



Overview

Executive Order 62 directed the Department of Public Service (DPS) to convene the State's transmission owners (TOs) to review the sufficiency of current practices for studying the system impacts of large loads and to report to the Commission within 90 days. New York State has seen a significant increase in large load interconnection requests, driven primarily by data centers. As of September 2026, there are nearly 14 gigawatts of large load requests in the New York Independent System Operator's (NYISO) interconnection queue, with over 8 gigawatts entering in 2025 alone.

DPS convened the transmission owners on August 25, 2026, and issued interrogatory / document requests to each transmission owner on August 18 and 19, 2026. Reports were received from the following TOs: Consolidated Edison Company of New York, Inc.; Orange and Rockland Utilities, Inc.; Niagara Mohawk Power Corporation d/b/a National Grid; New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation, Central Hudson Gas & Electric Corporation, the New York Power Authority, and PSEG Long Island on behalf of the Long Island Power Authority.

Large Load Demand and Intake

The TOs report a significant and accelerating increase in large load interconnection requests by a range of industries. Requests arrive through multiple channels and undergo an initial technical review, which ranges from one week to several months depending on the completeness of customer-provided information. Projects then proceed either through the NYISO's interconnection process for transmission-level or distribution-level projects greater than 80 megawatts, or through a TO study process for projects within their local jurisdiction.

Reported trends include developers targeting existing high-capacity interconnection points, submitting multiple incremental applications to maximize use of available capacity, and submitting requests at varying levels of project maturity. The TOs report that speculative or early-stage requests are prevalent, that they have limited formal mechanisms to identify duplicate or speculative applications, and that limited information sharing processes exist among utilities to flag duplicative requests across service territories. Across the transmission or distribution system TOs reported attrition rates ranging from 11 percent to 38 percent for large load requests.

Study Methodology and Interconnection Process

The TO's current interconnection study methodologies focus on reliability, use industry-standard power flow tools and NYISO's models adapted for local system conditions. Study scope depends on project-specific technical factors, including but not limited to, load size, point of interconnection, load characteristics, and local system conditions.



For NYISO-jurisdictional projects, the process typically involves a System Impact Study taking approximately six to twelve months; a Facility Study taking approximately six to fifteen months for lower-complexity projects; and in some instances, detailed engineering studies to confirm equipment, configurations, or assess modifications, taking approximately four months.

Depending on project characteristics, these studies may be conducted sequentially or concurrently. For projects within local TO jurisdiction, an initial high-level capacity study is completed first, then a detailed load study, with the overall process generally taking one to six months. The full interconnection pathway from initial engagement to energization can span approximately 42 to 80 months depending on project complexity.

The TOs report that the main driver of delays in the study process is incomplete or evolving project information submitted by customers. Additional reported causes include project scope changes, infeasible interconnection points requiring substantial upgrades, pre-existing local capacity constraints, overlapping impacts across multiple projects in development, and lengthy customer decision-making periods.

The TOs report that material costs are generally not incurred until a construction contract or binding agreement is executed, at which point customers post financial security. System capacity is not typically reserved during the study phase and becomes firm only upon the execution of an interconnection agreement.

Service Classification

The TOs report large loads currently receive service under existing service classifications. No separate classification for data centers currently exists, and these customers are evaluated under the same framework as others within their service classification. TOs broadly support consideration of a dedicated large load service classification implemented together with financial protection mechanisms.

Network Upgrades and Cost Estimation

TO cost estimates for interconnection and network upgrades are developed by combining proforma pricing from previously completed scope and competitive procurement for third-party vendor work. For NYISO-jurisdictional projects at the Facility Study stage, cost estimates are generally expected to fall within $-25\%/+50\%$ accuracy if scope and schedule remain unchanged, with broader ranges applied at earlier screening stages.

Network upgrade requirements vary based on project location, load characteristics, and available system capacity that together impact the extent of required infrastructure improvements. All network upgrades required to mitigate reliability impacts associated with a large load project are included in the project cost estimate and assigned to the interconnecting customer.



Cost Allocation

The TOs report that cost allocation follows the "beneficiary pays" principle. Facilities and upgrades required exclusively to serve a large load customers are assigned directly to that customer. Where upgrades provide broader system benefits, costs may be shared, and the large load customers may be responsible for a portion of the total upgrade cost.

Supply Cost Impacts

The TOs generally do not perform separate estimates of electric supply cost impacts attributable to individual large load customers. Supply cost modeling focuses on aggregated load forecasts rather than individual project-level impacts. Customers with loads above applicable thresholds may need to purchase supply based on certain market prices.

Risk Management

The TOs manage financial risk primarily through contractual mechanisms and up-front financial security requirements. Customers fund project-specific facility upgrades and provide financial security, such as letters of credit, bonds, parent guarantees, or cash, before the utility commits significant resources or incurs construction costs.

The TOs report that a large load customer reducing demand after service begins may reduce projected revenues, creating risk that the new load does not offset the cost of the system upgrades completed to serve the large load customers. In those instances, TOs may retain deposits or request additional financial assurance until the load materializes. In the event of project cancellation, costs already incurred are retained from deposits and unspent funds are returned to the customer. For project delays, applicable security requirements remain in effect, and new studies may be needed to complete or conduct additional engineering analyses.

The TOs state that requiring large load customers to fund 100 percent of costs for facilities and upgrades needed exclusively for their interconnection limits stranded asset risk, so that if demand decreases or a project does not proceed, the associated investment is not recovered from other customers.

Conclusion

The TOs broadly conclude that targeted improvements, rather than complete replacement of current frameworks are warranted. The TOs describe their objective as a balanced approach that protects existing customers from cost and credit risk, maintains system reliability, supports responsible economic development, and provides greater certainty for developers, utilities, regulators, and investors as New York prepares for electric growth from large loads.



List of Appendices

- A. Central Hudson Gas & Electric Corporation
- B. Consolidated Edison Company of New York, Inc. / Orange and Rockland Utilities, Inc.
- C. Long Island Power Authority / PSEG LI
- D. Niagara Mohawk Power Corporation d/b/a National Grid
- E. New York Power Authority
- F. New York State Electric & Gas Corporation / Rochester Gas and Electric Corporation

Appendix A

Central Hudson Gas & Electric

Case 26-E-0045

Proceeding on Motion of the Commission to Address Interconnection Reforms for Large Loads.

Report Outline

Executive Order 62 directs the Department of Public Service (DPS) to convene the State's transmission owners, to review sufficiency of current practices for studying the system impacts of large loads, and to report to the Commission within 90 days. To support the development of this requirement, DPS has issued IRs to the TOs with the intent to have the research and responses be the foundational element to develop the report. To ensure the report is consistent across organizations please follow the following outline.

1. Large Load Demand

a. Explanation of intake process for interconnection request

Central Hudson's large load connection process generally consists of six steps: (1) customer engagement and application review; (2) project development and scoping; (3) engineering and design; (4) pre-construction planning and procurement; (5) construction and execution; and (6) project closeout and energization. Intake tasks are completed in Step 1 where the Company engages with customers through in-person meetings and written correspondence. During this initial phase, Central Hudson collects preliminary information such as requested load, industry type, character of service, load shape, power factor and any customer process related impacts. The Company also engages internal subject matter experts for preliminary feedback and general awareness to enable a more productive interconnection process.

b. Summary of inventory – number of projects, MW, project status, etc.

Since 2022, Central Hudson has received applications for four projects requiring a grid connection greater than 10 MW, for a total requested peak load of approximately 290 MW. None of these projects have been interconnected and are currently in various phases from estimating and engineering through the New York Independent System Operator (NYISO) System Interconnection Study (SIS). Central Hudson is focused on progressing these applications expediently, as customer facilities sized to utilize available system capacity can help moderate delivery rates for all customers and support additional manufacturing activity in the Company's service territory.

c. Explanation of trends – application flow, notable categories, etc.

Of the four applications for projects greater than 10MW received since 2022, three have been received since December 2025. Recent applications seek to utilize legacy customer facilities already located near electrical infrastructure.

d. Requests outside NYISO queue

Three of the four applications for projects greater than 10MW received since 2022 are outside of the NYISO queue.

e. Identification and summary of inventory of projects with behind the meter generation, co-located services, or grid flexibility

Two of the four applications for projects greater than 10MW received since 2022 include back-up generators. For the four projects, at this time, Central Hudson is not aware of any co-located services or grid flexibility participation planned.

f. Assessment of ability to identify speculative/duplicated applications

Central Hudson is not aware of duplicate project applications with other utilities. Projects in Central Hudson's queue are generally seeking to adapt existing facilities in the Company's service territory.

g. Findings

To improve transparency and planning accuracy, Central Hudson supports requirements for large load customers to disclose whether they are simultaneously pursuing interconnection requests or parallel development discussions in other jurisdictions or with other New York utilities for the same projects.

2. Study Methodology and Interconnection Process

a. How is the analysis performed to study a large load

i. Assumptions, tools used, when does it take place in the process

Central Hudson has received a limited number of load interconnection requests exceeding 10 MW that required the Company to independently perform impact studies. For projects that are not subject to the NYISO interconnection process, Central Hudson performs an engineering assessment to evaluate the impact of the proposed load on the electric system. This review is initiated upon receipt of a complete application. As part of this review, Central Hudson may perform the analysis internally or utilize a contractor to model the proposed load within power flow software to identify potential thermal overloads, voltage violations, and other system constraints resulting from the incremental load. If violations are identified, Central Hudson evaluates and identifies the electric system upgrades required to mitigate those impacts and maintain safe and reliable system operation. As part of

the impact study process, Central Hudson also seeks to understand the customer's anticipated load profile, operating characteristics, and expected in-service date.

- b. How do methodologies vary between large loads vary from other service classes

While the fundamental study methodology does not vary based on customer type, information regarding the nature of the load, can help refine assumptions regarding load magnitude, load factor, diversity, and peak demand contribution, resulting in a more accurate assessment of system impacts and upgrade requirements.

- c. Process map from request to energization

As described above, Central Hudson's large load connection process generally consists of six steps: (1) customer engagement and application review; (2) project development and scoping; (3) engineering and design; (4) pre-construction planning and procurement; (5) construction and execution; and (6) project closeout and energization. Each stage identifying milestone that closes stage gate, stage timeframe, deliverable or action

- d. Compare stated vs actual timelines for each stage

- e. Timeframes vary based on project size, complexity, permitting requirements, equipment lead times, and required system modifications. Milestones, deliverables, and schedules are tailored to the unique characteristics of the proposed project.

Based on the Company's experience with projects that were not subject to the NYISO interconnection process, impact studies have generally taken approximately four to six months to complete. Actual timelines may vary depending on project size, point of interconnection (POI), system conditions, and overall project scope and complexity.

- f. Describe when utilities begin incurring material costs or reserving capacity, when does the customer post financial security

Central Hudson begins to incur material costs after a construction contract or other suitable agreement is executed by the Company and customer, at which point the customer posts financial security. These agreements include provisions for financial contributions and an outline of deliverables by both the Company and customer, including itemized long-lead time, high-cost materials. Capacity reservation is also established at this stage and is contingent upon the customer meeting any ongoing requirements, financial or otherwise.

- g. What are the main causes of delays, what solutions being explored to reduce cycle time to accelerate this process

The primary factors affecting study duration are project scope, complexity, the extent of system impacts identified during the review, as well as customer-driven changes. Examples include, but are not limited to:

- Whether the project can interconnect to existing electric infrastructure or requires new infrastructure to reach the proposed POI.
- The voltage level at the POI, as projects interconnected at higher voltage levels may require more extensive analysis, including contingency evaluations. In addition, projects meeting applicable NYISO thresholds may be subject to separate NYISO administered study processes and timelines.
- Whether the proposed load is located near other existing or proposed large loads such that cumulative impacts on upstream facilities must be evaluated.
- The magnitude and nature of any thermal, voltage, protection, or equipment loading violations identified during the study and the effort required to develop appropriate mitigation measures.
- Whether the project includes on-site generation, energy storage, or other equipment that requires additional system protection, operational, or reliability review.
- Customer-driven changes to project scope, including modifications to load size, operating characteristics, or proposed in-service dates after the study has commenced.
- The availability and completeness of customer-provided information necessary to perform the analysis.

For large load projects not subject to the NYISO interconnection process, Central Hudson may perform impact studies using internal engineering resources or engage qualified contractors to support study activities. Maintaining access to external engineering support provides flexibility to manage periods of increased study volume and can help reduce potential resource constraints.

In addition, where requested by the customer and appropriate under the circumstances, Central Hudson may perform certain project development activities in parallel with the impact study process to reduce the overall project timeline. Such activities may include executing agreements necessary to initiate engineering design, equipment procurement planning, and other long-lead time development activities.

Central Hudson is also participating in ongoing industry efforts related to large load interconnection processes, including discussions arising from the June 2026

FERC large load proceeding (EL26-69-000). These efforts may inform process improvements and other future enhancements to Central Hudson's internal study practices and requirements as appropriate.

- h. Can you assess the effectiveness of current communications and information flow with LLs and with NYISO

Where a large load customer is the primary entity navigating the NYISO interconnection process, Central Hudson's involvement is one of secondary support. The Company offers no comment on the effectiveness of current communications and information flow when serving a secondary support role. Central Hudson expects communications and information flows to change following implementation of process modifications being developed pursuant to the FERC large load proceeding.

- i. Findings

The Company's large load study methodology and interconnection processes have proven sufficient to date for customers that are not subject to NYISO processes, and interconnection delays are often driven by project-specific factors including interconnection points, permitting complexity, and equipment availability. Continued flexibility is necessary to accommodate utility- and customer-specific scenarios.

For projects that are subject to the NYISO processes, potential process-related improvements such as transparent, clear milestone definitions, adherence to schedules, and the use of coordinated or clustered studies may be able to materially reduce uncertainty during early planning phases. Coordinated cluster studies in particular would add rigor to the interconnection study process and make it possible to evaluate the impact that all pending projects pose to system reliability. Central Hudson is actively participating in industry efforts to respond to the June 2026 FERC large load proceeding, which may address these issues.

3. Service Classification

- a. Explain the service classification currently for large loads

Central Hudson evaluates customer eligibility for service classifications based on the Character of Service descriptions contained within the Company's applicable tariff Service Classification. The Character of Service descriptions establish the

criteria for the appropriate rate classification, including factors such as customer demand (kW), voltage level, and the nature of the service provided.

- b. Describe the different types of facilities that interconnect as large loads today, how many/how many MW

Since 2022, Central Hudson has received applications for 290MW across four projects requiring a grid connection greater than 10 MW.

- c. Explain whether interconnection process is different from other customer classes.

The interconnection process may vary based on the size, complexity, and infrastructure requirements of the customer request.

- d. Findings

Central Hudson supports the consideration of service classes unique to large loads, as they may be appropriate in some cases, but must be implemented in concert with other financial protection mechanisms including minimum contract terms, collateral requirements, or minimum monthly billing requirements.

4. Network Upgrades

- a. Explain how interconnections and network upgrades estimates are developed, the stage they are developed, estimated accuracy, and description of procedures used to develop costs.

The Company estimates large load project costs using a combination of 1) pro forma pricing when Central Hudson has previously completed the scope of work identified; and 2) Requests for Proposals for work identified for third-party vendors.

- b. What different types of interconnection and network upgrade costs are required by LL Ix requests

Any reinforcements needed to support a large load interconnection are considered holistically, and any component of an interconnection or network upgrade cost may need to be provided by the large load customer. Summarize interconnections and network upgrade costs for projects over 24-month period

Central Hudson has not completed any interconnections greater than 10 MW within the previous 24-month period.

- c. Compare actual costs with estimates and explain discrepancies

Central Hudson has not completed any interconnections greater than 10 MW within the previous 24-month period.

d. Findings

Central Hudson's existing cost estimation methodologies remain robust. These approaches are grounded in historical experience, project specific data, prevailing construction practices, and market conditions. Interconnection cost estimates for large loads are inherently sensitive to project timing, scope definition, and prevailing market conditions that are largely driven by developers. Extended timelines can amplify uncertainty in cost estimates, as actual labor availability, material pricing, equipment lead times, and system conditions evolve over time.

5. Cost Allocation

a. Explain whether a large load pays the full cost of interconnection

Where new grid infrastructure is required to accommodate a large load customer, Central Hudson distinguishes between facilities that provide broader system benefits (i.e., network upgrades) and those that are useful, exclusively, to the large load customer (i.e., sole use upgrades). Accordingly, a large load customer may be responsible only for a portion of a system reinforcement if the infrastructure upgrade also benefits the broader customer population, consistent with the "beneficiary pays" principle.

Describe which portion of network upgrade costs are paid by large load

Large load customers are responsible for providing a financial contribution sufficient to cover costs associated with their portion of the system reinforcement, which may be either refundable or non-refundable, including but not limited to refundable deposits, non-refundable deposits, Contribution in Aid of Construction (CIAC), or a facilities charge. To determine this contribution, Central Hudson evaluates whether the anticipated revenues from the new load are sufficient to offset the cost of any required system reinforcements. If projected revenues are insufficient, the customer is required to contribute non-refundable funds to cover the remaining costs, thereby protecting existing customers from increased delivery rates. If projected revenues are sufficient to offset the costs of any required system reinforcements, a refundable deposit may be required until the customer's load materializes. Cost responsibility and customer contributions are determined pursuant to General Information Section 26 of the Company's electric tariff – PSC No. 15 - Electricity.

b. What different types of interconnection and network upgrade costs are assigned to LL, what to others in LL class, what to customers

In general, for large load customers that required system upgrades funded by the Company's capital plan (beyond any upgrades paid directly by the customer through a CIAC) dedicated to the sole use by that large load customer, the Company has recovered costs associated with the investment through a customer-specific facilities charge, which is a charge to recover costs associated with infrastructure upgrades over time. The fee to the customer includes the revenue requirement effect of the Company's capital investment, as well as operation and maintenance (O&M) costs associated with the facilities.

In addition, for all assets in-service contributing to the Company's rate base, an engineering evaluation is made to determine the function of each plant asset and whether it is dedicated, in whole or in part, to serving a specific customer. Any portion of an asset dedicated in part to serving a large customer is allocated specifically to the class in which the customer resides with the remaining parts of the asset benefiting the broader electric system allocated across the broader customer base, as applicable.

- c. How could upgrade costs be recovered or credited to customers over time, what is the process

Upgrade costs can be recovered over time via a facilities charge that updates annually to recover the associated annual revenue requirement and inclusion in rate base, if applicable. Revenues collected from a large load through a facilities charge reduce the revenue requirement for all customers in a base rate proceeding and are therefore credited to customers over time.

- d. Explain how customers are protected from costs created by large load project that does not materialize or uses less capacity than expected

See above with respect to facilities charges – which are assessed independent of metered load – and refundable and non-refundable deposits that may be required from a large load customer.

- e. Findings

Central Hudson has mechanisms in place to address large load cost allocation and recovery, largely implemented through contract provisions. Central Hudson supports the concept of transparent and standardized mechanisms, such as large load-specific tariff terms, to reinforce established “beneficiary pays” principles and customer protections. These could include long-term take-or-pay arrangements, financial guarantees, and clearly defined exit fees. Central Hudson welcomes collaboration with DPS Staff to identify tariff elements that might benefit from updates. Should any modifications to general cost allocation

methodologies be deemed appropriate, Central Hudson recommends standardized principles that can be adopted by each utility as needed.

6. Supply Cost Impacts

- a. Explain whether utilities estimate the electric supply cost impacts from large loads

The Company does not perform a separate estimate of the supply cost impact associated with a large-load customer. Pursuant to the Company's Hourly Pricing Provision, customers with load greater than 300 kW purchasing their supply from Central Hudson are charged the hourly Day-Ahead Market (DAM) Locational Based Marginal Price (LBMP) applicable to Zone G, as published by the NYISO. As a result, the supply costs incurred by these customers are determined directly based on their hourly energy usage and the corresponding NYISO market prices and are not factored into the hedged portfolio purchased on behalf of Central Hudson's full service customers.

Large load customers may also manage their electric supply requirements internally or obtain supply through an established retail access provider. In those circumstances, the customer's supply requirements similarly would not be included when the Company assesses the supply requirements of its full-service customers.

- b. Describe which components the utility actually considers, energy market prices, capacity, ancillary services, congestion, etc.

The company does not consider energy, capacity, ancillary services, congestion, or other market prices when large loads are interconnected.

- c. Describe the procedure used by the company to assess supply impacts

The company does not have any procedure in place to assess supply impacts when large load is proposed.

- d. Findings

Central Hudson does not estimate supply-related cost impacts from large loads.

7. Risk Management

- a. Explain how the financial risk if large load changes demand consumption after service begins

Central Hudson evaluates whether the anticipated revenues from a new load are sufficient to offset the cost of any required system reinforcements. If a large load customer lowers their demand after service begins, the projected revenue may

correspondingly decrease and create a risk that the new load does not offset the cost of system reinforcements. If this risk is present, Central Hudson may withhold a current refundable deposit and to apply to reinforcement costs or request additional finance assurance until the customer's load materializes.

b. Describe the tools or process used to manage risk

See above with respect to facilities charges – which are assessed independent of metered load – and refundable and non-refundable deposits that may be required from a large load customer.

c. Summarize the attrition rate for large load requests over the last 24 months

Within the period covered by this request, Central Hudson has received inquiries and requests for large load service; however, no projects have progressed sufficiently to establish project attrition statistics.

d. How does attrition rate vary compared to stages

Within the period covered by this request, Central Hudson has received inquiries and requests for large load service; however, no projects have progressed sufficiently to establish project attrition statistics by stage.

e. Describe how project costs are handled after a project is cancelled or delayed.

If a project is cancelled due to actions of the customer, the company retains any costs incurred from any posted deposit. Any unspent funds would be returned to the customer. Project delays are handled by time-bound terms in the customer agreement.

f. Findings

Tools to manage financial risk are generally implemented through contract provisions. Refer also to the response to 5.e.

8. Internal process and tools

a. Describe the internal management reports, dashboards, reference materials or other reports used to monitor and manage large load interconnection.

Key attributes included in Central Hudson's internal management reporting include the location of the project, proposed load, basic project status, description of upgrades, and project cost (when available). As projects mature, other attributes such as length of time to complete each stage and in-service date become critical and monitored by affected internal parties.

- b. Describe the reports, how they are used, and what key metrics are tracked

Central Hudson's internal management reports serve to keep all affected internal parties informed about the status of large load projects, and contains attributes of interest for several internal parties including New Business, Engineering, Regulatory, Cost & Rate, Legal, Operations, and Executive personnel. Critical metrics such as Project Status, Estimated In-Service Date and Length of Time to Complete Each Stage are reviewed periodically to track progress. Adjustments are made upon periodic evaluation of key metrics and ongoing interactions with the large load customer. Internal parties at Central Hudson have access to this management report and can monitor progress as needed.

- c. Findings

None, at this time.

9. Overall Findings and Opportunities for improvements and for better management of ratepayer cost impacts

- a. Describe key conclusions

- b. Managed correctly, large load projects present opportunities for both economic development and customer rate moderation. Portions of Central Hudson's system, in particular, have capacity to incorporate smart-sized loads. Central Hudson has mechanisms in place to address large load cost allocation and recovery, implemented primarily through contract provisions. However, the Company supports the PSC's consideration of transparent, standardized mechanisms across utilities statewide, while preserving reasonable process flexibility to address individual utility circumstances. The Company also agrees that established "beneficiary pays" principles are important to protecting customers.

- c. Explain issues or challenges and opportunities for improvement

Central Hudson supports the use of additional financial protection mechanisms to address the unique risks presented by large load customers such as dedicated large load tariffs, minimum contract terms, collateral requirements, minimum monthly billing requirements, and other financial protection mechanisms. The Company recommended identifying tariff elements that may benefit from updates through the ratemaking process in the Joint Utilities' Comments in Response to the Commission's Order Instituting Proceeding and Soliciting Comments Concerning the Interconnection of Large Loads, at 8-9 (May 13, 2026). Any tariff modifications, however, should refrain from disrupting existing commercial arrangements.

Appendix B

Consolidated Edison Company of New York, Inc. / Orange and
Rockland Utilities, Inc.

Case 26-E-0045 — Executive Order 62 Large Load Report

Proceeding on Motion of the Commission to Address Interconnection Reforms for Large Loads

Executive Order 62 directs the Department of Public Service (DPS) to convene the State's transmission owners, to review the sufficiency of current practices for studying the system impacts of large loads, and to report to the Commission within 90 days. To support this requirement, DPS issued Information Requests (IRs) to the Transmission Owners with the intent that the resulting research and responses serve as the foundational element of the report. This document follows the DPS response outline of nine questions and their sub-questions, and consolidates the contributions of Consolidated Edison Company of New York, Inc. (CECONY) and Orange and Rockland Utilities, Inc. (O&R) ("The Companies").

Attached is the Companies' report in response to the DPS Staff request sent on August 25, 2026. This reflects information available as of today. We will supplement promptly if anything material changes.

Executive Summary

The Companies have experienced a significant increase in the number and scale of large load interconnection requests in recent years. Existing intake, study, cost-estimating, cost-allocation, and risk-management practices continue to support the evaluation and interconnection of these projects using established technical, engineering, and regulatory frameworks that protect the broader customer base from significant upgrade costs caused by a single applicant for service.

We find that current interconnection processes are generally effective and supported by established study methodologies and analytical tools. Project timelines are most often affected by the completeness and maturity of project information rather than limitations in study capability, or solely as a result of utility delays. Existing cost-allocation and risk-management mechanisms provide important customer protections and are designed to assign project-specific costs to the customers that cause them.

At the same time, the recent growth in large load activity presents new planning, operational, and cost-allocation considerations. As large load development continues to evolve, there may be opportunities to further strengthen existing frameworks so that costs are allocated responsibly, customers are protected from unreasonable cost impacts, and interconnection processes can continue to be improved.

Reiterating here the previously submitted comments on the PSCs Motion to Address Interconnection Reforms for Large Loads,¹ we believe that a well-designed cost allocation framework for large loads must minimize undue cost shifts from large loads to other customer groups. For example, the Commission should allow utilities to create a separate service classification for large loads and to require large load customers to bear significant responsibility for the recovery of costs incurred to provide them with electric service. However, in recognition of the fact that other customers may derive benefits from upgrades triggered by large loads, the

¹ Case 26-E-0045, *Proceeding on Motion of the Commission to Address Interconnection Reforms for Large Loads*, Comments of Con Edison and Orange and Rockland submitted May 13, 2026.

Commission should consider when, how, and to what extent other customer groups should contribute toward the costs of those upgrades.

Furthermore, given the uncertainty over whether large load projects will reach their expected levels of operation, a robust cost allocation framework should include safeguards against lower-than-expected revenues if projects like data centers are never built or do not ramp up to the requested level of service within a specific time. To reduce this risk, the Commission should set minimum billing requirements that would allow data centers to be billed based on their actual demand or a minimum percentage of the level of service they requested over a specific time, whichever is higher. This would not only support the recovery of costs to which data centers have contributed but should also encourage greater discipline by customers when estimating what level of service they will need and when.

The Commission should also allow utilities to require adequate forms of security from large load customers to limit other ratepayers' financial exposure if a utility makes investments to serve a data center but the data center is not ultimately built, if the data center customer ceases taking service before adequate cost recovery from that customer has occurred, or in the event of unforeseen circumstances.

The Companies determination is that current practices remain effective, while targeted enhancements may be warranted to address the increasing scale and complexity of large load development.

1. Large Load Demand

1a. Explanation of Intake Process for Interconnection Request

Con Edison has two processes for evaluating and providing service to customers. For projects interconnecting at thresholds that meet the NYISO's requirements, the Companies follow the NYISO's tariff through a process described below for Transmission. NYISO's Load Interconnection Procedures apply to load interconnections that are either greater than 10 MW connective at a voltage of 115 kV or above or 80 MW or more connecting at a voltage level below 115 kV. For all other requests for service generally on the distribution system, the Company follows its Schedule for Electricity, P.S.C. No. 10 (Electric Tariff) and the process identified below for Distribution. Throughout this report, where there are separate processes, Con Edison describes each process.

CECONY TRANSMISSION

Projects initiate the interconnection request process by submitting a load interconnection proposal, providing basic information on their load and project characteristics. These include load end-use, profile, interruptibility, power factor, in-service date, association with other projects, point of interconnection, behavior during fault conditions, load step size and ramp rate, load cycling behavior, switching demand, power quality characteristics, power sources and on-site generation characteristics, a one-line diagram, a site plan, and demonstration of site control, among other requirements. Projects also complete a modeling data summary form and provide models and other data for loads, transformers, feeders, tie lines, and reactive support devices, including a dynamics model, so that the project can be appropriately evaluated during study. This information is reviewed before projects proceed to future study phases.

While no formal stage gates currently exist, the process requires several steps. After the Load Interconnection Proposal and NYISO-led System Impact Study and Facilities Study, the project then advances to execution of the Interconnection Agreement. Engineering, Procurement, and Construction activities follow, with schedules determined by project scope and system requirements, eventually leading to final energization.

CECONY DISTRIBUTION

For a request for electric service on the distribution system, applicants for service follow a standard procedure and begin the process by submitting a work request to the Company through the Company's [Project Center](#). For requests of 10 MW or greater, Con Edison typically determines whether service should be provided through a 265/460V transformer vault (low-tension) or high-tension service (primary-voltage electric supply delivered at 4kV, 13kV, 27kV, or 33kV directly to large commercial or industrial customers who own and maintain their own transforming and switching equipment), consistent with General Rule 4.6 of the Electric Tariff. The choice of high- or low-tension service offered by the Company is driven by what is the lowest cost method of providing service to that customer. For customers who are offered a high-tension service connection, Con Edison also discusses the low-tension service option with the customer; if the customer elects the low tension option, the customer is responsible for the cost difference between the high- and low-tension connection. The Company owns and maintains its feeders up to the property line manhole/splice chamber, and the customer designs, installs, owns, and operates all equipment from the property line termination point, including cables, circuit breakers, transformers, and associated equipment. While the customer owns the transforming equipment and switchgear (if one is required to be built to serve the customer), the Company evaluates the design and construction of the substation to ensure there is no adverse impact on the electric distribution system. The process incorporating both design and installation is as follows:

- Customer submission of service request (including detailed load letter) to the Company.
- Company engineering performs a preliminary design review, generating the service determination (service voltage, number of feeders, preferred point of entry, etc.), which is provided to the customer; any cost implications are identified at this stage.
- A kickoff meeting between customer and Company personnel to discuss high-tension service requirements and site-specific issues, including how the Company-related portions of the project can be optimally sequenced against the customer's schedule.
- If the customer is required to pay a cost pursuant to the Electric Tariff, an invoice is generated and must be paid in full before any Company field work.
- The customer develops its substation design to meet the Company's interconnection requirements, submitting design documents at approximately 30% and 60% completion, as well as the finalized design package.
- Company engineering groups perform all reviews and generate a site-specific operating specification.
- The customer completes electrical equipment installation.
- The Company installs primary conduit and cables to the property line manhole/splice chamber.
- Pre-operational testing witnessed by both teams is completed (relay testing, switchgear inspection and operational tests, cable tests, meter installations, etc.).
- Company forces energize each feeder one at a time until the installation is fully energized.

ORU

The process for connecting a large load to the O&R electric system begins when the customer submits an application and supporting project information, including a load description, anticipated ramp-up schedule, and site plan. O&R then conducts initial scoping meetings and may seek information from the customer to better understand the project and its potential system impact. The duration of these initial stages depends on the completeness of the information provided and the complexity of the project. If the project meets applicable New York Independent System Operator (NYISO) thresholds, it may be referred to NYISO under its current interconnection procedures.

Once the project scope is sufficiently defined, the customer executes the required agreements, which may include one or more study agreements, and provides any required deposits or study funding. O&R then performs a System Impact Study to evaluate the effects of the proposed load on the electric system; under the local interconnection process, this study typically takes four to eight months. If the customer agrees, a Facilities Study commences to identify any required system upgrades, facility additions, and non-binding estimated construction costs, typically requiring six to twelve months. For projects subject to NYISO jurisdiction, the customer submits a Load Interconnection Request, participates in scoping activities conducted jointly by NYISO and O&R, and proceeds through the NYISO study process, the duration of which depends on NYISO procedures and queue volume.

1b. Summary of Inventory — Number of Projects, MW, Project Status

CECONY

Forty-eight large load projects have proposed to interconnect to the distribution system between 2022 and the present. The aggregate load for all requests totals approximately 864 MW across New York City and Westchester County. Of the forty-eight projects, twelve were cancelled, one is complete, thirty-one are in design, and four are in construction. Three large load projects have proposed to interconnect to the transmission system, totaling approximately 1,216 MW of peak load (one project at 1,000 MW, one project at 200 MW, and one withdrawn project at 16.5 MW). One was withdrawn prior to any study phase, one has completed the NYISO System Impact Study (SIS), and one is in progress toward completing the SIS.

ORU

Five large load projects have proposed to interconnect to the transmission system between 2022 and the present, totaling approximately 236 MW of peak load. Four are in the design phase pending the Interconnection Agreement, and one has been cancelled.

1c. Explanation of Trends — Application Flow, Notable Categories

CECONY

It is too early to identify a formal trend.

ORU

With only four active load interconnection requests currently in the NYISO queue, it is too early to identify a formal trend.

1d. Requests Outside the NYISO Queue

CECONY

There are 48 large load projects that have proposed to interconnect outside the NYISO queue.

ORU

There is one job request outside the NYISO queue

1e. Inventory of Projects with Behind-the-Meter Generation, Co-located Services, or Grid Flexibility

CECONY

Five of the 48 large load projects proposed to interconnect to the CECONY distribution system have stand-alone battery energy storage systems planned, and there are none on the transmission system. The distribution-connected projects range in export from 16.2 MW to 20.25 MW and in capacity from 80 MWh to 92.66 MWh.

ORU

Two of the five large load projects proposed to interconnect to the O&R transmission system have behind-the-meter emergency generation for critical systems planned.

1f. Assessment of Ability to Identify Speculative or Duplicated Applications

CECONY TRANSMISSION

Under NYISO's current large load interconnection process, subject to NYISO's Open Access Transmission Tariff (OATT) Sections 3.9 and 4.5.8, there are no formal mechanisms by which NYISO or the Transmission Owner (CECONY) can identify speculative or duplicated interconnection requests.

CECONY DISTRIBUTION

Duplicate requests may be found in the design phase through a review of the area using geospatial mapping data via ProceMX. The Company's customer request intake system, the Customer Project Management System (CPMS), has multiple searchable fields such as address or customer name. Speculative requests may be found through a thorough review of the submitted customer documents — looking for inaccuracies or lack of detail — or through customer meetings.

ORU

The O&R New Business Project Management System (NUCON) has multiple searchable fields such as address or customer name. Speculative requests have been reduced by requiring potential customers to formally apply and demonstrate site control for their specific project.

2. Study Methodology and Interconnection Process

2a. How the Analysis Is Performed — Assumptions, Tools, and Timing

CECONY TRANSMISSION

For interconnection requests that fall under the NYISO, the current process described in Sections 3.9 and 4.5.8 of the NYISO OATT and the Transmission Interconnection and Expansion Manual, projects submit a load interconnection proposal and modeling data summary along with models and other data. They then proceed through two main phases of study: a System Impact Study and then a Facilities Study. After the Facilities Study, the project can choose to negotiate and sign an Interconnection Agreement, and additional analysis can occur during the engineering, procurement, and construction phases.

- Analysis types: Con Edison performs Bus Flow Analysis to identify thermal adequacy of substation equipment, as well as Physical Feasibility Analysis. Steady-state, stability, and transfer analyses and any other applicable analyses are performed by NYISO.

- Assumptions: Project modeling assumptions come from validated project models and the modeling data summary. System modeling assumptions come from base cases developed by NYISO and reviewed/approved by Con Edison.
- Analysis tools: PSS®E is used for stability and bus flow analysis; TARA is used for steady-state and thermal/voltage transfer analyses; ASPEN is used for short-circuit analysis.

CECONY DISTRIBUTION

For all other requests connecting to the distribution system, the evaluation of a large load service request begins with a review of customer-submitted documents, including load letters, site plans, one-line diagrams, and equipment specifications. Engineering verifies the information for accuracy, completeness, and consistency; any discrepancies or missing information are returned to the customer for clarification, and meetings may be held as needed. Con Edison's Enterprise Geographic Information System (eGIS) ArcFM mapping system is reviewed to evaluate the existing electric distribution system for the customer location as well as interconnection options.

Once the project scope is confirmed, Con Edison Engineering develops a load estimate and determines the appropriate service configuration, typically either high-tension or 460V low-tension service. Project location and size also influence the complexity of the interconnection. Available transmission, area station, and distribution feeder capacity determine the extent of any required system upgrades and are key factors in both project complexity and interconnection timelines. Primary distribution feeder thermal loading and voltage impact is determined using Poly Voltage Loadflow (PVL) software.

ORU

Analysis of a large load interconnection is conducted during the System Impact Study and subsequent Facilities Study phases to assess the effects of the proposed load on the electric system. For large loads studied locally, Siemens PSS®E and TARA software are used to evaluate steady-state thermal and voltage impacts. Assumptions and base cases are developed using validated models with current system conditions and demand forecasts.

For projects that meet NYISO thresholds, NYISO performs steady-state, stability, transfer, and other applicable analyses as part of its System Impact Study. Base cases developed by NYISO for projects that fall under its interconnection process are reviewed/approved by O&R. If the customer elects to proceed to a Facilities Study, the project is studied again by O&R following acceptance of the NYISO System Impact Study.

2b. How Methodologies Vary Between Large Loads and Other Service Classes

CECONY

Large commercial customers are typically served under SC 9, General Large Service, Service classification does not drive the interconnection study methodology in either case. Study scope is determined by the electrical characteristics of the proposed load and the point of interconnection, not by the customer's service class.

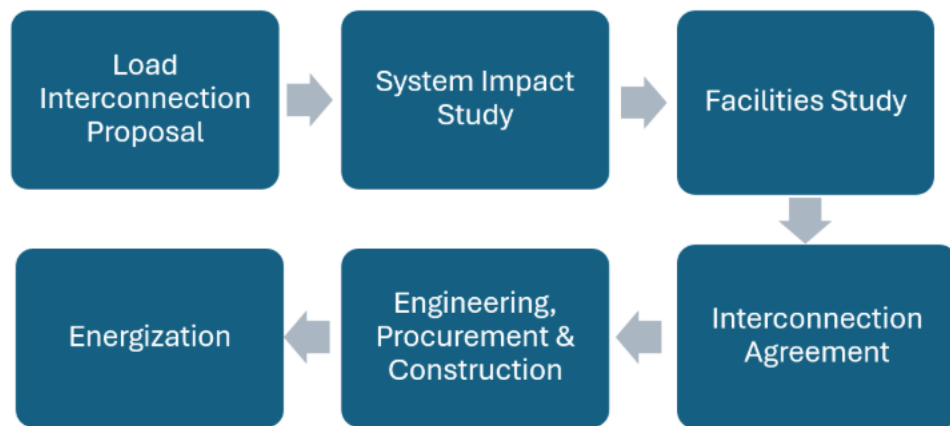
ORU

In O&R, Service Classification for non-residential service is based on requested service voltage, load, and finally type of customer facility. Specific to large loads, O&R's current tariff directs commercial customers who maintain a minimum demand over 1,000 kW taking service at primary or transmission voltages to fall under SC 9; industrial customers, as defined in the Standard Industrial Manual (1987 ed.) as Mining (Division B) or Manufacturing (Division D), fall under SC 22.

2c. Process Map from Request to Energization

CECONY TRANSMISSION

A process map for the transmission interconnection sequence is provided below.



CECONY DISTRIBUTION

The CECONY Distribution process from request to energization is described in Section 1a above.

ORU

The process for connecting a large load to the O&R electric system begins when the customer submits an application and supporting project information, including a load description, anticipated ramp-up schedule, and site plan. O&R then conducts initial scoping meetings and may seek information from the customer to better understand the project and its potential system impact. If the project meets applicable NYISO thresholds, it may be referred to NYISO under its current interconnection procedures.

Once the project scope is sufficiently defined, the customer executes the required agreements and provides any required deposits or study funding. O&R then performs a System Impact Study (typically four to eight months under the local process) and, if the customer agrees, a Facilities Study (typically six to twelve months) to identify required system upgrades, facility additions, and non-binding estimated construction costs. For NYISO-jurisdictional projects, the customer submits a Load Interconnection Request and proceeds through the NYISO study process. Upon completion of the required studies and customer acceptance of the Facilities Study, the customer and O&R negotiate and execute an Interconnection Agreement, including allocation of responsibilities and costs for required facilities and system upgrades. Following execution, detailed engineering and procurement are completed, construction proceeds, and the project undergoes testing and acceptance prior to energization and commencement of service. Customers are generally responsible for application fees, study costs, required deposits, customer-specific facilities, and the costs of any system upgrades necessary for interconnection, as specified in the applicable agreements.

2d. Stage Gates — Milestone, Timeframe, and Deliverable for Each Stage

CECONY

The stage sequence and timeframes are described in Section 1a above.

ORU

The stage sequence is described in Section 1a above.

2e. Stated vs. Actual Timelines for Each Stage

CECONY TRANSMISSION

There are no stated stage timelines, as the Company works through the NYISO process and back and forth with the applicant to efficiently evaluate and provide service.

CECONY DISTRIBUTION

For more standard requests for service, the target completion time for both major project load service determinations and feeder concurrence studies is 30 days. However, large load requests can require additional review time when area station impact studies and complex distribution system analyses are needed. Currently, major project service determinations are completed in an average of 35 days, while feeder concurrence studies average 32 days, both slightly above the established target.

ORU

There are no stated stage timelines at this time as the Company works through the NYISO process and back and forth with the applicant to efficiently evaluate and provide service.

2f. When Utilities Begin Incurring Material Costs or Reserving Capacity, and When the Customer Posts Financial Security

CECONY TRANSMISSION

Security will be posted after the Facilities Study is performed and identifies the costs.

CECONY DISTRIBUTION

The timing of material costs and financial security for CECONY Distribution is described in Section 1a above.

ORU

Upon completion of the required studies and customer acceptance of the Facilities Study, the customer and O&R negotiate and execute an Interconnection Agreement, including the allocation of responsibilities and costs for any required facilities and system upgrades. Following execution of the agreement, detailed engineering and procurement activities are completed, after which construction proceeds. The project then undergoes testing and acceptance prior to energization. Customers are generally responsible for application fees, study costs, required deposits, customer-specific facilities, and the costs of any system upgrades necessary for interconnection, as specified in the applicable agreements.

2g. Main Causes of Delay and Solutions Being Explored to Reduce Cycle Time

CECONY TRANSMISSION

The causes of delays for interconnection studies could be driven by a variety of different factors. Some projects could be proposed with only an end-use type in mind (e.g. a data center), but no specific customer and significant uncertainty about future facility design specifics. When project models are incomplete, inaccurate, or based on generic placeholder facilities, system impact studies may need to be repeated and network upgrades revisited if an actual facility later partners with the company who initially submitted the interconnection request.

A solution being explored is the potential new large load interconnection process in development by NYISO, in collaboration with the New York Transmission Owners (NYTOs) and other stakeholders, in response to FERC Show Cause Order EL26-69-000 dated June 18, 2026. This approach could accelerate large-load interconnection studies by replacing the

individual study process with a structured cluster process that may include stringent data-submittal requirements and financial commitments for large-load projects to advance to subsequent stages of the process. These measures could encourage customers to submit more developed interconnection requests. More complete project proposals could reduce the likelihood of changes that can affect other projects' schedules, shifting upgrade costs, or triggering restudies. NYISO is expected to submit the approach as a compliance filing to FERC on November 16, 2026.

CECONY DISTRIBUTION

Interconnection study timelines are often affected by feeder loading constraints, clustered or rapid customer load growth, and limited substation capacity. Projects in developed areas may require extensive analysis to assess thermal loading, voltage performance, contingency conditions, and equipment ratings. Where capacity deficiencies are identified, additional studies and infrastructure upgrade planning may be necessary before an interconnection can proceed. Thorough documentation reviews during the triage phase can significantly reduce delays and minimize rework once the study is underway, and customer familiarity with the Company's interconnection process and design standards is critical to maintaining schedules. Proactive customer outreach and engagement before application submission helps ensure that documentation is complete, accurate, and consistently formatted, reducing clarification requests and expediting review.

ORU

For large load requests processed under the Company's local interconnection procedures, the stated timeline for a System Impact Study is generally four to eight months, followed by a Facilities Study that typically requires an additional six to twelve months. For projects that meet NYISO thresholds, the timeline includes NYISO-administered study phases dependent upon NYISO's procedures, workload, and queue conditions. Actual timelines may vary depending on project complexity, the completeness and quality of customer information, study assumptions, data availability, coordination with NYISO and neighboring utilities, and the need for additional analyses.

Delays may result from incomplete or evolving project information, changes in scope or load characteristics, delays in executing study agreements or providing funding, resource constraints, and dependencies on other queued projects. The primary means of facilitating timely completion is for customers to provide complete and accurate project information early, respond promptly to inquiries, execute required agreements in a timely manner, and provide all required study deposits or funding without delay. The Company evaluates requests in accordance with established processes and does not provide preferential study treatment outside of applicable tariff or procedural requirements.

2h. Effectiveness of Current Communications and Information Flow with Large Loads and with NYISO

CECONY

Communication and information exchange between the Company, large load customers, and the NYISO (transmission only) is generally effective and support coordination throughout the interconnection study process. At times, the process can become more challenging when project information is incomplete or changes as a project develops, and extended timelines are frequently influenced by factors outside the utility's control, such as customer financing, equipment procurement lead times, permitting requirements, and environmental approvals. Continued coordination among relevant stakeholders and large load developers is important as large load interconnection activity continues to grow.

ORU

Generally, the effectiveness of communication and information flow has been assessed through regular meetings with the customer and feedback obtained during each phase of the interconnection process. For NYISO-studied projects, information is exchanged with the customer through the NYISO-administered System Impact Study (SIS) process.

Finding. The Companies apply established, tool-supported study methodologies at both the transmission and distribution levels. However, the large load study process is not yet governed by formal stage gates or stated stage timelines, and the principal driver of delay is less developed or incomplete project information rather than study capability — a condition the NYISO’s large load interconnection reform is intended to address at the transmission level.

3. Service Classification

3a. Service Classification Currently Applied to Large Loads

CECONY

Large commercial customers connecting to the CECONY system are served under SC 9, General Large Service.

ORU

In O&R, commercial large loads are classified under SC 9, and industrial large loads are classified under SC 22.

3b. Types of Facilities Interconnecting as Large Loads Today — Number and MW

CECONY TRANSMISSION

Large load interconnection requests currently consist of data center facilities. At this time, there are two active large load projects seeking interconnection to the transmission system, representing approximately 1,200 MW of peak load. An additional 16.5 MW industrial infrastructure project was previously proposed and later withdrew from the interconnection process.

CECONY DISTRIBUTION

Of the 48 large load projects proposed to interconnect to the CECONY distribution system, five are distributed energy resources, thirteen are transportation, six are mixed use, three are casinos, eight are data centers, five are real estate developments, four are offices, one is environmental protection, one is a research lab, one is a cruise terminal, and one is temporary construction.

ORU

O&R’s current large load queue includes four proposed data centers (one cancelled) and one pharmaceutical developer.

3c. Whether the Interconnection Process Differs from Other Customer Classes

CECONY

The interconnection process is determined by the system to which the customer connects and the size and characteristics of the load, rather than by service classification. Projects meeting NYISO thresholds proceed under the NYISO interconnection procedures; other requests proceed under the Company's distribution process described in Section 1a. Within the distribution process, requirements differ for customers taking High Tension service under SC 9, and Distributed Energy Resource projects above five megawatts follow the Utility System Impact Study process.

ORU

In O&R, Service Classification for non-residential service is based on requested service voltage, load, and finally type of customer facility. Specific to large loads, O&R's current tariff directs commercial customers who maintain a minimum demand over 1,000 kW taking service at primary or transmission voltages to fall under SC 9; industrial customers, as defined in the Standard Industrial Manual (1987 ed.) as Mining (Division B) or Manufacturing (Division D), fall under SC 22.

Finding. Large loads are served under existing service classifications (CECONY SC 9; O&R SC 9 for commercial and SC 22 for industrial), and no separate classification currently exists for data centers or for transmission-connected large loads.

4. Network Upgrades

4a. How Interconnection and Network Upgrade Estimates Are Developed

CECONY

The Company develops project-specific cost estimates based on the upgrades identified through system studies and engineering evaluations. Estimates are developed using conceptual scope, labor, materials, equipment, contractor costs, project schedule, permitting requirements, outage constraints, and anticipated procurement requirements. At a high level, the process includes:

- Defining the required facilities and scope of work.
- Developing direct labor, material, equipment, and contractor costs.
- Establishing the project schedule.
- Applying escalation assumptions.
- Applying contingency and applicable indirect costs.
- Performing internal review and approval.

ORU

O&R determines cost based on the identified system impacts of the specific project. Solutions to system impacts, if any, are evaluated through Facilities Studies, and high-level cost estimates are developed for any network attachment facilities and/or required network upgrades. In general, the process begins with defining the project scope based on engineering analysis. Cost estimates are then developed for labor, materials, equipment, and contractor services, followed by establishment of a project schedule. Applicable escalation assumptions are incorporated, and contingency allowances and relevant indirect costs are applied. The estimate is then subject to internal review and approval before finalization.

4b. Types of Interconnection and Network Upgrade Costs Required by Large Load Requests

CECONY

As described in Section 4a, estimates are developed using conceptual scope, labor, materials, equipment, contractor costs, project schedule, permitting requirements, outage constraints, and anticipated procurement requirements.

ORU

As described in Section 4a, cost estimates are developed for labor, materials, equipment, and contractor services, followed by establishment of a project schedule; applicable escalation assumptions are incorporated, and contingency allowances and relevant indirect costs are applied.

4c. Summary of Interconnection and Network Upgrade Costs Over the 24-Month Period

CECONY TRANSMISSION

The Company has not completed a transmission-connected large-load project during the previous 24-month period for which final network-upgrade costs are available. Accordingly, representative actual network-upgrade costs are not available for the requested period.

CECONY DISTRIBUTION

The Company does not segregate costs for individual projects into service-specific and network upgrade costs.

ORU

O&R has not had any network upgrade costs associated with large load projects within the previous 24 months.

4d. Comparison of Actual Costs with Estimates and Explanation of Discrepancies

CECONY TRANSMISSION

The Company has not completed a transmission-connected large-load project during the previous 24-month period for which final network-upgrade costs are available. Accordingly, representative actual network-upgrade costs are not available for the requested period.

CECONY DISTRIBUTION

Of the 48 large load projects proposed to interconnect to the CECONY distribution system, one has been completed. That project was ruled service adequate, meaning no upgrades were required.

ORU

O&R has not had any network upgrade costs associated with large load projects within the previous 24 months.

5. Cost Allocation

5a. Whether a Large Load Pays the Full Cost of Interconnection

CECONY TRANSMISSION

The Company does not currently have an executed transmission connected large load project. In the event that we do, we will follow all applicable PSC tariff provisions. We anticipate complying with the beneficiary-pays principle.

CECONY DISTRIBUTION

In some cases for distribution upgrades, Contribution in Aid of Construction (CIAC) payments may be required if the cost of construction exceeds the revenue requirements of a project. If the Company estimates the total construction cost directly attributable to supplying new service to a customer will exceed \$2M, the customer must pay the lesser of (a) the total construction cost in excess of \$2M, or (b) the total construction cost less the product of five times the estimated annual Pure Base Revenue (PBR).

Rider Y of the tariff applies to distribution customers requesting high load-density service exceeding the standard load density for the type of premises, as stated in the Company's applicable engineering specification in effect when the customer's Service Agreement is executed. Those customers are required to pay an Excess Facilities Amount — the difference, as determined by the Company, between (i) the capital costs of the delivery service facilities deemed necessary for the requested service (less any incremental portion incurred to meet the requirements of other specific customers at the time of application), and (ii) the capital costs of the delivery service facilities that would have been provided for service to the same premises at the Standard Load Density (less any comparable incremental portion).

ORU

Customers are generally responsible for application fees, study costs, required deposits, customer-specific facilities, and the costs of any system upgrades necessary for interconnection identified through the study process, as specified in the applicable agreements.

5b. Portion of Network Upgrade Costs Paid by the Large Load

CECONY DISTRIBUTION

As described in Section 5a, CIAC payments may be required where the cost of construction exceeds the revenue requirements of a project (subject to the \$2M threshold test), and Rider Y customers are required to pay an Excess Facilities Amount for high load-density service above the standard load density.

CECONY TRANSMISSION

Network upgrade requirements are identified during the Facilities Study process. The study results determine the extent to which the interconnecting customer is assigned responsibility for upgrade costs in accordance with applicable tariff provisions and the executed interconnection agreement. In the context of transmission upgrades within the CECONY territory, the Company does not anticipate that upgrades installed at the bulk system level would result in any stranded assets.

ORU

The financial risk of stranded assets is minimized by requiring the large load customer to fund 100% of the costs for facilities and upgrades needed exclusively for its interconnection. As a result, if the customer's demand decreases or the project does not proceed as planned, the associated investment is not recovered from other customers.

5c. Costs Assigned to the Large Load, to Others in the Large Load Class, and to Customers at Large

CECONY

In some cases for distribution upgrades, CIAC payments may be required where the cost of construction exceeds the revenue requirements of a project (subject to the \$2M threshold test described in Section 5a). Rider Y applies to distribution customers requesting high load-density service exceeding the standard load density, who are required to pay an Excess Facilities Amount as defined in Section 5a. In the context of transmission upgrades within the CECONY territory, the Company does not anticipate that upgrades installed at the bulk system level would result in any stranded assets.

ORU

The financial risk of stranded assets is minimized by requiring the large load customer to fund 100% of the costs for facilities and upgrades needed exclusively for its interconnection. As a result, if the customer's demand decreases or the project does not proceed as planned, the associated investment is not recovered from other customers.

5d. How Upgrade Costs Could Be Recovered or Credited to Customers Over Time

CECONY and ORU

See section 9 for recommendations.

5e. How Customers Are Protected from Costs of a Large Load That Does Not Materialize or Uses Less Capacity Than Expected

CECONY

The Companies have adequate processes in place in our various tariffs and procedures; however, given the novel issues created by large loads, see the response to question nine for the Company's recommendations.

ORU

The financial risk of stranded assets is minimized by requiring the large load customer to fund 100% of the costs for facilities and upgrades needed exclusively for its interconnection. As a result, if the customer's demand decreases or the project does not proceed as planned, the associated investment is not recovered from other customers.

6. Supply Cost Impacts

6a. Whether Utilities Estimate the Electric Supply Cost Impacts from Large Loads

CECONY and O&R do not estimate the electric supply cost impact from the addition of individual large loads. While the Company models aggregated zonal loads and forecasts, this modeling is focused on the impacts of load growth, in aggregate, for the Company's service areas and overall zonal capabilities. The current modeling workflow is not configured to accept individual large loads.

6b. Components the Utility Considers (Energy Market Prices, Capacity, Ancillary Services, Congestion)

CECONY and O&R do not estimate the electric supply cost impact from the addition of individual large loads. The Companies modeling addresses aggregated zonal loads and

forecasts rather than individual large loads, and the current modeling workflow is not configured to accept individual large loads.

6c. Procedure Used by the Company to Assess Supply Impacts

CECONY

CECONY and O&R do not estimate the electric supply cost impact from the addition of individual large loads. The Companies models aggregated zonal loads and forecasts, focused on the impacts of load growth in aggregate; the current modeling workflow is not configured to accept individual large loads.

Finding. While the Companies have production cost models that are used to forecast supply costs, neither CECONY nor O&R currently estimates the electric supply cost changes attributable to individual large loads. Supply modeling is viewed at an aggregate, zonal level. In the event that distribution of load within the Companies' service areas begins to change due to the addition of large loads to such an the extent that generation dispatch begins to change, production cost modeling can then be conducted to develop estimates of supply costs.

7. Risk Management

7a. Financial Risk if a Large Load Changes Demand Consumption After Service Begins

Both CECONY and ORU have processes or tariffs in place currently that require upfront costs to reduce infrastructure related risk. In addition to those provisions, CECONY has Rider Y. See response to question 5 for additional detail.

7b. Tools or Process Used to Manage Risk

The tools and processes used to manage this risk are the financial security and contractual mechanisms described in Section 5a above, including the maintenance of financial security for assigned cost responsibilities and the anticipated take-or-pay provisions within the interconnection agreement.

7c. Attrition Rate for Large Load Requests Over the Last 24 Months and Variation by Stage

CECONY TRANSMISSION

No large load interconnection requests proposing to connect to the transmission system have withdrawn from the interconnection process during the last 24 months. The attrition rate over that period has been zero. Since no requests have withdrawn, there has been no variation in attrition by project stage. The single withdrawn transmission project reflected in the Section 1b inventory was withdrawn more than 24 months ago.

CECONY DISTRIBUTION

Twenty-four cases were created in the last 24 months with a load of at least 10 MW. Of those, six cases have been cancelled by the customer, and none of the 24 cases have been completed.

ORU

Over the last two years, one of five transmission projects has withdrawn of the interconnection process.

7d. How Project Costs Are Handled After a Project Is Cancelled or Delayed

In the event a large load project is cancelled, the financial security provided by the customer is expected to be applied toward any outstanding obligations associated with the project, including incurred costs for assigned system upgrades. For project delays, applicable security requirements are expected to remain in effect until the customer's obligations have been satisfied in accordance with the applicable tariff provisions and executed agreements and may require system impact studies to be redone or additional engineering analyses to be conducted.

8. Internal Process and Tools

8a. Internal Management Reports, Dashboards, and Reference Materials Used to Monitor and Manage Large Load Interconnection

The Companies maintain project management and financial tracking systems covering all new business requests. Neither company maintains reporting specific to large loads.

8b. How the Reports Are Used and Key Metrics Tracked

Not Applicable, see response to 8a.

9. Overall Findings and Opportunities for Improvement and Better Management of Ratepayer Cost Impacts

9a. Key Conclusions

Current practices are adequate to study and interconnect large loads, but predate the present volume, scale, and speculative character of these requests. The Companies offer the following

1. Demand is growing rapidly, including requests from large loads. Intake processes capture the necessary technical data and provide some ability to identify duplicate or speculative applications at the distribution level, while no equivalent formal screening mechanism currently exists at the transmission level under the NYISO process.
2. Study methodologies are established and tool-supported. The Companies apply these methodologies at both the transmission and distribution levels. The principal driver of delay is less developed or incomplete project information rather than study capability, and the process is not yet governed by formal stage gates or stated stage timelines.
3. Large loads are served under existing service classifications (CECONY SC 9; O&R SC 9 for commercial and SC 22 for industrial), and no separate classification currently exists for data centers or transmission-connected large loads. These customers are therefore evaluated under the same framework as others in their class.
4. Cost-estimating methods are consistent. The Companies develop project-specific cost estimates using a consistent, scope-driven methodology.

5. Cost allocation follows established beneficiary-pays principles, supported by financial security, CIAC, and Rider Y mechanisms², and the Companies do not anticipate stranded bulk-system assets from upgrades installed at the bulk system level.
6. Risk is managed primarily through financial security and contractual obligations to address the risk of demand reduction or premature exit.

The Companies have determined that our existing intake, study, classification, cost estimating, cost allocation, risk management, and monitoring practices remain effective in supporting the evaluation of load interconnection requests. Nevertheless, the unprecedented volume and scale of recent large load requests present new considerations that were not contemplated when these processes were originally developed. Section 9b outlines the associated challenges and opportunities for targeted process enhancements.

9b. Issues, Challenges, and Opportunities for Improvement

Large loads have the potential, in the long run, to contribute substantially to funding the growth and maintenance of the electric system. However, in the short term, the rapid growth in the number and scale of large-load interconnection requests can put significant cost pressure and financial risk on other ratepayers unless additional mitigating measures are adopted.

This evolution of the electricity industry offers an opportunity for the Commission to adopt a cost allocation framework that respects established beneficiary-pays principles, includes safeguards against highly speculative or risky load requests, and thereby prevents unreasonable cost shifts between customers. Where upgrades provide benefits beyond the customer that triggered their development, costs should be allocated beyond that customer in a way that recognizes the shared benefits. Furthermore, given the speculative nature of many large loads and the risk of their premature exit from the market, provisions that assign a commensurate level of financial risk to the large load should be adopted. Finally, we believe rate designs that require large loads to contribute to the cost of the upgrades needed to interconnect them, using volumetric or demand based rates, can be developed. Such rate designs have the benefit of capturing the costs of O&M required to maintain the infrastructure serving the customer, and may facilitate the interconnection of beneficial large loads which may not be capable of providing the capital needed to pay for upgrades.

For New York State, in addition to contributing to the costs of the overall electric system, for costs associated with upgrades triggered by large load customers, the Commission should consider applying:

- A new service class with an associated rate for these large load customers;
- A temporary surcharge to large load customers to fully cover the revenue requirement associated with investments made on their behalf for a specified amount of time;
- Contract Demand requirements to ensure large load customers are contributing to upgrades that their stated requests triggered; and
- Financial security obligations that preclude the risk of unrecovered costs if the large load customer fails to keep up with its financial obligations or exits the market prematurely.

The temporary surcharge will prevent immediate cost impacts to other customers, reduce cost impacts when the unrecovered balance is eventually allocated more broadly after the surcharge

² For CECONY only.

sunsets, and encourage large load customers to right-size their service requests. The financial security requirements will restrict financial risk to the large load customers that create it.

Appendix C

Long Island Power Authority / PSEG LI

Proceeding on Motion of the Commission to Address Interconnection Reforms for Large Loads

Report on Large Load Interconnection Practices, Processes, and Cost Impacts of PSEG Long Island, on Behalf of the Long Island Power Authority

Executive Summary

In response to Executive Order 62 and New York State Department of Public Service (“DPS”) Staff Information Request DPS-08, PSEG Long Island (“PSEG LI”), acting as service provider to and agent of the Long Island Power Authority (“LIPA”), reviewed current practices associated with evaluating, planning for, and interconnecting large electric loads. For purposes of this report, large loads are generally defined as single-site customer loads requiring 10 MW or greater of electric demand.

Since 2022, PSEG LI has received eight identified large load interconnection requests exceeding 10 MW, representing a mix of distribution-connected and transmission-connected projects, including data centers, research facilities, commercial developments, and institutional customers. Five projects remain active while three have been cancelled, resulting in an observed attrition rate of approximately 38%.

Recognizing growing interest from data centers and other large load customers, LIPA and PSEG Long Island have proactively implemented a series of large load initiatives since 2025 to strengthen interconnection processes, enhance planning methodologies, and establish clear customer requirements. These efforts were undertaken in advance of widespread large load development to position the LIPA electric system to efficiently evaluate and accommodate future demand while maintaining system reliability, operational flexibility, and cost causation principles. Key actions have included revisions to the LIPA Tariff for Electric Service (the “Tariff”), the establishment of large load performance requirements, development of formal screening criteria, implementation of large load inclusion rules in load forecasting process, development of process flowcharts, and updates to the PSEG Long Island 2026 Specifications and Requirements for Electric Installations (Red Book) to clarify technical, interconnection, and cost responsibility requirements. Collectively, these initiatives establish a comprehensive and transparent framework for evaluating large load interconnection requests, supporting consistent and efficient decision-making while minimizing the risk of inappropriate cost shifts to existing customers. Several of these actions represented some of the earliest formal utility-led efforts in New York State to address the unique technical, operational, and regulatory challenges associated with the rapid emergence of large load development.

Large load interconnection evaluations are conducted through coordinated transmission and distribution planning processes. The specific characteristics of each project, including its scope, location, load profile, and operational requirements, directly influence the studies required, the complexity of the evaluation, the anticipated project schedule, and the associated costs. In addition, study requirements, timelines, cost responsibilities, and customer obligations vary depending on the proposed point of interconnection and the applicable review process, whether service is provided from the distribution system or the transmission system, including projects subject to the New York Independent System Operator (“NYISO”) Large Load Interconnection Process, as applicable.

1. Large Load Demand

1.1 Intake Process for Large Load Interconnection Requests

The large load interconnection process begins when a customer submits a request for electric service. At a minimum, customers are generally expected to provide a load letter, site information, anticipated demand, desired in-service date, proposed development schedule, and available technical information regarding the planned facility. Depending on the stage of project development, additional information may also be provided concerning load characteristics, operating profiles, phasing plans, backup generation, energy storage resources, and other project-specific requirements.

Upon receipt of a request, PSEG Long Island conducts an initial review of the proposed load, including its magnitude, location, voltage requirements, expected operating characteristics, anticipated point of interconnection, and overall project configuration. This preliminary assessment is used to determine the appropriate service arrangement, identify potential system impacts, establish study requirements, and determine the applicable interconnection pathway.

Depending on the size and characteristics of the proposed load, as well as the proposed point of interconnection, requests may proceed through one or more of the following pathways:

- Distribution service evaluation
- Transmission service evaluation
- NYISO Large Load Interconnection Process, where applicable

The interconnection processes applicable to large load requests, while distinct in their jurisdiction, study requirements, and technical scope, follow a generally comparable structure consisting of screening, engineering evaluation, infrastructure assessment, customer coordination, and service implementation activities. Within that framework, project-specific characteristics such as load magnitude, location, operating profile, development schedule, and point of interconnection significantly influence the scope of engineering studies, planning

assessments, customer obligations, and the transmission or distribution system upgrades required to reliably serve the proposed load. Consequently, although the overall evaluation approach remains consistent, the applicable interconnection pathway and resulting network upgrades, facility modifications, and infrastructure investments vary based on the unique characteristics and system impacts of each project.

Information requirements also evolve throughout the interconnection process as project plans mature and additional engineering assessments are performed. Customers may be requested to provide refined load forecasts, detailed site plans, equipment specifications, phased load growth schedules, point of interconnection information, operating characteristics, permitting status, site control documentation, financial commitment information, dynamic load models, and other technical data necessary to support transmission and distribution planning assessments. This iterative information-gathering process helps ensure that study assumptions remain aligned with the customer's latest project design and allows system impacts, infrastructure requirements, cost responsibilities, and project schedules to be evaluated using the most current information available.

1.2 Inventory Summary

PSEG Long Island reviewed large load interconnection requests received since January 1, 2022, including projects at various stages of development and across multiple interconnection pathways. The review encompassed active and cancelled projects, projects under engineering evaluation, projects progressing through NYISO interconnection procedures, and projects evaluated solely through local transmission or distribution planning processes.

Table 1. Large Load Project Inventory Summary

Project #	Interconnection Process	Peak MW Load	Current Status	Cancelled
1	Distribution	46 MW	Engineering Evaluation	Yes
2	Distribution	36 MW	Engineering Evaluation	Yes
3	Distribution	~10 MW Incremental	Engineering Evaluation	No
4	Distribution	10.6 MW	In-Service	No
5	Distribution	~13.4 MW Incremental	Initial Screening and Scoping	No
6	Transmission (Non-NYISO)	120 MW (50 MW Addition)	Engineering Evaluation	No
7	Transmission (NYISO)	176.6 MW	Engineering Evaluation	No

8	Transmission (NYISO)	300 MW	Initial Screening and Scoping	Yes
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Table 2. Project Portfolio Summary by Interconnection Pathway

Interconnection Process	Total Projects	Active	Cancelled	Peak MW Range
Distribution	5	3	2	~10 MW to 46 MW
Transmission (Non-NYISO)	1	1	0	120 MW
Transmission (NYISO)	2	1	1	176.6 MW to 300 MW
Total	8	5	3	~10 MW to 300 MW

Based on the projects reviewed, the majority remain active and continue to advance through planning, engineering, interconnection, or implementation activities. Three projects were discontinued during the development process, reflecting the evolving nature of large load development and the fact that not all proposed projects ultimately proceed to construction. This corresponds to an observed attrition rate of approximately 38 percent within the reviewed project population. In each case, the project was withdrawn during either the Initial Screening and Scoping phase or the broader Engineering Evaluation phase, prior to reaching construction or in-service status.

The projects reviewed represent a diverse range of customer types and development objectives, including data center developments, research facilities, telecommunications infrastructure, institutional customers, wastewater treatment facilities, and commercial development projects. The inventory also demonstrates that infrastructure requirements can vary significantly among projects, ranging from localized distribution upgrades to more substantial investments such as new substations, dedicated feeders, transmission line upgrades, and other system reinforcements necessary to maintain reliable service.

Overall, the project inventory illustrates that large load interconnection requests are highly project-specific and can differ substantially with respect to development maturity, infrastructure requirements, study complexity, implementation timelines, and associated costs. These observations reinforce the importance of conducting case-specific engineering evaluations and maintaining flexible planning processes capable of accommodating a broad range of customer needs while preserving system reliability, supporting efficient system planning, and minimizing inappropriate cost shifts to existing customers.

1.3 Observed Trends

Review of large load interconnection activity since 2022 indicates several emerging trends in customer development activity, project characteristics, and electric system requirements. While the overall volume of large load requests remains relatively limited, recent activity reflects growing interest in higher load projects and increasing complexity associated with evaluating and accommodating such projects.

Several notable trends have been observed:

- Increased interest from data center developers beginning in 2024 and 2025.
- Increased interest in projects requiring transmission planning review and transmission-level interconnection evaluations.
- Greater use of phased development approaches, where customers propose staged load additions over multiple years rather than a single in-service date.
- Continued refinement of project characteristics throughout the development process, including changes to load magnitude, development phasing, operating assumptions, and proposed points of interconnection.
- Increased need for coordination among customers, PSEG Long Island, NYISO, and other stakeholders as projects grow in size and complexity.

PSEG Long Island has also observed that large load projects frequently evolve as they progress through the development process. Project details provided in initial customer requests often become more refined as customers advance site selection activities, obtain permitting approvals, secure financing, develop operational requirements, and finalize facility designs. As a result, projected load levels, energization schedules, development phasing, operating characteristics, and potential changes to proposed points of interconnection, necessitating updates to study assumptions and additional engineering evaluations.

The project inventory further demonstrates that accommodating large load requests may require a wide range of infrastructure solutions. Depending on the location, size, and interconnection characteristics of the proposed load, serving a project may require new substations, dedicated feeders, transmission line upgrades, or other system reinforcements. The need for such upgrades is often influenced by the magnitude of the requested load and the capability of the existing electric system to accommodate additional demand. In some areas, existing substations and supporting infrastructure have limited capacity or expansion capability, necessitating more extensive facility modifications or the development of new infrastructure to reliably serve the proposed load while maintaining system reliability.

Another notable observation is the level of project attrition and uncertainty that exists during early stages of development. Several projects reviewed during the study period were ultimately cancelled before construction, demonstrating that a customer's initial expression of interest does not necessarily translate into a completed project and that project attrition remains an important

planning consideration. This reinforces the importance of validating project maturity, development readiness, and customer commitments before incorporating large load projects into forecasts, planning assessments, infrastructure investment decisions, and interconnection study activities.

Collectively, these trends reinforce the value of the transmission and distribution planning, interconnection, and forecasting processes already in place across the LIPA system. The trends observed to date also validate the proactive initiatives implemented by LIPA and PSEG Long Island since 2025, including formal screening and load forecasting criteria, issuance of the Performance Requirements for Large Loads Connected to the LIPA System, process flowcharts, updates to the PSEG Long Island Red Book, and Tariff revisions applicable to certain transmission-connected customers. Experience gained through the projects reviewed to date demonstrates that these enhancements were well-founded and have strengthened PSEG Long Island's ability to evaluate project readiness, assess system impacts, establish appropriate customer responsibilities, and accommodate a diverse range of large load projects while maintaining reliability and minimizing inappropriate cost shifts to existing customers.

An industry-wide effort to enhance large load interconnection processes remains underway. In response to the Federal Energy Regulatory Commission's ("FERC") June 18, 2026 Show Cause Order regarding large load interconnections, the NYISO and New York Transmission Owners are currently developing revisions to the NYISO Large Load Interconnection Process intended to enhance the assessment of statewide resource adequacy impacts, bulk power system reliability impacts, and other reliability considerations while also improving overall process efficiency and timeliness. These revisions are expected to be filed with FERC by November 16, 2026 and may further refine the framework used to evaluate large load interconnections across New York. As these efforts progress, the resulting process enhancements may provide additional insights regarding study scope, evaluation criteria, and procedural requirements applicable to future large load interconnection requests.

1.4 Requests Outside the NYISO Queue

Not all large load requests are required to enter the NYISO Large Load Interconnection Process. The applicable interconnection pathway is determined based on the proposed point of interconnection, service configuration, operating voltage, load magnitude, and the results of the engineering evaluation. As a result, large load projects may be evaluated through distribution planning processes, local transmission interconnection processes, or the NYISO interconnection process, depending on the characteristics of the proposed development.

The majority of projects identified during the review period were evaluated through the distribution interconnection processes, while only one non-NYISO related project was evaluated through the local transmission interconnection process. This reflects the diversity of large load

requests received, including differences in project size, development maturity, proposed service arrangements, and electric system requirements. Beyond illustrating the range of interconnection pathways utilized, the non-NYISO projects reviewed demonstrate that substantial planning, engineering, and infrastructure considerations may arise across a wide range of large load requests, regardless of whether the project is subject to NYISO review.

The experience gained from these projects also highlights the importance of understanding project maturity, development readiness, and project viability when making planning, forecasting, and infrastructure investment decisions. As large load activity continues to evolve, it is important that planning assumptions, forecasting methodologies, and interconnection processes appropriately reflect varying levels of project certainty and advancement. Doing so helps ensure that transmission and distribution planning activities, resource adequacy assessments, and interconnection evaluations are appropriately sequenced and informed by project maturity, enabling the aggregate needs of the electric system to be appropriately evaluated while maintaining alignment with actual customer development activity and evolving project plans.

1.5 Projects with Behind-the-Meter Resources, Co-Located Facilities, or Grid Flexibility¹

As part of the large load interconnection review process, PSEG Long Island collects information regarding existing and proposed behind-the-meter ("BTM") resources, co-located facilities, energy storage systems, and participation in grid flexibility programs, where applicable. This information is used to support engineering evaluations, infrastructure planning, operational assessments, and reliability studies, and may be refined as customer development plans mature.

Based on the projects reviewed for this report, the use of BTM and co-located resources remains limited. Most projects did not identify planned co-located generation, energy storage resources, or participation in grid flexibility programs at the time of review. One project identified emergency backup diesel generation intended to support facility resilience and continuity of operations during outage conditions. No projects identified active participation in a grid flexibility program.

While the current project population reflects limited deployment of these resources, customer plans often continue to evolve throughout the development process. As projects advance, additional information may become available regarding backup generation, energy storage capabilities, grid flexibility program participation, or contractual relationships with generation suppliers. Accordingly, resource configurations identified during the initial stages of project

¹ Grid Flexibility refers to a customer's ability to adjust, curtail, or otherwise manage electric demand through participation in programs currently available on the LIPA system such as Dynamic Load Management Program.

development may be refined as customers progress through engineering, permitting, financing, and facility design activities.

1.6 Speculative and Duplicate Requests

As large load development activity has increased, PSEG Long Island has observed that projects enter the interconnection process at varying stages of maturity and with differing levels of certainty regarding ultimate project development. The inventory reviewed for this report includes several projects that were subsequently cancelled during the Initial Screening and Scoping or Engineering Evaluation stages, demonstrating that an initial request for electric service does not necessarily translate into a completed project. These observations reinforce the need to distinguish between preliminary expressions of interest and projects that have demonstrated a meaningful likelihood of advancing to construction and operation.

To support informed planning and forecasting decisions, PSEG Long Island evaluates project readiness and development maturity throughout the interconnection process. Factors that may warrant additional evaluation include:

- Limited or incomplete site control;
- Incomplete development plans or undefined facility configurations;
- Lack of demonstrated financial commitment;
- Significant changes in requested load magnitude or development schedules;
- Changes to the proposed point of interconnection;
- Outstanding federal, state, or local permitting requirements;
- Uncertainty regarding the availability of essential services necessary to support facility operation; and
- Frequent revisions to operating assumptions or phased development plans;

The experience gained from recent large load requests reinforced the importance of evaluating project maturity before incorporating proposed loads into forecasts and planning assessments. To support this effort, PSEG Long Island established a formal review process to evaluate the readiness and viability of proposed large load projects using both quantitative and qualitative information. The review process helps distinguish between preliminary development concepts and projects demonstrating a meaningful likelihood of advancement. It also recognizes the importance of contractual commitments for projects that may require significant transmission or distribution infrastructure investments. Consistent with this objective, LIPA's 2026 Tariff revisions established Interconnection Agreement requirements for transmission-connected customers, providing a framework for defining project obligations, cost responsibilities, and other commitments necessary to support prudent planning and infrastructure development.

This framework helps ensure that planning assumptions, forecasting methodologies, resource adequacy assessments, and interconnection evaluations appropriately reflect varying levels of

project certainty and advancement. By incorporating project maturity into the planning process, PSEG Long Island can better account for speculative, duplicative, or otherwise uncertain requests while ensuring that credible large load developments are appropriately reflected in system load forecasts and planning studies.

1.7 Findings

The review of large load interconnection requests received since 2022 supports several key findings:

- Interest in large load development has increased in recent years, particularly from customers seeking service at load levels significantly above those historically observed within the LIPA service territory.
- Large load requests span a diverse range of industries, including data centers, research facilities, telecommunications infrastructure, institutional customers, wastewater treatment facilities, and commercial development projects. While data center development represents a significant emerging source of load growth, large load activity is not limited to any single customer sector.
- Large load projects vary considerably with respect to size, development maturity, service requirements, operating characteristics, and infrastructure needs. As a result, project-specific engineering evaluations remain necessary to assess system impacts and determine appropriate interconnection requirements.
- Project information frequently evolves throughout the development process as customers refine facility designs, development schedules, operating assumptions, load forecasts, and proposed points of interconnection. Maintaining current project information is therefore critical to effective planning and forecasting.
- Significant infrastructure investments may be required to accommodate certain large load projects, including new substations, dedicated feeders, transmission line upgrades, and other system reinforcements. The extent of these requirements is driven by both the characteristics of the proposed load and the capability of the existing electric system to accommodate additional demand.
- Project attrition observed within the inventory demonstrates that not all large load requests ultimately advance to construction and operation. Accordingly, project maturity, development readiness, and demonstrated customer commitment are important considerations when evaluating future load growth and planning assumptions.
- Early customer engagement, continued coordination throughout project development, and timely exchange of technical information improve study quality, facilitate identification of infrastructure needs, and support more efficient interconnection evaluations.
- The formal screening, forecasting, and planning enhancements implemented by LIPA and PSEG Long Island in 2026, including the establishment of large load evaluation criteria and

project maturity assessments, provide a structured framework for distinguishing between speculative and credible load development and for appropriately incorporating large load assumptions into load forecasts and planning studies.

- The diversity of projects reviewed, combined with the varying levels of project maturity and certainty observed across the inventory, reinforces the importance of maintaining flexible forecasting, interconnection, and planning processes that appropriately account for the aggregate needs of the electric system while remaining aligned with actual customer development activity.
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2. Study Methodology and Interconnection Process

2.1 Methodology Used to Study Large Loads

PSEG Long Island evaluates large load interconnection requests through a structured engineering and planning process intended to ensure system reliability, safety, operational performance, and compliance with applicable LIPA Tariff requirements and NYISO procedures. For purposes of this review, large loads generally refer to customer requests of 10 MW or greater, although key review thresholds under existing utility requirements occur at 1.5 MW, 20 MW, and 40 MW. The evaluation process varies depending on whether the customer is seeking service from the distribution system, transmission system, or a transmission-connected facility applicable to the NYISO process.

The scope of the analysis is tailored to the characteristics of the proposed project and is influenced by factors including the requested load magnitude, point of interconnection, service voltage, customer operating characteristics, anticipated transmission impacts, and project development schedule.

Large load requests are evaluated through a staged engineering process that generally includes preliminary screening, feasibility assessment, system impact analysis, facilities analysis, detailed engineering design, and construction planning. Throughout these stages, PSEG Long Island assesses the potential impacts of the proposed load on both the transmission and distribution systems and identifies any infrastructure modifications required to maintain reliable service.

The evaluation typically includes analysis of thermal loading, voltage performance, short-circuit impacts, dynamic stability, protection coordination, resource adequacy, transmission and distribution system impacts, operational considerations, required system reinforcements, dedicated customer facilities, and interactions with future load growth and planned system improvements.

For facilities classified as Large Load Facilities, defined as facilities with a Maximum Gross Demand of 20 MW or greater, additional evaluations are performed in accordance with the

Performance Requirements for Large Loads Connected to the LIPA System. These assessments include reviews of frequency response, voltage response, power quality, modeling requirements, protection systems, monitoring capabilities, and performance verification requirements.

Tools and Planning Inputs

The evaluation process utilizes a variety of planning models and engineering tools, including distribution and transmission planning models, the Annual Ten-Year Transmission & Distribution Development Study, load forecasting models, and customer-supplied load and dynamic models. Engineering studies may also utilize industry-standard power system analysis software, including PSSE, PowerGem TARA, Aspen OneLiner, CYME, and PSCAD, to evaluate system performance under normal and contingency conditions. Large distribution-connected loads are generally represented within transmission planning models as incremental demand at the serving transmission bus.

Timing of the Analysis

Interconnection review begins once sufficient customer information has been received to support the applicable evaluation and continues throughout the interconnection process. For transmission-connected projects, certain study activities are initiated following execution of the applicable study agreement and receipt of any required customer deposits. Depending on the characteristics of the proposed load and the applicable interconnection pathway, analyses may include initial screening activities, distribution assessments, transmission planning reviews, System Impact Studies, Facilities Studies, detailed engineering design, and commissioning-related assessments. These evaluations generally become progressively more detailed and comprehensive as the project advances through the interconnection process and additional project information becomes available. More rigorous technical analyses, including studies and testing necessary to demonstrate compliance with applicable performance requirements, are typically performed during the later stages of project development, detailed design, and commissioning. Study assumptions, models, and requirements are continually refined as customer plans mature, and the project progresses through the interconnection process.

2.2 Differences from Other Service Classes

The methodology used to evaluate large load interconnections differs significantly from the process applied to smaller commercial and industrial customers due to the potential impacts that large loads can have on both the distribution and transmission systems. While smaller customers are typically accommodated through existing distribution infrastructure and require only localized capacity reviews, large load customers are subject to progressively more comprehensive engineering, operational, and planning assessments.

For smaller commercial and industrial customers, the review process is generally limited to confirming that sufficient capacity exists on the serving distribution feeder and identifying any customer-specific facilities required to provide service. These customers are typically interconnected through existing distribution facilities and are generally responsible only for dedicated infrastructure necessary to serve their load.

In contrast, large load interconnections require detailed evaluations of distribution feeder capacity, substation capability, voltage performance, and potential transmission system impacts. Depending on the size and characteristics of the proposed load, additional studies may include thermal loading assessments, short-circuit analysis, dynamic stability evaluations, protection coordination reviews, resource adequacy screening, and identification of required transmission and distribution reinforcements. Large Load Facilities with a maximum gross demand of 20 MW or greater are also subject to the Performance Requirements for Large Loads Connected to the LIPA System, which impose additional requirements related to system performance, modeling, protection, monitoring, and verification testing.

The level of review also varies based on load size as documented in the PSEG Long Island Red Book. Loads between 1.5 MW and 20 MW are evaluated for distribution circuit capacity and may require dedicated feeders. Loads between 20 MW and 40 MW are subject to additional reviews of distribution and substation capacity and, depending on system capability or customer preference, may be considered for transmission service. Loads of 40 MW or greater are required to interconnect directly to the transmission system. New transmission-metered loads exceeding 10 MW may also be subject to the NYISO Large Load Interconnection Process and associated transmission planning reviews.

As a result, large load customers are subject to additional interconnection requirements, more extensive study processes, negotiated interconnection agreements, and greater cost responsibility than smaller customers. In particular, transmission interconnected load customers are responsible for all costs created by their interconnection request including transmission upgrades whereas distribution customers are only responsible for dedicated equipment.

2.3 Interconnection Process Overview

The process for connecting a large load to the LIPA system varies depending on whether the customer is served from the distribution system, directly from the transmission system, or through a transmission interconnection subject to the NYISO Large Load Interconnection Process. In all cases, the process begins with a customer service request and progresses through engineering evaluations, identification of required system upgrades, execution of agreements, design, construction, and final energization.

For distribution-connected large loads, the process typically begins with defining the load characteristics, including demand, load profile, power factor, operating characteristics, and

development schedule. Following receipt of sufficient customer information, a distribution system assessment is performed to evaluate feeder capacity, substation capability, voltage performance, and the need for distribution upgrades. Results are coordinated with Transmission Planning and incorporated into planning assessments, including the annual Ten-Year Transmission and Distribution Development Study, to identify any broader system impacts and required reinforcements. Upon completion of the engineering reviews, the project advances through detailed design, procurement, construction, and energization.

For transmission-connected large loads not subject to NYISO review, the process begins with initial screening and scoping to establish the point of interconnection and study requirements. This is followed by a System Impact Study to assess thermal, voltage, stability, and reliability impacts and identify preliminary upgrade requirements. If necessary, a Facilities Study is then performed to develop detailed engineering solutions, construction scope, and cost estimates. Once studies are complete, the customer executes the required interconnection agreements and funding commitments before the project proceeds through design, construction, commissioning, and energization.

For projects subject to the NYISO Large Load Interconnection Process, the customer first enters the NYISO application and screening process. Following acceptance, a NYISO System Impact Study is conducted to evaluate bulk power system reliability impacts and identify required upgrades. Upon completion of the NYISO study process, PSEG Long Island performs a Local Facilities Study to develop detailed engineering requirements and cost estimates. The customer then executes the required agreements and satisfies funding obligations before the project advances to detailed design, procurement, construction, commissioning, and final energization.

Regardless of the interconnection pathway, progression through each stage is contingent upon completion of the required technical studies, customer responsiveness, regulatory approvals, and satisfaction of all applicable contractual and financial obligations. The overall objective of the process is to ensure that new large loads can be interconnected reliably, safely, and in accordance with utility, Tariff, and NYISO requirements.

2.4 Milestones, Deliverables, and Timeframes

Stage	Closing Milestone	Typical Timeframe ²	Deliverable
Load Definition	Complete customer technical package	~4 weeks	Load characteristics established

² Timeframes are Project-specific and may be subject to timelines specified in respective agreements.

Distribution Assessment	Utility review complete	~3 months	Capacity evaluation and upgrade needs
Transmission Coordination	Review complete	1-12 weeks	Need for transmission studies identified
Ten Year T&D Development Study	Final Report	Annually	Ten year T&D development plan
System Impact Study	SIS issued	~6-9 months	Reliability impacts and upgrade needs
Facilities Study	Final facilities report	~180 days	Detailed scope and costs
Interconnection Agreement	Agreement executed	Project-specific	Funding obligations secured
Design & Construction	Commissioning complete	Project-specific	Facilities installed
Energization	Service placed in operation	Project-specific	Customer energized
Large Load Performance Requirement Compliance	Models Validated	Project-specific	Validation Report

2.5 Stated Versus Actual Timelines

PSEG LI does not maintain a single set of standard or stated timelines applicable to all large load interconnection requests. The timing associated with evaluating a proposed large load depends on project-specific factors, including the proposed point of interconnection, load magnitude, availability of customer-provided information, study scope, need for system reinforcements, and whether coordination with external entities (*e.g.*, NYISO), is required. Any uncertainty in the plans of interconnection customers can also alter the generic timeline for the studies, especially if the magnitude or the location of load interconnection is not firm.

For projects requiring NYISO review, the NYISO's role is generally limited to conducting a System Impact Study (SIS) to evaluate bulk power system reliability impacts. Following completion and approval of the SIS, projects typically transition to a separate facilities study process conducted directly between the customer and the Connecting Transmission Owner (CTO). The facilities study establishes detailed engineering requirements, local interconnection facilities, construction scope, and associated cost estimates.

For projects requiring formal transmission-level studies, study schedules are typically established through project-specific study agreements. These schedules are developed based on the agreed-upon scope of work and technical requirements associated with the individual project. As such,

stated study durations may vary considerably from project to project and may be subject to confidentiality provisions governing customer-specific information.

With respect to actual timelines, recent large load studies have required substantially longer periods to progress from study initiation through final deliverables and approvals due to project complexity, extensive time required to address multiple customer review cycles including supplemental requests, study revisions, and evolving project assumptions.

Review of large load projects demonstrate that while preliminary study findings may be available within several months of study commencement, actual timelines to complete a large load interconnection study and obtain all required reviews and approvals can extend well beyond one year depending on project-specific circumstances, including the need to address stakeholder and customer comments, evaluate alternative configurations, or incorporate material project changes during the study process.

For large load requests that do not require a formal study agreement, PSEG LI does not maintain a centralized record of planned versus actual study durations. Our primary focus is on supporting customers in achieving their desired in-service dates while meeting project expectations and requirements. PSEG LI works closely with customer needs and energization requirements and accelerates the studies to the extent practical.

For distribution interconnection projects the average time frame is three (3) months. This could be increased if significant challenges are identified as part of the process. One such example is the need for a new property to site a substation to serve the requested load, and the final property location may warrant additional studies.

2.6 Cost Incurrence and Financial Commitments

Material and equipment-related costs are generally not incurred during the initial screening and study phases of a large load interconnection project. Significant financial commitments typically begin only after the required engineering studies have identified the facilities and system upgrades necessary to serve the proposed load and the project advances into detailed design, procurement, and construction planning. At that stage, PSEG Long Island may begin securing long-lead equipment such as transformers, breakers, switchgear, cables, protection systems, telecommunications equipment, and other materials required to support the interconnection.

The timing and nature of customer financial commitments differ depending on the applicable interconnection pathway and the facilities required to serve the load.

For transmission-interconnected load projects, customers are responsible for all costs attributable to their interconnection request, including any required transmission system upgrades. Prior to the commitment of significant utility resources, procurement activities, or construction expenditures, customers are required to execute the applicable agreements and satisfy required

financial security or deposit obligations. These requirements help ensure that substantial investments in transmission facilities and equipment are supported by demonstrated customer commitment and reduce the risk of stranded infrastructure investments.

For distribution-connected projects, customers are generally responsible for the cost of facilities dedicated to serving their load, including customer-specific feeders, transformers, services, and other dedicated infrastructure required to provide electric service. As with transmission projects, procurement and construction activities associated with these customer-funded facilities generally do not proceed until the applicable customer funding obligations have been satisfied.

However, distribution-connected customers are not responsible for transmission system upgrades or other non-dedicated facilities identified through transmission planning assessments. Responsibility for infrastructure investments is determined through the engineering and planning evaluations performed as part of the interconnection process and depends on the type of interconnection, the facilities required to reliably serve the load, and applicable Tariff provisions and interconnection requirements.

Because many transmission and distribution projects involve equipment with extended procurement schedules, material purchases may need to be initiated well in advance of construction to support desired in-service dates. Accordingly, major procurement activities typically commence only after project scope, upgrade requirements, customer responsibilities, and associated financial commitments have been established through the interconnection process.

2.7 Major Delay Drivers and Potential Improvements

Large load interconnection studies are most commonly delayed by incomplete or evolving customer information, changes in load size or Point of Interconnection (POI), complex transmission and distribution upgrades, equipment procurement lead times, permitting and environmental reviews, real estate acquisition, and coordination with NYISO and other stakeholders. For NYISO-jurisdictional projects, additional review and approval requirements can further extend study schedules.

To reduce cycle times, PSEG Long Island has identified several improvement opportunities, including early customer engagement, submission of complete application packages, preliminary engineering reviews, early identification of transmission requirements, timely customer responses to data requests, development of load phasing plans, and enhanced coordination among the customer, utility, and NYISO. Providing customer-owned real estate for required electrical infrastructure can also help avoid delays associated with site acquisition.

Based on recent project experience, many schedule delays are driven by changes in project assumptions after studies have begun. As a result, better project definition and stakeholder

coordination early in the process offer the greatest opportunity to improve schedule predictability and accelerate interconnection timelines.

2.8 Communication Effectiveness

The current communication framework between PSEG Long Island, large load customers, and NYISO is generally effective in facilitating the exchange of technical information necessary to evaluate interconnection requests. The process relies on ongoing coordination throughout the project lifecycle, with customer data, study assumptions, and project requirements being refined as project development progresses. This collaboration supports the timely identification of potential system impacts, required upgrades, performance requirements, and project-specific interconnection obligations.

Communication with large load customers is most effective when the evolving project information is accurately captured throughout the study process. However, any changes to load forecasts, project scope, proposed point of interconnection, and project development schedules can result in additional information requests, study revisions, and extended review timelines. As a result, the quality, completeness, and timeliness of information provided by customers are important factors influencing overall process efficiency. Constant communication is necessary to minimize these issues resulting in additional time delays and to improve process efficiency.

Particularly for larger transmission-connected projects, early development and communication of accurate load models is critical to the study process. Dynamic, transient stability, electromagnetic transient (EMT), and other advanced reliability studies require detailed customer-specific modeling information describing the expected electrical characteristics and performance of the facility. The availability of this information can significantly influence study schedules, as many of the more comprehensive technical evaluations necessary to assess bulk power system impacts and demonstrate compliance with applicable performance requirements are dependent upon the development, validation, and acceptance of these models. Accordingly, timely submission of complete modeling information helps reduce study iterations, facilitates more efficient review, and allows technically complex analyses to commence earlier in the interconnection process.

Overall, the current communication and information-sharing process is technically comprehensive and supports informed decision-making by all parties. Opportunities for improvement include earlier customer engagement, timely development and submission of technical models and supporting data, more complete project information at the outset of the process, and enhanced coordination among customers, PSEG Long Island, and NYISO to reduce iterative reviews and improve schedule predictability.

2.9 Findings

Based on the review of PSEG Long Island's large load interconnection process, several key conclusions emerge. Large load interconnections require significantly more comprehensive engineering and planning assessments than traditional commercial and industrial service requests due to their potential impacts on both the distribution and transmission systems. These evaluations may include distribution and transmission analyses, system impact studies, facilities studies, resource adequacy assessments, and coordination with NYISO, depending on the size and configuration of the proposed load.

Project execution is heavily influenced by customer readiness and the quality of information provided throughout the process. Changes to load forecasts, operating characteristics, project scope, or points of interconnection can require additional study work and coordination among stakeholders. As a result, early project definition and timely information sharing are essential to maintaining an efficient review process.

Communication among customers, PSEG Long Island, and NYISO generally provides a robust framework for technical review and decision-making. However, opportunities exist to improve efficiency through earlier stakeholder engagement, more complete applications, and enhanced coordination during project development.

In response to growing interest from data centers and other large energy users, PSEG Long Island and LIPA have implemented performance requirements, screening criteria, and planning practices intended to provide a more consistent and transparent framework for evaluating large load interconnections while maintaining system reliability and minimizing cost impacts to existing customers.

Overall, the current framework provides a structured and technically rigorous approach to evaluating large load interconnections, with continued improvements focused on enhancing consistency, transparency, and coordination throughout the process.

3. Service Classification

3.1 Current Large Load Service Classification Framework

For purposes of this report, large loads are generally defined as single-site customer loads requiring 10 MW or greater of electric demand. The 10 MW threshold is used for reporting purposes only and does not represent a LIPA service classification or interconnection threshold. The applicable LIPA review thresholds are 1.5 MW, 20 MW, and 40 MW. The 10 MW threshold is relevant because new transmission-metered loads above 10 MW may be subject to NYISO load interconnection procedures and Transmission Planning review. Accordingly, the determination of whether a customer receives distribution or transmission service is based on the

requirements, engineering review, system capability, and customer preferences, rather than load size alone. These requirements are currently set out in the PSEG Long Island Red Book.

Customer service classifications are determined in accordance with the LIPA Tariff, applicable service requirements, and the characteristics of the customer's proposed electric service. All interconnection requests to Transmission System are defined as Transmission connected customers.

The determination process generally includes the following steps:

1. Customer Application

The customer submits a request for electric service, including a load letter, site plan, and other information necessary to evaluate the proposed service requirements.

2. Preliminary Review

PSEG LI reviews the proposed use, anticipated demand, service voltage requirements, and facility characteristics to identify the applicable service classification under the Tariff.

3. Engineering Assessment

Engineering personnel evaluate the requested load, available system capacity, and the facilities required to provide service. This assessment includes review of distribution facilities and, where applicable, transmission system impacts.

4. Service Configuration Determination

Based on the load characteristics, available infrastructure, and applicable Tariff provisions, an appropriate service arrangement is identified, which may include:

- Secondary-metered distribution service;
- Primary-metered distribution service; or
- Transmission service.

5. Customer Facility Requirements

The customer is informed of any facility, equipment, metering, or construction requirements associated with the selected service arrangement.

For example, primary-metered customers are generally responsible for providing and maintaining customer-owned transformers and associated equipment. Customers taking secondary-metered service receive transformer facilities from PSEG LI, subject to applicable Tariff provisions and associated customer charges.

6. Cost Determination

PSEG LI develops an estimate of utility construction costs attributable to the customer's request. Any required customer contributions are collected consistent with Tariff requirements and utility procedures prior to commencement of utility construction activities.

7. Rate Classification Assignment

The customer is assigned the applicable Tariff rate classification based on factors including customer type, service voltage, metering arrangement, and applicable Tariff provisions. For commercial customers, billing demand is generally based on measured peak demand in kilowatts (kW).

3.2 Types of Facilities Interconnected

Since 2022, PSEG Long Island has received large load interconnection requests from a diverse group of customers, including data center developers, research and institutional facilities, healthcare developments, logistics facilities, and large commercial development projects. As interest in electrification and high-density power users continues to grow, data centers have emerged as a significant category of new large load inquiries and interconnection requests.

Based on our review of large load interconnection requests greater than 10 MW received since January 1, 2022, we have identified eight projects within the scope of this review. These projects represent a combination of active, completed, and withdrawn requests and include both distribution-connected and transmission-connected customers. Several of these projects have progressed into formal engineering studies and, where applicable, the NYISO Large Load Interconnection Process.

The project portfolio includes:

- Data center developments and digital infrastructure facilities
- Research and institutional facilities
- Healthcare-related developments
- Large commercial and mixed-use developments
- Wastewater treatment facilities

Overall, current large load activity on the LIPA system is primarily being driven by data center developments, institutional expansions, healthcare facilities, logistics projects, and large commercial developments, reflecting the growing demand for high-capacity electric service across multiple sectors.

3.3 Differences from Other Customer Classes

The applicable interconnection process is generally influenced by the proposed point of interconnection, service voltage, load magnitude, and the results of the engineering evaluation.

Smaller Commercial and Industrial Customers

Smaller commercial and industrial customers are generally interconnected through existing distribution infrastructure. Reviews are typically limited to confirming that sufficient local distribution capacity exists and identifying any customer-specific facilities necessary to provide service. These customers are generally responsible for dedicated facilities required solely to serve their load.

Large Load Customers

As load magnitude increases, additional engineering evaluations may be required to assess impacts on the transmission and distribution system and identify any infrastructure upgrades necessary to reliably accommodate the requested service.

For loads between approximately 1.5 MW and 20 MW, distribution circuit capacity is evaluated and dedicated feeders may be required depending on the size and characteristics of the load. Customers may also request evaluation of transmission service where appropriate. Customers remain responsible for facilities dedicated to serving their load.

For loads between approximately 20 MW and 40 MW, both distribution circuit and substation capacity are evaluated. Where sufficient distribution capacity is not available, or at the customer's request, service from the transmission system may be considered.

For loads of 40 MW or greater, transmission interconnection is generally required.

Distribution vs. Transmission Service

Large loads are not automatically transmission customers. As detailed in the PSEG LI Red Book, loads between 1.5 MW and 40 MW may be served from either the distribution or transmission system depending on system capability, customer preferences, and the results of engineering review. Loads of 40 MW or greater are required to interconnect to the transmission system.

Customers taking service from the distribution system are generally responsible for the cost of dedicated facilities required solely to serve their load, including dedicated feeders and other customer-specific infrastructure.

Pursuant to LIPA Tariff provisions applicable to transmission-voltage service, customers taking service at transmission voltages are subject to transmission rate classifications and additional interconnection requirements. In addition, the LIPA Board of Trustees approved Tariff modifications, effective January 1, 2026, requiring execution of an Interconnection Agreement for customers taking service at or above 23 kV. The filing explains that these customers are typically very large loads and that the Interconnection Agreement establishes requirements related to interconnection, operations, maintenance, and system protection.

Accordingly, transmission interconnection load requests are subject to:

- Review by Transmission Planning;
- Applicable NYISO load interconnection procedures for new transmission-metered loads above 10 MW;
- Execution of a negotiated Interconnection Agreement governing the terms and conditions of service;
- Responsibility for all dedicated facilities required to serve the load; and
- Responsibility for all costs created by their interconnection request including transmission upgrades.

In summary, the interconnection process for large load customers follows the same general objective as that used for other customer classes, namely to identify the facilities and requirements necessary to provide reliable electric service. However, as load magnitude increases and potential impacts on the electric system become more significant, customers are subject to progressively more detailed engineering evaluations, additional interconnection requirements, and, for transmission-interconnected projects, broader responsibilities for system upgrades and associated infrastructure investments.

3.4 Findings

The review of large load interconnection activity and applicable service classification requirements supports several key findings:

- Large load customers are not assigned to a separate service classification solely based on the magnitude of their requested demand. Rather, the applicable service arrangement and interconnection pathway are determined based on engineering evaluations, system capability, service voltage requirements, the proposed point of interconnection, and applicable tariff provisions.
- The existing LIPA and PSEG Long Island framework provides a structured approach for evaluating load requests across a range of load levels. Established review thresholds at 1.5 MW, 20 MW, and 40 MW help guide the level of engineering review and the range of service options considered during the interconnection process.
- Large loads are not automatically required to interconnect to the transmission system. Loads between 1.5 MW and 40 MW may be served from either the distribution or transmission system depending on customer requirements, available system capability, and the results of engineering assessments. Loads of 40 MW or greater are required to take transmission service.
- While the overall objective of the interconnection process is consistent across customer classes, namely to identify the facilities and requirements necessary to provide reliable electric service, larger loads are subject to progressively more comprehensive engineering

evaluations due to their potential impacts on transmission and distribution system facilities.

- The project inventory reviewed for this report demonstrates that large load development spans a broad range of customer sectors, including data centers, institutional and research facilities, healthcare developments, logistics facilities, and large commercial projects. These projects exhibit diverse operating characteristics, infrastructure requirements, and service configurations.
- Transmission-interconnected large loads are subject to additional requirements beyond those typically applicable to distribution-interconnected customers. These requirements may include Transmission Planning review, applicable NYISO interconnection procedures, execution of an Interconnection Agreement, and responsibility for all costs attributable to the interconnection request, including required transmission upgrades.
- The LIPA tariff modifications that became effective January 1, 2026 provide an additional framework for the interconnection of transmission-voltage customers by establishing Interconnection Agreement requirements addressing interconnection, operational, maintenance, and system protection obligations.
- The current service classification and interconnection framework provides flexibility to accommodate a wide range of large load requests while ensuring that engineering evaluations, service arrangements, customer responsibilities, and infrastructure requirements remain aligned with the characteristics and impacts of the proposed load.
- As large load development activity continues to increase, particularly among customers requiring high-capacity electric service, the existing framework provides a consistent basis for evaluating whether distribution or transmission service is appropriate and for identifying the facilities, studies, and customer obligations necessary to reliably serve those loads.

4. Network Upgrades

4.1 Development of Upgrade Estimates

Cost estimates for large load interconnection projects are developed using the same established engineering, estimating, procurement, construction, and project management processes utilized for other transmission and distribution infrastructure projects across the LIPA system. Estimates are prepared by dedicated estimating personnel in coordination with engineering, planning, construction, operations, procurement, and other subject matter experts, with the scope of work driven by the facilities, modifications, and system reinforcements identified through the applicable interconnection studies and engineering assessments.

The estimates are intended to identify the facilities, modifications, and infrastructure investments necessary to reliably accommodate the proposed load while maintaining compliance with applicable planning, operational, maintenance, and reliability requirements. Depending on the size, location, and interconnection characteristics of a project, estimates may include transmission facilities, substations, distribution facilities, protection and control equipment, telecommunications infrastructure, civil works, property acquisition, permitting requirements, and other supporting infrastructure.

Estimate development generally includes:

- Engineering design and scope development;
- Work Breakdown Structure (WBS) development;
- Identification of required transmission, distribution, and customer-specific facilities;
- Procurement and construction cost development;
- Risk and contingency analysis;
- Estimate quality assurance reviews;
- Formal estimate review and approval processes; and
- Estimate reconciliation and refinement as project details become more defined.

Large load interconnection projects are evaluated using the same estimating methodology applied to other utility capital projects, with the primary distinction being the project-specific scope identified through the interconnection evaluation process. Consistent with PSEG Long Island's established estimating procedures, cost estimates are developed through a structured process that includes estimate initiation, estimate classification and development, work breakdown structure development, risk and contingency evaluation, quality assurance reviews, management review, and formal acceptance. As projects advance through engineering and design, estimates are periodically refined to reflect additional technical information, updated scope requirements, and an improved understanding of construction, permitting, procurement, and implementation needs.

For large load interconnection projects, estimated costs may include, as applicable:

- Project management
- Inside Plant engineering and design
- Inside Plant licensing and permitting
- Inside Plant procurement
- Inside Plant construction
- Outside Plant engineering and design
- Outside Plant licensing and permitting
- Outside Plant procurement
- Outside Plant construction

- Transformer installations and replacements
- Cable and conductor installations
- Foundations and civil work
- Switching and isolation equipment
- Protection and control systems
- Telecommunications systems
- Property acquisition and easements
- Environmental compliance requirements
- Risk and contingency allowances

The level of infrastructure investment required can vary considerably among projects depending on the proposed load magnitude, point of interconnection, existing system conditions, and the extent of any required system reinforcements. As a result, cost estimates are inherently project-specific and continue to mature alongside the engineering and interconnection evaluation process. While the estimating process itself is consistent with that used for other utility infrastructure projects, the scope, complexity, and cost of required upgrades are driven by the unique characteristics, location, interconnection requirements, and resulting system impacts associated with each large load request.

4.2 Types of Upgrade Costs

The type and magnitude of costs associated with a large load interconnection are highly dependent on the size, location, operating characteristics, and point of interconnection of the proposed load, as well as the capability of the existing electric system to accommodate the requested demand. Upgrade requirements are identified through the applicable engineering, planning, and interconnection studies and may range from localized facility modifications to more extensive transmission and distribution system reinforcements.

Based on large load projects evaluated during the previous 24 months, network upgrade costs ranged from approximately \$2.3 million to \$9.4 million, depending on the location of the project, load magnitude, interconnection voltage, existing system conditions, and the extent of infrastructure modifications required. Cost estimates continue to be refined as projects progress through engineering, design, permitting, procurement, and construction, and therefore may change as additional information becomes available.

Potential cost components may include, as applicable:

- Distribution feeder installations, extensions, reconductoring, or upgrades;
- Dedicated customer facilities and associated equipment;
- New substations or substation expansions and modifications;

- Transformer installations, replacements, or upgrades;
- Transmission line upgrades, rebuilds, or new transmission facilities;
- Cable and conductor installations;
- Switching and isolation equipment;
- Protection and control systems;
- Telecommunications and communications infrastructure;
- Engineering, design, and project management activities;
- Licensing, permitting, and environmental compliance requirements;
- Civil, structural, and site development work;
- Property acquisition, easements, and real estate requirements;
- Procurement of major equipment and materials;
- Construction labor and contractor services; and
- Risk and contingency allowances.

The project inventory reviewed as part of this report demonstrates the wide range of infrastructure modifications that may be required to serve large loads. Examples identified through recent projects include new substations, dedicated feeders, multiple feeder installations, transmission line upgrades, transmission circuit rebuilds, and transmission-connected substations required to accommodate large load interconnections. In some cases, projects can be served through localized distribution upgrades, while other projects may require substantial transmission and substation reinforcements due to the magnitude of the requested load and the limitations of existing infrastructure.

Upgrade requirements and associated costs are therefore inherently project-specific. They are driven by the facilities necessary to reliably serve the proposed load, maintain compliance with planning and reliability criteria, and address any transmission or distribution system impacts identified through the interconnection evaluation process. As a result, no single cost range or upgrade configuration is representative of all large load interconnection projects, and estimates continue to mature as engineering studies advance and project scope becomes more clearly defined.

4.3 Summary of Recent Costs

The cost of upgrades required to accommodate large load interconnection requests varies significantly based on project-specific conditions, including the magnitude of the requested load, interconnection voltage, location, available system capacity, and the scope of any required transmission or distribution system reinforcements identified through the interconnection evaluation process.

Based on projects evaluated during the previous 24 months, estimated network upgrade costs ranged from approximately \$2.3 million to \$9.4 million. The projects reviewed indicate that

required upgrades can vary considerably in scope, ranging from feeder and substation modifications to more substantial transmission and substation infrastructure investments.

Cost estimates are developed as projects progress through engineering evaluation and are refined as additional information becomes available regarding system impacts, facility requirements, project scope, permitting needs, procurement requirements, and construction considerations. As a result, initial estimates are often planning-level estimates and may be updated throughout the study, design, and implementation phases of a project.

Available project experience also indicates that actual project costs may differ from initial estimates as engineering designs mature and project scope is further refined. Accordingly, cost estimates should be viewed as project-specific and reflective of the information available at the stage of development when the estimate was prepared.

4.4 Actual Versus Estimated Costs

The cost of upgrades required to accommodate large load interconnection requests varies significantly based on project-specific conditions, including the magnitude of the requested load, interconnection voltage, location, available system capacity, and the scope of any required transmission or distribution system reinforcements identified through the interconnection evaluation process.

Based on projects evaluated during the previous 24 months, estimated network upgrade costs ranged from approximately \$2.3 million to \$9.4 million. The projects reviewed indicate that required upgrades can vary considerably in scope, ranging from feeder and substation modifications to more substantial transmission and substation infrastructure investments.

Cost estimates are developed as projects progress through engineering evaluation and are refined as additional information becomes available regarding system impacts, facility requirements, project scope, permitting needs, procurement requirements, and construction considerations. As a result, initial estimates are often planning-level estimates and may be updated throughout the study, design, and implementation phases of a project.

Available project experience also indicates that actual project costs may differ from initial estimates as engineering designs mature and project scope is further refined. Accordingly, cost estimates should be viewed as project-specific and reflective of the information available at the stage of development when the estimate was prepared.

These observations demonstrate that there is no single cost profile applicable to all large load interconnection projects. The facilities required to reliably serve a proposed load, and the associated costs, are determined through project-specific engineering, planning, and interconnection assessments that evaluate the unique characteristics, and system impacts of each request.

4.5 Findings

The review of recent large load interconnection projects supports several key findings regarding network upgrade requirements and associated costs:

- Large load interconnection projects are evaluated using the same engineering, estimating, procurement, construction, and project management processes applied to other transmission and distribution infrastructure projects across the LIPA system.
- The scope of required upgrades is identified through project-specific engineering, planning, and interconnection assessments and is driven by the size, location, operating characteristics, and point of interconnection associated with each proposed load.
- Infrastructure requirements can vary significantly among projects. Observed upgrades associated with recent large load requests included feeder reinforcements, dedicated feeders, substation modifications, new substations, transmission line upgrades, transmission circuit rebuilds, and other transmission and distribution system reinforcements necessary to reliably serve the proposed load.
- Existing system conditions play an important role in determining infrastructure needs. In some cases, projects can be accommodated through localized facility upgrades, while in other cases more substantial reinforcements may be required due to system limitations, available capacity, or the magnitude of the requested load.
- Network upgrade costs observed during the review period ranged from approximately \$2.3 million to \$9.4 million, reflecting the project-specific nature of required facilities and system modifications.
- Cost estimates are developed progressively throughout the engineering evaluation process and are refined as additional information becomes available regarding project scope, system impacts, permitting requirements, procurement needs, and construction considerations.
- Actual project costs may differ from initial estimates as engineering designs mature and project requirements become more clearly defined. Project experience reviewed during this period demonstrated that estimate variances are often driven by scope refinement, improved engineering definition, updated assessment requirements, and the availability of more detailed project information.
- No single upgrade configuration or cost profile is representative of all large load interconnection projects. Required facilities and associated costs depend on the specific infrastructure needed to reliably serve the proposed load while maintaining compliance with applicable planning, operational, and reliability requirements.
- As large load requests continue to increase in size and complexity, maintaining a structured engineering, estimating, and project review process remains important to ensuring that upgrade requirements, project costs, and customer responsibilities are appropriately identified and reflected throughout the interconnection evaluation process.

5. Cost Allocation

5.1 Customer Responsibility for Interconnection Costs

The cost responsibility for a large load depends on the type of interconnection. For distribution-connected large loads, the customer is responsible for the cost of dedicated facilities required solely to provide service, such as dedicated feeders, transformers, and other customer-specific infrastructure. However, distribution-connected customers are not typically responsible for broader transmission system upgrades identified through transmission planning assessments.

For transmission-connected large loads, the customer is responsible for all costs created by its interconnection request, including required transmission system upgrades, dedicated interconnection facilities, and other system modifications identified through the interconnection study process.

5.2 Network Upgrade Cost Responsibility

The portion of network upgrade costs paid by a large load depends on how the customer takes service.

Distribution-connected large loads are responsible for customer-specific facilities needed to serve the load. Under current practices, broader transmission network upgrades identified through planning assessments are generally not directly assigned to distribution-connected customers.

Transmission-interconnected load customers are responsible for all costs attributable to their interconnection request, including transmission network upgrades, local interconnection facilities, and any related system reinforcements required to reliably serve the load.

5.3 Cost Assignment Framework

Cost responsibility depends on whether the large load is connected to the distribution system or the transmission system.

For distribution-connected large loads, customers are generally responsible for dedicated facilities required solely to serve their project, such as dedicated feeders, transformers, and other customer-specific infrastructure. However, they are not typically assigned the cost of broader transmission upgrades identified through the transmission planning process. Those transmission investments are generally recovered through existing utility cost recovery mechanisms.

For transmission-connected large loads, customers are responsible for all costs created by their interconnection request, including interconnection facilities, transmission upgrades, substation

modifications, protection systems, and other required reinforcements identified through the study process.

As a result, customer-specific costs are generally assigned directly to the large load customer, helping protect existing customers from project-specific expenditures. An important exception is that transmission upgrades driven by distribution-connected load growth may be socialized through existing transmission cost recovery mechanisms rather than directly assigned to individual customers contributing to the need.

Overall, the framework is designed to align most upgrade costs with the customer causing the need while recognizing that certain transmission system investments associated with distribution load growth are shared across the system.

5.4 Recovery and Credit Mechanisms

To the extent that network upgrades or interconnection facilities are the responsibility of the large load customer under the applicable tariff or interconnection requirements, those costs are not recovered from, or credited back to, other customers over time.

As a result, other customers benefit from not bearing the costs associated with facilities and upgrades that are attributable to serving the interconnecting large load customer. Any recovery mechanisms applicable to non-customer-funded utility infrastructure are governed by applicable tariffs, regulatory requirements, and cost recovery processes.

5.5 Protection Against Non-Performance

PSEG Long Island employs several measures to limit the risk of stranded assets and inappropriate cost allocation. Distribution Planning reviews customer load forecasts and compares projected demand to actual usage patterns of similar customers using planning data and Advanced Metering Infrastructure (AMI) information. Forecasts are refined through ongoing coordination with customers throughout project development.

Large load projects are also evaluated in phases, allowing infrastructure investments to better align with actual customer development and load growth. This phased approach helps avoid overbuilding facilities that may become underutilized if a project is delayed, reduced in scope, or cancelled.

In addition, transmission-interconnected customers are responsible for all costs created by their interconnection request, including transmission upgrades. Customers are also required to notify PSEG Long Island of material changes to their facilities or operating characteristics, providing additional protection against unnecessary system investments.

5.6 Findings

The review of current cost allocation practices supports several key findings:

- Cost responsibility for large load interconnections is primarily determined by the type of interconnection, the facilities required to serve the load, and the results of the engineering and planning assessments performed during the interconnection process.
- Distribution-connected large loads are generally responsible for facilities dedicated solely to serving their load, including customer-specific feeders, transformers, and other dedicated infrastructure. However, these customers are not typically assigned the cost of broader transmission system upgrades identified through transmission planning assessments.
- Transmission-interconnected large loads are responsible for all costs attributable to their interconnection request, including dedicated interconnection facilities, transmission upgrades, substation modifications, protection systems, and any other system reinforcements required to reliably serve the load.
- The current framework largely follows cost-causation principles by assigning customer-specific costs directly to the customer creating the need for the investment. This approach helps protect existing customers from bearing costs associated with facilities constructed to serve a specific large load project.
- The distinction between distribution and transmission interconnections creates different cost allocation outcomes. While transmission-interconnected customers are responsible for all interconnection-related transmission upgrades, certain transmission investments associated with distribution load growth may continue to be recovered through existing utility cost recovery mechanisms rather than directly assigned to individual customers.
- Cost recovery and customer funding obligations are established through applicable tariffs, interconnection requirements, engineering studies, and project-specific agreements. For transmission-connected customers, the Interconnection Agreement provides an important mechanism for establishing cost responsibility, defining customer obligations, and supporting prudent investment decisions before significant utility expenditures are incurred.
- PSEG Long Island employs several measures to reduce the risk of stranded or underutilized infrastructure investments, including phased project development, continued evaluation of customer load forecasts, ongoing customer engagement, project maturity assessments, and financial commitments tied to project advancement.
- The observed level of project attrition among large load requests reinforces the importance of these protections. Requiring customer commitments, funding obligations, and project-specific agreements prior to major procurement and construction activities helps ensure that infrastructure investments remain aligned with actual project development and customer needs.

- Overall, the current framework provides a structured approach for allocating costs associated with large load interconnections while balancing customer responsibility, system reliability, and protection of existing ratepayers from costs attributable to individual large load projects.
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6. Supply Cost Impacts

6.1 Evaluation of Supply Cost Impacts

The evaluation of electric supply impacts associated with large load interconnections depends on the type of interconnection and the characteristics of the proposed load. For distribution-connected load interconnection requests, PSEG Long Island does not perform a separate electric supply cost impact analysis as part of the interconnection evaluation process. Distribution interconnection reviews are primarily focused on assessing the safety, reliability, operational, and infrastructure impacts associated with serving the requested load.

For certain transmission-connected large loads, electric supply considerations may be evaluated through PSEG Long Island's Resource Adequacy ("RA") planning processes. These evaluations are intended to identify whether the addition of a proposed large load could create a resource adequacy deficiency or accelerate the need for future resource additions necessary to maintain system reliability.

For certain large loads that are interconnected to the transmission system, electric supply considerations may be evaluated utilizing PSEG LI's resource planning processes, including Resource Adequacy ("RA") assessments.

6.2 Components Considered

When conducting resource adequacy evaluations for applicable transmission-connected large load projects, PSEG Long Island considers both supply-side and demand-side factors that influence the ability to reliably serve customer load over the planning horizon. The primary focus is on determining whether the proposed large load creates resource adequacy concerns that could affect long-term system reliability or advance the timing of future resource needs.

The Resource Adequacy assessment generally includes:

- Development of long-term load forecasts;
- Evaluation of available and expected future resources, transmission capability, and demand-side resources;
- Assessment of planning reserve margins and other reliability metrics;
- Scenario modeling

6.3 Assessment Procedure

For applicable transmission-connected projects, PSEG Long Island utilizes a staged review process.

The evaluation begins with a high-level Resource Adequacy screening designed to identify whether the proposed large load could result in a system capacity deficiency.

This screening may be followed by a resource adequacy assessment and, if applicable, it will be included as a requirement in respective agreements such as System Impact Study Agreement, Facilities Study Agreement and Interconnection Agreement.

PSEG Long Island utilizes an established Resource Adequacy criterion of 0.1 days per year to identify potential resource needs or advancement of future resources.

Accordingly, any Resource Adequacy impacts – including both immediately identified deficiencies and the advancement of future resource capacity additions attributable to the proposed load – may result in additional interconnection requirements and associated cost responsibilities. PSEG LI is an active participant in several working groups that evaluates the reliability impact and could result in the potential development of further requirements. Given the ongoing development of New York and LIPA regulatory and policy frameworks governing the planning and interconnection of large loads to the transmission system, such requirements and cost responsibilities may be further informed by applicable future regulatory or policy requirements.

PSEG Long Island also coordinates with the NYISO and participates in industry working groups evaluating the reliability implications of large load growth and the associated planning requirements.

6.4 Findings

The review of current practices supports the following findings:

- Distribution-connected large load interconnection requests are not subject to a separate electric supply cost impact assessment as part of the interconnection evaluation process.
- For certain transmission-connected large loads, supply-related impacts are evaluated through Resource Adequacy planning processes.
- Resource Adequacy assessments consider both load growth and available supply resources, including generation capability, transmission capability, demand-side resources, reserve margins, and future planning scenarios.
- An initial Resource Adequacy screening is used to identify potential capacity deficiencies associated with a proposed large load and determine whether additional evaluation is warranted.

- PSEG Long Island utilizes an established Resource Adequacy criterion of 0.1 days per year when evaluating resource needs and reliability impacts.
 - Resource adequacy impacts identified through the evaluation process may result in additional interconnection requirements and associated cost responsibilities for applicable transmission-connected projects.
 - Given the ongoing development of New York and LIPA regulatory and policy frameworks governing the planning and interconnection of large loads to the transmission system, interconnection requirements and cost responsibilities may be further informed by applicable future regulatory or policy requirements.
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7. Risk Management

7.1 Managing Changing Demand Profiles

PSEG Long Island manages the risk of changes in large load demand through load forecast validation, phased infrastructure development, and ongoing customer coordination. Customer projections are reviewed using planning assessments and operating data to help ensure infrastructure investments align with expected demand.

For distribution-connected projects, upgrades are often implemented in phases, reducing the risk of stranded assets if actual load growth is lower than forecasted. For transmission-connected projects, customers are responsible for all costs associated with their interconnection request, including required transmission upgrades, which helps protect other customers from project-specific financial risk.

In addition, customers must notify PSEG Long Island of material changes to their facilities or operating characteristics, allowing the utility to evaluate potential system impacts and adjust plans as necessary.

7.2 Risk Management Tools

PSEG Long Island manages large load risk through a combination of forecasting, engineering reviews, phased infrastructure planning, and ongoing customer engagement. Load forecasts submitted by customers are evaluated and compared against historical usage patterns of similar customers, with PSEG Long Island utilizing Advanced Metering Infrastructure (AMI) data and planning assessments to validate projected demand levels.

The utility also performs distribution and transmission planning studies to assess system impacts and identify required upgrades. For large projects, infrastructure investments are often phased to align with the customer's actual development schedule and load growth, reducing the potential for stranded assets and unnecessary capital expenditures.

Evaluations of various factors such as site control, permitting & financial standing are considered for including a specific large load in LIPA's load forecast. The system load forecast could drive the need for additional resources and hence appropriate scrutiny needs to be applied.

Transmission connected customers are responsible for all upgrades to the LIPA system and this requirement protects existing customers from potential cost shifts. Eligible Customers shall provide financial security in the form of an irrevocable Letter of Credit acceptable to LIPA. Similarly, as indicated in section 6.1, PSEG LI implemented resource adequacy assessments for large loads connected to the LIPA transmission system. These assessments may result in additional interconnection requirements and cost responsibilities to large load customers to address LIPA's resource adequacy needs. In addition, PSEG Long Island maintains ongoing coordination with large customers throughout the project lifecycle to monitor changes in demand forecasts, operating characteristics, and development schedules. Customers are required to notify the utility of material changes that could affect the assumptions used during the interconnection review process.

Together, these forecasting, planning, study, and coordination processes help ensure that infrastructure investments remain aligned with actual customer needs while minimizing financial risk and protecting existing customers from unnecessary costs.

7.3 Attrition Summary

Based on a review of large load interconnection requests greater than 10 MW received since January 1, 2022, PSEG Long Island identified eight projects within the study population. Of these eight projects, three were withdrawn or cancelled, resulting in an overall attrition rate of approximately 38%.

7.4 Attrition by Stage

While the sample size remains limited, the results indicate that project attrition is most likely to occur during the early screening and engineering evaluation phases, prior to execution of interconnection agreements or commencement of construction activities.

Stage	Attrition
Initial Screening & Scoping	50%
Engineering Evaluation	40%
In-Service	0%

7.5 Treatment of Cancelled Projects

When a large load project is cancelled or significantly delayed, cost treatment is dependent on the status of the project and the agreements in place at the time of cancellation. Customers are generally responsible for study costs incurred on their behalf, including engineering reviews, system impact studies, and facilities studies completed prior to withdrawal.

For customer-funded projects, any unused customer deposits or advance payments remaining after reconciliation of incurred project costs may be returned to the customer in accordance with the terms of the applicable study agreement, interconnection agreement, or construction funding arrangement. Costs already incurred for completed engineering, planning, procurement, or construction activities are typically not refundable.

To minimize financial exposure for both the customer and the utility, PSEG Long Island generally aligns infrastructure investments with project maturity and anticipated load growth. This phased approach helps limit the amount of capital committed before a project demonstrates readiness to proceed and reduces the risk of stranded assets if a project is delayed, downsized, or cancelled.

For transmission-connected projects, customers remain responsible for the costs created by their interconnection request, including study costs and any transmission upgrades already initiated as a result of the project. This approach helps ensure that project-specific costs are borne by the interconnecting customer rather than other customers on the system.

7.6 Findings

PSEG Long Island manages large load risk through a combination of forecast validation, engineering studies, phased infrastructure development, and ongoing customer engagement. These processes are intended to ensure that system investments are aligned with actual customer needs and to minimize the potential for stranded assets.

Since January 1, 2022, three of eight identified large load projects were withdrawn or cancelled, resulting in an observed attrition rate of approximately 38%. Most project attrition occurred during the early screening and engineering evaluation stages, before significant infrastructure commitments were made.

Cost responsibility requirements provide an additional layer of protection. Transmission-connected large load customers are responsible for costs associated with their interconnection request, including required transmission upgrades, while customer-funded study and construction activities help limit financial exposure to other customers if a project is delayed or cancelled. Resource adequacy assessment and subsequent impacts may result in additional cost responsibilities. Any unused customer deposits or advance payments may be reconciled and returned in accordance with the applicable agreements. Overall, the combination of phased planning, customer funding obligations, forecast validation, and ongoing project monitoring

helps reduce financial risk to both the utility and existing customers while supporting the efficient development of large load projects.

8. Internal Processes and Tools

8.1 Internal Management Reports, Key Metrics, and Findings

PSEG Long Island does not maintain a recurring management dashboard or report specifically dedicated to tracking all large load interconnection requests. Instead, large load projects are managed through existing planning, engineering, and project development processes that incorporate large load information as part of broader system planning and infrastructure management activities.

The primary internal reports and reference materials used to monitor and manage large load interconnections include:

- Annual Ten-Year Transmission & Distribution (T&D) Development Study – The primary system planning document used to evaluate forecasted load growth, including known and anticipated large load projects, assess future system performance, and identify transmission and distribution infrastructure needs.
- Project Justification Documents (PJDs) – Internal management documents used to support project approval and funding decisions when system upgrades are required. PJDs may include project drivers, system impacts, recommended solutions, cost estimates, schedules, and supporting technical analyses for projects associated with large load growth.
- System Impact Studies (SIS) – Engineering studies performed by either PSEG Long Island or NYISO to evaluate the reliability and operational impacts of proposed large loads and identify any required system upgrades.
- Facilities Studies – Detailed engineering assessments used to define project scope, required transmission and distribution upgrades, construction requirements, and cost estimates for specific interconnection projects.
- Large Load Screening Criteria and Performance Requirements – Internal reference materials used to evaluate project applicability, establish study requirements, and assess compliance with the Performance Requirements for Large Loads Connected to the LIPA System.
- 2026 Specifications and Requirements for Electric Installations (Red Book) – The primary reference document governing service requirements, interconnection criteria, voltage thresholds, and customer responsibilities associated with large load interconnections.

Collectively, these reports and reference materials provide the framework used by PSEG Long Island to monitor project development, evaluate system impacts, plan infrastructure investments, and manage large load interconnection requests while maintaining system reliability and compliance with applicable Tariff and planning requirements.

9. Overall Findings and Opportunities for Improvement

9.1 Key Conclusions

The review of large load interconnection activity since 2022 demonstrates that large load development represents an increasingly important planning consideration for the LIPA system. While the number of projects evaluated during the review period remains relatively limited, proposed load magnitudes have increased significantly, customer requirements have become more complex, and data center development has emerged as a notable source of new large load interest.

The project inventory also demonstrates that large load requests vary considerably in size, maturity, operating characteristics, infrastructure requirements, and likelihood of advancement. Several projects were ultimately withdrawn prior to construction, while others continue to progress through engineering evaluation and interconnection studies. These observations reinforce the importance of incorporating project maturity, development readiness, and customer commitment into forecasting, planning, and interconnection activities.

The review further demonstrates that accommodating large loads can require a broad range of transmission and distribution infrastructure investments, including dedicated feeders, substation modifications, new substations, transmission circuit upgrades, and other system reinforcements. The scope and cost of these investments are highly dependent on project-specific characteristics and existing system conditions. As a result, large load evaluations require detailed engineering reviews and cannot be effectively addressed through standardized assumptions or generalized screening alone.

PSEG Long Island's existing framework provides a structured and technically rigorous approach for evaluating large load requests. The interconnection processes currently in place support progressive engineering review, system impact studies, project-specific infrastructure assessments, customer coordination, cost estimation, resource adequacy evaluations, and identification of customer responsibilities. In addition, recent enhancements implemented by LIPA and PSEG Long Island, including formal screening and load forecasting criteria, the Performance Requirements for Large Loads Connected to the LIPA System, process flowcharts, tariff revisions, and updates to the PSEG Long Island Red Book, have strengthened the ability to

evaluate large load projects while maintaining system reliability and supporting cost-causation principles.

The review also indicates that the current cost allocation framework provides substantial protection for existing customers. Distribution-connected customers are generally responsible for dedicated facilities required to serve their load, while transmission-connected customers are responsible for all costs attributable to their interconnection request, including transmission upgrades. These requirements, combined with customer funding obligations, project-specific agreements, and phased infrastructure development practices, help limit the potential for stranded investments and inappropriate cost shifts to other customers.

Finally, experience gained from recent projects demonstrates the importance of maintaining coordination among customers, PSEG Long Island, NYISO, and other stakeholders. Project schedules, study requirements, infrastructure needs, and planning assumptions frequently evolve throughout the development process, requiring flexibility within existing planning and interconnection frameworks while maintaining consistent technical and reliability standards.

9.2 Issues, Challenges, and Opportunities

Although the current framework has generally proven effective, several challenges and opportunities for improvement were identified through this review.

One of the most significant challenges is the evolving nature of large loads. Customer plans frequently change as projects mature, resulting in revisions to load magnitude, development schedules, operating characteristics, phased build-out plans, and points of interconnection. These changes often necessitate updates to engineering studies, planning assumptions, forecasting inputs, and infrastructure evaluations. Continued efforts to refine project details and customer readiness earlier in the development process could reduce study iterations and improve schedule predictability.

The review also highlighted the importance of timely and complete customer-provided technical information. For larger transmission-connected projects, advanced reliability studies, including dynamic, transient stability, and electromagnetic transient analyses, depend on the availability of accurate and validated customer models. Delays in the development or submission of these models can affect study schedules and extend project timelines. Increased emphasis on early model development and data exchange may help improve the efficiency of the interconnection process.

In addition, opportunities exist to further enhance customer application and screening processes. As large load development continues to evolve, particularly among data centers, artificial intelligence facilities, and other computational load customers, additional upfront information regarding facility characteristics, development status, operating assumptions, resource adequacy

implications, and expected load profiles may improve the ability to efficiently screen projects and direct them into the appropriate interconnection pathway at an earlier stage of development.

Project attrition remains another important consideration. The observed cancellation of several projects prior to construction demonstrates that not all customer requests ultimately advance to operation. Continued application of formal screening criteria, project maturity assessments, forecasting controls, and periodic project validation efforts will remain important to ensure that planning assumptions and infrastructure investments reflect projects with a credible likelihood of advancement.

As large load activity grows, utilities may also face increasing requirements to collect and maintain information that has not historically been required for traditional load forecasting, planning, and interconnection activities. Examples include data needed to support project maturity assessments, resource adequacy screening, aggregation of multiple large load requests within a geographic area, characterization of computational load facilities, phased development schedules, and customer-specific operating characteristics. Additional regulatory, planning, and interconnection requirements may further expand the types of information needed to evaluate the collective impacts of existing and proposed large loads on the electric system. As a result, developing processes to efficiently maintain and utilize these emerging datasets may become increasingly important to supporting forecasting, planning, interconnection evaluations, and evolving industry requirements.

Resource adequacy considerations are also expected to become increasingly important as large loads continue to increase in size and complexity. The current Resource Adequacy screening and assessment framework provides an initial mechanism for evaluating potential supply impacts; however, ongoing industry efforts may further enhance the evaluation of large load impacts on long-term reliability needs and future resource requirements.

At the statewide level, ongoing efforts by the NYISO and New York Transmission Owners to revise the NYISO Large Load Interconnection Process in response to FERC's 2026 Show Cause Order present an opportunity to further improve the assessment of statewide resource adequacy impacts, bulk power system reliability impacts, and overall interconnection process efficiency. As those efforts advance, resulting process enhancements may help improve consistency between statewide and local evaluations and provide opportunities to further refine planning, forecasting, and interconnection practices.

Overall, the review indicates that the existing LIPA and PSEG Long Island framework is well positioned to accommodate future large load growth. Continued emphasis on project maturity assessment, customer accountability, accurate forecasting, early technical engagement, phased infrastructure development, and cost-causation principles will help support reliable system

planning while minimizing adverse ratepayer impacts associated with speculative, duplicative, or uncertain large load development.

Appendix D

Niagara Mohawk Power Corporation d/b/a National Grid

NEW YORK STATE
PUBLIC SERVICE COMMISSION

Case 26-E-0045

*Proceeding on Motion of the Commission to Address
Interconnection Reforms for Large Loads*

LARGE LOAD EO 62 REPORT

Prepared for the New York State Department of Public Service

Prepared by Niagara Mohawk Power Corporation d/b/a National Grid

Date: September 18, 2026

Purpose and Background

Executive Order 62 directs the Department of Public Service (DPS) to convene the State's Transmission Owners, review the sufficiency of current practices for studying the system impacts of large loads, and report to the Commission. This report describes National Grid's current practices based on information provided in response to DPS information requests and identifies, where relevant, prospective reforms described in National Grid's comments and reply comments in Case 26-E-0045.

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1. Executive Summary

New York is experiencing a significant surge in requests from large electric loads, driven primarily by data centers, advanced manufacturing, and other energy-intensive development. As of September 2026, National Grid had identified approximately 54 large load projects representing roughly 7,228 MW of requested demand, including 34 prospective projects that have not yet entered the NYISO queue. While this level of interest signals substantial economic development opportunity, requested capacity should not be viewed as committed future demand because projects vary considerably in maturity, readiness, and likelihood of advancement.

The report finds that the existing NYISO and utility interconnection framework provides a sound foundation for evaluating large loads and protecting electric system reliability. However, the scale, complexity, and pace of current development activity are creating increased pressure on forecasting, study resources, transmission planning, infrastructure delivery, and stakeholder coordination. The greatest challenge is not the ability to study large loads, but rather improving predictability, transparency, and efficiency while ensuring projects advance based on demonstrated readiness and credible development milestones.

National Grid's analysis highlights the importance of distinguishing mature, actionable projects from early-stage or speculative requests. Queue position alone does not establish project viability. Stronger readiness criteria, improved data requirements, milestone-based advancement, and enhanced transparency can improve forecasting accuracy and focus resources on projects most likely to proceed. The report also emphasizes that customer protection and economic growth must advance together through clear financial commitments, disciplined planning standards, and equitable allocation of infrastructure costs and risks.

Looking forward, National Grid supports targeted reforms rather than wholesale replacement of the current framework. Recommended improvements include stronger project-readiness requirements, clearer study milestones, standardized data and modeling requirements, enhanced digital customer tools, greater visibility into network upgrades, and consideration of a dedicated large-load tariff framework with appropriate financial protections. The goal is a balanced approach that protects existing customers, maintains reliability, supports economic development, and provides greater certainty for developers, utilities, regulators, and investors as New York prepares for sustained growth in large electric loads.

2. Large Load Demand

2.1 Explanation of Intake Process for Interconnection Requests

Large load customers may engage with National Grid through a variety of channels, including strategic account discussions, economic development initiatives, site selection activities, state agency referrals, early engagement assessments, or formal interconnection requests submitted through the New York Independent System Operator (NYISO) process. National Grid utilizes a structured intake and readiness process to identify, evaluate, and monitor prospective large load projects from the earliest stages of development through interconnection and energization activities. This process supports customer engagement, system planning, load forecasting, infrastructure assessment, and coordination across National Grid business functions.

As part of the intake process, customers are encouraged to provide available information regarding the proposed project location, anticipated electric demand, development schedule, expected load growth profile, preferred point of interconnection, project milestones, and other preliminary project characteristics. Information may be refined and supplemented as a project matures. National Grid uses this information to establish a consistent understanding of project scope, assess readiness for further engineering evaluation, identify potential system considerations, and support long-term planning activities. Projects may be tracked

through the intake process even if they are not yet sufficiently developed to enter the formal NYISO interconnection process.

National Grid may also perform a preliminary, non-binding assessment to identify potential transmission or distribution constraints, feasible points of interconnection, anticipated study requirements, and information needed to support subsequent evaluations. These preliminary assessments are intended to inform customer planning and facilitate efficient project development. Such assessments do not reserve transmission or distribution capacity, establish interconnection rights, or determine the outcome of any future studies performed by National Grid or NYISO.

Participation in an early engagement assessment is optional and may be conducted under a customer-funded support services arrangement. National Grid encourages customers with sufficiently developed projects to enter the applicable NYISO interconnection process as early as practicable to support formal engineering studies and evaluation under the NYISO tariff.

National Grid's intake and readiness process includes cross-functional coordination among customer, engineering, transmission planning, forecasting, operations, regulatory, and other relevant business functions. These activities support data validation, identification of project risks and dependencies, infrastructure planning, and consistent application of planning assumptions across the large load portfolio. Information collected through this process may also be utilized to support jurisdictional load forecasting, transmission planning, and assessment of system impacts associated with emerging large load development across National Grid's service territory.

While National Grid tracks and manages prospective projects through its internal intake and readiness framework, project tracking, readiness assessments, or planning activities do not establish interconnection priority or queue position. For projects subject to the NYISO load interconnection process, study sequencing, interconnection evaluations, and determinations are governed by the applicable NYISO tariff, agreements, and procedures.

For projects entering the NYISO load interconnection process, the customer submits a formal interconnection request, the required study deposit, and supporting information in accordance with NYISO requirements. The information required for a complete NYISO Interconnection Request includes a completed load interconnection request form and a conceptual one-line diagram showing the proposed project facilities and proposed Point of Interconnection (POI). NYISO validates the request, identifies the Connecting Transmission Owner, Affected Transmission Owner(s), and Affected Systems, and coordinates the applicable scoping process.

Prior to validation and following the scoping meeting, the customer must provide sufficient project and modeling information to support development of the System Impact Study (SIS) scope and associated study assumptions. This information includes load classification and end-use application, load flexibility characteristics, daily and seasonal load profiles, details regarding any existing or prior-phase load associated with the project, phased development and in-service plans, and the required power system modeling data, including power flow, dynamic stability, and short-circuit models.

The information required to support engineering studies becomes more detailed as the project progresses. Depending on the stage of development and project-specific characteristics, required information may include updated load forecasts, development schedules, equipment specifications, one-line diagrams, project site plans, power factor and reactive power requirements, facility design information, protection and control information, behind-the-meter generation details, and other technical information necessary to perform the required engineering evaluations and interconnection studies. This staged approach allows studies to reflect project development as it advances, while recognizing that significant project changes after study activities have begun may require revised assumptions, additional analysis, or further study work.

2.2 Summary of Inventory

For purposes of the inventory and process discussion, National Grid’s response principally addresses transmission-connected requests of 10 MW or greater, many of which require evaluation on the Company’s 115 kV-and-above transmission system. This population should not be interpreted as encompassing every distribution-level inquiry of 10 MW or greater.

As of **September 2026**, National Grid had identified approximately **55 large load projects seeking to interconnect on National Grid’s system, representing approximately 7,792 MW of requested demand** within the scope of this report. The inventory includes **35 prospective projects totaling 4,800 MW** that had engaged with National Grid but had not entered the NYISO queue.

Large Load Inventory (as of September 2026)			
	# of projects	Load (MW)	Source
Total	55	7,792.2	
NYISO Queue	20	2,992.2	NYISO
Prospective	35	4,800	Internal data

Projects are at different stages, including preliminary inquiry, System Impact Study, Facility Study, agreement development, engineering, procurement and construction, and energization. Requested capacity is a point-in-time measure and should not be interpreted as a forecast that every project, or the full requested demand of every project, will materialize.

Even the projects in the NYISO queue only represent requested MW, which may differ materially from expected or forecasted MW. Requested capacity is useful for understanding the potential scale of demand under review, but it does not account for project attrition, revised phasing, changes in requested service, or whether multiple alternative configurations ultimately represent one development. For these reasons, project stage and maturity should always be considered alongside aggregate capacity.

2.3 Explanation of Trends

National Grid has experienced a significant increase in the number and size of large load requests. The portfolio includes data centers and other digital infrastructure, advanced manufacturing, industrial development, public infrastructure, research and institutional facilities, and other energy-intensive uses. Requests >10 MW typically require transmission-level evaluation and coordination with NYISO.

The pipeline is dynamic. Customers may revise requested capacity, development phases, in-service dates, points of interconnection, transformer configurations, and other design assumptions as projects mature. Observed project withdrawals have occurred in the early stages of the interconnection process, supporting the need to distinguish early-stage requested capacity from projects that have completed major study, contractual, or financial milestones.

The increase in requests has implications beyond the aggregate MW total. Larger projects can require more extensive transmission analysis, coordination with affected systems, and long-lead substation or line work. A concentration of projects in a particular area may also create compounding impacts that are not apparent when requests are viewed individually. The NYISO process and utility planning therefore must account for both project-specific impacts and the interaction of multiple requests.

Project schedules supplied during early development may also be more aggressive than the time required for studies, permitting, procurement, construction, testing, and ramp-up. As a result, the inventory should record both the customer-reported in-service date and the project stage or latest available implementation schedule. This provides a more balanced view of when requested demand could reasonably affect the system.

2.4 Requests Outside the NYISO Queue

National Grid receives inquiries from prospective customers before formal entry into the NYISO queue. Through early engagement, customers may seek a high-level understanding of local transmission conditions, potential points of interconnection, and the information required to proceed. A customer may fund a preliminary, non-binding local transmission assessment, but that assessment does not replace a NYISO System Impact Study, evaluate all potential impacts on other Transmission Owners, or reserve capacity.

As of **September 2026**, National Grid was aware of **35 prospective projects totaling 4,800 MW** outside the NYISO queue. Because these requests are at an earlier stage, uncertainty regarding scope, timing, and likelihood of completion is greater than for projects that have entered the formal process.

National Grid maintains available information concerning known prospective projects based on ongoing customer inquiries. The completeness and maturity of information vary substantially, and the prospect list should not be treated as a comprehensive forecast or formal queue. Some customers may have identified a site and proposed electrical configuration, while others may be evaluating multiple locations or service options. Therefore, unqueued prospects should be considered a separate, less mature category rather than committed additions.

In comments filed in Case 26-E-0045, National Grid recommended stronger and more standardized front-end information and readiness requirements. The Company identified financial commitment, site control, disclosure of duplicative development activity, realistic schedules, operating characteristics, commercial readiness, and sufficient technical information as potential indicators of a credible request. These are proposed reforms, not current practice.

2.5 Projects with Behind-the-Meter Generation, Co-Located Services, or Grid Flexibility

National Grid requests information regarding behind-the-meter generation, energy storage, co-located services, and operational flexibility when applicable. Relevant information may include resource type and capacity, expected load profiles, ramping behavior, curtailment capability, reactive-power requirements, and whether requested grid demand accounts for on-site production.

As of **September 2026**, **one project, totaling 50 MW, out of the 55-project inventory** reported proposed behind-the-meter generation. Identification of a potential capability does not mean that it has been incorporated into firm-service planning assumptions. Reliance on such a capability would require sufficient technical information and enforceable operating arrangements consistent with applicable reliability requirements.

The study treatment of these resources depends on how they are expected to operate. A resource that is merely contemplated, or that is not subject to enforceable controls, may not provide the same planning value as a resource with defined performance, telemetry, and operating obligations. Study assumptions must also address whether generation may export, whether storage can sustain the required output, and how the facility behaves if the resource is unavailable.

In its Case 26-E-0045 comments, National Grid described flexibility as a potential bridge-to-wires solution that could permit some load to energize before permanent system upgrades are complete. The Company also discussed curtailment, storage, co-located generation, phased ramps, and demand response. National Grid believes that these options should be evaluated case by case and must be supported by operational and contractual agreements where they are relied upon for reliability.

2.6 Assessment of Ability to Identify Speculative or Duplicated Applications

National Grid reviews project location, requested load, point of interconnection, timing, developer information, and known relationships among proposed developments to identify potential overlap. Coordination with NYISO and other Transmission Owners may also reveal projects with similar sites or configurations. However, customers may legitimately evaluate alternative sites, points of interconnection, project phases, or configurations. Similarity is therefore an indicator for review rather than conclusive evidence of duplication.

Progress through technical studies, execution of agreements, satisfaction of information requirements, and provision of financial commitments provide increasingly strong indications of project maturity.

No single data field conclusively establishes whether a request is speculative. Queue position confirms that an application has entered a process, but it does not establish site readiness, financing, permitting, construction status, or the likelihood that the full requested load will materialize. Conversely, an early-stage project may be credible even though it has not yet completed major studies. A maturity assessment is therefore stronger when it considers multiple objective milestones rather than one binary label.

National Grid's Case 26-E-0045 filed comments and reply comments support a more disciplined, milestone-based approach. Potential indicators include site control, financial commitments, executed agreements, realistic ramp schedules, technical and modeling data, key permitting and engineering milestones, and disclosure of related requests. The Company also supported clearer advancement milestones, limits on material post-study modifications, and removal and re-entry rules for projects that fail to progress.

2.7 Findings

The large load pipeline is substantial but should not be treated as a firm load forecast. Projects differ materially in maturity, commercial certainty, and anticipated timing. Public reporting should distinguish direct National Grid connections, projects affecting National Grid but connecting elsewhere, and prospects outside the NYISO queue.

Data centers are a significant driver of requested capacity, but the portfolio also includes manufacturing, industrial, institutional, and public-sector demand. Improved project identifiers, standardized information, milestone-based maturity measures, and regular updates would improve visibility into which requests are most likely to advance. Strengthened queue-discipline measures, including increased study deposits, commercial-readiness deposits and milestones, limits on post-study modifications, and withdrawal penalties or removal-and-reentry requirements for projects that fail to progress, may also be effective to discourage speculative requests and focus engineering and planning resources on the most credible projects. Early engagement can improve readiness and siting decisions but does not establish queue priority or reserve capacity.

3. Study Methodology and Interconnection Process

3.1 How the Analysis Is Performed to Study a Large Load

National Grid evaluates proposed large loads under applicable NYISO tariffs and procedures and National Grid planning criteria. Loads meeting NYISO applicability thresholds are studied through the NYISO Load Interconnection Process. NYISO performs the System Impact Study in coordination with the Connecting Transmission Owner and any Affected Transmission Owners. The study evaluates whether the proposed load would create adverse reliability impacts and identifies potential alternatives or transmission reinforcements.

The NYISO System Impact Study is informational and non-binding. More detailed facility requirements, cost estimates, and schedules are developed through subsequent Facility Study and engineering activities conducted by the impacted applicable Transmission Owner. Power-flow analysis, thermal assessment, voltage analysis, stability analysis, short-circuit and protection reviews, and operational assessments are conducted during the System Impact Study. Where an adverse impact is identified, the study evaluates potential alternatives or system modifications. The identified solution may change as the analysis becomes more detailed.

After a System Impact Study, National Grid then evaluates the proposed interconnection against applicable transmission planning and reliability criteria in the Facility Study. The SIS provides an informational assessment of impacts and potential reinforcements, while the Facility Study determines the specific facilities, configuration, cost estimates, and preliminary schedule needed to implement the connection. The fundamental reliability methodology is generally consistent across large load types, while inputs reflect project-specific conditions such as load profile, ramping, power factor, operational flexibility, fault ride-through performance, behind-the-meter generation, and development phasing.

3.2 Assumptions, Tools Used, and Timing within the Process

The study process begins with customer-provided information and becomes progressively more detailed as the project advances. For projects subject to the NYISO Load Interconnection Process, the customer submits a formal Interconnection Request, the required study deposit, and supporting information, including a completed request form and a conceptual one-line diagram showing the proposed project facilities and Point of Interconnection (POI). NYISO then validates the request, identifies the Connecting Transmission Owner, any Affected Transmission Owners and Affected Systems, and coordinates the scoping process. To support development of the SIS scope and applicable base cases, the customer must provide sufficient project and modeling information, including the requested MW, project location, load classification and end-use application, service date, load-flexibility characteristics, daily and seasonal load profiles, details of any existing or prior-phase load, phased development and in-service plans, and the required power-flow, dynamic-stability, and short-circuit models.

National Grid supports applicable NYISO base cases and modeling requirements together with Company planning criteria and engineering tools (e.g., PSSE, TARA, and ASPEN). Assumptions are updated as customer information, system conditions, and project designs change. Facility-study and detailed-engineering activities use more specific information concerning equipment, physical configuration, permitting, real estate, protection and control, telecommunications, construction sequencing, and outages.

Study results are sensitive to the load representation and the system base case. Customer inputs concerning real and reactive power, seasonality, ramp rate, equipment behavior, development phases, and behind-the-meter resources must be represented consistently with the proposed service. The analysis also considers applicable reliability criteria and firm facilities that are expected to be in service in the relevant study case.

National Grid's filed comments identified recurring data gaps in seasonal real and reactive power requirements, utilization and ramp-up profiles, dynamic performance, and expected participation in flexibility or demand-response arrangements. The Company recommended that NYISO and Transmission Owners develop a standard modeling package, define when advanced or electromagnetic-transient studies are appropriate, and establish expectations for model verification during commissioning. These recommendations concern future process improvements and are consistent with the North American Electric Reliability Corporation (NERC) draft requirements in CLO-001 "Computational Load Interconnection, Studies, & Modeling Data."¹

¹ <https://www.nerc.com/standards/reliability-standards-under-development/2026-02-computational-loads>

3.3 How Methodologies Vary from Other Service Classes

The principal difference is driven by the size, voltage, and system impact of the request rather than the customer's industry label. Smaller commercial and industrial requests that can be served from existing distribution facilities or through standard distribution planning generally do not enter the NYISO load interconnection process. Transmission-connected large loads typically require regional reliability studies and coordination among the customer, NYISO, National Grid, Affected Transmission Owners, other Independent System Operators / Regional Transmission Organizations (ISO-NE; PJM; IESO (Canada)) and other stakeholders.

For a smaller distribution customer, the principal questions may be whether the local feeder, transformer, metering arrangement, and distribution facilities can serve the request. For a transmission-connected large load, the analysis can extend beyond the immediate point of interconnection to regional power flows, contingencies, affected Transmission Owners, stability, short-circuit performance, and operating requirements. The scope is therefore generally broader and involves a larger set of entities.

The underlying objective remains the same: identify the facilities and operating conditions necessary to provide safe and reliable service. The difference is the scale of potential impact and the corresponding applicability of NYISO, NERC, NPCC, NYSRC, and transmission-owner requirements.

3.4 Process Map from Request to Energization

Each stage builds on the preceding stage but may overlap where practical. National Grid may begin certain local facility-study or engineering activities before the broader SIS is complete when the local scope is sufficiently defined and the customer accepts the associated cost of performing the study at risk in parallel. This can reduce elapsed time, but later NYISO findings must still be incorporated into the non-local scope and the final interconnection solution. Not every project must complete each stage, for instance, if a System Impact Study identifies no reliability violations, a Facility Study and associated engineering, procurement and construction of facilities to support the interconnection may not be needed.

Energization follows completion of required construction, testing, commissioning, metering, protection, control, communications, and operating arrangements. The specific prerequisites are project-dependent. The process is complete only when facilities are placed in service and the customer can operate in accordance with the applicable agreements and reliability requirements.

Stage	Principal activity	Closing milestone	Timeline
1. Early engagement and planning	Customer provides preliminary project information; National Grid may perform a non-binding local assessment.	Customer elects to proceed and submits a formal request where applicable.	1-3 months
2. NYISO System Impact Study	NYISO validates the request, identifies Transmission Owners, and establishes study scope and data needs. NYISO and Transmission Owners evaluate reliability impacts and potential alternatives or upgrades.	Final informational SIS report.	6-12 months
3. Facility Study	National Grid develops detailed facility scope, planning-level cost estimate, and preliminary schedule.	Facility Study deliverable and customer decision to proceed.	9-15 months
4. Project Initiation & Engineering, Procurement, Construction	Agreements and financial arrangements are executed; detailed design, procurement and construction proceed.	Facilities are ready for testing and commissioning.	2+ years*

5. Energization and closeout	Facilities are tested, commissioned, placed in service, and connected.	Successful energization and project closeout.	
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*Timeline is dependent upon system upgrades required by the project

3.5 Stage Timeframes, Deliverables, and Actions

The table above shows indicative timeframes for National Grid’s large load process of approximately one to three months for early engagement and planning, six to twelve months for the NYISO System Impact Study where applicable, and nine to fifteen months for Facility Study. Engineering, procurement, and construction for projects requiring transmission or substation upgrades can extend the overall project timeline depending on scope of the upgrades needed. These ranges are not commitments and depend on project complexity, information completeness, study coordination, required equipment, permitting, property rights, outages, and scope changes.

The indicative durations should be read as planning ranges rather than tariff requirements. Early engagement can be completed more quickly when a customer provides a defined site and technical request. SIS and facility-study durations can increase when information is incomplete, multiple affected systems are involved, or the project changes materially. Construction duration depends on the scope identified, including whether new lines, substation work, permits, property rights, outages, or long-lead equipment are required.

3.6 Comparison of Stated and Actual Timelines

Actual durations vary significantly by project. National Grid does not independently establish the NYISO System Impact Study schedule and performs its work within the NYISO framework. National Grid’s own evaluation and engineering timelines are also affected by iterative project development information received from the interconnecting customer, including changes in requested load, service voltage, transformer configuration, point of interconnection, line routing, substation arrangement, and phasing.

A portfolio comparison should use consistent start and end points. For example, “SIS duration” may differ depending on whether the clock begins at initial application, scoping, study selection, or receipt of complete modeling data. Not every project goes through each step – an SIS might find no reliability violations, avoiding the need for a full Facility Study and engineering, procurement, and construction of associated upgrades.

National Grid’s estimated timelines, as posted on the Company’s website, are based on recent experience with actual project timelines where available.²

3.7 When Material Costs Are Incurred, Capacity Is Reserved, and Financial Security Is Posted

Preliminary engagement does not reserve transmission capacity. Customers fund applicable preliminary assessments and NYISO study deposits. During Facility Study, customers enter into Support Services Arrangements (SSA) and fund the preliminary engineering study. Material utility capital outlays generally begin after the customer elects to proceed, the applicable Cost Reimbursement Agreements (CRA) and project agreements are executed, and required customer payments or security arrangements are in place. Procurement of long-lead equipment and construction then proceed based on project-specific approvals and agreements.

Early-stage costs are principally study and support costs funded by the customer under the applicable arrangement. More material capital exposure arises when detailed engineering begins, long-lead equipment is ordered, property or permitting work advances, and construction has mobilized. The timing and form of

² https://www.nationalgridus.com/media/pdfs/microsites/wholesale-interconnections/new_york_large_load_transmission_interconnections.pdf

customer payment or security depend on the facilities, tariff provisions, and agreements applicable to the project.

Contribution in Aid of Construction (CIAC) payments for attributable facilities are generally due before the start of utility capital outlays. Revenue assurance (further defined in Section 6, Cost Allocation) can be used under the current tariff as an alternative for eligible costs, supported by minimum contract demand and financial security (e.g., an irrevocable letter of credit).

3.8 Main Causes of Delay and Solutions Being Explored

Factors affecting duration include incomplete or evolving customer information; delays in receiving models and technical data; iterative validation of developer submissions; project complexity; transmission constraints; coordination among NYISO, Transmission Owners and customers; the volume of concurrent requests; permitting and real-estate requirements; outage availability; and long equipment lead times. National Grid has found that the availability, quality, and completeness of technical information early in development can materially affect study efficiency.

Current practices intended to improve efficiency include early customer engagement, preliminary screening, regular working sessions, evaluation of phased load additions and alternative interconnection points, and, where practical, commencement of local facility-study work before completion of broader NYISO analyses. These activities are intended to identify data gaps and potential constraints earlier, while preserving applicable reliability review. As mentioned previously, the customer accepts the associated cost of performing the study at risk in parallel.

Customer-driven changes can require more than an administrative update. A different MW request, point of interconnection, transformer configuration, service voltage, line route, or phasing plan can change system impacts and require revised modeling, facility scope, estimates, and coordination. Similarly, an identified Affected Transmission Owner can add necessary review beyond the connecting utility's direct control.

Potential solutions include preliminary screening, earlier identification of data needs, frequent coordination, evaluation of alternative points of interconnection, phased load additions, and parallel advancement of sufficiently defined local work. National Grid's filed comments additionally support clearer NYISO milestones, standardized designs, improved developer portals, and analytics that may accelerate sensitivity analysis and early cost information.

The NYISO and the Transmission Owners in New York are currently engaged in developing reforms and compliance filings to comply with the Federal Energy Regulatory Commission's (FERC) show cause orders on large loads, which include extensive process reforms that may lead to improved timelines for the interconnection process.

3.9 Communications and Information Flow with Large Loads and NYISO

National Grid cannot broadly disclose non-public transmission system information or CEI to any requesting customer; appropriate confidentiality protections are often required to facilitate meaningful discussions regarding customer expansion plans and electric service options. National Grid communicates with customers through meetings, calls, site visits, document exchanges, and coordination across internal engineering and customer teams. NYISO coordinates formal scoping and study communications for projects in its process. Communication needs increase as project scope changes and as studies identify affected systems or alternative solutions. Early engagement and recurring coordination can reduce later redesign, but overall effectiveness remains dependent on timely, complete, and consistent information from all parties.

The current process provides multiple opportunities for communication, including early engagement, the NYISO scoping meeting, study coordination, facility-study discussions, agreement development, and construction coordination. National Grid also meets with customers to review voltage level, point of

interconnection, routing, substation arrangement, phasing, and project alternatives. These interactions can improve the final solution and reduce later redesign when decisions are made early.

At a high level, communications are most effective when requirements, responsibilities, assumptions, decisions, and information dates are documented consistently and when customers promptly identify material changes.

3.10 Findings

Existing studies provide a structured means to identify reliability impacts, but the process is inherently iterative and project-specific. Better information and firmer project definitions early in the process can reduce rework and improve predictability. In its comments and reply comments in Case 26-E-0045, National Grid recommended stronger and more standardized intake requirements, milestone-based project maturity criteria, enhanced queue discipline, model validation, clearer study milestones, and improved transparency concerning non-local upgrades. National Grid also supported standardized substation designs, developer-facing digital tools, advanced analytics, and other technologies where they can improve efficiency without compromising reliability.

The current process is capable of studying large loads, but predictability depends on disciplined inputs, defined stage gates, sufficient engineering resources, and coordination among organizations.

The strongest near-term opportunities are standard data packages, maturity criteria, clearer milestones, earlier visibility into non-local impacts, and measured use of parallel work. Longer-term improvements can include customer-facing digital tools, standard station designs, and enhanced model validation.

4. Service Classification

4.1 Current Service Classification for Large Loads

National Grid determines service classification and billing treatment based on the characteristics of the requested service, applicable tariff provisions, facility ownership, metering configuration, and the entity receiving service. For retail customers, the review considers end use, expected demand and usage, load characteristics, service voltage, metering, billing determinants, and tariff eligibility. Final assignments are governed by the tariff and validated in Company systems.

Not every transmission-connected project becomes a National Grid retail customer. A project may receive retail service directly from National Grid, obtain service through a municipality or another utility, receive energy under a wholesale or border arrangement, or combine load with existing generation or another specialized configuration. The applicable classification and contractual treatment therefore depend on the specific arrangement.

For non-residential retail service, the applicable service classification is based on tariff eligibility rather than the “large load” label used for this report. National Grid’s rate reference identifies demand and usage thresholds, metering requirements, and service characteristics for the existing general-service classifications. Large retail customers may be served under an existing large general service classification where the tariff criteria are met, subject to the particular service and billing arrangement.

The service classification determines the applicable delivery-rate treatment, but it does not itself determine the transmission study process or the facilities needed for interconnection. A project can require transmission-level study while its eventual billing classification is determined separately under the retail tariff or another applicable service arrangement.

4.2 Types of Facilities Interconnecting as Large Loads

The current inventory of projects seeking to interconnect directly on National Grid’s system includes data centers and digital infrastructure, advanced manufacturing, industrial expansions, institutional and research facilities, public infrastructure, and other energy-intensive development. As of **September 2026**, the inventory of projects in the NYISO queue included **10 data-center projects totaling 1,620 MW; 5 manufacturing and industrial projects totaling 1,177 MW; and 11 other projects totaling 195 MW.**

4.3 Differences from Other Customer Classes

The process for determining a rate classification is distinct from the process for evaluating system impacts. Smaller customers that can be served through existing distribution facilities ordinarily follow distribution connection and planning procedures. Large loads requiring transmission service generally involve additional NYISO studies, regional reliability evaluation, engineering, and coordination. These differences arise from the size and electrical system impact of the request, not solely from the customer’s end-use sector.

Large load projects may require dedicated personnel and extensive coordination through study, engineering, agreements, procurement, and construction. Smaller requests may be processed through established distribution work-request and design procedures, including collection and validation of load, one-line, metering, billing, and design information. The difference in process reflects the facilities and reliability analysis required, rather than preferential treatment of one customer class.

National Grid’s existing customer-connection procedures also illustrate that rate validation and technical design are related but distinct activities. Customer rate eligibility is reviewed and documented, while engineering determines how the requested load can be served safely and reliably.

4.4 Findings

Existing tariff classifications can be applied based on customer and service characteristics, but the scale and operating characteristics of the largest loads may warrant additional rate transparency and tailored protections. In Case 26-E-0045, National Grid proposed that the Commission direct utilities to develop a dedicated large-load rate class for the largest customers, with cost-of-service allocation and rate design reflecting their load shapes, ramp profiles, and contribution to system peaks.

The principal current-practice finding is that “large load” is not itself a complete retail service classification. Billing treatment depends on the final service arrangement and tariff eligibility. The Commission may nevertheless determine that the largest loads have sufficiently distinct usage, ramping, and risk characteristics to justify a new class or tailored provisions.

National Grid’s proposed dedicated class would be intended to make cost responsibility for these larger customers more transparent and permit rate design and contractual provisions tailored to the largest loads. The threshold, allocation method, rate design, and transition treatment would require further development and Commission approval.

5. Network Upgrades

5.1 Development of Interconnection and Network Upgrade Estimates

Required facilities and potential network upgrades are identified through NYISO studies and subsequent National Grid facility-study and engineering work.

National Grid’s estimation process follows the progression of estimate classes defined by the Association for the Advancement of Cost Engineering (AACE) and is tailored to align with study requirements within the

NYISO OATT Tariff and National Grid's Network Development Playbook. Following acceptance of cost responsibility, execution of a Cost Reimbursement Agreement (CRA), and customer provided security, the project is advanced through the Project Development phase where estimates mature to Class 2 and are developed by the Estimating Department using significantly more detailed engineering information. At this stage, project-specific risk analyses may be performed, including quantitative risk assessments and Monte Carlo simulations to develop confidence-based cost ranges such as P50 and P80 values. The P50 and P80 estimates are based on complexity.

The cost-estimating process follows the maturity of the engineering solution. Early estimates may be appropriate for screening alternatives and understanding order of magnitude, but they are not equivalent to a facility-study estimate or a sanctioned construction estimate. Later estimates incorporate more complete engineering, equipment quantities, labor assumptions, market pricing, site conditions, construction methods, permitting, property, outage, and project risk information.

For more complex projects, National Grid may perform quantitative risk analysis, including Monte Carlo analysis, to develop confidence-based ranges such as P50 and P80 estimates. Presenting a range and estimate class is more informative than presenting a single figure without context because it communicates the level of definition and uncertainty at the time the estimate was prepared.

5.2 Types of Interconnection and Network Upgrade Costs

Depending on the project, facilities may include customer attachment facilities; revenue metering and remote-terminal equipment; transmission or sub-transmission lines; substation additions or modifications; transformers; protection and control systems; telecommunications; short-circuit or voltage-performance solutions; engineering and project management; construction management; permitting; real-estate interests; and other infrastructure needed to provide reliable service. The exact mix is determined by the project's location, size, operating characteristics, point of interconnection, and system impacts.

Costs can be grouped by facility function as well as by physical asset. Generally, costs fall into various categories such as: interconnecting-customer attachment facilities; system-upgrade facilities for metering and remote-terminal equipment; system upgrade line and station facilities; and network upgrade line and station facilities. The classification is informed by the configuration, identified violation, and selected solution.

Physical scope may include line extensions or rebuilds, new or modified substations, transformers, breakers, protection and control, telecommunications, metering, civil work, engineering, construction management, environmental permitting, property rights, and outage coordination. Not every project requires each category, and the final mix cannot be determined solely from requested MW.

5.3 Costs over the 24-Month Reporting Period

During the 24-month period ending August 2026, no projects had been completed with network-upgrade costs.

5.4 Comparison of Actual Costs with Estimates

Only projects that have advanced sufficiently into procurement or construction can support a meaningful comparison of estimated and actual costs. Given that National Grid has had no projects completed in the last 24 months with network upgrade costs incurred, an analysis of actual costs compared to estimates cannot be completed.

5.5 Findings

Current estimating practices appropriately become more detailed as projects mature, but early-stage uncertainty limits the precision available to customers and policymakers. Clear identification of estimate class, assumptions, contingency, risk range, and information date are needed for comparability. In Case 26-E-0045, National Grid described ongoing work on standardized substation starter designs and associated order-of-magnitude estimates, developer-facing digital tools, advanced analytics, and grid-enhancing technologies. These initiatives could improve early cost visibility and reduce development time, but site-specific engineering and reliability review would remain necessary.

National Grid's proposed standard substation designs may reduce repeat engineering decisions and support earlier order-of-magnitude cost ranges for common configurations. The Company also described potential use of digital tools and analytics. These initiatives complement, but do not replace, site-specific design, environmental review, procurement, and reliability analysis.

6. Cost Allocation

6.1 Whether a Large Load Pays the Full Cost of Interconnection

Under current practice, a large load does not necessarily pay every cost of all system facilities identified in connection with its request. National Grid applies its retail tariff and applicable agreements to determine customer responsibility. Facilities serving only the customer, unusual expenditures required because of the location, character, or service requirements of the installation, and special facilities requested by the customer may be assigned to the customer. Examples can include dedicated service laterals, express feeders, customer-specific transformers, dual feeders, special substations, future-capacity facilities, or enhanced-reliability facilities, depending on the applicable tariff provision and project configuration.

Facilities that are part of the integrated utility network and are not directly assigned under applicable provisions are generally treated as utility-network facilities and recovered through Commission-approved rates. The determination is project-specific and depends on facility function, configuration, ownership, applicable voltage and tariff provisions, and the reason the facility is required.

6.2 Portion of Network Upgrade Costs Paid by the Large Load

Customer-assigned facilities may be funded through a Contribution in Aid of Construction (CIAC), revenue assurance, or another customer-specific mechanism authorized by the tariff or project agreement. Where a facility remains part of the shared network and is not deemed chargeable under the applicable tariff provisions, its revenue requirement is generally recovered through rates, and the large load contributes through its allocated share of delivery charges. Thus, a large load may pay directly for customer-specific facilities and also pay an ongoing share of embedded and incremental system costs through rates.

Over the past 24 months ending August 2026, National Grid has not had any network upgrade costs incurred to serve a large load, and therefore had no payments from large loads for network upgrades.

6.3 Assignment among the Large Load, Other Large Loads, and Customers Generally

The current framework distinguishes direct customer responsibility from recovery of integrated network costs. Direct assignment follows applicable tariff provisions and customer agreements. Costs recovered through rates become part of the utility revenue requirement and are allocated among customer classes in rate proceedings through cost-of-service studies. Those studies consider how classes use the system, contribute to system peaks, benefit from facilities, and drive investment. Large load customers therefore

contribute not only to facilities directly assigned to them but also to shared system costs through their tariffed rates.

The tariff and cost-of-service study framework reflects both beneficiary-pays and cost-causation principles. Under current tariff treatment, facilities determined to be customer-specific and chargeable to the customer under the tariff are assigned to the customer receiving the principal benefit, while shared network facilities not determined to be chargeable under the tariff are recovered from classes that use and benefit from the integrated system, proportionally to how they drive costs on the system. As a result, the fact that a facility was identified during a large-load interconnection study does not by itself determine cost responsibility. Cost responsibility depends on how the facility is treated under the tariff and ratemaking framework, including whether it serves a customer-specific function or forms part of the integrated utility system.

Under cost-of-service ratemaking, utility revenue requirements are assigned and allocated to customer classes and then recovered through rate design. The process considers the functions and cost drivers of the system and each class's use of and contribution to those costs. A large load's high demand and energy usage can result in a material allocation of transmission, distribution, and other delivery costs under the applicable methodology.

A future dedicated large-load class would permit the Commission and stakeholders to evaluate that responsibility separately from the existing large general-service class. National Grid's comments in case 26-E-0045 state that such a class should use cost-of-service allocation and tailored rate design. This remains a proposed policy rather than present treatment.

6.4 Recovery or Credit of Upgrade Costs over Time

Costs directly assigned to a customer are recovered through CIAC, revenue assurance, or another customer-specific charge and are not also recovered from other customers through delivery rates. Shared utility-system costs enter the Company's accounting records as incurred and, where authorized, become part of the revenue requirement when placed into service. Depreciation, taxes, operating costs, and return are reflected through Commission-approved ratemaking, and the resulting revenue requirement is allocated among classes through embedded cost-of-service studies and rate design. Revenue requirements and embedded cost-of-service allocations are developed in rate proceedings rather than during the initial engineering estimate.

This sequencing is important. The engineering estimate determines the anticipated cost of the project scope. Tariff analysis determines customer responsibility for applicable facilities. Accounting records actual expenditures by account as work proceeds. Ratemaking then determines the authorized revenue requirement and allocation of shared costs. These are connected processes, but they are not one simultaneous model used at the first estimate stage.

6.5 Protection from Projects that Do Not Materialize or Use Less Capacity

Current protections include the prospective customer funding the interconnection studies, CIAC for applicable customer-assigned facilities, cost-reimbursement agreements, revenue-assurance arrangements, minimum contract demand obligations, and financial security. Under revenue assurance, projected incremental revenue may be considered in determining whether a CIAC is required. A participating customer agrees to a minimum monthly contract demand and provides an irrevocable letter of credit. If actual demand is below the contractual minimum, billing at the minimum level helps protect the Company and other customers from revenue shortfalls associated with the facilities constructed to serve the project.

CIAC provides the clearest protection for the capital cost of directly assigned facilities because the customer funds the applicable responsibility before utility capital outlays. Revenue assurance reduces or replaces an upfront contribution by recognizing projected incremental revenue, but it also binds the

customer to a minimum contract demand and requires collateral. If the customer uses less than the minimum, billing at the minimum demand supports the revenue commitment.

The irrevocable letter of credit provides additional protection if the customer does not connect after construction, fails to pay, or closes before the end of the agreement term.

In its comments and reply comments in Case 26-E-0045, National Grid proposed additional prospective protections for the largest loads. The proposals include 100 per cent upfront CIAC for sole-use facilities, elimination of revenue assurance for those facilities, mandatory long-term take-or-pay agreements, minimum demand charges, minimum contract terms, exit fees, collateral, a dedicated large-load rate class, and a State-prescribed customer-benefit contribution. National Grid also proposed continued rate-based recovery of integrated network upgrades, paired with binding customer commitments (take-or-pay agreements) intended to address delay, underutilization, attrition, financing, and credit risks. The purpose of these proposals is to retain beneficiary-based recovery for network facilities while reducing the risk that other customers bear costs if the new load fails to materialize or underutilizes capacity. These proposals have not yet been adopted as current tariff practice.

6.6 Findings

Current practice differentiates customer-specific facilities from integrated network facilities and uses both direct charges and tariffed rates to recover costs. The principal policy challenge is not simply whether the large load pays, but how payment should be structured over time and how risk should be allocated if the project is delayed, downsized, or cancelled. National Grid supports retaining clear direct responsibility for sole-use and other customer-assigned facilities while strengthening commitments tied to system investment.

National Grid's position is that requiring a single requester to fund every shared network upgrade identified in their interconnection process is unjust and unreasonable because it:

- (1) fails to account for broader reliability, capacity, asset-condition, and future-use benefits and is therefore inconsistent with beneficiary pays principles.
- (2) may distort integrated system planning, favoring piecemeal lowest-cost individual customer planning over holistic assessments of low cost, best fit solutions for all customers served by the shared network infrastructure broadly.
- (3) creates first mover penalties and free rider concerns when an initial load triggers and pays for shared upgrades while subsequent loads can use the capacity created by those upgrades without payment.

The proposed alternative is to maintain beneficiary-based rate recovery for integrated network facilities while ensuring the large load contributes through a dedicated cost-reflective class and binding financial commitments. Any final framework will require Commission action and tariff implementation.

The framework is not a binary choice between "customer pays" and "ratepayers pay." Large loads can bear direct responsibility for customer-assigned facilities and, at the same time, contribute to shared facilities through cost-reflective rates. The critical questions are which facilities are customer-specific, which provide integrated system benefits, and whether the customer's financial commitment is sufficient for the timing and scale of investment.

7. Supply Cost Impacts

Under current policies and practice, National Grid has no input or control over supply costs and therefore does not maintain a formal procedure in the ordinary course of business for estimating the electric supply cost impact associated with an individual large load interconnection request. As a transmission and distribution utility, National Grid's evaluation of large load projects is focused on transmission and

distribution system impacts, including the identification of any transmission or distribution facilities, modifications, or network upgrades required to provide reliable electric service. Wholesale market administration, energy and capacity market operation, and resource adequacy assessments are principally performed by the New York Independent System Operator (“NYISO”). Accordingly, National Grid does not maintain a standard project-specific methodology for evaluating the effect of an individual large load on wholesale energy prices, capacity prices, ancillary-service markets, congestion costs, or other supply-related market outcomes.

National Grid recognizes that New York State has a shrinking reliability margin and a future load forecast that is expected to exacerbate the problem. The Company also is aware that wholesale market impacts under constrained or scarce conditions, whether arising from aggregate large-load growth or extreme weather, can adversely affect supply costs. Comprehensive consideration of market impacts from large loads is a matter that the Department of Public Service should consider undertaking, with participation from NYISO, utilities, and other stakeholders.

8. Risk Management

8.1 Financial Risk if Demand or Consumption Changes after Service Begins

A large load may create financial risk if the utility constructs facilities based on forecast demand and the customer later operates at a materially lower level, delays commencement, or closes before the investment is recovered. Risks can include unrecovered capital-related revenue, ongoing operation and maintenance, property taxes, and a shift of shared costs to other customers. The significance of the risk depends on facility assignment, contractual protections, customer credit, timing, and whether facilities provide broader system benefits.

Risk differs by facility type. For customer-funded facilities, upfront recovery limits or eliminates direct capital exposure, although the Company may still own and maintain facilities after energization. For shared network facilities recovered through rates, a shortfall in the expected billing contribution can increase the amount recovered from other customers unless other protections apply. The duration and utilization of the load are therefore important alongside the initial interconnection cost.

A change in demand profile can also affect system planning. If actual demand ramps more slowly than forecast, capacity may be underutilized for a period. If demand ramps more quickly or operates differently from the studied profile, additional reliability review or operational measures may be required. Financial and technical risk management should therefore use consistent contractual and operating assumptions.

8.2 Tools and Processes Used to Manage Risk

Current tools include study deposits, customer-funded preliminary and facility studies, CIAC for applicable customer-assigned facilities, cost-reimbursement agreements, revenue assurance, minimum contract demand billing, and irrevocable letters of credit. CIAC collected before utility capital outlays limits direct capital exposure for customer-assigned facilities. Revenue assurance permits projected future incremental revenue to support the facilities while contract demand and collateral provide protection if actual demand or payment falls short.

National Grid also monitors project development, updated schedules, forecasts, study milestones, engineering progress, agreements, and financial commitments. The ability to adjust planning assumptions as information changes helps limit reliance on requests that have not demonstrated sufficient maturity. In addition, National Grid reviews and provides input to NYISO’s zonal market forecast that is published annually.

Study deposits and customer-funded engineering protect other customers from the cost of evaluating a project that does not proceed. CIAC and cost-reimbursement agreements address applicable construction and development costs. Revenue assurance addresses recovery through a guaranteed minimum demand and collateral. Project monitoring and updated customer information support decisions about when to advance engineering, procurement, and construction.

These tools operate at different points in the process and should not be treated as interchangeable. A study deposit does not secure the full construction exposure. A letter of credit supports the contractual obligation but does not itself define the customer's cost responsibility. The tariff and agreements establish the underlying obligation, while the financial security protects performance.

8.3 Attrition Rate over the Last 24 Months

Since 2022, National Grid has been identified as the Connecting Transmission Owner ("CTO") for 25 large load interconnection requests submitted to the NYISO. Eighteen of these requests were submitted within the last 24 months. Of the 25 projects submitted since 2022, five have withdrawn from the NYISO interconnection process, representing an attrition rate of approximately 20 percent. Of the 18 projects submitted within the last 24 months, two have withdrawn, representing an attrition rate of approximately 11 percent.

The reported attrition percentage describes a defined historical population and should not be applied mechanically as a forecast for the current pipeline. The sample is limited, the mix of projects is changing, and many active projects remain in early stages. The statistic is most useful as evidence that not every request advances and that maturity should be reflected in forecasting and investment decisions.

Any reporting of attrition rates should disclose the numerator, denominator, time period, connection role, and definition of withdrawal. If projects that are prospective, affected-system, superseded, or paused are included elsewhere in the report, they should not be added to this attrition calculation without restating the methodology.

8.4 Variation in Attrition by Project Stage

All withdrawn projects exited the NYISO interconnection process prior to completion of the System Impact Study. National Grid is not aware of any projects that have withdrawn after completion of the System Impact Study, during the Facility Study phase, or after execution of Cost Reimbursement Agreement.

Accordingly, attrition observed to date has occurred during the early stages of the interconnection process, prior to completion of detailed engineering studies and identification of final facility requirements.

The concentration of withdrawals before SIS completion is consistent with greater uncertainty early in development. At that stage, customers may still be evaluating site feasibility, system impacts, commercial arrangements, and alternatives. Advancement beyond study, execution of agreements, and financial commitments generally indicate increasing maturity, although they cannot eliminate all delay or closure risk.

Because no withdrawals were identified in later stages for the reported population, the available data do not support a statistically meaningful comparison of later-stage attrition rates.

8.5 Treatment of Costs after Cancellation or Delay

Customer-funded study and project-development costs are handled under the applicable study, support-services, or cost-reimbursement agreement. CIAC and other customer-specific payments protect against costs directly assigned to the customer. Treatment of costs for shared utility-system facilities depends on whether costs have been incurred, whether work remains useful for the system or another project, applicable agreements, and Commission-approved accounting and ratemaking.

Cost treatment after cancellation or delay vary depending on category: customer studies are customer-funded up front, work in progress that is chargeable to the customer has either been paid via CIAC ahead of the expenditure or covered by a letter of credit when revenue assurance has been applied, and company-owned assets generally are recovered after completion once they are reflected in rates.

8.6 Findings

Current mechanisms provide meaningful protection, particularly where customer-specific costs are funded before material capital outlays. However, the scale, long lead times, and potential volatility of the largest requests can create risks not fully addressed by traditional arrangements. Early-stage attrition indicates that queue entry alone should not be treated as evidence that demand will materialize.

In Case 26-E-0045, National Grid proposed a standardized large-load tariff framework with minimum demand commitments, long contract terms, exit fees, collateral, and project-readiness requirements. The Company also supported site control, duplicate-project disclosure, realistic schedules, technical data, modeling inputs, deposits, advancement milestones, limits on major post-study changes, and removal and re-entry rules for stalled projects. These proposals are intended to distinguish credible projects, improve forecast quality, and protect customers from financial and cost shifting risks before major system investments are made. Current protections are strongest once enforceable payment, contract demand, and security obligations are in place. The greatest uncertainty arises before those commitments, when requested capacity may already influence workload and expectations but project maturity is not established. This supports stronger readiness screens before early-stage requests materially affect forecasts or trigger major expenditure.

National Grid's proposed take-or-pay and dedicated-class framework is intended to address utilization and credit risk for shared network investment while preserving direct CIAC for sole-use facilities. The details, including threshold, minimum billing level, term, collateral, and exit-fee calculation, would require tariff development and Commission approval.

9. Internal Processes and Tools

9.1 Internal Management Reports, Dashboards, and Reference Materials

National Grid does not rely on a single system of record for large load requests. Rather, information is maintained and managed across multiple business processes, engineering tools, studies, reports, and tracking mechanisms. The large load inventory consolidates available project information from these sources to support portfolio-level visibility and management reporting. The inventory captures available information concerning project identity, end use, requested MW, location, NYISO queue status, point of interconnection, Connecting and Affected Transmission Owners, project stage, study availability, and anticipated in-service timing. Because projects are often in various stages of development, information may be incomplete, preliminary, or subject to change as additional details become available.

Management reporting provides an aggregated view of the queue, requested capacity, Connecting and Affected Transmission Owner exposure, sector mix, project stage, accomplishments, risks, and next steps. Engineering teams use NYISO studies, National Grid planning criteria, the Network Development Playbook, and progressively detailed estimating practices to manage individual projects. Customer and rate teams use applicable tariff provisions and rate references to determine service classification and customer responsibility.

The management report aggregates available project data to directionally understand load growth in the territory and is intended for management visibility rather than for regulatory reporting. Project teams also rely on formal studies, engineering records, estimates, agreements, and the Network Development Playbook for project execution.

9.2 How Reports Are Used and Key Metrics Tracked

Internal tools support portfolio visibility, resource coordination, project escalation, executive reporting, and identification of emerging constraints. Key metrics include number of projects, requested MW, project sector, Connecting or Affected Transmission Owner status, NYISO zone and point of interconnection, stage, study and agreement status, forecast in-service date, cost-estimate maturity, major schedule risks, and withdrawal status. Project teams also track customer information needs, scope changes, technical deliverables, agreements, security, procurement, construction, and commissioning milestones as applicable.

Portfolio reporting supports understanding of workload, potential system exposure, project progression, and issues requiring coordination or escalation. Project records support the detailed technical, commercial, and schedule decisions needed to advance an individual request. Rate and tariff references support service-classification and customer-responsibility determinations. The different tools should therefore be reconciled, but they should not be assumed to have identical purposes or data definitions.

9.3 Findings

Existing tools provide substantial project and portfolio information, but consistent definitions and a single reporting cut-off are important. A public aggregate report should avoid combining direct connections, affected-system projects, and unqueued prospects without explanation. Standard data definitions, project identifiers, stage gates, confidence levels, and regular reconciliation with NYISO would improve comparability and reduce the risk of double counting. In Case 26-E-0045, National Grid also described development of a next-generation customer portal and supported clearer NYISO milestones, more structured information sharing, and earlier non-binding transmission-system information.

National Grid's filed comments describe a next-generation self-service portal intended to improve status visibility, information exchange, and customer interaction. The Company also supports continued publication and updating of interconnection guidance. These measures could improve transparency, but implementation details and recovery of associated costs remain prospective.

10. Overall Findings and Opportunities for Improvement

10.1 Key Conclusions

- Large load demand includes a diverse mix of data centers, manufacturing, industrial, institutional, public-infrastructure, and other projects. Requested capacity is not the same as forecast or committed demand because the portfolio includes projects at substantially different levels of maturity.
- Existing NYISO and utility study processes provide a structured framework for evaluating reliability impacts and required facilities. The main constraints on predictability are evolving customer information, project complexity, coordination across entities, study volume, permitting, long-lead equipment, and construction requirements.
- Current tariff and ratemaking practices distinguish customer-specific facilities from integrated utility-system facilities. Large loads contribute through direct payments for assigned facilities and through tariffed rates for shared network costs that are not deemed chargeable under the tariff. Financial protections are particularly important where utility investments precede customer revenue.

- National Grid does not maintain a routine project-specific supply-cost model. The broader wholesale supply implications of aggregate large load growth are more appropriately evaluated at a State or NYISO level using consistent assumptions.
- No single technology or operating arrangement is appropriate for every project. Curtailment, storage, co-located generation, phased ramps, demand response, advanced analytics, standardized designs, and grid-enhancing technologies may support earlier or more efficient connections where technically feasible, observable, and enforceable.

On balance, the current framework provides the core technical, tariff, contractual, and ratemaking tools needed to process large load requests, but the unprecedented scale and pace of queue growth and the associated demand create material pressure on forecasting, study resources, transparency, financing, and customer protection. The principal gaps identified in this report relate to project maturity and forecasting, consistency of data and modeling inputs, transparency regarding study milestones and non-local upgrades, early-stage cost and schedule visibility, and customer protection against delay, attrition, underutilization, and credit risk. Some improvements can be implemented through near-term administrative actions, including standardized project definitions, common reporting populations, enhanced data requirements, clearer milestones, improved transparency, and regular reconciliation of project information. Other reforms, including maturity criteria, queue-discipline measures, large-load tariff structures, treatment of inter-transmission-owner upgrades, and long-term financial commitment requirements, would require coordination with NYISO and/or Commission action. The principal need is targeted reinforcement of the existing framework rather than wholesale replacement of current processes.

The public record should distinguish established practice from pending policy proposals. Current practice includes NYISO and utility studies, customer-funded study work, tariff-based cost responsibility, CIAC and revenue assurance where applicable, cost-of-service recovery of shared utility facilities not deemed directly chargeable under the tariff, and project monitoring. Proposed changes include stronger maturity screens, a dedicated class, take-or-pay contracts, revised sole-use treatment, and statewide treatment of inter-transmission-owner upgrades.

10.2 Issues and Challenges

- Distinguishing credible demand from preliminary, duplicative, alternative, or speculative requests before those requests influence forecasts and investment decisions.
- Obtaining complete and stable technical information early enough to avoid repeated studies and redesign.
- Providing useful early cost and schedule information while acknowledging that reliable estimates require progressively detailed engineering.
- Coordinating non-local upgrades and cost recovery when a project connects to one Transmission Owner but affects another.
- Protecting customers from underutilization, delay, cancellation, and credit risk without assigning shared network costs in a manner that ignores broader benefits or distorts long-term planning.
- Maintaining reliability as very large, power-electronics-intensive, or highly variable loads connect at transmission voltage.
- Aligning interconnection timing with generation adequacy, State policy objectives, and the long lead times required for transmission and substation infrastructure.

The issues are interdependent. More rigorous intake can improve forecast and study quality, but requirements should be calibrated so that credible projects can enter the process. Earlier cost information can support development decisions, but overly precise early estimates can be misleading. Financial commitments can protect customers, but cost assignment should still reflect whether facilities are customer-specific or provide broader system benefits.

Similarly, flexibility can accelerate service where it reliably limits net demand, but a capability that is not visible, measurable, and enforceable should not be treated as firm capacity. Co-located generation can reduce net load, but its study and operating treatment must account for export, availability, and coordination with NYISO. These trade-offs support a case-specific framework with consistent minimum standards.

10.3 Opportunities for Improvement

National Grid's comments and reply comments in Case 26-E-0045 identify a prospective package of reforms. These include standardized intake and modeling requirements; milestone-based maturity and forecast-inclusion criteria; stronger queue discipline; clearer study milestones; improved transparency for non-local upgrades; project-ready customer portals; standardized substation designs and estimates; and case-specific use of flexibility, storage, co-located generation, phased ramps, demand response, and grid-enhancing technologies.

For customer protection and cost recovery, National Grid proposed upfront CIAC for sole-use facilities, a dedicated large-load rate class, long-term take-or-pay contracts, minimum demand charges, exit fees, collateral, and a State-prescribed customer-benefit contribution. The Company also proposed a statewide approach to inter-transmission-owner network upgrades and continued beneficiary-based recovery of integrated network investments.

The most immediate opportunities are to establish consistent project populations and definitions for reporting; strengthen information and readiness requirements before projects influence forecasts; improve transparency regarding stage, estimate confidence, and schedule; and align financial commitments with the timing of utility investment. Longer-term reforms should preserve engineering judgment and case-specific evaluation while providing customers, utilities, NYISO, DPS, and the Commission with clearer expectations and more comparable information.

Near-term administrative improvements include a statewide data template, common project-stage definitions, consistent reporting populations, explicit estimate classes, defined timeline start and end points, and regular reconciliation among utilities and NYISO. These measures can be implemented without pre-determining the Commission's final decisions on tariffs or cost allocation.

Process improvements requiring broader coordination include NYISO maturity and forecasting criteria, queue discipline, standard modeling packages, clearer SIS milestones, transparency for affected-system upgrades, and streamlined study of co-located resources. Utility initiatives include standard station designs, analytics, digital customer tools, and evaluation of advanced technologies.

Policy reforms requiring Commission action include dedicated large-load tariffs or classes, long-term minimum demand commitments, exit fees, collateral, treatment of revenue assurance for sole-use facilities, customer-benefit contributions, and a statewide approach to inter-transmission-owner upgrade costs. The objective should be a framework that permits responsible growth while protecting reliability and ensuring that existing customers do not bear inappropriate cost or credit risk.

11. Conclusion

New York is entering a period of transformative electric load growth that presents both a major economic opportunity and a significant planning challenge. The scale of interest from data centers, advanced manufacturing, and other large energy users underscores the State's attractiveness for investment and innovation. At the same time, the magnitude, timing, and characteristics of these requests introduce new demands on system planning, infrastructure development, interconnection processes, and customer protections. The central finding of this report is that New York's existing framework remains fundamentally

capable of accommodating large load growth, but continued success will require greater transparency, stronger readiness standards, improved data quality, and more predictable processes for all participants. National Grid believes that reliability, affordability, and economic development are not competing objectives. The State can support substantial new investment and electrification while maintaining a safe and reliable electric system, provided that project advancement is grounded in demonstrated readiness, sound engineering, and clear financial commitments. Future policy should distinguish between mature and speculative requests, ensure that infrastructure planning reflects project certainty and customer benefit, and maintain cost-allocation principles that recognize both direct customer responsibility and the broader benefits provided by shared network investments. Long-term success will depend on balancing the need to attract growth with the obligation to protect customers from inappropriate cost, utilization, and credit risks.

Accordingly, National Grid supports targeted reforms that strengthen and modernize the existing framework rather than replace it. Enhanced project-readiness requirements, clearer study milestones, improved visibility into network upgrades, standardized data and modeling practices, modern digital tools, and appropriate financial protections can improve predictability and accelerate responsible development while preserving reliability. The objective should be a durable statewide framework that enables economic growth, supports investment in critical infrastructure, promotes fairness and transparency, and ensures that New York remains positioned to meet the energy demands of the future while protecting the customers and communities it serves.

Appendix E

New York Power Authority

Case 26-E-0045

Proceeding on Motion of the Commission to Address Interconnection Reforms for Large Loads.

Report Outline

Executive Order 62 directs the Department of Public Service (DPS) to convene the State’s transmission owners, to review sufficiency of current practices for studying the system impacts of large loads, and to report to the Commission within 90 days. To support the development of this requirement, DPS has issued IRs to the TOs with the intent to have the research and responses be the foundational element to develop the report.

In response, NYPA offers the following to support and assist DPS in preparing the DPS report:

Pursuant to Public Authorities Law §1014, the New York Power Authority (“NYPA,” “the Power Authority”) and its rates, services, and practices are non-jurisdictional. We respectfully note that NYPA’s participation in the above proceeding and responses shall not be interpreted as submitting to any jurisdiction over the Power Authority. In support of DPS in its effort to prepare its report pursuant to Executive Order 62, NYPA provides the following information.

As a bulk transmission owner, NYPA’s processes for load interconnection and cost recovery are subject to the NYISO’s Federal Energy Regulatory Commission-approved Tariff and processes. Information on seeking connection to NYPA’s system is publicly available on NYPA’s load interconnection website and the NYISO’s tariff, manuals, tech bulletin, and website.¹ NYPA’s load interconnection website helps direct potential connecting loads and provides required information.²

Specifically, NYPA’s Load Interconnection process is a structured, multi-phase pathway designed to take a new large-load developer from initial concept through engineering, regulatory

¹ <https://www.nyiso.com/interconnections>

² <https://www.nypa.gov/Power/Transmission/loadinterconnection>

approvals, construction, and final energization. The process will also require coordination with the franchise service territory utility and potentially affected transmission owners. The full timeline spans approximately 42–80 months, depending on project complexity and NYISO study duration. System capability is determined through the NYISO System Reliability Impact Study (SRIS) and developers are studied on a first-firm, first-served basis.

Process Overview

1. Early Engagement & Site Control

Developer contacts NYPA to initiating fact-finding discussions and execution of non-disclosure agreements (NDAs). Developer establishes site control and receives preliminary guidance on available programs.

2. NYISO Interconnection Studies

Developer files a load interconnection request with NYISO. Upon receipt and review of the request, NYISO conducts the SRIS to determine system impacts, required upgrades, and affected transmission owners. Developer must demonstrate substation site control and secure long-lead equipment positions. Developer must also engage with franchise service territory utility for service agreements and coordination with NYPA system upgrades.

3. Facility Study & Firm Commitment

NYPA performs the Facility Study while other transmission owners complete Affected System Studies. Costs are finalized, and the developer must post financial security. A project becomes “firm” only once the Facility Study is complete and security is posted.

4. Commercial Agreements

NYPA issues draft versions of the Developers Agreement and Asset Purchase Agreement. These documents undergo iterative review among NYPA, the developer, load serving entity, and other stakeholders until all comments are resolved.

5. Engineering, Procurement & Construction (EPC)

Developer engages an EPC firm. NYPA may support design review, procurement specification review, construction oversight, testing, commissioning, and final transfer of assets at Developer's cost. Energization marks the completion of the interconnection with NYPA; the load may have other obligations with the franchise service territory utility.

Critical Requirements

- Developer projects must not degrade system reliability or transfer limits, and as such must mitigate the adverse impacts on the system.
- Developer pays all interconnection-related upgrade and process costs.
- NYISO SRIS determines system capability; study position is granted on a first-firm, first-served basis.
- Hiring NYISO-experienced engineers is strongly recommended to avoid delays and reduce project risks.

NYPA currently has 14 large loads seeking potential interconnections to its systems. At present, NYPA requires interconnecting load projects to fund all necessary upgrades and to post security to ensure that NYPA and its transmission rate ratepayers do not bear the costs. This requirement ensures 1) alignment with the generator process where interconnecting projects bear

the costs to incentivize projects to seek lower interconnection cost sites; and 2) that projects avoid passing on the costs to interconnect new load projects to existing ratepayers.

As a bulk transmission owner whose facilities cross the entire state, NYPA is unique in that it does not have a franchise service territory like distribution utilities. In addition, NYPA's transmission system can often be an affected transmission facility that requires upgrades to support the load interconnections on another transmission owner's system.

NYPA appreciates the opportunity to participate in the Commission's proceeding and looks forward to continued collaboration with DPS and the transmission owners.

Appendix F

New York State Electric & Gas Corporation / Rochester Gas and Electric
Corporation

Case 26-E-0045

Proceeding on Motion of the Commission to Address Interconnection Reforms for Large Loads.

Report

Executive Order 62 directs the Department of Public Service (“DPS”) to convene the State’s transmission owners, to review sufficiency of current practices for studying the system impacts of large loads, and to report to the Commission within 90 days. To support the development of this requirement, DPS has issued IRs to the TOs with the intent to have the research and responses be the foundational element to develop this report. This report on New York State Electric & Gas Corporation (“NYSEG”) and Rochester Gas and Electric Corporation (“RG&E”) (collectively, the “Companies”) practices related to large loads builds on those IRs and follows the report outline provided by DPS on August 25, 2026.

1. Large Load Demand

a. Explanation of intake process for interconnection request

Large load requests may be received through multiple channels. The Companies first review each request for adequate technical accuracy and coordinates with the customer to resolve discrepancies. This initial review generally requires at least one week, but customer coordination may extend for days or months until enough information is available to begin a study.

For projects under New York Independent System Operator (“NYISO”) jurisdiction, the request proceeds through the applicable NYISO interconnection process. For projects fully within the local Transmission Owner’s jurisdiction, the Companies initiate an internal study equivalent to a System Impact Study. Depending on the point of interconnection, distribution and transmission analyses may begin concurrently, or distribution analysis may need to advance before transmission analysis can begin.

b. Summary of inventory—number of projects, MW, project status, etc.

NYSEG and RG&E have received a total of 36 large (10 MW+) load projects. 12 of these are NYISO jurisdictional projects (total 2,460 MW); 24 are non-NYISO jurisdictional (total 560 MWs). Of these 36 total projects, 10 projects are canceled, two are in service, and the remaining projects are in various stages of the applicable study process. See Table 1 below for additional details.

Table 1. Summary of NYSEG and RG&E Large Load Requests

#	Jurisdiction	Industry	Initial Request Submission Date	Peak MW Load	Controlling Utility
1	Non-NYISO	EV	Aug 2024	10	NYSEG
2	Non-NYISO	EV	Aug 2024	10	NYSEG
3	Non-NYISO	EV	Aug 2024	12	NYSEG
4	Non-NYISO	Manufacturing	Sep 2024	14	NYSEG
5	Non-NYISO	EV	Sep 2024	10	NYSEG
6	Non-NYISO	Housing	Oct 2024	13	NYSEG
7	Non-NYISO	Manufacturing	Jan 2025	40	NYSEG
8	Non-NYISO	Manufacturing	Apr 2025	10	RGE
9	Non-NYISO	Data Center	Apr 2025	11	NYSEG
10	Non-NYISO	Data Center	May 2025	34	RGE
11	Non-NYISO	Manufacturing	May 2025	24	NYSEG
12	Non-NYISO	Data Center	Jun 2025	100	RGE
13	Non-NYISO	Industrial Park (Misc)	Jun 2025	30	NYSEG
14	Non-NYISO	Data Center	Jun 2025	23	NYSEG
15	Non-NYISO	Dairy Manufacturing	Jul 2025	22	RGE
16	Non-NYISO	Data Center	Aug 2025	40	NYSEG
17	Non-NYISO	Data Center	Feb 2026	20	NYSEG
18	Non-NYISO	Data Center	Jan 2026	20	NYSEG
19	Non-NYISO	Data Center	Jul 2026	10	NYSEG
20	Non-NYISO	Manufacturing	Jul 2026	25	NYSEG
21	Non-NYISO	Manufacturing	Jul 2026	10	NYSEG
22	Non-NYISO	Warehouse	Aug 2026	11	RGE
23	Non-NYISO	Data Center	Aug 2026	25	NYSEG
24	Non-NYISO	Manufacturing	Aug 2026	40	NYSEG
25	NYISO	Data Center	Oct 2018	60	NYSEG
26	NYISO	Data Center	May 2019	250	NYSEG
27	NYISO	Data Center	May 2019	50	NYSEG
28	NYISO	Data Center	Jan 2024	250	NYSEG
29	NYISO	Data Center	Apr 2024	88	NYSEG
30	NYISO	Data Center	Dec 2024	200	NYSEG
31	NYISO	Data Center	Mar 2025	250	NYSEG
32	NYISO	Data Center	Mar 2025	162	NYSEG
33	NYISO	Research & Development	Oct 2025	250	NYSEG
34	NYISO	Data Center	Apr 2026	150	NYSEG
35	NYISO	Data Center	May 2026	400	NYSEG
36	NYISO	Data Center	May 2026	350	NYSEG

c. Explanation of trends—application flow, notable categories, etc.

The Companies have experienced an increase in large load application activity and note the following observations:

- Seven applications have been received for existing high-capacity transmission grid interconnection points. This includes legacy large generation sites and former large industrial sites.
- In some cases, site owners have submitted multiple applications in a way that would establish an initial large load and then increase the load in increments up to the limit of the interconnection point capacity.
- The Companies encounter speculative proposals and projects at differing maturity levels. Multiple projects in the same region may have overlapping impacts and require management as a “load queue”. This complicates and delays studies while introducing uncertainty for developers who may have interdependencies with projects ahead in the queue.

d. Requests outside NYISO queue

Table 1 includes requests that are not required to be evaluated through the NYISO interconnection process. Non-NYISO jurisdictional classified projects are evaluated through the local Transmission Owner process. This process includes technical screening, internal system-impact analysis, discussion of preliminary results, optional cost-estimate development, determination of any customer responsibility for pre-existing violations or system benefits, communication of results, customer decision-making, agreement negotiation, and project execution.

Often these large load requests involve re-purposing existing facilities which have historically had much smaller electrical demands. Consequently, capacity constraints are common and frequently require costs to upgrade circuits and/or lead times for construction that may no longer align with the customer’s project objectives or timeline.

e. Projects with behind-the-meter generation, co-located services, or grid flexibility

The Companies have one applicant that is currently serving a 60 MW load with on-site generation under the NYISO’s “Behind the Meter: Net Generation” program. The site owner has requested the ability to serve the load from the grid when the on-site generator is not generating. Customers that have the ability to self-supply 15 percent or more of its load are required to be on the Companies’ standby rate. NYSEG and RG&E currently have 27 and 10 standby customers, respectively.

f. Ability to identify speculative or duplicated applications

The Companies have limited ability to identify speculative or duplicate applications at the time requests are received. When practical, during preliminary discussions with developers, the Companies will provide high-level observations regarding potential site constraints and system limitations. Requests that do not advance beyond the preliminary stages of the interconnection process may be indicative of speculative inquiries. However, the Companies do not have sufficient information to conclusively determine an applicant's intent. Nor are there formal procedures or information-sharing mechanisms among utilities to identify when a developer proposes similar projects across multiple service areas. As a result, the Companies' ability to identify duplicative applications is limited.

g. Findings

NYSEG and RG&E have received 36 large load interconnection requests exceeding 10 MW, representing approximately 3,020 MW of proposed demand. The Companies have observed increasing interest in utilizing existing high-capacity interconnection locations, particularly former generation and industrial sites, and note that some developers are pursuing phased load expansions intended to maximize available site capacity. The portfolio includes projects at varying levels of maturity, creating study and queue-management challenges, particularly where multiple projects produce overlapping regional impacts. For non-NYISO jurisdictional projects, available system capacity, upgrade costs, and construction timelines are frequently key factors influencing project viability. The Companies also continue to observe evolving customer operating models, including proposals that combine large loads with behind-the-meter generation and flexible reliance on grid-supplied power.

2. Study Methodology and Interconnection Process

a. How analysis is performed

The scope of the study is first based on the jurisdiction (NYISO vs non-NYISO process), but there is a broad overlap between the two. For NYISO jurisdictional projects, NYISO determines the scope with Transmission Owner input. The Companies' inputs are based on load size, point of interconnection, load characteristics (power factor, seasonality, abnormal operating patterns, etc.), and local system conditions. The study identifies reliability violations and mitigation options necessary to maintain existing levels of system reliability. Depending on the proposed interconnection point, distribution and transmission studies may be performed concurrently or sequentially. Non-NYISO jurisdictional projects

generally follow a similar scope but exclude some analyses that are not necessary for smaller projects (e.g., transfer limit analysis).

For NYISO-jurisdictional projects, the process includes a NYISO System Impact Study (“SIS”), the Companies’ Facility Study, and any required detailed engineering studies. For non-NYISO jurisdictional projects, the analysis progresses through successive study stages. An initial High-Level Capacity Study is conducted to identify major constraints and challenges. Projects that proceed beyond this stage are evaluated through a Detailed Load Study which is generally equivalent to a NYISO SIS.

i. Assumptions, tools, and timing

Transmission Owner study assumptions are project-specific and reflect the proposed load, load characteristics, point of interconnection, point of change of ownership, if applicable, and local system conditions. For all projects, power flow studies are based on NYISO models, which for non-NYISO jurisdictional studies are modified to more accurately reflect local system conditions. Peak system loading conditions, which may be models representing summer and/or winter, are used to establish a system representation that is realistically conservative. The Companies use industry-standard tools (e.g., PSS/e, TARA, etc.) to perform all power flow studies.

For NYISO jurisdictional projects, the timeline for the SIS is under NYISO control. The Companies’ Facility Study builds off the NYISO SIS results, further defining the scope details with a further analysis made against internal record drawings and/or other project impacts to further identify or clarify scope for estimating all of which will be included in a formatted study report.

Non-NYISO projects follow a similar process, but there is not a formal separation between the SIS and the Facility Study. Once the contingency analysis has been completed and reviewed, there is a period of customer coordination followed by a transition to physical feasibility confirmation and upgrade cost estimation. The non-NYISO jurisdiction study process generally takes between 1 month and 6 months. See response to 2.d. for additional details.

b. Variation from other service classes

Service Class is not a factor in determining study scope or timeline. The study scope is driven by technical impacts rather than solely by customer classification or the load threshold. A relatively small difference around the 10 MW threshold does not necessarily change the study approach. Larger projects typically require broader and more complex analysis because they can affect a wider region.

c. Process map from request to energization

NYISO-Jurisdictional Projects

For NYISO-jurisdictional projects, the process begins with request intake, technical review, and scoping activities, which culminate in the execution of a study agreement and submission of the required customer deposit. Once these prerequisites are satisfied, a study consultant is engaged and a study kickoff meeting is held to initiate development of the system impact study. The consultant prepares a draft report that is reviewed by Transmission Owner subject matter experts, with comments incorporated as cost estimates are developed and refined. Following inclusion of the cost estimates, a revised report is issued and may be discussed with the customer before the study is finalized. Upon receipt of the final study results, the customer determines whether to proceed with the project and accept the identified costs.

If the customer elects to move forward, the project enters the agreement negotiation phase, during which project-specific terms, security requirements, payment obligations, milestone schedules, and other commercial provisions are developed and finalized. Concurrently, internal reviews involving finance, risk, insurance, and project execution personnel are completed. Following execution of the agreement, responsibility for the project transitions to the execution team, which undertakes conceptual engineering, procurement of long-lead equipment, detailed engineering, permitting activities where required, and construction planning.

Upon completion of planning and coordination activities, a Notice to Proceed is issued and construction begins. Construction is followed by installation and integration of protection and control systems, testing and commissioning activities, and completion of any punch-list items. A final project walkdown and management review are then conducted to confirm readiness for energization. Following approval, any required asset transfers and project closeout activities are completed, after which the Transmission Owner facilities are energized and, as applicable, synchronized and placed into service to provide electric service to the customer facilities.

Local Transmission Owner Projects

For local Transmission Owner projects, the generalized process includes request receipt; technical reviews and customer coordination; internal system-impact analysis; discussion of preliminary results; customer decision on whether to move forward with a detailed load study with cost estimates. Once a detailed load study with cost and schedule development is completed, there is a communication of results and customer decision period, which

would move to; agreement negotiation and project execution. The project execution stage is the same process as noted above in NYISO Jurisdictional projects.

d. Stages, milestones, timeframes, and deliverables

For NYISO-jurisdictional projects, current timelines include:

- System Impact Study: 8 to 12 months.
- Facility Study for a low-complexity project: approximately 11 months.
- Detailed engineering studies, when required: approximately 4 months.
- Customer deposit before study commencement: approximately 2 weeks.
- Purchase-order issuance to the study consultant: approximately 4 weeks.
- Consultant kickoff: approximately 3 weeks after purchase-order issuance.
- Draft report: approximately 6 weeks after kickoff.
- Transmission Owner subject-matter-expert review: approximately 3 weeks.
- Cost-estimate development and consultant coordination: approximately 12 to 16 weeks.
- Final report and optional customer meeting: approximately 2 weeks.
- Agreement negotiation and execution: approximately 3 to 6 months.
- Project execution: approximately 3 to 5 years, depending on scope.

For local Transmission Owner projects:

- Initial requests and technical validation: at least 1 week, with customer coordination potentially extending for days or months.
- Internal system-impact study: 2 weeks to 3 months.
- Cost-estimate and execution-timeline development: 2 to 4 months.
- Communication of results and customer decision: 2 weeks to 6 months.
- Cost estimates expire after 6 months.

e. Comparison of stated and actual timelines

For NYISO-jurisdictional projects, actual System Impact Studies required up to 12 months, a low-complexity Facility Study requires approximately 11 months, and detailed engineering studies may require approximately 4 months.

For local Transmission Owner projects, actual System Impact Study timelines consistently fall within the stated range of one to four months. Cost-estimate and timeline development consistently falls within three to four months during 2025–2026. During 2024–2025, particularly complex projects extended to approximately six months. Customer coordination and detailed-scope development typically require one to four months or longer and depend heavily on project maturity.

f. Material costs, capacity reservation, and financial security

For NYISO-jurisdictional projects, the customer provides a deposit before study commencement, after which the Companies will issue a purchase order to a study consultant. No work occurs during the study window so there are no costs incurred for material during this stage. Costs identified in the study report include all costs necessary to interconnect the customer project including engineering, procurement, and construction. Upon completion of negotiations enumerated in 2.c., the customer must agree to the project costs and payment schedules, in addition to providing financial security in the form of Bond, Letter of Credit, Parent Guarantee or cash.

For local Transmission Owner projects, the same requirements apply as noted in the paragraph above. The customer's financial commitment begins with the execution of the agreement. Again, the customer-specific facilities are funded 100 percent by the customer, so the same financial security and prepayment required as noted above apply.

In general, capacity is not reserved. The project is considered firm once they have entered an Engineering, Procurement, and Construction (EPC) agreement or other binding contractual agreement. Once a project is fully operational, unless otherwise stated in their interconnection agreement, their capacity is based on their historical load.

g. Delays and cycle-time improvements

Primary drivers of delays include project complexity, changes in project location or scope during the study phase, and proposed interconnection points that are ultimately determined to be infeasible at the requested voltage and require substantial upgrades. Delays may also result from pre-existing local capacity constraints for which no funded solution exists, as well as situations in which multiple projects within a region have overlapping system impacts but are at different stages of development. In addition, customer delays in providing required information or extended decision-making periods can further increase overall cycle times.

Current jurisdictional thresholds limit the Transmission Owner's ability to accelerate certain large load studies. NYISO and the Transmission Owners have proposed process changes in response to the FERC Show Cause Order that are expected to create mechanisms to streamline studies.

h. Communications and information flow

Both the NYISO and non-NYISO jurisdictional processes include continuous coordination with customers to resolve technical discrepancies, review preliminary study results, discuss cost estimates, review final reports, and negotiate agreements. NYISO-

jurisdictional projects involve coordination among each customer, NYISO, the Transmission Owner, consultants, and internal subject-matter experts. Non-NYISO jurisdictional projects are negotiated between the customer and Transmission Owner at decision points throughout the process.

i. Findings

Large load interconnection requests are evaluated through a reliability-based study process, regardless of whether they are subject to NYISO or non-NYISO jurisdiction. Study scope is determined by project-specific technical factors, including load magnitude, operating characteristics, interconnection location, and local system conditions. NYISO-jurisdictional projects generally progress through System Impact and Facility Studies, while non-NYISO jurisdictional projects follow comparable high-level and detailed load study processes.

The Companies have observed that study duration and overall project timelines are driven primarily by project complexity, customer readiness, required system upgrades, and the level of coordination necessary among stakeholders. Common causes of delays include scope changes, local capacity constraints, overlapping project impacts, procurement and construction requirements, and extended customer decision-making or negotiations. Customers are responsible for project-specific interconnection costs and associated financial security requirements once they elect to proceed following study completion. Capacity is generally not reserved during the study process and becomes firm only after execution of the applicable agreement. Throughout the process, ongoing coordination among customers, planners, consultants, and other stakeholders is essential to advance projects from evaluation through energization.

3. Service Classification

a. Current service classification for large loads

For large loads, in NYSEG's service territory, the customer would be served under NYSEG's PSC-filed rate tariff Service Classification 7 ("SC7-X"), which has sub-classes with different customer charges and rates that are dependent upon voltage level. A customer with a large load is likely to be served under SC 7-4 Transmission (greater than 115 kV) or SC 7-2 Primary (2.4 kV to 46 kV) depending on the interconnection voltage. Similarly, within RG&E's service territory, the customer would be served under SC 8, likely SC 8-Transmission (greater than 115 kV) or SC 8 Primary (2.4 kV to 46 kV), depending on the interconnection voltage. For customers with large loads and on-site generation, they may

be required to take service under the Standby service classes, which are NYSEG SC 11 and RG&E SC 14. Standby service has sub-class designations that are based on the otherwise applicable service class without generation – which would be NYSEG SC 7 and RG&E SC 8.

b. Types of facilities, project counts, and MW

See Table 1 in response to Question 1.b above.

c. Differences from other customer classes

The Companies' technical study scope is determined by project size, location, load characteristics, and system impacts; Service Class is not a factor in determining study scope or timeline.

d. Findings

Large load customers are served under existing PSC-approved tariff structures based on voltage level and service configuration rather than under dedicated large load service classifications. Within NYSEG and RG&E service territories, customers are assigned to the applicable transmission, primary, or standby service classifications based on their interconnection characteristics and operational requirements. From an interconnection perspective, service classification does not affect the scope, methodology, or timing of technical studies. Instead, study requirements are driven by project-specific factors, including load magnitude, location, operating characteristics, and system impacts. As a result, projects with similar technical characteristics are evaluated using the same engineering and reliability criteria regardless of the service classification under which service is ultimately provided.

4. Network Upgrades

a. Estimate development, timing, accuracy, and procedures

With the study results, a one-line electrical drawing, and the customer site plan, an engineering scoping document is developed to scope project details by discipline including network upgrades. Record drawings are reviewed for the project's current scope to assess need. Additionally, the Companies conduct an internal check with the planning department and capital projects to assess potential conflicts with other planned or active upgrades. Estimators use standardized substation and transmission-line tools populated with current framework-agreement pricing, bid results, and procurement data. Tool outputs are compiled in a cost-summary table, and overhead and contingency are added according to the estimate-accuracy class. Draft results receive peer and subject-matter-expert

review, followed by internal approval and transmission to the customer. Any network upgrade required to support project load will be included in the project cost estimate and if the customer desires to interconnect, the cost of any required network upgrade would be borne by the customer.

For NYISO jurisdictional projects at a Facility Study stage, service cost estimates are generally expected to fall within –25 percent/+50 percent if scope and schedule remain unchanged. Cost estimate accuracy ranges vary by stage with early local feasibility estimates using broader accuracy ranges, up to –50 percent/+100 percent for high-level screening.

Depending on the complexity of the project, the cost estimate deliverable timeframe typically falls within an 8-to-12-week range.

b. Types of interconnection and network-upgrade costs

The interconnection types are wide-ranging (data centers to dairy processing facilities) but all interconnections include assessing network upgrades, which may identify requirements such as the addition of capacitor banks, upgrading of transmission line conductor scope or any variety of upgrades that may preserve or improve overall reliability. If network upgrades are required as part of any load project, those costs are included in the estimating process noted above in Section 4a. Large load projects are fully responsible for costs associated with upgrades to mitigate reliability degradations associated with their projects.

c. Costs over the previous 24 months

The Companies have not completed any network upgrades for large load projects in the last 24 months. Two projects have interconnected but are in interim states, so final costs have not yet been reported. Based on our estimates, costs borne by the customers vary widely based on scope, location, complexity, available headroom, and other project-specific factors.

d. Actual costs compared with estimates

No projects have completed their upgrades within the last 24 months, as such there are no actuals to compare against estimates.

e. Findings

Network-upgrade requirements and associated costs are highly dependent on project-specific system impacts identified through the interconnection study process. Required transmission and distribution upgrades are developed through engineering and reliability analyses, with cost estimates prepared using standardized estimating tools, current

market pricing, procurement data, and engineering assumptions. Estimate accuracy improves as project scope and engineering details mature, with final cost estimates generally developed within several months of study completion.

The Companies also note that large load customers are responsible for the costs of network upgrades required to support their projects and maintain system reliability. Network-upgrade costs vary significantly based on project location, load characteristics, available system capacity, and the extent of required infrastructure improvements. Because no company-performed large load network-upgrade projects have been completed in the past 24 months, the Companies do not have recent historical data for comparing estimated and actual project costs. Overall, the Companies observed that network-upgrade costs and schedules are driven primarily by project-specific engineering requirements and the infrastructure necessary to accommodate new large load demand safely and reliably.

5. Cost Allocation

a. Whether the large load pays the full interconnection cost

For all large load projects, regardless of jurisdiction, the customer generally pays the full cost of facilities and upgrades required to interconnect and mitigate any adverse system impacts associated with its project. In cases where the Companies' investment plans have already allocated capital to address preexisting conditions that overlap with project associated system impacts, costs are not the responsibility of the customer.

b. Portion of network-upgrade costs paid by the large load

Large load customers pay 100 percent of the required network upgrades identified in the Facility Study or other applicable study results, with the caveat regarding preexisting conditions explained above in Section 5a.

c. Costs assigned to the large load, its class, or customers generally

Customer-specific facilities and upgrades are assigned to the requesting large load customer. Cost sharing may occur if two or more customers independently agree to share costs or through another mutually agreed customer-driven arrangement. Historically the Companies have not seen examples of customers sharing costs. All customers more generally would pay for system upgrade costs where capital has already been allocated to address preexisting conditions.

d. Recovery or crediting over time

The circumstance in which a large load customer's upgrade costs are recovered from or credited to later customers has not been applicable in recent history.

e. Ratepayer protection if a project does not materialize or uses less capacity

The customer pays 100 percent up front for the installation of assets that are required to support its interconnection request. The only stranded asset risk is to the load project customer, as the process requires contract terms, security and prepayments that insulate the ratepayer while the project is ongoing. If, once constructed, the customer abandons its facilities, the system upgrades installed as part of the project are wholly owned by the Companies and remain if beneficial to the system or are removed at the expense of the customer. Customer assets are disconnected at point of change of ownership.

f. Findings

The current cost-allocation framework assigns responsibility for interconnection-related facilities and network upgrades directly to the requesting large load customer. Customers are responsible for 100 percent of the costs required to interconnect their projects and mitigate associated reliability impacts, including customer-specific facilities and network upgrades identified through the study process. While customers may voluntarily enter into cost-sharing arrangements, project-driven infrastructure costs are generally borne by the customer creating the need for the upgrades.

The Companies also note that there is no established mechanism for recovering interconnection or upgrade costs from future customers, and such costs are not broadly allocated to other customer classes or ratepayers. Existing contractual requirements, prepayments, and financial security provisions provide protection against stranded-asset risk by ensuring that project-specific costs remain the responsibility of the requesting customer. As a result, the financial risks associated with project cancellation, delay, or underutilization are largely borne by the large load customer.

6. Supply Cost Impacts

a. Whether the Company estimates supply-cost impacts

The Companies do not have an established process to estimate supply-cost impacts. The Companies do not readily determine the future impact, if any, on the supply portion of electric bills. Supply prices are established through competitive wholesale markets administered by the NYISO, and the Companies do not control, set, or profit from the

supply portion of customers' bills. Questions regarding the potential effect of a 500-megawatt load on regional energy market prices would therefore be more appropriately directed to NYISO and other market participants.

b. Components considered

See response to Section 6a.

c. Procedure used to assess supply impacts

See response to Section 6a.

d. Findings

See response to Section 6a.

7. Risk Management

a. Financial risk if demand changes after service begins

The Companies manage stranded-asset risk principally by requiring the customer to pay 100 percent up front for assets that are identified as customer project requirements to support interconnection. Consequently, customer-specific stranded assets are not a significant financial risk. Please refer to Section 5e.

If a customer requests additional load, the request would follow the standard process described above; it would be evaluated, studied, and agreed upon, with needed infrastructure prepaid and constructed.

b. Risk-management tools and processes

Risk-management tools reflected in this reply include up-front customer funding and security submission for customer-project required upgrades, with staged customer decision periods that require advanced commitments. Additionally, internal financial and risk dossier submission is required, with reviews performed by the Companies Risk Management department. The Companies experts review security form and issuer ratings all subject to advanced approval before interconnection project construction. Further, a pre-established company agreement form is required which enumerates terms of risks and responsibilities.

c. Attrition during the previous 24 months

The Companies do not track proposals until study work commences. It may coordinate with known speculative projects before that point, but the rates associated with proposals

reaching maturity are not tracked. Of the 36 projects listed in Table 1, 10 have been canceled.

d. Attrition by project stage

The majority of the attrition occurs after study results and associated costs have been communicated to the customer. Based on available data in recent years, the Companies believe it is rare that projects do not proceed once a contract has been signed and project construction has commenced.

e. Costs after cancellation or delay

Up-front customer funding and security for customer required upgrades as well as contract terms that address default or termination cost responsibilities ameliorate exposure.

In the event of delay, study and construction agreements address the responsibility of the customer with all costs incurred being borne by the customer, including cost of impacts from delays. Cost estimates expire after six months.

f. Findings

Financial risks associated with large load interconnections are mitigated through a customer-funded framework that requires customers to fund project-specific facilities and upgrades and provide applicable financial security before project execution. As a result, stranded-asset risk related to customer-specific infrastructure is borne primarily by the project developer rather than by the Companies or ratepayers. Requests for additional load after service begins are subject to the same evaluation, study, funding, and agreement processes as initial interconnection requests.

Risk management is supported through contractual and financial controls, including upfront customer funding, security requirements, formal decision milestones, internal risk reviews, and standardized agreements that define project obligations and cost responsibilities. While project proposals are not generally tracked prior to formal study initiation, key customer decision points occur after study results, cost estimates, and schedules have been communicated. Existing agreements further protect the Companies and ratepayers by requiring customers to remain responsible for costs associated with project delays, cancellations, or other schedule impacts, ensuring that project-specific financial risks remain with the customer requesting service.

8. Internal Processes and Tools

a. Management reports, dashboards, and reference materials

The Companies utilize a monthly “Large Load Project Tracker” report to maintain visibility of large load project interconnections for applications where NYSEG or RG&E is the Connecting Transmission Owner or Affected Transmission Owner. The threshold for projects to be included in this report is as follows; projects over 10 MW connecting at a voltage level of 115 kV or above, and projects over 80 MW connecting at a voltage level below 115 kV. This report only includes NYISO projects.

b. Use and key metrics

The report is updated as new information becomes available and is circulated monthly. The report is circulated to leadership of departments covering transmission system planning. The report includes relevant project identification information such as developer, project name, and NYISO queue number; technical information is also included such as load size, point of interconnection, voltage level, study status and necessary upgrades (if available), along with geographic division, and expected in-service date.

c. Findings

The Companies maintain a monthly Large Load Project Tracker to monitor significant large load interconnection requests and support planning, study coordination, and management oversight. The tracker focuses on NYISO-jurisdictional projects meeting established reporting thresholds and is updated regularly as new information becomes available.

The tracker provides leadership with visibility into project development, study progress, anticipated system impacts, and potential infrastructure requirements. Key information tracked includes project size, interconnection location and voltage, study status, identified upgrades, and expected in-service dates. Overall, the tracker supports coordination across planning and engineering functions, resource prioritization, and proactive management of emerging large load demand.

9. Overall Findings and Opportunities

a. Key conclusions

The Companies apply a technically driven study process that adapts to project size, location, characteristics, jurisdiction, and system conditions. NYISO-jurisdictional projects follow formal study stages, while the local Transmission Owner process is more flexible.

Customer-specific network-upgrade costs are directly assigned and funded by the requesting customer. The estimating process is structured and uses standardized tools, maturity-based accuracy classes, peer review, and internal approval. Finally, The Companies pre-established agreement forms ensure legally binding terms with financial security mitigations, including customer cost responsibility for actual costs, and clearly defined ownership and responsibility from project kickoff to energization of the load.

b. Issues, challenges, and opportunities for improvement

Issues and challenges have been summarized in the various Sections above. Key opportunities are highlighted below, all of which are being addressed through Transmission Owner and NYISO coordination as part of the large load interconnection process reform that is in progress.

- Improvement in coordination between stakeholders for NYISO jurisdictional projects, including clearer clustering methodology and cost-splitting mechanisms.
- Improvement in identification and coordination of duplicate, speculative, or overlapping requests between utilities.
- Implementing speculation-prevention measures to provide useful information to developers during the site selection process but prevent inefficient utilization of planning resources for intensive study work on speculative projects.