UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Interconnection of Large Loads to the Interstate Transmission System	)	Docket No. RM26-4-000

JOINT COMMENTS OF THE INDUSTRIAL CUSTOMER ORGANIZATIONS

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The Industrial Energy Consumers of America ("IECA"), the American Forest & Paper Association ("AF&PA"), the PJM Industrial Customer Coalition ("PJMICC"), and the Coalition of MISO Transmission Customers ("CMTC") (collectively, "Industrial Customer Organizations"), welcome the opportunity to submit these Comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") October 27, 2025 Notice Inviting Comments on Interconnection of Large Loads to the Interstate Transmission System ("Notice"), in the above referenced docket. The Notice was prompted by the Secretary of Energy's proposed Advanced Notice of Proposed Rulemaking ("ANOPR"), which was issued on October 23, 2025.[1]

I. DESCRIPTION OF THE INDUSTRIAL CUSTOMER ORGANIZATIONS

The Industrial Customer Organizations include associations of leading manufacturing companies, trade-exposed users of electricity, institutional users, and other energy-intensive customers representing more than $1 trillion dollars in sales, including thousands of manufacturing facilities and millions of family-sustaining jobs in the United States. The Industrial Customer Organizations advocate and collaborate on matters regarding the availability, use, and cost of energy. The companies and customers that comprise the Industrial Customer Organizations

[1] On October 23, 2025, pursuant to section 403 of the Department of Energy ("DOE") Organization Act, 42 U.S.C. § 7173, the Secretary of Energy released a proposed ANOPR for consideration and final action by the Commission.

include a diverse set of industries including chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceuticals, building products, automotive, independent oil refining, cement, educational and medical institutions, data centers, and others.

The Industrial Customer Organizations are primarily manufacturers. Manufacturing employs over 15 million people in the United States[2] and contributed $2.3 trillion to U.S. Gross Domestic Product ("GDP") in 2023 (amounting to 10.2 % of total U.S. GDP, measured in chained 2017 dollars).[3] Manufacturing is unique as compared to all other sectors. Manufacturers are energy intensive, frequently operate 24/7, are price sensitive, and compete globally. Small changes to the price of electricity can have significant impacts to competitiveness of existing facilities and serious implications for reshoring and expanding facilities and production capability in the United States.

II. INTRODUCTION

The nature of load growth is shifting dramatically, and the energy industry is scrambling to keep up—and affordably keep the lights on. Herein, the Industrial Customer Organizations address several discrete issues, but most centrally, to urge the Commission to fiercely guard the cost-causation principle to protect industrial consumers. Cost-causation is the bedrock principle of FERC-jurisdictional utility rates. The concept is straightforward in theory—costs are assigned to those who cause the costs, and beneficiaries are assigned costs according to their use or benefit. However, the principle can be challenging to implement, especially where the drivers of cost are multi-dimensional and indirect, with rippling near-term and long-term consequences.

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[2] *See* U.S. Bureau of Labor Statistics (2024 data), https://www.bls.gov/cps/cpsaat18.htm (last accessed Nov. 21, 2025).

[3] *See* U.S. Manufacturing Economy, NIST, https://www.nist.gov/el/applied-economics-office/manufacturing/manufacturing-economy/total-us-manufacturing (last accessed Nov. 21, 2025).

Currently, rapid deployment timelines of large load entrants are driving substantial and immediate demand for new generation and transmission infrastructure. Unlike traditional industrial manufacturing load, which typically evolves through deliberate, methodical planning, a substantial portion of today's large load entrants are pursuing highly accelerated timelines, with unprecedented scale. Consequently, new load is emerging in an environment where:

1. There is insufficient time to plan, permit, and construct the necessary resources; and
2. There is limited historical data to assess the operational characteristics or long-term viability of these new entrants.

Due to the unprecedented pace at which loads seek to come online, time is a defining variable. This urgency is reshaping the landscape of power system planning and investment, and it threatens to short-circuit the traditional manufacturing sector's ability to expand and grow as a key anchor in the nation's economy. Just as expedited logistics services carry premium costs, the power sector must now grapple with the implications of speed-to-market as a cost driver and planning constraint.

The core policy challenge, therefore, is how to meet this surge in demand without undermining reliability, affordability, or access for any sector—including manufacturing and service sectors critical to America's economic backbone and national security. If rules of the road are not well-crafted, there will be increased risk of crowding out existing and future customers, distorting market signals, and driving up costs system-wide. Industrial customers must retain the ability to build, expand, reshore, and operate under just and reasonable rates, supported by planning processes grounded in transparent studies and robust cost-benefit analyses. As the Commission has long recognized, "It is long-established that the 'primary aim' [of the Federal Power Act] is the **protection of consumers from excessive rates and charges**."[4]

[4] *Xcel Energy Services v. FERC*, 815 F.3d 947, 952-53 (D.C. Cir. 2016) (emphasis added).

III. EXECUTIVE SUMMARY

The Industrial Customer Organizations recognize that the Commission has jurisdiction over the interstate, bulk electric system and over facilities used in interstate transmission and wholesale sales of power. As a result, there is a jurisdictional foundation for regulating *aspects* of direct interconnections to the transmission system. However, FERC must tread carefully to avoid intruding into state regulation over retail ratemaking, including new customer service applications, distribution service to end-use customers, and certain generation-related issues. The Industrial Customer Organizations are concerned that mandating a standardized and federalized large load interconnection process for all load greater than 20 MW would be highly disruptive to existing processes; trigger state-federal jurisdictional conflicts; create business uncertainty; and divert limited and scarce resources from staff at the Commission, at Regional Transmission Organizations ("RTOs") or Independent System Operators ("ISOs"), at other transmission providers, and at public utilities. Consequently, the Industrial Customer Organizations respectfully submit that the Commission, through its jurisdiction over the interstate transmission system, focus its near-term efforts on optimizing existing system capacity via reconductoring and deployment of Grid Enhancing Technologies ("GETs"); incentivizing load flexibility commitments, demand response, and bring-your-own generation options; and enhancing the transparency of load forecasting and assumptions underlying transmission system studies.

In developing any Notice of Proposed Rulemaking ("NOPR"), the Commission should:

- Protect existing customers and ensure that costs for new load connections are allocated based on cost-causation principles. The speed-to-market demands of some large load entrants in some utility zones and regions have significant transmission and capacity pricing reverberations. Cost impacts caused by the rapid entrance of large loads cannot be measured solely in terms of the direct cost of infrastructure, and the Commission must

protect other ratepayers from cost shifts where ratepayers are neither causing nor benefitting from the new entrants' upgrades.

- Clearly delineate the Commission's view of state-federal jurisdictional lines to limit future uncertainty and litigation. For example, distribution facilities or step-down facilities may be owned by the local utility (and not the large load); it should be clear what entails a "transmission-level" connection. FERC can exercise jurisdiction over interstate transmission system impacts but not over distribution system impacts or retail tariffs.
- Consider implementing an elective "Fast Lane Interconnection" approach for customers connecting directly to the FERC-jurisdictional transmission system for whom speed is paramount, who are willing to bear the higher costs and credit requirements that result from upward pressures placed on the system from rapid interconnection and buildout; who have curtailable load with flexibility commitments; who can add new generation to the system; and/or who have hybrid, dispatchable facilities.
- Provide a reasonable transition period *if* the Commission proceeds with mandating a new federal interconnection process for all large loads. Any new, federal standardized interconnection approach must not disrupt existing customer new service applications, projects, and studies that are already underway. Nor should the Commission preempt a large load's preferred option to proceed with a new customer service application that is processed at the state level.
- Develop a short-term solution to address the immediate challenges, and provide a sunset provision for any regulation that governs processes currently managed at the state level.

- Develop rules that enhance the ability of regional grid operators to forecast and provide transparency to industry stakeholders, allowing an increase of innovative solutions and better regional transmission and resource adequacy planning.
- Facilitate transparent, improved load forecasting measures, through coordination with states and local utilities.
- Require transparency improvements and clear standards for load studies and system impact studies pertaining to the FERC-jurisdictional transmission system.
- Protect customers with existing behind-the-meter generation by measuring cost allocation via actual use of the transmission system, with the caveat that substantial upgrades triggered by one large user should not shift costs to other users who do not benefit.
- Reject a large-load classification based on 20 MW, as 20 MW is far too low, arbitrary, and would capture a significant number of manufacturers and other industrial and institutional entities that do not have the speed-to-market and scale demands that are driving today's grid challenges. Instead, the Commission should provide non-discriminatory access to an optional federal connection process that respects jurisdictional lines by appropriately involving state-jurisdictional utilities, where needed. FERC's Seven Factor Test, rather than an arbitrary peak load amount, should be used to evaluate the jurisdictional nature of the interconnection. FERC can consider using the North American Electric Reliability Corporation's ("NERC") definition of the bulk electric system, defining transmission lines and interconnections and associated equipment generally operating at voltages of 100 kV or higher. The Commission may also consider a definition of "large load" that is based on the transmission impact to the applicable region and transmission zone.

IV. COMMENTS

A. Successful Application of the Cost Causation Principle in the Context of Large Load Interconnections May Require Adjustments to Current Methodologies.

1. The Commission Must Protect Existing and New Customers by Ensuring That Costs for New Load Connections Are Allocated Based on Cost Causation Principles.

The cost causation and beneficiary pays principles require that "costs are to be allocated to those who cause the costs to be incurred and reap the resulting benefits."[5] The D.C. Circuit Court of Appeals ("D.C. Circuit") has held that "all approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them."[6] Further, the beneficiary pays principle requires that costs must be allocated to customers in a manner that is "roughly commensurate" with benefits.[7] The Industrial Customer Organizations are uniquely positioned to comment on these principles because we seek to protect both cost causers and beneficiaries as well as potentially impacted non-benefitting customers from overpaying for transmission.

Cost impacts cannot be measured solely in terms of the direct cost of infrastructure. Speed-to-market demands, volatility in load forecasts, and the potential for stranded assets must also be considered in evaluating cost responsibility. Each of these factors is magnified by the size and speed of many contemporary large load additions. When large loads require accelerated timelines, they often impose operational and financial burdens on the system that go beyond traditional

[5] *Nat'l Ass'n of Reg. Util. Comm'rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007). *See also Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255 (D.C. Cir. 2018) (adding that the "cost-causation principle" has been recognized "for decades" by "the Commission and the courts").

[6] *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *City of Lincoln v. FERC*, 89 F. 4th 926, 930 (D.C. Cir. 2024); *see BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268 (D.C. Cir. 2014) (ensuring that "the burden is matched with benefit"); *see also Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) ("we evaluate compliance with this unremarkable [cost causation] principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.").

[7] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009); *Neb. Pub. Power Dist. v. FERC*, 957 F.3d 932, 941 (8th Cir. 2020); *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1264 (D.C. Cir. 2018).

planning assumptions. While network upgrades are often rolled into rates in the respective transmission owner zone, the cost causation analysis may need to be more precise and nuanced when the benefits accrue primarily to the new large load (as a result of the scale and speed by which that new large load seeks to interconnect) and where the existing customer base is disproportionately small compared to the size of the new large load. FERC must ensure the "protection of consumers from excessive rates and charges."[8]

2. Requiring All New Loads, Including Manufacturers, to Be Responsible for 100% of Network Upgrades They Are Assigned, Is Contrary to Longstanding Cost Causation Principles.

The ANOPR appears to be squarely focused on addressing the needs and impacts of data centers bringing large-scale demand with pressing speed-to-power requirements. The ANOPR suggests that new large loads should pay for 100% of network upgrades they are assigned through the interconnection studies.[9] The Industrial Customer Organizations affirm the ANOPR's goal of protecting existing customers from unjustified cost shifts. However, to appropriately apply cost causation principles in this context, the Commission will need to balance two distinct principles:

- If the new large load presents certain features, including unprecedented scale and speed-to-power requirements in the respective transmission owner zone as well as load portability (*i.e.*, data center migration or shifting cryptocurrency mining to another geographic location) and heightened risks of transient load, then requiring a new large load to pay 100% of its interconnection and "but-for" upgrade costs—and serve as a financial backstop to guarantee any assets that could become stranded or not fully paid for by that large load—

[8] *Xcel v. FERC*, 815 F.3d at 952-53.

[9] ANOPR at P 25. Interestingly, in particular interconnection requests where there is headroom on the system and the large load does not trigger substantial upgrades, then the existing customer zone could potentially benefit from reduced transmission rate exposure given that the zonal transmission rate is spread out over a larger customer base.

in exchange for a faster interconnection is likely an appropriate approach to protect existing customers.

- However, mandating 100% cost responsibility for all network upgrades triggered by a new large load interconnection would bring an unjust and unreasonable result in some cases, particularly where growth is methodical, planned, and fits within the existing framework, and where existing customers in the impacted utility zone are generally allocated costs of new network upgrades that benefit them.[10] The Commission recently reaffirmed this policy of rolling in costs when integration of facilities exists.[11]

Importantly, the ANOPR overlooks the practical and financial consequences of potentially subjecting manufacturers (who are trade-exposed, labor intensive, and price sensitive) to a mandatory large load interconnection rule in which they pay 100% of upgrade costs, even if the ensuing network upgrades benefit other customers.[12] Several manufacturers are seeking to onshore and expand facilities; however, their growth trajectory and planning tends to have a longer time horizon, without the same exact speed-to-power requirements of data centers responding to the nation's ambitious Artificial Intelligence objectives. In evaluating where to make long-term investments in communities, manufacturers have relied on this approach to cost allocation for

[10] Indeed, the Commission just upheld this concept. *See Ky. PSC v. AEP et al*, 193 FERC ¶ 61,110 at P 59 (Nov. 7, 2025) ("the cost causation principle requires that the costs for a transmission project be allocated to those who benefit from the project").

[11] *Ky. PSC v. AEP* at P 57 (citing Opinion No. 311, 44 FERC ¶ 61,206 at 61,748); *see also Utah Power & Light Co.*, 28 FERC ¶ 61,088, at 61,165 (1984); *Otter Tail Power Co.*, Opinion No. 93, 12 FERC ¶ 61,169, at 61,420 (1980) ("Given a finding that the system operates as an integrated whole, transmission costs have generally been rolled-in, absent a finding of special circumstances. The principal reason behind adoption of this methodology is that an integrated system is designed to achieve maximum efficiency and reliability at a minimum cost on a systemwide basis. Implicit in this theory is the assumption that all customers . . . receive the benefits that are inherent in such an integrated system.")).

[12] Generally, in most utility zones and jurisdictions, new large loads pay for all of the direct costs that are assigned to the new large load and will bear financial responsibility for any assets that only serve that new load. However, if the new load request triggers a transmission system upgrade elsewhere on the system, then the costs of that network system upgrade are often rolled into rates across the zone or customer base, given that the system upgrade benefits all customers in the particular utility zone or service territory.

years, as it is supported by cost causation principles. While certain large loads may be able to commit to pay for all network system upgrades, such an approach would be financially devastating to manufacturers and discourage manufacturers from onshoring, engaging in redevelopment, and expanding new facilities or lines of production. Accordingly, the Commission, in its ensuing NOPR in this proceeding, should develop guardrails for transmission cost allocation that ensure the beneficiary pays principle remains intact, particularly where short timeframes demanded by some large load customers dramatically impact the cost calculation and resultant rate impacts.

The Commission may need to refine its approach to cost allocation in particular contexts where the existing customer in a smaller utility zone could be prone to disproportionate cost increases associated with interconnecting a new large load. A larger utility in a larger zone is more capable of spreading out network upgrade costs across its customer base. In utility zones with a smaller customer base, the utility may assign more direct costs or cost responsibility for upgrades to the new large load customer, as the adverse cost impacts on a smaller customer base could be more pronounced. For example, in Pennsylvania, Duquesne Light Company has testified as to the impacts and scale of potential new data center load compared the existing customer base wherein the new large load from a single data center could account for as much as 30% of the current peak load in the entire service territory in Allegheny and Beaver counties.[13] On the other hand, FirstEnergy Pennsylvania, which has a larger service territory across Pennsylvania, will generally roll the costs of upgrades into rate base for recovery through rates charged to all of its customers.[14] FirstEnergy explained:

[13] "Comments of Duquesne Light Co." *En Ban Hearing on Interconnection and Tariffs for Large Load Customers*, PA PUC Docket No. M-2025- 3054271 at p. 3 (filed June 6, 2025) (citing Testimony of Duquesne Light Company, filed April 23, 2025) *available at* https://www.puc.pa.gov/pcdocs/1882372.pdf (last accessed Nov. 21, 2025).

[14] "Comments of FirstEnergy Pennsylvania." *En Ban Hearing on Interconnection and Tariffs for Large Load Customers*, PA PUC Docket No. M-2025- 3054271 at p. 4 (filed June 6, 2025), *available at*

> For those network transmission upgrades that are used to serve all customers, FERC's policy is that when facilities are integrated, and thus provide system-wide benefits, the facility costs are 'rolled-into' the zonal transmission rate and charged to all customers served by the transmission utility.[] FERC's policy is based on the logic that the transmission grid is a single interconnected system serving and benefitting all transmission customers. Further, FERC's default assumption is that network transmission facilities serve all customers, and hence the costs of such facilities are rolled into the zonal network transmission rate.[15]

Accordingly, if the Commission exercises jurisdiction over all large load interconnection requests involving a transmission-level service connection, then the Commission should also evaluate the potential refinements as to how the cost causation and beneficiary pays principles are applied in the context of different large load interconnection requests.

B. The Commission Must Clearly Delineate State-Federal Jurisdictional Lines and Respect State Jurisdiction Over Retail Regulation.

In the ANOPR, the Secretary of Energy has proposed a more expansive view of FERC jurisdiction than has been traditionally assumed by the Commission, raising important questions of what role FERC can and should play in directly addressing large load additions. In the Industrials Customer Organizations' view, the most effective rulemaking will respect jurisdictional lines, focus on optimizing existing transmission system capacity (*i.e.*, reconductoring and GETs) and *leverage* the unique roles and vantage points of the federal actors (e.g., FERC, RTOs, and jurisdictional transmission owners) and the state actors (state commissions, local distribution utilities, and Load Serving Entities – LSEs). Importantly, the ANOPR proposes limiting FERC's jurisdiction to transmission-level interconnections (not sales); however, FERC

https://www.puc.pa.gov/pcdocs/1882403.pdf (last accessed Nov. 21, 2025) (hereinafter "FirstEnergy PA PUC Comments on Large Load Tariffs").

[15] FirstEnergy PA PUC Comments on Large Load Tariffs at 11, 24 (citing *Pinnacle West Capital Corp.*, 131 FERC ¶ 61,143, at P 42 (2010); *Sw. Power Pool*, 182 FERC ¶ 61,141 at P 101 (2023)).

must carefully assert its jurisdiction to avoid unintended consequences, such as discouraging and delaying the onshoring and expansion of manufacturing facilities in the United States.[16]

In *National Association of Regulatory Utility Commissioners ("NARUC") v. FERC*, the D.C. Circuit upheld FERC's asserted authority over generation interconnections in Order No. 2003 because it "applies to jurisdictional transactions only."[17] In other words, the essential purpose of a generator interconnection—to transmit power and sell it at wholesale—was squarely in line with FERC's clear jurisdiction to regulate the transmission and wholesale sales of power. Consequently, the D.C. Circuit upheld FERC's authority. The D.C. Circuit contrasted its holding in *NARUC* with its decision in *Detroit Edison*, where it rejected FERC's attempt to assert jurisdiction over unbundled retail service.[18] In *Detroit Edison*, FERC had attempted to assert jurisdiction where "such service involved neither jurisdictional sales nor jurisdictional transmission."[19]

On November 11, 2025, NARUC passed a resolution ("Resolution") urging FERC to modify the ANOPR's federal jurisdictional claims over large load interconnections.[20] NARUC highlighted the Federal Power Act's express reservation of jurisdiction to states over generation and intrastate transmission. Concluding that the ANOPR represents "potential intrusion on the

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[16] As noted by the Secretary, any rule issued by FERC in this proceeding should be limited to "interconnections directly to transmission facilities." ANOPR at P 18. The ANOPR emphasizes the Commission's clear and exclusive jurisdiction over the transmission of electric energy in interstate commerce and the sale of electricity at wholesale in interstate commerce. ANOPR at P 2 (citing Section 201(b) of the FPA). The ANOPR also recognizes the FPA's reservation of state jurisdiction "over facilities used for the generation of electric energy or over facilities used in local distribution or for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter." 16 U.S.C. § 824(b); *see* ANOPR at P 2.

[17] *Nat'l Ass'n of Regul. Util. Comm'rs v. FERC ("NARUC")*, 475 F.3d 1277, 1280 (D.C. Cir. 2007).

[18] *Detroit Edison Co. v. FERC*, 334 F.3d 48, 53 (D.C.Cir.2003).

[19] *NARUC* at 1280 (explaining the court's holding in *Detroit Edison*).

[20] *See* EL-1 *Resolution Urging Modification of the Department of Energy's Proposal for a Federal Energy Regulatory Commission Rulemaking Asserting Jurisdiction Over Large Load Interconnections* (passed Nov. 11, 2025) (hereinafter "NARUC Nov. 11 ANOPR Resolution"), *available at* https://pubs.naruc.org/pub/97FE08D1-CF4D-9199-BA7F-5884DD427E55?_gl=1*mabnp7*_ga*NjQxOTUyOTc0LjE3NTc0MjQ3NTM.*_ga_QLH1N3Q1NF*czE3NjI5NTc2MTYkbzYkZzEkdDE3NjI5NTc2MzMkajQzJGwwJGgw (last accessed Nov. 21, 2025).

states' historic retail regulatory authority" over resource adequacy and affordability for electric retail customers, the Resolution emphasized the need to avoid "introducing potential confusion, unintended customer consequences and/or legal uncertainty where none currently exists."[21]

The Industrial Customer Organizations acknowledge that Congress clearly authorized FERC to regulate the transmission of electricity in interstate commerce and a standardized transmission-level interconnection process could yield transparency, cost savings, and efficiencies. However, the Industrial Customer Organizations also appreciate NARUC's concerns and recognition that a mandated, federal standardization over all aspects of new large load requests is contrary to longstanding practices wherein new large load customer applications are processed by the local utility or LSE under state-jurisdictional retail tariffs. NARUC also advances practical concerns around disruptions and uncertainty for existing customers.

Consistent with the D.C. Circuit's holding in *NARUC*, FERC should fashion regulations that (1) recognize the impact of large load additions on the transmission grid by improving assumptions and standards used in transmission system studies[22]; (2) allow for federal-level coordination of direct transmission interconnections; (3) consider resource adequacy at the wholesale level as part of the framework while respecting state integrated resource planning in jurisdictions less reliant on a regional capacity market; (4) recognize the jurisdictional differences between generation interconnections and large load interconnections; (5) provide sufficient regulatory space for state commissions to govern end-use load pursuant to state commission-

[21] NARUC Nov. 11 ANOPR Resolution.

[22] Transmission study assumptions and standards should be clear, and the customer should be assured that the affected utility is evaluating and recommending the most cost-effective solution, including any solution that optimizes the existing system and does not necessitate additional upgrades.

approved tariffs[23]; (6) ensure state-jurisdictional utilities are not bypassed; and (7) avoid creating a mandatory structure that can be bypassed on a technicality.[24]

To provide a means for enhancing the development of the grid without impinging on state jurisdiction, the Commission could potentially adopt an *optional* large load interconnection pathway with no arbitrary MW-based threshold. A model optional proposal is set forth in greater detail in the "XL Connect" example in Section IV.C, *infra*. Under this concept, load could interconnect to the transmission grid if it (1) connects at transmission-level voltages; (2) incorporates a local distribution component (at minimum, a distribution utility-owned or controlled meter) in compliance with state utility tariffs; (3) takes responsibility for network transmission upgrades that do not provide substantial benefits to other users; and (4) addresses resource adequacy concerns, such as by bringing flexibility and new capacity resources (generation or demand resources) to offset the load and system impacts. This approach preserves jurisdictional lines by refusing to eliminate the relationship between a local distribution utility and its large load customer, avoiding the pitfall in *Detroit Edison*, where FERC had erroneously "enabled the shipper to escape stranded cost charges imposed under state-approved tariffs."[25] Thus, a large load

[23] Several states have recently approved or are in the process of developing high impact or large load model tariffs. *See, e.g.*, Kansas Corporation Commission, *KCC Approves Large Load Rate Plan with Consumer Protections* (Nov. 6, 2025), available at https://www.kcc.ks.gov/news-11-6-25; Michigan Public Service Commission, *MPSC Approves Terms of Service between Consumers Energy and Data Centers, Other Very Large Customers; Adds Protections for Existing Customers* (Nov. 6, 2025), available at https://www.michigan.gov/mpsc/commission/news-releases/2025/11/06/mpsc-approves-terms-of-service-between-consumers-energy-and-data-centers; American Public Power Association, *Ohio Regulators Order Utility to Create Data Center Specific Tariff*. FERC must ensure that its new large load interconnection rule accommodates state PUC tariffs unless the state PUC clearly intrudes on FERC's jurisdiction.

[24] For example, if FERC claims jurisdiction over large load interconnections above a certain threshold (e.g., 20 MW) that connects directly to the transmission grid, such jurisdiction could theoretically be blocked by a distribution utility requiring the large load to connect to the distribution utility first, or by the customer avoiding direct interconnection to the transmission grid.

[25] As affirmed in *NARUC*, FERC's regulations may permissibly have "incidental effects on non-jurisdictional entities." *NARUC* at 1281. Here, the "incidental effect" could be the distribution utility's location of meter placement or placement of other minimal equipment. (A distribution utility would be required under most state commission-approved tariffs to place a meter at retail load.)

customer interconnecting through this voluntary process would retain connection to its local distribution entity, subject to state-approved tariffs and states' historic retail regulatory authority over end-use retail transactions. This would minimize state jurisdictional concerns, while enabling the RTO to coordinate the interconnection studies, governed by the applicable FERC-jurisdictional tariffs for the RTO/ISO and applicable Transmission Owner.[26]

Whether the Commission adopts this approach or a different approach, any regulations it fashions should be based on FERC's authority over transmission and wholesale sales—and "over all facilities for such transmission or sale of electric energy."[27] Accordingly, FERC's authority over matters pertaining to large load interconnections is likely at its zenith when regulating transmission system studies, transmission-level interconnection studies, and other jurisdictional activities that do not impinge on state authority over retail tariffs and retail rates. States, on the other hand, retain authority over remaining retail issues pertaining to new customer applications and state tariffs governing all end use customers (including transmission-level customers).

Currently, transmission system studies and load impact studies are generally conducted by the local utility or LSE. The local utility certainly retains full authority to evaluate distribution system impacts subject to state oversight. However, the local utility's coordination with the applicable transmission owner (which is often not the same company, especially in the case of a

[26] Instead of regulating all large load interconnections, FERC may want to limit its rulemaking to apply to facilities bringing substantial onsite or nearby generation to support large load additions coming online. Such an approach would have to account for state jurisdiction over retail sales, but the interconnection study process, construction, and deployment may be able to be largely managed at the RTO/transmission owner level. Put another way, instead of building new federal rules to interconnect **load** *with behind-the-meter generation*, this approach would use FERC jurisdiction over **generation** to facilitate the large load interconnection. While the *retail sale* element of this configuration would still be state-jurisdictional, and the state retail tariffs would still apply, the study process and physical interconnection approvals could fall under FERC jurisdiction, which would naturally provide an incentive for large load additions to bring a generation component in order to be able to interconnect through the optional federal generation interconnection process. FERC could potentially offer an expedited process firmly within its own jurisdiction, established in Order 2003, Order 2023, and elsewhere, over generator interconnections, as the studying of load and generation together has the potential for efficiencies and cost-savings.

[27] 16 U.S. Code § 824(b)(1).

cooperative or transmission dependent utility) in evaluating transmission system impacts is an area where the Commission may wish to focus exercising its jurisdiction over large load, transmission-level interconnections. The Commission may wish to increase transparency around study assumptions and standardize rules for those large load studies, in coordination with state actors.

C. Rather Than Federalizing All Large Load Interconnection Requests, the Commission Should Consider an Elective Federal Large Load Interconnection Process for Loads That Bring Flexibility Commitments, Bring Their Own Generation, and Minimize (or Fund) Resulting Transmission Upgrades.

In addition to jurisdictional concerns, the Industrial Customer Organizations have substantial practical concerns with a standardized, federalized approach to new large load additions, particularly on a short time frame. The ANOPR attempts to analogize FERC-jurisdictional generation interconnection procedures to the proposed large load interconnection procedures by highlighting the benefits of standardization.[28] However, mandating all new loads greater than 20 MW to go through a separate, new, federal process could cause significant negative impacts, including: disrupting existing processes; triggering confusion between state and federal organizations and regulators; creating business uncertainty; and diverting limited and scarce resources from staff at the Commission, at RTOs/ISOs, and at public utilities. Consequently, the Industrial Customer Organizations respectfully propose that the Commission consider developing an elective, "fast-lane" interconnection approach that addresses regional transmission and resource adequacy impacts without cutting out the distribution utility or violating state-level tariffs. The optional process could apply to large loads with pressing speed-to-power requirements that – in

[28] *See* ANOPR at PP 7-11. Highlighting the complexity of a standardized process, the Commission issued Order No. 2003 in July of 2003, refined its procedures in April 2018 in Order No. 845, and recently in July 2023 issued Order No. 2023 to establish a cluster study process, increased study deposits, increased financial commitments, and study delay penalties. ANOPR at P 11 (citing *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh 'g*, 185 FERC ¶ 61,063 (2023), *order on reh 'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024)).

exchange for a faster interconnection and in recognition of risks associated with the magnitude of their load and the potential portability or transience of their load – are willing to financially bear the costs of stricter study and collateral requirements, including for the network upgrades associated with their interconnection request.[29]

Following is a conceptual proposal of an optional, fast-lane process, entitled XL Connect:

Proposal Summary

XL Connect is an optional federal, fast-lane interconnection process for a large load connecting to the FERC-jurisdictional transmission system at transmission-level voltage.

The purpose of XL Connect is to enable rapid, transmission-level interconnection of large electricity loads (e.g., data centers, industrial facilities) for customers for whom speed-to-market and/or interconnection certainty is critical, and who can make adequate financial and contractual assurances to the grid. It provides a choice-based context that preserves jurisdictional lines and ensures resource adequacy. The goal of XL Connect is to facilitate American energy and technology dominance in a way that benefits – rather than harms – other ratepayers, including residential, commercial, and other industrial and institutional customers.

Eligibility

- Non-discriminatory access for customers desiring to connect at transmission-level voltage to the transmission grid, who meet other requirements and make commitments that avoid adverse impacts to the grid and existing customers.

- A new customer/load seeking transmission level interconnection would still submit a new customer service application with their local utility subject to state jurisdiction; however, the transmission-level service application would also include a new application/submission that is concurrently made through an RTO/ISO or transmission provider portal (with notice to the applicable transmission owner and local utility/load serving entity).

[29] As explained herein, requiring the new large load to pay 100% of all network upgrades associated with the new load's interconnection request may be inconsistent with cost causation principles (given that the network upgrades provide benefits to other customers in the utility zone). Accordingly, all new loads should not necessarily be subjected to paying 100% of network upgrades unless the new large load with speed-to-power demands elects the fast lane interconnection approach. That said, the Commission should also pursue and preserve optionality for large loads, including manufacturers, to proceed through either a federal or state-administered interconnection process. Accordingly, while we envision that the XL Connect option may be of most interest to hyperscale data centers, such an option should be available to large manufacturers who may bring their own generation or provide other grid benefits to reduce or offset upgrade costs.

1. **Rapid Study Process**
    - 90-day interconnection study timeline coordinated by RTO/ISO and applicable utility/transmission owner
        - Must include transparent assumptions and detail on study used in the load interconnection process
    - Higher fees to fund expedited engineering and system impact analysis
    - Study results to include both curtailable and non-curtailable service options
    - Studies must evaluate potential use of Grid Enhancing Technologies and reconductoring to accommodate the large load
    - Studies must ensure the most cost-effective solution is recommended
    - Transparent load forecasts and ramping data
    - Coordination with local utility and compliance with any applicable state retail tariff requirements

2. **Cost Responsibility Consistent with Speed-to-Power Requirements**
    - Large load will pay for its direct costs for any assets (such as lines and transformer or substation that directly and only serve the large load)
    - "But For" Costs: The study must identify network transmission upgrades that would not be needed "but for" the XL customer's interconnection
    - These upgrades are designated as XL-Designated Assets, which are tracked in a separate account, distinct from general network upgrades
    - Transmission Owners ("TOs") must maintain two accounting tracks for the TOs' rate base:
        - General Transmission Assets: Costs allocated via standard methods (e.g., 12-Coincident Peak)
        - XL Account: Costs for XL-Designated Assets allocated exclusively to the XL customer for a 10-year period, after which the XL-Designated Assets are moved to the General Transmission Assets
            - TOs may require credit posting from XL customers to cover XL asset costs over the 10-year term, in case of default.

3. **Physical Interconnection**
    - Direct facilities serving only the XL Customer billed to XL Customer or negotiated between TO and XL Customer (not added to rate base).
    - Transmission level interconnection established by TO.
    - Minimum of metering facilities owned or controlled by local distribution utility – electric energy must still pass through distribution facility to reach XL Customer
    - Distribution utility may own additional step-down facilities at XL Customer's option, but XL Customer's service must be served through transmission facilities (via the distribution meter), not primarily through other stepped-down distribution facilities.

4. **Demonstrated Effort to Minimize, Avoid, or Defer Transmission Upgrades**
    - **Flexibility:** Large load flexibility commitments – load ceases to draw energy from the grid in whole or in part (through curtailment or use of co-located or adjacent supply or behind-the-meter generation).[30]
    - **Efficiency:** Deployment of Grid Enhancing Technologies or advanced reconductoring, including willingness to fund such measures

5. **Resource Adequacy Compliance**
    - XL Customers must address resource adequacy as follows:
        - Load Flexibility/Curtailment Plan: Includes behind-the-meter generation to mitigate grid impacts under RTO-defined conditions
        - Bring Your Own Generation/Self-Supply: Bilateral contracts with new or non-capacity resources (not recently cleared capacity)
        - Hybrid Option: Combination of the above, subject to RTO and/or FERC approval
    - If RTO, state, or applicable planning region projects sufficient resource adequacy 3–5 years ahead, XL Customer may bypass this resource adequacy requirement
    - Resource adequacy compliance must be enforced with substantial penalties for non-performance
    - Reports must be made at various milestones to relevant agencies (RTOs, TOs, state level authorities) to facilitate accurate transmission and capacity forecasting

D. The Commission Must Provide for a Reasonable Transition Period to Avoid Unintended Detrimental Consequences to Manufacturers That Are Currently Onshoring, Redeveloping Sites, and Adding New Facilities.

The ANOPR appropriately recognizes the need for a transition plan to implement the proposed reforms, including the assessment of large load interconnections that are already being studied for interconnection.[31] As explained herein, the Commission should consider making the large load interconnection process elective at the option of the large load, facilitating an effective transmission study process while still respecting state jurisdiction over retail sales. If the Commission proceeds with implementing and mandating interconnection rules for all large loads,

[30] *See* "How DOE's Proposed Large Load Interconnection Process Could Unlock the Benefits of Flexibility," Duke and Nicholas Institute for Energy, Environment, and Sustainability (Nov. 2025), *available at* https://nicholasinstitute.duke.edu/sites/default/files/publications/how-does-proposed-large-load-interconnection-process-could-unlock-benefits-load-flexibility.pdf (last accessed Nov. 21, 2025).

[31] ANOPR at P 30.

then the Commission must establish a reasonable transition period, with an effective date for the new rule to take effect for interconnection applications (not electing a fast lane approach) to be established in 2027 or later. Utilities, RTOs, and large loads will need time to adjust to a new standardized approach at the federal level, given the historical processing of new customer service applications at the local retail utility level, subject to state and local jurisdictional rules.

Importantly, the new rule should not apply retroactively to any existing loads—nor should it apply to new projects and facility additions where the planning and investment is already substantially underway. Not all states and state commissions are delaying interconnection requests for new large loads. FERC's rule should allow for optionality, in the event the new large load wishes to pursue use of any new federal interconnection process or the existing local utility or state process.

Further, FERC's NOPR must be consistent with the Administration's goal to reshore manufacturing quickly. As proposed (without exempting loads already in the interconnection process), the draft ANOPR would delay, and possibly prevent, construction of new manufacturing and the associated jobs and broader economic benefit. This is a serious concern of the Industrial Customer Organizations. The new rule should not apply to new large loads where the customers have pending transactions, pending studies, pending new customer service applications, or demonstrated site control for a new or redeveloped project underway before the new rule is finalized. If the Commission were to implement and apply a mandated process to manufacturers that have already started redevelopment projects and begun working with their local retail utility, then the Commission risks making those redevelopment projects uneconomic and injects unnecessary and substantial business and financial uncertainty into ongoing efforts to expand and grow manufacturing in the United States. Some manufacturers are trying to reshore and expand

operations, including redeveloping projects at sites with existing transmission infrastructure and/or generation resources. Other manufacturers are simply trying to remain economic and keep their plants running. The Industrial Customer Organizations stress that, while certain large loads may be highly interested in a federalized interconnection process, an accelerated mandate that manufacturers comply with that process would be counterproductive and jeopardize the viability of projects that are already underway, running counter to the ANOPR's important economic development and national security objectives.

E. Regulations Promulgated by the Commission to Address the Rapid Emergence of Large Loads Should Be Time-Limited.

The Secretary of Energy, in the ANOPR, made clear that the ANOPR was prompted by the need for "unprecedented and extraordinary quantities of electricity and substantial investment in the Nation's interstate transmission system."[32] Because the ANOPR seek to address a short-term issue occurring over the next few years, we caution the Commission to not upend existing processes that are working. FERC may want to consider developing a short-term solution to address the immediate challenges. Regulations that affect processes currently managed at the state level could include a sunset provision, while regulations that are squarely focused on transmission grid transparency, load forecasting, and grid efficiency could be permanent reforms. This would give the industry an opportunity to aggressively welcome growth and avoid cost shifts, without saddling FERC with permanent responsibilities that would best remain at the state level.

[32] Letter from the Secretary of Energy, *Secretary of Energy's Direction that the Federal Energy Regulatory Commission Initiate Rulemaking Procedures and Proposal Regarding the Interconnection of Large Loads Pursuant to the Secretary's Authority Under Section 403 of the Department of Energy Organization Act* (Oct. 23, 2025).

F. The Commission Should Protect Industrial Customers with Existing Behind the Meter Generation Under Net Billing Arrangements, and Maintain Billing For Transmission and Capacity Obligations on a Net Basis.

Cost-causation is long-established as a central principle in just and reasonable rates. As stated by the D.C. Circuit, "For decades, the Commission and the courts have understood [the just and reasonable] requirement to incorporate a 'cost-causation principle'—the rates charged for electricity should reflect the costs of providing it."[33] As expressed by the Fifth Circuit in *El Paso Electric Co. vs. FERC*, "This principle is 'foundational' and a 'basic tenet' of ratemaking."[34] Cost-causation jurisprudence has addressed two aspects of cost causation: those who cause the costs and those who reap the benefits. As stated in *El Paso*, "Courts have generally held that costs 'are to be allocated to those who cause the costs to be incurred and reap the resulting benefits.'"[35]

The rubber meets the road on this concept when FERC determines how transmission infrastructure and upgrade costs are allocated and how cost responsibility is measured. When determining how to allocate these costs, the Commission has determined that "actual use" of the transmission system is a just and reasonable approach that comports with cost causation. In *Occidental Chemical Corp. v. PJM Interconnection, L.L.C.*, the Commission declared that "[network] access charges for use of PJM's transmission system should be allocated to network customers based on a network customer's *actual use* of PJM's system, consistent with the principle of cost causation."[36] The "actual use" principle is critically important to the calculation of billing

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[33] *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255 (D.C. Cir. 2018); *see also El Paso Elec. Co. v. FERC ("El Paso")*, 76 F.4th 352, 357 (5th Cir. 2023).

[34] *El Paso* at 357 (citing *El Paso Elec. v. FERC*, 832 F.3d 495, 505 (5th Cir. 2016)); *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 85 (D.C. Cir. 2014) (per curiam).

[35] *El Paso* (citing *NARUC* at 1285); *see also BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268 (D.C. Cir. 2014) (The principle is a "matter of making sure that burden is matched with benefit.")

[36] *Occidental Chem. Corp. v. PJM Interconnection*, 102 FERC ¶ 61,275, 61,852 (emphasis added). At issue in Occidental was PJM's use of a cost-allocation methodology that added the value of curtailed load back to a customer's actual load to determine the customer's network access charge based on a customer's coincident peak usage. *Id.* ¶¶ 1, 3-7. The Commission expressed concerns that this "calculation appeared inconsistent with the underlying rationale,"

determinants and the assessment of various Commission-jurisdictional charges for transmission service, and also for capacity service and ancillary services. Customers with behind-the-meter generation should be billed on a net basis (accounting for their net demand requirements) and not on a gross load basis.

The Industrial Customer Organizations believe that this approach provides for efficient use and buildout of the transmission system, and it must remain a bedrock of transmission cost allocation.[37] However, the rapid speed-to-market demands of data centers have added an important caveat to the "actual use" cost allocation formula. Actual use works as a cost allocation methodology where many customers are sharing the system and upgrades happen methodically over time. However, where you have new entrants with sweeping demands for *scope and speed,* it is *also* critical to ensure that the new entrants do not trigger massive upgrades and then fail to bear the costs of those upgrades, which would not have happened "but for" the massive size and rapid speed-to-market demands of the new entrants. The size and speed-to-market needs of certain large loads, such as data centers, have essentially added a new layer to the cost-causation analysis.

Put another way, the "beneficiary pays" principle must account for situations where rapid and massive buildout occurs that risks substantial cost shifts to other users (while *also* incidentally squeezing those same users from a resource adequacy perspective). Where substantial system upgrades are *caused by* and *benefit* a new large load entrant, but are *not* caused by other users and

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and that such an approach would discourage demand response from customers. *Id.* ¶ 4. PJM sought to defend the practice that the Commission ultimately found to be unjust and unreasonable by arguing that PJM's infrastructure would still serve the customers. *Id.* ¶¶ 1, 7, 14. The Commission rejected that contention, instead embracing a netting approach. In its order on rehearing, the Commission stated that the netting approach is "in the public interest because it ensures that PJM allocates its transmission charges to those using the system on peak periods and helps ensure that customers have incentives to curtail load during peak periods." *Id.* ¶ 2.

[37] Manufacturers with behind-the-meter generation have long relied on the net basis approach to establishing capacity and transmission obligations for customers. While the net basis billing has been used throughout PJM, other regions and utilities have been moving away from net billing and charging customers on a gross basis. Such an approach will deter, not incent, redevelopment and onshoring.

do *not* provide commensurate benefits to them, an element of "but for" cost allocation is appropriate, *i.e.*, assigning costs to an entity when those costs would not have been incurred "but for" that entity's demands. The "but for" approach is applicable when narrowly focused on incremental necessity, particularly where there are not commensurate benefits to other users.

In addition to the "but for" principle, other FERC precedent supports a guardrail to ensure that massive large-load additions to the grid do not shift costs to other users. In Order 1000, the Commission set forth principles of cost allocation in a transmission context, one of which was to establish a minimum benefit-cost ratio. In Order No. 1920, the Commission reaffirmed the minimum benefit-cost ratio principle as a selection criterion for long-term regional transmission facilities.[38] This principle indicates that projects should bring a substantial benefit that exceeds the costs. But if these substantial benefits accrue solely to the large load entrant, not other users, the costs of those benefits should also accrue to the entrant.

As a result, the Commission should affirm measurement of "actual use" of the transmission system in allocating transmission costs, with the exception of upgrades and new buildouts that are both caused by and primarily benefit only one or a few new entrants. The size and speed of new large load entrants whose need to connect to the grid as soon as possible is driving new infrastructure costs and new resource adequacy costs. The XL Connect optional proposal is designed to accommodate those prospective loads whose "need for speed" generates a "but for" cost allocation approach.

[38] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (2024).

G. The Commission Should Avoid an Arbitrary Size Threshold; However, if the Commission Chooses a MW-Based Threshold, It Should Be Substantially Higher than 20 MW and Applicable Only to New Loads.

The ANOPR suggests a 20 MW large load threshold for applicability of new interconnection rules that the Commission may promulgate. While the ANOPR references the Commission's *pro forma* Large Generation Interconnection Procedures ("LGIP") and Large Generator Interconnection Agreement ("LGIA"), which use a 20 MW threshold, Order 2003 was upheld by the DC Circuit Court of Appeals ("DC Circuit") in *NARUC v. FERC* because it "applies to jurisdictional transactions only."[39] In other words, FERC's jurisdiction in Order 2003 was not affirmed because of the 20 MW size threshold but because the essential purpose of a generator interconnection—to transmit power and sell it at wholesale—was squarely in line with FERC's clear jurisdiction to regulate the transmission and wholesale sale of power.

In contrast, load interconnection of all sizes has traditionally been managed at the state level. Setting a threshold to define "large load" does not resolve any underlying jurisdictional issues. Consequently, the Industrial Customer Organizations believe an optional process, such as what is described in Section IV.C, *supra*, should be offered on a non-discriminatory basis for any load connecting at a transmission level, as determined by the FERC's Seven Factor Test.[40] Establishing a bright-line threshold risks being challenged as unduly discriminatory, unless it is clearly grounded in FERC's authority to regulate the transmission of electric energy in interstate commerce.

If the Commission pursues a mandatory threshold, it should choose a threshold aligned with the key drivers of the current transmission demands and posed risks to reliability. Rather than

[39] *NARUC*, 475 F.3d at 1280.

[40] *See generally* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996).

a bright-line standard across all regions and transmission zones, the Commission should consider the relative impact of large load on the applicable region and transmission zone. What is "large load" with massive implications to a small territory may not be so "large" in a larger utility's service territory.[41] In a July 2025 white paper, *Characteristics and Risks of Emerging Large Loads*, the North American Electric Reliability Council ("NERC") defined large load as "[a]ny 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 [Bulk Power System] due to its demand, operational characteristics, or other factors."[42] Rather than a bright-line threshold, this definition takes stock of the differences between utilities and territories. The Commission should consider aligning with NERC's efforts to develop standards for new large loads. FERC's Seven Factor Test, rather than an arbitrary peak load amount, should be used to evaluate the jurisdictional nature of the interconnection. FERC can also consider using NERC's definition of the bulk electric system, defining transmission lines and interconnections and associated equipment generally operating at voltages of 100 kV or higher.[43]

More broadly, the projected transmission challenges and looming resource adequacy crisis are primarily driven by substantially larger facilities than 20 MW. The Industrial Customer

[41] To bring this into focus, consider that one data center can dramatically increase peak loads in small territories. In the PJM region, for example, approximately half a dozen transmission zones have Network Service Peak Loads ("NSPLs") of under 3,000 MW. *See* PJM.com, *PJM Network Service Peak Loads (NSPL) for 2026*, available at https://www.pjm.com/-/media/DotCom/markets-ops/settlements/network-service-peak-loads-2026.pdf. For a 2,000 MW service territory, a sole 1,000 MW data center addition could increase peak transmission flow by 50%--a dramatic increase for one large load addition. Assuming $500,000 per MW for construction, a 1,000 MW transmission upgrade project would be $500 million. If the utility's ROE was 10%, that could mean approximately $50 million added to rates each year in that small territory.

[42] "Characteristics and Risks of Emerging Large Loads," NERC at p. 1 (July 2025), *available at* https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf (last accessed Nov. 21, 2025).

[43] Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, 72 FR 16,416 (April 4, 2007), FERC Stats & Regs. ¶ 31,242 (2007) at P 75, fn 47.

Organizations believe a 20 MW limit is far too low and would capture a significant number of manufacturing entities and other industrial and institutional organizations that do not have the speed-to-market and scale demands that are primarily driving today's grid challenges. Consistent with that approach, the Texas Legislature passed a law recently that sets the threshold for ERCOT at 75 MW (though the Texas Public Utility Commission may lower it, as appropriate). Similarly, the Kansas Corporation Commission recently approved a Large Load Power Service rate plan designed for new facilities with an expected peak load of 75 MW. If a threshold is set by the Commission, it should be at a minimum of 75 MW-100 MW (or higher), restricted to new load added to the grid, and with reasonable and clear aggregation rules.

H. Any Regulations Promulgated by the Commission Should Support Accurate Forecasting, Public Transparency, and Efficiency by Transmission Owners and Regional Grid Operators.

If the Commission proceeds to issue a NOPR, the Commission should also focus on improvements to transparency around load forecasts and how load studies, including transmission system impact studies, are conducted. Accurate, transparent forecasting provides two critical benefits: it facilitates creative industry solutions and promotes accountability, both of which lead to a more efficient grid. In a potential NOPR, the Commission should consider developing rules that strengthen regional grid operators' ability to develop accurate and transparent forecasts. Providing transparency to industry stakeholders promotes an increase of innovative solutions and better regional transmission and resource adequacy planning.

Additionally, in recognition of the incentive to overbuild and expand rate base, the Commission could – to protect existing customers and promote an efficient electric system – mandate the relevant transmission owner or regional grid operator evaluate the use of advanced reconductoring and the use of GETs, and other efficiency and optimization measures for any new large load interconnection application and related studies. State, regional, and federal leadership,

including the Commission, have been exploring and/or enacting measures requiring GETs for both the transmission system and distribution system.[44] Achieving speed-to-power in the near-term, while also protecting customers, will require the use of GETs, advanced reconductoring, and unlocking all available system capacity.

[44] *See, e.g.*, Va. H.B. 2346, 2025 Reg. Sess. (Va. 2025) (enacted as Act of May 2, 2025, ch. 709) ("An Act to direct certain electric utilities to petition the State Corporation Commission for approval to conduct a virtual power plant pilot program."); Pa. H.B. 505, 2025-26 Reg. Sess. (Pa. 2025) (bill proposed to define "measures to reduce distribution system loss" to include "the retrofit or replacement of distribution systems with advanced, resilient and energy-efficient conductors and transformers and deployment of advanced sensors, meters, switches, control systems and other components that increase energy efficiency and grid resilience between and including the substation and the individual consumer and other technologies, practices or measures approved by the commission."); Marketing Analytics, *2024 State of the Market Report for PJM*, at 654-655 (recommending that "all PJM transmission owners investigate the applicability and potential cost savings of Grid Enhancing Technology"); *see also* Advanced Notice of Proposed Rulemaking, *Implementation of Dynamic Line Ratings*, Docket No. RM24-6-000 (Jun. 27, 2024).

V. CONCLUSION

WHEREFORE, the Industrial Customer Organizations respectfully request that the Commission afford due consideration to these Comments.

Respectfully submitted,

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Dated: November 21, 2025

CERTIFICATE OF SERVICE

I hereby certify that I have this day served, via first-class mail, electronic transmission, or hand-delivery the foregoing upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at this 21st day of November, 2025.

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