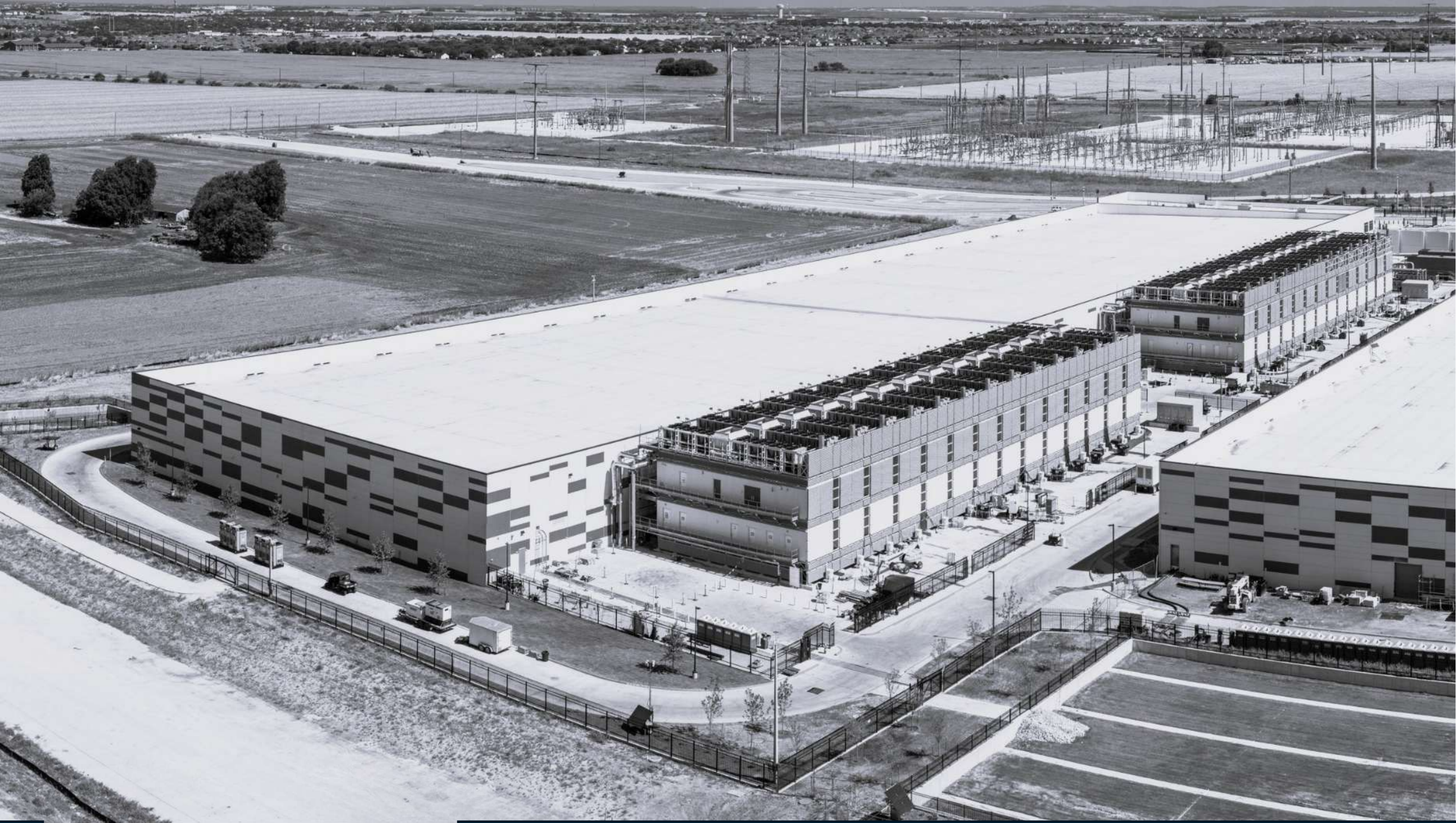

ENERGY FUTURES GROUP

LARGE LOAD COST ALLOCATION

Framework for States to Reduce Cross-Subsidization and Risk to Existing Customers

Energy Futures Group, September 24, 2026

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I. INTRODUCTION

Large load growth is straining a cost allocation framework built for an era in which electric grid assets were treated as shared assets benefiting a broad range of customers. This paper examines the breakdowns in that existing framework at the state regulatory level when a small number of large load customers drive tremendous demand for electric utility service, requiring high-cost and sometimes risky investments and creating the material possibility that existing customers could be left on the hook to pay for those assets. It then proposes a set of potential solutions centered on direct assignment and other mechanisms aligned with retail standard cost causation principles all of which are aimed at ensuring large load customers bear the costs they cause. Our recommendations are primarily targeted to jurisdictions within RTO footprints, but certain solutions such as assignment of generator and transmission capital costs are applicable to jurisdictions outside RTO regions as well.

The categories of costs covered in this report include:

1. New generator capital and O&M costs,
2. Energy market costs, especially congestion costs,
3. Costs already in rates,
4. Interconnection, network upgrade, and regional transmission costs, and
5. Costs incurred to manage post in-service reliability concerns and/or during outages to connect or to serve a large load customer.

We also address cost-benefit analyses that are increasingly being used to justify not revisiting established cost allocation methods.

The volume of large loads being added or contemplated in most jurisdictions is likely to create stepwise changes in prices faced by all consumers. Per the basic tenet of economics, more demand generally equals more cost for that good, particularly in industries with barriers to entry like the electric sector. Our paper does not address all price inducing effects of large loads such as increased costs in capacity markets or increased costs of natural gas. These are complex, but important topics that are worth their own paper and may require solutions that go beyond the retail allocation sphere, e.g., solving the problem of capacity price increases socialized to a jurisdiction with no large load additions.

II. BACKGROUND

II.A COST-OF-SERVICE STUDIES, RATE CASES, RIDERS, AND SPECIAL CONTRACTS

Cost allocation refers to the division of a utility's total revenue requirement among customer classes such that each class pays rates that reflect the costs it causes. In this paper, we use the term in two common senses: broadly, as shorthand for the full embedded cost-of-service study (COSS), and narrowly, as the third of three steps in that cost-of-service study process. Those steps are *functionalization*, which divides total utility costs into major functions (generation, transmission, distribution, and customer service) and their sub-functions; *classification*, which categorizes costs based on their driving factor (demand-, energy-, or customer-related); and *allocation*, which assigns costs to customer classes using allocation factors that approximate each class's contribution to total utility costs.

Figure 1, developed by the authors of the Regulatory Assistance Project's Electric Cost Allocation for a New Era Manual, visualizes this sequence of steps. In practice, cost-of-service studies involve a far more granular assessment of each category.

Figure 1. Modern Embedded Cost of Service Study Flowchart[1]

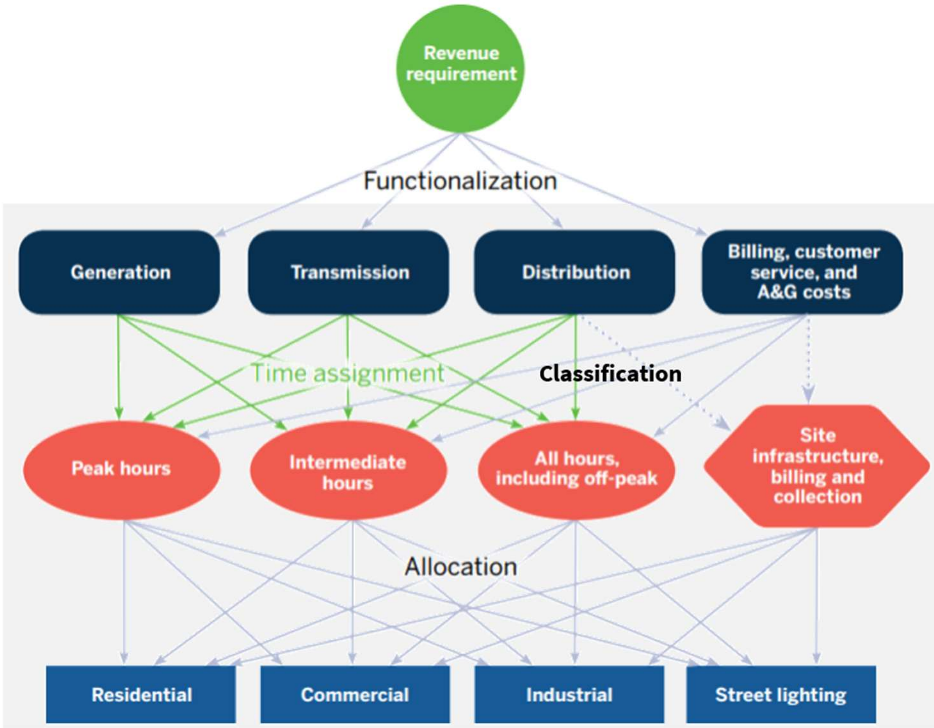

*Figure annotated with "classification" label for clarity.

Cost-of-service studies serve as the analytical core of utility rate case proceedings. The default venue for ratemaking is a general rate case, where a utility's COSS is filed, litigated, and used to justify proposed rates by class. As such, it is traditionally the forum where cost allocators are determined and disputes about the choice of allocator are adjudicated.

There are two mechanisms commonly used to recover costs without approval in general rate cases. First, *riders* (also called *trackers*) recover costs not otherwise included in base rates for a specific category, such as fuel costs that exceed the level included in base rates, or new transmission costs, via periodic updates between rate cases, typically without re-running a full COSS. Second, *special contracts*, or bilateral agreements between a utility and a customer, may set terms outside the standard class-based rate structure and may be negotiated without a parallel COSS or update to the COSS. Because both methods occur outside the general rate case and COSS, it can be difficult to determine whether affected new customers truly bear the full cost of their service. The rate case should serve as the default venue for testing cost

[1] Jim Lazar, Paul Chernick, William Marcus, and Mark LeBel, "Electric Cost Allocation for a New Era: A Manual," January 2020,https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

causation, and where riders and special contracts are used, they warrant additional scrutiny. [2,3,4]

The venue and method for assessing cost causation become particularly crucial when interconnecting new large load customers. Utilities traditionally treat generation and transmission as all-system resources that benefit every customer. Therefore, these costs are typically classified as demand- and/or energy-related, while customer-related classification is reserved for distribution and customer service, where the number of customers drives the underlying costs to the utility. This approach can create issues, however, when a small number of large load customers require dedicated transmission upgrades and the addition of new generation, which is often considerably more expensive than existing power plants. In this emerging case, these additional costs would not exist but for the new customer, but conventional allocation would spread them across all customers. Addressing this cross-subsidization risk sits at the core of this paper's proposed solution set.

II.B INTERSECTION OF WHOLESALE AND RETAIL TRANSMISSION COST ALLOCATION

Pursuant to the Federal Power Act, the Federal Energy Regulatory Commission (FERC) authorizes the transmission rates, terms, and conditions for transmission service for wholesale customers that includes revenue requirements for capital projects as well as ongoing operational and maintenance transmission costs, referred to as O&M. In addition, FERC oversees the Open Access Transmission Tariffs that govern how wholesale energy costs, such as congestion cost,[5] are allocated to wholesale customers. FERC oversees the allocation methods for rates related to transmission based on capital costs of network transmission and O&M within a regional transmission organization (RTO) (see Figure 2). Similarly, in RTOs, costs associated with wholesale energy market operations are billed to the participants of that market based on the Locational Marginal Price (LMP) that each face at a given point in time. Utilities then allocate these wholesale costs to each retail customer class via transmission and other allocators, which determines the portion paid by residential, commercial, and industrial customers, respectively.

Large loads may induce wholesale costs that are difficult to separate from those incurred in serving other loads. And/or their costs may be difficult to disentangle using the RTO settlements process. Because RTOs cannot assign costs to any individual retail customer, only to their wholesale market participants, which are typically utilities, retail allocation is the

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[2] Ibid.

[3] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (NARUC, 1992).

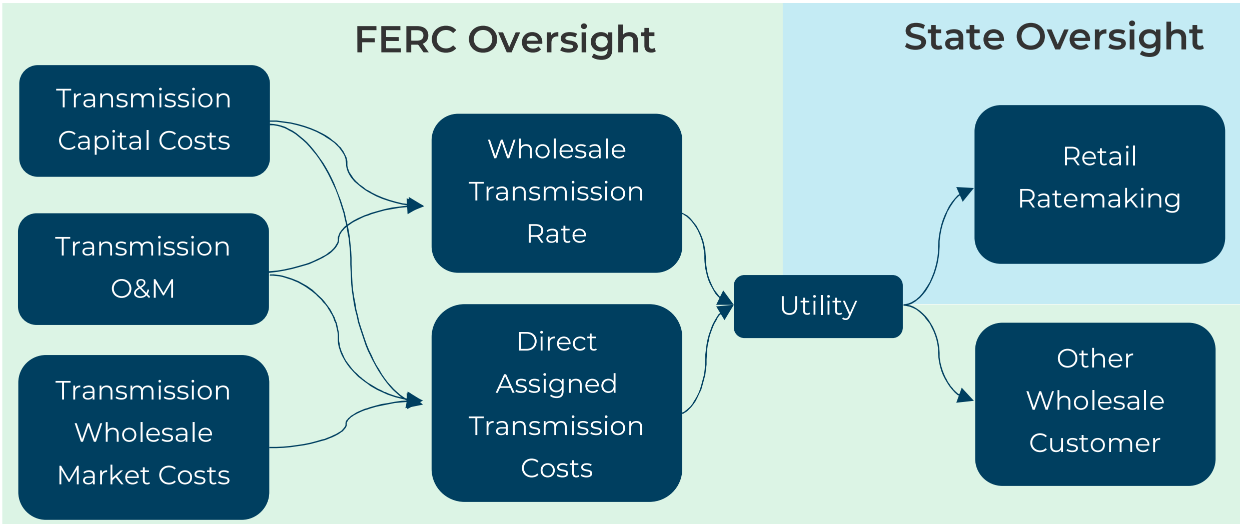
[4] Synapse Energy Economics, *Ratemaking Fundamentals* (2017).

[5] *Infra* section III.B.

domain in which cost causation and class/customer assignment will typically determine how wholesale costs are shared between customers.

This report will focus on the uncertainty that exists when wholesale transmission system costs resulting from the development of large loads, including costs directly attributed to large load development, shift into retail rate structures where costs need to be allocated at a more granular level but the information to do so is lacking.

Figure 2. Jurisdictional Separation of Transmission Costs



III. ALLOCATION CHALLENGES SPECIFIC TO LARGE LOADS

III.A NEW GENERATOR COSTS

As noted in Section II.A, utilities traditionally treat new generation as an all-system resource. A new power plant is typically built to serve many customers. For this reason, no one unit can be tied to any one customer, in part because the generators are often larger than any one customer. Thus, generation costs are typically classified as demand- and energy-related and allocated across classes through factors that estimate each class's proportional use.[6] Single large load customers flip that paradigm, where one or many plants may be added to provide service for a single customer.

Utilities are now proposing substantial blocks of new generation capacity purportedly to serve a small number of identifiable customers,[7] yet conventional classification provides no customer-related category to capture generation built for a specific load. Without adjustment, demand- and energy-based allocation disperses the costs of that new generation capacity, which would not be needed but for the new customer, across all customers.

The mismatch can persist even when allocation tracks demand. Peak-based allocators are determined using a customer's measured coincident peak, so a large load customer that has not yet ramped to its full contracted demand contributes a smaller share than the capacity built on its behalf warrants, and the shortfall is covered by other customers until a full COSS is performed to correct the issue. The enormous scale of these loads heightens the risk: a single new customer can trigger a capacity addition so large that no ordinary load growth could absorb the cost if that customer takes a lesser amount of service, delays their in-service date, fails to materialize, and/or exits the system. It may also be the case that the generator's size does not exactly match the customer's load even at full ramp and therefore a portion of the generator's cost would be allocated to others using peak allocators. Because the embedded COSS is often backward-looking and rate cases lag behind actual utility operations, new generation costs may be allocated based on data that predates the large load's material impact, compounding the gap between when the cost is incurred and when the large load customer begins to bear it.

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[6] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (NARUC, 1992).

[7] Some utilities do see substantial load growth coming from many individual customers whose aggregate load necessitates new generation. These customers often share attributes, e.g., they are looking for fast interconnection and operate at high load factors.

Further, on a capital cost basis, new generator costs continue to rise, as evidenced in substantial cost increases for new gas-fired generators in recent years.[8] Thus, even if new large load customers operate exactly as forecasted, higher cost new generators would drive system costs up. If those costs are socialized to other customers, rates for those customers will also rise.

See section **IV.A.i New Generators** for a discussion of solutions.

III.B OPERATIONS & MAINTENANCE COSTS

Utilities and retail regulators have established processes to account for the costs of both native growth from the expansion of the communities served as well as establishing new service for commercial and industrial customers who choose to develop operations in a utility's service territory. The growth being encountered today does not just rely on a more frequent application of a utility's existing process for adding loads but also represents a unique challenge to serve new customers on a scale that has not been encountered before. From development timelines that are simultaneously expedited and increasingly uncertain to near instantaneous changes in energy requirements, forecasts can no longer depend on historical trends. The strenuous demands large loads place on the operation of utility systems range from expedited acquisition of new capacity to increased costs to operate those resources, and from variations in transmission constraints resulting from large loads to the costs of maintaining reliable service for all customers after an outage. This section dives into costs resulting from large load development that go beyond the direct capital costs needed to interconnect and supply that new demand.

III.B.i Plant O&M

Large loads can significantly increase operations and maintenance (O&M) costs on a per megawatt-hour basis. Without proper tracking and cost allocation, those costs can end up shared across all customers rather than borne by the load that caused them.

Some examples of increases to O&M expenses triggered by new large loads include:

- Less efficient, more costly plants are dispatched more frequently to serve increased load using existing capacity or these units are kept online in lieu of retirement. These plants, which historically have operated less, are likely to have increased O&M expenses.
- Data centers used for artificial intelligence (AI) training cause more frequent and abrupt shifts to demand than traditional loads, forcing plants to cycle rather than run steadily.

[8] GridLab, Energy Futures Group, and Halcyon, *The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S.* (September 2025).

This operational pattern can also push plants outside their optimal operating range, either below minimum efficient output or above normal limits. This added cycling and off-spec operation accelerates wear and tear, shortens equipment life, and increases maintenance costs.

- Continuous operation of equipment and conductors at higher loading degrades transmission assets faster than lower loading that would be experienced without a large load being present. This decreases the useful life of assets and increases the frequency in which maintenance is required.

See section **IV.E O&M Costs** for a discussion of solutions.

III.B.ii Congestion

Congestion costs represent the financial impact of a transmission constraint in a wholesale energy market. When the amount of transmission path is insufficient to allow the cheapest energy to reach customers' demand when and where that energy is needed, congestion is the result. The geographic difference in LMPs due to the existence of congestion is commonly referred to as 'price separation' and impacts wholesale energy costs differently depending on which side of a constraint a pricing node is located. The cost of congestion can be viewed through two lenses:

Customer Lens: The customer side of a transmission constraint is considered the "high" side of a price separation where higher cost generation is required to meet customer demand due to the existence of a transmission constraint. The constraint results in an overall increase in the LMP on the customer side of a transmission constraint where demand is greater than the availability of the lowest-cost generation available.

Generator Lens: The generator side of a transmission constraint is considered the "low" side of a price separation where low-cost energy production is greater than the customer demand it can serve. The constraint

What are the 3 components of a Locational Marginal Price?

Energy Component
Accounts for the cost to serve the next increment of customer demand irrespective of constraints and losses. In other words, what is the cost of the energy produced by resources that would increase output to meet the increased demand in a specific area? In non-market areas, this component may not be directly calculated for specific points but represented as a net value of the system costs for energy production, sales (export) and purchases (imports).

Congestion Component
Reflects the cost impacts resulting from constraints on the transmission system, or how much a specific area is impacted when the transmission system is constrained. This is represented by the cost savings that would be realized if an existing transmission constraint were relieved by one megawatt. Congestion increases LMPs on one side of a constraint and decreases LMPs on the other side of a constraint. In areas that are not participating in wholesale energy markets, congestion is not a direct measure, rather it is the summation of impacts resulting from the need to operate around transmission constraints. This can take the form of reliability must-run requirements, Transmission Loading Relief (TLR), or generation redispatch in system operations.

Loss Component
Calculates the impact of energy losses for a given area. No piece of electric equipment that is perfectly efficient. Even if the inefficiency is small, it results in lost energy. This component relies on a loss factor that increases LMPs as the cost to generate the power consumed through losses is added back into the energy price. Outside of wholesale energy markets, losses may be directly calculated but could also be represented only by the difference between the gross energy production adjusted for imports and exports compared to the demand served.

Once these three components or their equivalents are known, they are combined in an energy price that accounts for energy costs, system constraints and inefficiencies.

LMP = Energy Component + Congestion Component + Loss Component

results in an overall decrease in the LMP on the generator side of a transmission constraint.

Price separation is most impactful when both the customer and generator impacts are experienced at once by the same market participant, such as vertically integrated utilities or generation and transmission cooperatives. When the price paid to a supply resource, for example a natural gas plant, is reduced due to congestion, while the customer price is also raised due to that same congestion, there is a mismatch. This scenario results in a cost and revenue mismatch that is generally made up via a pass-through to customers.

When considering the impacts of large load development, there is a fundamental shift in how transmission is used and where constraints appear. The addition of a new or expanded large load customer can act as a vacuum on electric power,[9] diverting power flows to transmission paths that previously may have never constrained the delivery of cheap energy, but end up becoming that constraint on the system once the new load is introduced. For example, if a large load is located at a mid-point of an existing transmission line, the transmission network originally intended to move power from one end of that line to the other would now experience power flowing to serve the large load, likely in opposite directions and a higher magnitude than originally designed. This change in how power flows will impact the surrounding transmission system supporting that existing transmission line, creating power flows that diverge from what was historically experienced.[10] Given the limited number of scenarios analyzed during interconnection studies for large loads, this change in flow magnitude and direction is likely to cause congestion.[11]

The PJM Interconnection, L.L.C. (PJM) region in particular has seen a significant increase in large loads in recent years, which has led to an increase in both the magnitude as well as the number of occurrences of spikes in the congestion costs experienced. The chart below (Figure 3), taken from the 2025 PJM Quarterly State of the Market Report,[12] illustrates this trend of more common price separation occurring, i.e., a large difference between load and generation LMPs, as large loads are placed in service.

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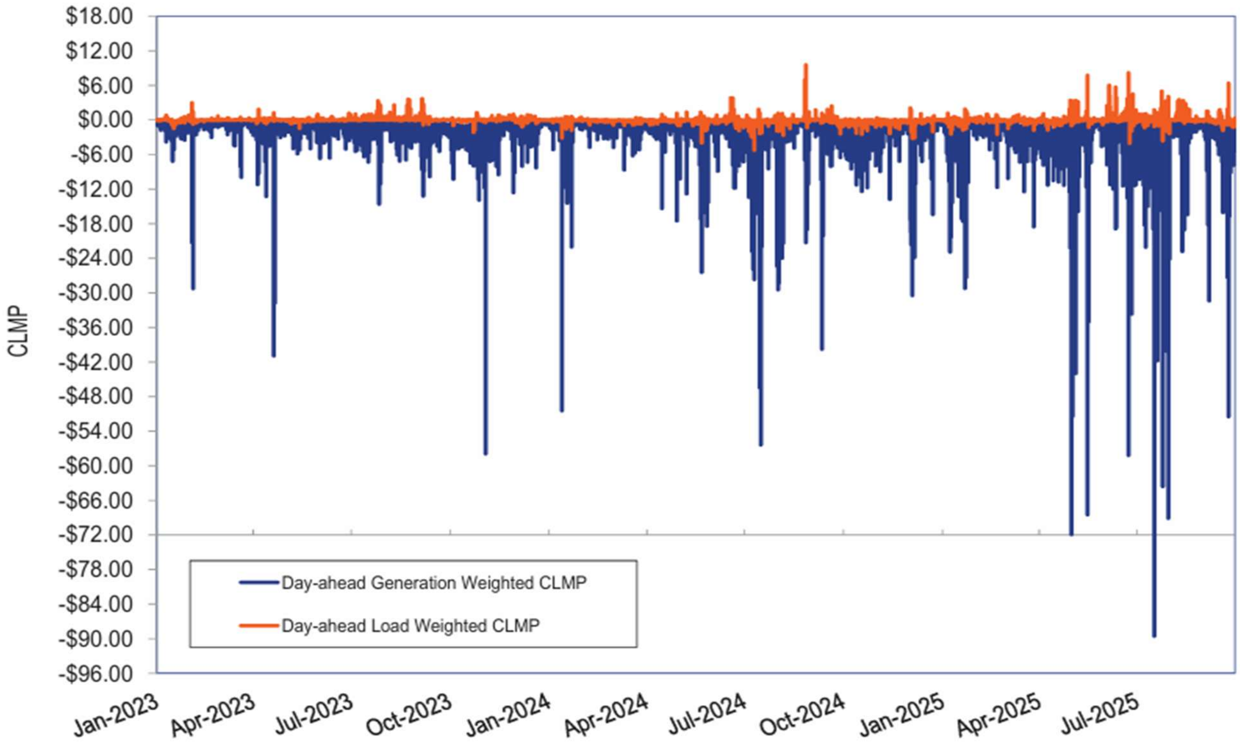
[9] Casazza, J., and F. Delea, *Understanding Electric Power Systems: An Overview of the Technology and the Marketplace*, Wiley-IEEE Press, 2003, Chapter 6, "Technology of the Electric Transmission System."

[10] Casazza, J., and F. Delea, *Understanding Electric Power Systems: An Overview of the Technology and the Marketplace*, Wiley-IEEE Press, 2003, Chapter 6, "Technology of the Electric Transmission System."

[11] RMI, "Large Loads and Network Upgrades," https://rmi.org/resources/large-loads-and-network-upgrades/.

[12] Monitoring Analytics, LLC, "2025 Quarterly State of the Market Report for PJM: January through September," Monitoring Analytics, 2025, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025q3-som-pjm-sec11.pdf.

Figure 3. Comparison of Day-Ahead Congestion Locational Marginal Prices (CLMPs) between Load and Generation in PJM



As shown in the PJM data, this shift in use can create major congestion issues seemingly overnight if not adequately addressed prior to new customer interconnection, even if typical system reliability metrics are met. Figure 3 shows by the increasing spikes in LMPs that generators are more likely to face negative congestion pricing and that the difference between load and generator pricing is significant. The magnitude of risk related to the impacts of congestion depends on wholesale market structure as well as supply and off-take agreements between utilities and the resources used to meet customer demand. For example, a vertically integrated utility risks their customers paying higher energy costs from congestion while also missing out on revenues from energy sales that would otherwise offset retail rate impacts from generation. Accounting for these changes in congestion resulting from the addition or expansion of a large load customer allows for better alignment of cost responsibility in retail recovery processes where congestion costs are commonly recovered by utilities via direct pass through to customers and allocated proportionally based on class consumption.

See sections **IV.F Hedging Against Congestion Costs** and **IV.A.ii Transmission** for a discussion of solutions.

III.C EXISTING RATE BASE

Generally, existing rate base comprises the book value of all generation, transmission, and distribution assets already in service, separate from those incremental costs associated explicitly with serving new customers.[13] These costs are generally recovered through depreciation and return on the capital invested (excluding any costs that are expensed). A substantial amount of rate base costs exist regardless of whether a new large load customer interconnects. Traditional allocation of existing rate base would mean rolling a new large load customer into an existing class. Theoretically, this is an instance in which large load growth could benefit existing customers: a new large load customer taking on some amount of existing fixed costs could place downward pressure on rates – by spreading those costs across more sales, the per unit cost of service goes down. This is often the primary narrative benefit of adding large load customers.

However, this potential benefit is contingent on two conditions:

1. A large load customer's allocation must reflect its actual reliance on, and cost to, the system. That may not be the case if a new large load customer ramps across several years to its full load; downward pressure on existing customer rates would lag until the customer reaches full load and a general rate case is completed. Further, increased utilization of existing assets can actually increase costs, e.g., in the form of increased generator and transmission O&M, increased fuel costs, etc.[14]

2. The large load customer must maintain consistent demand. If at any point the customer reduces demand or exits the system, the costs it previously absorbed revert to other customer classes.

Thus, the challenge for existing rate base allocation (and indeed allocation of cost through rates going forward) in the face of new large load customers is that, while the cost may not be caused directly by the new customer alone, misallocation or customer exit can turn what would have been a benefit to existing customers into an unexpected burden if they are forced to absorb those costs years down the road.

See section **IV.B Existing Rate Base Allocation** for a discussion of solutions.

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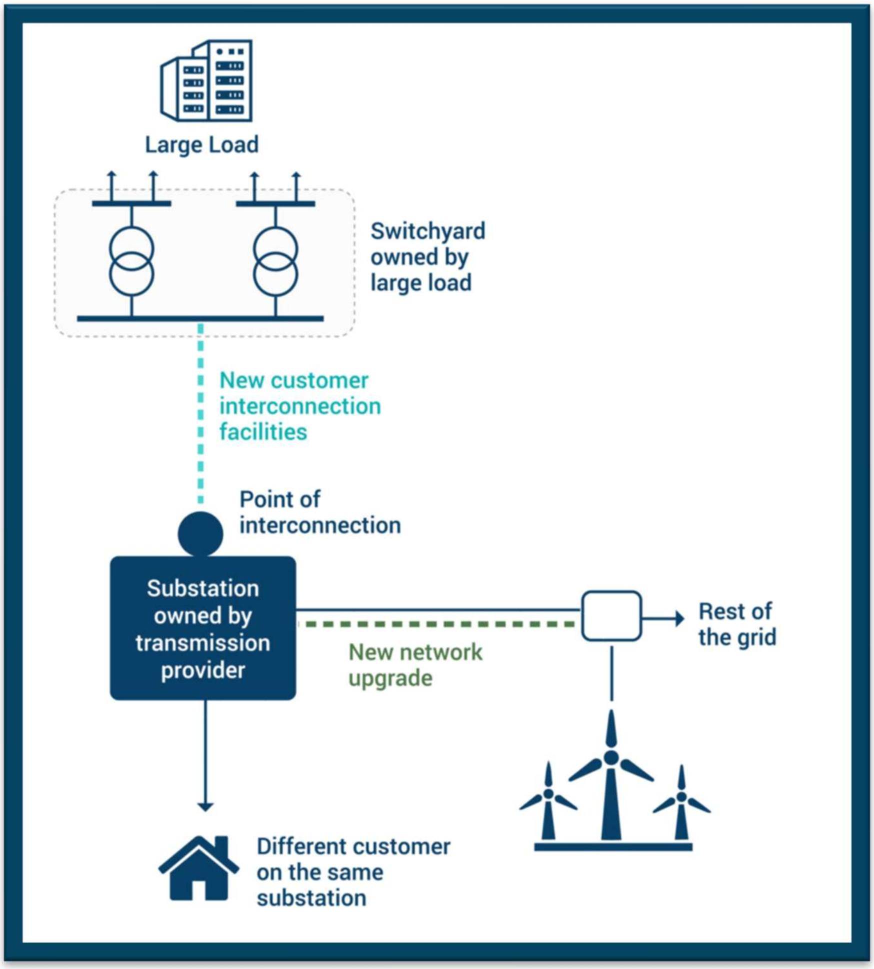
[13] The assets incorporated into existing rate base depend on the regulatory and ownership structure of the specific utility. This section covers those assets that are included in rate base.
[14] See for example Fiaz Hossain et al, "Limiting the Impact of AI Data Centers on Fatigue Life of Thermal Turbine Generators in the Grid: A Frequency-Domain Approach," arXiv, May 2, 2026, https://arxiv.org/html/2605.01173.

III.D INTERCONNECTION, NETWORK UPGRADE, AND TRANSMISSION COSTS

Until recently, most new customer demand focused on service via connections to utility distribution systems. This approach works for the types and sizes of customer interconnections that were typically encountered and continue to be developed today. In contrast, the magnitude of large loads is such that run-of-the-mill large load interconnection requests are in the hundreds of megawatts (MW), and some in excess of a gigawatt (1,000 MW). The physical capabilities of distribution grid interconnections are too limited and too inefficient to serve as primary power sources. Transmission level facilities have the physical capabilities to carry the full capacity needed to serve these large load customers as well as providing the redundancy being sought to ensure reliability of service. Because of this relationship between large loads needs and transmission system capabilities, this section focuses on transmission interconnections, although large loads can utilize both transmission and distribution interconnections.

Although transmission systems are technically capable to meet the demands and novel usage behaviors of new large loads, most were not designed with the excess capacity that would enable them to serve large loads immediately. To address this, the transmission system needs to be analyzed and upgraded to ensure not only reliable service for the new large load, but also to retain the reliable service expected by existing customers. This gap between capability and demand tends to increase timelines to achieve interconnections. These upgrades typically fall into three categories: Interconnection Facilities, Network Upgrades, and Post In-Service Transmission Projects. The difference between interconnection and network upgrades is illustrated in Figure 4. Post In-Service transmission projects may occur anywhere on the transmission system including behind the point of interconnection.

Figure 4. Transmission Facilities Typically Needed for a Large Load[15]



Regardless of the upgrade type needed, we would expect increased utilization of the transmission system. Therefore, regardless of the upgrade type, additional O&M costs are also necessary and risk being subsidized by non-large load customer classes.

While wholesale rates for transmission facilities are under FERC jurisdiction, costs resulting from expansion, operation and maintenance of the transmission grid are ultimately allocated to load-serving utilities and funded through retail customers. Knowing how these transmission costs are incurred allows for the redistribution of wholesale transmission rate to customers and customer classes in line with the value provided by those costs via retail ratemaking processes.

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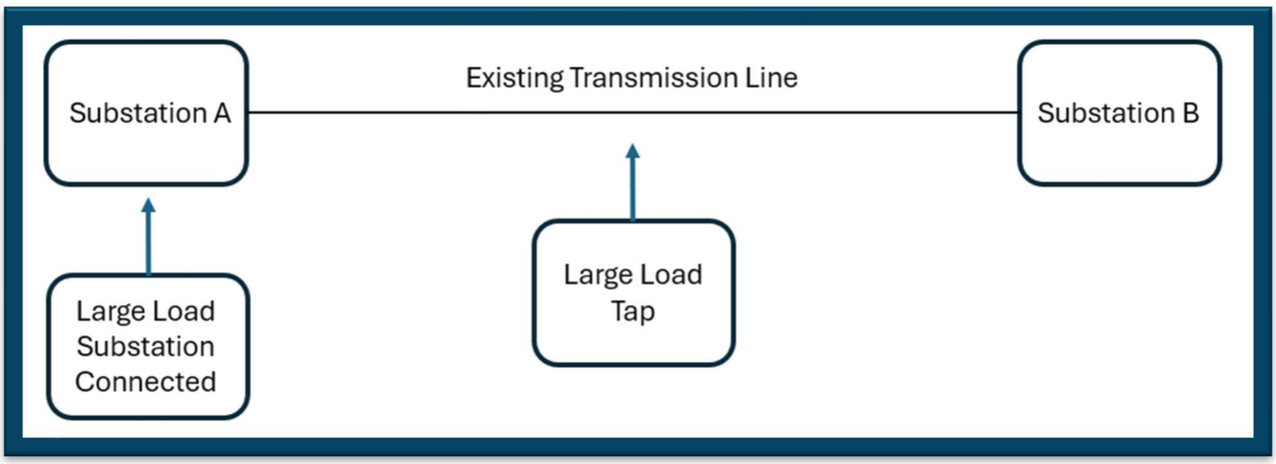
[15] T. Farrell, C. Wayner, S. Wang, M. Lozano, and Chaz Teplin, *Understanding Large Load Interconnection* (RMI, April 14, 2026), https://rmi.org/resources/understanding-large-load-interconnection/.

III.D.i Applying Line Extension Policies to Interconnection Facilities

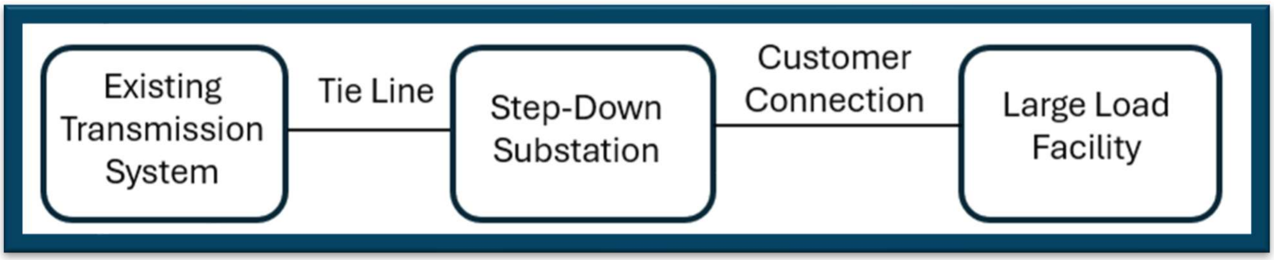
The first of these is the interconnection facilities or transmission system upgrades that are needed to physically connect a large load customer to the existing transmission system. In contrast, line extensions are typically associated with distribution system interconnections where the costs incurred could include benefits to multiple customers such as improved performance and lower overall cost required for additional interconnections. Interconnection facilities consist of the control points (substations or switching stations) that either expand and connect to substations, or 'tap' an existing transmission line by inserting a new control point (Figure 5).

Figure 5 Large Load Interconnection Types



Interconnection facilities may also include transmission lines reaching to the large load development site (tie-lines), substations to reduce voltages (commonly referred to as 'stepping-down'), and connections from the stepped down service to the locations where power is ultimately delivered within the large load facility (Figure 6).

Figure 6 Simplified Large Load Interconnection Facility Configuration



Additionally, metering is installed to measure power use and protection systems are included for the large load facility as well as the greater transmission system.

Historically, load interconnections utilize distribution systems for electric service, and utilities regularly socialize the costs either directly or via refunds over time of upfront payments by the new customer that were incurred for interconnection facilities, or line extensions or upgrades, to new customers. The general view that supports this socialization is that the introduction of the new customer at the distribution level benefits the rest of a utility's customer base via increased system reliability, more socialization of other costs, utilization of the infrastructure by many customers, and other benefits based on economies of scale.[16] In some cases, utilities include protections[17] that could help ensure the cost of serving a new customer is balanced with the benefits that would justify socializing all or part of those costs.

Unlike smaller loads, large loads are typically tied directly to the transmission system via facilities designed to meet the individual customer's specific needs. Given the size and scale of large loads, socialization of interconnection costs tips the balance of cost sharing in favor of the large load over other customer classes. This results from the type and magnitude of interconnection as well as the reduced ability to further extend those interconnection facilities for the utilization of other customers. This means that these facilities are unlikely to improve the local distribution or transmission system beyond the ability to meet the needs of only the new or expanded large load. In addition, interconnection facilities for large loads typically exceed minimum design standards, resulting in increased costs.[18] The type and size of transmission interconnection facilities exceeds what is available at the distribution level[19] and

[16] Lawrence Berkeley National Laboratory, Energy Analysis Division, "Allocating Distribution System Upgrade Costs for Distributed Energy Resource Interconnection: Practical Lessons and Innovations," https://energyanalysis.lbl.gov/publications/allocating-distribution-system.

[17] Examples: Mississippi Power Cost-to-Revenue Ratio, El Paso Electric Escrow Based Revenue Guarantee, Benton PUD—Contribution-in-Aid-to-Construction (CIAC) with Revenue Recovery.

[18] Institute of Electrical and Electronics Engineers, *IEEE Std 493-2007: IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems* (Gold Book).

[19] The relationship further separates the historical treatment of line extensions for new loads from interconnection requirements of new or expanded large loads since historical line extensions are developed to be reliable under the

is determined not by the utility, but by the size of the new interconnection, the point at which the new load is requesting to interconnect, whether the interconnection is within an existing control point, and the level of reliability requested by the load interconnection.[20]

Transmission interconnections also mean the costs of interconnection are significantly higher, from the use of generally larger and more robust equipment to the need for significantly more land; individual transmission level facilities[21] are orders of magnitude more expensive than individual distribution facilities.[22] For example, the interconnection facilities for two data centers in Indiana Michigan Power's service territory exceeded $400 million whereas a group of residential customer interconnections may be one one-thousandth of that level. Line extension policy that results in the socialization of these costs are therefore much more likely to shift more costs away from large loads than would be shifted from the socialization of *distribution* facilities for customers connecting at lower voltages. This is the case simply because of the magnitude of costs that would be socialized when compared to the potential value realized by other customer classes who are unlikely to be provided service using a large load customer's interconnection facilities. Finally, the specialized nature of the interconnection for large loads[23] means that the additional expansion and use of those facilities beyond that specific large load is very limited, reducing the ability of the existing customers of a utility to benefit from the interconnection facilities of the large load.

At the retail rate level, interconnection costs today are either directly recovered from the interconnecting customer or socialized via line extension policies. With transmission level interconnections, direct assignment of the costs for interconnection facilities is more commonplace. These costs for large loads are unlikely to result in benefits to the rest of a utility's customers, meaning any socialization of those costs would deviate from assignment based on the beneficiary of the facilities.

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loss of a single major element whereas the redundancy requested by large loads often include the ability to withstand the loss of *any* two or more pieces of equipment.

[20] By way of example, a large load seeking to interconnect at 345 kV will have higher cost than a large load interconnecting at 230 kV. Similarly, a large load seeking N+2 reliability, or reliability that can be maintained after the loss of two portions of the interconnection facilities, will have a higher cost than a large load seeking an N+1 level of reliability. All of these are the result of the new or expanded large load customer requirements. In contrast to the customization accommodated by utilities to meet requests for the interconnection of new or expanded large loads, a typical service application via distribution systems only specifies type of service requested, and service size that receives the level of reliability required by the utility. This difference in customization increases reliability for an impactful interconnection, but reduces the alignment of cost at the transmission and distribution levels that could be socialized.

[21] MISO, "Cost Estimation Guide for MTEP26," https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Workbook%20for%20MTEP26547535.xlsx.

[22] FARADY, "Price Range for Electrical Substations Cost Comparison," https://www.distribution-transformer.com/price-range-for-electrical-substations-cost-comparison/.

[23] Institute of Electrical and Electronics Engineers, *IEEE Std 493-2007: IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems* (Gold Book).

See sections **IV.A.ii Transmission** and **IV.H Fixing Line Extension Policies** for a discussion of solutions.

III.D.ii Network Upgrades

The second group of potential transmission costs resulting from the interconnection of large loads is the system, or "network," upgrades required to ensure transmission system reliability (that is, stability in terms of voltage, frequency, thermal limits, and other electrical engineering aspects of the grid) is maintained when the new large load customer is interconnected. These are different from interconnection facilities required for physical interconnection to the existing transmission system as network upgrades are identified as mitigations to constraints on the transmission system beyond the point of interconnection serving the new large load and are not related to the physical interconnection of that new large load to the grid. In other words, network upgrades are transmission costs required to maintain the same level of reliability for the transmission system even after the introduction of the new or expanded large load.

Network upgrades are identified through a series of reliability studies that look at the ability of the transmission system to stay within rated limits during times when all existing and planned transmission facilities are in place, but also under contingency conditions where single or combinations of transmission facilities are taken out of service.

In general, this study process follows the requirements set by NERC in the TPL-001-5 standard.[24] This standard lays out the types of contingencies to be analyzed and provides guidance on which types of mitigations are acceptable for each type of contingency. The types of analysis undertaken to identify these costs vary utility to utility. In some cases, network upgrades are identified only via steady-state power flow analysis[25] looking at facility loading and voltage levels compared to facilities ratings. This is likely to change as NERC,[26] FERC,[27] and Regional Reliability Organizations are beginning to require system stability and Electromagnetic Transient (EMT) analyses in addition to power flow analysis to be performed prior to the interconnection of new or expanded large loads.

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[24] NERC, "TPL-001-5.1 — Transmission System Planning Performance Requirements," accessed July 14, 2026, https://www.nerc.com/globalassets/standards/reliability-standards/tpl/tpl-001-5.1.pdf.

[25] GridLab, "Power System Analysis for Energy Advocates," August 2025, https://gridlab.org/portfolio-item/power-system-analysis-for-advocacy/, 20.

[26] NERC, "Level 3 Alert: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection and Control," https://www.nerc.com/globalassets/programs/bpsa/alerts/level-3-computational-load-alert.pdf.

[27] Federal Energy Regulatory Commission, "FERC Launches Aggressive Targeted Action to Speed Large Load Integration," https://www.ferc.gov/news-events/news/ferc-launches-aggressive-targeted-action-speed-large-load-integration.

In current generator interconnection processes, network upgrade costs are treated inconsistently across the industry. In some areas, network upgrade costs are directly assigned to the new generator interconnection as it is the primary driver for the upgrade and the direct assignment would in turn be roughly commensurate with the benefits resulting from the network upgrades. In other areas, the costs of network upgrades are initially paid for by the new generation interconnection, then refunded over a period of time given the resource is included in a utility's plan to meet resource adequacy requirements. To the extent that interconnecting generators are credited back for the cost of network upgrades over time, this cost recovery approach is premised on the theory that while the generator is the cost causer, the network upgrades being built will eventually be utilized by other generators and/or customers. On the load interconnection side, network upgrade costs are typically included in the embedded cost rate charged by the transmission owner/operator to all load impacted by the wholesale transmission rate in which the costs for these upgrades are included, with the ultimate allocation of the costs to end-use customers decided at the retail level. That said, the same logic as FERC applies in the generator interconnection context could apply in the load context as well.

Despite the typical approach applied by RTOs in the generator interconnection context, some utilities have argued that other customers may benefit from the network upgrades undertaken to incorporate a large load into the transmission system. Without clear requirements for classification of network upgrades as being directly assigned to new or expanded large load interconnections, these projects risk being classified as system reliability projects that are spread are included in wholesale transmission rates that impact all customers subject to that rate. This wholesale transmission rate is then spread across all customer classes when the benefit may redound only to the single new large customer and, conversely, risk being directly assigned to large loads despite broader system benefits when the benefits do not justify that allocation.

It is worth noting that whether it is most reasonable to include these costs in wholesale transmission rates or directly allocate them to large loads in any given area may take direction from the treatment of generation interconnection policies that already include processes to make this distinction.

Similar to the allocation of costs of interconnection facilities, the characteristics of large loads favor the initial direct assignment of network upgrade costs to the large loads that trigger their need, but with additional considerations for benefits that assignment of costs could extend beyond the new or expanded large load. This is because the identified network upgrades for any given load likely would not be required but for the interconnection of the new or expanded large load.[28] However, network upgrade costs are initially being driven to retain the level of

[28] GridLab, "Power System Analysis for Energy Advocates," 20.

reliability provided prior to the presence of the large load and may secondarily provide benefits to other customers. Thus, the appropriate approach may be for network upgrades to generally be the responsibility of the large load, but the costs may be socialized across all customer classes if the benefits of a network upgrade extend beyond the large load interconnection for which the need for the network upgrade was identified. To address this potential disconnect between costs and benefits over time, the costs initially assigned directly to a large load may be refunded over time and shared over a large group of benefitting customers.

See section **IV.A.ii Transmission** for a discussion of solutions.

III.D.iii Post-In-Service Local or Regional Projects

Once a new or expanded large load has reached sufficient certainty, e.g., through the signing of an interconnection services agreement, that large load is then incorporated into normal transmission planning processes to assess its impact on the overall reliability and efficiency of the transmission system.

Regional cost allocation methods approved by FERC for transmission projects selected in these more integrated planning processes do not assess the degree to which certain loads triggered transmission needs, though this may depend on the cost allocation method used by the respective planning region. Consideration of how the costs of regionally allocated transmission projects are recovered at the retail level is part of retail ratemaking, which can ensure those who benefit from transmission costs allocated at the wholesale level are not being subsidized by those end-users that see limited or no benefit of transmission upgrades.

See section **IV.B Indirect Transmission Cost Assignment** for a discussion of solutions.

III.D.iv Outage Related Costs

For interconnection to, and maintenance of, the transmission system, pieces of the transmission system are typically de-

Post-In-Service Project Example

Ongoing reliability:
Interconnection studies utilize static assumptions to determine impacts caused by the interconnection of a large load. Once that large load has been placed in-service, additional capital transmission projects may be required to maintain reliability that may not have been required but for the large load being developed.

Scenario:
After a large load is placed in service, a need for voltage support is identified during non-peak hours with high reliance on distant generation. This scenario was not studied in the load interconnection process.

Transmission Project: Build dynamic support facility to support variable reactive power requirements driven by increase demand and fast changes in energy consumption.

Allocation: This project is considered a system reliability upgrade. The wholesale transmission allocation includes these costs in wholesale transmission rates, effectively assigning cost responsibility of this project to all customers of a utility or group of utilities impacted by that wholesale transmission rate.

Solution to enable retail recovery of costs from beneficiaries:
Consideration of need with and without a large load provides the transparency needed to assess contribution to the identified reliability need

energized to allow for safe construction, maintenance, and connection of new service. These outages result in an often overlooked risk for shifting of costs when new or expanded large loads are under construction or increase the costs to maintain transmission facilities that now are under greater stress. Energy costs, congestion, system losses, and simply maintaining the transmission system are fundamentally changed once the work to interconnect a new or expanded large load customer begins and can result in cost shift to existing customers if not directly measured via dedicated pricing nodes or accounted for appropriately through cost of service evaluations for the duration of an outage.

While grid operators have a robust process to account for the reliability aspects of transmission facility outages, these temporary system changes can result in an unaccounted-for increase in operating costs.[29] These unaccounted-for costs manifest in changes in energy market pricing due to congestion. For example, planned generation and transmission outage schedules are approved by MISO. This approval process considers only reliability concerns associated with requested outages and not the potential economic costs. As MISO's Independent Market Monitor noted in its 2024 State of the Market report. [30]

> *Transmission and generation outages often occur simultaneously and affect the same constraints. Multiple simultaneous generation outages contributed to $540 million in real-time congestion costs in 2024 – 29 percent of real-time congestion costs.*

Without a policy to also consider the economic impacts of outages necessitated by large loads, there is significant potential for cost-shifting absent a reallocation of those costs. Incorporating the economic impact of outages into scheduling processes, particularly in the RTOs, reduces congestion by shifting when outages are allowed to occur based on reliability and the congestion cost that would be incurred. Considering congestion impacts in outage scheduling provide relief to the wholesale energy market impacts of outages.[31] Therefore, in this section, we discuss the three components of LMPs and how they are impacted by outages that would be required to interconnect new or expanded large loads.

Energy Cost

The energy cost can be impacted by effectively reducing the pool of resources available to meet the next incremental MW of demand during an outage. This would result in an increased reliance on higher cost generation, resulting in an increase in wholesale energy prices in an

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[29] MISO, "MTEP24 Near-Term Congestion Study Report," https://cdn.misoenergy.org/MTEP24%20Near-Term%20Congestion%20Study%20Report657728.pdf.
[30] Potomac Economics, "2024 MISO State of the Market Report," https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-MISO-SOM_Report_Body_Final.pdf, 112.

[31] Potomac Economics, "2025 State of the Market Report," https://www.potomaceconomics.com/wp-content/uploads/2026/07/2025-State-of-the-Market-Report.pdf, 111

area. Starting in 2021, MISO has experienced an increase in maximum generation events during off-peak months due to forced and planned outages resulting in insufficient capacity projections. This led to higher cost resources being made ready to cover gaps in capacity during times in which capacity levels were historically a risk.

Losses

An additional consideration in the cost of outages is the amount of losses that may be incurred throughout the duration of the outage. Transmission losses are the measure of power consumed by the transmission equipment before it reaches an end user. Outages result in a piece of the transmission system being removed that would otherwise reduce the losses resulting from service to an area, decreasing efficiency and increasing costs.

As outages occur to interconnect new or expanded large loads, or to maintain transmission facilities, the utilization of the remaining transmission paths increases.[32] This increases current flow on the transmission facilities, resulting in proportionately greater losses.

This concept also carries to situations in which a new or expanded large load has already been interconnected, but no outages are present. This new or expanded large load results in increased utilization, or more power flowing, on transmission facilities. This increase in utilization increases power consumed by those facilities, resulting in increased losses.

While losses can be calculated for a given area, splitting them between customer classes becomes difficult to quantify when recovering costs via retail rates without dedicated metering at the wholesale level that is used to develop separate LMP calculations for the new or expanded large load.

Congestion Cost

As mentioned in an earlier section, this congestion results in a mismatch between the revenues paid to owned or contracted generation and the wholesale costs that are paid to serve customer demand. Outages reduce the capability of the transmission system, increasing the occurrences of insufficient transmission being available, increasing energy costs.

Unplanned Events

Outage related costs can also be incurred either directly or indirectly from forced outages. Forced outages will experience the same impacts to operating costs as planned outages, but forced outages also carry the risk of additional strain on the power grid to recover from those unexpected outages. This can fall into three primary areas: system response costs, emergency redispatch costs, and in the worst cases, system restoration costs.

[32] Casazza, J., and F. Delea, *Understanding Electric Power Systems: An Overview of the Technology and the Marketplace*, Wiley-IEEE Press, 2003, Chapter 6, “Technology of the Electric Transmission System.”

System response costs stem from the automatic and manual actions taken to return the power grid to stable operations after an event and result in a short-term mismatch in generation and load creating swings in voltage and frequency. These are conditions that are continuously studied and accounted for in terms of the forced outage of generation resources but are less common when considering the forced outage of large loads. When a large load experiences a forced outage, a similar reaction from protection and control systems than what is needed to recover from the forced outage of a generator occurs. In both cases, recovery results in "swings" or alternating from low to high voltages and frequency over a short period of time that increase the operating costs during those periods as transmission and generators work together to retain reliable service.

Emergency redispatch costs are incurred immediately after a forced outage. When this outage is unexpected, that economic value of redispatch is forfeited in favor of ensuring reliability is maintained. These additional costs are the result of relying on the flexibility of the generation resources online at the time of a forced outage with rapid changes in output requiring more fuel usage and reduced efficiency than what would have been incurred if the forced outage did not occur.

In extreme events, a complete restart of the impacted areas of the power grid may be needed, typically starting with high-cost generation, is used to support restarting more economic generation. While this is the worst case, the costs can be significant in terms of both system restoration as well as the economic and health impacts that would be experienced as a result of blackouts. As large loads and inverter-based resources grow, mitigation becomes increasingly complex and requires increased diligence when studying the impacts of new or expanded large loads. It is necessary to ensure the power grid can maintain reliable service after the loss of that large load as well as to identify any potential risk where forced outages of large loads can impact system reliability, and to subsequently ensure that costs associated with outage events can be allocated correctly.

When considering outages, the transmission constraints, congestions cost and reliability risks identified materially change. If the outage is experienced, either planned or forced, this would be expected to result in a significant cost incurred that may not have occurred without the large load being present. This impact is first experienced before the new or expanded large load is placed in service as outages required to ensure upgrades are in place prior to serving a large load. Typical allocators for these outage-related costs are based on a combined charge for all operational costs to a load serving entity (LSE), typically recovered in retail rates through riders or adjustment clauses. These allocators do not include the new demand until that customer starts receiving service and would shift costs driven by the outages required to interconnect a large load to existing customers, which would not have been incurred but for the interconnection of the new or expanded large load. Adequate identification of risks and potential costs, paired with measurement of costs during specific outages, requires additional and more detailed evaluation of impacts from new or expanded large loads that extend beyond prior practices and standards related to planning for new load interconnections.

See section **IV.C Collection of Data from Wholesale Markets: Assigning a New Node** for a discussion of solutions.

III.D.v Allocation of Wholesale Transmission Costs at the Retail Level

The share of local, regional, and interregional transmission costs allocated to a utility can only be recovered via the end-use retail customers to which that utility provides service. These transmission costs can follow a path that directly accounts for them in retail rate-making processes, or via parallel mechanisms, such as adjustment clauses and riders. In both cases, the transmission costs are generally allocated among retail customers based on separate allocators, such as a volumetric share of transmission costs per customer, or customer class. The transmission cost itself that is incurred by the utility is considered as a single charge that is not typically separated into sub-categories of costs at the wholesale level that can be allocated to retail customers to align with the benefits that are expected by each retail customer or customer class from those incurred costs. The exceptions to this are instances where a single or small group of customers make a request, such as an interconnection or transmission service request, for which costs can be reasonably allocated in a direct manner to cost causers. Notably, retail regulators cannot disallow the recovery of FERC-approved transmission costs allocated at the wholesale level to utilities.

When considering the impacts of new or expanded large loads, this single charge approach at the retail level for transmission costs allocated at the wholesale level introduces a distinct risk of new or expanded large loads being subsidized by the remainder of a utility's customers. The introduction of that new or expanded large load, as previously discussed, is likely a direct connection to the transmission system, and in turn, has direct impacts on transmission system costs from which the value produced may not be shared by other customers of that utility providing service. This introduction of a new or expanded large load can also have a material impact on the magnitude of transmission costs allocated to a utility providing service to that large load customer. In areas where transmission costs are allocated based on a direct calculation of benefits or are socialized based on share of peak demand or share of energy use, this large load can only serve to increase the percentage of transmission costs allocated to a utility. The example in Table 1 below illustrates how, when all else is held static, the introduction of a new or expanded large load within a utility's service obligation increases the share of costs that utility would be allocated.

Table 1. Regional Project Allocation based on Share of Peak Demand

	Before Large Load	After Large Load

Region	Peak Demand	10,000 MW	10,500 MW
	Cost to be Allocated	$10,000,000	$10,000,000
	Cost Allocated per Peak MW	$1,000/MW	$952.38/MW
Utility A	Peak Demand	1,000 MW (10% of region)	1,500 MW
	Cost Allocation	$1,000,000	$1,428,571
Utility B	Peak Demand	9,000 MW	9,000 MW
	Cost Allocation	$9,000,000	$8,571,429

The initial shares of regional peak demand result in Utility A being allocated a fixed 10 percent of the costs of a project. If Utility A then incorporates a new or expanded large load, increasing its peak demand by 50 percent, the fixed allocation based on the previous peak demand would need to be updated (as shown in the right-hand column) to ensure costs remain allocated in a manner that is roughly commensurate with estimated benefits.

Most existing allocation methods for regional and interregional transmission costs use static demand projections. Without a method to reflect changes in usage brought by new or expanded large loads in this example, the allocation would result in Utility B paying $428,571 more than they would be allocated if the impacts of the new or expanded large load were considered. In contrast, allocation methodologies like the MISO Multi-Value Project allocation, which relies on allocating costs based on a percentage of total monthly withdrawals, are continuously correcting for changes that would otherwise result in misalignment of costs and beneficiaries.

MISO Multi-Value Project (MVP) Allocation:

$$\textbf{MVP Usage Rate} = \text{MVP Annual Revenue Requirement} \div \text{Total Monthly Net Actual Energy Withdrawals (MWh)}$$

$$\textbf{MVP Allocation} = \text{Utility Monthly Net Actual Energy Withdrawals (MWh)} * \text{MVP Usage Rate}$$

The example above shows how the introduction of a new or expanded large load could bring risk of subsidizing large loads to the customers of both the utility serving the new or expanded large load, and the remainder of the utilities participating in a regional planning process where failure to account for the inclusion of a new or expanded large loads could result in subsidization of that change in customer make-up.

When transmission costs filter into retail rates, a lack of flexibility in cost allocation can result in the subsidization of large loads. Ensuring retail allocations of transmission costs can account for changes as soon as possible after they are introduced, similar to the monthly usage rate MISO leverages in MVP allocations, can limit subsidization of large loads and reduce burdens on regulatory bodies to reassess retail rates when new or expanded large loads are developed. Additionally, transmission costs under current assignment mechanisms (typically riders and adjustment clauses) are unlikely to be granular enough when incurred by each utility to identify which cost differences result from the new or expanded large load. Establishing direct requirements to monitor such changes associated with the addition of new or expanded large loads would provide data that more accurately recover transmission costs from those that benefit.

See section **IV.B Indirect Transmission Cost Assignment** for a discussion of solutions.

III.E NET REVENUE ANALYSES

Applications for approval of new large load customer service contracts often include a financial analysis purporting to show significant net benefits to other customers in the form of revenues in excess of costs.[33] These analyses do not take a single form, but their general intent seems to be to demonstrate that the proposed contract sufficiently guarantees recovery of costs caused by the new customer and that their interconnection will result in lower rates for other customers. The subtext of these analyses is that existing cost allocation methodologies need not be revisited and are sufficient to guarantee that costs are not shifted to other consumers.

However, these analyses are often only a partial look at the full cost of service for a large load customer and may also depend on assumptions that are likely to be erroneous, e.g., that the utility's transmission revenue requirement does not change with the addition of large customers. Rather than performing a full embedded COSS to calculate the large load customer's full embedded cost of service, the utility may only identify *incremental* costs to serve the customer. Incremental costs, reflecting additional transmission and generation assets needed to help serve the customer, are often substantially below a customer's full embedded cost of service, which includes a share of existing system costs that are also necessary to serve the customer. A utility's demonstration that a large load customer is paying all of its incremental costs, plus some contribution towards fixed system costs, does not mean that the customer is paying its fair share of costs, nor is reflective of the cost causation principle. In addition, as we describe in other sections of this report, costs may increase simply due to

[33] See, for example, the filing of DTE Electric Company in Michigan Public Service Commission Case No. U-22058.

the presence of more load, e.g., congestion pricing, and those effects are frequently not accounted for in such analyses though they may be quite significant in magnitude. Finally, differences between how charges are assessed based on actual versus contracted load can materially affect the results of such analyses. It may be presumed that the customer will always consume its contracted load, in practice this is often not the case.

These analyses merit closer scrutiny in and of themselves, but a principal question they raise is whether a forecasted reduction in rates to other customers in the form of the large load customer's contribution to existing fixed system costs is sufficient justification to set aside cost causation determination across the many costs that the large load customer will influence. While the ratemaking implications of large load customers are relatively new to utility commissions and intervenors, we have not yet seen reasonable justification to set aside cost allocation principles. Even in an ideal scenario where a benefit-cost analysis is well formed and comprehensive across costs, it is still only a projection that likely rides on assumptions about static fuel costs, static energy market pricing, and/or other assumptions that are difficult to forecast but unlikely to remain unchanged. Not infrequently, net revenue analyses come with a promise to reevaluate cost allocation if net benefits are not realized, but this is likely to dramatically increase the burden on Commissions to track the revenue requirements for each cost component and reconcile them with the net revenue analysis projections. It's difficult to see how this special rate treatment would be warranted or necessary. Instead, a fully formed cost of service study that accounts for all loads and all costs is a better tool to assign costs and is likely to be updated anyway as load composition and costs change.

See section **IV.I Net Revenue Analyses** for a discussion of solutions to this challenge.

III.F CONTRACTUAL VERSUS ACTUAL DEMAND

One or more charges on a large load customer's bill may be based upon that customer's actual demand. The demand may be based on any number of methodologies such as the highest peak in a multi-month period, a rolling average, minimum demand, or other approach that connects the operational demand to the demand-related charge. Historically, this has been a key element of tariffs for industrial customers in part because it can incentivize them to shift their loads to off-peak hours and/or reduce their consumption overall. However, because it is increasingly rare that any given utility system has headroom to add new, large customers there is generally a need for new infrastructure, whether generation or transmission or both. Therefore, a demand charge based on operational demand leaves the door open for significant cost shifting away from new customers. This is because that new infrastructure is generally built to serve a customer's contractual demand, which constitutes the utility's obligation to serve and cannot or will not be adjusted based on actual demand.

With smaller loads, the risk of a customer reducing consumption, failing to ramp up to projected levels, going out of business, or failing to reach its projected or contracted demand was manageable. Utilities could reasonably assume that broader load growth within the service territory would continue to justify need. That assumption does not hold for loads at the size of recent large load requests. No realistic native load growth can offset the stranded cost exposure created if a 500 MW customer significantly curtails its load, never reaches full operation, or ceases operations entirely. In that scenario, the costs incurred to support that customer do not disappear — they are shifted to the remaining customer base until load growth may eventually justify the infrastructure investment. This risk is further compounded when the exposure is concentrated in a single large load customer rather than distributed across a broader large load customer class, which would allow costs to be maintained within the class even if one customer within it were to exit. Even with minimum demand thresholds based on contracted capacity, if a large load customer fails to fully ramp up to its requested demand level, there is typically no existing mechanism to recover the transmission investment attributable to that customer from that customer directly if those costs are not directly assigned. The shortfall does not disappear; instead, it is effectively shifted to the broader customer base.

This problem is compounded by the historical nature of coincident peak-based allocation that is typically used to allocate transmission costs. A customer's cost responsibility is calculated using historical peak measurements, typically from the prior year; therefore, the allocation does not reflect the customer's true cost responsibility until they have been fully operational and contributing to the system peak for a full measurement period. During the intervening time, which could span multiple years for a large industrial or data center customer with a phased ramp-up, other customers effectively subsidize the transmission costs attributable to the large load customer. Direct assignment of transmission costs oftentimes makes sense for large customers and can eliminate any gap between the customer's in-service date to full contractual load and the cost recovery of this infrastructure, but if costs are instead recovered through demand-related charges based on actual demand cost shifting can occur.

This risk was on full display in the case of the Foxconn manufacturing facility development and interconnection in Mount Pleasant, Wisconsin. In that case, the new large load was being developed expecting a full manufacturing facility including an expected 13,000 local jobs. It utilized an estimated public funding of $2.9 billion[34] in infrastructure upgrades across transportation, utility, and energy system improvements to accommodate this development. Upon completion, the facility was shifted into smaller roles until it settled with less than 10% of

[34] Wisconsin Economic Development Corporation, "Annual Report on Economic Development WEDC Awards FY2018Q2" (file download), accessed July 14, 2026, https://wedc.org/wp-content/uploads/2024/04/Annual-Report-on-Economic-Development-WEDC-Awards-FY2018Q2.xlsx.

the jobs created compared to initial estimates[35] for roles with a far different purpose than originally intended.

Given the magnitude of this risk, it is critical that costs associated with large load interconnections are allocated correctly and recovered through a mechanism that prevents those costs from shifting to other customers if the anticipated load does not materialize or while the load ramps up over a period of time (typically several years).

See section **IV.G Contractual Demand Cost Allocation** for a discussion of solutions.

III.G COST RECOVERY OPTIONS

Utilities have several options for financing capital expenditures related to transmission and distribution — and, for vertically integrated utilities, generation as well. These options include debt financing, equity financing, and retained earnings. Separately, utilities have options for recovering these costs from customers once financed, primarily through rate-based recovery mechanisms, namely construction work in progress (CWIP) and allowance for funds used during construction (AFUDC). This can also include funding from public programs, such as federal loans and U.S. Department of Energy programs. A utility may also avoid financing a project altogether by having a customer directly fund it through contributions in aid of construction (CIAC). CIAC serves to directly assign the costs of an upgrade to the customer causing it thus avoiding cross-subsidization; however, CWIP and AFUDC to recover new-build and upgrade costs when CIAC is not utilized can result in existing ratepayers subsidizing large load upgrades.

Given that CWIP recovery could begin before the cost-causing customer is interconnected or has ramped to its full contracted load, meaning non-large load customers bear those costs in the interim. If the large load is already a customer, then CWIP could be rolled into rate base. Allowing CWIP into rates prior to the large load becoming a customer (online) will result in existing ratepayers subsidizing costs that should be borne by the large load. It also shifts risk onto existing ratepayers, who would be prepaying for an asset that may be delayed, run over budget never be completed, or be built for a load that fails to materialize (in full or in part).

See section **IV.J CIAC, CWIP and AFUDC** for a discussion of solutions.

[35] Wisconsin Economic Development Corporation, "Annual Report on Economic Development WEDC Awards FY2026Q3" (file download), accessed July 14, 2026, https://wedc.org/wp-content/uploads/2026/07/Annual-Report-on-Economic-Development-WEDC-Awards-FY2026Q3.xlsx.

IV. SOLUTIONS

IV.A DIRECT ASSIGNMENT

This section examines direct assignment as a key mechanism for allocation of generation and transmission costs associated with new large loads, by expanding the customer-related classification introduced in Section III.

IV.A.i New Generators

When a utility builds or procures generation capacity to serve new large load customers, one of the clearest solutions to allocation concerns is direct assignment. Direct assignment is a simple term for a detailed set of approaches that take two general forms: (1) assignment to a single identified customer, or (2) proportional assignment to the large load class based on its proportional contribution. From an administrative standpoint, the proportional approach is more logical where several large load customers drive a shared capacity investment, though it requires the utility to carefully define the set of resources driving specific investments

Both forms rest on the same departure from traditional classification. As discussed in Sections II.A and III.A, utilities traditionally classify generation costs as demand- or energy-related, with customer-related classification reserved for distribution. Direct assignment extends that customer-related treatment to generation, recognizing that capacity built to serve new large load customers is attributable to those customers with the same clarity long accepted at the distribution level. Absent a customer-related category for generation, the traditional COSS has no mechanism to assign the costs of a new build to the customers who caused it.

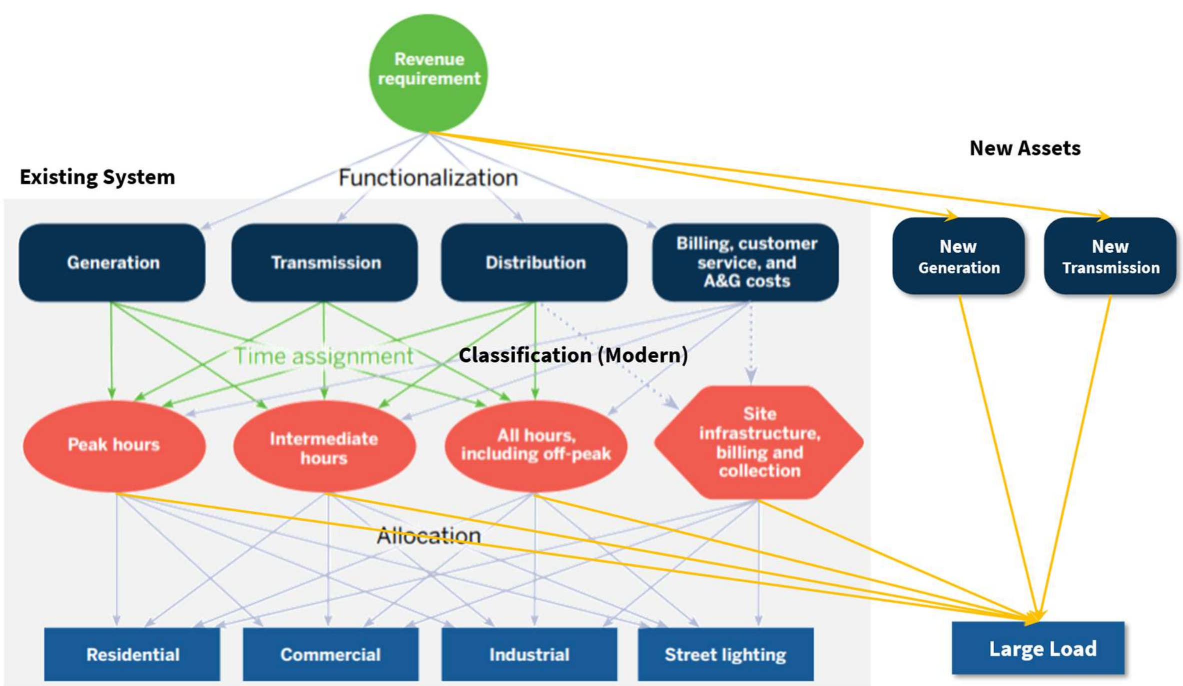
Table 2 is a simplified version of traditional cost classification as presented in the foundational 1992 NARUC Cost Allocation Manual. Here, we have added customer-related classification to both the generation and transmission functions to represent the emerging need for customer-related classification for large load customers.

Table 2. Cost allocation classification in the era of large load deployment

Cost Function	Typical cost classification
Generation	Demand-related Energy-related Customer-related (new)
Transmission	Demand-related Energy-related Customer-related (new)
Distribution	Demand-related Energy-related Customer-related
Customer service	Demand-related Customer-related

Shown differently, Figure 7 demonstrates how direct assignment would appear if the Regulatory Assistance Project diagram presented in Section II.A were adjusted. New generation would be classified and subsequently allocated directly to new large load customers.

Figure 7. Cost allocation classification in the era of large load deployment



One early example of the direct assignment to a single customer approach is Wisconsin Electric Power Company's (WEPCO) Very Large Customer tariff, which requires new large-load customers over 500 MW to subscribe to dedicated generation facilities, assigning those facilities' costs to the subscribing customer rather than socializing them across the system. WEPCO estimates that without the tariff, traditional ratemaking would allocate over $1.5 billion in additional capital costs to non-large-load customers.[36]

Oregon offers the most developed example of a proportional assignment to multiple customers approach to date. Under the 2025 POWER Act, the state's Public Utility Commission (OPUC) directed Portland General Electric (PGE) to establish a dedicated large load rate class and to directly assign the costs caused by those customers to those customers to mitigate cost risks to other classes.[37] In Order No. 26-154, the OPUC adopted PGE's Peak Growth Modifier, a mechanism that allocates investment in new generation and transmission to customer classes in proportion to their share of peak load growth. Critically, OPUC declined to time-limit the mechanism: where PGE had proposed assigning growth costs only for an initial rolling period before returning them to system-wide allocation, OPUC made the approach indefinite.

There are three other features of the PGE approach worth noting. The Peak Growth Modifier applies to *shared* new assets; facilities dedicated to a single customer are assigned to that customer directly. Further, OPUC paired the modifier with minimum demand charges set at 90 percent of contracted capacity, recovering the capacity reserved during ramp while acknowledging that the new resource may provide other customers some limited benefit. Finally, OPUC ordered further study into alternative cost allocation factors that could replace the modifier approach down the road and apply more universally across allocation methods.[38] This example illustrates the promise of both class-based and direct customer assignment and its central design question: whether the assignment endures for the life of the new asset.

IV.A.ii Interconnection Costs and Network Upgrades

Direct Assignment

As noted previously, the cost to interconnect new or expanded large loads increases in tandem with the network upgrades required to maintain system reliability as load grows. At the retail level, direct assignment of transmission costs would be a reasonable approach to ensure costs to interconnect are borne by the new or expanded large loads that are driving those incremental costs.

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[36] Wisconsin Electric Power Company, "Application – Very Large Customer & Bespoke Tariffs," Public Service Commission of Wisconsin, March 31, 2025, https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=539747.
[37] Public Utility Commission of Oregon, *Order No. 26-154* (May 7, 2026), https://apps.puc.state.or.us/orders/2026ords/26-154.pdf.
[38] Ibid.

IV.B INDIRECT TRANSMISSION COST ASSIGNMENT

Transmission cost allocation processes at the wholesale level across local, regional, and interregional footprints follow established ex-ante allocation methodologies. As currently implemented, wholesale transmission rates are unlikely to include sufficient detail to ensure retail allocation of transmission costs are to the benefiting customers or classes of that transmission. This shortcoming presents an opportunity for retail regulators to develop ratemaking processes that both acknowledge the impacts of a new or expanded large load and also assess the balance between the value produced by a new or expanded customer base and the costs incurred for that new service obligation at a higher level of granularity.

To ensure transmission facility costs, including direct facility as well as operations and maintenance costs, are correctly allocated among retail customers and customer classes, utilities must develop a method for delineating magnitude of use in order to calculate expected value from incurred costs. This can be done in several ways, including but not limited to those approaches suggested below and shown in Figure 8.

Cost of Service Allocations

A standard COSS utilizes historical or future test years to establish required revenue based on projected costs and establishes allocation methods among retail customers or customer classes to reasonably align costs with beneficiaries. With respect to inclusion of new or expanded large loads, updated COSS can effectively ensure that expected costs of operation, maintenance, and planned transmission improvements are classified correctly and allocated to align with the benefits received.

A distinct disadvantage to this approach when considering transmission costs associated with new or expanded large loads is the speed and uncertainty associated with their development. In simple instances, the time from request for interconnection to the start of service can be completed between occurrences of COSS efforts at the retail regulatory level. This means that a future test year or other assumptions in the COSS may not result in a reasonable approach for transmission costs incurred to interconnect new or expanded large loads, nor would a COSS accurately account for variable costs such as changes in congestion.

Contribution Allocations

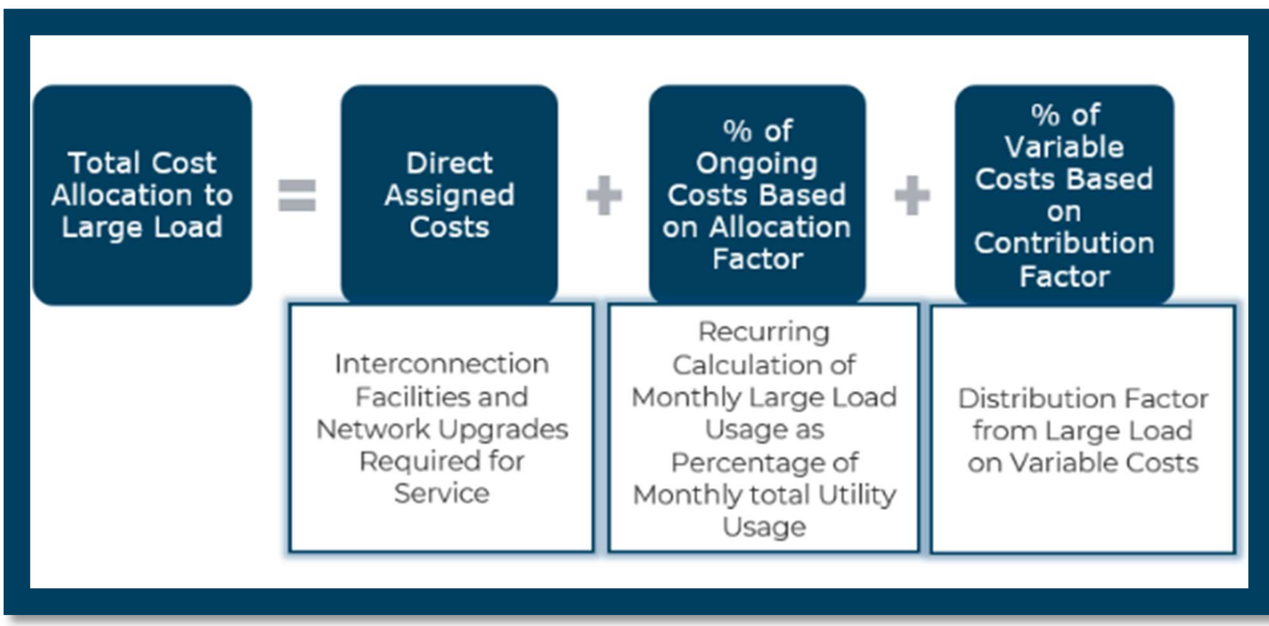
When considering the variable costs incurred because of operating and maintaining transmission, it may be possible to directly calculate the contribution of a new or expanded large load to the driver of such costs. With respect to congestion, a utility may calculate a distribution factor for each customer or customer class. That distribution factor would allow time-specific contribution to align with cost responsibility. Congestion costs, when assessed by utilities and made available to stakeholders, are an excellent example of this approach – they align drivers with allocation as the time and conditions of the congestion costs can be reasonably identified. For the transition of wholesale transmission costs into retail rates, where data is available to allocated based on measured impacts, utilities should not utilize rate base socialization of costs.

This methodology becomes less reasonable for costs incurred that are expected to cover large periods of time and multiple operating scenarios. Contribution factors require specific topology, dispatch and demand levels to accurately identify impacts from a new or expanded large load customer.[39] In the cases of transmission expansion and interconnection facilities, the data set required to calculate contribution over every potential scenario becomes unwieldy and includes scenarios that may never materialize.

Transmission Cost Solution

The combination of direct assignment at the retail level for interconnection and network upgrade costs, cost of service allocations for ongoing transmission expansion and fixed costs, and contribution calculation for variable costs would ensure the least risk of socializing costs.

Figure 8. Total Cost Allocation Formula for Transmission



The transmission system we rely upon has been developed to reach a point of common use and widespread value, and therefore, it does not provide states with enough information to allocate costs to specific customers. Marginal cost approaches address some of this uncertainty but fail to provide states with discrete information for retail rate design purposes.

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[39] Energy Systems Integration Group, "Large Loads Forecasting Report," 2025, https://www.esig.energy/wp-content/uploads/2026/02/ESIG-Large-Loads-Forecasting-report-2025.pdf, Recommendation 6.

Tracking where costs originate, who benefits from those costs being incurred, and granular measurement of transmission system use by large loads ensures the data is available for retail regulators to make informed decisions.

IV.C COLLECTION OF DATA FROM WHOLESALE MARKETS: ASSIGNING A NEW NODE

Utilities that participate in a wholesale energy market normally pass energy market costs through to consumers proportional to their class consumption during the true-up period in question, e.g., each quarter. However, wholesale market costs can vary significantly by hour and can be heavily influenced by the size and location of load. If wholesale prices are settled at the locations of large loads, data specific to how large loads impact wholesale operating expenses, such as congestion and energy losses, can be collected for use in retail ratemaking processes. RTOs have existing processes that would allow load specific information to be created which in turn could be use in retail cost allocation. These data are created through the establishment of individual pricing nodes for large loads and are operational data rather than accounting or forecasted data.

In wholesale energy markets, LMPs are calculated for each pricing node established in the market. These pricing nodes can account for wholesale customers (such as transmission dependent distribution utilities), generators and interchange points between market participants. Essentially, anywhere a settlement is needed, a pricing node can be established. An example of this is Great River Energy (GRE) in the MISO footprint. GRE is a generation and transmission cooperative that does not directly serve demand but has established more than twenty load-focused pricing nodes to target impacts of specific GRE member utilities. Just as GRE leverages nodal data to facilitate cost allocation to specific member, new pricing nodes for large loads would provide more granular data to inform more accurate allocation of wholesale costs in retail rates.

Within a wholesale energy market, simple processes have been established for making a change to update or create pricing nodes for large loads. The simple processes require a market participant to submit a request to establish a new pricing node on behalf of a large load such that the direct impacts of large loads can be measured instead of forecasted. Below is the typical process this entails:

1. An entity must be registered as a Market Participant in the wholesale energy market for which the large load will participate through their Load Serving Entity. In most cases, the Market Participant will be the utility serving the large load.
    a. Since the service territory may be determined by the state and local requirements for utility service, a large load customer must first coordinate with the utility providing service

2. A Market Participant submits a request for a new or updated pricing node by submitting the following information:
    a. Node location (substation, bus or coordinates)
    b. Electrical connection (actual point of electrical connection)
    c. Load characteristics
    d. Settlement requirements

    Note: To obtain the required information, the LSE may need to coordinate with the balancing authority operator
3. After a request is received, the balancing authority and network model administrator will approve the request and update the network model to include the additional pricing node

In a wholesale market where a pricing node is established for large load customers, that node will provide settlement level granularity on par with data used to calculate the node LMP in a time interval that matches wholesale operations. This level of data granularity would be the most appropriate way to inform allocators of wholesale costs within retail rates based on a Contribution Factor and represents an ideal source of data to inform retail allocation of variable transmission costs. Establishing requirements at the retail level for load serving entities to create dedicated pricing nodes within wholesale energy markets for large loads should be a primary consideration of retail regulators concerned with data-driven allocations of costs from wholesale energy markets.

IV.D EXISTING RATE BASE ALLOCATION

As described in Section III.C, the treatment of existing rate base assets through traditional cost allocation risks under-recovery from large load customers if the actual costs of serving those customers are misestimated or unrealized. The remedy is not direct assignment, as these costs are genuinely shared across the system. Rather, a class structure should be designed to fix the large load's contribution to its contract commitment and secure the utility against non-performance.

A recent tariff adopted by Santee Cooper illustrates a full-cost coverage approach. The Santee Cooper Large Load Service tariff, adopted in 2025, applies to new customers with load >50 MW and requires a minimum 15-year contract.[40] Utility executives stated that this tariff is explicitly designed to ensure new large load customers cover their full costs, so that existing customers

[40] South Carolina Public Service Authority, *Large Light and Power Experimental Large Load Service Schedule* L-25-LL (April 25, 2025), https://www.santeecooper.com/Rates/_pdfs/Industrial-Wholesale/L-25-LL-FINAL.pdf

do not subsidize new load.[41] This approach differs meaningfully from the incremental approach used elsewhere, which charges the large load class for its cost to the system going forward, but does not require the class to absorb a share of the sunk, embedded costs of the existing generation fleet. Santee Cooper, instead, charges large load customers for their full proportional share of both new and existing costs using the same demand and energy rates as other customers. Because those rates are set via the utility's cost-of-service study, rather than a bespoke incremental calculation, customers are charged both embedded and going-forward costs. Critically, the success of such an approach hinges on ongoing revisitation of those allocators in rate case proceedings together with carefully calibrated minimum billing demand provisions.

IV.D.I Simplified Allocation Methods

Modern cost allocation has trended toward greater granularity, described in detail in the Regulatory Assistance Project's 2020 Cost Allocation Manual.[42] Typically, we recommend granular or time-differentiated methods, which allocate costs based on contribution across multiple peaks or anticipated events rather than a single annual peak, as the most appropriate approach across the majority of resource classes. Examples of such methods include 12-CP, where costs are allocated based on a system's monthly peaks, or Probability of Dispatch, which assigns costs to specific periods based on the likelihood that specific assets are required in those periods. Of course, the preferred method depends on the individual jurisdiction's characteristics.

Simplified allocators are sometimes proposed for large load customers on the theory that a class of one or two customers with forecasted flat demand lacks the monthly variation that a method like 12CP is designed to capture, and that a simpler method is therefore sufficient. However, substituting a single-peak method does not merely simplify the calculation – it may ultimately change the outcome, and in the large load class's favor. Single peak allocators disregard demand variation, which systematically advantages classes with flatter usage profiles at the expense of classes with more variable demand. Adopting a simplified allocator at the class level could functionally shift cost burden from large loads onto other ratepayers under the guise of administrative efficiency. We recommend against it.

A simplified single-peak method may, however, have a legitimate role *within* the large load class, as a sub-allocator. Within the large load class itself, a method based on contracted peak

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[41] Holdman, Jessica, "SC's state-owned utility enacts higher rates for data centers, large users," *SC Daily Gazette* (April 25, 2025), https://scdailygazette.com/2025/04/25/sc-power-company-enacts-higher-rates-for-data-centers-large-users/

[42] Lazar, Jim, Paul Chernick, William Marcus, and Mark LeBel. 2020. Electric Cost Allocation for a New Era: A Manual. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

demand may be a reasonable and appropriate method to divide that class's fixed costs amongst the customers within it.

IV.E O&M COSTS

To the extent that generator capital costs are directly assigned to a customer, it will likely make sense to assign O&M costs in the same way. There are several reasons for this. In the past, new generators were presumed to have lower marginal costs of operation precisely because they were new – they tended to also be more efficient. However, the pressure to build capacity quickly enough to meet loads that are coming online quickly has resulted in decisions to build generators that are generally not intended to be frequently operated, specifically, combustion turbines. The addition of these generators may then raise rather than lower average O&M expenses.

For example, in 2025, Wisconsin Electric Power Company (WEPCO) requested approval to build reciprocating internal combustion engines (RICE) and heavy frame combustion turbines to serve data centers seeking to locate in its service territory. These units were projected to run at atypically high capacity factors, driving higher O&M expenses. Socializing the O&M costs of these units across all customers does not make sense when the units are built specifically to serve data center load.

This recommendation has no dispatch implication. Generators would presume to continue to be subject to security constrained economic dispatch. Instead, it is intended to address cost shifting resulting from heavy utilization of generators that are not typically used for baseload operation.

As identified in Section III.B.ii, in cases where a plant is slated for retirement but is instead kept in service specifically to meet large load demand, that unit is often not the most efficient generator either. In such cases, cost causation supports directly assigning the associated O&M costs to the large load customer responsible for keeping the unit in service. This is distinct from cases where a new, efficient resource, reduces overall O&M expenses across the fleet and benefits rather than burdens other customer classes.

IV.F HEDGING AGAINST CONGESTION COSTS

In terms of forecasting costs related to large load development, the cost of congestion in wholesale energy markets is one of the more difficult. The magnitude of these costs depends on transmission capacity available at any given moment but also directly impacted by the cost of generation offered for each dispatch cycle. To combat this variability, wholesale energy markets offer financial tools, known as Financial Transmission Rights (FTRs) which are either assigned to utilities based on transmission system use, or purchased via wholesale FTR auctions. The value of an FTR is inversely equivalent to the level of congestion costs associated with the transmission path defined by the FTR, creating an opportunity to match the variability and offset congestion costs incurred by load serving entities. Hedging can be an effective method for load serving entities participating in wholesale energy markets to offset all or part of transmission costs incurred due to congestion resulting from the development of large loads. While effective, hedging also carries the burden of identifying when and where FTRs can be beneficial, requiring the expertise be acquired to successfully offset cost.

Acquiring FTRs themselves represents an additional cost paid for by the market participant acting on behalf of a group of customers. Knowing when and where to leverage FTRs based and offers an opportunity to shift some risk to large load customers while also benefiting the non-large load customers through offsetting congestion costs. Since FTRs would be held or acquired by the LSE on behalf of their customer base, the revenue associated with FTRs can be used as a balance against unforeseen costs that may be driven by large loads, but impact other customer classes. Similar to performance incentives used to keep capital projects on time and within budget, treating FTR revenues appropriately can incentivize utilities to pursue hedging strategies that may not have otherwise been taken and that reduce costs for all customers.

One solution that would shift some risk to a new or expanded large load would be to allocate the initial costs of acquiring an FTR to the large load customer. Once the FTR is acquired, the revenues received from the FTRs acquired can be applied generally across all customer classes in a way that offsets costs for non-large load customers as well as ensuring large load customers can also benefit from the FTR.

According to Yes Energy's FTR Market Performance and Trends Review: June 2025 – May 2026 report,[43] hedging strategies do not necessarily require a high magnitude of FTR positions, but can produce substantial profits. Table 3 below shows the top ten entities' performance in the FTR market in the past year.

[43] Daniel Cullen, "FTR Market Performance and Trends Review: June 2025–May 2026," July 6, 2026, https://www.yesenergy.com/blog/ftr-market-performance-and-trends-review-june-2025-may-2026.

Table 3. Performance of FTR revenues compared to costs in the RTOs

Participant	Approx. Profit/Cost
DC Energy	4.18x
FirstEnergy	4.15x
Fuelwinds Energy	3.94x
Saracen	1.99x
Appian Way Energy Partners	1.60x
Duke Energy	1.34x
Solios Power	1.08x
Hamilton Liberty	1.02x
Appalachian Power	0.91x
Dominion Energy (LSE)	0.91x

Yes Energy also states that a strong correlation exists between increased FTR profits across all participants during atypical operations, including extreme weather events and significant transmission outages.

During a time with increased development of large loads interconnecting to the transmission system paired with increased occurrences of extreme weather events, retail regulators have the opportunity to incentivize utilities under their jurisdictions that participate in wholesale energy markets to pursue development of FTR hedging programs, subject to the review of the applicable retail regulators, that align with specific circumstances of each utility. Leveraging these programs can produce significant offsets and protect against cost spikes during both normal operations and extreme events.

IV.G CONTRACTUAL DEMAND COST ALLOCATION

Using contractual demand rather than actual demand to calculate total demand-related charges goes a long way to fixing the problem of demand charges fall short of recovery of costs needed to serve a load. The actual mechanism used to reconcile differences between contractual and actual demand is likely to vary depending on the tariff or contract terms. Whether this occurs through demand charges or otherwise will depend on jurisdictional details.

If a large load customer fails to reach its contracted demand, the transmission or generator infrastructure built to serve that customer may be left partially or fully underutilized, with the associated costs still being recovered through retail rates. A bill credit or rate reduction for this capacity if it becomes utilized by a subsequent large load customer would be appropriate and cost causation principles. Additionally, it would be inequitable for the original customer to continue bearing the full cost of infrastructure that another customer is now utilizing and benefiting from. An example of this is The Cleveland Electric Illuminating Company's (a subsidiary of FirstEnergy) Line Extension Policy, which allows for a customer to be entitled to a refund if a new customer utilizes the line extension project within 50 months of completion for which CIAC has been paid by the original customer.[44]

IV.H FIXING LINE EXTENSION POLICIES

As previously mentioned, current line extension policies are not a viable path to ensure costs are aligned with beneficiaries during the treatment of interconnection facilities required for new or expanded large loads. When considering the development of transmission to connect new large loads, a similar approach to the 7-Factor Test[45] should be applied by retail regulators when considering large load interconnection costs and how those costs should be allocated to new large load customers:

1. Is the transmission project electrically close to a new large load or required for its interconnection?
2. Is the transmission project's configuration primarily radial?
3. Is the transmission project expected to see power flowing in a single direction to the new large load?
4. Is the transmission project intended to establish or maintain service for a single or small group of new large loads?
5. Is the transmission project intended to serve a specific geographic area?
6. Does a wholesale metering point exist between the new large load and the distant end of the transmission project?
7. Does the nominal voltage of the transmission project match a nominal voltage of interconnection facilities required to establish service to a new large load?

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[44] The Cleveland Electric Illuminating Company, "Schedule of Rates for Electric Service," Sheet 4, 2nd Revised Page 8 of 21. PDF page 13, https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/Ohio/tariffs/CEI-2018-Electric-Service.pdf.

[45] FERC Order 888 established the 7-Factor test to identify distribution versus transmission facilities.

In the case where the responses to these questions indicate that the project will primarily serve a large load customer, associated project costs should be directly assigned as required to establish and maintain service to that customer, as established in the ‘but for’ clause. In cases where it is clear that the primary driver for a transmission project is more than just establishing or maintaining service to a large load customer, associated facilities may be evaluated to determine shared benefits between the large load customer and other non-large load customers served by that utility. Given the size and scale of facilities required to establish and maintain service for large load customers, utilizing line extension policies that result in all or some portion of the line extension being socialized in retail rates would constitute an allocation that is neither just nor reasonable.

IV.I NET REVENUE ANALYSES

Since net revenue analyses are not a form of cost allocation but rather are typically a justification for *not* revisiting cost allocators, the only meaningful solution is to perform an embedded cost of service study. To the extent that net revenue analyses are considered, they must be thoroughly audited. Below, and based on EFG’s experience in multiple large load dockets, we provide a list of potential assumptions that are likely to be understated and/or the offsetting benefits are likely to be overestimated. Net revenue calculations do not take one form, so there may well be other considerations to evaluate. Our principal recommendation is to audit the calculations and understand what the projections are based on to ensure that all costs and financial risks are accounted for and that potential benefits of the large load customer are not overstated. Even if a cost of service study is performed, some of these same assumptions may bias or invalidate the COSS conclusions.

More specific areas of inquiry should include:

1. **Generator Costs.** These projections may not include all the generator costs needed to serve new loads. Some agreements may include provisions for direct assignment of a subset of costs, leaving the remainder undefined for consideration in later dockets and/or subject to socialization across classes. Additionally, the COSS may be updated using generator costs that are too low in an effort to show that existing allocator methods are adequate to prevent rate increases for consumers.

2. **Determination of Portfolio to Serve Load.** How was the portfolio of resources to serve the load determined? Through a capacity expansion simulation, a resource adequacy study, or otherwise? Especially to the extent that resources in the portfolio serving the load are subject to changes in accreditation, a resource adequacy study is more likely to be needed to determine the portfolio that can reliably serve this new load.

3. **Transmission Costs.** Transmission-related costs may be entirely unaccounted for, underestimated, and/or assumed to be unchanged. This could be the result of a lack of study results related to the interconnection of generators to serve new load or a lack of information about interconnection and network upgrade costs for the load itself. It may also be assumed that interconnection costs must be socialized under the utility's line extension policy and are therefore separate and apart from the calculation.

4. **Customer Demand Assumptions.** The net revenue analysis may make simplifying assumptions about when the customer comes online or how quickly its load ramps, typically assumed to be earlier than planned. The analysis may also assume that the customer operates at a 90% load factor, or otherwise operates at a higher load factor than it is contractually required to, without considering whether a lower load factor is possible and evaluating its impact.

5. **Credits for Avoided Infrastructure.** If a credit for costs avoided due to the new customer is applied, unpacking the rationale for that assumption would be very important. For example, is there evidence that those costs would be required in a scenario without the new customer? What kind of need analysis was done to justify these costs to begin with? What is the basis for claiming that the addition of the large load customer, as opposed other changed conditions, is the reason that previously planned costs can now be avoided?

6. **Energy, Fuel, and Capacity Purchase Pricing.** Net revenue analyses often assume that per-unit energy, fuel, and capacity purchase pricing remain unchanged in scenarios with and without new loads. To the extent that the loads do not have threshold impacts, e.g., the gas-fired generator(s) serving them are among many customers of the pipeline serving the generator, this may be a correct assumption. However, as explained in prior sections, new load in organized markets has already changed congestion patterns and increased congestion costs. Without mitigation of that impact, a change in energy costs can be expected. Energy costs are typically apportioned based on consumption and recovered through fuel adjustment riders. If new loads are likely to be served by high-marginal-cost generators, e.g., combustion turbines or reciprocating engines, they increase the likelihood that the energy component of LMPs will also increase either because these generators will represent a greater share of energy production or because generators elsewhere with higher than historical marginal costs will have to serve these loads.

   Similarly, a failure to maintain balance between load and generation additions can cause capacity prices to spike as organized markets reach shortage or near shortage conditions. An expectation of increased capacity market pricing also drives expectations for pricing of bilateral contracting to smooth short periods of deficit. For purposes of net revenue analyses, these impacts can be considered through sensitivities, e.g, high pricing cases or determining break-even price assumptions. But more importantly, these effects can be at least partially addressed through cost allocation methods that anticipate these potential effects. See, for example, solutions discussed in Sections IV.C O&M and Fuel Costs and IV.D Hedging Against Transmission Costs.

7. **Other Riders.** Some jurisdictions have many riders intended to recover items, such as environmental compliance costs, demand-side management program costs, grid "modernization" costs, etc. Whether rider costs are included/excluded from the analysis and assumed to be shared by the new customer can be an important factor influencing a net benefit analysis. Each utility publishes an electronic book of its tariffs on its website, so reviewing rates by class is the easiest way to understand the riders that apply to the jurisdiction in question.

8. **Multi-Jurisdictional Utilities.** It may be assumed that allocators between the states of multi-jurisdictional utilities remain unchanged even if one state adds significantly more load than the other. This assumption would tend to benefit the state adding more load.

IV.J CIAC, CWIP AND AFUDC

The question of how construction costs are financed and recovered takes on heightened importance for ratepayer protection when addressing large load customer and the potential for multi-year ramp ups. Three mechanisms govern this process: CIAC, CWIP, and AFUDC, each with distinct implications for who bears the financial risk of new infrastructure and when. While CIAC shifts costs directly to the customer causing the need for investment, CWIP and AFUDC determine whether and when existing ratepayers begin subsidizing a project's financing costs before that customer is brought online and consuming power. Getting this allocation wrong—as the Vogtle nuclear plant's cost overruns demonstrate—can expose ratepayers to billions in prepaid costs for assets that are delayed, over budget, or never fully utilized. This section examines each mechanism in turn and recommends a framework for large load cost recovery that prioritizes CIAC where feasible, restricts CWIP to costs allocated to existing customers until the large load is online, and, where CWIP is used, requires performance-based safeguards established at the outset of project approval rather than negotiated after the fact.

CIAC is cash contributed by a customer to fund construction of a project. This is different from debt or equity financing, which utilities repay and receive a return on through rates charged to ratepayers. Since CIAC is paid directly by the customer causing the need for the investment, it reduces rate base as the contributed amount offsets the utility's investment in the assets, so the utility earns no return on that portion. This protects existing ratepayers from bearing the cost of infrastructure built solely to serve the new customer. When a large load customer seeks interconnection, whether through a dedicated line, transformer, substation, or renewable or generator interconnection, those costs can be financed through CIAC. CIAC is the simplest cost allocation method for ensuring that the beneficiary pays and prioritizing it as a funding mechanism for large loads customers protects existing ratepayers by removing those costs from rate base entirely.

CWIP is the account used to track costs incurred during construction of a generation, transmission, or distribution project. It captures capitalized costs including materials, labor, engineering studies and fees, and overhead. When permitted or required by regulators, a utility may include CWIP in its rate base while a project is still under construction, allowing it to begin receiving a return before the asset is placed in service. In instances where the regulator only allows recovery of project financing prior to the project being used and useful, this results in ratepayers paying the ongoing financing costs of the project during its construction, instead of the financing costs accruing interest and being recovered after the asset is placed in service. However, like the example described below for Georgia, regulators can include both financing and accrued capital costs as part of the CWIP recovery in base rates prior to a project being used and useful.

When CWIP is not permitted in rate base prior to the asset being considered used and useful, AFUDC is used to track the utility's carrying costs during the construction period. AFUDC is recorded within CWIP and, once the project is considered used and useful, the full CWIP balance, including accrued AFUDC, is rolled into rate base. The key difference between CWIP and AFUDC is when the financing costs are recovered from ratepayers. Table 4, below, summarizes the primary benefits and drawbacks of each approach based on when CWIP is included in base rates.

Table 4. Benefits and Drawbacks of CWIP's Timing for Rate Base Inclusion

CWIP in Base Rates Prior to Used and Useful	AFUDC in Base Rates When Used and Useful
Benefit	**Benefit**
Can reduce overall financing costs and mitigate rate shock in the long-term compared to waiting until used and useful	The large load customer (cost causer) will be interconnected at the time the project is included in rates.

as costs are rolled in as they are incurred rather than all at once.	
Drawback	**Drawback**
Recovery begins to occur before project completion when the large load customer (cost causer) is not interconnected. As a result, the recovery of these costs is allocated to existing customers until the large load customer is interconnected and a new COSS is performed. Under this method, existing customers may be prepaying for an asset that may be delayed or not be placed in service.	Unless modified to allocate a large load customer's fully contracted load, non-large load customers will subsidize the project until the large load customer reaches its contracted load, if that occurs. Due to compounding of interest over the years until the project is placed into rates, the financing costs are higher than if CWIP is rolled into base rates prior to it being used and useful.

The practice of including CWIP in base rates prior to a project being used and useful has its roots in crisis-driven policy, not routine capital planning, and became widespread in the 1970s in response to the energy crisis. The grid investment required to accommodate large loads is neither an emergency nor a crisis — it is planned, deliberate capital deployment. Allowing CWIP in base rates for projects driven by large load interconnection is therefore inconsistent with the policy's original intent and should not be considered. For shared-cost projects involving large load customers, CWIP treatment should be limited so that costs allocated to the large load customer or class are not recovered in rate base until that load is a customer (see Section IV.G regarding a recovery method when the load has not fully materialized). In practice this means that only the portion of CWIP allocated to existing customers should be rolled into rate base prior to the asset being used and useful; the portion allocated to the large load customer should remain excluded from rate base, accruing AFUDC instead, until that customer is online to avoid subsidization.

Beyond the ratepayer equity concern, CWIP creates a structural incentive problem for utilities. Because the utility earns a return on the total cost of the project, including overruns, and ratepayers bear the financing cost throughout construction, the utility has limited financial pressure to complete projects on time or within budget. If CWIP is used, recovery should be performance-based and include commission-established cost caps, construction milestones, penalties for delays, and claw-back provisions for overages and abandoned projects. Construction overages should also trigger a reduction in allowed carry charges and/or a penalty to the utility's authorized rate of return. Construction milestones requirements that trigger a reduction in an authorized rate of return when missed can provide the guardrails needed to ensure that ratepayer funds are prudently utilized to finance construction costs related to any project, but particularly for large load related projects. Existing ratepayers should be shielded from the risk associated with construction overages, particularly in a time when there are supply chain shortages associated with bringing large load facilities online. Establishing penalties for overages will encourage utilities to be considerate when taking on large load customers in an area without available excess capacity.

The Vogtle nuclear plant recently built in Georgia serves as a cautionary tale of when CWIP is being used without adequate cost controls and the limited protection that belated safeguards can provide. The plant, originally estimated at $14 billion, saw total spending surpass $35 billion, with Unit 3 finishing seven years behind schedule.[46]

Throughout construction, cost overruns ran into the billions while regulators deferred meaningful consumer protections, promising a prudency review at the end of the project. The review never materialized. Only in December 2023 did the Georgia Public Service Commission finalize a settlement establishing substantive ratepayer protections. The settlement capped ratepayer-recoverable capital construction costs at $7.56 billion and set $2.63 billion of cost to be absorbed by Georgia Power's parent company, with any costs incurred after Unit 4's commercial operation deadline of March 31, 2024, to be absorbed by Georgia Power rather than passed to customers. The settlement also imposed a direct financial penalty: if Unit 4 missed the March 31 deadline, Georgia Power's return on equity for its Nuclear Construction Cost Recovery tariff and AFUDC would be reduced to zero until the unit entered service. Georgia Power missed the Unit 4 deadline by 29 days, triggering the zero-return penalty, and the post-deadline capital costs were borne by shareholders rather than ratepayers.

The Vogtle case illustrates both the value and the limits of performance-based CWIP recovery. The cost cap and ROE penalty did protect ratepayers from the final increment of overruns, and the penalty mechanism functioned as intended when the deadline was missed. But these protections were negotiated at the tail end of a 15-year project, well after billions in cost overruns had already been socialized through rates. The lesson is clear: performance metrics, cost caps, milestone requirements, and penalty provisions must be established during project approval. For vertically integrated utilities, the same framework applied to transmission and distribution should extend to generation assets. Where generation is being built exclusively to serve large load customers, those costs should be recovered through CIAC rather than socialized across the existing rate base.

[46] Drew Kann, "Georgia Power rates: Public to pay bulk of Plant Vogtle costs," *The Atlanta Journal-Constitution*, December 19, 2023. https://www.ajc.com/news/psc-raises-georgia-power-rates-passing-most-plant-vogtle-expansion-costs-on-to-customers/6BAIOWM7J5BVHFZ2UN27KYXENA/.

V. CONCLUSION

At best, large load growth strains the ability of existing cost allocation frameworks to maintain cost causation principles. At worst, it spurs substantial cross-subsidization by existing customers of large capital and operating costs of new large load customers. Section III of this paper outlines several core challenges:

1. Traditionally, generation and transmission costs are allocated based on energy and demand alone, so new capacity built for one customer is spread across all other classes by default.

2. Even where existing allocation practices track increasing demand, ramp-up periods, forecast uncertainty, and the sheer scale of new large loads mean actual cost responsibility could lag behind investment. Customer exit or under-performance can transform a purported benefit into a long-running cross-subsidy.

3. Interconnection, network upgrade, and other transmission cost allocation methodologies were not designed with enough transparency to address the allocation of transmission-level connections. Current line extension policies and static allocation methods do not reflect the actual impact of new large load interconnections.

4. Net revenue analyses are used to justify skipping updated cost-of-service studies even though they are projections only and provide no guarantee of avoiding cross-subsidy.

Throughout Section IV, this paper explores a solution set to address these challenges:

1. New generation capital costs should be directly assigned to the new large load or class of customers that cause them, whether via single-customer or proportional assignment.

2. At the retail level, transmission costs should receive layered treatment: interconnection and network upgrades should be directly assigned, shared ongoing investments should be allocated via COSS, and variable costs such as congestion should be handled using contribution-based factors.

    a. The use of dedicated wholesale pricing nodes for new customers would enable the collection and provision of data necessary to facilitate these methods.

3. For costs in the existing rate base, a dedicated large load class with minimum bills tied to contracted rather than actual demand and backed by collateral and exit fees can ensure appropriate allocation under current models.

4. To offset congestion cost risk, hedging tools, such as Financial Transmission Rights, can assign acquisition costs to new large customers while sharing resulting revenues more broadly.

5. Outdated line extension policies should be replaced with a factor-based test for large load interconnections. Customer-specific transmission charges should be applied to recover costs once facilities are in-service.

6. Net revenue analyses should receive close scrutiny as they are not substitutes for updated cost allocation.

7. Large load growth requires updated cost allocation and guardrails for CWIP and AFUDC recovery to protect existing customers from construction cost risk.

Ultimately, these solutions share a common thread: aligning cost recovery with the customers who cause costs and doing so when those costs are first incurred. Each solution must be considered in the context of a careful, case-specific analysis – this framework should serve as a starting point rather than a final answer and will necessarily evolve alongside the industry itself.