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Matthew L. Homsher, Esq., Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, Pennsylvania 17120

Re: Interconnection and Tariffs for Large Load Customers; Docket No. M-2025-3054271

Dear Secretary Homsher:

Enclosed for filing are the comments of the Energy Association of Pennsylvania to the November 2, 2025 Tentative Order and Model Tariff in the above-referenced proceeding.

Sincerely,

Nicole W. Luciano
Director of Policy

Enclosure

cc via email:
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Interconnection and Tariffs for Large Load Customers	:	Docket No. M-2025-3054271

COMMENTS OF THE ENERGY ASSOCIATION OF PENNSYLVANIA
TO NOVEMBER 2 TENATIVE ORDER

I. INTRODUCTION

On April 12, 2025, the Pennsylvania Public Utility Commission ("PUC" or "Commission") issued a Secretarial Letter scheduling an *en banc* hearing for April 24, 2025 on issues related to interconnection and tariffs for large-load customers. As a part of the *en banc*, Commissioners posed questions in advance to invited panelists to facilitate discussion on topics related to the efficient and timely interconnection of this unique category of electric customers. The Commission received testimony from panelists during the *en banc* and received and reviewed comments and reply comments from other interested parties to the Docket in June 2025. The Energy Association of Pennsylvania ("EAP" or "Association") submitted both comments and reply comments on behalf of its members. Individual utility members also submitted comments and reply comments relative to their individual company circumstances and service territories.

On November 2, 2025, the Commission issued a Tentative Order and an accompanying Appendix – Model Tariff for Customers at or Over 50 MW Individually or 100 MW in the Aggregate outlining its guidelines for a model large load tariff.[1] Interested parties are invited to provide comment within thirty (30) days of its publication in the *Pennsylvania Bulletin,* i.e., by December 22, 2025. The Commission's guidelines are broken out by topic area, and EAP's

[1] *Interconnection and Tariffs for Large Load Customers,* Tentative Order entered November 6, 2025, Docket No. M-2025-3054271.

comments will follow accordingly. Primarily, EAP's feedback represents the consensus position of its members; individual companies may also submit more specific feedback.

II. OVERVIEW

This proceeding addresses issues of critical importance to Pennsylvania's economic future, grid reliability, and fair cost allocation. Large Load Customers, particularly hyperscale data centers supporting artificial intelligence and other advanced computing operations, present significant opportunities for job creation, economic development, technological advancement, and strengthening national security infrastructure. Pennsylvania's distribution utilities are committed to supporting this growth in a manner that ensures system reliability, maintains affordability for all customers, and prevents unreasonable cost shifts to existing ratepayers.

At the same time, utilities are equally committed to ensuring that infrastructure costs caused by new Large Load Customers are properly allocated to those customers and recovered from the cost-causers, not subsidized by existing residential, commercial, and industrial customers. As energy costs continue to be a significant concern for Pennsylvania households and businesses, it is essential that large load development does not exacerbate affordability challenges for other customer classes. The fundamental principle of cost causation—that customers should pay for the costs they impose on the system—must guide large load tariff design. This principle protects existing customers from bearing costs they did not cause, while ensuring that Large Load Customers pay their fair share for the substantial infrastructure investments required to serve their unprecedented energy demands.

EAP recognizes the delicate balance required: encouraging economically beneficial large load development while safeguarding the interests of the millions of existing customers who depend on affordable, reliable electric service. Both objectives can be achieved through properly designed tariff provisions that accurately identify infrastructure costs driven by large load interconnections, appropriately allocate those costs between the cost-causing customers and the broader system beneficiaries, and establish mechanisms that ensure cost recovery occurs as intended without stranded investments being borne by other ratepayers.

At the outset, EAP highlights several threshold concerns that fundamentally affect how large load policies can and should be implemented in the Commonwealth. A central challenge in Pennsylvania's framework is that the Commission's authority is limited to distribution service and default service procurement and rate design.[2] However, many of the most significant costs and impacts associated with large load interconnections occur at the transmission level, which falls under Federal Energy Regulatory Commission ("FERC") jurisdiction. As documented in previous electric distribution company ("EDC") testimonies and comments, large load interconnections typically involve both distribution and transmission system upgrades.[3] It is important as the Commission seeks to finalize a model tariff framework that it be clear that the model tariff framework applies only to distribution-level service, which is within the Commission's jurisdiction, and recognize that transmission-level impacts will continue to be addressed through existing FERC-jurisdictional processes. Where coordination between state and federal frameworks is necessary, the Commission should establish principles and objectives, rather than mandates, which will preserve flexibility for EDCs to navigate the complex jurisdictional landscape.

For the large load projects currently being contemplated, transmission system impacts often represent the majority of total infrastructure costs. Much of the infrastructure investment needed to serve large loads requires transmission level service, which is recovered via transmission rates, not the distribution rate. Transmission cost allocation, network upgrade determinations, and

[2] EAP acknowledges that the Commission also has authority over retail rate design associated with transmission service.
[3] *See* Testimony of Kelly Gower, Vice President of Finance and Regulatory of FE PA to En Banc Hearing Concerning Interconnection and Tariffs for Large Load Customers Docket No. M-2025-3054271

rate recovery mechanisms are governed by FERC-approved tariffs and established federal precedent, not through the PUC.

A second threshold concern is the conflation of distribution infrastructure issues (within PUC authority) with generation capacity and resource adequacy issues (largely beyond the PUC's current authority in Pennsylvania's restructured competitive market except for default service procurement and rate design). Several provisions in the Commission's Tentative Order appear designed to address generation capacity and resource adequacy concerns, such as requirements or incentives for large loads to "bring your own generation" and interruptible service provisions aimed at reducing peak demand and capacity obligations. While generation and resource adequacy concerns are legitimate and important, they cannot and should not be fully addressed through distribution tariffs within the Commission's authority.

A. Regulatory Promulgation Concerns: Model Tariff vs. Binding Requirements

EAP highlights a fundamental concern with the scope and prescriptive nature of certain provisions in this Tentative Order. While the proceeding is framed as developing "model tariff" guidance, several proposed requirements appear to constitute new regulations that substantially expand Commission authority and impose binding obligations on EDCs and customers beyond traditional tariff provisions. Commissioner Coleman articulated similar concerns in his statement accompanying the Commission's November 6, 2025 issuance of the Tentative Order[4], which EAP shares.

The Public Utility Code grants the Commission authority to regulate rates, services, and facilities of public utilities to ensure they are just, reasonable, and non-discriminatory. Tariffs traditionally establish the rates, terms, and conditions under which utilities provide service to

[4] Statement of Commissioner John F. Coleman, Public Meeting held November 6, 2025, Docket No. M-2025-3054271

customers—addressing matters such as rate schedules, connection fees, service standards, billing practices, and cost allocation methodologies. However, certain provisions in the Tentative Order venture beyond traditional tariff matters into territory that more closely resembles regulatory rulemaking. As addressed below, certain items – such as a mandatory universal service fund contribution for Large Load Customers, mandatory EDC reporting requirements as well as equity and outreach obligations, and mandatory interruptible service offerings – are more akin to regulatory requirements, which implicate the need for a more formal process than contemplated here.

Instead of creating a number of prescriptive mandates as part of this proceeding, the Commission's final guidance and model tariff should outline the PUC's overall principles and objectives sought to be achieved in the Commonwealth and recommend topics or approaches EDCs should consider when developing a Large Load Customer tariff, rather than attempting to impose detailed, mandatory requirements on EDCs and customers. The Commission can then utilize existing processes for review and approval of proposed utility tariffs to ensure they achieve the Commission's objectives while allowing for EDC-specific adaptation. This process will enable the EDCs to propose approaches for bringing on new Large Load Customers in a manner that matches their system and operational requirements, but while also protecting other customers and providing transparency.[5]

[5] "Instead of trying to achieve a resolution where no consensus exists, it may be appropriate to allow an EDC to submit and support its own proposal in a tariff filing." Statement of Commissioner John F. Coleman, Public Meeting held November 6, 2025, Docket No. M-2025-3054271, p.2.

III. COMMENTS

A. Appropriate MW Size Designation for Large Load Tariffs in Pennsylvania

EAP appreciates the Commission's effort to establish clear thresholds for defining Large Load Customers and recognizes the value of regional consistency within the PJM footprint. However, large load interconnections typically require coordination between customers, EDCs, transmission owners, the PUC, and FERC. The guidelines and model tariff should clearly articulate that these thresholds apply to distribution-level interconnections under PUC jurisdiction, with recognition that transmission-level interconnections may trigger additional FERC-jurisdictional requirements regardless of whether the 50/100 MW thresholds are met.

The Commission is correct that the 50 MW threshold may not be appropriate[6] in all circumstances and, therefore, utilities should retain discretion whether to apply the model tariff below the threshold. [7] This is a particularly salient issue for smaller utilities where 50 MW would be too high a threshold to trigger these impacts and considerations.

To ensure that the intended applicability of the tariff is not ambiguous, EAP requests the Commission clarify whether these provisions apply to new and existing Large Load Customers. The model tariff language indicates that "[c]ontact requests from existing Large Load Customers shall continue to be addressed by the Company consistent with the Company's existing requirements."[8] However, this could be interpreted several ways. For example, if an existing Large Load Customer requests additional (new) service at a new location (not closely located to their existing location) within the same EDC service territory, is this request properly treated as a "new" customer subject to the new large load tariff, or as an "existing" customer subject to existing

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[6] A strict threshold of 50 MW – where load size is the only distinction for applicability of this tariff – will capture other / existing customers that the Commission may not intend to include as part of this proceeding.
[7] Tentative Order, pp.7-8.
[8] Annex, Model Tariff, section titled "Existing Large Load Customer Contracts."

requirements? This situation would also apply in the case where a customer is currently taking service for a warehouse but wants to build a large data center in the same EDC service territory.

B. Deposits, Financial Security, or Collateral from Large Load Customers

EAP supports the Commission's proposed framework for financial security that is graduated based on proposed load size, reduced as load ramp milestones are met, refunded when load reaches maximum committed levels, and sufficient to cover network upgrade costs.[9] This approach aligns with current EDC practices documented in the testimonies and comments, and appropriately balances customer financial burden with ratepayer protection.

However, the term "major beneficiary"[10] in the guidelines requires further definition. In vertically integrated utilities, benefit analysis is straightforward. In Pennsylvania, distribution benefits accrue to EDC customers and transmission benefits accrue across PJM. Who determines "majority beneficiary" when transmission and distribution are separate entities under different regulatory jurisdictions? Absent a definition, the Commission's guidelines and model tariff should explicitly indicate that the benefit analysis being done is distribution-level only; that is, the EDC determines whether upgrades benefit primarily the interconnecting customer or provide broader system benefits using established engineering and planning criteria subject to regular oversight by the PUC.

The Commission's proposed model tariff includes provisions allowing certain Large Load Customers to reduce or eliminate collateral requirements based on credit ratings or liquidity thresholds.[11] As discussed herein, financial security (collateral) requirements protect existing

[9] Tentative Order, p. 13.
[10] Appendix, Model Tariff, definition of "network improvements" which means "all incremental facilities needed to provide electric service to the Large Load Customer while maintaining reliable service to the remainder of the grid, if the Large Load Customer receives the majority of benefits from that incremental facility."
[11] Appendix, Model Tariff, "Collateral Requirements" Section

ratepayers from bearing stranded infrastructure costs if Large Load Customers fail to materialize, terminate service prematurely, or breach contractual commitments. The collateral is not punitive—it directly corresponds to the infrastructure investment EDCs must make upfront to serve the customer. EAP does not oppose recognizing customer creditworthiness in collateral determinations—but mandatory exemptions are not the appropriate mechanism. Discretion should remain between the EDC and the customer for individual case-by-case determinations. Mandating collateral exemptions removes EDC discretion in fundamental risk management decisions.

C. Contributions in Aid of Construction ("CIAC")

EAP supports the Commission's recognition that Large Load Customers may be the primary beneficiaries of network facilities that would historically have been broadly socialized. The fundamental principle—that customers should contribute to infrastructure costs in proportion to the benefits they receive—is sound and consistent with long-standing cost causation principles emphasized throughout EAP and its member companies' comments at this docket. However, as raised above with the term "majority beneficiary," the practical implementation of a "more than half of the benefit"[12] standard presents significant operational, engineering, and jurisdictional challenges.

The Commission's proposal may be unnecessary when considering that almost everything built in the distribution system would in fact be to the direct benefit of, and cost-attributable to, the Large Load Customer, as much of the expense and therefore calculation of benefit across the system happens at the transmission level. EDCs do not rate base transmission-level assets in distribution rates.

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[12] "Seeing as many of the loads at issue here could use most of that capacity or even nearly all of the capacity, we tentatively find that the triggering customer should make a CIAC contribution to offset the cost of the line if they receive more than half of the benefit of this line." Tentative Order, p. 16.

The Commission's 230 kV line example[13] highlights EAP's concerns that the proposed model tariff conflates state and federal jurisdictional assets. A 230kV line is unambiguously a FERC-jurisdictional transmission asset, and, therefore, beyond the scope of the Commission's jurisdiction for ratemaking purposes. A 230 kV facility meeting the FERC network facility requirements must be treated as a network upgrade with rolled-in cost recovery under FERC jurisdiction, regardless of what percentage of capacity one customer initially utilizes. If the PUC orders an EDC to collect CIAC for a FERC-jurisdictional transmission network facility, FERC could find the PUC model tariff CIAC requirement conflicts with its filed and approved transmission tariff requiring rolled-in rate recovery. Pennsylvania EDCs and their affiliated transmission companies cannot implement cost allocation methodologies that conflict with FERC-approved tariffs and orders.

Determining "more than 50% benefit" for each large load interconnection would require an undue study and analysis burden on EDCs. To meet this requirement, utilities would need to undertake detailed power flow studies under multiple system conditions (peak, off-peak, seasonal variations, contingency scenarios); complete long-term projections of how benefit percentages will change as other customers interconnect; and carry out iterative re-analysis as system conditions evolve. Potential disputes could arise between customers, EDCs, transmission owners, and regulators about how to calculate benefits. Ultimately, this analysis burden would significantly extend interconnection timelines—directly conflicting with the "speed to market" needs that customers emphasize and that the Commission recognizes as important for economic development. EAP supports maintenance of adherence to long-standing cost allocation principles.

If the Commission proceeds with a benefit-based test, critical clarifications are needed.

[13] Tentative Order, p.16.

Guidelines should include a definition of how benefits are calculated (capacity basis, energy basis, contingency scenarios, study parameters), whether initial determinations are fixed or subject to adjustment, how parties will resolve disagreements about benefit calculations, how PUC determinations interface with FERC-jurisdictional transmission cost allocation, whether and how customers receive credits if their benefit percentage declines and exactly what "more than half" means (>50.0%? ≥50.0%? >50% with some tolerance band?).

The Commission also asked for interested parties' feedback on mechanisms whereby voluntary CIAC contributions could move projects up in the construction queue or expedite interconnection timelines.[14] It is important to clarify that distribution-level large load interconnection does not operate with a formal "queue" system in the same manner as generation interconnection. The generation interconnection queue – governed by FERC – is a highly structured regulatory construct designed to manage hundreds or thousands of generation projects seeking to interconnect to the transmission system, with strict queue positions, milestone requirements, and withdrawal/restudy protocols. As documented in their *en banc* testimonies and comments, Pennsylvania's EDCs currently manage their own interconnection queues on a first-come, first-served basis determined by when an application is complete (executed study agreement and paid deposit). This non-discriminatory queue management is fundamental to fair utility service obligations.

Payments to a distribution utility will not facilitate or expedite the FERC process or its associated costs.[15] Large load interconnection studies are FERC jurisdictional, and the queue as it

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[14] Tentative Order, p. 16.

[15] On October 10, 2024, the FERC issued a Notice of Inquiry (NOI) initiating a proceeding to examine interconnection issues related to large loads, including data centers, at Docket No. RM25-2-000. See Interconnection of Large Loads, Notice of Inquiry, 189 FERC ¶ 61,043 (2024). FERC is examining whether its existing interconnection procedures and policies adequately address the unprecedented scale and characteristics of large load requests, particularly with respect to transmission system impacts, cost allocation, and coordination between transmission providers and distribution utilities. FERC has indicated its intent to issue a Notice of Proposed

is for this process is not equivalent to the PJM generation queue. Furthermore, CIAC is already covering the associated study costs on the part of the distribution utility. Overpayment of the amount it costs to conduct the study does not mean a study can be completed any faster.

On principle, EAP opposes allowing voluntary CIAC payments to alter queue position[16]. Allowing better resourced customers to "pay to skip the line" raises fundamental fairness and non-discrimination concerns. Smaller customers without significant capital resources cannot access expedited service even if their projects are equally beneficial to the community. Manufacturing facilities, which meet the definition of a Large Load Customer based on peak load, may be delayed because another Large Load Customer can afford to pay extra. Utilities are required under the Public Utility Code to serve customers of the same class in a non-discriminatory manner based on objective criteria, not an ability to pay premiums.[17]

D. Minimum Contract Terms

EAP strongly supports the Commission's recognition that minimum contract terms are essential to protect ratepayers from stranded cost risk. As emphasized throughout the EDC testimonies and comments, Large Load Customers trigger substantial infrastructure investments that must be recovered over time through customer rate payments. To address this reality in a fair and equitable manner, minimum contract terms ensure customers remain connected long enough

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Rulemaking and final rule by April 2026. Given the significant transmission-level impacts of large load interconnections and the jurisdictional overlap between state distribution matters and federal transmission regulation, the Commission's final guidance in this proceeding should be coordinated with and reconcilable to FERC's ultimate framework to avoid conflicts, provide regulatory certainty, and ensure workable implementation for utilities operating under both state and federal jurisdiction.

[16] Queue position is not simply an administrative construct – it reflects utility engineering and operational constraints. Major transmission upgrades require PJM-approved outage windows. These are limited and scheduled based on system reliability needs, not customer payment preferences. Long-lead equipment (transformers, circuit breakers, specialized components) is often ordered based on queue sequence. Reordering the queue disrupts supplier relationships and may actually delay all projects. Construction crews and engineering resources are allocated based on project sequencing. Disrupting the known sequence creates inefficiencies. Moreover, many large load studies are interdependent—later projects in queue are studied assuming earlier projects complete first. Reordering queue invalidates study assumptions and requires re-analysis.

[17] 66 Pa.C.S. § 1303

to justify those investments. However, the appropriate minimum contract length should be tied to cost recovery timelines rather than an arbitrary number of years. EAP recommends a flexible framework that allows contract terms to match the specific financial commitments at stake.

The financial exposure that requires contract protection differs dramatically across large load interconnections. For example, consider the scenario where a 60 MW customer interconnects to an area with available transmission and distribution capacity. This may require only $5 million in customer-specific facilities (100% CIAC paid upfront), minimal network upgrades, and negligible socialized costs. The EDC rate base impact may only be $500,000. A five-year contract may exceed what is necessary to protect this investment. Another scenario may show that five years is too short a timeframe: Take, for example, a Large Load Customer that commits to 150 MW but ramps up over three years: 50 MW in year one, 75 MW in year two, and 150 MW in year three. In this case, infrastructure must be built upfront for full 150 MW capacity, but the early years generate minimal revenue while the full investment remains outstanding. Under this fact pattern, a five-year contract from initial energization may provide only two or three years of full-load revenue, which is insufficient for cost recovery.

For these reasons, EAP does not support a blanket five-year minimum floor that applies to all Large Load Customers in all cases, or even most cases, to justify its usage as a parameter for a model tariff. In many cases, much, if not all, the money (CIAC) collected by a distribution utility to connect a Large Load Customer is collected up-front, well before any five-year contract would expire. The model tariff should instead allow for language already present in existing EDC tariffs that address this issue on a case-by-case basis. Alternatively, the five-year minimum (or any suggested minimum term) should begin when the customer reaches committed full load, not at initial energization. Without this adjustment, a "five year contract" with a three-year ramp provides only two years of full-load cost recovery.

E. Interconnection Studies and Interconnection Agreements

1. Interconnection Timelines

EAP shares the Commission's goal of providing timely, transparent interconnection processes for Large Load Customers. Economic development opportunities require reasonable certainty about timelines and costs. However, several proposed requirements in the model tariff fail to account for the unprecedented complexity, scale, and technical challenges of large load interconnections, which are documented extensively in previous EDC comments in this proceeding. These requirements risk creating perverse incentives, undermining study quality, and potentially exposing ratepayers to liability—while failing to actually accelerate legitimate interconnection timelines.

The Commission proposes that "six months is a reasonable maximum time to complete interconnection studies unless there are exigent circumstances."[18] EAP strongly objects to this proposal as both technically and operationally infeasible for large load interconnections. Large load interconnection studies involve complex, sequential processes that cannot be artificially compressed without compromising technical accuracy.[19] EAP member company comments further identify multiple factors that can significantly extend study timelines beyond six months, regardless of utility diligence.

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[18] Tentative Order, p. 25.

[19] *See* Joint Comments of FirstEnergy Pennsylvania Electric Company, Mid-Atlantic Interstate Transmission, LLC, Keystone Appalachian Transmission Company, American Transmission Systems, Incorporated, and Trans-Allegheny Interstate Line Company (p.5); Comments of PPL Electric Utilities Corporation (p.18); Comments of PECO Energy Company (p.3-4); and Comments of Duquesne Light Company (p.8-9) to En Banc Hearing Concerning Interconnection and Tariffs for Large Load Customers Docket No. M-2025-3054271, dated June 6, 2025.

Position in the interconnection queue is based upon the date when an application is considered complete, which means each application must await completion of other studies ahead of it. A large load application submitted today cannot begin detailed engineering studies until prior applications in the queue complete their studies, because earlier interconnections may trigger system upgrades affecting later studies, the system base case for analysis depends on assumed completion of earlier projects, and resource allocation must prioritize queue order. If 5-10 large load applications are ahead in queue, six months may expire before studies even begin.

Impact analysis completed one day can be altered the next day by interconnection requests filed in other regional transmission systems, even in other states. Pennsylvania's separated transmission/distribution structure requires coordination between EDCs and transmission owners. Most large load requests involve the standards, rates, rules, and policies of the transmission owner along with those of the distribution utility and any guidelines or model tariff should recognize that the details of serving Large Load Customers also requires elements under FERC jurisdiction. For example, while EDCs cannot control transmission owner or PJM study timelines, the proposed six-month deadline, if enacted, would penalize EDCs for delays in FERC-jurisdictional processes. This is particularly salient for projects occurring on the border of EDC service territories, where transmission is handled by different entities across the two utilities, or for distribution-only EDCs that must coordinate with the transmission owner.[20] Large load studies may require re-analysis when new large loads interconnect in adjacent territories affecting power flows, generation interconnections in the PJM queue affect transmission loading patterns, system topology changes due to other utility projects, or PJM identifies regional transmission needs affecting study assumptions.

[20] The neighboring transmission entity may not even be in Pennsylvania which further complicates the study as there may be different requirements at play.

Study delays can also result from customer-side circumstances including design optimization, changes in project scope, site selection considerations, permitting delays, and financing.[21] Another complicating factor is the current supply chain and equipment lead times. During current supply chain conditions, obtaining reliable vendor quotes can take 60-90 days alone. As such, the six-month requirement after which EDCs would be penalized is both unreasonable and confiscatory.

The Commission's proposed six-month maximum is also dramatically shorter than industry standards. In some of the other states cited to as examples in the Tentative Order[22], Indiana (Indiana Michigan Power) does not apply a mandated maximum timeline for interconnection but instead utilizes a reasonable diligence standard. Similarly, West Virginia (Appalachian Power) has no mandated maximum, as timelines are tied to complexity. Virginia's timelines remain under development, but proposals contemplate 9-12 months for large loads.[23]

If forced to complete studies in six months regardless of complexity, shortcuts in analysis may miss critical system impacts, leading to underestimation of required upgrades, cost overruns during construction, and system reliability issues post-interconnection. Such an artificially shortened timeframe may also result in inadequate coordination with transmission owners and PJM, conservative over-design (specifying excessive upgrades to avoid missing requirements), and higher costs for customers due to rushed, inefficient designs.

EAP recommends the Commission establish general principles for timely, transparent interconnection study processes while preserving EDC discretion to establish reasonable timelines

[21] For example, PPL outlined in its prior comments at this docket that many of the variables that cause interconnection delays are not within the EDC's control, such as right-of-way acquisition negotiations or permitting and approval processes. (See PPL Electric Comments at 24-25.)
[22] Again, EAP cautions against direct comparisons to vertically integrated utilities.
[23] Technical Conference held by the Virginia State Corporation Commission on December 12, 2025, PUR-2024-00144 - Flexibility.

based on project complexity and system-specific factors. Rather than imposing a rigid six-month maximum study deadline with automatic penalty provisions—which is technically infeasible for large, complex interconnections requiring extensive transmission coordination, PJM review, and multi-phase engineering analysis—the Commission should continue to allow for EDC flexibility.. This approach recognizes that study timelines vary dramatically based on factors including project size (50 MW vs. 500 MW), voltage level (distribution vs. transmission), available system capacity, geographic location, queue interdependencies, transmission owner coordination requirements, project development dynamics, and supply chain considerations. EDCs commit to processing studies as expeditiously as reasonably possible consistent with technical accuracy, system reliability, and appropriate cost allocation analysis, but arbitrary deadlines with automatic financial penalties would compromise study quality, create perverse incentives, and penalize EDCs for delays beyond their control (transmission owner processes, PJM review, customer-driven changes, permitting issues). The Commission can ensure adequate performance through case-by-case review of alleged unreasonable delays rather than one-size-fits-all mandates that ignore the unprecedented complexity of large load interconnections.

2. Refunds

The Commission also proposes "that failure of an EDC to complete the required studies in a timely manner should result in remuneration to the applicant."[24] This creates inappropriate liability exposure. EDCs would face penalties based on arbitrary deadlines for delays potentially caused by transmission owners, PJM, customers, or external events beyond an EDC's control. Study fees are intended to cover the EDC's actual costs of performing studies, including engineering staff time, contractor fees (e.g., for specialized studies), software and modeling costs,

[24] Tentative Order, p. 25; Appendix, Model Tariff under "Maximum Times for Interconnection Studies."

management and review time, etc. If the EDC has incurred these costs prudently, refunds should not be required. Doing so denies the utility its opportunity to recover prudently-incurred costs, in violation of basic utility ratemaking precedent.[25]

Rather than automatic penalties tied to rigid deadlines, the ultimate model tariff and associated guidelines should affirm EDCs' commitment to completing interconnection studies with reasonable diligence given project complexity and circumstances. If a customer believes an EDC is unreasonably delaying an interconnection, they retain the ability to file a complaint with the PUC documenting timeline commitments made by the EDC, actual timeline experienced, evidence of delay, and alleged harm. The EDC can then demonstrate whether the timeline was in fact met per agreed-to milestones, any delays were justified (customer changes, transmission-owner delays, queue position, etc.) and whether the company exercised reasonable diligence under the circumstances. The PUC can determine an appropriate penalty at that time should it be warranted.

EAP recommends the model tariff's ultimate approach should maintain accountability without rigid mandates that ignore reality, focus on EDC diligence rather than punishing delays beyond EDC control, and preserve study quality by not forcing arbitrary compression and monetary penalties if unrealistic deadlines are not met.[26]

3. Independent Contractor Studies

The Commission also proposes that "after six months, independent studies conducted by approved contractors at the Large Load Customer's expense should be an option if an EDC cannot meet this deadline."[27] EAP has serious concerns about this proposal. Independent contractors would likely require access to detailed system models, proprietary system information, critical

[25] See *Popowsky v. Pa. Pub. Util. Comm'n*, 542 Pa. 99, 665 A.2d 808 (1995).
[26] As raised *supra*, EAP has concerns with establishment of a penalty via guidelines and a model tariff.
[27] Tentative Order, p. 25. Appendix, Model Tariff, under "Maximum Times for Interconnection Studies"

energy infrastructure information (subject to NERC security requirements) to complete their studies. Providing this level of information to third parties raises serious security risks, NERC Critical Infrastructure Protection compliance issues, and liability concerns. EDCs remain ultimately responsible for the safe, reliable operations of their systems. If the independent contractor study misses critical system impacts, specifies inadequate or unnecessary upgrades, or uses flawed assumptions, the EDC will be the one facing the repercussions. The Commission's proposal does not offer a way for the utility to supervise, control, or otherwise audit / approve, review or object to the independent contractor's work, while protecting critical transmission and distribution system information. As discussed above, large load studies are interdependent with other interconnection studies in queue. How would the independent contractor access information about other pending interconnections, coordinate assumptions with studies being performed by the EDC for other customers, and ensure consistency with transmission owner studies and PJM analysis? Further, there is no detail on how a contractor would be deemed "approved" and by whom.

The Commission states interconnection study costs "should not be recovered from other ratepayers."[28] However, if an independent study proves inadequate and the EDC must re-study or if the EDC must review the independent study for accuracy, EDCs and therefore ratepayers will incur costs. EAP recommends this provision be removed from the guidelines and model tariff.

4. Cluster Studies

The Commission also proposes "biannually (2-times per year), during a specified Network Open Season, Large Load Customers may apply for interconnection studies, which will be analyzed as cluster studies." EAP supports the ability of Large Load Customers and EDCs to

[28] Ibid.

utilize cluster study approaches, but the proposal needs further clarification. Requiring customers to wait for next "open season" to apply could delay projects by six months or more before studies even begin. Data centers in particular emphasize "speed to market" as critical factor in site selection. If Pennsylvania requires waiting for next open season while neighboring states accept applications continuously, projects may locate elsewhere. The Commission also proposes that costs for the studies will be allocated to the Large Load Customers requesting the interconnection studies in a "pro rata share."[29] However, it is not clear how pro rata is defined (e.g., by MW capacity, connection costs, equal share as to number of applicants). Cost causation principles suggest costs should be allocated based on each customer's actual system impact, not simply divided equally. But determining each customer's specific impact within a cluster study is complex. For these reasons, EAP recommends maintaining EDC discretion as to the appropriate use and timing of cluster studies.

5. Public Website Disclosure of Applications

The Commission proposes that "EDCs make available on their public websites a list of Large Load Customer interconnection applications by zip code listing the date accepted, the MW interconnection amount sought, and the stage of interconnection study process."[30] EAP strongly opposes this requirement as inconsistent with customer confidentiality, economic development practices, and competitive business interests.

Large load interconnection applications contain or reveal highly sensitive business information. Site location (even if only zip code disclosed) may identify specific parcels under evaluation. Project timing disclosure can permit competitors to learn when a rival is planning development. Load requirement information would reveal the scale of business operations. Public

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[29] Tentative Order, p. 26; Appendix, Model Tariff under "Network Open Season Planning Studies"
[30] Tentative Order, p. 26; Appendix, Model Tariff under "Public Interconnection Queue"

availability of this information would allow a customer's competitors to identify specific markets their rival is targeting, anticipate their capacity additions, adjust their own strategies based on this intelligence, and make agreements to undercut the initial customer's business development. Premature disclosure (that is, at any time prior to the planned disclosure by the customer) can trigger community opposition, generate public relations challenges, and complicate local permitting processes that can jeopardize the development. If Pennsylvania requires public disclosure of interconnection applications, it could result in projects locating in states offering higher standards of confidentiality.

The Commission cites transparency as reason for application disclosure as proposed. However, transparency is already provided through other mechanisms including EDCs' Long-Term Infrastructure Improvement Plans ("LTIIPs"), PJM's public Regional Transmission Expansion Planning ("RTEP") process, base rate cases, and, in particular, Letter of Notification ("LON") and Full Siting Application ("FSA") filings. When EDCs seek to construct facilities to serve large loads, they file LONs or FSAs with the PUC that are publicly available and subject to public comment. These filings provide transparency about specific projects after customers have made firm commitments and projects are ready for public disclosure.

The LON and FSA process specifically address the Commission's transparency objectives without prematurely disclosing confidential business information during the early application and study phase.

Standard interconnection practices treat customer applications as confidential business information. While PJM publishes queue information for generation interconnections (which are fundamentally different), even that information is published only after customers have reached advanced stages and made substantial financial commitments. Early-stage applications are not publicly disclosed with specific location details. FERC-jurisdictional transmission service requests treat customer information as confidential, with public disclosure limited to aggregated system information. EAP is not aware of other jurisdictions that require public website disclosure of large load interconnection applications by location during the study phase; likewise, there has been no compelling public interest case for this kind of disclosure for other "large load" customers, e.g., manufacturing. To the extent that there is a public benefits case for more transparency in these projects specifically, EAP does not believe the PUC nor EDCs are the appropriate conduit for such disclosures.[31]

F. Minimum Demand Charges

EAP agrees with the Commission's assessment that any "demand charge should be tied to the actual need for the utility to recover fixed costs associated with serving that particular customer's load[32], consistent with cost causation and cost-of-service principles..."[33] However, the Commission should clarify that the suggested 80% threshold applies only to the distribution part of the large load system, as that is the only portion under PUC jurisdiction. Minimum demand charges on the transmission side are handled separately and not implicated by an EDC distribution-level tariff. EAP reiterates its points regarding viability / applicability of such a rule in the distribution case from Section C (CIAC) above.

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[31] EAP again raises its initial concerns that this proposal is akin to new regulation and should be subject to further scrutiny, not included in a model tariff.

[32] While the Commission's emphasis on cost causation principles is appropriate, EAP notes that the Tentative Order's reference to tying demand charges to "that particular customer's load" could create confusion about traditional ratemaking methodologies. Pennsylvania utilities do not establish customer-specific rates for each discrete customer; rather, utilities assess costs to serve each *class* of customers and establish rates applicable to all customers within that class. Large load customers meeting the threshold criteria may constitute a distinct customer class for ratemaking purposes or may be included in a broader, large commercial and industrial rate class as appropriate to each EDC, with rates designed to recover class-wide costs. Customer-specific provisions—such as CIAC requirements, financial security amounts, and contract terms—appropriately vary based on individual project characteristics, but the underlying rate structure (demand charges, energy charges) should be established on a class basis consistent with traditional cost-of-service ratemaking. This distinction preserves regulatory consistency and ensures non-discriminatory rates within customer classes.

[33] Tentative Order at pp.28-29.

G. Load Ramp Schedule

EAP supports the Commission's recognition that load ramping schedules should be determined on a case-by-case basis with flexibility to address project-specific circumstances. As the Commission acknowledged, "[t]he determination of appropriate terms involves balancing cost protection for ratepayers with commercial viability, considering local conditions, and ensuring that investments do not result in stranded costs borne by other rate classes, which are unique variables for each EDC, respectively."[34] EDCs need to maintain significant flexibility in establishing load ramping schedules because ramping characteristics vary dramatically from site to site and customer to customer based on phased development plans, technology and operational factors, infrastructure construction sequencing, as well as customer market and business conditions, and financial and permitting considerations.

In lieu of a rigid number, EAP recommends the Commission establish a principle that load ramp schedules should be reasonable, reflect realistic project development timelines, and include appropriate protections ensuring infrastructure cost recovery.

H. Exit or Early Contract Termination Fees

EAP supports the Commission's recognition that exit fees are essential to protect ratepayers from stranded cost risk when Large Load Customers terminate service or significantly reduce contracted capacity before infrastructure investments are fully recovered. The principle that customers should not be able to walk away from infrastructure built to serve them without compensating for unrecovered costs is fundamental to utility cost allocation. However, Pennsylvania EDCs note that current practices vary across companies, and the Commission's

[34] Tentative Order at p. 30.

proposed uniform approach would unduly constrict EDCs as they account for other factors including project costs or the nominal load represented by the related (e.g., 20%) percentage.

Either exit timeline suggested – 42 months or 48 months – may be an overcorrection as the EDC's associated costs have likely already been recovered. For example, if a utility collects full upfront CIAC, it may not require an exit fee as there are no remaining unrecovered costs. An additional fee may represent something above and beyond normal cost of service calculations, as the EDC is balancing the unique facility costs against its revenues for every customer/project. Exit fee formulas should account for system-specific factors. Furthermore, it is not clear from the model tariff or associated guidance how the utility is supposed to collect these fees or how they are to be used and/or applied. For these reasons, EAP suggests leaving exit/early termination provisions to the contracts / agreements between the EDC and the individual Large Load Customer.

I. Interruptible Service and Standby Rates for Large Load Customers

EAP recognizes the potential benefits of interruptible service programs for Large Load Customers and appreciates the Commission's interest in exploring these options. However, it is not clear that there would be much in the way of impact on the portion of supply the EDCs control in these cases. When looking at what we consider large customers today, practically all of the load takes supply directly from electric generation suppliers ("EGSs"), not the EDC. This is likely to remain the case with Large Load Customers, as well. The Commission cannot and should not mandate that EDCs offer customers interruptible distribution or default service.

The Commission notes that interruptible service could help address resource adequacy concerns. However, interruptible service is no replacement for the need to match generation supply and demand, and it is the PJM capacity market that seeks to ensure sufficient generation to meet peak demand. Demand response programs allow load curtailment to substitute for generation capacity on a short-term basis, where interruptible large loads participating in PJM demand response provide genuine system value. This value accrues at the PJM regional level, not specifically to individual EDCs or individual service territories. The local distribution system must be built to serve full load. Interruptible service participating in PJM demand response programs provides regional benefits that should be compensated through PJM mechanisms, not necessarily through reduced EDC distribution rates. Conflating these two value streams creates cross-subsidy issues. Any model tariff design for firm versus interruptible load should be coordinated with PJM's demand response programs.

Overall, any interruptible service should remain a voluntary customer election, not a mandate or condition of service under a Large Load Customer tariff. The Commission should instead establish broad principles and requirements for distribution-level interruptible service and allow each EDC to determine whether and how to offer interruptible service based on operational feasibility. There should be no automatic assumption that interruptiblity equates to lower rates as there is explicit accounting for costs that do not decrease (e.g., infrastructure reliability, backup capacity). The operational, planning, and cost allocation complexities are substantial, particularly for loads at the unprecedented scale currently being contemplated. As the EDCs have previously emphasized in this proceeding, system planning requirements may not differ significantly whether service is firm or interruptible, limiting infrastructure cost savings and justification for rate reductions.

J. Infrastructure Upgrades by Large Load Customers

EAP reiterates its initial comments in opposition to the ability of Large Load Customers to do their own infrastructure upgrades to utility systems so long as they are "required to meet any standards in the Public Utility Code for the inspection, maintenance, and repair of their facilities."[35]

[35] Tentative Order, p. 42.

Allowing third parties to do their own upgrades to the broader electric grid can compromise safety and reliability standards even with the best intentions. Utility infrastructure construction requires specialized expertise developed through decades of experience with specific system characteristics. Even if third-party construction technically meets minimum standards, subtle variations in construction practices can create long-term reliability vulnerabilities that may not be immediately apparent. This creates an unreasonable liability for EDCs. Integration with existing systems presents significant technical challenges that extend beyond simple compliance with specifications. Seamless integration requires detailed understanding of existing infrastructure characteristics, protection schemes, and operational parameters that are often specific to each utility's system. Seamless integration also reflects that large-load customer interconnection often requires material transmission network upgrades; the Commonwealth's transmission utilities must follow applicable PJM rules for such transmission planning. Experience has shown that infrastructure ownership transitions often create confusion regarding maintenance obligations, leading to potential reliability risks and customer disputes.

Perhaps most importantly, EDCs must maintain ultimate operational control over critical infrastructure regardless of construction responsibility. The interconnected nature of the electric system means that equipment failures or operational issues can have cascading effects well beyond the immediate service point. This reality necessitates unified operational control under the utility's established procedures and protocols.

K. Universal Service Cost Allocation

EAP recognizes the critical importance of universal service programs in ensuring that all Pennsylvanians have access to affordable utility service. Hardship funds provide essential assistance to low-income customers and help maintain service continuity for vulnerable populations. EDCs are committed to supporting these programs and appreciate the Commission's focus on ensuring adequate funding as the customer base evolves with the addition of Large Load Customers. However, EAP seeks further clarification on several implementation questions to ensure that any universal service contribution requirements are equitable, legally sound[36], and administratively workable.

Many Large Load Customers operate under long-term service agreements that specify rates and charges. Imposing new contribution requirements could constitute a material change to contract terms. The proposal is defined as an "annual" contribution. This may mean applying a new requirement to existing customers who made location and investment decisions under different rules and subsequently raises fairness questions. Existing large industrial customers who would meet the technical definition of a Large Load Customer (e.g., manufacturing, steel, chemical facilities, etc.) may face competitive disadvantages if suddenly subject to substantial new annual charges not contemplated in their business plans. The Commission should clearly specify whether this suggested requirement would apply to existing customers and, if so, provide appropriate transition mechanisms.

The proposal is also broken down along "peak demand" for purposes of determining contribution level, but peak demand can be measured several different ways: a single month maximum, 12-month rolling average, summer peak, highest interval in a contract year, etc.; whether the peak demand is based on contracted or actual demand; or whether there is impact based on a ramping schedule. Additionally, the model tariff does not specify if or when peak demand should be reassessed for purposes of this contribution.

Given the uniqueness of this proposed requirement, utilities will likely have other operational concerns should this be put into place such as how this contribution should be

[36] EAP believes this requirement is best addressed in a separate regulatory proceeding, not via a model tariff.

collected, what happens if a customer fails to pay, how is this charge reflected, and at what point in the process it should be collected (at the beginning of the contract year, included as a part of financial security requirements, other). These large contributions also raise operational concerns, as they would increase some current hardship fund budgets over 100%, as total annual donations for hardship funds across voluntary customer contributions and utility / shareholder contributions ranged from $68,000 to $1.6 million in 2023.[37] Utilities and their community partners may struggle to distribute this level of funds, negatively impacting the contributions' goal of helping to offset any impact the addition of Large Load Customers has on rates. It may be more fair and more administratively feasible to have such contributions offset the cost of universal service programs generally, not the hardship fund specifically.[38]

In addition, EAP is not aware of other jurisdictions imposing large fixed annual contributions specifically on Large Load Customers.[39] These customers evaluate total cost of service including all fees, contributions, and charges. Annual contributions of $500,000-$1,000,000 affect project economics. Combined with other Pennsylvania-specific requirements suggested in the Tentative Order (financial security, minimum contract terms, CIAC), these

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[37] 2023 PA PUC Universal Service Programs & Collections Performance Report, pp.78-79. https://www.puc.pa.gov/media/3433/2023_universal_service_report-final_rev041525.pdf

[38] The Commission has previously addressed the allocation of universal service program costs among customer classes in *Lloyd v. Pa. Pub. Util. Comm'n*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *aff'd*, 602 Pa. 645, 983 A.2d 74 (2009). In *Lloyd*, the Commonwealth Court upheld the Commission's authority to allocate universal service costs across customer classes based on cost causation principles and policy considerations but emphasized that such allocations must be supported by substantial evidence and reasoned decision-making in the context of formal rate proceedings.

[39] EAP is not aware of other jurisdictions imposing large fixed annual contributions specifically on large load customers outside of negotiated settlements or customer-specific agreements. The Tentative Order references practices in other PJM states (Indiana, Ohio, West Virginia, Virginia), but review of those jurisdictions' large load tariffs does not reveal comparable mandatory hardship fund or universal service contribution requirements in the fixed dollar amounts proposed here ($250,000 to $1,000,000 annually based on MW tiers). To the extent any other jurisdictions have established special universal service contributions for large load customers, such provisions appear to have resulted from comprehensive rate case settlements where the specific customer (or small group of customers) agreed to contributions as part of negotiated terms addressing their unique circumstances, cost allocation, and rate treatment.

additional contribution requirements may create a cumulative burden that disadvantages Pennsylvania.

As highlighted above, while EAP appreciates the intended goal of this provision, achievement of such an objective must be done through the appropriate regulatory mechanism. universal service funding is already handled via USECP[40] proceedings and base rate cases. These established regulatory processes ensure that individual company level funding decisions reflect demonstrated need, are supported by evidence, receive comprehensive stakeholder input, and comply with statutory requirements. A determination that Large Load Customers should contribute to universal service programs at levels beyond what would result from standard cost allocation in rate cases should be made through a separate rulemaking proceeding, USECP proceeding modifications, or case-by-case review in base rate cases, not as a part of a model tariff.

L. Reporting Requirements

EAP recognizes the Commission's legitimate interest in monitoring large load development, understanding system impacts, and ensuring that tariff provisions are functioning as intended to protect ratepayers and support economic development. EAP appreciates the Commission's recognition that much of this information is commercially sensitive and should be protected from public disclosure and disclosure to competitors. However, the proposed reporting requirements raise several concerns regarding administrative burden, confidentiality protection, competitive sensitivity, and alignment with information already provided through other regulatory mechanisms.[41]

[40] Universal Service and Energy Conservation Plan ("USECP") Proceedings. Under 52 Pa. Code Chapter 54, Subchapter O and 52 Pa. Code Chapter 62, EDCs file Universal Service and Energy Conservation Plans with the Commission on a periodic basis.

[41] EAP believes such reporting as contemplated by the Tentative Order establishes a regulatory requirement and is not properly imposed via a model tariff.

While we recognize statutory advocates' important role in protecting consumer interests, EAP has concerns about sharing highly detailed, customer-specific information even under confidentiality agreements. The more aggregated the information, the lower the confidentiality risk. But highly detailed reporting (e.g., "each MW reduction separately identified," investment details by project) creates information that even under confidentiality protection could be inadvertently disclosed through summaries in public documents or inform advocates' positions in ways that indirectly reveal confidential information. The proposal states confidential information should not be provided to "competitively interested stakeholders," but statutory advocates may be stakeholders in other proceedings where this information could indirectly influence positions or arguments.

It is not clear what benefits such a report would have, other than to be "informative"[42] to the Commission. In particular, EAP is concerned with the requested information related to "equity and outreach."[43] Measures taken by EDCs to protect other customers (inclusive of low-income customers) are those already defined by existing regulations and through basic cost-causation principles as highlighted above and in previous EAP comments to this docket. It is unclear what the Commission contemplates a utility would be undertaking and therefore describing under this section. Regarding "disadvantaged communities,"[44] utility services are designed to be non-discriminatory. Utilities do not track the existence of or otherwise have a common definition of "disadvantaged communities" and do not and would not offer different service to such communities. With respect to associated consumer education and outreach, utilities already routinely provide outreach on universal service programs and energy efficiency as a part of existing

[42] Tentative Order, p. 43.
[43] Tentative Order, p. 45.
[44] Id.

regulations and obligations governing those programs. Such efforts are already reported to the Commission and made publicly available and should not be duplicated here.

While EAP appreciates the intent of an additional reporting provision, its associated risks and costs outweigh the benefits and therefore it should be struck in its entirety. Should the Commission proceed with such any associated Large Load Customer reporting requirement, six months is insufficient for EDCs to develop associated reporting systems, templates, and processes. EAP asks that the Commission allow at a minimum 12 months for the first report. The Commission should also provide a standardized template or format for semi-annual reports, ensuring consistency across EDCs and simplifying preparation.

IV. CONCLUSION

Pennsylvania utilities are prepared to work collaboratively with the Commission, stakeholders, customers, and peer utilities to develop and implement large load tariff provisions that appropriately balance all interests and position Pennsylvania as a preferred location for large load development while protecting existing customers and maintaining system reliability.

The Commission's leadership in addressing large load issues is commendable and necessary. However, the path forward needs to respect traditional distinctions between tariff provisions (rates, terms, and conditions of service) and regulatory requirements (broader obligations imposed through formal rulemaking), and any mandatory requirements should be implemented through procedurally appropriate mechanisms. EAP respectfully requests the Commission consider these comments as it moves forward with this important proceeding, and we stand ready to provide additional information or clarification as needed.

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