POLICY BRIEF

Connection Costs

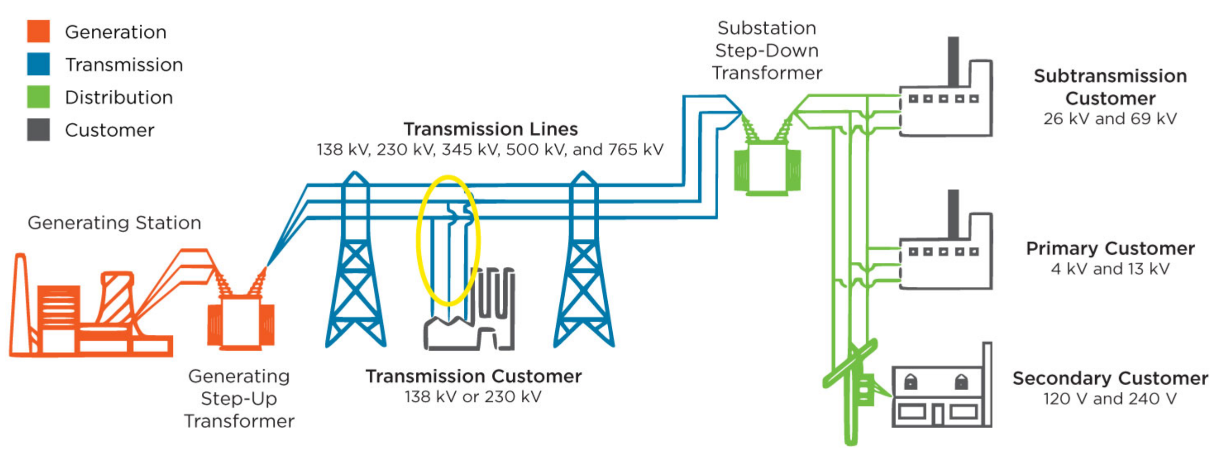
Loophole Costs Customers Over $4 Billion to Connect Data Centers to Power Grid

Introduction

Electricity demand from new data centers is reshaping the utility industry. After two decades of minimal load growth, many utilities are forecasting and preparing for a 30–80 percent increase in electricity sales in 10 years (MISO 2024). In the region served by PJM, the regional transmission organization (RTO) for which this growth has been the greatest thus far, all customers' electric bills are rising to pay for new electricity supply (Monitoring Analytics 2025). Costs are also rising because all customers pay for the new transmission lines required to connect new, large data centers. Such costs are passed on to all customers because existing rules for recovering the costs of transmission upgrades did not anticipate that individual customers could create such high demand and subsequent high costs.

The Union of Concerned Scientists (UCS) found that in 2024 alone, utilities in seven PJM states passed more than $4.3 billion in additional costs on to customers, with billions more still to come. These costs come from local transmission upgrades made to provide transmission-level service directly to data centers. This brief's appendix tracks these costs from the data center driver to their inclusion in regional transmission plan costs.

Figure 1. Utility Transmission Lines



Transmission lines may have direct connections to customers (marked in yellow) and connect to the distribution system. The federal government supervises transmission costs and rates, while state governments largely supervise distribution. Source: NPS 2023.

Union of Concerned Scientists

New Rules Needed for Data Center Boom

Historically, the typical new data center's electricity demand has been under 10 megawatts (MW), and grid connections have been similar to ubiquitous, low-voltage retail service on existing distribution lines. In contrast, utilities usually charge the costs of connecting a new, nonstandard individual customer directly to that customer. Now, the development of 100–400 MW data centers is widespread, and numerous states host projects under development that will call for utilities to deliver 1,000 MW or more.

This leap in demand requires something new: high-voltage transmission infrastructure built to reach new customers, which are, increasingly, data center facilities (Lazar et al. 2020). In PJM's service area, a hotbed of data center activity, states and commonwealths with utilities designing and building connections for 100–1,000 MW load requests include Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia.

Utilities have 100-year-old processes and regulatory mechanisms for supporting both economic growth and load growth with grid expansions. State public utility commissions (PUCs) have established standard regulatory practices for utilities to build new connections, provide service to new customers, and allocate the resulting revenues and costs. However, the data center boom—particularly the extraordinary size of individual new facilities, leading to direct connection to the transmission (high-voltage) system, rather than the distribution (low-voltage) system—is unlike past growth addressed by these existing rules and regulatory assumptions.

The rapid growth in data center electricity demand creates a new category of costs (which are tallied in the appendix) in addition to the costs of maintaining adequate supply. Connecting large data centers to the existing transmission system can raise electricity bills for all customers served by the same utilities. The existing rules and practices allow for this—the worst—outcome, largely because regulatory cost reviews are practically nonexistent for these transmission-level facilities and utility incentives reward this practice.

Grid Costs for Data Centers Fall Through a Regulatory Gap

Transmission-level connections for data centers incur costs under federally regulated rates, which are mixed in with typical transmission costs. These typical costs reflect customers' collective use, reliability needs, and the replacement of aging equipment. The costs are then passed on to retail customers via state PUC-approved rate cases. The process obscures any tracking of cost causation for these new transmission-level data center connection investments.

States supervise the rates and services of each investor-owned electric utility with a retail service territory. These utilities own and expand the network of wires that connect the electric supply to customers, including both low-voltage distribution and high-voltage transmission. However, the federal government has jurisdiction over the review of utility company expenses for transmission investment and expansion. This boundary between state and federal jurisdiction was established under the assumption that transmission lines would be used only for wholesale, not retail, deliveries of energy. This assumption generally supports the notion that customers' collective use drives transmission-level investments and that costs should be allocated broadly across all customers.

Transmission is generally defined as grid infrastructure that operates above 69 kilovolts (kV). However, the distinction between transmission and the lower-voltage electricity distribution network that reaches individual customers for retail service is determined on a case-by-case basis. One factor in this determination is whether the higher-voltage transmission delivers electricity across state boundaries, thus directly involving interstate commerce (Lazar et al. 2020). Because interstate commerce is involved, the Federal Energy Regulatory Commission (FERC) administers transmission service conditions, rates, and terms, while states regulate the same for distribution service.

Federal supervision of transmission is divided into two categories: local and regional transmission planning (FERC 2007). Federal rules evolved with the creation of independent system operators (ISOs) and RTOs, which make regional transmission plans in much of the US (FERC 2011; FERC 1996). In the current approach, utilities provide local planning to replace and expand transmission primarily serving their own customers. These local plans are funneled through ISO/RTO approval processes and incorporated into the regional plans. Costs for local transmission projects are allocated entirely to the zone in which the transmission facilities are located, typically mirroring the utility's service territory (Monitoring Analytics 2023). Thus, the locally planned transmission is presumed to be for wholesale market purposes. Regardless of whether the utility and state are in an RTO region, utility-planned transmission is added to FERC-supervised rates, which are then paid for by the customers in the utility's service territory.

Billions in Costs Now, Billions More Coming

Consumer representatives and advocates have raised concerns about utilities' local transmission planning because of the limited scope of review, the potential for poor planning efficiency, and the unsupervised costs of the resulting transmission upgrades (Chen and Hartman 2022; Wayner et al. 2024). Increasingly, data centers' connection costs are being allocated to all customers of the same utility (Martin and Peskoe 2025). The high concentration of data centers in states served by PJM has altered the profile of local transmission investment.

From 2022 through 2024, utility companies initiated over 150 local transmission projects in Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia. These projects were needed only to connect data centers. The transmission expansions have cost consumers $5 billion thus far (including over $4.3 billion in 2024, as shown in Table 1 and the appendix) and, under existing rules, have been allocated to all customers of these utilities. Early indications for 2025 show that many more new connection costs will follow this same pattern, raising customer bills.

Table 1. Data Center - Caused Transmission Costs in Millions of Dollars Approved in 2024

State	Number of Projects	Cost (Millions)
Illinois	3	$239.0
Maryland	4	$107.5
New Jersey	8	$14.5
Ohio	37	$1,299.7
Pennsylvania	16	$491.8
Virginia	60	$1,988
West Virginia	2	$215.8
Total	130	$4,356.3

PJM's operating agreement requires utilities to disclose their local transmission plans as part of its FERC-approved planning process (PJM Interconnection 2025). Through the PJM Transmission Expansion Advisory Committee (TEAC), utilities submit transmission assumptions and designs for review and comment before adding locally planned facilities to the Regional Transmission Expansion Plan (RTEP). Utilities can bring specific requests for new customer service at a specific location to TEAC's monthly meetings. There, they present initial designs for building transmission lines and substations to fulfill these individual customers' requests for connection.

Utilities briefly describe the customer demand levels and the expected year of need. These briefings are informational only; no PJM approvals are required. Throughout this process, utilities disclose the names of new substations (often to be built at the customer's location), the cost of major project segments, and a tracking number that will appear in PJM's annual RTEP. From that point through state proceedings to determine retail customers' bills, the causation of these costs (attaching a single customer to the transmission system) is not visible.

Current Practices Obscure Money Trail

With the limited reporting of transmission system expenditures needed to connect data center customers to the power grid, the key question must be asked: "From where do the utilities collect that money?"

Utilities are pushing reforms that would ensure data centers pay their bills for 10–15 years (Commonwealth Edison Company 2025; Indianapolis Power & Light Company 2025; Ohio Power Company 2025), yet utilities are not taking steps to prevent these connection costs from being assigned to rates paid by all consumers. Throughout the US, state PUCs assign FERC-approved aggregated transmission costs to retail customers without cost causation information. Cost causation information could be reported to inform state rate-making proceedings through three potential avenues.

1) First, if utilities collected prepayments from data center owners for their connection costs at the outset, this would be reflected in the utilities' TEAC descriptions and RTEP tracking, which is available through PJM. It would also be reflected in the utilities' state filings—which report "customer advances" or "contributions in aid of construction"—or in the utilities' annual transmission rate FERC filings under Account 107, which is titled "Construction Work in Progress" (Appalachian Power Co v. FERC 2025).

2) Alternatively, if utilities maintained categories of customer classes that cause transmission costs, then the FERC-supervised annual RTEP reporting of transmission investments and subsequent transmission revenue requirements would distinguish costs for the direct connection of customers from other investments included in these reports.

3) If, in their state PUC filings, utilities used a category of transmission costs for the direct connection of customers or added a new, very large customer class to their recordkeeping and rate collections, subsequent reviews of costs to serve customers in state rate proceedings would separate the transmission costs caused by that one large customer, or a new class of very large customers, from the costs charged to other customers.

These changes would allow utilities and/or states, at rate-making proceedings, to assign transmission connection costs to the customers that cause the costs. However, utilities usually assign transmission costs for data center connections to all of their customers. With this practice, costs caused by a single customer are not differentiated or separated when annual local transmission plans are processed and rates are calculated. This is not the application of cost causation that is so often cited in utility cost allocation debates (Bonbright 1961).

UCS examined these three reporting approaches to determine whether utilities in the PJM territory use them to report and collect transmission costs to connect large customers.

1) Do utilities collect transmission connection costs from data centers, either up front or by direct assignment?

Yes, but only in 5 percent of cases. In 2024, utilities described six of the 130 transmission connection projects for large loads as having no cost to other customers and being paid for by the single customer.

Consequently, utilities assigned $4.3 billion in connection costs for the remaining 95 percent of data center projects to the same pool of costs paid by all consumers. Prepayment from customers for direct connections to the transmission system would lower utilities' rate base and profits (Lazar et al. 2020).

If any of the other 124 projects are counted as having customer contributions, either through special contracts or line extension policies, that revenue has not been credited in the development of costs collected through transmission rates.

2) Do utilities maintain categories of customers with transmission connection costs so that these costs can be assigned separately?

No, because utilities' representation of costs through FERC-supervised RTEP reports and revenue requirements does not distinguish a category of retail customers. This makes it impossible to allocate costs to the largest customers. An existing loophole allows the cost of connecting new data centers to transmission lines to raise the rates of all consumers (Martin and Peskoe 2025).

3) Do utilities keep transmission connection costs separate from other transmission costs?

No, except when state legislation has introduced such a requirement (Next Generation Energy Act 2025). Utility rate filings with transmission costs set by FERC formula rates are provided to state regulators, but do not distinguish or separate data center connection costs from other transmission costs spread across all utilities' customers.

Protecting Customers

To protect customers from unfair cost burdens, retail rate cases usually include an important step: a cost-of-service study. This study determines which costs should be included in which customers' rates (Lazar et al. 2020) The lack of information about which large customers are causing transmission costs, however, prevents the rate-setting process from working well. Enforcing the principle of cost causation and assigning costs to a class of very large customers (i.e., users that connect at the transmission level) require the regulatory process to include the tracking of new patterns of single customers causing specific transmission upgrades that would not be needed but for the new customer.

In a state utility commission rate case, regulators set rates for customer classes to reflect the different costs of serving groups of customers and the revenues from those customers (Lazar et al. 2020). Responding to a recent formal inquiry, one Pennsylvania utility explained that revenues from data centers are allocated only to lowering rates of the largest customer class and do not benefit all customers (Duquesne Light 2025). Hence, revenues are recognized only for the largest customer class, but not the costs. This is standard in all US utility rate-making.

Recommendations

Fair and prudent allocation of power sector infrastructure costs requires care. Utilities must track costs from these interconnection/line extensions to the appropriate retail rate class, and state and federal regulators must oversee this process. State and federal regulators must require that costs be assigned to the specific customer—or an appropriate rate class that is causing the costs—to avoid subsidization by all other customers. Simply creating a rate class for the largest new customers will not solve this problem unless the costs presently mixed with other transmission costs are separated.

When creating retail rates for large customers, regulators must allocate the costs of transmission-level connections to the customer or class responsible for those costs. Doing so requires tracking the costs of that type of connection and the retail customers that are causing the costs. To that end, UCS recommends the following:

1) FERC should require transmission built for single customers to be paid for by those customers, as is the requirement for new generators.

2) FERC and state PUCs should require utilities to track transmission costs caused by specific customers through the rate-setting processes.

3) FERC should require utilities to create a customer class in FERC formula rates for customers with direct transmission connection costs.

4) State PUCs should require utilities to recognize the transmission costs created by direct connection customers in retail rate cost-of-service studies.

Without one or more of these additional requirements, action by the utility, PUC, or state legislature to create a new customer class for very large consumers to be used in retail rate-making will not capture transmission costs or new generation costs.

UCS took these recommended steps to create the tables in the appendix. The tables include links to information on collecting and tracking transmission connection costs for data centers in Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia.

As utilities prepare their 2025 transmission plans to build additional transmission lines for connecting data centers, the same PJM websites will provide similar information for subsequent years' expenditures.

Author

Mike Jacobs is senior manager, energy in the UCS **Climate and Energy Program.**

References

Appalachian Power Co. v. FERC, 191 FERC ¶ 61,238, at p.64 (2025)

Bonbright, James C. Principles of Public Utility Rates. New York: Columbia University Press, 1961.

Chen, Jennifer, and Devin Hartman. 2022 Transmission Reform Strategy from a Customer Perspective: Optimizing Net Benefits and Procedural Vehicles. Policy study no. 257. Washington, DC: R Street Institute. https://www.rstreet.org/wp-content/uploads/2022/05/RSTREET257.pdf.

Commonwealth Edison Company. 2025. Proposal for Changes to New Service Requests for Large Demand Project Applicants or Customers. Docket No. 25-0679. Springfield: Illinois Commerce Commission.

Duquesne Light. 2025. Comments of Duquesne Light Company Before the Pennsylvania Public Utility Commission En Banc Hearing on Interconnection and Tariffs for Large Load Customers, Docket No. M-2025-3054271 (2025) (statement of Lindsay A. Baker, Senior Manager, Energy Policy and Public Affairs). https://www.puc.pa.gov/pcdocs/1882372.pdf.

FERC (Federal Energy Regulatory Commission). 1996. 18 CFR Parts 35 and 358 (Dockets Nos. MR95-8-000 and TM94-7-001; Order No. 888). April 24.

FERC (Federal Energy Regulatory Commission. 2007. 18 CFR Parts 35 and 37 (Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890). Preventing Undue Discrimination and Preference in Transmission Service. February 16.

FERC (Federal Energy Regulatory Commission). 2011. 18 CFR Parts 35 and 37 (Docket Nos. RM010-23-100; Order No. 1000) Transmission Planning and Cost Allocation by Transmission Ownings and Operating Public Utilities. July 21.

Indianapolis Power & Light Company. 2025. Petition for Authority to Increase Rates and Charges for Electric Utility Service. Cause No. 46258. Indianapolis: Indiana Utility Regulatory Commission.

Lazar, Jim, Paul Chernick, William Marcus, and Mark LeBel, eds. 2020. Electric Cost Allocation for a New Era: A Manual. Montpelier, VT: Regulatory Assistance Project.

Martin, Eliza, and Ari Peskoe. 2025. Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power. Cambridge, MA: Harvard Law School, Environmental & Energy Law Program.

MISO (Midcontinent Independent System Operator). 2024. Long-Term Load Forecast. https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

Monitoring Analytics. 2023. *State of the Market Report for PJM*. Eagleville, PA.

Monitoring Analytics. 2024. *State of the Market Report for PJM*. Eagleville, PA.

Monitoring Analytics, LLC . Analysis of the 2025/2026 RPM Base Residual Auction Part G. June 2025

Next Generation Energy Act, H.B. 1035, Chapter 626, Maryland General Assembly (2025).

Ohio Power Company. 2024. *Application for New Tariffs Related to Data Centers and Mobile Data Centers*. Case No. 24-508-EL-ATA. Columbus: Public Utilities Commission of Ohio.

PJM Interconnection. 2025. *PJM Operating Agreement*. Schedule 6 § 1.3. Audubon.

POWER Act, H.B. 3546, Chapter 323, Oregon Legislative Assembly (2025).

Wayner, Claire. 2023. "Increased Spending on Transmission in PJM—Is It the Right Type of Line?" RMI, March 20, 2023. https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/.

U.S. National Park Service. *Transmission Infrastructure and Renewable Energy*. Photograph. Accessed September 25, 2025. https://www.nps.gov/subjects/renewableenergy/images/transmission_original.jpg.

Wayner, Claire, Kaja Rebane, and Chaz Teplin. 2024. *Mind the Regulatory Gap: How to Enhance Local Transmission Oversight*. Boulder, CO: R

The Union of Concerned Scientists puts rigorous, independent science into action, developing solutions and advocating for a healthy, safe, and just future.