Large Load Considerations

Issue Paper

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Contents

Executive Summary

California faces a surge in electricity demand over the next 5-10 years, driven in part by new large loads. With California at the center of the hyperscaler economy, data centers are a significant driver, but electric vehicle charging, and electrification of agricultural and industrial processes also will contribute to this growth. The California Independent System Operator (ISO) is committed to staying ahead of the curve, meeting new energy demand reliably and affordably. As of January 2026, the California Energy Commission (CEC) forecasts data center load in the ISO grid to increase by 1.8 gigawatts (GW) by 2030 and 4.9 GW by 2040.[1] The ISO also is aware that utilities are receiving an increasing number of large load interconnection and service applications. The ISO embraces innovation in its tools and processes and works closely with utilities and the state to anticipate and address emerging needs. Currently, the ISO effectively accounts for new large loads through the annual transmission planning process, which is highly integrated with statewide load forecasts and integrated resource planning to ensure both supply and transmission adequacy. Recent transmission plans included transmission approvals and modifications to previously approved projects to provide increased capacity in the Bay Area to support data center load growth and position the system for additional expansion. The ISO works daily to minimize “friction” on the system, i.e. enhance the efficiency and effectiveness of grid development and operation, with technologies such as grid-enhancing technologies and process improvements such as coordinated resource, transmission and interconnection, yielding a grid that is highly optimized and responsive.

Given the acute interest in these issues, and the complex interplay among the ISO, state and federal regulators, transmission service providers, utility distribution companies, load-serving entities (LSEs), and customers, the ISO recognizes the importance of clarity on roles in planning for large loads. This Issue Paper describes the ISO’s current role in integrating large loads on the ISO grid and identifies issues that may arise in future stakeholder discussions to refine processes for integrating large loads.

The current assignment of responsibilities for the system under the ISO’s operating control gives lead responsibilities for generation interconnection and transmission planning to the ISO, and load interconnections to the utilities. As such, utility federal and state tariffs and state regulations generally govern the study, interconnection, rates, and cost recovery for serving new loads, with active participation by the ISO. The ISO also

[1] California Energy Demand 2025 Hourly Forecast - CAISO – Planning Scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=268127&DocumentContentId=105135

coordinates on planning for large loads with local, state, and federal regulators and is exploring these issues with utility and industry partners.

This paper summarizes the current treatment of the following elements of large load planning, interconnection, and operations within the ISO system:

1. Transmission and resource planning
2. Transmission service offerings
3. Cost allocation and responsibility
4. Technical requirements and standards
5. Operational requirements

Recognizing the active regulatory discussions around large load integration, the ISO highlights important considerations throughout this paper and notes areas that may be subject to policy changes and potential tariff clarification. The ISO is monitoring and engaging in all relevant regulatory discussions such as the Federal Energy Regulatory Commission's (FERC) Advanced Notice of Proposed Rulemaking (ANOPR) on the Interconnection of Large Loads onto the Interstate Transmission System[2], and Pacific Gas and Electric Company's (PG&E) Application to the California Public Utilities Commission (CPUC) proposing a new electric rule tariff, Electric Rule 30, to interconnect transmission-level customers seeking retail service.

The ISO is responsible for maintaining continued system reliability and is exploring the possible need for technical standards for new large loads to maintain reliable operations of the grid. The ISO is also monitoring and participating in North American Electric Reliability Corporation (NERC) discussions regarding the need for technical standards. These and other changes could be considered in either a formal stakeholder initiative or potentially in a future compliance filing.

[2] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251027-4001&optimized=false&sid=4fd48919-3af9-4518-a67e-3d4d26486228

1. Introduction and Background

California has been preparing to meet new load growth as part of its statewide planning processes for several years; these efforts have resulted in roughly 31 GW of nameplate new generation and storage capacity coming online to serve ISO load since 2020.[3] The close coordination between the ISO and state agencies on demand forecasts and resource planning provides a pathway for proactive transmission planning that anticipates emerging large load growth and aligns with resource needs to serve new loads. For example, the ISO has approved transmission projects in the San Jose region to serve increasing data center load and to position the system for additional expansion.

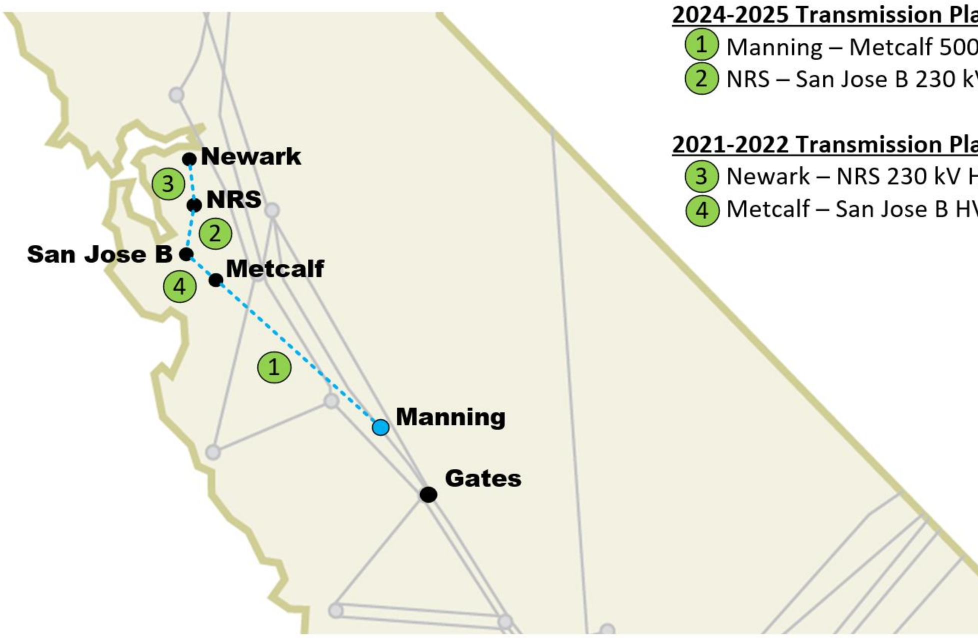

Figure 1. Recent Transmission Projects driven by large load forecast increases. Projects (3) and (4) were modified in November 2024 to provide increased capacity to the area and better position the system for additional expansion. Project (3) was converted to an AC solution at that time.

Given the interplay among the ISO, transmission service providers, transmission owners, utility distribution companies and load-serving entities, the ISO has created an ISO webpage on large loads to clarify the current roles in planning and integrating large loads on the ISO system. The webpage also identifies issues for future stakeholder discussions to explore refinements to the ISO's processes for integrating large loads.

The current assignment of transmission responsibilities for the system under the ISO's operating control gives lead responsibilities for resource (generator and storage) interconnection and transmission planning to the ISO, and load connections to the

[3] See Tracking Energy Development

utilities, specifically the participating transmission owners (PTOs).[4] These relationships are set out in the FERC-approved tariffs of the ISO and the PTOs. This structure has worked efficiently and effectively, as most of the load interconnections were distribution-system connections informed by the utilities' distribution system requirements, and third-party customer connections were managed with the utilities. This enabled the utilities to manage both their PTO responsibilities for transmission connections regulated by FERC and their state-jurisdictional responsibilities for rates and charges that applied to the end-use customer.

The ISO commenced its investigation into the issues in this issue paper to ensure effective integration of large loads into the grid within the context of the current roles and responsibilities of the ISO and the utilities. The extent to which ISOs generally can or should be more heavily involved with the interconnection of large loads is a national issue that regulators are addressing. The ISO is closely monitoring recent developments in federal and state regulatory policy and is considering additional tariff clarifications that may be necessary to fulfill the ISO's responsibility to ensure reliability.

To stay ahead of increasing load growth, the ISO works with the state energy agencies, utilities, and stakeholders on a number of levels. A 2022 Memorandum of Understanding (MOU) between the CEC, CPUC, and the ISO tightened the linkages between resource and transmission planning, interconnection, and procurement so California is better equipped to meet its reliability needs and state clean energy policy objectives.[5]

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[4] At times in this paper, the ISO will distinguish between utility responsibilities as either 'participating transmission owner (PTO)' or 'utility distribution company (UDC)' as both carry different responsibilities depending on the type of load and regulatory topic in question. Utility distribution company refers to an entity that owns a Distribution System for the delivery of Energy to and from the CAISO Controlled Grid, and that provides regulated retail electric service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer. Participating Transmission Owner refers to a party to the Transmission Control Agreement who has placed its transmission assets and Entitlements under the CAISO's Operational Control in accordance with the Transmission Control Agreement.

[5] ISO CEC and CPUC Memorandum of Understanding - Dec 2022

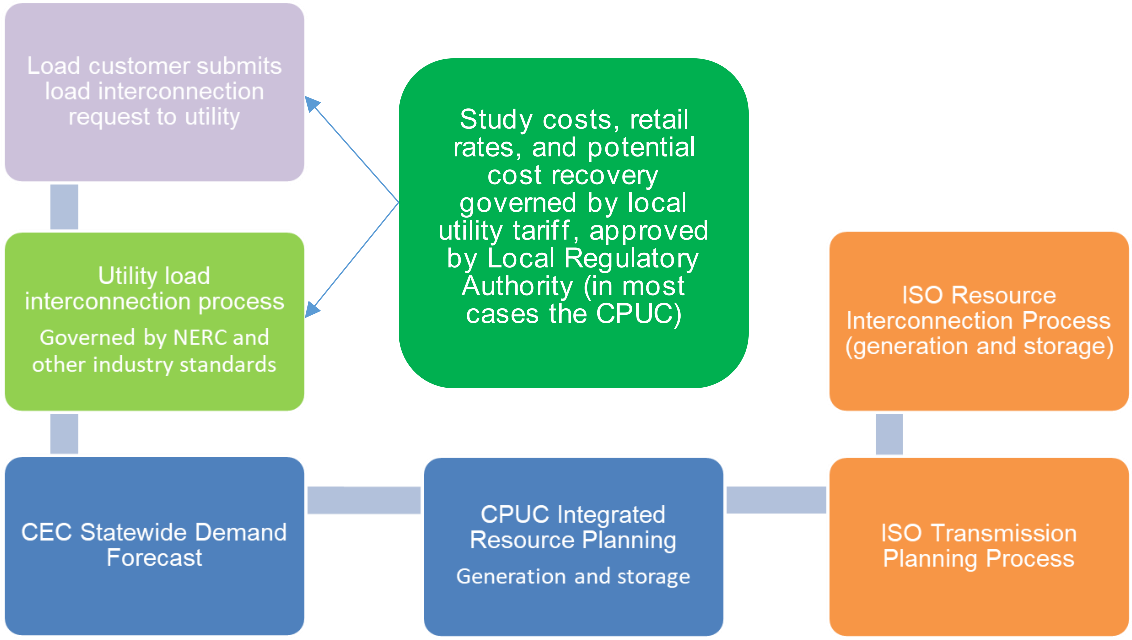

Figure 2. Current Large Load Interconnection and Planning Efforts

This paper is intended to address the broad set of related issues. Recognizing the potential for regulation on the topic addressed in this paper, the ISO may open a stakeholder initiative to propose policy clarifications or explore new elements related to large load interconnection and welcomes feedback from stakeholders.

2. Policy and Stakeholder Considerations

Federal and state regulators are addressing the processes for planning, interconnecting, and operating large loads with significant attention and urgency. NERC is developing draft guidelines and FERC has issued an ANOPR on this issue. Similarly, California agencies are examining the implications of large load planning, interconnection, and energization[6] with open proceedings at the CPUC and in certain dockets at the CEC.

The ISO has an important role in planning for and maintaining reliable operations of the grid. As such, this paper describes the broader large load policy landscape and areas where the ISO may consider additional policy development to ensure safe and reliable system operations. Considering the urgency of onboarding new large loads and the technical and operational concerns associated with large loads, the ISO is considering commencement of a policy initiative to ensure maintenance of a reliable system without compromising economic development or speed to power. This paper broadly describes

[6] The CPUC refers to load interconnection as 'energization'.

and explores certain issues, but the ISO anticipates additional clarity from FERC before issuing specific proposals.

3. Transmission and Resource Planning

The ISO leads transmission capacity expansion planning for the networks in the ISO footprint, and the emergence of large load requirements must be addressed on a timely basis. As set out in the 2022 MOU, the CEC develops a statewide long-term energy demand forecast, which incorporates information from utilities across the ISO footprint. The CEC's demand forecast includes large loads mapped to substation locations used in the ISO's transmission studies. Using the CEC's forecast, the CPUC provides resource planning information to the ISO for its annual transmission planning process. The ISO also receives resource planning information from publicly owned utilities. The ISO uses these inputs to develop a final transmission plan and initiate development of the recommended transmission projects. Developers and stakeholders then use the transmission plan to understand new transmission approvals and available capacity.

As of January 2026, the California Energy Commission (CEC) forecasts data center load in the ISO Balancing Authority (BA) area to increase by 1.8 GW by 2030 and 4.9 GW by 2040.[7] The ISO also is aware that utilities are receiving an increasing number of large load interconnection and service applications. The CPUC's resource planning information expects that new generation and storage resources will be built to meet more than 30 GW of new peak demand by the mid-2030s.[8] The CPUC shares detailed information about the location of expected new resources so the ISO can consider the need for new transmission and the expected transmission availability in studying developers' generator interconnection requests.

The CPUC's resource planning supports the ISO's transmission planning process and drives procurement requirements for load. In 2025, California brought more than 6 GW of new nameplate capacity online to serve load in ISO territory for the second consecutive year. State resource planning and procurement policies have driven investments that have yielded roughly 31 GW of efficient, new power plants coming online since 2020 to serve ISO load, including more than 16 GW of new storage.

The ISO has submitted its filing in compliance with FERC Order No. 1920 in December of 2025 and will enhance its current practices of long-term (20-year) regional transmission planning in implementation of that Order.

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[8] See CPUC Transmission Planning Process information from the Integrated Resource Planning Process, available here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/resource-and-transmission-development

3.1 Long-Term Demand Forecasting

The CEC's Integrated Energy Policy Report's (IEPR) long-term demand forecast estimates future electricity consumption and peak demand that is reasonably expected to occur. The forecast considers the impacts of large loads including data centers, electric vehicle charging stations, and manufacturing facilities. The CEC incorporates large loads into the forecast using data collected from utilities.

For data centers, the CEC gathers information on applications for service submitted to utilities and applies adjustments to requested capacity based on utilization factors, confidence levels, and ramping assumptions.[9] Confidence levels are determined based on the status of project applications. If projects have signed agreements with the utility for electric service, they are included in the highest confidence group.

The CEC's 2025 California Energy Demand Forecast (2025 IEPR forecast) projects data center load in the ISO BA area to increase by 1.8 GW by 2030 and 4.9 GW by 2040.[10] The CEC demand forecast has projected capacity and energy needs of new loads for several years and these new loads have been incorporated into the statewide planning processes. The CEC's 2025 IEPR forecast expects an increase in 30 GW of peak load by the mid-2030s, a portion of which is new large loads from data centers.

The State's integrated resource planning queues off the CEC's Demand Forecast, establishing procurement targets and resource needs to satisfy load growth while maintaining affordability and reliability. The CPUC, which conducts integrated resource planning across much of the State, is able to respond to changes to load in each integrated resource planning process.

3.2 The California ISO Transmission Planning Process

The ISO's Transmission Planning Process and CPUC's Integrated Resource Planning process both account for new large loads as fundamental inputs, helping to ensure resource and transmission plans which are able to affordably and reliably meet new demand.

Participating Transmission Owners (Participating TOs) participate in the ISO's Transmission Planning Process and propose transmission solutions to best meet the needs of the system. To address a new large load interconnection request that comes

[9] See CEC data center forecast assumptions here: https://www.energy.ca.gov/sites/default/files/2025-11/2025_IEPR_Preliminary_Data_Center_Forecast_ada.pdf
[10] California Energy Demand 2025 Hourly Forecast - CAISO – Planning Scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=268127&DocumentContentId=105135

in after development of the demand forecast and CPUC resource portfolios, Participating TOs may submit proposals into the ISO's Transmission Planning Process for the ISO's concurrence in the Transmission Plan. The concurrence for load interconnections only considers the transmission component of the load interconnection. The ISO reviews and provides concurrence that the load interconnection and potential network upgrades to interconnect the load meet the transmission reliability requirements and are consistent with the long-term transmission plans in the area.

3.3 Interconnection of Large Loads

Large loads, including data centers, industrial facilities, and EV charging stations, can interconnect on either the distribution or transmission system. The end-customer interaction in the load interconnection process for CPUC-jurisdictional utilities is regulated through CPUC-approved rules.

In November 2024, PG&E proposed Electric Rule 30 to establish a standardized tariff for large load customers applying for electric retail service at transmission level voltages, defined as voltages between 50 kV and 230 kV.[11] The rule aims to replace the current case-by-case application process with a standardized approach, streamlining interconnection for large loads seeking retail-rate transmission-level service. In July 2025, the CPUC approved interim implementation of Electric Rule 30, with the caveat that customers interconnecting under Electric Rule 30 would cover the full initial infrastructure costs while the CPUC continued to evaluate cost causation, cost allocation, and cost recovery mechanisms.[12] In January 2026, the CPUC issued a ruling requesting comments on cost causation, financing transmission facilities, and the apportionment of facility costs to further develop the record on PG&E's proposed Electric Rule 30 tariff.[13]

3.4 Co-located large loads and generation

Large loads that are co-located with generation or storage that are subject to FERC jurisdiction are studied in separate interconnection processes. The load interconnection is studied through the transmission owner's process; the generator interconnection is studied through the ISO's resource interconnection process. Today, transmission providers must account for co-located retail loads subject to state-

[11] PG&E, Application of Pacific Gas and Electric Company (U39E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service (Application 24-11-007), November 21, 2024: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M547/K155/547155949.PDF
[12] CPUC, July 24, 2025: https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-streamlines-electric-grid-connections-for-high-energy-users-like-data-centers-and-ev-chargers
[13] CPUC, *Administrative Law Judge's Ruling Establishing Proceeding Schedule*, January 9, 2026: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M593/K231/593231120.PDF

jurisdictional retail tariffs while using FERC jurisdictional tariffs for eligible generator interconnections.[14] The ISO tariff currently does not have a mechanism to consider large loads in its generator interconnection study process.

4. Transmission service offerings

The ISO is responsible for balancing demand for electricity with available supply through operation of wholesale electricity markets. Today, demand is met through market participation of scheduling coordinators for load serving entities. The ISO markets meet this demand with the least-cost dispatch of available resources that ensures system reliability. Transmission service for load on the ISO-controlled grid is generally firm. With a few exceptions,[15] the ISO's transmission planning processes generally assume that if the planned transmission infrastructure is developed to serve a new large load, forecasted demand will be met reliably through market operations under normal conditions. Thus, the ISO would assume that the utility provides firm service for the load in the context of NERC standards.

FERC recently directed PJM to amend its tariff "to establish three new transmission services that reflect that eligible customers taking service on behalf of co-located load are willing and able to limit their energy withdrawals from the transmission system under certain conditions."[16] FERC continued "these new transmission service options reflect a co-located load's ability to limit withdrawals from the transmission system and potentially avoid costly and inefficient transmission buildout."[17] PJM was directed to establish a new interim, non-firm transmission service; firm contract demand transmission service, and non-firm contract demand transmission service. Although the ISO does not have various levels of transmission service, it could face an equivalent requirement to provide load interconnection customers with interconnection timelines based on willingness to be curtailed.

The ISO understands that offering customized service to large loads (e.g. interruptible service or being the first-in-line to be curtailed) may enable faster interconnection – or speed to power - by providing some interim, potentially reduced level of non-firm service to the large load as system reinforcements are built. Customized service offerings may also reduce costs of infrastructure expansion on a longer-term basis. In either case, additional service offerings would need to be properly incorporated into operations and

[14] All generating facilities that are subject to FERC jurisdiction seeking Interconnection with a utility's Transmission System apply to the ISO for interconnection and are subject to ISO tariff, and to the utility and be subject to the utility's wholesale distribution access tariff if seeking connection to the distribution system.
[15] Exceptions include participating loads and demand response resources.
[16] *PJM Interconnection*, 193 FERC ¶ 61,217 (2025).
[17] *Id.*

aligned with the corresponding adjustments to existing ISO planning activities. This approach will ensure other load customers are not negatively impacted by the faster interim service offered to the large load, and that any savings achieved by reducing transmission expansion needs are planned across the ISO-controlled grid where a reduced level of service is accepted on an ongoing basis to reduce initial interconnection costs. New service offerings will require a clear understanding of existing NERC requirements and may need adjustments to the ISO planning standards to more accurately account for system conditions, withdrawals, and transmission service provision.

5. Cost allocation and responsibility

Cost allocation rules for large load interconnections will affect both transmission wholesale customers and retail customers at all voltages. Transmission cost allocation between utilities and others taking transmission level wholesale service from the ISO are established through FERC-jurisdictional transmission tariffs. For retail customers interconnected at the transmission level, FERC has the authority to approve costs, while retail rate design is typically addressed through the state-jurisdictional rates of the utilities. The two may or may not directly align, creating complexity.

The complexity of cost allocation is especially true for co-located facilities with load and generation onsite. It will not be possible in many instances to distinguish between which networked facilities were triggered by the load or by the generation. Likewise, it will not always be clear to the extent other ratepayers benefit from networked facilities triggered by the new large load. As electric regulators are fond of saying, cost allocation 'is not a matter for the slide rule.' Enhancing large load cost allocation rules and responsibilities will thus require significant coordination across tariffs, including the ISO's. Ensuring that costs are allocated commensurate with benefits helps bring about timely and orderly interconnection of new large loads while supporting affordability and efficient investment incentives. Issues could include, for example, whether a hybrid facility whose generator interconnects through the ISO tariff should be eligible for the same reimbursement rules as a conventional stand-alone generator.[18]

[18] In the ISO, wholesale generators finance the network upgrades they require to safely and reliably interconnect, but the transmission owner reimburses them in cash within five years after the generator and their upgrades are online. These reimbursement costs are then put into the transmission owner's transmission revenue requirement. Alternatively, other transmission providers require interconnection customers to finance network upgrades without cash reimbursement. Interconnection customers may receive transmission credits or may include their interconnection costs in their capacity/RA contract or in their ongoing generation costs.

6. Technical requirements and standards

In October 2025, the ISO established an informal Large Load technical requirements working group, comprised of a number of PTOs with active large load interconnection requests to study and develop a coordinated set of technical requirements for interconnecting data center loads to the ISO-controlled grid. The objective is to ensure that these large loads can reliably and safely interconnect while meeting the ISO's planning and operating criteria across steady-state, dynamic, protection, and power-quality domains.

Specifically, the ISO and utilities are addressing the following, in line with recommendations in the NERC Preliminary Draft Reliability Guideline – Risk Mitigation for Emerging Large Loads:[19]

- **Modeling requirements:** Large load customers must provide accurate, validated, and up-to-date steady-state, dynamic, and if required, electromagnetic transient (EMT) models that appropriately represent their equipment and operational characteristics. These models are essential for assessing system reliability, transient performance, and potential interactions with nearby generation and transmission facilities.
- **Power quality:** Large loads with fast, pulsating demand characteristics can introduce voltage distortion, flicker, and harmonic content that degrade local power quality. Interconnection requirements will need to ensure that load behavior does not cause unacceptable voltage deviations or negatively affect neighboring customers or grid equipment.
- **Rapid ramping:** Data center and other electronically controlled loads can exhibit sub-second step changes in demand, leading to rapid ramping events. These abrupt changes can stress the local transmission system, affect voltage profiles, and contribute to frequency deviations. In extreme conditions, high rates of change of frequency (ROCOF) could challenge generator protection settings and system stability in the area.
- **Voltage and frequency ride-through:** To help maintain system reliability during grid disturbances, large loads will be required to remain connected and continue absorbing power through voltage or frequency excursions. Appropriate ride-through capability helps avoid unnecessary tripping, reduces the risk of cascading impacts, and supports post-disturbance system recovery.
- **Sub-synchronous oscillation behavior:** Fast or periodic variations in power demand—either from a single large facility or from multiple large loads in an

[19] https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/draft_reliabilityguideline_riskmitigationforemerginglargeloads.pdf

area—can interact with transmission elements or nearby generators at sub-synchronous frequencies. These interactions can excite torsional modes, cause sub-synchronous oscillations, and pose risks of equipment damage or broader system instability. Studies will be needed to evaluate and mitigate such risks.

- **Persistent small load fluctuations:** Even modest but continuous fluctuations in load can produce voltage flicker or unacceptable variations in local power quality. Over time, such fluctuations may also contribute to mechanical fatigue in equipment such as rotating machines and transformers. Requirements will need to ensure that persistent small-signal load variations remain within acceptable limits.
- **Impact on short circuit levels and transmission protection coordination:** Interconnection of large loads can materially affect local short-circuit levels and the performance of existing transmission protection schemes. Although loads generally do not contribute significant fault current, the UPS and the backup generation in some large data center loads can potentially influence breaker duty margins at nearby substations. In some cases, the addition of large load transformers or associated reactive compensation equipment may increase short-circuit duties or require adjustments to relay settings to maintain proper coordination and dependability. Short-circuit and protection requirements are therefore necessary to ensure that transmission protection systems continue to operate reliably and within equipment ratings after the load is interconnected.

A decision on where these requirements will ultimately be documented and enforced—whether through a tariff, ISO Business Practice Manual, utility interconnection handbooks, or another vehicle—will be made at a later stage. This decision will need to consider the direction NERC is taking to identify national standards.

The technical working group is reviewing existing technical requirements, including those in use by California utilities and entities such as ERCOT, Dominion Energy, ATC, Southern Company, and others. A parametric study will then be performed to evaluate whether those external requirements can be applied directly to the ISO system or whether modifications or additional ISO-specific requirements may be necessary.

Subject to resource availability, the working group is targeting completion of the first draft of the technical requirements by the end of Q1 2026.

7 Operational Requirements

This section outlines operational reliability requirements for large loads within the ISO BA area. It describes how large loads affect system balancing and Interconnection frequency and introduces the operational mechanisms used by a BA for balancing and specifies requirements for market-participating and non-participating large loads — including ramping, telemetry, outage management, and coordination pathways.

7.1 Balancing Authority Responsibilities and Mechanisms

As a BA, the ISO must maintain load–interchange–generation balance and operate the BA Area in a manner that supports the Interconnection's frequency.

Balancing is achieved through the following layers:

1. Primary Frequency Response (PFR via Governors): Automatic response of frequency-responsive resources within approximately 0.5–20 seconds after the frequency deadband is breached. All generators with active governors respond—regardless of which BA's actions caused the excursion. Note: Thermal and hydro units may experience mechanical stress during PFR events.

2. Automatic Generation Control (AGC): Automatic balancing based on the BA's Area Control Error (ACE), typically initiating ~20 seconds after ACE exceeds a threshold. Many BAs deliberately moderate AGC speed to control oscillations.

3. Operator Action: Manual intervention within minutes of a contingency (e.g., redispatch orders, topology changes) to stabilize frequency and restore balance.

4. Market Dispatch: Security-constrained redispatch—typically within up to 10 minutes—to reestablish balance following disturbances or forecast/schedule deviations.

7.2 Emerging Frequency Challenges

Sudden changes in load or generation directly move Interconnection frequency; gradual changes are manageable via AGC, but rapid movements typically exceed AGC response speed and trigger PFR.

To avoid triggering PFR, ramping requirements will need to be established for the day-to-day operation of large loads, including when coming back from outage, and/or a disturbance, but excluding automated responses to faults or disturbances.

7.3 Participating vs. Non-Participating Load Pathways

Under evolving federal policy (e.g., FERC ANOPR concepts), large loads that agree to be curtailable or hybrid facilities that agree to be dispatchable may qualify for expedited load interconnection. Such loads must provide the following:

- Telemetry

- Planned operating schedules and outage notifications
- 24/7 curtailment capability for curtailable large loads
- Acceptable ramp rate

Key Differences in the ISO's Operations:

- Market-Participating large loads: Integrated into ISO markets with established processes for scheduling, ramping, outage management, visibility, and curtailment.
- Non-Participating large loads: Managed via utility. ISO visibility to individual large loads parameters is limited unless additional data-sharing is established.

Coordination Requirement: Regardless of participation status, any dispatch or curtailment of large loads must be coordinated with the utility and load serving entity (LSE) to ensure distribution reliability is not compromised.

8 Related Issues

8.1 Short-term demand and uncertainty forecasting

As the growth of large loads, flexible demand, and distributed energy resources (DER) activity reshape demand profiles and power flows, it is increasingly important that the ISO and utilities have awareness, visibility, and can communicate proactively to work together to coordinate on reliability, lower operational costs, and maintain efficient wholesale market outcomes. As large loads combined with DER technologies proliferate, their increasing flexibility creates more uncertainty and makes them more difficult to predict.

Key challenges for short-term demand forecasting include:

- Limited visibility into DER operations
- Rapid growth in co-located large land DER adoption
- Evolving retail rate structures
- Expansion of load flexibility programs

Demand forecasting is a critical input for balancing supply and demand across the grid. Inaccurate forecasts can lead to market inefficiencies and reliability risks. The ISO relies on demand forecasts for both forward-looking and real-time operations:

- Day-Ahead: Hourly forecasts for DA+1 through DA+10, used in Reliability Unit Commitment (RUC) and system health monitoring.
- Real-Time: Sub-hourly (5–15 minute) forecasts for current-day operations.

The ISO relies on uncertainty forecasts for both forward-looking and real-time operations:

- Day-Ahead: Hourly forecasts for DA+1 through DA+4, used in future Imbalance Reserve requirements, Reliability Unit Commitment (RUC), and system health monitoring.
- Real-Time: Flexible Ramp Requirements that are formed Sub-hourly (FMM to RTD) and Regulation Requirements (RTD to Actual) for current-day operations.

Large Load growth in combination with DERs are a major variable in short-term demand forecasting. Improved accuracy in data directly enhances forecast precision. Without visibility into large load and DER-driven demand changes, the ISO may need to rely more heavily on near-term reliability products like flexible ramping and regulation reserves adding cost and complexity.

Better understanding of underlying demand and DER generation will improve the following:

- Operational forecasting & resource management
- Market optimization
  - Commitment and pricing in Day-Ahead and Real-Time Markets
- Grid coordination and visibility
  - Outage coordination
  - Situational awareness
  - Uncertainty assessments
  - Contingency planning
  - Ability to perform key reliability responsibilities such as frequency control.

As flexible demands grow, it is essential to ensure that we can protect the critical function of forward demand predictability within the market optimization as well as operational forecasting. Accurate forecasts are crucial for reliable utility distribution and transmission operations.

8.2 Market participation

In part to address the issues cited in the previous section, the ISO has been actively working with industry partners to explore how large loads can participate in ISO energy and ancillary service markets more efficiently. In 2025, the ISO launched its Demand and Distributed Energy Market Integration (DDEMI) stakeholder working group to discuss enhancements to the ISO's existing demand-side market integration options and explore new paths to market integration.

The 2025 scoping phase of the working group served to explore, confirm, and document stakeholder problem statements related to demand flexibility. These problem statements included topics related to large, nonconforming loads, including participating wholesale loads and loads that may be co-located with generation. Additionally, reforms to the ISO's reliability demand response resource model were discussed.

While the working group scoping phase for the DDEMI effort has been completed, stakeholders are encouraged to participate in upcoming policy development work related to these issues. Market participation rules and market design issues related to participating large loads and related demand response programs fall within the scope of the DDEMI working group's efforts.

8.3 Coordination Framework

The ISO is working with industry partners to develop a coordination framework between the ISO and utilities inside and outside of the ISO balancing area. This framework is intended to strengthen situational awareness across the transmission and distribution (T&D) interface, support accurate short-term demand forecasting, maintain market efficiency, and support reliable operations across the transmission and distribution (T&D) interface. Key focus areas include managing large loads with and without co-located generation; strengthening operational coordination, information sharing, and visibility; improving demand and DER forecasting; and advancing technology solutions that enable flexible demand-side resources – both within and outside of the ISO market. As system conditions evolve with increasing demand flexibility, including the evolution of large loads, enhanced situational awareness and timely coordination across entities will be critical. The coordination framework will support proactive operational coordination, reduce uncertainty, and help ensure reliable and efficient grid operations.