of storage entirely. Second, additional clarity is needed regarding the phrase “aggregate connected Load capability” in relation to “a single point of interconnection” in Appendix 5B, page 8. Specifically, it is unclear whether the intent is for the aggregated connected load to exist behind a single POI in order to meet the registration threshold. For example, if multiple adjacent POIs each serve approximately 19 MW of load, it is uncertain whether those loads would collectively be considered for Compliance Registry applicability or treated independently below the threshold

Adrian Harris
Advisor / Regulatory Compliance

1700 Centerview Drive, Little Rock, AR 72211 | www.misoenergy.org



NYPA supports the comments submitted by the Trade Associations (APPA, LPPC, EEI, NRECA and TAPS) on the proposed revisions to NERC Rules of Procedure.

Libin Varghese
Engineer, Reliability Standards & Compliance

New York Power Authority
123 Main Street, 11th Floor (11-A)
White Plains, NY 10601

www.nypa.gov

To whom it may concern:

I am emailing to express Oracle's support for the comments being submitted today by the Data Center Coalition on the proposed Rules of Procedure changes with definitions and registration criteria for Computational Loads, attached for reference. Oracle is a Registered Ballot Body participant within Segment 7.

Sincerely,
Madeline Fleisher

ORACLE

Madeline Fleisher | Senior Managing Counsel
Oracle Legal

2750 Monroe Blvd.
Audubon, PA 19403

May 15, 2026

RE: PJM's response to NERC's Rule of Procedures (ROP) revisions related to Computational Loads.

Hello,

Background to the following comments: In PJM's experience, many of the entities that build and own data centers are essentially landlords, who lease out the data center facility to an anchor tenant or multiple tenants. As a result, the entity that owns the physical facility and interfaces/contracts with the distribution utility may be separate and distinct from the entity that controls the computational equipment therein. The draft ROP changes to Appendix 5B appear to capture this concept better than the definition in the currently drafted Computational Load Standard Authorization Request[1], by defining Computational Load Entity as "[*t]he end-user or the entity that hosts end-users that receives electric power for Computational Load*." Whichever definition is ultimately adopted, the goal should be the same—to provide the Regional Entity with clear authority to ensure that contractual relationships between the computational load and the host do not frustrate the Regional Entity's ability to register the party who presents the actual risk to the BES.

PJM notes that the draft revisions to Appendix 5B establish that a Computational Load Entity will be registered only if it: 1) contributes to an aggregate connected Load capability greater than or equal to 20 MW; 2) at a single point of interconnection to the Bulk Power System at a voltage greater than or equal to 60 kV; and 3) hosts 1 MW or greater of Computational Load. PJM recommends increasing the load threshold from 20 MW to 50 MW. This is the threshold by which PJM defines a large load and will "right size" any subsequent compliance obligations to avoid capturing a wide range of entities that do not present the same risk to BES reliability as larger data centers. Increasing this threshold will also permit Regional Entities to focus their resources on auditing only those Computational Load Entities that present the most risk to the BES, in line with the overall policy trajectory of the risk-based Reliability Assurance Initiative. PJM correspondingly recommends reducing the DP threshold to greater than 50 MW of peak Load that is directly connected to less than or equal to 60kV. The original DP threshold was 25 MW, and the threshold was increased to 75 MW in 2015 with the aim of reducing the regulatory burden on smaller, lower-risk distribution systems. While this may have made sense in 2015, PJM is now dealing in real time with the challenges of the increased DP threshold, such as collecting IBR and DER data now required by MOD Standards (and soon to be TOP and IRO

[1] Project 2026-02 Computational Loads Standard Authorization Request: https://www.nerc.com/globalassets/standards/projects/2026-02/sar-comment-period/2026-02-computational-load-alignment-phase-1-sar_sc-approved.pdf

2750 Monroe Blvd.
Audubon, PA 19403

Standards) where the host DP is not a NERC registered entity. Aligning the Computational Load Entity threshold with the DP registration threshold will ensure a level playing field from a compliance and implementation perspective. In addition, NERC must be wary of a scenario in which multiple data centers exist at the same campus, but they are physically segregated to fall below 50 MW each, so that none of them are required to register as a Computational Load Entity. To address this, NERC should consider the “one-mile” rule that FERC has used for many years regarding Qualifying Facilities under PURPA. Under this rule, a one-mile radius is drawn around a given facility to ensure that entities cannot escape regulatory requirements by breaking themselves into smaller parts. See 18 C.F.R. § 292.204.

Please feel free to contact me should you have questions regarding this matter.

Sincerely,

Elizabeth (Becky) Davis
Sr. Lead Analyst, FERC & Reliability Compliance

cc: Thomas Devita

To Whom it may concern,

Eversource would like to voice its support for the joint comments filed by the American Public Power Association (APPA), Edison Electric Institute (EEI), Large Public Power Council (LPPC), National Rural Electric Cooperative Association (NRECA), the Transmission Access Policy Study Group (TAPS), and the National Association of Regulatory Utility Commissioners (NARUC).

Eversource supports the comments submitted by EEI and the trades, with one exception: we oppose limiting the registration of Computational Loads (CL) exclusively to those "75 MW connected at >= 100kV for Computational Load Facilities, consistent with the NERC Bulk Electric System definition for dispersed power producing resources (i.e., inverter-based resources) – where the current criteria of greater than 75 MVA at a common point of connection at >= 100kV is utilized". Instead, Eversource aligns with the Trades' alternative proposal for a model similar to Generator Owner/Operator, establishing Category 1 and Category 2 classifications. Eversource and its Regional Transmission Organization currently plan to include all large loads (>20 MW) in regional planning and study processes. Adopting this two-category approach allows for a risk-based compliance structure, ensuring uniform reliability requirements for all large loads, while allowing stricter reliability and security standards for Category 1 when warranted and technically justified.

Thank you and please reach out if you have any questions or comments.

Respectfully,

Joshua London
Senior Engineer, Reliability Compliance

EVERSOURCE

Good morning,
Consumers Energy is submitting comment on the Proposed Computational Load Entity ROP Revisions.

Neither NERC's *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Load* nor the findings in the *NERC Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations* provide sufficient justification for establishing the proposed registration thresholds of an aggregate load of 20 MW with a 1 MW Computational Load component.

While NERC's publications to date have demonstrated the potential reliability risks associated with large loads—particularly Computational Loads—Consumers Energy agrees that the creation of a new registered entity is appropriate. However, Consumers Energy does not agree with the proposed thresholds. Rather than defining both an aggregate load threshold and a Computational Load sub-threshold, NERC should simplify the criteria by establishing a single threshold based on total Computational Load, as this load characteristic has been identified by NERC as posing the greatest potential risk to the Bulk Power System (BPS).

The Level 2 Alert report indicates that approximately 90–95 percent of existing industry-defined large load thresholds are at or above 20 MW. However, the report does not demonstrate that a load at or near 20 MW, in and of itself or in reasonable local aggregation with similar loads, presents a material risk to BPS reliability. NERC recently revised their Rules or Procedure to include IBR generators 20 MW or larger interconnecting at 60 kV or higher and demonstrated that, in aggregate, these units could impact the BPS. Therefore, it is logical that NERC would propose a similar threshold for Computational Load Entities, however, NERC must acknowledge the fundamental difference in quantity and magnitude of interconnections between dispersed IBR generation resources expected to interconnect to the system and Computational Loads expected to interconnect to the system. Consumers Energy recommends that NERC consider increasing the proposed threshold to better align with thresholds already established—or currently being proposed—by Regional Transmission Organizations.

As currently defined, Consumers Energy does not believe the proposed criteria sufficiently

distinguish between traditional industrial customers with de minimis Computational Load and entities whose primary business purpose is Computational Load. While the proposed 1 MW Computational Load threshold may have been derived from responses to NERC's Level 2 Alert questionnaire, this value is unreasonably low if the intent is to capture entities whose Computational Loads are expected to have a meaningful impact on the BPS.

If the Computational Load threshold is increased to a more appropriate level, Consumers Energy recommends removing the proposed 60 kV voltage threshold for clarity. The reliability gaps identified by NERC are not inherently tied to a specific interconnection voltage level, but rather to the size and characteristics of the aggregated load. If NERC determines that retaining a voltage threshold is necessary, Consumers Energy recommends including clarifying language such as: *"at a single point of interconnection directly to the Bulk Power System, or through facilities primarily designed to deliver power to the Computational Load Entity from a common point of connection, at a voltage greater than or equal to XX kV."* This clarification would mitigate potential interpretation issues. For example, scenarios exist where the Transmission Owner owns a networked transmission system, the Distribution Provider interconnects one or more 138/34.5 kV transformers, and the Computational Load Entity could assert that its facilities interconnect at 34.5 kV and are therefore exempt from registration. Incorporating language similar to NERC's BES Inclusion I4 would help prevent such gaps in interpretation.

Regards,
Eric R. Sutlief

Eric R. Sutlief, **FERC/NERC Regulatory Compliance**



Hello,

After discussing with our neighboring utilities, PacifiCorp would like to submit the following minor proposed modifications to item III.c.1 in Appendix 5B:

> III(c) Computational Load Entity: III.c.1 Computational Load Entity that 1) contributes to an aggregate connected Load capability greater than or equal to 20 MW; 2) aggregates to ~~at~~ a single point of interconnection or substation on ~~to~~ the Bulk Power System operated at a voltage greater than or equal to 60 kV; and 3) hosts 1 MW or greater of Computational Load.

Many thanks,
Lindsay

Lindsay Wickizer
NERC Compliance
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

Good morning,

Southern Company offers the following comments for consideration:

"Southern Company supports the comments from the joint Trade Associations (APPA, EEI, LPPC, NRECA, and TAPS) on the proposed Rules of Procedure modifications pertaining to Computational Loads."

Best regards,

Laura Winston
NERC Compliance Coordinator
Operations Compliance
Southern Company Services

Comments on Proposed Changes to NERC Rules of Procedures Regarding Computational Loads

The Solar Energy Industries Association (SEIA) values the opportunity to provide comments on proposed changes to NERC Rules of Procedures (ROP) regarding Computational Loads.

SEIA is a trade organization of over 1,200 members in the solar PV and storage industry. Many of our members are involved in creating solutions that provide electric power to Computational Loads. This includes solar PV and Battery Energy Storage Systems (BESS) which operate through Power Purchase Agreements (PPAs), market participation, and co-location with Computational Loads. It also includes the stand-alone supply of BESS co-located with Computational Load, which can provide multiple value streams to Computational Load. In addition, some members are evaluating if resources co-located with Computational Load can provide services to the grid.

SEIA and its members are committed to working with NERC to maintain Bulk Power System (BPS) reliability.

We offer the following comments, arranged by ROP section.

Appendix 2

Proposed Terminology "Computational Loads"

As proposed, "Computational Load means Load comprised of electric power demand from information technology equipment, such as servers, storage, and networking hardware." We agree with NERC staff that a term other than "Large Load," without including additional descriptors for the electronic loads like data centers, AI centers, and crypto-currency mining, is not a satisfactory term. "Large Load" also applies to large process facilities, oil and gas loads, education and medical campuses, pharmaceutical loads, and manufacturing loads. These large loads do not contain the same amount of servers, data storage, and networking equipment, nor the same operational characteristics as the loads which are the subject of NERC's "Large Load Action Plan."

However, the term "Computational Load" to describe loads such as data centers, AI training and inference facilities, and cryptocurrency mining facilities may not be sufficient. The proposed "Computational Load" definition includes "Load comprised of electric power demand from information technology equipment." However, most Bulk Electric System (BES) loads contain a Computational Load component and would therefore be included in the definition, which is not the intention of the "Large Load Action Plan".

The definition also contains the term "**such as** servers, storage, and networking hardware." The term "such as" is non-inclusive and introduces ambiguity as to the equipment that may, or may not be, included in the definition.

In addition, the term "storage" should be amended to "data storage", to clarify that it is referring to information technology equipment such as Network Attached Storage (NAS), Hard Disc Drives (HDDs), and Solid State Devices (SSDs) and not "energy storage" such as BESS.

Solar Energy Industries Association (SEIA)
1425 K Street, NW, Suite 1000, Washington, DC | seia.org

Furthermore, the use of "Computational" is too inclusive for some of the provided examples, particularly "networking hardware" and "data storage". These types of equipment have very minimum "computational" capability as compared to central processing units (CPUs) and graphical processing units (GPUs). A broader term such as "electronic load" would be more appropriate for NERC's definition, like ERCOT's adoption of the term "Large Electronic Load," which extends beyond purely computational activities. Having a uniform definition across industry also facilitates standards and compliance activities. Regardless of the term selected to represent computational loads, it also needs to be clear that Inverter-based Resources such as solar PV, battery energy storage systems (BESS), and modern wind turbines are not included under the term.

Proposed Terminology "Computational Load Entity"

As proposed, "Computational Load Entity means the end-user or the entity that hosts end-users that receives electric power for Computational Load." We believe it would be beneficial to include the same entity naming structure that is used for Generation and Transmission Owners and Operators (e.g., GO's/GOP's). In many cases, data center owners and operators will be separate entities and could have different reliability responsibilities.

There is some uncertainty in the phrase "end-user or the entity that hosts end-users." At a given facility, if both exist, is the Computational Load Entity inclusive of both of those parties? Or if both exist, is it just the end-user with compliance obligations, and the entity that hosts the end-users has no compliance obligations?

In addition, the use of "end-user" introduces some ambiguities. Traditionally, end-user has been thought of as the entity which uses electricity for a given purpose. End-users could be entities that are lessees of facilities in the computation load facility. Holding an end-user/lessee of computational facilities responsible for compliance seems to be intractable. As end-users/lessees rent computational capabilities, the lessees can frequently change, they could be difficult to identify, and there could be very large numbers of end-users who shouldn't have any compliance obligations on the BPS.

Appendix 5A

No comments.

Appendix 5B

The proposed criteria is "III.c.1 Computational Load Entity that 1) contributes to an aggregate connected Load capability greater than or equal to 20 MW; 2) at a single point of interconnection to the Bulk Power System at a voltage greater than or equal to 60 kV; and 3) hosts 1 MW or greater of Computational Load."

With the proposed criteria, there is a risk that certain facilities interconnected at a single point of interconnection greater than 60 kV may be required to register even though they do not pose a risk to the BPS. For example, if a manufacturing facility is 75 MWs, and has 1 MW of Computational Load at the facilities (used in servers for process control, data storage, personal computers, PLC's, RTU's, routers, etc.), that facility would need to be registered, even though it does not pose the

Solar Energy Industries Association (SEIA)
1425 K Street, NW, Suite 1000, Washington, DC | seia.org

same operational characteristics and risks that were identified in the NERC white papers, alerts and guidelines.

The 1 MW of Computational Load compared to 20 MW of aggregate load is 5%. As the aggregate load becomes larger, the percentage of computational load that would be subject to the criteria is reduced, as shown by the example above. Other entities have proposed higher percentages, reflective of the risk on the BPS. For example, ERCOT's proposed definition of Large Electronic Load in NPRR 1308 is "A Large Load in which **50% or greater** of the Demand at the site consists of power electronic based load, specifically computational load, such as data centers and cryptocurrency mining facilities," and the accompanying definition of Large Load is "One or more Facilities at a single site with an aggregate peak Demand greater than or equal to **75 MW** behind one or more common Points of Interconnection (POIs) or Service Delivery Points."

As NERC develops reliability standards for all North America, it should establish minimum acceptable requirements, which would support significantly higher percentage thresholds of computational loads. Having computational loads which are 5% or lower of the total aggregate demand is not reflective of the minimum acceptable level of requirements consistent with some ISOs/RTOs. While we understand that FERC mandated loads greater than 20 MW in their ANOPR, we believe this definition requires further discussion. It is suggested that NERC leverage the LLWG's conclusions to date to develop load criteria aligned with actual reliability risk, while permitting transmission entities to adopt more stringent requirements, if appropriate for their systems.

Thank you for the opportunity to provide these comments.

Tim Taylor

SEIA NERC Working Group Lead

Solar Energy Industries Association (SEIA)
1425 K Street, NW, Suite 1000, Washington, DC | seia.org

NERC,

The Sacramento Municipal Utility District (SMUD) and the Balancing Authority of Northern California (BANC) support the joint comments submitted by the Trade Associations (APPA, LPPC, EEI, NRECA and TAPS).

Tim Kelley, PE
Senior Regulatory Advisor, Government Affairs

SMUD | Powering forward. Together.
6201 S Street, Mail Stop B404, Sacramento, CA 95817
P.O. Box 15830, Sacramento, CA 95852-0830

Hello,

I would like to submit on behalf of Salt River Project that SRP supports the joint comments submitted by the Trade Associations (APPA, LPPC, EEI, NRECA, and TAPS).

Thank you,

Tim Singh
Principal Engineer
SRP | Regulatory Audit & Compliance | PAB4TE
P.O. Box 52025, Phoenix, AZ 85072-2025

Trade Associations Comments

Thank you for the opportunity to comment on the draft proposed revisions to the North American Electric Reliability Corporation's (NERC) Rules of Procedure (ROP) on the registration of large computational loads. The Trade Associations,[1] on behalf of their members, support NERC's objective of protecting the bulk electric system from reliability risks associated with large computational loads. The Trades understand there are various considerations needed in developing registration criteria and mechanisms for the owners and operators of computational loads.

To achieve our shared objective, the Trade Associations provide these comments in four parts:

I. **Overarching Principles**: We describe core principles that form the basis for our proposed and alternative solutions in sections II and III, as well as our comments to NERC's proposal in section IV. We urge NERC to consider these principles when drafting the registration criteria for new entities.

II. **Proposed Solution**: We propose changes to definitions and registration criteria that focus on the highest priority risks.

III. **Alternative Solution**: We propose alternate definitions and registration criteria that would define two categories of large computational loads.

IV. **Comments with NERC's Proposal**: If NERC does not accept the Trade Associations'' proposed or alternative solutions, we describe the concerns we have with NERC's draft proposal that we urge NERC to address.

I. OVERARCHING PRINCIPLES

DATA CENTER REGISTRATION SHOULD BE RISK-BASED.

Treating different-sized facilities the same would depart from NERC's longstanding risk-based approach to registration. Registration criteria should focus on the loads most likely to have a material impact on bulk electric system (BES) reliability and should avoid imposing unnecessary compliance obligations on facilities that do not present comparable reliability risks.

[1] The Trade Associations are the: American Public Power Association (APPA), Edison Electric Institute (EEI), Large Public Power Council (LPPC), National Rural Electric Cooperative Association (NRECA), Transmission Access Policy Study Group (TAPS), and the National Association of Regulatory Utility Commissioners (NARUC) as a member association.

THE DEFINITION SHOULD CAPTURE LARGE DATA CENTERS AND CRYPTO MINES BUT NOT CAPTURE TRADITIONAL COMMERCIAL OR INDUSTRIAL LOADS.

The registration criteria should focus on the category of large computational loads that NERC has identified as potentially presenting material reliability risks. They should not inadvertently capture traditional commercial or industrial loads that contain information technology equipment but do not operate primarily as computational load facilities, because such loads do not pose material risk to the BES.

For example, large office buildings with server rooms, defense infrastructure (e.g., the Pentagon), and industrial facilities (e.g., aluminum smelters or automobile manufacturing plants) should not be registered merely because they use servers, storage, networking hardware, or other information technology equipment in support of their ordinary operations. The criteria should distinguish facilities whose primary load characteristics raise the reliability concerns identified by NERC from facilities that use information technology equipment only as an incidental part of a broader commercial or industrial process.

RESPONSIBILITY FOR IDENTIFYING NEWLY REGISTERED ENTITIES SHOULD NOT FALL ON EXISTING REGISTERED ENTITIES.

Transmission Owners (TO), Transmission Operators (TOP), Transmission Planners (TP), Distribution Providers (DP), and other existing registered entities do not always have—and may lack legal authority to obtain—the information necessary to determine whether a particular customer meets the criteria for registration as a computational load owner or operator. NERC and the Regional Entities should therefore retain responsibility for identifying large computational loads that may meet the registration criteria.

The registration framework should not impose new, open-ended data collection obligations on existing registered entities or require them to determine whether a customer's facilities meet the proposed computational load criteria. Existing registered entities may have relevant system information, but they should not become the default mechanism for identifying, classifying, or certifying customers for registration.

NEW REGISTRATION CRITERIA SHOULD NOT CREATE COMPLIANCE OBLIGATIONS FOR SMALL DISTRIBUTION UTILITIES OR RESULT IN CHANGES TO THE DEFINITION OF BULK ELECTRIC SYSTEM.

Any new registration criteria for large computational load should not directly or indirectly change the criteria for registering distribution providers, nor should it result in changes to the BES definition. For example, if a large computational load interconnects to a non-BES line, that should not inadvertently convert that line into a BES facility and cause the owner of that facility to become a Transmission Owner.

II. TRADE ASSOCIATIONS' PROPOSED SOLUTION

The Trade Associations propose that NERC define computational load facilities as facilities with at least 75 megawatts (MW) of computational load connected at 100 kilovolts (kV)[2] or higher, and that NERC register the owners (e.g., the landlords) and operators of the computational load facilities.

CONSISTENT WITH OTHER REGISTRATION CATEGORIES, NERC SHOULD DEFINE FACILITIES AND THEN REGISTER THE OWNERS AND OPERATORS OF THOSE FACILITIES.

A. Add a definition of "Computational Load Facility": A clear definition of a Computational Load *Facility* is essential for Project 2026-02 success. Existing standards that currently address the same types of essential actions being proposed for data centers but are applicable to other comparable equipment (like generators) consistently rely on a *Facility*-type definition. This is consistent with how Generator Owner/Operator and Generating Facility are treated, defined, and included in the registration criteria.

Data center sites can have a significant number of physical and electrical configurations. For example, many data center sites can consist of one or more buildings, with each building having one or more connections to the Bulk Power System (BPS) at the same location. In some cases, data center owners may consider that each building is an individual data center, while in other cases the collection of buildings connected to the grid is viewed as the data center. The risk to the BES comes from the aggregate load behavior of facilities *at a single site*. This was emphasized in NERC's "Characteristics and Risks of Emerging Large Loads" whitepaper that, while specific load types and thresholds to define large loads could not be defined across industry at that time, all agreed that any such definition should include "aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS."

We therefore recommend the following definition of "Computational Load Facility" – A collection of electrical equipment located at one or more buildings, structures, or installations that is designed to receive power, has an aggregate connected maximum peak demand of Computational Load greater than or equal to 75 MW, and is served through electric facilities at a voltage level greater than or equal to 100 kV from one or more points of connection.

B. Replace "Computational Load Entity" with "Computational Load Owner" and "Computational Load Operator" or alternatively make changes to "Computational Load Entity."

The Trade Associations recommend that the Computational Load Entity definition be replaced with new definitions that align with the "Owner" and "Operator" Model currently in place in the NERC Rules of Procedure for registration criteria. Today we have registration criteria for TO, TOP, Generator Owner (GO), and Generator Operator (GOP). This structure is in place because for transmission and generation facilities, there are often situations that occur where the owner of the facilities is

[2] NARUC's position is 115kV or higher as opposed to 100kV or higher.

different from the operator of the facilities. This registration criteria set up allows different entities to be responsible only for the activities for which they are contractually obligated as the owner and/or operator. For Computational Load Facilities, these facilities have the same type of structure. There are many cases where the owner is different from the operator.

Therefore, because of the actual structure of the facilities, and to align with existing NERC registration criteria, the Trade Associations recommend replacing the Computational Load Entity definition with Computational Load Owner and Computational Load Operator, with proposed definitions for each included below.

"Computational Load Owner" means the end-user entity that owns and maintains a Computational Load Facility, **and/or** the entity that owns and maintains a Computational Load Facility that hosts end-users that receives electric power **at a** Computational Load **Facility**.

"Computational Load Operator" means the end-user entity that operates a Computational Load Facility, **and/or** the entity that operates a Computational Load Facility that hosts end-users that receives electric power **at a** Computational Load **Facility**.

However, as discussed in more detail below, if NERC staff retains only one registered entity, the Trade Associations suggest the following modifications to the Computational Load Entity definition:

"Computational Load Entity" means the end-user **and/or** the entity that hosts end-users that receives electric power ~~for~~ **at a** Computational Load **Facility**.

The risk to the BPS and the gaps in NERC's reliability standards, as noted in NERC's "Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads" are driven by computational load impacts and behavior, not *other type* of loads, so the Computational Load Entity definition should focus only on the amount of data-centric/information technology type of load.

COMPUTATIONAL LOADS SHOULD BE DEFINED AS LOADS MADE UP PRIMARILY OF POWER ELECTRONICS-BASED INFORMATION TECHNOLOGY EQUIPMENT.

Clarify the Computational Load definition: The Trade Associations recommend that the proposed Computational Load definition focus on the power electronic-based information technology equipment, which is the focus of the risks to the BPS as documented by NERC's Large Loads Task Force and Large Loads Working Group.

NERC's "Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads" identifies risks associated with the behavior and impacts of computational loads. Those risks arise from the data-centric and information technology characteristics of the load, not from unrelated load at the same site. The definition should therefore focus only on the amount of computational load and should not sweep in other types of loads that do not raise the same reliability concerns.

Therefore, we urge NERC to update it as follows: **"Computational Load"** means Load comprised **primarily** of electric power demand from **power electronic-based** information technology equipment.

THE REGISTRATION THRESHOLD SHOULD BE SET TO 75 MW/100 KV.

The Trade Associations recommend that NERC revise the proposed thresholds in Appendix 5B. The proposed 20 MW/60 kV threshold with the 1MW Computational Load criteria is set unnecessarily low and sweeps in a substantial number of facilities that pose no material impact to the reliability of the BPS and, thus, does not justify the burden of NERC registration. The current Rules of Procedure, Registration, and Standard Drafting efforts related to Computational Loads should focus on those loads that pose the most meaningful risk to the BPS. The threshold criteria (20 MW, 60 kV) is too low and we recommend the threshold be set to 75 MW connected at >= 100kV for Computational Load Facilities, consistent with the NERC BES definition for dispersed power producing resources (i.e., inverter-based resources) – where the current criteria is greater than 75 mega volt amperes (MVA) at a common point of connection at >= 100kV is utilized.

Although NERC has developed a Technical Reasoning Proposed Computational Load document, it does not provide sufficient explanation or practical examples to justify the selected thresholds in the proposed registration criteria. The Trade Associations are concerned that NERC's proposed approach could inadvertently create compliance obligations for DP entities by effectively deeming them TO or TOP. It is critical to ensure that DP do not lose the radial system exemption when solely serving load and not operating transmission facilities. Clear justification and refinement of the proposed thresholds are required to demonstrate that there are identifiable and material risks to the BES.

In addition, NERC's "Characteristics and Risks of Emerging Large Loads" indicated that "most of the survey respondents qualified 'large' as greater than 50 MW, and the single size number most commonly suggested was 75 MW," and the NERC Alert 2 results confirmed this. NERC's "Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads" references the first Whitepaper and in the definition section, and focuses on really large loads and how several smaller loads (still much bigger than 20 MW) are not as big of a risk. "The potential impact of several 100 MW loads may be less than the impact of a 500 MW load and may require different treatment."

Furthermore, NERC's "Ten benchmarks of an Effective Reliability Standard" white paper emphasizes that "each [NERC reliability standard] requirement is 'not a lowest common denominator' exercise but instead achieves an objective that is the best approach for bulk power system reliability." The same applies to definitions and reliability criteria. NERC's decision to select 20 MW appears to be a "lowest common denominator" choice, instead of a higher value that the majority of the industry agrees with.

The Trade Associations recommend NERC adopt an initial threshold of 75 MW at a common point of connection of 100 kV or higher. This pairing adheres to the current BES definition and appropriately balances reliability risk to compliance burden. A 75 MW/100 kV starting point focuses computational load entity registration on the facilities most likely to have a material impact on BPS reliability. It would also give NERC and the Regional Entities time to identify entities for registration, develop reliability standards, and gain compliance oversight experience with a manageable population. Further, it avoids imposing new obligations on facilities whose individual contribution to reliability risk is limited.

III. TRADE ASSOCIATIONS' ALTERNATIVE PROPOSAL

As an alternative, the Trade Associations recommend that NERC adopt an approach that mirrors the Category 1 and Category 2 Generator Owner and Generator Operator definitions adopted as part of NERC's Inverter-Based Resources Registration Initiative.

THE NEW REGISTRATION FRAMEWORK SHOULD STILL DEFINE FACILITIES AND THEN REGISTER THE OWNERS AND OPERATORS OF THOSE FACILITIES.

As with our primary proposal, our alternative proposal retains the structure of defining Computational Load Facilities and registering the owners and operators of those facilities.

THE NEW REGISTRATION SHOULD CONSIST OF TWO CATEGORIES OF COMPUTATIONAL LOAD OWNERS AND OPERATORS.

If a threshold lower than 75 MW is deemed necessary by NERC staff, the Trade Associations recommend that NERC staff enhance the Technical Reasoning document to reflect the analysis/evidence demonstrating the lower facility threshold is needed for BPS reliability. In addition, in this scenario, the Trade Associations also recommend that NERC staff adopt the same registration criteria model that was developed for inverter-based resources with the Category 1 GO/GOP and Category 2 GO/GOP. NERC should create a new Category 1 Computational Load Owner/Operator (CLO/CLOP) and Category 2 CLO/CLOP definitions, and structure the MW and voltage criteria for each to align with the Category 1 GO/GOP and Category 2 GO/GOP.

With NERC expected to address computational load risk on an accelerated timeline by the end of 2026, this structure would allow ERO Enterpriseto focus its initial entity registration, standards development efforts, and compliance education activities on the highest-risk CLOs/CLOPs first. This framework also establishes a more manageable path to subsequently address lower-risk Category 2 CLOs/CLOPs in future work phases. Finally, this structure would enable a risk-based compliance approach by allowing more stringent reliability and security requirements to be applied to Category 1 CLOs/CLOPs compared to Category 2 CLOs/CLOPs.

Under this alternative structure, the following definitions are proposed:

"Computational Load Facility" means a collection of electrical equipment located at one or more buildings, structures, or installations that is designed to receive power, is served through electric facilities from one or more points of connection **and meets the criteria in either Category 1 or Category 2 Computational Load Owner/Operator registration categories.**

"Category 1 CLO/CLOP" should be aligned with the BES criteria, which would be entities who own/operate Computational Load Facilities (CLFs) that are **>= 75 MW** of Computational Load connected at **>= 100kV**.

"Category 2 CLO/CLOP" should be aligned with the lower threshold value supported by NERC and industry, which would be entities who own/operator Computational Load Facilities that are **>= 20 MW** of Computational Load connected at **>= 60kV**.

IV. COMMENTS ON NERC'S PROPOSED REVISIONS

As noted earlier, the Trade Associations have several concerns with NERC's proposed revisions to the Rules of Procedure. If, however, NERC declines to adopt either solution, and proceeds with the approach in the April 1, 2026, draft, we urge NERC to address the following concerns before finalizing any revisions.

REPLACE "CAPABILITY" WITH "MAXIMUM PEAK DEMAND."

The draft Computational Load Entity registry criteria use the word "capability," which can be interpreted as the maximum load of a Computational Load Facility (CLF). For example, if the CLF facility has a maximum possible load demand of 100 MW, then this is the load "capability" of the CLF. However, this "capability" term as used with load is likely not widely understood or utilized today.

We recommend an alternative to the use of "capability" such as "**maximum peak demand**" of a facility to be clearer. In addition, evaluating a CLF's impact on the BES should not rely solely on its size. Incorporating operational characteristics, such as interruptibility, load flexibility, and the availability of on-site or contracted backup generation, will provide a more comprehensive and accurate assessment of system impacts.

CLARIFY HOW "POINT OF INTERCONNECTION" APPLIES TO LARGE COMPUTATIONAL LOADS.

The proposed registration criteria include a reference to a "point of interconnection" at 60 kV. "Point of interconnection" is primarily a term referring to generation interconnections – interconnections that most often rely on one generating tie-line. Data centers often have many connections to the BPS at the same location. The ownership of equipment can also vary site to site, in which some connect to utilities directly at the high voltage kV bus by owning the high-voltage transformation, while others do not own the transformation or equipment greater than 60 kV.

CLARIFY HOW TOTAL AGGREGATE LOAD WILL BE CALCULATED.

NERC's current proposed Computational Load Entity registration criteria would register an entity that "contributes to an aggregate connected Load capability" f 20MW or greater. How will NERC determine the amount of Computational Load or the amount of aggregate connected load thresholds? Will it be based on the "nameplate" of the various racks in a data center warehouse or some other methodology? Regardless of the method(s) for determining these values, the Trade Associations recommend that this should be confirmed between the CLE and its Regional Entity and NERC should not be dependent on other registered entities for providing this information to Regional Entities. Critically this criteria state load, not Computational Load. The Trade Associations believe this is incorrect and should be updated to state "Computational Load capability." In our proposed Computational Load Facility definition, we have included the use of Computational Load in the definition so that the focus is only on data-centric/information technology load.

NERC should also clarify how it will calculate the relevant load quantity. For example, NERC should explain whether the calculation will rely on the nameplate rating of server racks or other equipment, contract demand, projected maximum peak demand, measured demand, or another methodology. Clear rules will reduce uncertainty and improve consistency across regions.

THE 1 MW THRESHOLD SHOULD BE ELIMINATED.

It is unclear how, in NERC's April 1 proposal, a Computational Load is fundamentally different from other large traditional loads, such as steel mills, food processors, or automobile manufacturers. All large loads must be studied to ensure their interconnection and operation do not create grid reliability issues. There is concern that, as written, it may capture facilities that are not data centers or cryptocurrency mining operations, which are the business types that NERC has identified as potentially impacting the reliability of the BES. For example, many industrial and commercial facilities may operate more than 1 MW of information technology equipment (either now or in the future), such as servers, storage, and networking hardware to control and support processes, yet these are not solely or primarily computational in nature. In addition, it seems unreasonable that the loss of a 1 MW load, regardless of load type, would have a significant impact on the BES, therefore including a de minimis criteria of 1 MW of Computational Load drives significant confusion, pulls in a significant number of entities unnecessarily, and has no justification pertaining to actual risk to the BPS. The 1 MW de minimis threshold conflicts with the material impact standard applied throughout Appendix 5B and would expand registration beyond entities capable of materially impacting BPS reliability. The 1 MW de minimis threshold should be removed from the Computational Load threshold.

THE TERM "ENTITIES THAT HOST END-USERS" IS UNCLEAR AND SHOULD BE REPLACED.

The proposed materials use the phrase "entities that host end-users." That phrase appears intended to address data center owners or landlords that host tenants. But the phrase could also be read more broadly.

For example, a distribution utility may own a substation that serves 20 MW of load, including a credit card processing facility with 2 MW of servers. In that circumstance, the distribution utility could be described as "hosting" the load on its system, even though it does not own or operate the computational load facility. The registration criteria should not create that result.

NERC should replace or clarify the phrase "entities that host end-users" to ensure that it does not include distribution utilities, retail service utilities, TO, TOP, TP, or DP that merely serve, study, or interconnect computational load facilities. The registered entity should be the entity that owns or operates the Computational Load Facility, not the utility that provides electric service to it.

As noted above, the Trades suggest the following language to address the concern:

"Computational Load Entity" means the end-user **and/or** the entity that hosts end-users that receives electric power ~~for~~ **at a** Computational Load **Facility**.

ADDITIONAL TRADE ASSOCIATIONS QUESTIONS REGARDING NERC'S APRIL 1 PROPOSAL

To build on the concerns shared and the alternatives provided the Trade Associations ask the following questions

- "How will a Computational Load Entity(ies) be identified for registration under the proposed framework?"
- Will the TO, TOP, or TP be responsible for identifying this/these load(s) and sharing that information with their Regional Entity?
- Additionally, will responses to the NERC Level 3 Alert on Computational Loads be used to inform or determine registration requirements?

In addressing these questions, the Trade Associations recommend that the identification CLEs for potential registration should be the responsibility of the Regional Entity and NERC should not be dependent on other registered entities for providing this information to Regional Entities.

CONSIDER AN EXCEPTION PROCESS FOR LARGE COMPUTATIONAL LOADS THAT MEET THE CRITERIA BUT CAN BE SHOWN NOT TO HAVE A MATERIAL IMPACT ON THE BULK ELECTRIC SYSTEM.

Brightline Criteria

Computational Load Entity (CLE) registration should be based on clear, brightline criteria coupled with a formal exception process similar to the BES definition framework. Such an approach would allow an entity to demonstrate, through documented technical justification, that its facilities do not have a material impact on the BES. This balance is necessary to ensure that registration and compliance obligations are applied only where there is a substantiated reliability risk, while

avoiding unnecessary regulatory burden for entities whose operations do not pose a material threat to BES reliability.

NERC SHOULD DEVELOP A REFERENCE DOCUMENT.

The proposed criteria raise practical questions about how facility topology and interconnection configurations will affect registration. NERC should develop a reference document addressing the new registration criteria. The document should give industry and the drafting team a clear opportunity to review how NERC and the Regional Entities expect to apply the criteria. That reference document would promote consistent implementation and reduce the risk of unintended consequences.

CANDIDATES MUST MEET ALL CRITERIA TO BE REGISTERED.

The Trade Associations also note that NERC's document "Summary of Revisions" states candidates for Computational Load registration must meet all the criteria in the proposed revisions in Appendix 5B to be registered as a Computational Load Entity; however, that is not explicitly stated in the proposed changes in Appendix 5B and should be stated.

Submitted Electronically to ROPComments@nerc.com

May 22, 2026

Marisa Hecht
Senior Counsel, Legal and Regulatory
North American Electric Reliability Corporation

Re: American Chemistry Council Comments on Proposed NERC Computational Load Entity Rules of Procedures Revisions

Dear Ms. Hecht:

The American Chemistry Council (ACC)[1] appreciates the opportunity to provide input on the proposed revisions to the North American Energy Reliability Corporation (NERC) Rules of Procedures (ROP) to create a new category of registered customer entities, "Computational Load Entities," and associated reliability considerations on the Bulk Power System (BPS). ACC and our members recognize the essential role NERC plays in ensuring the reliability of America's electricity grid and chemical sector's continuous access to affordable and reliable industrial power. NERC's leadership is more important than ever during this pivotal period of rising demand, evolving load and generation characteristics, and the need for rapid deployment of critical energy infrastructure.

ACC represents a diverse set of companies engaged in the business of chemistry, a $673 billion enterprise. The chemical manufacturing industry is an energy intensive and trade exposed cornerstone of American competitiveness, national security, and technological innovation. ACC's members produce a wide variety of chemicals, polymers, and related products that make modern life safer, more productive, and more sustainable, supporting over 25 percent of U.S. GDP and directly touching nearly all manufactured goods. As a foundational sector of the U.S. economy, the chemical industry plays a critical role in enabling domestic manufacturing, supply chain resilience, and long-term economic growth.

[1] The American Chemistry Council's mission is to advocate for the people, policy, and products of chemistry that make the United States the global leader in innovation and manufacturing. To achieve this, we: Champion science-based policy solutions across all levels of government; Drive continuous performance improvement to protect employees and communities through Responsible Care®; Foster the development of sustainability practices throughout ACC member companies; and Communicate authentically with communities about challenges and solutions for a safer, healthier and more sustainable way of life. Our vision is a world made better by chemistry, where people live happier, healthier, and more prosperous lives, safely and sustainably—for generations to come.

While ACC's membership is diverse, our members share one common characteristic: heavy reliance on reliable, around the clock, affordable energy inputs to drive operations and thermally intensive processes and, in many cases, to serve as essential chemical feedstocks. Chemical manufacturing accounts for approximately 40 percent of industrial sector energy consumption, including 20 percent of electricity, 42 percent of natural gas, and 56 percent of purchased steam. Over the past 15 years, the U.S. chemical sector has become a global leader in manufacturing competitiveness, driven in significant part by access to abundant and reliable energy supplies, including electricity.

As NERC, its regional partners, and states address the infrastructure and reliability foundations needed to support hyperscale computational load and other sources of demand growth, ACC urges careful consideration of how resulting policies could intentionally or unintentionally affect the competitiveness of American industrial customers and lead to outcomes that put customers at greater financial and compliance risk without achieving commensurate reliability protections.

ACC offers the following recommendations, beginning with considerations that would be essential under any potential path forward, followed by concerns regarding process and statutory authority, with a focus on avoiding unintended expansion of regulatory scope and protecting energy-intensive industrial customers from disproportionate impacts.

Should NERC elect to proceed with regulating electricity customers in any manner, such policy should incorporate clear guardrails and limitations. Definitions and registration criteria must be narrowly and precisely drawn to avoid inadvertent overlap with traditional industrial and manufacturing loads and incorporate an explicit limiting principle confirming that the action is not intended to establish a precedent or pathway for future expansion of NERC authority to other end use customer groups. Absent such clarity and constraints, the risk of unintended scope creep, regulatory uncertainty, and collateral impacts on energy intensive industries that may not present the same reliability considerations for the BPS would be substantial.

More fundamentally, ACC urges NERC to reconsider the premise of the proposed Computational Load Entity ROP Revisions, which would expand mandatory reliability registration and compliance obligations to end use customer groups. Such an expansion would be unprecedented, raising serious questions regarding the scope and intended reach of Section 215 of the Federal Power Act. Extending NERC's regulatory scope in this manner would introduce a new layer of regulatory burden by shifting or diffusing responsibility away from existing registered entities—those with operational control of the bulk power system, established protocols, and the technical workforce necessary to execute reliability obligations—toward users that generally lack the specialized expertise, staffing, systems visibility, and compliance infrastructure to assume grid reliability functions.

Finally, given the novel expansion of NERC's regulatory scope, its implications for the scope of NERC's authority under Section 215 of the Federal Power Act, and the resulting application to industries not previously subject to NERC oversight, ACC would recommend, NERC expand its

formal public consultation process and conduct a robust regulatory and economic impact assessment, consistent with the level of scrutiny that would accompany any other significant federal regulatory action. That process should include broad outreach to both computational load customers and other large-load industries potentially affected by future efforts to register end-use customers. ACC also recommends that NERC's impact assessment clearly demonstrates why the reliability concerns identified cannot be addressed through refinements to existing standards and obligations applicable to entities already subject to NERC oversight and should establish this proceeding as an exception rather than a general model for managing grid reliability.

ACC appreciates the opportunity to comment and looks forward to continued engagement as NERC adapts and updates its policies to address today's grid challenges. We would welcome the opportunity to consult further should the drafting team have any questions. Please feel free to contact me at Charles_Franklin@americanchemistry.com or (202) 249 6412.

Sincerely,

Charles Franklin

Charles Franklin
Senior Director, Energy, Climate and Environment
Regulatory and Scientific Affairs
American Chemistry Council

NERC

Consideration of Comments

Rules of Procedure (ROP) Revisions to Appendices 2, 5A, and 5B (Computational Load Entities)

August 19, 2026

Table of Contents

Introduction iii
List of Commenters iv
Summary of Proposed Revisions Posted for Comment 1
NERC Rules of Procedure Appendix 2 – Definitions Used in the Rules of Procedure 1
NERC Rules of Procedure Appendix 5A – Organization Registration and Certification Manual 1
NERC Rules of Procedure Appendix 5B – Statement of Compliance Registry Criteria 1
Comments 1
Definitions 1
Thresholds 5
Criteria Clarifications 8
Other 12

Introduction

NERC thanks all commenters who submitted comments on the proposed changes to the Rules of Procedure. NERC posted the proposed changes for public comment from April 1, 2026 through May 15, 2026. NERC received 32 sets of comments from 44 commenters, as shown in the table on the following pages.

NERC has posted submitted comments on the Rules of Procedure page.

List of Commenters

	Entity
1	Equinix
2	Persistence Analytics Group LLC (Persistence)
3	AIONTRACKS, Inc.
4	Southwest Power Pool (SPP)
5	Entergy
6	Large Public Power Council (LPPC)
7	Arkansas Electric Cooperative Corporation (AECC)
8	American Chemistry Council (ACC)
9	PacifiCorp
10	Alphataraxia
11	Southern Company (Southern)*
12	Independent Electricity System Operator (IESO)
13	American Electric Power (AEP)
14	Solar Energy Industries Association (SEIA)
15	Crusoe Technologies (Crusoe)**+
16	Industrial Energy Consumers of America (IECA)
17	Eversource*
18	Sacramento Municipal Utility District and Balancing Authority of Northern California (SMUD/BANC)*
19	Corscale Data Centers (Corscale)**
20	Dominion Energy (Dominion)*
21	Google**
22	Electricity Consumers Resource Council
23	Edison Electric Institute, American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, Transmission Access Policy Study Group, and National Association of Regulatory Utility Commissioners (Trades)
24	New York Power Authority (NYPA)*
25	FirstEnergy*
26	Bonneville Power Administration (BPA)
27	Digital Power Network (DPN)

28	CenterPoint Energy Houston Electric, LLC (Centerpoint)*
29	DC Energy Management, LP (DC Energy Mgmt.)
30	Salt River Project* (SRP)
31	PJM Interconnection (PJM)
32	Oracle**
33	Ameren*
34	Consumers Energy
35	Arizona Public Service (AZPS)*+
36	Independent System Operator/Regional Transmission Organization Council Standards Review Committee (IRC SRC)
37	Invenergy
38	Data Center Coalition (DCC)
39	Arevon
40	Microsoft
41	ATC*+
42	Electricity Customer Alliance, Electricity Consumers Resource Council, and Industrial Energy Consumers of America (End-User Groups)
43	Midcontinent Independent System Operator (MISO)
44	City of Santa Clara (dba Silicon Valley Power(SVP))*+

*supports Trade Associations

**supports DCC

+means support and additional comments

Summary of Proposed Revisions Posted for Comment

The following section summarizes the proposed revisions to the NERC Rules of Procedure posted for comment from April 1-May 15, 2026 regarding registry criteria for computational loads. In response to comments, NERC is posting further revisions to the proposed criteria as described in the response to comments and is providing this summary on the original proposed language commenters reviewed for convenience.

NERC Rules of Procedure Appendix 2 – Definitions Used in the Rules of Procedure

Appendix 2 to the NERC Rules of Procedure includes defined terms used throughout the Rules of Procedure. The proposed revisions add the following two terms and definitions:

- "Computational Load means Load comprised of electric power demand from information technology equipment, such as servers, storage, and networking hardware."
- "Computational Load Entity means the end-user or the entity that hosts end-users that receives electric power for Computational Load."

NERC Rules of Procedure Appendix 5A – Organization Registration and Certification Manual

Appendix 5A contains the process used by NERC and the Regional Entities to register certain functional entity types to which mandatory and enforceable Reliability Standards apply. The proposed revisions to Appendix 5A added "Computational Load Entity (CLE)" as a type of entity that is required to register on the NERC Compliance Registry. In addition, proposed revisions to Appendix 5A include minor administrative corrections.

NERC Rules of Procedure Appendix 5B – Statement of Compliance Registry Criteria

Appendix 5B contains the specific criteria NERC and the Regional Entities use to identify which organizations may be candidates for registration for functional entity types. In accordance with the Federal Power Act, NERC must identify the owners, operators, and users of the Bulk Power System (BPS) who have a material impact on the BPS. To that end, the proposed revisions in Appendix 5B added threshold criteria to identify those organizations that should be registered as Computational Load Entities, summarized below:

1. A Computational Load Entity must be the end-user or the entity that hosts end-users that receives electric power for Computational Load; and

2. A Computational Load Entity that 1) contributes to an aggregate connected Load capability greater than or equal to 20 MW; 2) at a single point of interconnection to the Bulk Power System at a voltage greater than or equal to 60 kV; and 3) hosts 1 MW or greater of Computational Load.

Candidates must meet all the criteria in the proposed revisions in Appendix 5B in order to be registered as a Computational Load Entity.

Comments

The following section provides a summary of issues raised in stakeholder comments along with NERC's response.

Definitions

Entity	Summary of Stakeholder Comments	Response
AEP ATC AZPS DCC Crusoe Corscale Google Oracle Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren AZPS ATC SVP PJM	Several commenters recommended NERC use a definition of Computational Load Facility to clarify what sort of "site" owners or operators are subject to registration. Commenters note this definition would assist in the standards development project addressing computational loads. Some commenters provided a proposed definition for consideration: "Computational Load Facility means a collection of electrical equipment located at one or more buildings, structures, or installations that is designed to receive power, has an aggregate connected maximum peak demand of Computational Load greater than or equal to 75 MW, and is served through electric facilities at a voltage level greater than or equal to 100 kV from one or more points of connection." Others suggested borrowing concepts FERC uses in implementing PURPA through use of the "one-mile" rule to better define sites.	NERC agrees that defining the composition of a site provides clarity to the registry criteria for the owner and operator entities that must register. Accordingly, NERC is proposing a definition of "Computational Load Site." The proposed definition does not include the word "Facility" as proposed by some commenters because NERC determined that using such a term could lead to confusion. For example, a "Computational Load Facility" would include the term "Facility", which is associated with Bulk Electric System (BES) Elements, a narrowly defined subset of the BPS. In addition, NERC determined that the Computational Load Site definition does not need the numerical thresholds for MW and kV because those will be in the registry criteria only, whereas the Computational Load Site definition can also be used by the standard drafting team in the proposed Reliability Standards. This ensures alignment across ROP terms and NERC Glossary terms while maintaining registry thresholds in the ROP only. See the revised ROP Appendix 2 posted for comment for the proposed "Computational Load Site" definition.

Entity	Summary of Stakeholder Comments	Response
AECC AEP Arevon ATC AZPS DCC Crusoe Corscale Google Oracle ELCON IRC SRC Microsoft MISO SEIA Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren SVP	Some commenters suggested that Computational Load definition needs clarification on its scope as it may include unintended entities or information technology infrastructure. Some commenters suggest it to mean "Load comprised *primarily* of electric power demand from *power electronic-based* information technology equipment." Other commenters noted that some terms used in the definition created ambiguity, such as "storage" instead of "data storage" or the use of "such as." Other commenters suggested creating a "volatile loads" definition instead of Computational Load. Others suggested "Computational Load" means "Load that uses electric power for equipment needed for operation of computers or computer programs. Examples of such equipment include, but are not limited to, processors, memory, data storage devices, and networking equipment." Others note that "electronic load" may be a better description.	NERC determined that with the use of the newly proposed Computational Load Site definition, the definition of Computational Load is no longer needed for registry criteria purposes. Where appropriate, NERC considered applying the proposals from the comments on the Computational Load definition to other components of the revised proposed criteria. For instance, the use of "primarily" as suggested by some commenters in the Computational Load definition is now used in the proposed definition of Computational Load Site.

Entity	Summary of Stakeholder Comments	Response
AEP AIONTRACKS Arevon ATC AZPS SVP DCC Crusoe Corscale Google Oracle ELCON Entergy IRC SRC Microsoft PacifiCorp SEIA Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren	Some commenters proposed that Computational Load Entity should be Computational Load Owner and Computational Load Operator. Other commenters suggested further clarity or guidance on which end-users, particularly in a multitenant situation, would be registered as the Computational Load Entity. Others suggested to clarify that Computational Load Entities are "operators of the facility" that uses power for Computational Load. Others suggested clarifying that the Load "aggregates" at a point of interconnection "or substation."	NERC agrees that two functions provide more clarity on the types of entities subject to registration. Accordingly, NERC changed the proposed functional entity from "Computational Load Entity" to "Computational Load Owner" (CLO) and "Computational Load Operator" (CLOP). Additionally, NERC removed references to "end-user or entity that hosts end-users" from the functional registrations as the two separate functions address differing organizational arrangements more clearly.

Entity	Summary of Stakeholder Comments	Response
BPA Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren AZPS ATC SVP	Several commenters stated not to revise the BES definition at this time. One commenter suggested that NERC consider revisions to the definition of BES to address computational loads, in particular by adding to Inclusion I6, to address entities that may have BES-qualifying equipment.	NERC determined that the proposed registry criteria, without revising or expanding the BES, address the identified risk to the BPS. Based on comments received, NERC will continue that approach and not revise the BES definition at this time.

Thresholds

Entity	Summary of Stakeholder Comments	Response
AECC AEP Arevon ATC AZPS BPA SPP Equinix Crusoe DCC Crusoe Corscale Google Oracle ELCON Invenergy IRC SRC Microsoft Consumers Energy SEIA ACC Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren SVP	Stakeholders opposed the 1 MW “de minimus” Computational Load threshold as too low, confusing, or capturing unintended entities, such as industrial or commercial large loads that did not pose similar risks as entities with greater computational load. Some entities suggested using “50 % or greater” of Computational Load. Some suggested alternative amounts of Computational Load instead of 1 MW, ranging from 3 MW to 20 MW.	NERC revised the Section III registry criteria thresholds to remove the 1 MW “de minimus” Computational Load. Instead, NERC is proposing to define “Computational Load Site” as “primarily” containing certain IT infrastructure. This approach achieves the same objective by ensuring those with a small amount of computational load that do not pose the same impact are not included in the registry criteria through a focus on indicating the site “primarily” contains IT infrastructure.

Entity	Summary of Stakeholder Comments	Response
AEP Arevon AZPS Crusoe DCC Crusoe Corscale Google Oracle Invenergy IRC SRC Microsoft PJM Eversource Consumers Energy ACC Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren	Some commenters suggested the 20 MW threshold was too low and may capture sites that could be considered only local distribution or commercial or industrial loads that are not historically impactful to the BPS. Comments recommended increases ranging between 50 to 100 MW. Some commenters alternatively suggested that if the lower threshold is maintained, NERC should consider a tiered threshold approach to registration that mimics the GO/GOP Category 1 and 2 structure. Others suggested that the thresholds align with RTO/ISO tariff definitions of large loads.	Based on comments and ongoing analysis during and after the April 1-May 15, 2026 posting, NERC was able to refine its understanding of the aggregate risks associated with data center sites and clusters connected throughout the BPS. Further analysis was expanded to sites planned to be operational by the end of 2027.From the ongoing and expanded analysis, NERC determined that the threshold could be raised to 50 MW while still addressing the risks. In addition, NERC reviewed Regional Transmission Organizations (RTO) and Independent System Operator (ISO) definitions of large loads and considered whether those would be appropriate for continent-wide reliability purposes. NERC found that a 50 MW is generally in alignment with some RTO/ISO large load definitions.
AIONTRACKS ATC SVP	Some commenters supported the proposed 20 MW threshold.	Based on comments and ongoing analysis during and after the April 1-May 15, 2026 posting, NERC was able to refine its understanding of the aggregate risks associated with data center sites and clusters connected throughout the BPS. As a result, NERC determined that the threshold could be raised to 50 MW.

Entity	Summary of Stakeholder Comments	Response
AZPS SVP	Some commenters supported the proposed 60 kV threshold.	Based on comments and ongoing analysis during and after the April 1-May 15, 2026 posting, NERC was able to refine its understanding of the aggregate risks associated with data center sites and clusters connected throughout the BPS. As a result, NERC determined that the threshold could be raised to 100 kV.
AEP Arevon Crusoe DCC Crusoe Corscale Google Oracle ELCON Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren ATC	Some commenters suggested the 60 kV threshold was too low and may capture sites that could be considered only local distribution or commercial or industrial loads that are not historically impactful to the BPS. Some commenters alternatively suggested that if the lower threshold is maintained, NERC should consider a tiered threshold approach to registration that mimics the GO/GOP Category 1 and 2 structure.	Based on comments and ongoing analysis during and after the April 1-May 15, 2026 posting, NERC was able to refine its understanding of the aggregate risks associated with data center sites and clusters connected throughout the BPS. As a result, NERC determined that the threshold could be raised to 100 kV.
Consumers Energy	Remove the kV threshold for clarity.	NERC determined that including voltage in the registry criteria ensures registration of entities with the most impactful connection to the BPS. As each candidate goes through the registration process, Regional Entity staff will assist candidates in assessing the appropriate voltage threshold or connection configuration.

Criteria Clarifications

Entity	Summary of Stakeholder Comments	Response
Arevon AZPS BPA SPP IESO Microsoft MISO Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren ATC SVP	Commenters remarked that “single point of interconnection” needs further clarification as it does not address facilities with multiple points of interconnection, shared substations, or co-located generation. Some commenters suggested revisions such as “Connects to the Bulk Power System (BPS) operated at a voltage greater than or equal to 60 kV on the high side and behind one or more common Points of Interconnection (POIs) or Service Delivery Points” instead of the “single point of interconnection” language. Others noted the need for clarification on whether the point of interconnection is the immediate customer connection point or the upstream transmission connection point.	NERC revised the proposed criteria to state the Computational Load Site could be connected from “one or more points of connection” to address the possible configurations that meet the registry criteria.

Entity	Summary of Stakeholder Comments	Response
Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren AZPS ATC SVP	Clarify that entities must meet all criteria, including criteria in "Section III" to be registered.	NERC clarifies that in order to be registered as a Computational Load Owner or Operator, a candidate for registration must meet all criteria applicable to those functions in order to be placed on the NERC Compliance Registry. However, NERC declines to further revise the proposed registry criteria in response because Section III of the proposed ROP already states that "Entities identified in Section II above as being subject to Registration as a Distribution Provider, Computational Load Operator, or Computational Load Owner should be included in the Compliance Registry for these functions only if they meet any of the criteria listed below." Accordingly, the ROP already dictates that CLO or CLOP will not be placed on the NCR without meeting the criteria in Section III. NERC also notes this is how it has been applying Section III to Distribution Providers over the past several years, and historically for Generator Owners, Generator Operators, Transmission Owners, Transmission Operators, and other functions prior to implementation of the BES Definition.

Entity	Summary of Stakeholder Comments	Response
IECA Arevon Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren AZPS ATC SVP	Some commenters requested clarification that industrial or commercial large load are not included in the proposed criteria, citing the lack of a demonstrated reliability gap for these types of entities. Others suggested that the criteria is too narrow by excluding non-IT load and is inconsistent with the LLWG findings.	NERC revised the proposed criteria to clarify that large industrial or commercial loads historically have not posed a material impact to the BPS, such as manufacturing facilities or large hospitals, are not included. Clarity is accomplished through the removal of the term "Computational Load" and the required 1 MW "de minimus" amount and the addition of the Computational Load Site term, which includes the word "primarily" to indicate the use of the IT infrastructure at the site. Therefore, entities that have computational load but are not "primarily" performing computational activities do not meet the proposed registry criteria. While NERC recognizes the LLWG efforts reviewed other large loads in addition to computational loads, NERC determined that the risk is appropriately addressed at the moment by focusing on computational loads due to their aggregate and operational impacts on the BPS.
AIONTRACKS Persistence	During registration, NERC should capture a "class descriptor" of the type of computational load (e.g., training dominant, inference-dominant, etc.) to better apply Reliability Standards requirements.	NERC recognizes computational loads differ, and while this information may be captured during the registration process, it likely would be more appropriately captured by the Regional Entities during their risk-based compliance monitoring and enforcement processes.

Entity	Summary of Stakeholder Comments	Response
AZPS BPA	The proposed registry criteria should clarify that it applies to all those computational loads that meet the thresholds, including those that are served through small distribution entities. In addition, the proposed registry criteria should clarify that the voltage refers to the high-side and not necessarily the interconnecting utility's stepdown low-side voltage.	NERC clarified that the proposed registry criteria applies across various configurations of users of the BPS through addition of the following language: "supplied through electrical equipment" connected to the BPS at 100 kV or above. This is intended to reference the BPS connection of the electrical equipment serving the Computational Load Site, irrespective of the site's service or interconnection agreement voltage. NERC plans to post an ERO Registration Reference document that will provide better clarity on various configurations relative to high- and low-side voltage and may be factors in determining registration.
AZPS IESO MISO Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren ATC SVP	The proposed registry criteria uses an unclear term of "capability" which can be interpreted as maximum load. Some commenters recommend using "maximum peak demand." Other comments noted the need to clarify whether it is gross load, net load, maximum connected load capability, or another metric. Others questions how to calculate "aggregate connected Load capability."	NERC revised the proposed registry criteria to use the term "connected Load", which refers to all the electrical equipment in a Computational Load Site, for better clarity on how to determine the MW.

Other

Entity	Summary of Stakeholder Comments	Response
End-user Groups Arevon DCC Crusoe Corscale Google Oracle IESO Microsoft Consumers Energy	Commenters requested additional technical justification or legal basis supporting the proposed registry criteria. To that end, some commenters requested additional information on why NERC is including certain end-users in the proposed registry criteria or why the criteria does not cover all load instead of just computational load.	Consistent with the Federal Power Act section 215, the NERC registry criteria identify the set of owners, operators, and users who have a material impact on the BPS and must therefore comply with applicable Reliability Standards. As NERC noted in its technical reasoning document in the first posting of the proposed registry criteria, the technical justification for proposing to register computational loads is based on their aggregate impact to the reliability of the BPS. The assessment of this aggregate impact resulted from the work performed by the Reliability and Security Technical Committee Large Loads Working Group and verified through the Aggregated Report on NERC Level 2 Alert and industry confirmation. Further analysis identified entities that should be registered to address the identified risk based upon their MW capability and voltage connection to the BPS.. Upon review of the comments received on the initial proposed criteria and further analysis, NERC determined to revise the criteria to the higher 50 MW/100 kV thresholds and revised the technical reasoning document to provide justification for the new proposed thresholds.
Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren AZPS ATC SVP	Some commenters suggested that NERC and the Regional Entities be responsible for the identification of entities that can meet the new function instead of requesting the information from existing registered entities.	While NERC endeavors to ensure its processes are not overly burdensome on entities, there may be instances where existing registered entities are best positioned to provide the necessary information to ensure identification of appropriate entities to support reliability.

End-users Group Microsoft ELCON	Commenters questioned why existing registered entities cannot address the risk posed to the BPS instead of a new functional registration.	Existing Reliability Standards provide important precedents and framework for maintaining the reliability of the BPS, but they were not developed specifically for this type of large load with its unique characteristics and aggregate impact. The NERC Large Loads Working Group identified gaps in existing Reliability Standards in "Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads" and recommended development of new and/or updated Reliability Standards to address the unmitigated risks to the BPS. This need was also underscored in NERC's Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations. Further analysis identified entities that should be registered to address the identified risk based upon their MW capability and voltage connection to the BPS. When determining the need for new Reliability Standards, the LLWG also assessed whether existing registered entities could take on the new requirements. Through this assessment, the LLWG determined that while a Transmission Owner could include requirements such as disturbance ride-through or modeling into interconnection requirements via NERC Reliability Standard FAC-001.A Transmission Owner does not always have the ability to assess performance-based financial penalties to better ensure appropriate performance when connected to the BPS. Furthermore, the LLWG asserted that if computational loads do not have NERC standards directly applicable to them, the existing registered entities will then be responsible for the performance of that computational load. The LLWG noted that 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 an existing entity be responsible for their performance. Accordingly, the LLWG determined that requirements applicable to a new functional entity would

Entity	Summary of Stakeholder Comments	Response
		provide clear enforcement mechanisms to help ensure the risk to the BPS is addressed by those able to control performance. This assessment was further supported by NERC's Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations. Further analysis identified entities that should be registered to address the identified risk based upon their MW capability and voltage connection to the BPS.
DCC Crusoe Corscale Google Oracle ELCON	Some commenters requested that NERC wait until it receives the responses to the Level 3 Alert. Others requested that the recommendations from the Level 3 Alert become standards for existing registered entities.	As noted in the Large Load Action Plan, NERC has intended for the Level 3 Alert and NERC standards and registry criteria development to occur simultaneously in order to most expeditiously address the risks posed by computational loads. In addition, FERC issued an order directing NERC to complete registry criteria revisions and standards development for computational loads by the end of 2026, NERC must continue its efforts simultaneously to meet its regulatory deadlines.

Entity	Summary of Stakeholder Comments	Response
DCC Crusoe Corscale Google Oracle DPN ELCON	Some commenters requested more information on NERC's jurisdiction or statutory authority to register large or computational loads.	Under section 215, the Federal Power Act provides the Commission, via the ERO, authority to regulate "users, owners, and operators of the Bulk Power System (BPS)." This statutory authority to regulate includes: (1) developing and enforcing mandatory Reliability Standards that provide for reliable operation of the BPS, subject to approval by FERC; and (2) assessing BPS reliability and adequacy. Consistent with federal jurisdiction over interstate commerce and other sections of the Federal Power Act, Congressional authority under section 215 pertains only to the BPS and "users, owners, and operators" of the BPS. As such, under section 215, NERC cannot: (1) develop and enforce Reliability Standards for reliable operation of facilities used in the local distribution of electric energy, or (2) order the construction of additional generation or transmission capacity or set and enforce compliance with standards for adequacy or safety of electric facilities or services. FERC's regulations echo Federal Power Act section 215 by requiring that "each user, owner and operator of the [BPS] within the United States…shall register with the [ERO] and the Regional Entity for each region within which it uses, owns, or operates [BPS] facilities, in such manner as prescribed by the Rules of the [ERO] and each applicable Regional Entity. While NERC's reliability authority extends to all users, owners, and operators of the BPS, NERC's registry criteria and Reliability Standards identify the appropriate users, owners, and operators based on an exercise of reasonable judgment as to their potential material impact to the BPS. NERC applies risk-based engineering judgment, often in coordination with its stakeholder technical groups, to assess the impact of a particular user, owner, or operator on the BPS and whether any action(s) taken by that user, owner, or operator could mitigate risks posed by that impact.

Entity	Summary of Stakeholder Comments	Response
AZPS DCC Crusoe Corscale Google Oracle Microsoft Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren ATC SVP	Some commenters suggested NERC develop an exception process similar to the BES Exceptions process that allows entities without a material impact to be exempt from registering despite meeting the criteria. Other commenters requested that existing entities be allowed an exception from any future rules.	NERC already has an established process to handle circumstances where an entity does not believe it meets the registry criteria or does not believe its Computational Load Site has a material impact on BPS reliability. Under Rules of Procedure Appendix 5A, entities may request a review of their registration determinations under the NERC-led Registration Review Panel. Through that process, NERC and Regional Entities review an entity's materiality to the BPS and may either deregister an entity that meets registry criteria or register an entity that does not meet registry criteria. As for exceptions for existing entities, NERC notes that the Project 2026-02 standards drafting team considers appropriate implementation time of Reliability Standards. The drafting team will consider whether existing facilities are allowed different implementation timeframes, or exceptions based on reliability risk.

Entity	Summary of Stakeholder Comments	Response
Alphatraxia Arevon Crusoe Trades Southern Eversource SMUD/BANC Dominion NYPA FirstEnergy Centerpoint SRP Ameren AZPS ATC SVP IESO	NERC should provide more guidance on how the registry criteria applies to entities in differing configurations, such as those with co-located configurations among others. In addition, some commenters noted that NERC should provide guidance on a reasonable timeline and clear communication on that workflow for implementation and registration of those entities.	As was done with the Category 1 and 2 GO/GOP criteria once approved, NERC and the Regional Entities plan to develop an ERO Registration Reference document that provides additional detail on how the registry criteria is applied. This will occur once the registry criteria is more finalized, but in the interim, NERC registration staff collaborated with the Project 2026-02 drafting team to develop a Frequently Asked Questions (FAQ) document that provides some information on applicability of the registry criteria and Reliability Standards. While actual registration determinations are made after assessment of an individual entity's configuration compared to the criteria, the FAQ document provides some insight into the general application of the registry criteria. In response to communication and timelines, NERC and the Regional Entities will coordinate registration efforts based on the anticipated effective date of the newly proposed Reliability Standards that will be applicable to the new functional entities. As such, once those Reliability Standards are filed and then approved at FERC, NERC will base its registration activities timeline around the Reliability Standards' effective dates and ensure timely communication and outreach to new entities occurs to support a smooth registration process and effective dates of registration.
IRC SRC PJM	NERC should revise the Distribution Provider MW threshold to match the computational load MW threshold.	At present, NERC is not revising the Distribution Provider criteria.

End-users Group Arevon DPN ACC	NERC should work with governmental authorities and policymakers on the appropriate approach or process to addressing the risk posed to the BPS by computational loads. Others suggest a more robust regulatory and economic impact assessment.	NERC recognizes the importance of collaboration with federal and state governmental authorities, policymakers, and stakeholders on this matter. To that end, NERC engagement with governmental authorities on key issues is a continuous high priority. This includes several key engagements with critical state and provincial policymakers on large computational load entities. NERC has presented on its efforts to address reliability risk from large computational loads to associations representing the state legislator community, state energy officials, state regulators, and other key policymaker organizations. NERC has engaged several times with the National Association of Regulatory Utility Commissioners, also known as NARUC, and its relevant committees to discuss major efforts related to the Large Loads Working Group (LLWG), including briefings on various LLWG white papers and proposed updates to NERC's registration criteria. NERC and NARUC co-hosted two feedback sessions between NERC staff and six state commissions that are 'first-movers' addressing reforms to large load rate structure and interconnection requirements. In similar ways, the Regional Entities are actively engaging with government officials in their respective states. Continued dialogue between NERC, its state government representatives on NERC committees, and the organizations representing state policymaker interests is essential to address risks stemming from integrating large computational load entities onto the bulk power system. As for FERC input, NERC notes that on July 16, FERC issued an order directing NERC, under its section 215(d)(5) authority of the Federal Power Act, to "develop and submit new or modified Reliability Standards addressing the reliability risks associated with the integration of computational loads into the Bulk-Power System." The Commission also directed NERC to "develop revisions to its Rules of Procedure, including registry criteria for computational load entities." Accordingly, FERC, through this

Entity	Summary of Stakeholder Comments	Response
		order, indicates its agreement that the risks to the BPS should be addressed through registration of computational load and subsequent application of Reliability Standards.
IESO	Any revisions to the Rules of Procedure registry criteria should maintain existing compliance structures for non-U.S. entities.	NERC affirms its intent to maintain existing compliance structures for non-U.S. entities.
Alphatraxia Arevon DC Energy Mgmt DPN	Some commenters suggest NERC registration should require transparency on historical consumption data. Conversely, other commenters note the commercially sensitive nature of such data.	While NERC endeavors to provide as much transparency as possible in its regulatory activities, NERC also recognizes the sensitive nature of certain Confidential Information submitted as part of the registration process or other regulatory processes. Accordingly, NERC and the Regional Entities protect such information under its Rules of Procedure Section 1500. Due to the sensitive commercial nature of consumption data, NERC does not plan to collect it on computational loads, and if collected, would treat it as Confidential Information and only collect such information to aid in registration determinations based on the registry criteria.
Arevon	NERC should develop a clear de-registration process specific to computational loads due to their dynamic nature.	At this time, NERC determined the current Appendix 5A deregistration process is appropriate for any new functional registrations. Therefore, NERC will not create separate de-registration processes in the proposed ROP revisions. NERC or the Regional Entities can develop additional guidance around de-registration should issues arise in the future for the new entities specific to computational load.
SVP DPN	Some commenters submitted comments on the Standards Authorization Request, proposed Reliability Standards, or other standards development matters.	NERC notes that those comments should be submitted through the comment periods conducted by the Project 2026-02 Computational Loads drafting team, whose web page provides information on ways to engage or comment on the development of the proposed standards.

Attachment 5

NERC Engagement Activities

NERC Engagement Activities

NERC conducted the following engagement activities related to the proposed Rules of Procedure revisions:

1st Quarter 2026

- February 24-25, 2026: NERC hosted the Emerging Large Loads Technical Conference that explored critical aspects of computational load integration into the BPS and set the stage for the development of registry criteria and Reliability Standards for computational load entities.
- March 16, 2026: NERC staff led a briefing on its large load efforts, inclusive of registration, hosted by the Data Center Coalition ("DCC").
- March 30, 2026: NERC staff held a public webinar for interested stakeholders that outlined next steps associated with its Large Loads Action Plan, including the effort to develop registry criteria.

2nd Quarter 2026

- April 9, 2026: NERC staff hosted a feedback session for the National Association of Regulatory Utility Commissioners ("NARUC") on computational load efforts, including the proposed registry criteria.
- May 6, 2026: NERC staff led an educational webinar for large end-use customers hosted by Electricity Consumers Resource Council ("ELCON"), the Electricity Customer Alliance ("ECA"), and a NERC Member Representatives Committee member representing Sector 8 (Large End-Use Electricity Customer) that included a presentation on the proposed registry criteria.
- May 14, 2026: NERC staff presented on the proposed registry criteria to a committee of the Corporate Energy Buyers Association ("CEBA").
- June 10, 2026: NERC staff presented to the joint meeting of the NERC Reliability and Security Technical Committee and the NERC Standards Committee.

3rd Quarter 2026

- July 13, 2026: NERC staff hosted a public webinar for interested stakeholders to provide an overview of the updates to proposed registry criteria language in response to comments and educate stakeholders on the registration process.
- July 17, 2026: NERC staff presented the proposed registry criteria and held a discussion with the Digital Power Network.
- July 22, 2026: NERC staff presented the proposed registry criteria and held a discussion with the DCC.

- July 23, 2026: NERC staff presented the proposed registry criteria and held a discussion with representatives from the American Public Power Association ("APPA"), Edison Electric Institute ("EEI"), Large Public Power Council ("LPPC"), NARUC, National Rural Electric Cooperative Association ("NRECA"), and Transmission Access Policy Study Group ("TAPS").
- July 28, 2026: NERC staff presented to and held a discussion with ELCON and ECA on the proposed registry criteria.
- July 30, 2026: NERC staff presented to and held a discussion with Real Estate Roundtable on the proposed registry criteria.
- August 24, 2026: NERC staff hosted a webinar for policymakers detailing the proposed changes to registration criteria.
- August 24, 2026: NERC staff presented on the proposed registry criteria to the Information Technology Industry Council.
- September 3, 2026: NERC staff presented to and held a discussion with Independent System Operator/Regional Transmission Organization Council committees.