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Digital Assurance for Grid Reliability in the Era of Large Load Growth

Digital Assurance Brief #2

Center for Securing Digital Energy
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ACRONYMS

AI	Artificial Intelligence
BPS	Bulk Power System
BTM	Behind-the-Meter
CPUC	California Public Utility Commission
DER	Distributed Energy Resource
DOE	U.S. Department of Energy
EMS	Energy Management System
EMT	Electromagnetic Transient
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GPU	Graphical Processing Unit
GW	Gigawatt
HVAC	Heating, Ventilation, and Air Conditioning
IBR	Inverter-based Resource
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
kV	Kilovolt
LGP	Limited Generation Profile
LFLTF	Large Flexible Load Task Force
LLTF	Large Load Task Force
LTRA	Long-Term Reliability Assessment
MISO	Midwest Independent System operator
MW	Megawatt
NERC	North American Electric Reliability Corporation
PG&E	Pacific Gas & Electric
RTO	Regional Transmission Organization
UPS	Uninterruptible Power Supply
U.S.	United States

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Executive Summary

Accommodating large load growth is essential to supporting the United States (U.S.) Department of Energy's (DOE's) goals to unleash American energy and win the artificial intelligence (AI) race [1, 2]. Data centers are predicted to triple their share of electric load from 4% in 2024 to 12% in 2028 [3]. However, utility integration of these large loads faces several challenges, one of which is the reliability risks they pose to the grid. Never before have utilities seen single loads this large, now known to exceed the gigawatt threshold, and often concentrated in favorable geographic areas.

Reliability risk is exacerbated operators lack assured digital visibility, control, and validation of large-load behavior. Events within the last few years have demonstrated the reliability risk associated with the unexpected loss or disconnect of large loads from the grid, raising concerns about the long-term ability to meet reliability requirements for all customers. Ride-through refers to the ability to remain connected during brief power quality disturbances that typically last less than a few seconds, such as voltage sags from transmission faults. To maintain grid stability, generation and load must remain balanced. When equipment lacks adequate ride-through capability and disconnects unnecessarily during these disturbances, voltage and frequency deviate outside of acceptable ranges. These deviations can damage equipment and force additional loads and generators to disconnect to protect their own systems, creating potential for cascading impacts that compromise reliability

Addressing these challenges requires both policy changes and enhanced digital assurance capabilities. In the context of large load growth, digital assurance refers to the ability of grid operators and asset owners to verify, in advance and in real time, that large loads will behave predictably during normal operations and disturbances. This includes assured data quality, validated models, secure communications, and enforceable control and response mechanisms.

As these challenges are considered, several parallels emerge highlighting the similarity in reliability risks and regulatory options between large loads today and inverter-based resources (IBRs). Just like large loads, IBRs have been present on the grid for many years; the technologies are not new. However, the scale of deployment and capabilities of the resources are undergoing dramatic shifts, though the changes in large loads lag a few years behind those for IBRs. As utility-scale IBRs and aggregations of IBRs rose in scale, their potential to affect grid reliability also increased, and as these impacts were demonstrated through real-world events, the need to change how they were integrated into grid planning and regulation became clear. Though still recent, actions from state and federal authorities demonstrate the approaches that can be used to drive changes in asset interaction with the grid. There are several lessons that can be learned from the challenges that IBRs posed and the regulatory solutions. In some cases, the changes provide clear templates for adjustments that may work for large loads.

Based on assessment of these known events, and drawing on lessons learned from IBRs, several regulatory options have emerged, which are central to address to mitigate the reliability risks. Models available to grid planners for data center behavior must be more accurate, field-validated, and kept current. Understanding and accurately simulating large load behaviors is critical to designing systems that provide resilience and reliability for the large loads themselves and other customers. Interconnection studies and interconnection requirements should be modernized to account for the impact that large loads can have on the grid. Updating these agreements can be mutually beneficial, allowing large loads to connect sooner even while supporting grid infrastructure is still under development. Ride-through requirements have potential to alleviate key risks from known events. Finally, a mechanism to enforce requirements is needed, leading to discussions about large load registration requirements.

Leveraging lessons from implementation of new IBR standards and regulations, likely technical requirements for data centers can be predicted. Success depends fundamentally on enhanced digital assurance capabilities: advanced metering infrastructure that provides time-synchronized, real-time visibility into large-load behavior; bidirectional communication protocols that support coordinated, verifiable response during disturbances; and data management systems that enable validated modeling, post-event analysis, and compliance verification. Early adoption of these technologies, rather than just-in-time upgrades to meet emerging regulation, positions both utilities and data center developers for economical and secure integration.

1. Reliability Challenges from Large Load Growth

Data centers and crypto-mining facilities create distinct reliability challenges through massive point loads with operating characteristics unlike traditional industrial customers. Individual facilities over a gigawatt in size are planned but with binary operational modes that amplify grid impacts.

The July 2024 Eastern Interconnection incident in Virginia demonstrates the challenge. When lightning caused voltage disturbances on a 230-kilovolt (kV) line, an estimated 60 data centers across ~30 substations dropped around 1.5 gigawatts (GW) of load [4]. The facilities implemented protective settings where uninterruptible power supply (UPS) systems automatically transfer to backup generation after detecting notable disturbances, then executed on "three-strikes" policies, where three disturbances are detected within a defined time window, causing facilities to remain off the grid and leveraging backup generation for extended periods despite fault clearance [4]. Varying UPS settings and controllers, along with sensitivities in protection schemes for facilities overall or even sub-systems like heating, ventilation, and air conditioning (HVAC) systems can create different responses to grid faults that are cleared quickly, leading to full or partial load reductions [5, 4], This behavior, designed to protect computing equipment, creates challenges for grid operators attempting to restore normal conditions. The unpredictability of which facilities will transfer and how long they will remain offline complicates both real-time operations and contingency planning.

The Electric Reliability Council of Texas's (ERCOT's) experience with crypto mining demonstrates similar patterns. The agency documented 25 separate load-loss events between November 2023 and January 2025, with individual events involving 100-400 megawatt (MW) drops and some facilities experiencing up to 95% load reduction compared to pre-disturbance consumption [6] [5]. An event on December 7, 2022, caused over 1,500 MW of load reduction across multiple industrial facilities in West Texas. Although the geographic distribution of this event likely helped to prevent widespread instability, it does highlight how the concentration of large loads or large loads without ride-through requirements could threaten system stability [6]. A variety of factors, including various UPS designs and controls, safety limitations on IT equipment, neutral overcurrent protection, overcurrent protection, and cooling system load may play a role in the disconnects that create large load loss events on the grid [5].

Beyond disconnection events, large computing facilities present additional operational challenges through their inherent load variability. Load predictability varies significantly by facility type. Traditional cloud and enterprise data centers typically maintain steady demand driven by diverse user activity or predictable business cycles [3]. In contrast, AI training facilities can experience rapid power swings of tens of megawatts within seconds as synchronized graphical processing unit (GPU) clusters alternate between computing and communication phases [7]. Crypto mining operations display different but equally challenging behavior: while they often run at constant full capacity, they can instantly curtail hundreds of megawatts in response to electricity prices or grid conditions [7]. For facilities at or above 500 MW, even modest percentage variations represent swings equivalent to small generation units, potentially stressing grid balancing and reserve requirements, although systematic studies of these patterns are still needed [7].

In addition to load consumption behavior that can be attributed to the computing operations of these facilities, there are also concerns that the sub-systems and power electronics required to manage data centers could create oscillations on the grid that threaten stability. For example, Dominion Energy documented an incident nearly 2 hours long, where voltage oscillations of approximately 15 Hz were measured and later attributed to UPS behaviors at data centers [8]. A change in a STATCOM setpoint was executed, which appeared to dampen the voltage oscillations. While these oscillations were not intentional and did not match any oscillatory modes in the power system, there is concern that power electronics involved in data center operation or AI data center load profiles could exhibit subsynchronous oscillations that create risk of equipment damage [7].

Visibility challenges are also particularly acute for large loads. Utilities see only aggregate power consumption at the point of interconnection but lack insight into the subsystems (e.g. computer hardware, cooling equipment, UPS batteries, and backup generators) that determine facility behavior during disturbances [7]. Data centers internally track UPS protection settings, battery status, generator availability, and scheduled computational workloads, but utilities generally do not have access to this data [7]. In the July 2024 Virginia large load disconnect event, utilities had limited visibility into the UPS settings of the approximately 60 data centers that disconnected, arguably contributing to the transforming of a routine transmission fault into a 1.5 GW reliability event [4].

Finally, geographic concentration multiplies all these risks, with Northern Virginia alone hosting over 60 data center facilities [9]. The development timeline disparity creates persistent infrastructure mismatches: data centers are built within two years while transmission upgrades require 5-10 years, often forcing grid accommodation of large loads without supporting infrastructure [10].

2. Lessons Learned from IBR Deployments

2.1. Parallels Risks to Reliability

The reliability challenges associated with IBRs were not primarily technological failures, but digital assurance failures: models did not reflect field behavior, operators lacked visibility into protection settings, and compliance mechanisms were insufficient to enforce performance expectations.

Like data centers today, IBRs have failed to ride through short-lived, normally cleared faults, disconnecting in ways that synchronous machines are required to avoid. The 2022 Odessa Disturbance illustrated this when a transmission line fault in West Texas caused approximately 1.7 GW of solar inverter generation to unexpectedly trip within seconds. This routine transmission fault led to a total loss of 2.5 GW, nearly exceeding ERCOT's contingency criteria and threatening system stability [11]. Investigations revealed that the disconnections were not random but rather systemic, driven by default inverter protection settings, including overcurrent, overvoltage, and anti-islanding functions. These protections, potentially appropriate for small-scale distribution environments, caused large consequences in scaled environments [11]. Like the mass large load disconnection events, the scaling in deployments and geographic concentration of IBRs can make these tripping events much more impactful.

A lack of accurate models compounded challenges for utilities to understand, predict, and plan for IBR behaviors, a challenge mirrored in data center compute unpredictability and variation in power electronics providers and controls governing operation. Commonly used positive-sequence models do not capture hard-coded inverter protection behavior, while electromagnetic transient models are often unavailable or insufficiently validated [12]. When models demonstrate ride-through capability, commissioning practices do not always ensure that as-built inverter settings match modeled assumptions [12]. The North American Electric Reliability Corporation (NERC) concluded that modeling gaps and lack of data on settings reflect an industry-wide pattern rather than isolated plant errors [12, 13].

At the distribution level, individual distributed energy resources (DERs) may be small, but their aggregate response during disturbances can amount to hundreds of megawatts. A 2023 incident in the

Midwest Independent System Operator (MISO) territory demonstrated how distributed resources can amplify disturbances. When a grounding fault occurred on the transmission system, approximately 300 MW of DERs tripped offline alongside voltage-sensitive loads [14]. Investigators found that many DER inverters lacked smart-inverter ride-through capability, a claim validated by a 2023 study from the Independent System Operator (ISO) New England [15].

The visibility gap exacerbates these challenges. A recent Siemens/Oxford Economics survey found that utilities have visibility into only about one-third of their behind-the-meter (BTM) DERs, limiting their ability to forecast aggregate behavior or coordinate with DER aggregators [16]. This limitation has also been noted in a 2025 NERC report, highlighting that the poor visibility to balancing authorities means that operators must use conservative load-shedding assumptions during disturbances that may over- or under-react during critical events [17]. Similarly, utilities have limited visibility into BTM operations at large load facilities, which may include not only the large loads, but also generation resources that may sometimes feed the grid. The combined unpredictability of demand or generation and lack of context for BTM operations creates parallel challenges for small DERs and large loads. This visibility gap could be bridged: utilities need more granular behind-the-meter data, real-time power monitoring, and access to short-term load forecasts that align with energy provisioning and services (e.g., 15-minute, 1-hour, and 1-day lookaheads). NERC's 2024 Long-Term Reliability Assessment (LTRA) confirms that most balancing authorities still lack real-time visibility of DER performance, constraining their ability to coordinate DER behavior in emergencies [18].

2.2. Regulatory Approaches to IBRs

As modeling and performance issues were identified as systematic challenges with IBRs that posed a risk to system reliability, NERC released several recommendations in 2022 with clear paths towards regulatory enforcement.

- NERC recommended an overhaul and modernization of the interconnection process, to include revisions to interconnection agreements and enhancements to interconnection studies and commissioning [19]. These recommendations on interconnection agreement changes served as a pillar for the Institute of Electrical and Electronics Engineers (IEEE) standard 2800-2022 revisions.
- NERC published recommendations for IBR performance standards so that utilities could better plan for IBR behaviors and reduce risk of unexpected disconnection. To put this into practice, they requested to overhaul the Protection and Control -024 standard to provide clear generator ride-through performance requirements [19]. On July 24, 2025, the Federal Energy Regulatory Commission (FERC) approved the Protection and Control-029-1 standard and the Protection and Control-024-4 standard, making ride-through and uniform voltage/frequency disturbance response mandatory for IBRs [20]. This follows events such as a 2.5 GW solar inverter trip in Texas in 2022 and is part of a suite of standards directed by FERC in 2023 [21]. These standards establish mandatory ride-through performance criteria aligned with IEEE 2800-2022, require detailed documentation of inverter settings and design capabilities, and mandate coordination with planning and reliability entities for exemption requests and system modifications. In 2025, NERC issued a Level 3 Alert requiring immediate action from Generator Owners, Transmission Owners, Transmission Planners, and Planning Coordinators to include detailed IBR-specific performance expectations that were transparent, publicly available, and uniform where feasible [22].
- NERC addressed modeling quality issues, noting that models need to be updated during the interconnection process to reflect changes in design and commissioning [19]. They recommended development of models suitable for electromagnetic transient (EMT) models and endorsed a Standard Authorization Request promoting modeling quality and EMT

requirements for the FAC, MOD, and TPL standards. The 2025 NERC Level 3 Alert directed planning entities to validate that IBR models accurately reflect field behavior and directed utilities to retrospectively review models for IBRs already operating on their system [22]. This Level 3 Alert was issued to elevate the urgency of addressing these issues after key issues were found to persist despite 10 major event reports and four Level 2 Alerts [23].

- NERC called for new standards to be developed to address the challenge that very few IBR Generator Owners were conducting performance validation activities, and neither were Reliability Coordinator and Balancing Authorities [19]. If discrepancies, Reliability Coordinators and Balancing Authorities did not have suitable mechanisms to seek corrective actions.

It is worth noting that these NERC actions and standards only apply to NERC-registered IBRs. In 2022, FERC directed the development of the IBR Registration Initiative to register bulk power system-connected IBR owners and operators who were previously not required to adhere to NERC Reliability Standards. The initiative was launched in 2023, and the final milestone of the initiative began in 2025, completing the actual registration of new Generation Owner candidates. By May 2026, eligible Generator Owners and Generation Operators are expected to register and start reporting to their Regional Entities [24]. The new registration requirements lower thresholds from 75 MVA at 100 kV to 20 MVA at 60 kV [24]. FERC's proposed reliability standards would make such ride-through capabilities mandatory for all IBRs above 20 MW, with compliance monitoring and enforcement through NERC [25]. Since 2017, industry and regulators have implemented inverter setting updates and ride-through requirements; by 2023 most bulk power system (BPS)-connected solar inverter sites reported NERC's preferred ride-through control modes [26].

DER aggregations below these size and voltage thresholds remain outside NERC's direct regulatory scope. These smaller systems are instead governed by state-adopted interconnection standards such as IEEE 1547-2018, [24]. IEEE 1547-2018 has been fully adopted by at least 10 states, with another 6 states in the process of adoption, and at least 17 additional states where major utilities independently require IEEE 1547-2018 compliance despite no statewide mandate [27]. The standard established mandatory ride-through requirements for IBRs, replacing the previous disconnect-on-disturbance approach. The 2022 Odessa Disturbance demonstrated the consequences of outdated settings as many of these resources could have ridden through the disturbance with updated IEEE 1547-2018 settings [11].

California has emerged as the laboratory for IBR integration policies. California's Smart Inverter Working Group has beyond IEEE 1547-2018, requiring additional grid support functions including volt-var control, frequency-watt response, and dynamic voltage support during faults. California's 2016 Blue Cut Fire and 2017 Canyon 2 Fire revealed how inverter protection settings could trigger large-scale PV disconnections during transmission disturbances. These unexpected generation losses complicated firefighting efforts by creating voltage instability on circuits serving affected areas, motivating need for increased scrutiny [26]. In March 2024, the California Public Utilities Commission (CPUC) adopted a landmark decision allowing energy systems to interconnect by following Limited Generation Profiles (LGPs) [28]. LGPs specify the maximum export a DER may send to the grid at various times based on local constraints, enabling projects to avoid costly infrastructure upgrades [29]. LGPs are now available statewide [30]. The order requires utilities to publish time-varying hosting-capacity data and allows DER developers to design export schedules that align with grid conditions [31]. This makes California the first state to integrate temporal flexibility into interconnection review and demonstrates how detailed grid data and scheduling can increase hosting capacity [32].

Implementation of both federal and state-level standards relies heavily on digital assurance capabilities, including advanced metering to verify ride-through performance, communication systems to coordinate with grid operators, and data management systems to document inverter settings and operational capabilities.

3. Regulatory Considerations for Large Loads

3.1. Initial Actions from Regulatory Bodies

3.1.1. NERC Investigation and Actions

Recognizing the challenge of large loads, NERC established its Large Load Task Force in 2024 following alarming load-loss events in both the Eastern and Texas interconnections. The task force's first white paper identified emerging large loads, particularly data centers and crypto-mining, as connecting to the bulk electrical system faster than existing loads, with less predictable behavior that poses unique risks [7]. NERC concluded that planners need accurate models to study coincident large-load losses, should consider registering large loads as reliability entities, and may need new or modified standards. The Large Load Task Force's framework will produce reliability guidelines and potential standards by 2026 [7]. While traditional loads often do not have communications-based interoperability requirements or direct digital communication with the grid, execution of guidelines to protect the reliability of the bulk power system will likely require new control algorithms governing data center behavior and may even require direct communications with the grid. This increase in digitization and grid control is a paradigm shift for large loads, but a shift that has already occurred with grid-edge devices, from meters, to distributed generation, to demand response.

NERC's 2024 Long-Term Reliability Assessment (LTRA) also identified large flexible loads as a growing reliability challenge, highlighting the risks associated with geographic clustering in PJM and ERCOT as well as the development timeline mismatches [18]. NERC's 2025 State of Reliability assessment identified rapid growth of data centers and crypto facilities as a major immediate reliability challenge; these facilities take two years to be built and are often sited in rural areas where electric infrastructure is thin [10]. The report notes that planning generation and transmission is complicated by speculation about where and when data centers will be built and calls for better models and tools [10].

3.1.2. ISO/RTO and State Approaches

Regional transmission organizations (RTOs) are developing their own approaches to manage the influx of variable resources and large loads, with varying degrees of urgency based on local conditions.

PJM launched a fast-track stakeholder process after its 2025 long-term forecast showed ~32 GW peak load growth from 2024-2030, almost all from data centers [33]. It is considering "capacity-backed" requirements for large loads, emergency curtailment provisions, and flexible interconnection agreements that would allow conditional connections based on available transmission capacity. Automation and optimized prioritization will be required to make decisions on curtailment and load-serving capability with these proposed new measures. These measures acknowledge that traditional interconnection processes cannot keep pace with data center development.

ERCOT's Large Flexible Load Task Force (LFLTF) has adopted a more technical approach following extensive ride-through incidents. In March 2025, the task force reviewed 13 voltage ride-through incidents from 2020-23 involving crypto miners and data centers [6]. Multiple load reduction events prompted ERCOT to form a data-center subgroup specifically addressing low-voltage ride-through, rapid load ramping, and harmonic distortion [6]. The July 2024 Eastern Interconnection incident was also reviewed at the same ERCOT meeting. The meeting concluded that more detailed dynamic models and improved coordination of automatic reclosing are required to manage large-load rejection events [6].

State regulators are also beginning to address the reliability challenges of large loads through transparency and oversight mechanisms. Texas now requires disclosure of backup generation and grants ERCOT authority to direct its use during emergencies, reflecting recognition that uncoordinated backup switching can destabilize the grid [34]. ERCOT dispatch of onsite backup generation for large loads will require thoughtful data sharing and integration of layered controls to enable emergency dispatch. In contrast, West Virginia's Power Generation and Consumption Act of 2025 allows data centers with power loads of 90 MW or greater to operate independent microgrids exempt from state utility regulation and local zoning restrictions [35]. Even without grid interaction, the microgrid coordination requires layers of control, dispatch, protection, and metering, often through a centralized digital hub. These examples demonstrate diverse state-level approaches where some emphasize grid coordination while others prioritize economic development through regulatory flexibility.

Collectively, these ISO/RTO and state actions signal a shift from ad hoc accommodation of large loads toward enforceable reliability expectations, with modeling, interconnection processes, ride-through performance, and registration frameworks examined in the sections that follow.

3.2. Modeling

As demonstrated by the large load loss event both in Virginia and Texas, a level of variability exists in terms of data center response to faults or other power quality issues. This variability stems from different facility-level configurations and technologies in place. For example, static centralized UPS and dynamic rotary UPS have different load characteristics in response to transient disturbances [4]. Both steady-state and dynamic simulations are needed for grid planning, and without accurate models, these studies will not properly account for the load's impact on the BPS nor support large loads through understanding of the uptime requirements they face. NERC's Load Modeling Working Group has put out public requests for data center information that will be used for transmission planning studies [36]. Their request includes information not only about the distribution of power consumption across IT equipment, power distribution, and cooling, but also about what type of cooling is used, what type of motors drive the cooling components, what criteria must be met for voltage sags or swells to cause the data center to disconnect from the grid, how and when reconnection occurs, and what type of backup power is in place. This information will be used to validate composite load models and better understand the response of loads in response to changes in voltage and frequencies, and how those responses will affect the overall grid's voltage and frequency.

ERCOT noted the lack of accurate models as a key gap in their assessment of large load loss events in Texas [6]. They responded quickly to this need, approving modeling requirements for large loads in May 2025, which went into effect in December 2025 [37]. In parallel, their Dynamic Studies Team has been seeking data to design model parameters based on survey responses, with the goal to release a new standard model soon [38]. The newest survey, released in December, 2025, requests significantly more data that the first, released in 2022, highlighting that the need for highly accurate models based on a several facility-specific variables are needed for accurate transmission studies, especially given the explosion of new large load interconnection requests [39]. The Dynamics Working Group recommends that, in addition to the standardized models under development, interconnecting load entities should be required to provide composite or user-defined loads models of their facilities [40]. This push to develop both standardized models and require user-validated models has strong parallels to requirements that emerged for IBRs. While the challenge of accurate models is still not a solved problem for IBRs, the need for accurate models for grid-impacting assets for both steady-state and dynamic simulations is clear from the release of a NERC Level 3 Alert in 2025. Proactive research and information sharing for data center models will support grid reliability and enable faster interconnection when studies can be trusted for accuracy.

3.3. Interconnection Process Limitations

California's LGP system represents a sophisticated attempt to modernize interconnection processes for a high-variability grid. Rather than assuming worst-case conditions at all times, LGPs allow resources to connect based on time-varying grid capacity Under CPUC Resolution E-5296 (March 2024), distributed energy resources can agree to curtail output during constrained periods in exchange for avoiding infrastructure upgrades and accelerating interconnection timelines [24]. While this framework currently applies to generation resources only, the underlying principle – operating within real-time grid capacity through scheduled limits – could be adapted to manage large loads facing similar interconnection constraints.

Recognition that interconnection processes and terms need to change has strong parallels to the recognized need five years ago that interconnection modernization was required to handle the growth in IBRs on the grid, and adoption of new measures for data centers is underway across the country. Pacific Gas & Electric (PG&E) is testing this concept for loads through its Flex Connect pilot, launched in late 2024 with five sites operating as of Q3 2025 [41]. The pilot allows charging stations, battery installations, and industrial facilities to connect more quickly by accepting time-varying consumption limits during peak hours. Outside California, transmission operators are developing similar frameworks: PJM proposed Non-Capacity-Backed Load service for loads greater than 50 MW that accept emergency curtailment in exchange for waived capacity charges [42], while Southwest Power Pool introduced a Conditional High Impact Large Load Service offering temporary transmission service for large loads [43]. These initiatives reflect growing recognition that flexible interconnection can address the mismatch between rapid load growth and slower infrastructure development.

For data centers, such frameworks could be transformative. A facility could agree to limit consumption during transmission constraints in exchange for expedited interconnection. However, adapting these principles to loads presents distinct challenges. While generation curtailment relies on inverter controls to limit output, load curtailment requires energy management systems (EMS) coordinated with utility operations, often supplemented by on-site batteries or backup generation to maintain facility operations during grid constraints [44]. PG&E's pilot required months of testing to develop fail-safe protocols ensuring that communication failures would not compromise grid safety [41].

Additionally, many utilities lack the advanced distribution management systems, granular modeling capabilities and basic hosting capacity information required [12]. Without federal standards or funding for system upgrades, flexible interconnection adoption could remain limited to leading utilities. However, there is movement on the federal front, with proposed new pathways for co-location and load flexibility though creation or new transmission services, firm and non-firm contract demand transmission service [45]. The benefits are compelling. Data centers could connect quickly with conditions, while utilities maintain reliability through operating limits rather than capital investments. This aligns with American Council for an Energy-Efficient Economy's (ACEEE) recommendation for "grid-aware computing," where AI workloads shift based on grid conditions [26].

3.4. Ride-Through Standards

The evolution of ride-through standards reveals an asymmetry in how the grid treats generation versus load. While generators are required to remain connected during minor disturbances, no equivalent standards exist for large loads. Recent events have shown this gap to be increasingly problematic.

For large loads, the regulatory gap exists primarily because (1) most traditional loads do not disconnect when there are slight variations in power quality or faults that are quickly cleared; and (2) most loads are not large enough individually, nor geographically concentrated like they are in Northern Virginia, to create BPS impact. A data center consuming 300 MW can have similar grid stability impact to a medium-sized power plant but faces no similar requirements to ride through disturbances.

The technical solution is straightforward: the requirement for large loads to ride through the same disturbances as generators. IBRs, similarly seen as historic grid elements that had limited impact on reliability, experienced a similar increase in calls for ride-through standards through NERC ride through requirements, IEEE 1547, and IEEE 2800. For large loads, challenges would emerge through implementation of ride through capabilities, which could require specific UPS settings, prohibit unnecessary transfers to backup power, and ramped responses to disturbances.

3.5. Large Load Registration: Redefining Reliability Obligations

NERC's LLTF is exploring a change in thinking: requiring large loads to register as reliability entities, similar to generators [7]. This would create enforceable standards for facilities that can destabilize the grid as severely as any power plant failure.

Various utilities have implemented their own large load thresholds ranging from 10 MW to 100 MW [21]. Defining “large” will be central to any registration framework, but NERC’s LLTF suggests that defining “large” by megawatt size alone is insufficient. System strength, interconnection voltage, and operational behavior matter as much as absolute size [21]. A 20 MW facility could be inconsequential on a strong transmission network but destabilizing on a weak radial line. Ramp rates, the firmness or flexibility of service, backup system behavior, and BTM status should all be considered [21]. Without a multi-factor definition, uniform standards risk creating loopholes or perverse incentives, such as facilities sizing deliberately below a static cutoff [21].

As NERC enters the final stage of new IBR registration requirements, lessons should be taken from the challenges faced by new IBR Generator Owners and Generator Operators. These often involve new entities who previously have not dealt with NERC-registered assets, similar to how most data center operators will be new to this regulatory space. Industry comments emphasize that interactions with the grid must be two-sided. While RTOs, ISOs, and Balancing Authorities will see benefits to their ability to require enforcement of reliability standards with large loads, data center operators look to utilities and grid operators to move quickly to expand generation, transmission, and programs to maintain reliability for large loads. Second, they warn that compliance obligations would raise costs and disadvantage U.S. facilities in global competition for computing resources [46]. Third, they contend that mandatory registration or reporting requirements could compromise data security by forcing disclosure of sensitive operational data [44]. Grid operators have countered that loads consuming hundreds of megawatts instantly must bear appropriate reliability obligations, especially when traditional industrial customers face similar scrutiny for far smaller impacts [44].

Jurisdictional authority is complex. FERC has authority over wholesale market participants and transmission reliability, but large loads are traditionally regulated by states. Some argue that reliability registration would create federal oversight of retail customers, triggering legal challenges [47]. The solution may be to coordinate federal standards with state implementation.

4. Technical Recommendations

As both state and federal requirements evolve to accommodate the growth in large loads, especially the growth of large electronic loads like data centers, both utilities and data center developers will need to undertake technical challenges to meet those requirements. In this section, key technical recommendations are provided based on the key challenges for reliability under large load loss, the emerging requirements and recommended regulations from state and federal authorities, and the lessons learned from the evolution of IBR requirements and the industry’s response.

Effective integration of large electronic loads requires layered digital assurance: (1) **measurement** to observe behavior, (2) **models** to predict system response, (3) **communications** to coordinate actions, and (4) **governance mechanisms** to enforce performance expectations. Failure at any layer undermines reliability, regardless of hardware robustness. Proactive adoption of these technical measures will support both utilities and data center developers in meeting new requirements as they emerge, reducing the need for costly upgrades that may experience rushed timelines due to regulatory deadlines.

A common thread across these recommendations is the increased digitization that will be required to execute. Solving the complex challenges to reliability with high penetrations of large electronic loads will require all of the tools at industry’s disposal, ranging from state-of-the-art control and coordination, to advanced sensor deployment and metering analytics, to more points of communication supporting both centralized and distributed decision-making for optimized grid performance, protecting both grid reliability and grid service availability for data centers. Outside of pure cost and timelines for retrofits, the growth of digital technologies on the grid is another area that is best tackled proactively. Integration of digital technologies from the design phase enables smoother coordination and maximizes the utility of these technologies. It also allows for safety and security measures to be accounted for when they are most effective, providing increased digital assurance for all stakeholders. Consistent with cyber-informed engineering principles, these recommendations prioritize engineering controls that constrain unsafe behavior by design, reducing reliance on procedural compliance or real-time operator intervention during disturbances.

4.1. Recommended Actions

4.1.1. Increase Monitoring and Leverage Advanced Analysis Techniques

Assurance outcome: Grid operators can detect, attribute, and respond to large-load behavior in real time with sufficient fidelity to prevent cascading reliability impacts.

In order to detect large load behaviors that could pose reliability challenges to the grid and to detect grid conditions that may pose risks to sensitive large load systems, both utilities and data center operators should ensure that they have power quality monitoring in sufficient locations for robust system visibility. Determining the frequency of measurements required to detect relevant grid conditions and the optimal sensor placement location is still an open question for research and testing. In order to accomplish real-time visibility and control for automated responses, communications between centralized grid dispatch and grid-edge devices, or even BTM meters, may be required. New methods of data processing and optimization can also mitigate reliability risks, with potential for both traditional methods and AI algorithms to support situational awareness. In addition to real-time metering, short-term forecasts (15-minute, 1-hour, and 1-day lookaheads) and the ability to coordinate emergency response are needed to detect and respond to reliability risks. To the extent possible, stakeholders should come together to establish mutually agreeable data sharing frameworks so that the information can be leveraged across organizations for optimal dispatch of grid assets and behind-the-meter assets.

4.1.2. Enhance Modeling Capabilities, Accounting for Variability in Facility Operations

Assurance outcome: Planning and operational studies reflect validated, field-accurate representations of large-load behavior, enabling assured system planning and credible contingency analysis.

Digital assurance requires clear ownership for model creation, validation, and updates as facility configurations, protection settings, or operating modes change over time. A standardized modeling protocol based on requirements developed for better IBR modeling may require data center developers to provide validated dynamic models of their UPS and backup systems and demonstrate compatibility with emergency response systems like under frequency load shedding. Both templated, high-level models, and customized, field-validated models of individual facilities would support utility planning requirements for different time frames, from system stability studies to long-term capacity planning. As with real-time data, information sharing frameworks need to be established between data center facilities and utilities, providing grid planners with the information they need to make assessments while protecting sensitive or proprietary information of large load customers. Where validated models and observed field behavior diverge, defined mechanisms must exist to require corrective action.

4.1.3. Centralized and Distributed Grid Communication with Large Loads

Assurance outcome: Utilities and large-load operators maintain assured, secure communication channels that support verifiable coordination, acknowledgement, and execution of reliability actions during normal and emergency conditions.

At the boundary between data centers and utilities, standardized communication protocols are to enable real-time telemetry, which could eventually include not just power consumption but also key facility health or performance metrics to enable coordination of data center uptime requirements and grid reliability. Data transfer may not be required only at the grid edge but also filtered up to centralized platforms to enable grid-scale coordination, dispatch, and emergency coordination. Securely communicating this information and protecting sensitive data must be a top priority in implementation. If changes in IBR dispatch are to be taken as an indicator, these same channels may eventually carry control signals, for curtailment, ride-through, or ancillary services, similar to how smart are increasingly used for active grid support. Options for grid-edge communication or communication through market signals both have precedence in utility operations. Facility designs should consider command-acceptance logic now to avoid costly retrofits later.

4.1.4. Flexible, Digital Substation Design

Assurance outcome: Substation protection, control, and operating limits adapt predictably to large-load conditions, ensuring assured disturbance ride-through and minimizing unnecessary disconnections.

Modernizing substations with digital architectures creates the foundation for flexible interconnection of large loads. Digitization enables adaptive protection that adjusts relay settings and reclosing logic based on measured system strength and known facility behaviors (e.g., UPS transfer sensitivity, ramp constraints), improving disturbance ride-through while reducing unnecessary trips. Substation automation should incorporate data center operational states, such as critical load segments online, backup generation status, or onsite storage dispatch mode if these status signals are available, so that switching, voltage control, and remedial action schemes can be dynamically reconfigured during faults or planned constraints. For utilities, digital substations also accelerate remote configuration of interconnection conditions and staged operating limits, reducing the need for lengthy field interventions when conditions change. For developers, publishing EMS/substation data exchange points streamlines commissioning and ongoing operations. Additionally, protection and control logic should be configurable, documented, and testable so that disturbance responses can be verified against planning assumptions.

4.1.5. Advance and Coordinate Control Schemes for Behind-The-Meter Loads

Assurance outcome: Behind-the-meter large loads can exhibit predictable, testable, and enforceable responses to grid conditions, reducing uncertainty in system operations and emergency planning.

Data centers should implement hierarchical control that coordinates HVAC, UPS, onsite storage, and backup generation under a facility EMS, while exposing a utility override for declared emergencies. Predefined response modes provide predictable, testable behaviors that operators can rely on. For example, (1) ride-through hold (delay UPS transfers for cleared faults), (2) staged curtailment of non-critical computing and cooling loads, (3) coordinated dispatch of onsite storage before generator start. These modes should be interoperable via OpenADR or IEEE 2030.5 so utilities can request actions with clear semantics and facilities can acknowledge, execute, and log outcomes. Looking forward, real-time optimization can augment these presets: AI-assisted EMS can weigh compute service level agreements, thermal inertia, backup power availability, market signals, and grid constraints to select the least-impact action set in relevant response intervals. When implemented as default operating modes within facility control systems, these schemes function as engineering controls by bounding load response during disturbances and preventing unsafe or destabilizing actions even under loss of communications or operator error. These response modes should be periodically tested under controlled conditions, with results shared with grid operators to validate expected behavior.

4.2. Conclusion

Large electronic loads now interact with the bulk power system at a scale and speed comparable to generation resources, yet they are integrated under regulatory and operational assumptions developed for passive demand. Continuing to rely on those assumptions places increasing strain on planning, operations, and emergency response.

Digital assurance provides the mechanism to close this gap by making large-load behavior observable, predictable, and governable before disturbances occur. Implemented proactively, these capabilities reduce uncertainty for grid operators, lower integration risk for developers, and allow reliability requirements to evolve in step with technology deployment. Delayed action, by contrast, shifts costs and risk to system operators and the public, increasing the likelihood that future policy responses will be driven by disruptive events rather than deliberate design.

These policy and technical solutions work in concert to address the challenges posed by the growth of large electronic loads, for both utilities and large load customers. Success depends fundamentally on enhanced digital assurance capabilities: advanced metering infrastructure that provides real-time visibility into large load behavior, bidirectional communication protocols that enable coordinated response during disturbances; and data management systems that support validated modeling, post-event analysis, and compliance verification.

As regulatory requirements shift towards mandatory ride-through standards, registration frameworks, flexible interconnection mechanisms, and the digital infrastructure to monitor and appropriately manage these resources, regulators can maintain grid reliability while enabling the digital transformation essential to economic competitiveness. Achieving this outcome requires sustained collaboration across the electricity sector, including regulators, system operators, utilities, and stakeholders responsible for the development and operation of large loads. Each brings complementary expertise in power systems engineering, digital systems, and operational governance that is necessary to translate policy intent into reliable grid performance.

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