Grid Strategies

VOLUME 2

FEDERAL TRANSMISSION PRICING

Options for Ensuring Affordability and Reliability in an Era of High Load Growth

Sophie Meyer
Gretchen Kershaw, J.D.
John D. Wilson
Rob Gramlich

June 2026

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ELECTRICITY CUSTOMER ALLIANCE

Americans for a Clean Energy Grid

EXECUTIVE SUMMARY

With unprecedented load growth from data centers and other large customers, a pressing question driving news headlines and landing on policymakers' desks is whether existing federal transmission pricing policies are equipped to meet the moment. New and existing electricity customers alike are increasingly asking whether the Federal Energy Regulatory Commission's (FERC) policies around planning and paying for the grid can maintain reliability, ensure affordability, promote fairness and avoid unfair cost shifts, and enable the infrastructure investment needed for resilience and economic growth. Adding new electricity demand to the system need not raise rates for existing customers—and in fact can put downward pressure on existing customer rates—but that depends on the policy choices federal and state regulators make now.

This report is part of a two-volume series. The first report, *Federal Transmission Pricing Volume 1: The Evolution of Current Policies and Practices* (Volume 1 Report), explains the evolution and current framework of federal transmission pricing. This report, *Federal Transmission Pricing Volume 2: Options for Ensuring Affordability and Reliability in an Era of High Load Growth*, identifies guiding principles from that history and applies them to a series of policy options that industry and FERC could adopt to ensure all transmission customers, including new data centers and other large electric system users, are paying their "fair share" of transmission costs.

Much of the public discussion about large loads focuses on generation, capacity, and retail large load tariffs, which this report does not evaluate comprehensively. State large load tariffs are likely to remain the primary mechanism for translating large load customers' stated willingness to pay their fair share into enforceable customer-specific commitments, minimum bills, financial assurances, and other payments. Generation and resource adequacy policies may also involve larger total dollars than transmission in many regions. But transmission pricing remains an important piece of the puzzle because FERC-jurisdictional rules determine which transmission costs are approved, how they are allocated at wholesale to load serving entities (LSEs), and whether states can clearly trace those costs to large loads when designing retail tariffs and contracts and allocating costs to end users. Even where states have large load tariffs or similar policies in place, these transmission pricing issues may be beyond their jurisdictional reach.

This report is organized around three key observations. First, adding load need not raise rates for existing customers, but the outcome depends on system conditions, planning, tariff design, and cost allocation choices. Second, large load growth can promote economic development and other system benefits, but only if the grid can expand in a timely and cost-effective way. Third, proactive, well-planned transmission and transparent cost assignment are essential to capturing those benefits while avoiding unjustified cost shifts.

This report evaluates twelve transmission pricing policy options across four categories:

- **Timing-of-funding options** that address when costs are paid and who bears the risk of transmission investments if large loads delay, downsize, or do not materialize: LSE service and financial security commitments; and LSE upfront funding and reimbursement.
- **Local transmission cost recovery options** that address costs associated with local transmission, including upgrades triggered by new large loads interconnecting: mandatory "higher of" pricing; a new form of "and" pricing; and large load-driven local transmission transparency.
- **Regional transmission cost allocation options** that address how regional transmission costs are allocated across LSEs and zones: targeted cost allocation of large load-driven regional transmission costs; transparency of large load-driven regional transmission costs; widespread load ratio share cost allocation; and voluntary supplement and expedited service.

- **Innovative approaches** that would more proactively plan for and allocate transmission capacity and give large load customers more options to directly initiate and fully pay for grid expansions needed to serve them, including: planning-led zonal capacity reservation; an open season model for large load interconnection; and a consolidated load and generation integration framework.

Across these options, several themes emerge. **First, timing matters.** Transmission costs may begin flowing into rates before large loads fully materialize or reach expected demand, increasing the risk that existing customers temporarily or permanently bear costs incurred to serve new loads. Long-term service commitments, minimum payment obligations, upfront funding, financial security, and exit charges can reduce the risk that existing customers bear costs for load that delays, downsizes, or never appears.

Second, no single cost allocation and recovery approach addresses every concern. Options that assign costs more directly to LSEs serving large loads may better align with cost causation but can create disputes over which costs are truly caused by particular loads and may miss opportunities for those loads to contribute to the fixed costs of the existing system and drive down rates for others. Broader regional methods may better preserve multi-value planning and avoid free ridership, recognizing the widespread benefits of large-scale transmission, but may charge LSEs serving large loads less directly for the incremental impacts of those loads.

Third, transparency and federal-state alignment are critical. State retail tariffs can protect customers only if state regulators have visibility into which FERC-approved transmission costs are associated with large loads and how those costs flow to LSEs and retail customers, including large loads. The most durable approach is likely to combine strong state retail tariffs, better federal-state alignment, improved transparency, and targeted federal reforms where transmission costs, planning processes, or cost allocation decisions are beyond the reach of state retail regulation, alongside innovative new customer-centric approaches to transmission planning and expansion.

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I. INTRODUCTION

Utility bills are rising across the country and electricity consumers and voters are increasingly focused on the potential drivers of those increases, including large load growth, utility investment trends, fuel prices, and other factors that may affect customer bills.[1] At the same time, U.S. electricity demand forecasts have been revised upward sharply in the last several years, with significant attention on the role of data centers and other large loads as a primary driver of near-term load and energy growth, and the use of electricity for space heating and transportation also expanding.[2] Against this backdrop, policymakers, regulators, utilities, consumer advocates, and large load customers are increasingly focused on achieving dual goals while avoiding unjustified cost shifts to other customers. In the near term, there must be a way to achieve "speed to power," meaning timely access to the electric service needed to energize new large loads. In the longer term, additional transmission infrastructure is needed to integrate new large loads into the system and capture the reliability, economic, and system benefits that well-planned load growth and transmission investment can provide.

That scrutiny is playing out in concrete political and policy actions. At the federal level, the White House and the National Energy Dominance Council have increasingly foregrounded electricity affordability and reliability in energy and regional market policy, including in the PJM Interconnection (PJM) region.[3] In March 2026, the White House also announced the Ratepayer Protection Pledge, under which major technology companies committed to pursue rate structures and infrastructure arrangements intended to prevent data center growth from increasing electricity costs for existing customers, and the Administration's subsequent National AI Legislative Framework called on Congress to reinforce that approach.[4] Similar themes have emerged at the state level across both parties. In Texas, the Republican-led legislature enacted Senate Bill 6 in 2025 to establish large load interconnection standards aimed at minimizing stranded infrastructure costs, maintaining reliability, and requiring large load customers to contribute to interconnection cost recovery.[5] In Virginia and New Jersey, electricity affordability and data center-related cost concerns also became prominent campaign and early-governance issues.[6]

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1 Pew Research Center, *Many Americans Hold Utility Companies Responsible for Their Rising Home Energy Bills* (May 6, 2026); PowerLines, *Utilities Requested Record $31 Billion in Rate Increases in 2025, Double That of 2024* (Jan. 29, 2026), https://powerlines.org/utilities-requested-record-31-billion-in-rate-increases-in-2025-double-that-of-2024/; Lawrence Berkeley National Laboratory (LBNL), *Retail Electricity Price Trends and Drivers: 2026 Edition* (Mar. 2026), https://eta-publications.lbl.gov/sites/default/files/2026-03/retail_price_trends_2026_edition.pdf.

2 Grid Strategies, *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers*, at 3 (Nov. 2025), https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf (Grid Strategies 2025 Load Report).

3 White House National Energy Dominance Council, *Statement of Principles Regarding PJM* (Jan. 15, 2026), https://www.energy.gov/documents/statement-principles-regarding-pjm.

4 The White House, *Ratepayer Protection Pledge* (Mar. 4, 2026), https://www.whitehouse.gov/releases/2026/03/ratepayer-protection-pledge/; The White House, *National Policy Framework for Artificial Intelligence: Legislative Recommendations* (Mar. 20, 2026).

5 Texas S.B. 6, 89th Leg., Reg. Sess. (2025) (enacted June 20, 2025).

6 Abigail Spanberger for Governor, *Energy Affordability Plan* (June 2025), https://abigailspanberger.com/wp-content/uploads/2025/06/Spanberger_EnergyAffordabilityPlan_L4.pdf; Office of Governor Mikie Sherrill, *Promise Kept: Governor Sherrill Takes Bold Action with Executive Orders Declaring State of Emergency on Utility Costs*, Press Release (Jan. 20, 2026), https://www.nj.gov/governor/news/2026/20260120a.shtml.

Concerns about affordability are not without cause. Recent data and analyses confirm that electricity prices and utility bills have risen meaningfully in many regions in recent years.[7] At the same time, utilities and grid operators are highlighting the need for substantial near- and long-term investment in transmission and other grid infrastructure.[8] Narratives attributing electricity price increases to any one driver are overly simplistic: the drivers of price changes differ significantly across regions and years and include factors such as wildfires, extreme weather, and exposure to natural gas price volatility.[9] Nonetheless, the scale of investment needed to serve new large loads means that ratepayer impacts could be significant if transmission costs are not allocated appropriately.

New large loads need not raise rates. The effect on other customers depends on system conditions, the amount and timing of new infrastructure required to serve load growth, and how those costs are allocated.[10] Where large loads are efficiently sited to maximize grid utilization, grid expansions are cost-effectively planned to serve them, and they pay an appropriate share of the costs they cause, they can drive down rates for all customers by spreading fixed costs over more units of demand and opening new capacity for all users. At the same time, though, well-planned grid investment is needed. Large-scale transmission expansion can reduce total system costs and improve reliability by increasing access to diverse resource portfolios and smoothing regional supply-demand imbalances, while delays in transmission development can increase costs and reduce the benefits of regional resource sharing.[11] Those benefits matter not only for existing customers, but also for the new large loads, which generally seek the reliability, scale, and flexibility that come with full network grid service. Large load customers have identified inadequate transmission capacity as a key barrier to meeting development timelines, underscoring that transmission expansion is not just a cost issue but also a prerequisite for serving large loads at scale.

This report focuses on that rate impact question in the specific context of federally regulated transmission pricing. It does not address generation (and associated transmission upgrades that may be triggered by new generation), capacity, or distribution cost allocation in detail. Rather, we examine how transmission costs associated with new large loads are allocated and recovered, with a focus on the policy levers within the jurisdiction of the Federal Energy Regulatory Commission (FERC). This report, *Federal Transmission Pricing*

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7 LBNL, *Retail Electricity Price Trends and Drivers: 2026 Edition* (Mar. 2026), https://eta-publications.lbl.gov/sites/default/files/2026-03/retail_price_trends_2026_edition.pdf; PowerLines, *Utility Bills Are Rising: 2025 Review* (Jan. 2026), https://powerlines.org/wp-content/uploads/2026/01/0126_PowerLines_Rising-Utility-Bills-Q4-Update-FINAL.pdf.

8 Laila Kearney, et al., Reuters, *US utilities spend big on rising data center demand, but affordability concerns loom* (Feb. 12, 2026); Grid Strategies & Americans for a Clean Energy Grid, *2025 Transmission Planning and Development Report Card* (Feb. 2026), https://cleanenergygrid.org/wp-content/uploads/2026/02/ACEG_2025-Transmission-Planning-and-Development-Report-Card-1.pdf.

9 Lawrence Berkeley National Laboratory, *Retail Electricity Price Trends and Drivers: Data Update—2026 Edition* (Mar. 2026), https://emp.lbl.gov/sites/default/files/2026-03/Retail%20Price%20Trends_2026%20edition.pdf; Ryan Wiser, et al., *Factors Influencing Recent Trends in Retail Electricity Prices in the United States*, 38 Elec. J. 4 (2025), https://www.sciencedirect.com/science/article/pii/S1040619025000612.

10 Electric Power Research Institute, *The Economics of Load Growth: When New Loads Lower (or Raise) Electricity Prices*, Win-Win Watts (Jan. 27, 2026), https://winwin.epri.com/en/load-growth-economics.html (EPRI Economics of Load Growth); Lawrence Berkeley National Laboratory, *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities* (Jan. 2025), https://eta-publications.lbl.gov/sites/default/files/2025-01/electricity_rate_designs_for_large_loads_evolving_practices_and_opportunities_final.pdf (LBNL Electricity Rate Designs Report).

11 U.S. Department of Energy, *National Transmission Planning Study* (Oct. 2024), https://www.energy.gov/gdo/national-transmission-planning-study (DOE 2024 National Transmission Planning Study).

Volume 2: Options for Ensuring Affordability and Reliability in an Era of High Load Growth, builds on the first report in this two-volume series, *Federal Transmission Pricing Volume 1: The Evolution of Current Policies and Practices* (Volume 1 Report),[12] which explains the evolution and current framework of federal transmission pricing. This report identifies guiding principles from the history discussed in the Volume 1 Report and applies those principles to test a series of policy options aimed at ensuring all transmission customers, including new large loads, pay their "fair share" of transmission costs.

II. THE EMERGING LARGE LOAD LANDSCAPE

Load forecasts from utilities and other planning entities point to a scale of near-term load growth that would have been difficult to imagine just a few years ago. Aggregated nationally, those projections indicate over 150 GW of summer peak load growth between 2025 and 2030, a six-fold increase over the numbers projected in comparable forecasts published in 2022.[13] Based on analysis of utility planning documents, Grid Strategies estimates that roughly 130 GW of the projected 2025–2030 peak growth is associated with large load categories, including approximately 90 GW tied to data centers alone.

The scale of the individual projects driving these forecasts is also changing quickly. Bain & Company reports that, historically, "large" data centers ranged from roughly 50–200 MW, but continued growth in cloud services and AI demand is pushing project scales higher over the next five to ten years.[14] Indeed, as of October 2025, at least 16 data centers at the GW-scale were planned to come online in 2026 and 2027 alone.[15] Recent CBRE Research likewise points to rapid growth in project scale and continued power constraints, noting that customers now prioritize access to 300 MW-plus deliveries.[16] Project scale is especially relevant in transmission cost allocation conversations because individual projects can be very large relative to the systems serving them, sometimes driving new transmission facilities or other significant system upgrades.[17]

Data centers and other large loads, when taken as a group, can also drive significant regional transmission investments. PJM's Independent Market Monitor (IMM) reported that PJM approved $1.2 billion of baseline

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12 Grid Strategies, *Federal Transmission Pricing Volume 1: The Evolution of Current Policies and Practices* (May 2026), https://gridstrategiesllc.com/wp-content/uploads/GS_Federal-Transmission-Pricing-Vol-1.pdf (Volume 1 Report).

13 Grid Strategies 2025 Load Report at 3.

14 Bain & Company, *AI Changes Big and Small Computing*, Technology Report (2024), https://www.bain.com/insights/ai-changes-big-and-small-computing-tech-report-2024/; Bain & Company, *AI Data Center Forecast: From Scramble to Strategy* (2026), https://www.bain.com/insights/ai-data-center-forecast-from-scramble-to-strategy-snap-chart/.

15 Grid Strategies 2025 Load Report at 11.

16 CBRE, *U.S. Real Estate Market Outlook 2026: Data Centers* (Jan. 14, 2026), https://www.cbre.com/insights/books/us-real-estate-market-outlook-2026/data-centers.

17 North American Electric Reliability Corporation (NERC), *Characteristics and Risks of Emerging Large Loads*, at 4, 9, 17 (July 2025), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf; *see also* Gabelli Funds, *Utilities Outlook 2026*, at 13 (Jan. 5, 2026), https://gabelli.com/wp-content/uploads/2026/01/Utility-Outlook-2026.pdf; Alger Delta Cooperative Electric Association, *Self-Assessment of Ability to Meet Customer's Expected Electric Requirements for 2016–2020*, at 2 (filed in Mich. Pub. Serv. Comm'n Case No. U-17992 Mar. 22, 2016), https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000001URNLAA4 (reporting an expected large load growth of roughly 1 GW by 2029 and 1.5 GW by 2032 for a utility with historical peak demand of ~17 MW).

regional transmission upgrades associated with "Data Center Alley" reinforcements in the 2022 Regional Transmission Expansion Plan Window 3 process, and the IMM's 2025 *State of the Market Report* updates that figure to $1.4 billion.[18] The Maryland Office of People's Counsel argues a broader version of the same point, alleging that, between 2024 and 2025, PJM advanced almost $12 billion in new regional transmission infrastructure primarily driven by data center growth, largely in Northern Virginia.[19] Together, these examples illustrate that large load-related transmission cost allocation questions are not limited to customer-specific interconnection facilities or local transmission upgrades; these questions are also arising at the regional level as high load growth begins to materially drive grid expansion, with consequences for regional transmission cost allocation.

Large loads, and data centers in particular, are pursuing faster ways to secure power, including onsite generation. But this does not mean they want to remain permanently islanded from the grid. There is ample evidence to the contrary. For example, comments filed in response to the U.S. Department of Energy's (DOE) proposed Advance Notice of Proposed Rulemaking on large load interconnection (Large Load ANOPR) filed at FERC consistently point toward large loads wanting to connect to the bulk power system.[20] Comments, including from large load customers themselves, suggest large loads need clearer pathways to interconnect, develop generation to serve their needs, and obtain necessary transmission service, and that large loads value the long-term reliability, efficiency, and economies of scale that can be delivered from connection to the broader transmission system.[21] Large load customers recognize the need for significant transmission and generation expansion and prefer grid connection to meet their long-term needs.[22]

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18 Monitoring Analytics, LLC, *2024 State of the Market Report for PJM*, § 12: Generation and Transmission Planning, at 544 (Mar. 13, 2025), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec12.pdf; Monitoring Analytics, LLC, *2025 State of the Market Report for PJM*, Vol. 1, at 352 (Apr. 24, 2026), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-vol1.pdf.

19 Maryland Office of People's Counsel, *Data Centers* (accessed May 11, 2026), https://opc.maryland.gov/Consumer-Learning/Data-Centers.

20 *Interconnection of Large Loads to the Interstate Transmission System*, 195 FERC ¶ 61,045 (2026) (Large Load ANOPR).

21 Electricity Customer Alliance, Comments, Docket No. RM26-4-000, at 2-3 (filed Nov. 21, 2025); Americans for a Clean Energy Grid, Comments, Docket No. RM26-4-000, at 2 (filed Nov. 21, 2025); Electricity Consumers Resource Council, Comments, Docket No. RM26-4-000, at 2-4, 8, 12 (filed Nov. 21, 2025); Google LLC, Reply Comments, Docket No. RM26-4-000, at 3-4 (filed Dec. 5, 2025); Vantage Data Centers, Comments, Docket No. RM26-4-000, at 2 (filed Nov. 21, 2025) (explicitly stating Vantage prefers "grid-connected sites to support reliability and resilience" and operational continuity).

22 *E.g.*, Microsoft Corporation, Comments, Docket No. RM26-4-000, at 1-2, 5, 8-10 (filed Nov. 21, 2025); *see also* Ed Crooks, Wood Mackenzie, *Energy Gang*: *A solution to the problem of paying for data centre power?* (Feb. 17, 2026), https://www.woodmac.com/podcasts/energy-gang/a-solution-to-the-problem-of-paying-for-data-center-power/ (reporting that Amazon Web Services has called grid connection "the most cost effective way to scale up."); AlphaStruxure, Schneider Electric, & Data Center Frontier, *Before AI, After AI: The Energy Crunch in the "After AI" Era—How Data Centers Are Adapting*, at 23-24 (Apr. 2025), https://alphastruxure.com/wp-content/uploads/2025/04/AlphaStruxure_Before_AI_After_AI_Energy_Crunch_Survey.pdf (industry survey finding that customers pursuing on-site power in the near term preferred an arrangement that remained interconnected to the grid, and the most popular configuration was a bridge-to-power model in which on-site generation is used until utility service becomes available).

Vantage's Virginia VA2 campus is one useful example: Vantage developed the site with on-site generation because the local utility's large load interconnection process could not meet the customer's schedule, but it "remains committed to connecting this project to the grid" because doing so would let the site scale more effectively and bring broader system benefits.[23] Amazon Energy likewise supports reforms that would connect new AI and advanced manufacturing investment quickly while strengthening grid reliability and affordability for all customers, and supports optional pathways, including co-location and better large load planning, not as substitutes for the grid but as ways to improve access to it.[24] Reuters reported that, although Google is exploring co-location and other approaches that may accelerate deployment, the company's "hope is that these can eventually be grid-connected resources," and that Google's general preference is to connect to the grid.[25]

This matters for transmission pricing policy because it underscores that grid expansion will be needed for large load integration. Large loads may pursue temporary workarounds when the grid cannot serve them on the desired schedule, but the long-run objective remains access to the grid. That, in turn, reinforces the importance of transmission investment and planning processes capable of accommodating them at reasonable cost.

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23 Vantage Data Centers, Comments, Docket No. RM26-4-000, at 3-4 (filed Nov. 21, 2025).

24 Amazon Energy LLC, Comments, Docket No. RM26-4-000, at 1, 3-7 (filed Nov. 21, 2025); *see also* Ed Crooks, Wood Mackenzie, *Energy Gang*: *A solution to the problem of paying for data centre power?* (Feb. 17, 2026), https://www.woodmac.com/podcasts/energy-gang/a-solution-to-the-problem-of-paying-for-data-center-power/ (underscoring that large loads are seeking highly reliable, scalable grid service rather than long-term separation from the network).

25 Reuters, *Google says U.S. transmission system biggest challenge for connecting data centers* (Jan. 14, 2026), https://www.reuters.com/world/us/google-says-us-transmission-system-biggest-challenge-connecting-data-centers-2026-01-14/.

Not All Large Loads Are Created Equal

Large loads are often discussed as a single category, but they are not a single customer type. Even within the category most closely associated with recent load growth—data centers—the relevant customers and load profiles are far from uniform. At a high level, three broad categories are commonly distinguished: hyperscale, colocation, and enterprise data centers. Those categories matter because they differ in scale, business model, load profile, site-selection constraints, and ability to respond to power and transmission constraints, which can matter for forecasting, transmission planning, and cost allocation.

Hyperscale data centers are the largest facilities and are typically developed or directly procured by cloud providers and other very large technology firms. They dominate much of today's incremental demand for data center capacity to support continued expansion of cloud computing services (which still dominate data center use) and AI development. Hyperscaler facilities under development are rapidly shifting toward larger campuses and higher-power deliveries. Note that cloud, search, and storage uses may have different rack densities, cooling requirements, and power profiles than newer AI training and inference workloads. This impacts both their power demand and relative dispatchability and flexibility.

Colocation data centers, by contrast, are facilities in which a specialized provider develops and operates the building and core infrastructure while leasing capacity to multiple customers. Note that the term "colocation" is confusingly also used to signify on-site generation, but here we are talking about the term as it is used in the data center industry. Colocation loads can still be very large, but their business model differs from hyperscalers because a single campus may serve many end users rather than one anchor tenant, which may impact how likely a planned project is to materialize and how project power usage ramps up after initial energization.

Enterprise data centers are generally smaller facilities owned or operated to serve the needs of a single company or institution, often outside the largest cloud platforms. Historically, enterprise data centers made up a large share of the installed base, though the growth frontier has shifted toward hyperscale and large colocation campuses.

Crypto mining facilities, which use specialized computing hardware to validate blockchain transactions and produce digital assets, are analytically distinct from most data centers because their operating model, locational flexibility, and potential responsiveness to price signals can differ substantially.

MEETING HIGH LOAD GROWTH REQUIRES ROBUST TRANSMISSION PLANNING AND INVESTMENT

Serving large load growth affordably and reliably will require substantial transmission investment in well-planned transmission. But the required transmission investment is not driven by large loads alone. This era of high load growth is emerging at a moment when the transmission system already needs significant investments to continue to reliably serve current customers. The key affordability question is not whether to make investments in the transmission system but rather how to do so in a way that captures broader system benefits, minimizes long-run costs, and favors projects that meet multiple customer and system needs while avoiding piecemeal and just-in-time grid expansion. This means investing in more efficient and cost-effective regional transmission, planned on a proactive, multi-value basis, to the benefit of all electricity customers.

The grid is aging. Much of the system already requires replacement and modernization. Around 31% of transmission infrastructure and 46% of distribution infrastructure is near, or already beyond, its useful life, underscoring that a substantial share of current utility investment reflects preexisting replacement needs.[26] At the same time, the cost of the equipment needed for grid expansion has risen materially (e.g., since 2019, unit costs have increased by 77% for power transformers).[27]

Against this backdrop, the grid also needs to expand. NERC's 2025 Long-Term Reliability Assessment states that planning participants are expecting nearly 250 GW of peak demand growth over the next 10 years and warns that keeping pace with that growth will require not only new generation resources, but also transmission development to enable interregional transfers that take advantage of geographic diversity.[28] DOE's National Transmission Planning Study likewise concludes that, to meet growing demand, improve electric service reliability and resilience, reduce consumer costs, and enable access to low-cost generation, the United States will need substantial transmission expansion.[29]

But transmission development was lagging before the rapid increase in large loads. Only 888 miles of new 345 kV+ transmission lines were completed in 2024, up from 420 miles in 2023, but still far below the nearly 4,000 miles built in 2013, and even farther off from the anticipated need.[30] That slowdown matters because new demand growth is increasingly tied to strategic industries such as semiconductor manufacturing, AI, and advanced manufacturing, all of which depend on reliable, affordable electricity. A grid that cannot expand in step with demand risks becoming a binding constraint on economic development as well as on reliability.

Robust, multi-value transmission planning is central to affordability. Consumer benefits depend not just on how much transmission infrastructure is built, but also on whether more efficient and cost-effective infrastructure is built, meaning transmission that leverages economies of scale, solves multiple needs efficiently, and gets the most out of every dollar invested. Well-planned transmission can reduce total system costs, improve reliability, and broaden access to lower-cost generation resources. DOE estimates that accelerated transmission expansion can produce $1.60 to $1.80 in savings for every dollar spent by enabling greater access to low-cost generation and expanding opportunities for resource sharing for reliability.[31] Similarly, recent national analysis finds that well-planned, high-capacity transmission could save residential consumers $6.3–$10.4 billion per year, and

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26 Bank of America Institute, *Power Check: Watt's Going on with the Grid?*, at 2 (July 22, 2025), https://institute.bankofamerica.com/content/dam/transformation/us-electrical-grid.pdf.

27 Wood Mackenzie, *Transformer troubles: manufacturing and policy constraints hit US transformer supply* (Aug. 13, 2025), https://www.woodmac.com/news/opinion/transformer-troubles-manufacturing-and-policy-constraints-hit-us-transformer-supply/; U.S. Bureau of Labor Statistics, *Producer Price Index by Industry: Electric Power and Specialty Transformer Manufacturing: Primary Products* [PCU335311335311P], retrieved from FRED, Federal Reserve Bank of St. Louis (accessed May 11, 2026), https://fred.stlouisfed.org/series/PCU335311335311P.

28 North American Electric Reliability Corporation, *2025 Long-Term Reliability Assessment*, at 30-31 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

29 DOE 2024 National Transmission Planning Study at 12, 19.

30 Grid Strategies, *Fewer New Miles: Strategic Industries Held Back by Slow Pace of Transmission*, at 16 (July 2025), https://gridstrategiesllc.com/wp-content/uploads/ACEG_Grid-Strategies_Fewer-New-Miles-2025_vF.pdf (Grid Strategies 2025 Fewer New Miles).

31 DOE 2024 National Transmission Planning Study at 12, 19.

$16.8–$27.7 billion annually across residential, commercial, and industrial customers combined.[32] The cost savings potential is even more apparent with interregional transmission, where ties between regions can allow systems to share capacity and energy in ways that reduce total reserve needs and lower costs.[33] Conversely, delaying transmission development postpones or forfeits these benefits, increasing the risk that customers bear higher congestion costs, higher production costs, and less efficient system investment over time.[34]

Recent analysis emphasizes that cost-effective outcomes require more proactive and comprehensive transmission planning: planning that considers multiple drivers over longer time horizons, uses scenario-based or least-regrets approaches to manage uncertainty, and looks first to lower-cost options such as better use of existing rights-of-way, upgrades to existing lines, and advanced transmission technologies before defaulting to entirely new corridors.[35] Transmission projects developed through proactive, larger-scale planning can often solve multiple needs at once: for example, serving new load, improving access to lower-cost generation, reducing congestion, and strengthening reliability. By contrast, an overly reactive approach to transmission expansion that relies too heavily on piecemeal, siloed, and serial transmission fixes will produce a more fragmented and expensive system over time.[36] Recent PJM experience illustrates the risk that reactive planning can impose large and contested costs on customers. The Maryland Office of People's Counsel has alleged that data centers are driving substantial local transmission upgrades across PJM, including 130 local projects initiated from 2022 through 2024 to connect new data centers.[37]

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32 Grid Strategies, *Large-Scale Transmission Deployment Saves Consumers Money*, at 2-3, 23-25 (June 2025), https://gridstrategiesllc.com/wp-content/uploads/GS_Transmission-Deployment-Saves-Consumers-Money.pdf (Grid Strategies Cost Savings Report).

33 Grid Strategies, *Resource Adequacy Value of Interregional Transmission*, at 1, 7, 13 (June 2025), https://cleanenergygrid.org/wp-content/uploads/2025/06/250610_RAValueInterregionalTx_Corrections.pdf (Grid Strategies Resource Adequacy Report); Dasom Ham, et al., Proceedings of the National Academy of Sciences 123, no. 9, *Transmission Lowers US Generation Costs, but Generator Incentives Are Not Aligned*, at 1, 3 (2026) (finding billions in potential savings from removing interregional transmission constraints).

34 Grid Strategies, *Delaying Transmission Increases Costs and Reduces Benefits for Consumers*, at 10-13 (Nov. 2025), https://ctcglobal.com/wp-content/uploads/2026/03/Cost-of-Delayed-Transmission-Report-by-Grid-Strategies-for-WIRES.pdf.

35 Brattle Group, *Transmission Landscape and Outlook: Proactive Planning for a More Cost-effective and Affordable Energy Transition*, at 11-12, 16 (Oct. 2025), https://www.brattle.com/wp-content/uploads/2025/10/Transmission-Landscape-and-Outlook-Proactive-Planning-for-a-More-Cost-effective-and-Affordable-Energy-Transition.pdf; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, at PP 86-89, 241-246, 1186-1187 (2024).

36 *E.g.*, DOE 2024 National Transmission Planning Study at 12, 19-20; American Electric Power Co., Comments, Docket No. RM26-4-000, at 15-18 (filed Nov. 21, 2025) (arguing the siloed and reactive approach to transmission planning "will not deliver infrastructure on the timeline needed" and instead calling for proactive, forward-looking, "least regrets" planning that can address multiple needs in a holistic and cost-effective manner); MISO, Comments, Docket No. RM26-4-000, at 5-7 (filed Nov. 21, 2025) (emphasizing need for reforms to identify larger, more comprehensive transmission that can bring generation online more quickly and at lower cost than more reactive approaches).

37 Maryland Office of People's Counsel, Complaint, Docket No. EL26-63-000, Attach. B, at 27-28 (filed May 7, 2026).

NEW LARGE LOADS CAN BE SERVED WITHOUT SHIFTING COSTS TO EXISTING CUSTOMERS

As just explained, the grid needs to be upgraded, expanded, and modernized. This was true before large loads, but high load growth is certainly adding to the pace and scope of the need, with associated impacts on electricity rates. But new load need not shift costs to existing customers, as many fear, so long as policies keep pace with the changing system.

The Volume 1 Report explains, in detail, the federal transmission pricing paradigm of today, so we will not repeat it here.[38] For this Volume 2, several points are most relevant:

- FERC's transmission pricing rules generally apply to transmission customers at the wholesale level, not directly to individual retail loads. In many cases, the relevant wholesale customer is the load serving entity (LSE) taking transmission service to deliver and sell electricity supply at retail to end-use customers, like large loads.
- FERC regulates allocation of transmission costs to LSEs, commonly on a load ratio share basis (i.e., costs are allocated in proportion to the amount of load served by the LSE at a specified snapshot in time).
- Those FERC-approved costs are then, in most cases, included in and recovered through state-jurisdictional retail rates (with exceptions in states with bundled generation, transmission, and distribution sales and some other limited instances).
- As a result, regardless of structure, new large loads generally enter a system in which transmission costs are not assigned directly to individual retail customers. The ultimate allocation of transmission costs to specific end-use customers and customer classes, such as homes and businesses, is generally a matter of state law and regulations.

The cost impacts of new loads on existing customers depend on a number of factors. Like many capital-intensive industries, electric utilities have high fixed costs that must be paid regardless of how much customers use the system, so when additional demand can be served in whole or in part using existing capacity, higher utilization can lower average costs by spreading those fixed costs over more sales.[39] Put simply: more customers can spread the fixed costs over more units of demand so each individual customer pays less in fixed cost per unit consumed. That outcome is most likely where there is demonstrable capacity on the generation and delivery system, where the new load can be served with limited marginal investment, and where the added revenues arrive before major new costs are incurred. In those circumstances, additional sales can help reduce the average cost of recovering sunk or already-committed system costs, rather than increasing the burden on existing customers.[40]

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38 *See* Volume 1 Report, Sections V (FERC Transmission Pricing Today: Cost Allocation and Cost Recovery) and VI (How FERC-Approved Transmission Costs Flow to Retail Customers).

39 Brattle Group, *The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability*, at 4-7 (Mar. 2026), https://www.brattle.com/wp-content/uploads/2026/03/The-Untapped-Grid-Mar-2026.pdf (Brattle Group Untapped Grid Report).

40 Lawrence Berkeley National Laboratory, *Transmission Cost Allocation Practices*, at 1-2, 4 (Jan. 8, 2026), https://eta-publications.lbl.gov/sites/default/files/2026-01/transmission_cost_allocation_brief_final_v2.pdf (LBNL Cost Allocation Report).

Recent analyses emphasize that this logic is real, but conditional. EPRI explains that new load can either lower or raise prices depending on whether the system has spare capacity and how much incremental investment is needed to serve that load.[41] Brattle Group similarly argues that better utilization of existing grid assets can improve affordability when additional demand can be absorbed without major new buildout.[42] However, large increases in demand can also put upward pressure on wholesale capacity or energy prices, and any such cost increases are likely to flow through to customers more quickly than the longer-lived infrastructure investments that are the focus of this report.

When serving new load requires material incremental costs that are large relative to the system's current average cost, or when those costs must be incurred ahead of realized load, appropriate planning and cost allocation methods must be deployed to avoid upward pressure on rates.[43] Incremental costs can include new generation, transmission and distribution upgrades needed to deliver power to the interconnection point, interconnection-related network upgrades, and accelerated replacement or hardening investments where load growth interacts with broader infrastructure needs. The risk of high incremental costs and an associated impact on rates is especially pronounced when the limiting factor to serving new load is a local substation, feeder, or transmission constraint that requires a large, lumpy upgrade with a long lead time.[44]

Lawrence Berkeley National Lab notes that rate impacts depend heavily on existing system conditions, the pace and location of load growth, and the extent to which utilities can mitigate stranded cost risk and align cost responsibility with actual system impacts when planning and deploying new incremental investment.[45] For example, where utilities must spend significant capital before new load is fully online, carrying and financing costs may begin flowing into rates before associated revenues are fully realized under current policies, potentially requiring new approaches.[46] And if the load is delayed, reduced, ramps more slowly than expected, or never materializes, the result can risk stranded costs unless that risk is mitigated through contract terms or tariff design, as states are currently doing with retail large load tariffs.[47]

41 EPRI Economics of Load Growth.

42 Brattle Group Untapped Grid Report at 4-7.

43 EPRI Economics of Load Growth; *Commonwealth Edison Co.*, 194 FERC ¶ 61,183 (2026) (Chang, Comm'r, concurring) (raising concerns that transmission upgrades needed to serve new large loads could increase rates for other customers if upgrade costs are rolled into transmission rates and customer commitments are not sufficient to cover those costs).

44 Brattle Group Untapped Grid Report at 2-5, 10.

45 LBNL Cost Allocation Report at 1-2, 4-5, 8-10.

46 PwC, Utilities and Power Companies Guide, *Construction Work in Progress in Rate Base*, Chap. 18.4 (accessed Mar. 31, 2026), https://viewpoint.pwc.com/content/pwc-madison/ditaroot/us/en/pwc/accounting_guides/utilities_and_power_/utilities_and_power__US/chapter_18_regulated_US/184_construction_wor_US.html; Volume 1 Report, Section VII (Timing Considerations for Transmission Cost Recovery).

47 LBNL Electricity Rate Designs Report at 4-5, 8, 10; Rocky Mountain Institute, "Tariffs for Large Load Customers," *Electricity Affordability Toolkit* (last updated Nov. 24, 2025), https://affordability-toolkit.rmi.org/policies/tariffs-for-large-load-customers (RMI Large Load Tariffs Toolkit).

There is some evidence from recent utility and public statements that large loads can help moderate rates in practice. Pacific Gas and Electric Company (PG&E) has publicly stated that each additional GW of data center demand it serves could lower bills by roughly 1-2% because additional revenues help offset a large planned capital program.[48] In Georgia, public reporting similarly quotes the Chair of the Georgia Public Service Commission as crediting revenue from large load customers with helping enable the state's ability to freeze Georgia Power base rates for a multi-year period.[49] These examples do not show that large loads always lower rates, but they do support the narrower point that load growth can, in some circumstances, help hold rates down rather than push them up.

As it stands today, load growth can, in some cases, help lower average costs by spreading fixed costs over more sales. In others, it can increase rates where incremental infrastructure needed to serve it is substantial and the costs are unfairly allocated. Adjusting transmission planning systems, risk mitigation practices, and cost allocation and recovery policies at the federal and state levels can protect existing customers while ensuring that investments also strengthen the broader grid to the benefit of all.

RETAIL LARGE LOAD TARIFFS

At the state level, there has been a wave of reforms aimed at ensuring that large loads pay a fair share by clarifying cost responsibility, reducing stranded cost risk, and aligning rates with the characteristics of new large loads. Retail large load tariffs are state-regulated rates, riders, special contracts, and service rules that govern how large end-use customers take service and how the costs and risks of serving them are allocated. These tariffs determine not only what large customers pay, but also the conditions under which they connect to the system, and they are increasingly being used to incorporate safeguards against stranded costs and cross-subsidies.[50]

Adoption of large load tariffs has accelerated rapidly, with an estimated 77 approved and proposed tariffs and service rules across 36 states and 60 utilities, including 51 approved and 26 pending proposals.[51] These tariffs have become a mainstream state-level response to rapid load growth.[52]

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48 PG&E, *PG&E Data Center Demand Pipeline Swells to 10 Gigawatts with Potential to Unlock Billions in Benefits for California* (July 31, 2025), https://investor.pgecorp.com/news-events/press-releases/press-release-details/2025/PGE-Data-Center-Demand-Pipeline-Swells-to-10-Gigawatts-with-Potential-to-Unlock-Billions-in-Benefits-for-California/default.aspx.

49 Atlanta News First, *Georgia PSC chairman defends data center power expansion amid criticism* (Mar. 17, 2026), https://www.atlantanewsfirst.com/2026/03/17/georgia-psc-chairman-defends-data-center-power-expansion-amid-criticism/.

50 RMI Large Load Tariffs Toolkit.

51 Smart Electric Power Alliance, *U.S. Data Center Gold Rush Drives Surge in New Utility Tariffs* (Apr. 20, 2026), https://sepapower.org/knowledge/u-s-data-center-gold-rush-drives-surge-in-new-utility-tariffs/ (SEPA Q1 2026 DELTa Updates).

52 Edison Electric Institute, *Large Load Projects and Tariffs*, at 9 (May 2026), https://www.eei.org/-/media/Project/EEI/Documents/Issues%20and%20Policy/List%20of%20Large%20Customer%20Projects%20and%20Tariffs (EEI Large Load Tariffs Report) (based on a survey of EEI members, identifying 23 states with at least one approved large load tariff and 7 states with pending tariffs).

Large load tariffs sometimes have different goals across jurisdictions. In practice, those objectives produce several recognizable tariff "flavors." Some are primarily attraction or economic development tariffs, designed to attract high-volume customers or provide optional service structures for new large loads.[53] Others are procurement-oriented tariffs or riders, allowing or requiring customer-identified generation, clean energy procurement, or bespoke resource arrangements. Many are focused on customer protections and include terms intended to avoid cost shifts, reduce stranded-asset risk, and align cost responsibility with the infrastructure needed to serve the load.[54] Many newer tariffs are hybrid frameworks that pursue several of these aims at once—for example, pairing long-term commitments and minimum billing with provisions for on-site generation, customer-procured resources, or flexible service.[55] The below discussion focuses on the third category: tariffs primarily emphasizing customer protection and cost responsibility.

Customer protection tariffs are becoming more prominent as states move toward increasingly tailored large load frameworks, rather than generic commercial and industrial rates, as indicated by eligibility criteria. While older tariffs often determined eligibility based on size thresholds at or below 25 MW, about two-thirds of the large load tariffs and service rules approved in 2025 used materially higher thresholds, typically between 50 MW and 150 MW.[56] Beyond project size, newer tariffs often define eligibility based on delivery voltage and load profile, or some combination of all three.[57] These criteria help to identify and include the subset of loads that can materially affect planning and cost recovery, and to make the resulting protections more transparent and easier to administer.[58]

Large load customer commitments are a key element of customer protection tariffs as utilities and regulators seek to translate uncertain future load growth into explicit financial and operational commitments by locking in assumed load levels.[59] These typically fall into the following categories:

- **Contract terms and exit charges:** Contract terms are the minimum period for which the customer commits to take service under the tariff, usually through a service agreement or special contract.[60] They are typically in the 10- to 20-year range and are intended to help ensure that large load customers remain on the system long enough to help pay for the capacity and facilities built for them.[61] Exit charges are charges assessed if the customer terminates service early, downsizes materially, or otherwise stops

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53 *Id.* at 10, 13.

54 Energy and Environmental Economics (E3), *Large Load Tariff Whitepaper*, at 3 (May 2026), https://www.ethree.com/wp-content/uploads/2026/05/E3_Large-Load-Tariff-Whitepaper-1.pdf (E3 Whitepaper).

55 *Id.*; EEI Large Load Tariffs Report at 10, 13.

56 SEPA Q1 2026 DELTa Updates.

57 RMI Large Load Tariffs Toolkit.

58 *Id.*; EEI Large Load Tariffs Report at 9.

59 E3 Whitepaper at 3.

60 EEI Large Load Tariffs Report at 9-10.

61 Smart Electric Power Alliance, *Database of Emerging Large-Load Tariffs (DELTa): March 31, 2026 Public Update*, Excel Spreadsheet (Downloaded May 7, 2026), https://sepapower.org/large-load-tariffs-database/ (SEPA May 7 Spreadsheet) (author's review of tariff entries with stated contract-term provisions).

taking the level of service on which utility investment was premised.[62] An exit charge can take several forms: a fixed termination fee, a true-up tied to unrecovered facilities costs, or a schedule that declines over time as the utility recovers more of its costs.[63]

- **Minimum billing demand:** Minimum billing demand is the tariff mechanism that requires the customer to pay at least a specified minimum level of demand each month, even if actual usage falls below that level, and is sometimes referred to as a "take-or-pay" provision.[64] Recent large load tariffs often include minimum demand charges of 80–90% of contract demand; the minimum bill calculations include an energy component in some jurisdictions.[65]
- **Financial assurance:** Financial assurance is the package of collateral, credit support, or creditworthiness requirements used to demonstrate that the customer can cover the costs its project may impose, including monthly bills, required infrastructure payments, and any termination or true-up amounts.[66] In practice, this category can include upfront deposits, letters of credit, parent guarantees, milestone-based security, or other forms of credit support, depending on the tariff and the customer's balance sheet profile.[67]

Large load tariffs, or utility contracting practices, may also seek to ensure that large loads bear the cost of facilities needed to connect to the grid. Retail end-use customers, especially large loads connecting at higher voltages, are often required under retail tariffs and service rules to pay for customer-specific connection facilities and other non-standard or "excess" facilities needed to serve the site. Excess facilities charges may apply for substation, primary distribution, and high-voltage line investments that exceed what would normally be provided for the same type of service.[68] Missouri regulatory staff testimony elaborates, explaining that all excess facilities are customer-specific, though not all customer-specific facilities are excess, and giving the example of a new radial line built to serve a particular customer.[69] Indeed, in some jurisdictions, large load customers take service under tariffs that include the three types of commitments listed above for customer-specific costs, but not for other costs that result from new customers interconnecting to the grid.

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62 EEI Large Load Tariffs Report at 9-10.

63 RMI Large Load Tariffs Toolkit.

64 EEI Large Load Tariffs Report at 9-10; E3 Whitepaper at 3.

65 SEPA May 7 Spreadsheet (author's review of tariff entries with stated minimum billing demand provisions); American Electric Power, *First Quarter 2026 Earnings Presentation*, at 12 (May 2026), https://docs.aep.com/docs/newsroom/resources/earnings/2026-05/1Q26EarningsReleasePresentation.pdf.

66 EEI Large Load Tariffs Report at 9-10.

67 RMI Large Load Tariffs Toolkit.

68 E3, *Designing Electric Rates and Tariffs for Large Loads*, at 36-37 (Dec. 2025), https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf. For example, PG&E's Rule 30 defines "special facilities" to include facilities requested beyond standard service, facilities constructed for the applicant's sole use, or facilities required by project-specific circumstances. PG&E, *Electric Rule No. 30: Retail Service Transmission Facilities Interim Implementation*, at 4, 10, 12 (effective Dec. 4, 2025).

69 Sarah L.K. Lange, Direct Testimony on Behalf of Missouri Pub. Serv. Comm'n Staff, *In the Matter of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area*, File No. ER-2024-0261, at 63 (July 21, 2025).

In some tariffs, charges for customer-specific facilities take the form of upfront contributions. PG&E Rule 30 (a tariff for transmission-connected retail customers), for example, requires an advance and then provides a refund if actual costs are lower than the advance.[70] In other tariffs, the same objective is pursued through ongoing charges rather than upfront payments. Dominion's Schedule GS-4 (a retail large load tariff for certain customers served at primary or transmission voltage) states that, after 12 months of active service, a customer may execute an agreement for electric service and pay a monthly facilities charge for any excess facilities.[71] A related June 2025 Virginia agreement amendment specifies that the monthly facilities charge may apply to excess transmission facilities, excess substation facilities, and excess distribution facilities.[72]

These tariff mechanisms reflect a broader shift toward clearer assignment of large load-related infrastructure costs. That shift is increasingly matched by public statements from large load customers that they are willing to pay their fair share of the energy and infrastructure costs needed to serve them.

Many large load customers have indicated their willingness to pay their "fair share" for electricity and even to pay more than other customers to access timely and reliable service. This posture is reflected in the White House's March 2026 Ratepayer Protection Pledge, under which seven leading hyperscalers and AI companies agreed that the energy and infrastructure needed to build and operate data centers should be paid for by those companies rather than passed on to households.[73] In comments on the Large Load ANOPR at FERC, Microsoft stated that it already "pays for the electricity it consumes and for its share of infrastructure costs" and supports transparent mechanisms to ensure that its neighbors and local communities do not bear Microsoft's share of those costs.[74] Microsoft has also made extensive public commitments to paying their own electricity costs.[75] Vantage has similarly stated that direct assignment of network upgrade costs to large loads "accords fully with Vantage's commitment to absorb the full cost of upgrades required by its projects" and "avoids imposing undue burden on the utility's ratepayers."[76] Google has likewise committed to paying for 100% of the power and infrastructure costs driven by its growth (whether through its Capacity Commitment Framework or otherwise).[77] And OpenAI has made a public commitment to "pay our own way on energy, so that our operations don't increase your electricity prices."[78]

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70 PG&E, *Electric Rule No. 30: Retail Service Transmission Facilities Interim Implementation*, at 10, 12 (effective Dec. 4, 2025).

71 Dominion Energy Virginia, Schedule GS-4, at 5 (effective Jan. 1, 2026).

72 Virginia Electric & Power Co. d/b/a Dominion Energy Virginia & Virginia Energy Purchasing Governmental Ass'n, *Amendment No. 12*, at 49-50 (effective July 1, 2025) (specifying monthly facilities charges for excess transmission facilities, excess substation facilities, and excess distribution facilities).

73 The White House, *Ratepayer Protection Pledge* (Mar. 4, 2026), https://www.whitehouse.gov/releases/2026/03/ratepayer-protection-pledge/.

74 Microsoft Corporation, Comments, Docket No. RM26-4-000, at 5, 11-12 (filed Nov. 21, 2025).

75 Microsoft, *Building Community-First AI Infrastructure* (Jan. 13, 2026), https://blogs.microsoft.com/on-the-issues/2026/01/13/community-first-ai-infrastructure/.

76 Vantage Data Centers, Comments, Docket No. RM26-4-000, at 10-11 (filed Nov. 21, 2025).

77 Google, *Supporting the White House Ratepayer Protection Pledge: Google's approach for responsible energy growth* (Mar. 4, 2026), https://blog.google/innovation-and-ai/infrastructure-and-cloud/global-network/affordability-pledge-responsible-energy-growth/.

78 OpenAI, *Stargate Community* (Jan. 20, 2026), https://openai.com/index/stargate-community/.

Taken together, the retail large load tariff landscape is moving toward clearer cost assignment, stronger mitigation of potential risks to other ratepayers, and more explicit customer commitments. The result is a fast-evolving but increasingly recognizable tariff architecture: larger eligibility thresholds, longer service commitments, minimum billing provisions, collateral requirements, direct assignment of some customer-specific studies and facilities.

FEDERAL-STATE COORDINATION

Large load issues implicate both state-regulated retail service and FERC-jurisdictional transmission matters. While retail tools can be powerful mechanisms for consumer protection and ensuring fair cost allocation, FERC-jurisdictional rules shape which transmission costs are approved, how they are allocated at wholesale, and whether states can clearly trace those costs to large loads. This overlap matters in practice because state retail tools operate downstream of FERC-jurisdictional transmission planning, cost allocation, and cost recovery. State-jurisdictional retail contracts and large load tariffs can require customer commitments, minimum bills, financial assurance, and customer-specific facilities payments, but they cannot reconsider whether FERC-approved transmission costs are recoverable in retail electricity rates or allocated appropriately to the LSE.[79]

Load forecasting creates a related overlap. Utilities often have more visibility into specific large load service requests and associated commitments than regional planners. Utilities provide load forecasts that feed into regional planning processes that select transmission projects under FERC-jurisdictional tariffs and allocate the costs of those projects across the region. This system relies on accurate load forecasts from utilities and regional planners, FERC-jurisdictional cost allocation mechanisms that account for changing load across the region, and sufficient transparency at the state level into the costs allocated to customers in the state.[80]

Recent disputes illustrate the stakes. In its complaint against PJM, the Maryland Office of People's Counsel (OPC) argues that PJM's regional cost allocation rules result in substantial transmission costs flowing to Maryland customers for projects allegedly driven by data center growth concentrated in other PJM zones. The Maryland OPC contends that relying on state-regulated retail large load tariffs alone is insufficient to avoid what it sees as unfair cost shifts at the FERC-jurisdictional level—across state lines—via PJM's regional cost allocation method.[81] Other recent actions at FERC are summarized in the Volume 1 Report, including the Large Load ANOPR, Tri-State Generation and Transmission Association's large load tariff, the PJM co-location order to show cause proceeding, and bespoke transmission-related agreements negotiated between utilities and data centers.[82]

For the federal transmission pricing options discussed later in this report, the central question is not whether federal or state regulators alone should solve the large load cost allocation challenge. Rather, the question is which options are both sound policy and appropriately addressed at the federal level, and how federal transmission pricing policy can complement retail large load tariff reforms while preserving cost recovery, open access, economic efficiency, fairness, and administrative feasibility—the five guiding principles we next discuss.

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79 *See* Volume 1 Report at 7, 42-45 (explaining how FERC-approved transmission costs flow to retail customers and identifying the two-step pathway through which FERC first approves and allocates transmission costs to LSEs, while states determine how those costs are allocated among end-use retail customers).

80 Energy Systems Integration Group, *Forecasting for Large Loads: Current Practices and Recommendations*, at 2-4, 8-10, 40-49 (Dec. 2025), https://www.esig.energy/wp-content/uploads/2025/12/ESIG-Large-Loads-Forecasting-report-2025.pdf (ESIG Load Forecasting Report).

81 Maryland Office of People's Counsel, Complaint, Docket No. EL26-63-000, at 22-23 (filed May 7, 2026).

82 *See* Volume 1 Report, Section VIII.

III. GUIDING PRINCIPLES FOR EVALUATING FEDERAL TRANSMISSION PRICING OPTIONS

Below are five equally important principles against which we test the federal transmission pricing options discussed in this report. They are drawn from the evolution of federal transmission pricing policy and reflect key themes consistently guiding FERC actions from the 1994 Transmission Pricing Policy Statement to today, as outlined in the Volume 1 Report. The objective of this guiding-principles framework is not to prescribe a single best federal transmission pricing option for ensuring affordability and reliability in an era of high load growth. Rather, the guiding principles allow us to compare policy options based on their ability to achieve the outcomes that federal transmission pricing should aim to achieve across jurisdictions and wholesale market structures.

PRINCIPLE 1: ENSURE OPPORTUNITY FOR APPROPRIATE COST RECOVERY

Federal transmission pricing should continue to ensure transmission owners have the opportunity to recover their prudently incurred costs of providing transmission service and a return on those costs sufficient to attract future investment when needed, per longstanding Supreme Court precedent.[83] At the same time, federal transmission pricing need not guarantee cost recovery and should guard against excessive returns far beyond the cost of providing the transmission service.

PRINCIPLE 2: SAFEGUARD NON-DISCRIMINATORY OPEN ACCESS

Federal transmission pricing should safeguard non-discriminatory open access to the transmission system for generation and load, consistent with foundational FERC precedent. Since Congress enacted the Energy Policy Act of 1992, FERC has consistently acted to encourage competitive wholesale electricity markets and to require transmission providers to offer open and non-discriminatory access to their transmission system to third-party users.[84] Thus, FERC's rules ensure comparability of service for similarly situated wholesale customers, including in the rate and non-rate terms and conditions of service.

PRINCIPLE 3: PROMOTE ECONOMIC EFFICIENCY ON THE ELECTRIC SYSTEM

Federal transmission pricing should promote economic efficiency on the electric system, including in transmission expansion, use of existing transmission capacity, and location of new generation and load. This includes incentivizing more efficient transmission investments that leverage economies of scale over piecemeal and just-in-time grid expansion. It also includes efficiently allocating constrained transmission capacity and sending price signals to guide the location of new generation and load to locations with existing transmission capacity or at least less significant transmission expansion needs. Promoting economic efficiency also encompasses federal transmission pricing that promotes deployment of technologies that get more out of the existing transmission system.[85]

83 *See Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1998); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of WV*, 262 U.S. 679 (1923).

84 *See* Volume 1 Report, Section IV (describing FERC Orders 888, 2000, 2003, and 890 and the rules FERC put in place to ensuring open access transmission service).

85 T. Bruce Tsuchida, et al., The Brattle Group & Grid Strategies, *Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920* (Apr. 2025), https://gridstrategiesllc.com/wp-content/uploads/Report__Incorporating-GETs-and-HPCs-Under-FERC-Order-1920__April-21-2025.pdf.

PRINCIPLE 4: PROMOTE FAIRNESS IN LINE WITH COST CAUSATION AND BENEFICIARY PAYS PRINCIPLES

Federal transmission pricing should promote fairness in line with the core FERC principles of cost causation and beneficiary pays.[86] The cost causation principle essentially stands for the proposition that those who cause the costs to be incurred should also pay the costs. Beneficiary pays, a corollary of the cost causation principle, states that a customer who benefits from new facilities can be said to have "caused" the costs and thus must pay a share of the costs "roughly commensurate with the estimated benefits" they receive. This principle—promoting fairness—goes beyond the cost causation and beneficiary pays principles to more broadly focus on avoiding unfair cost shifts (e.g., third-party transmission service customers should not subsidize existing customers nor should existing customers subsidize new customers' use of the transmission system) that could arise in the unique current context of large load growth.[87] Since charges to large retail loads are generally determined under state jurisdiction, ensuring fair cost responsibility for new large loads requires close coordination between FERC-jurisdictional transmission pricing and state retail rate design.

PRINCIPLE 5: BE ADMINISTRATIVELY FEASIBLE, FAST, AND TRANSPARENT

Federal transmission pricing should be administratively feasible, fast, and transparent. Put even more simply, "[t]ransmission pricing should be practical," as FERC emphasized in its 1994 Transmission Pricing Policy Statement. Under this principle, "administratively feasible" means the rules can be implemented easily by industry and FERC (e.g., upending longstanding practices and/or court precedent may cause years-long litigation delays). "Fast" means the rules can be implemented in the near term and can afford customers timely interconnection to the grid (e.g., leveraging existing best practices can be implemented more quickly as can more surgical tweaks). Lastly, "transparent" means customers can understand how transmission cost allocation and cost recovery at the wholesale level works (e.g., clear definitions of services and pricing, clearly articulated cost allocation methods and factors, simple formulas, robust documentation requirements).

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86 *See* Volume 1 Report, Section III (describing core FERC transmission pricing principles and providing citations to FERC and court precedent around each principle); *see also Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, at 476-77 (7th Cir. 2009).

87 *Id.,* Section IV (providing multiple examples of where FERC transmission pricing policy has evolved to avoid cross-subsidies between new and existing transmission service customers).

IV. FEDERAL TRANSMISSION PRICING OPTIONS

FERC has broad ratemaking authority[88] and has changed course in the past by acknowledging the change and explaining, in detail (with evidence), the reason for the change.[89] In its 1994 Transmission Pricing Policy Statement, FERC explained the need for a more flexible transmission pricing policy to: provide flexibility to accommodate the evolving needs of both transmission owners and customers; encourage efficient investments in and use of the transmission system; allow for regional variation that may justify differences in transmission pricing; and ensure comparable access to efficiently priced transmission service.[90] Like then, FERC is now faced with changes in the electric system that may similarly warrant a refresh around federal transmission pricing.

There are two paths for FERC to change federal transmission pricing in the current era of high load growth and rising electricity bills. FERC can proactively require its own changes to regional or utility tariffs under Federal Power Act (FPA) section 206. Or FERC can reactively approve "bottom-up" proposals from regions or utilities under FPA section 205. In general, all the options we present below would be more administratively feasible and fast if implemented via a bottom-up proposal to FERC as opposed to FERC establishing a standard requirement, which generally requires a rulemaking.

The options presented below generally assume a traditional federal-state divide, with FERC rules applying to LSEs as wholesale customers taking unbundled transmission service on behalf of retail load, including large loads.[91] But if the approach were to apply the FERC rules directly to large loads, where the options discuss cost allocation to and recovery from LSEs, large loads could replace the role of LSEs for purposes of federal transmission pricing.

While Congress could weigh in on federal-state jurisdictional boundaries or take direct action on cost allocation to large loads, this report focuses on regulatory rather than legislative options.

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88 *See Duquesne Light Co. v. Barasch*, 488 U.S. 299, at 316 (1998); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, at 602 (1944); *Colo. Interstate Gas Co. v. Fed. Power Comm'n*, 324 U.S. 581, at 589 (1945).

89 *See FCC v. Fox Television Stations*, 556 U.S. 502 (2009); *Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10 (D.C. Cir. 2021) (upholding FERC's departure from prior precedent regarding cost allocation for grid upgrades in PJM).

90 *See* 1994 Transmission Pricing Policy Statement ("The electric utility industry of today is very different from the electric utility industry that existed only 20 years ago and even five years ago. Just as we today change our policies to reflect recent changes, we must remain flexible if we are to respond to future changes.").

91 As discussed in the Volume 1 Report, FERC has, to date, declined to generically assert jurisdiction over the transmission used for bundled retail sales. As a result, transmission pricing for most—but not all—of the FERC-jurisdictional transmission costs outside RTOs is determined at the state level. The options in this report do not assume a change from this status quo. While largely applicable in RTOs, in non-RTO regions the options apply most authoritatively to rates that transmission providers would charge wholesale customers as part of unbundled transmission sales. That said, the concepts could be leveraged to establish similar rules for bundled sales as well. *See* Volume 1 Report at 8 & n.15, 38-40.

To understand the options, it is important to understand the different types of transmission at issue.

- **Local Transmission:** Transmission facilities that are planned, built, and owned by monopoly transmission owners to meet needs triggered by the transmission owner's local planning criteria and located entirely within their franchise service territories (the service territories define what is within the scope of "local"). Local transmission upgrades are commonly triggered by new load being added to a transmission owner's system, particularly if a longer-term transmission planning process, such as is conducted at the regional level, does not adequately anticipate and plan for the new load. In the generator interconnection context, these upgrades are called "network upgrades,"[92] but in the load interconnection context, the same upgrades are considered "local transmission." A significant amount of transmission investment today is locally planned and zonally allocated.[93]
- **Regional transmission:** Transmission planned through a FERC-approved regional transmission planning process that identifies regional transmission needs and selects solutions to those needs that are more efficient or cost-effective than each individual transmission owner planning and building transmission in its own service territory to address local needs. The costs of regional transmission projects are allocated across a broader transmission planning region using a FERC-approved regional cost allocation method.[94]

Categories of Federal Transmission Pricing Options

The federal transmission pricing options discussed in this report can be placed in four categories:

1. Options to address timing concerns, both on the front end (concerns about costs beginning to flow to existing customers before new large loads materialize and begin paying) and back end (concerns about stranded costs if large loads fail to materialize or leave the system prior to fully covering costs incurred to provide them with service);
2. Options to establish transmission charges for costs allocated to local zones, including upgrades triggered by new large loads interconnecting;
3. Options to adjust regional cost allocation mechanisms to determine where costs are allocated across a region; and
4. More holistic and innovative approaches to planning and allocating the costs of transmission needed to meet the needs of both new supply and new demand.

92 *See* FERC *Pro Forma* Large Generator Interconnection Procedures, § 1 (Definitions) ("Network Upgrades shall mean the additions, modifications, and upgrades to Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to Transmission Provider's Transmission System.").

93 *See* Volume 1 Report at 28-29.

94 *Id.* at 23-26, 29-34 (describing FERC's regional transmission planning and cost allocation rules and common regional cost allocation methods).

Most of the options to reform federal transmission pricing discussed in this report require some definition of "large loads," at least to identify the degree to which LSEs would be subject to new rules envisioned by the options. This report does not seek to establish such a definition. Large loads could be defined according to specific physical characteristics, such as direct interconnection with the transmission system, high contract demand (e.g., over 100 MW), high load factor (e.g., 80% or higher), or loads that trigger transmission upgrades over a specific dollar threshold. Or FERC could rely on criteria established by NERC as part of its ongoing efforts related to ensuring reliability with new large loads.[95] It may be appropriate for regions and/or state regulators to propose threshold criteria based on factual differences in their specific areas and power systems. In addition, the appropriate definition may depend on the option pursued and its overarching aim.

The options broadly reflect many of the themes that have appeared in the Large Load ANOPR proceeding at FERC.[96] The list is not meant to be exhaustive but rather a sampling of options and their pros and cons. We believe the next step is further discourse and development of the details of reforms to be pursued to address the unique circumstances in different areas of the country, recognizing that every option has upsides and downsides and a combination of options may be needed to achieve the ultimate aims of reform.

95 NERC defines "Large Load" as "[a]ny commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the [Bulk Power System] due to its demand, operational characteristics, or other factors." NERC, *Reliability Guideline: Risk Mitigation for Emerging Large Loads* (May 2026), https://www.nerc.com/globalassets/our-work/guidelines/reliability/RG_Risk-Mitigation-For-Emerging-Large-Loads.pdf.

96 The Large Load ANOPR suggests FERC adopt rules to: limit the need for network upgrades to facilitate interconnections; standardize entry and exit requirements to deter speculation (e.g., study deposits, withdrawal penalties, financial commitments); and ensure large loads pay for 100% of the network upgrades they are assigned, possibly with crediting back. FERC indicated in April that it had received over 3,500 pages of public comments in the docket; more have been filed since then.

Snapshot: Federal Transmission Pricing Options in the Era of High Load Growth

TIMING OF FUNDING:

- Option 1: LSE Service and Financial Security Commitments
- Option 2: LSE Upfront Funding and Reimbursement

LOCAL TRANSMISSION COST RECOVERY:

- Option 3: Mandatory "Higher of" Pricing
- Option 4: New Form of "And" Pricing
- Option 5: Large Load-Driven Local Transmission Transparency

REGIONAL TRANSMISSION COST ALLOCATION:

- Option 6: Targeted Cost Allocation of Large Load-Driven Regional Transmission Costs
- Option 7: Transparency of Large Load-Driven Regional Transmission Costs
- Option 8: Widespread Load Ratio Share Cost Allocation
    - Sub-Option 8A: Historic Coincident Peak-Based Allocation Factor
    - Sub-Option 8B: Forecasted Coincident Peak-Based Allocation Factor
    - Sub-Option 8C: Energy Usage-Based Allocation Factor
    - Sub-Option 8D: Incremental Load Growth-Based Allocation Factor
- Option 9: Voluntary Supplement and Expedited Service

INNOVATIVE APPROACHES:

- Option 10: Planning-Led Zonal Capacity Reservation Model
- Option 11: Open Season Model for Large Load Interconnection
- Option 12: Consolidated Load and Generation Integration Framework

TIMING OF FUNDING

The first two options are focused on the timing aspects of federal transmission pricing as applied to local and regional transmission costs. These options could be adopted for a subset of transmission costs associated with large loads or be configured to cover all transmission costs. They are not mutually exclusive and could be combined with later options as well.

The Volume 1 Report (Section VII) explains the nuances of when cost recovery in rates paid by customers begins, how long it lasts, and the relative length of customer commitments. In the large loads context, this raises both near-term timing issues (transmission costs are incurred before large loads come online and begin to contribute to the costs) and longer-term concerns (risk of stranded costs if large loads fail to materialize or prior to fully covering costs incurred to provide them with service). Options 1 and 2 both address near-term timing and back-end stranded cost risks but differ in the mechanism they use. Option 1 focuses on commitments and credit support that help ensure large loads remain responsible for costs and risks over time, including if they delay, downsize, or leave the system. Option 2 focuses on upfront funding of identified transmission costs, paired with a tariff-defined reimbursement or crediting mechanism.

Another category of costs to note are those costs to transmission owners of the actual interconnection process, incurred before an actual service agreement is signed. These are primarily study costs, including the costs of early engineering designs for required upgrades. They are typically covered under FERC rules for generator interconnection by interconnection customers via study deposits, specific study charges, reimbursement provisions, and security postings tied to the studies. On the load side, FERC does not currently have any requirements related to these costs, but many utilities have established upfront funding and deposit requirements for large load customers at the retail level.

OPTION 1: LSE SERVICE AND FINANCIAL SECURITY COMMITMENTS

This option requires long-term service commitments, collateral, or other financial guarantees from LSEs serving large loads. Depending on the implementation, this option could address both near-term and longer-term timing concerns, though it is primarily aimed at addressing the risk of stranded costs. LSEs serving a defined set of large loads would be required to make meaningful service and financial security commitments as a condition of taking FERC-jurisdictional transmission service for those large loads. In regional transmission organizations (RTOs),[97] these provisions could limit assignment of identified transmission costs to other LSEs, mitigating the exposure of those LSEs to stranded costs.

This option aligns with the fourth principle outlined in the Large Load ANOPR, which proposes that, "[L]oad and hybrid facilities should be subject to standardized study deposits, readiness requirements, and withdrawal penalties. These provisions deter speculative projects and provide transmission providers with more useful information to more accurately forecast demand on their systems."[98]

This option borrows concepts from retail large load tariffs to be applied at the FERC level. Thus, it could work in tandem with retail rules that pass LSE financial obligations determined by FERC onto the large loads. State retail tariffs would need to incorporate FERC's definition of large loads for purposes of transferring the effect of those provisions to the appropriate customers.

These requirements could take a variety of forms, including long-term service commitments, minimum revenue or minimum payment obligations, security posting requirements, milestone-based development obligations, or other forms of collateral. The form may depend on the type of costs (see above discussion of interconnection study costs, local transmission costs, and regional transmission costs) or risk at issue, including the risk that costs are incurred based on a large load that later fails to materialize or remain on the system. The requirements may also be paired, e.g., a long-term commitment may be backed by a credit requirement or security posting, or a minimum revenue obligation may be combined with milestone requirements and exit charges. We treat these tools as a single option family.

Unlike Option 2 below, this option would not necessarily require the LSE to provide upfront funding for identified

97 Although there are independent system operators (ISOs) that are not RTOs, this report uses RTOs for simplicity, unless specific reference to ISOs is needed.

98 *See* Large Load ANOPR, P 21.

transmission upgrades; rather, the LSE would make commitments designed to ensure that costs and risks associated with serving the large load are not shifted to other customers if the load delays, downsizes, or leaves the system.

Principle 1: Ensure opportunity for appropriate cost recovery. Commitments, collateral, or other financial guarantees can increase certainty that the LSE hosting a large load bears responsibility for the transmission investments needed to serve it. Actual financial recovery under the commitment or security requirement would occur only if the LSE does not meet the applicable service or payment commitment, or if collateral or financial guarantees are otherwise triggered. Any amounts recovered through those mechanisms would offset costs that would otherwise be recovered through embedded cost rates, avoiding the over-recovery risk associated with charging both embedded and incremental cost rates for the same transmission service.

Principle 2: Safeguard non-discriminatory open access. Singling out load growth driven by specific customers (i.e., large loads) for which LSEs must make financial commitments and meet other requirements raises discrimination concerns that a court could find violates the FPA. In addition, financial commitment requirements that are passed through to LSE customers may be manageable for hyperscale data center companies and other highly capitalized firms, but too blunt or extensive for smaller developers, newer entrants, and others operating with different balance-sheet structures.[99]

Principle 3: Promote economic efficiency on the electric system. These requirements could improve load forecasting accuracy, especially in the near term, by improving certainty around committed large loads, resulting in improved system planning.[100] These requirements could also send price signals to promote efficient load configurations, flexibility, and location to the extent the requirements are tied to incremental costs of serving the large loads (e.g., by defining the category of large loads based on a specific dollar threshold of triggered upgrades) and the large loads feel the impact via state-regulated rate design (i.e. LSEs flow costs/commitments to large loads).

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. Depending on the structure, these requirements could address timing concerns, providing insurance against uncertainty and unfair cost shifts. On the front end, upfront financial commitments could offset costs that flow into rates before large loads fully materialize (e.g., by requiring payments or security as transmission costs are incurred in lieu of, or as an offset to, early recovery from other customers through a Construction Work in Progress (CWIP) incentive) or delay inclusion of costs in rates by derisking investments (encouraging use of Allowance for Funds Used During Construction (AFUDC) rather than CWIP).[101] On the back end, long-term commitments and collateral requirements could reduce stranded cost risk. In addition, establishing these requirements at the federal level could avoid unfair cost shifting that occurs when one state imposes requirements of this nature but another state in the same region does not, such that customers in one state are protected against stranded costs allocated across the region but customers in another state are not.[102] Depending on design, these requirements

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99 Energy and Environmental Economics, *Balancing Risk and Growth: Best Practices for Utility Credit and Collateral for Large Load Projects*, at 1, 10, 14 (July 2025), https://www.ethree.com/wp-content/uploads/2025/08/E3_Utility-Credit-and-Collateral-for-Large-Load_Whitepaper.pdf; LBNL Electricity Rate Designs Report at 6, 9.

100 *See* ESIG Load Forecasting Report at 40-41.

101 *See* Volume 1 Report at 45-46 (describing AFUDC and the CWIP incentive at FERC).

102 *See, e.g.*, Maryland Office of People's Counsel, Complaint, Docket No. EL26-63-000 (filed May 7, 2026) (alleging PJM's regional cost allocation rules result in unfair costs imposed on Maryland customers).

could also help protect existing customers by ensuring that LSEs serving large loads contribute to the embedded fixed costs of the existing system over time, rather than paying only incremental costs or providing security that is drawn only upon default or early exit.

Conversely, this option raises fairness concerns. If the service commitments are short relative to the transmission asset lives,[103] they may allow for unfair cost shifts, especially if costs are allocated on an embedded cost basis. Similarly, long-term revenue guarantees calculated on an embedded rather than incremental cost basis do not necessarily eliminate risk of cost shifting.[104] There is also the risk of unfairness depending on how closely the federal and state cost allocation and cost recovery rules are aligned since this would apply to LSEs and not large loads. Finally, the financial commitments under this option should be carefully calibrated to actual risk and designed to avoid unnecessarily deterring investment or foreclosing viable projects.[105]

Principle 5: Be administratively feasible, fast, and transparent. To the extent the requirements are based on specified cost categories or risk exposure rather than a full "but for" incremental-cost analysis for each large load, implementation may be relatively simpler than the incremental cost-based pricing approaches discussed in the text box below. Similarly, financial requirements that are not tied to current credit ratings are likely to be easier to implement because they do not need to consider the impact of credit ratings shifting during the life of the commitment. However, these design choices, while supportive of administrative feasibility, may reduce the efficacy of this option in mitigating cost-shift risk. In any case, FERC would need to justify singling out service to specific large loads for additional requirements, and such distinguishing would likely face challenge.

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103 Ten- to 20-year service commitments are emerging as the norm in state-level large load tariffs, but transmission assets commonly have 40- to 50-year lives. *See* Smart Electric Power Alliance & NC Clean Energy Technology Center, *Database of Emerging Large-Load Tariffs (DELTa)*, https://sepapower.org/large-load-tariffs-database/; RMI, *High Voltage, High Rewards: Appendix C*, at 6 (Feb. 2025) (using a 40-year financial life for transmission projects as a conservative assumption and noting that some utilities use a 55-year life for transmission lines).

104 *See, e.g.*, *Commonwealth Edison Co.*, 194 FERC ¶ 61,183 (2026) (Chang, Comm'r, concurring) (raising similar concerns about a Transmission Security Agreement filed at FERC).

105 *See* Energy and Environmental Economics, *Balancing Risk and Growth: Best Practices for Utility Credit and Collateral for Large Load Projects,* at 10 (July 2025), https://www.ethree.com/wp-content/uploads/2025/08/E3_Utility-Credit-and-Collateral-for-Large-Load_Whitepaper.pdf.

Pitfalls of Incremental Cost-Based Pricing

- It is challenging to determine the incremental costs to serve new transmission service customers (to make a "but for" determination). It requires a power flow study for every service request as well as robust documentation for filing at FERC. Incremental pricing outcomes can vary substantially depending on the modeling assumptions used, which may be reasonably contested. Because the modeling assumptions can be so important, it is often impossible for customers to estimate what the cost will be to interconnect at a given location and facility size. This lack of transparency makes it hard to offer efficient price signals.
- Nearby affected systems may also need to study transmission impacts, creating additional schedule and cost uncertainty.
- Additional service requests or request cancellations in nearby areas can trigger the need for restudies before the rate is set, delaying the process further.
- Similar pricing approaches have been applied to generator interconnection requests (e.g., participant funding in RTOs), which have contributed to years-long interconnection delays, repeated restudies, cost uncertainty, and disputes over technical study assumptions and upgrade cost assignments.[105]

OPTION 2: LSE UPFRONT FUNDING AND REIMBURSEMENT

Under this option, LSEs would be required to provide upfront payment, on behalf of a defined set of large loads, for specified transmission costs driven by those large loads, with reimbursement. This option addresses the timing mismatch between when transmission costs are incurred and begin to flow in FERC-regulated rates and when large loads materialize and begin contributing to those costs through the LSE (by paying state-regulated retail rates). The upfront payment could include interconnection study costs, local transmission costs (what are called network upgrades in the generator interconnection context at FERC), and/or regional transmission costs. Like Option 1, this option would be designed to work with retail rules that allow LSEs to pass the requirements at the federal level onto the large loads at the retail level. This option would similarly require a clear definition of large loads that is aligned at the federal and state levels.

This option could align with the eighth principle outlined in the Large Load ANOPR, which proposes that, "[L]oad and hybrid facilities should be responsible for 100% of the network upgrades that they are assigned through the interconnection studies. We seek comment on whether such costs should be offset through a crediting mechanism and, if so, over how many years."[107]

106 *See, e.g.*, Grid Strategies & Brattle Group, *Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid* (Aug. 2024), https://gridstrategiesllc.com/wp-content/uploads/Exec-Sum-and-Report-Unlocking-Americas-Energy-How-to-Efficiently-Connect-New-Generation-to-the-Grid.pdf; Grid Strategies & Brattle Group, *Generator Interconnection Scorecard* (Feb. 2024), https://gridstrategiesllc.com/wp-content/uploads/2024/03/AEI-2024-Generation-Interconnection-Scorecard.pdf; Grid Strategies, *Resolving Interconnection Queue Logjams: Lessons for CAISO from the U.S. and Abroad* (Oct. 2021), https://gridstrategiesllc.com/wp-content/uploads/2024/05/resolving-interconnection-queue-logjams-lessons-for-caiso-from-the-us-and-abroad-1.pdf.

107 Large Load ANOPR, at P 25.

This option would adapt FERC-approved generator interconnection network upgrade upfront funding and reimbursement rules to the large load context. The LSE serving a large load would be treated similarly to a generation interconnection customer. The LSE would provide upfront funding for specified transmission costs, just as generators provide for network upgrades under FERC's *pro forma* large generator interconnection procedures (unless the transmission provider elects to provide the funding itself).

The LSE would then be reimbursed through a tariff-defined crediting or repayment mechanism. Under FERC's default crediting approach used in non-RTO regions for interconnecting generators, the LSE would receive credits against embedded cost-based transmission charges that include the funded costs, with any remaining unreimbursed balance repaid after a set period of years.[108] The *pro forma* large generator interconnection procedures provide for a balloon payment after 20 years, but there are FERC-approved mechanisms for faster reimbursement. For example, under the "participant financing" approach used by the California Independent System Operator (CAISO) for interconnecting generators, reimbursement occurs over no more than five years.[109]

Principle 1: Ensure opportunity for appropriate cost recovery. By requiring upfront funding for transmission costs as well as ongoing embedded cost-based transmission charges, this approach ensures that the host LSE is responsible for cost recovery of specified transmission costs. By requiring reimbursement, this approach avoids over-recovery risks present with "and" pricing (charging both embedded and incremental costs of the same transmission service on the same system).[110] Including the transmission costs for which the LSE provides upfront payment in the transmission owner's embedded cost rate, as appropriate per existing transmission cost recovery rules, ensures a return on and of the investment.

Principle 2: Safeguard non-discriminatory open access. Same as Option 1.

Principle 3: Promote economic efficiency on the electric system. Potentially stronger efficiency signals for load configurations, flexibility, and location than Option 1 if the LSE's upfront funding obligation is passed through to the large load customer, who would then need to finance that obligation over the refund period at its own cost of capital, rather than at the LSE's cost of capital.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. Similar to Option 1, upfront funding requirements could address timing concerns on the front end if funding begins when costs are incurred (rather than at the start of service to the large loads) as well as on the back end (if loads do not meet minimum expectations). The LSE's reimbursement for the upfront funding would depend on its state-regulated recourse to recover from large loads. Another consideration is that the costs for which the LSE provides upfront funding are typically only included in the embedded cost rate as the transmission provider reimburses them (and thus incurs the costs itself). This can slow the growth of rate base over time, mitigating near-term rate impacts on all customers that pay the embedded cost rate.

This option also leverages the opportunity for new large loads to contribute to the fixed system costs of the existing system by charging an embedded cost rate to the LSE serving those loads on an ongoing basis. However, the extent of that contribution depends on the design of the upfront funding and reimbursement

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108 *See* Volume 1 Report at 20-22, 38-39 (describing FERC transmission pricing for interconnecting generators, both historically and current approaches).

109 Cal. Indep. Sys. Operator, CAISO eTariff, App. D, § 14.3.2.1 (12.0.0).

110 For more nuance around the "and" pricing that FERC has and has not allowed, see Volume 1 Report at 41 (Text Box: What is "And" Pricing and Does FERC Allow It? Mixed Signals).

mechanism. If credits fully offset the LSE's embedded cost-based transmission charges during the reimbursement period, the LSE may not contribute to fixed system costs on behalf of the large loads during that period. Partial crediting, such as limiting credits to 75% of the embedded cost-based charge, could mitigate that concern by ensuring that front-end funding does not excuse an excessive share of the LSE's ongoing contribution to embedded transmission costs.[111] Separately, shorter reimbursement timelines, such as those used in CAISO's five-year participant financing model, would reduce the duration of the crediting period but may be less effective at protecting against back-end cost-shift risk if the large load does not remain on the system long enough to support cost recovery.[112] As with Option 1, this option also depends on federal-state alignment to ensure that obligations assigned to the LSE are passed through to the large loads driving the costs.

Principle 5: Be administratively feasible, fast, and transparent. Because this option relies on existing FERC-approved mechanisms for interconnecting generators as an analogy, it would be easier to implement than an entirely new approach. However, those mechanisms should be understood as analogues rather than plug-and-play rules. As they were developed for generator interconnection customers, a load-side adaptation would require tariff design around how to specify transmission costs, including identifying relevant large loads. It would also require new practices to coordinate reimbursement with embedded cost rates. Crucially, it would need to be designed to encourage and facilitate state-jurisdictional retail large load tariffs or contracts to assign the relevant costs and obligations to the large loads in an enforceable manner. Depending on how FERC specifies which transmission costs are funded upfront, this option could either suffer from the pitfalls of incremental cost-based pricing (see text box above) or fall short of other LSEs' expectations for protection of their consumers from transmission cost impacts. Same as Option 1, this option requires FERC to justify which large loads are singled out and would be more administratively feasible as a bottom-up proposal to FERC (i.e., proposed by a transmission provider) rather than a generic FERC-imposed rule.

LOCAL TRANSMISSION COST RECOVERY

These three options are focused on FERC-approved transmission costs allocated to local transmission zones. This includes transmission triggered by new large loads interconnecting, which falls into the local transmission category and is generally allocated to the transmission owner's local zone and recovered from customers in that zone on an embedded cost basis.[113] It also includes existing transmission facilities already included in the zonal embedded cost rate. It is unlikely to include regional transmission costs, at least within RTOs that have separate charges for transmission customers to cover regional costs.

Options 3 (mandatory "higher of" pricing) and 4 (new form of "and" pricing) are mutually exclusive. Option 5 (large-load driven local transmission transparency) could be combined with the other options.

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111 California Public Utilities Commission, Resolution E-5439, *Pacific Gas and Electric Company Advice Letter 7635-E*, at 21-22, 25-26 (Jan. 15, 2026) (limiting annual refunds for Microsoft's upfront energization costs to 75% of PG&E's annual net revenues from Microsoft, based on the rationale that the standard refund approach could return upfront costs before PG&E's net revenues equaled those costs, and finding that the modified approach reduces ratepayer risk).

112 Cal. Indep. Sys. Operator, CAISO eTariff, App. D, § 14.3.2.1 (12.0.0) (providing that reimbursement of amounts financed by an interconnection customer under CAISO's participant financing rules occurs over a period not to exceed five years).

113 *See* Volume 1 Report at 28-29 (local transmission cost allocation), 35-41 (how costs allocated at the wholesale level are recovered from wholesale customers).

Large Load Rate Class at the Federal Level

When discussing definitions of large loads for purposes of any federal transmission pricing options, some have referred to a "large load rate class." However, it would not be simple for FERC to establish a retail-style rate class for purposes of transmission cost allocation and cost recovery. The term "rate class" is more naturally associated with retail ratemaking, where regulators allocate costs among multiple end-use customer classes. Traditionally, most retail customer load has been assigned to residential, commercial, and industrial rate classes, but some states are creating rate classes for large loads or specifically for data centers.[113]

Creating rate classes at the state level is distinct from the FERC context, where FERC typically allocates transmission costs among wholesale customers based on their total load and not based on other distinguishing factors.[114] In other words, FERC has one rate class for customers taking the same transmission service.

Rate class-based cost allocation generally requires more granular assignment of customers among several rate classes. If FERC created a large load rate class, it is unclear what other classes FERC would assign the remaining costs. A further complication is that most large loads do not take transmission service directly under a FERC-approved transmission tariff.

OPTION 3: MANDATORY "HIGHER OF" PRICING

Under this option, transmission providers would be required to charge LSEs serving a defined set of large loads the "higher of" the embedded or incremental cost rate.[116] FERC's current policy is to allow the option for transmission providers to charge LSEs the "higher of" the embedded or incremental cost rate, but transmission providers infrequently elect the incremental cost rate.[117] This option would remove discretion and mandate that the higher rate be charged to an LSE serving a large load that fits into a defined category.

The theory underlying this option is that, to the extent defined large loads have materially different impacts on local transmission costs than other load served by an LSE, charging the LSE the higher cost-based rate for serving those large loads would better align cost responsibility with cost causation and reduce the risk of unfair cost shifts to other transmission customers in the local zone. In reality, if there is only one LSE in a transmission provider's zone, the option only addresses the risk of unfair cost shifts to the extent it is aligned with state-level rules that pass the costs associated with the higher rate paid for serving large loads onto those large loads.

114 *Id.*, Section VI (describing how FERC-approved transmission costs flow to retail customers).

115 *Id.*, Section V (explaining how FERC-approved transmission costs are allocated at the wholesale level).

116 Embedded cost-based transmission pricing refers to the traditional cost-of-service revenue requirement approach. Embedded costs are the rolled-in, total cost of capital investments in facilities that are part of the utility's integrated transmission system. Incremental cost-based transmission pricing refers to the pricing approach whereby rates are based on the incremental expansion costs needed to serve a new customer. Incremental costs are often defined as the costs that would not be incurred "but for" the customer's request for service, also known as marginal costs.

117 *See* Volume 1 Report at 14-16 (describing origins of "higher of" policy), 38-40 (explaining limited circumstances under which incremental cost rates have been used).

Principle 1: Ensure opportunity for appropriate cost recovery. On the one hand, transmission providers would be required to charge the "higher of" two potential rates, both of which are designed to ensure cost recovery. On the other hand, where there is no long-term service commitment, an incremental cost rate for a short period of time could result in stranded costs unless the transmission provider is allowed to reallocate those costs.

Principle 2: Safeguard non-discriminatory open access. By removing the option for transmission providers to choose whether to charge embedded or incremental cost rates regardless of which is higher, this option would remove the potential for discrimination where a non-independent transmission provider has incentive to favor affiliated LSEs serving large loads over non-affiliated competitors (such as competitive retail providers or municipal or cooperative utilities). On the other hand, like Options 1 and 2, singling out specific customers (i.e., large loads) for which LSEs must pay the "higher of" rate raises discrimination concerns that a court could find violate the FPA (e.g., delays caused by determining the "higher of" rate for only a subset of customers could hinder open access).

Principle 3: Promote economic efficiency on the electric system. This option could send price signals to promote efficient load configurations, flexibility, and location by exposing LSEs serving a defined set of large loads to the "higher of" rate for serving the large loads, but only to the extent that federal and state cost allocation mechanisms are aligned sufficiently for those costs to be flowed directly to large loads (such as through a state-regulated large load tariff).

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. Requiring "higher of" rates be used is aimed at ensuring that LSEs serving defined large loads cover the cost of the impact of those large loads on the system and do not shift costs to other LSEs (and end-use customers). While this option would promote fairness in theory, there are two key factors critical to its success: (1) the ultimate cost allocation to end-use customers, including large loads, remains with the states, so fairness depends on close federal-state alignment; and (2) pure incremental cost rates can be misaligned with cost causation and beneficiary pays principles depending on the nature and extent of the upgrades triggered to serve the new large load and the length of the service commitment (see text box below). In addition, incremental cost rates fail to leverage the opportunity of new large loads to spread fixed system costs across a larger pool of customers.

Principle 5: Be administratively feasible, fast, and transparent. This option would likely be difficult for industry to administer, raising the challenges with incremental cost-based pricing identified earlier (see text box above).[118] That said, this shortcoming could be reduced by narrowly defining the large loads to which the option applies and this option would build on existing practices for establishing embedded and incremental cost rates as opposed to an entirely new approach.

118 In response to the Large Load ANOPR at FERC, transmission owners have largely advocated for continue use of embedded cost rates. *See* WIRES, Supplemental Comments, Docket No. RM26-4-000, at 3-5 (filed Mar. 30, 2026); Exelon Corp., Initial Comments, Docket No. RM26-4-000, at 6-10 (filed Nov. 21, 2025).

Pure Incremental Cost-Based Pricing Risks Unfair Cost Shifts and Misses Opportunities to Spread Fixed Costs

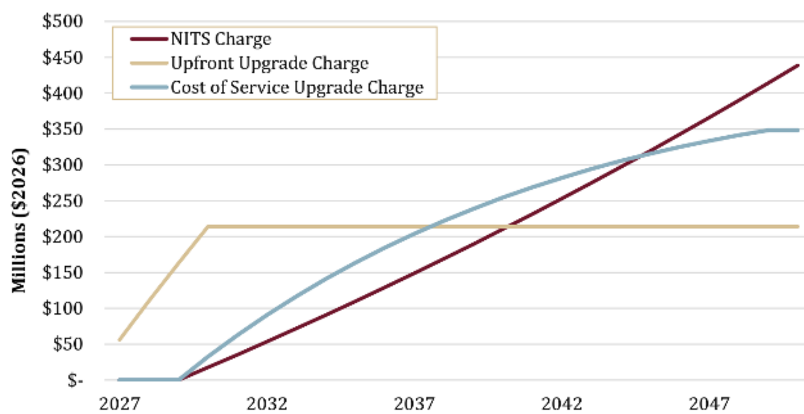
While directly assigning marginal costs is often discussed as a proxy for customers paying their "fair share," the reality is more complicated. Pure incremental cost-based pricing—meaning the charge is based exclusively on the marginal costs triggered by the new customer and no embedded system costs—may fail to reflect that the benefits of transmission often extend beyond individual customers that trigger the need. FERC and courts have repeatedly found that high-voltage transmission "afford[s] two different kinds of benefits—local benefits that accrue primarily to utilities close to the project at issue, and regional benefits that accrue throughout the grid."[119] Thus, charging only individual customers for transmission that benefits other customers may be misaligned with cost causation and beneficiary pays principles.

Pure incremental cost-based pricing risks unfair cost shifts in two directions: (1) unfairly charging 100% of transmission costs to individual customers that pay an incremental cost rate while giving other customers a "free ride" despite benefitting from the new transmission; and (2) unfairly charging other customers for existing system costs (embedded cost rate) while giving individual customers that pay an incremental cost rate a "free ride" despite benefitting from the existing system.[120] This notably forfeits the opportunity to leverage new large loads to spread fixed system costs across a larger pool of customers.

For instance, if large loads pay only an incremental cost rate and do not also contribute to existing system costs, their total contribution may, over time, fall below the costs of providing them service. In that case, the costs the transmission provider incurs, some of which may be caused by the large loads, would be recovered from other customers through embedded cost rates, risking unfair cost shifts.[121]

This concern is illustrated using a hypothetical 200 MW large load customer. The figure to the right from a Concentric Energy Advisors report compares the embedded cost rate for network transmission service with two incremental cost rates and finds that cumulative payments using both incremental cost rates eventually fall below cumulative payments using the embedded cost rate.

Cumulative Cost Contributions for Hypothetical Customer for Three Scenarios (2027-2050)[122]



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119 *Long Island Power Auth. v. FERC*, 27 F.4th 705, at 709 (D.C. Cir. 2022); *see also* Order No. 2003, at PP 21, 65; Order No. 2003-A, at P 585.

120 *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,217, at PP 205-206, 224-226 (2025).

121 *Commonwealth Edison Co.*, 194 FERC ¶ 61,183 (2026) (Chang, Comm'r, concurring).

122 Concentric Energy Advisors, *The Risks of Cost Shifts in Serving Large Loads Under a Framework with Direct Allocation of Transmission Costs*, at 9 (Mar. 30, 2026), https://ceadvisors.com/wp-content/uploads/2026/03/CEA_Large-Load-Cost-Shift-Report_vF.pdf.

OPTION 4: NEW FORM OF "AND" PRICING

Under this option, transmission providers would be required to charge LSEs serving a defined set of large loads for both some portion of incremental costs and an embedded cost rate (excluding from embedded costs any costs directly assigned to the LSE). The incremental costs piece could range from full incremental costs to a subset;[123] may be based on a threshold (e.g., "and" pricing approach applies only where incremental costs exceed $10 million) or percentage (e.g., only 25% of incremental costs are directly assigned); and could be paid up front or over time (without reimbursement).

This option envisions a form of "and" pricing for LSEs serving defined large loads. FERC has, at least arguably, remained consistent with its general prohibition on what it calls "corporate 'and' pricing" where a non-independent transmission provider is involved, though the stated rationale may differ across FERC orders.[124] Essentially, "and" pricing is charging both the embedded costs and the incremental costs of the same transmission service on the same system. FERC's prohibition on "corporate 'and' pricing" appears to mainly be concerned about undue discrimination and unfair cost shifting with "and" pricing and thus FERC has allowed its use in RTOs where the transmission provider is independent, and all transmission customers are subject to the "and" pricing.[125]

Principle 1: Ensure opportunity for appropriate cost recovery. While this option ensures opportunity for cost recovery by transmission providers, it also risks over-recovery by allowing transmission providers to charge both for incremental and embedded costs. Careful parsing of costs may be required to guard against double recovery of the same costs.

Principle 2: Safeguard non-discriminatory open access. This option is a form of "and" pricing. FERC's general prohibition on "and" pricing outside RTOs is focused on preventing undue discrimination. For example, there is some potential for discrimination where a non-independent transmission provider has incentive to favor affiliated LSEs serving large loads by charging "and" prices only to unaffiliated LSEs (such as competitive retail providers, municipal utilities, or cooperatives). To address this concern, discretion to use "and" pricing could be limited or cabined. The context is distinct from generator interconnection, where non-independent transmission providers can exercise vertical market power and favor their own generation and discriminate against competitors. It is unclear whether FERC would find this application of "and" pricing allowable, but the option likely could be developed in a way to avoid FERC's concerns. Nevertheless, like earlier options, singling out costs associated with serving specific customers (i.e., large loads) for which LSEs must pay an "and" price raises discrimination concerns that a court could find violate the FPA.

Principle 3: Promote economic efficiency on the electric system. This option could send price signals to promote efficient load configurations, flexibility, and location by exposing LSEs serving a defined set of large

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123 Note that customer-specific, "non-grid" facilities, such as radial lines from the network to the large load, may already be directly assigned under existing policy. *See* Volume 1 Report at 39 (explaining FERC allows transmission providers to charge the "higher of" rate plus directly assignable, non-grid costs, which are facilities that FERC calls Interconnection Customer's Interconnection Facilities in the generator interconnection context).

124 *See* Volume 1 Report, Section IV (detailing FERC's statements on "and" pricing over time, from the 1994 Transmission Pricing Policy Statement to Order 2000-A, to Order 2003) and at 41 (Text Box: What is "And" Pricing and Does FERC Allow It? Mixed Signals).

125 *See, e.g.*, *Midwest Indep. Transmission Sys. Operator*, 84 FERC ¶ 61,231 (explaining that FERC's prohibition on "and" pricing "does not extend to regional rate proposals"), *order on reconsideration*, 85 FERC ¶ 61,250, *order on reh'g*, 85 FERC ¶ 61,372 (1998) (rejecting MISO "and" pricing proposal because it would not apply to "all transmission customers, including the owners").

loads to at least some of the incremental costs associated with serving them. The efficiency of this option is limited by the effectiveness of alignment between federal and state cost allocation mechanisms, such that costs would flow directly to large loads through a state-regulated large load tariff.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. This option could reduce the risk that LSEs serving defined large loads underpay for transmission service by blending embedded and incremental cost responsibility. The incremental cost component could reduce the risk that significant transmission costs triggered by large loads are rolled into embedded rates and shifted to other customers. The embedded cost component could avoid a separate concern associated with pure incremental cost-based pricing: allowing large loads to benefit from the existing transmission system without contributing to its fixed costs. This blended approach may result in better alignment with cost causation and beneficiary pays principles. One caution is that determining the "fair" allocation is likely to be subjective, and thus could depend on FERC and the states aligning on a single approach. Many potential variations could be considered. For example, there could be a form of dynamic "and" pricing whereby an LSE serving a large load begins taking service under an incremental cost rate and, over time, if the incremental cost rate becomes lower than the embedded cost rate, the embedded cost rate is charged thereafter (addressing the issue illustrated in the text box above).

Principle 5: Be administratively feasible, fast, and transparent. Similar challenges with incremental cost-based pricing as identified earlier but could be reduced by narrow definitions of the large loads and the incremental costs. Using narrow definitions could minimize technical burdens associated with identifying costs and regulatory disputes, but might weaken perceived fairness.

OPTION 5: LARGE LOAD-DRIVEN LOCAL TRANSMISSION TRANSPARENCY

Under this option, FERC would require transmission providers to identify the costs of local transmission driven by a defined set of large loads, with the goal of improving transparency. Transmission providers could provide this information in their formula rate informational filings or when they file new stated rate cases at FERC.[126] The costs could be reported on a project-specific basis (transmission providers do not currently provide project-specific information), as a bucket of costs with a "large load tag" in rate inputs, or in a new accounting category. While many states have begun assigning costs to large loads through retail large load tariffs, commenters and state regulators have emphasized that they often lack clear visibility into which transmission costs are driven by large loads and therefore it may be difficult to accurately allocate FERC-approved costs.[127] This option could address that concern for local transmission costs.

Note FERC could likely take this action under FPA section 301, unlike the other options, which would be implemented through FPA section 205 or 206.[128]

126 *See* Volume 1 Report, Section V (describing the process transmission providers that opt to use formula rates for transmission at FERC must follow).

127 Federal and State Current Issues Collaborative, Transcript, Docket No. AD24-7-000, at 17:11-14, 26:16-25 (Feb. 11, 2026) (statements of Kelsey Bagot, Chairman, Virginia State Corporation Commission, and Philip Bartlett, Chair, Maine Public Utilities Commission); Electricity Customer Alliance, Comments, Docket No. RM26-4-000, at 11 (filed Nov. 21, 2025).

128 Section 301 requires FERC-regulated utilities to maintain records, per FERC rules and regulations, as needed for FERC to perform its duties under the FPA, including information about transmission. This provision forms the basis for FERC's Uniform System of Accounts and other reporting requirements. 16 U.S.C. § 825.

Principle 1: Ensure opportunity for appropriate cost recovery. This option does not change the status quo around cost recovery.

Principle 2: Safeguard non-discriminatory open access. Requiring transmission providers to separately identify the local transmission projects and/or costs only associated with large loads while lumping all other costs into a single category raises concerns about whether FERC has adequate resources to verify whether identified costs are appropriately tagged and ensure no undue discrimination. Most likely, effective oversight would be left largely to the states, which may still lack sufficient information and resources to diligently oversee transmission providers' identification of costs and projects associated with serving defined large loads.

Principle 3: Promote economic efficiency on the electric system. Increased transparency should allow for better-informed transmission cost allocation and cost recovery policies at the federal and state levels around how to promote efficient transmission investments. That said, the transparency itself does not achieve economic efficiency. Rather, the transparency should lead to more fulsome consideration of more cost-effective and efficient regionally planned solutions, which would minimize more costly piecemeal local transmission solutions.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. Increased transparency would enable states to more accurately allocate costs to cost causers at the retail level and avoid unfair cost shifts. On the other hand, FERC would have to take further steps to align local transmission cost allocation or cost recovery at the federal level with state efforts. And again, transparency itself does not achieve fairness.

Principle 5: Be administratively feasible, fast, and transparent. This option is less likely to draw litigation on the requirement itself than other options in this report. If limited to sufficiently large loads (i.e., a small subset of new load on the transmission provider's system), it could be relatively easy to implement. On the other hand, distinguishing which local transmission projects and/or costs are sufficiently associated with large loads to warrant tagging could be cumbersome (especially if the category of large loads is broad) and contentious where it is expected that tagged costs would be allocated to large loads at the retail level.

Also, for project-specific transparency to be effective, this option would require transmission owner reporting to align with RTO records. At present, the same project may appear under different names, project numbers, or cost categories in transmission owner reporting and RTO project databases. Without common identifiers or a standardized crosswalk, states may struggle to determine which projects transmission owner-tagged costs correspond to, challenging administration of the option.

REGIONAL TRANSMISSION COST ALLOCATION

The following four options are focused on FERC-approved transmission costs associated with regional transmission only, meaning transmission planned and selected through a regional transmission planning process. To date, no regional project outside an RTO has ever been selected in a FERC-approved regional transmission planning process, so regional cost allocation has largely been a matter for RTO regions. The allocation of these costs to LSEs varies among the RTOs, as discussed in the Volume 1 Report, which includes a table describing each region's cost allocation methods.[129] The four options in this report focus on adjustments to these regional cost allocation methods consistent with our five principles. Like today, LSEs would then allocate costs among retail customers, including new large loads, according to state-regulated retail rate design.

129 *See* Volume 1 Report at 26-34.

Options 6 (targeted cost allocation of large load-driven regional transmission costs) and 7 (transparency of large load-driven regional transmission costs) are mutually exclusive because Option 7 is achieved if Option 6 is pursued. Options 6 and 8 (widespread load ratio share cost allocation) are also mutually exclusive. Option 7 could be combined with Option 8. Option 9 (voluntary supplement and expedited service) could be combined with any of the other options.

OPTION 6: TARGETED COST ALLOCATION OF LARGE LOAD-DRIVEN REGIONAL TRANSMISSION COSTS

Under this option, transmission planning regions would allocate large load-driven regional transmission costs to LSEs serving the large loads, with state regulators then determining how those costs flow through to the large loads and other end-use customers. Regional planners could identify these costs by, for example, modeling regional transmission needs and solutions including the defined large loads and separately identifying regional transmission needs and solutions without the defined large loads ("with/without" analysis). The difference in costs between the two plans would be allocated in a targeted manner to LSEs serving defined large loads. The remainder of the costs would be allocated using the applicable regional cost allocation method, such as load ratio share, which could result in additional costs being allocated to the LSEs, consistent with cost causation and beneficiary pays principles.

Certain time-saving proxy methods could be developed to lessen the modeling burden introduced by a plan-based with/without comparison. For example, rather than developing a full transmission portfolio to solve the "without" system needs, exploratory transmission costs used to solve system needs could be used as the counterfactual. The Southwest Power Pool (SPP) has used exploratory transmission costs to resolve thermal and voltage overloads—without undergoing a full transmission solution development analysis—when evaluating its avoided or delayed reliability projects benefit.[130]

Principle 1: Ensure opportunity for appropriate cost recovery. This option provides for full cost allocation among LSEs in the region.

Principle 2: Safeguard non-discriminatory open access. As with several of the prior options, singling out costs driven by specific customers (i.e., large loads) for assignment to host LSEs raises discrimination concerns that a court could find violate the FPA.

Principle 3: Promote economic efficiency on the electric system. This option could address fears that regional transmission is being driven primarily by large loads, leading to greater buy-in for more efficient regional transmission that leverages economies of scale over piecemeal and just-in-time transmission. In addition, similar to the incremental cost approaches in Options 3 and 4, this option could send price signals to promote efficient load configurations, flexibility, and location but only to the extent large loads feel the impact. On the other hand, separating large load-driven costs could inadvertently create pressure for bare-minimum, short-sighted planning. It could also upset settled agreements around regional cost allocation methods, leading to fresh controversy and delays. Delays in regional transmission projects undermine economic efficiency by driving up electricity costs (e.g., congestion) whether those delays are caused by cost allocation disputes or by strategic anticipation that a forthcoming large load could be said to have caused a regional transmission need (and therefore have to cover at least a portion of the costs).

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130 Southwest Power Pool, *Benefit Metrics Manual (Version: 1.5)*, at 8 (Published Dec. 16, 2025), https://www.spp.org/documents/75533/benefit%20metrics%20manual%20v1.5.pdf.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. This option could be well-positioned to ensure cost causers pay for the regional transmission costs they cause so long as states are able and willing to take the next step of fairly allocating costs to end-use customers. A successful approach would also include a mechanism for reallocation of costs should large loads not materialize or leave the system before full cost recovery, ideally with mechanisms in place at the state level to avoid unfair cost shifts. For example, state regulators could reallocate those costs to other members of a large load class. However, in states that lack substantial large loads, that option may not be available, and the result may be reallocation of those unrecovered costs to smaller customers. There are other fairness concerns as well. For one, FERC and courts have found that high-voltage transmission, like is typical of regional transmission, has widespread benefits. This risk is relevant because regional transmission needs are often difficult to isolate to a single load or LSE: multiple loads may contribute to the same need, existing system conditions may also drive the project, and future customers may benefit from facilities initially associated with current large load growth.[131] Thus, allocating a subset of the costs of regional transmission, as this option envisions, may be misaligned with the cost causation and beneficiary pays principles.

Principle 5: Be administratively feasible, fast, and transparent. This option is administratively feasible, in theory, especially if done on a portfolio rather than project-by-project basis, and significantly more so if using proxy methods to identify costs. This would also be an important first step in facilitating states' ability to allocate regional transmission costs attributable to large loads to those end-use customers. Nevertheless, this approach depends on regional planners conducting a time-consuming exercise, which could lead to delays in the regional planning process. In addition, it would likely result in extensive debates as to which portion of regional transmission costs are attributable to large loads, whether based on a plan or a proxy of costs. This option also depends on states having capacity to ensure regional transmission costs allocated to LSEs as large load-driven flow through to rates for large load customers. It also depends on federal-state alignment on such issues as the definition of large load. Lastly, FERC would need to justify its approval of singling out specific large loads, which would likely face challenge.

OPTION 7: TRANSPARENCY OF LARGE LOAD-DRIVEN REGIONAL TRANSMISSION COSTS

Under this option, transmission planning regions would identify the costs of regional transmission projects driven by large loads, using similar approaches to those described in Option 6, but the identified costs would be for informational purposes only. Unlike Option 6, this option would not assign those costs directly to LSEs serving large loads; instead, the currently approved regional cost allocation method would apply. The added transparency could allow states to more accurately identify the portion of FERC-approved transmission costs allocated to LSEs in their state from regional transmission driven, at least in part, by large loads and reflect those costs in retail ratemaking (like Option 5 for local transmission costs).

Principle 1: Ensure opportunity for appropriate cost recovery. This option does not change the status quo around cost recovery.

Principle 2: Safeguard non-discriminatory open access. Similar concerns as Options 5 and 6 with separately identifying costs associated only with large loads.

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131 SPP, Cost Allocation Review & Evaluation Team, *Summary of Motions and Action Items*, at 8-10 (May 6, 2026), https://spp.org/documents/76726/care%20team%20minutes%2020260506.pdf; SPP, Consolidated Planning Process Task Force, *Minutes*, at 3-4 (Apr. 22, 2026), https://www.spp.org/documents/76607/cpptf%20minutes%2020260422.pdf (describing GRID-L framework options and stakeholder discussion of risk mitigation, fair treatment of large loads coming online, and accurate cost share based on system impact).

Principle 3: Promote economic efficiency on the electric system. Similar weighting as Option 5 around transparency as a tool and as Option 6 around with/without analyses and potential for greater buy-in.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. Similar fairness considerations as Option 5. In addition, simply handing more data to states does not ensure FERC-approved transmission costs driven by large loads are not unfairly shifted to other customers, especially in the regional context because states are limited by geographical boundaries in where they can allocate costs, making getting the regional cost allocation right in the first place even more important.

Principle 5: Be administratively feasible, fast, and transparent. Promotes transparency. But shares similar concerns as Option 6 around feasibility of with/without analyses and disagreements over identified costs. Disagreements may be lessened with this option because cost identification is for transparency only and not for FERC-level cost allocation.

OPTION 8: WIDESPREAD LOAD RATIO SHARE COST ALLOCATION

This option would use load as a proxy for regional transmission cost responsibility. Rather than identifying specific projects or costs as large load-driven, regional transmission costs would be allocated across LSEs or zones based on their share of load in the relevant region. Load ratio share cost allocation methods, which this option employs, are the most common regional cost allocation methods used today. They allocate costs based on the share of load served by the relevant LSE or zone within a defined geographic area.[132]

The first key design choice is how often those load shares are updated. The load ratio share cost allocation method, by design, addresses changing load across a region through regular updates to the load shares and reallocation of regional transmission costs. More frequent updates—annual, at a minimum, but perhaps even more regular in areas experiencing rapid load growth—can ensure costs continue to be allocated roughly commensurate with where the estimated benefits of regional transmission are expected to flow over time.

The second key design choice is the allocation factor: the measure of load used to calculate each LSE's or zone's share of regional transmission costs. Because this input determines how costs are divided among paying entities, different allocation factors can produce meaningfully different cost allocation outcomes. Sub-options 8A through 8D each consider distinct pros and cons of allocation factor options related to Principles 3 and 4. Coincident peak-based allocators may better reflect the cost of building transmission to meet peak demand, an energy usage-based allocator may better capture the year-round benefit to customers of using the transmission system, and an incremental load growth allocator may better reflect where new demand is driving future transmission needs. Sub-options could be blended (e.g., 50% using historic coincident peak-based allocation factors and 50% using incremental load growth-based allocation factors).

Principle 1: Ensure opportunity for appropriate cost recovery. This option provides for full cost allocation among LSEs in the region.

Principle 2: Safeguard non-discriminatory open access. This option would treat all LSEs similarly without singling out any particular customers or buckets of costs; rather, all LSEs serving any category of load would be allocated costs using load ratio share methods, at least within a region, if not nationwide.

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132 *See* Volume 1 Report at 29-31, 30-31.

Principle 3: Promote economic efficiency on the electric system. Similar to Options 6 and 7, this option could address fears about existing regional cost allocation methods not appropriately accounting for high load growth through load-based cost allocation with frequent updates (i.e., reallocations) as load grows for different LSEs/zones. This option would avoid concerns with undermining efficient multi-value regional transmission planning by separating out specific drivers and beneficiaries—large loads—and could avoid upsetting settled agreements around regional cost allocation methods (especially where load ratio share may already be employed).

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. Load ratio share cost allocation with frequent load share updates should align with cost causation and beneficiary pays principles by ensuring costs continue to follow the growth in system use across a region over time. This is also an effective cost allocation method for ensuring costs associated with difficult-to-quantify benefits are appropriately allocated and recognizes the widespread benefits of high-voltage transmission that is typical of regional facilities.[133]

On the other hand, too much focus on load patterns alone may ignore the value of alternative regional cost allocation methods, such as granular benefits-based methods that can offer greater precision in quantifying benefits and aligning costs with beneficiaries, or hybrid methods that can balance precision with administrability.[134] In addition, purely regional load ratio share may fail to account for the different spread of benefits of different voltages of transmission. This option also does not address front-end timing concerns (but could be combined with Options 1 or 2 for that purpose) nor does it allocate regional transmission costs associated with large loads as directly as Option 6. Like Option 6, this option similarly relies on states to take the next step of fairly allocating costs to end-use customers.

Principle 5: Be administratively feasible, fast, and transparent. This option tweaks the status quo and leverages a regional cost allocation method that is already commonly used, making for relatively easy and fast implementation. Annual load share updates may be the most feasible with increasing administrative burden as the updates become more frequent. This option shares the reliance on and need for alignment with states but the importance of alignment on things like the definition of large loads is diminished with a load ratio share method that applies across LSEs and their customers. The largest challenge for this principle may be the creation of winners and losers in shifting to a new cost allocation methodology and the ensuing disputes, but these are likely to be limited to the near term.

SUB-OPTION 8A: HISTORIC COINCIDENT PEAK-BASED ALLOCATION FACTOR

Under this sub-option, transmission planning regions would use a historic coincident peak-based allocation factor, thereby establishing load shares based on each LSE's historic contribution to coincident peak demand. A system's coincident peak is the moment in time when electricity demand is at its highest across the system. A specific customer's coincident peak means the specific demand level of the customer when the system is hitting its peak. The specific customer may have higher demand at other times, but that demand will not be said to be "coincident," i.e., aligned in time, with the system peak. A coincident peak-based allocation factor reflects the fact that transmission is typically planned to serve peak demand and, thus, costs are caused in proportion to the extent of an LSE's demand coinciding with the system peak.

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133 *See Long Island Power Auth. v. FERC*, 27 F.4th 705, at 713 (D.C. Cir. 2022); *Sw. Power Pool*, 131 FERC ¶ 61,252 (2010); *Old Dominion Elec. Coop.*, 898 F.3d 1254, 1260 (D.C. Cir. 2018).

134 *See* Volume 1 Report at 26-34; Amy Rose, et al., National Laboratory of the Rockies, *Lessons Learned for Transmission Cost Allocation in U.S. Regional Markets* (Feb. 2026), https://www.nlr.gov/docs/fy26osti/97370.pdf.

There are variants within coincident peak-based allocation factors: 1CP refers to an allocation factor based on each entity's share of demand during a single annual coincident peak; 4CP refers to an allocation factor based on each entity's average share of demand during four specified coincident peaks, commonly seasonal or summer peaks; and 12CP refers to an allocation factor based on each entity's average share of demand during the 12 monthly coincident peaks. These variants differ in how strongly they reward peak-shaving behavior and how well they capture broader patterns of system use. For instance, compared to 1CP or 4CP, a 12CP method may be less susceptible to avoidance based on a small number of predictable peak intervals and may better reflect the contribution of high load factor customers by measuring demand across monthly system peaks throughout the year.[135] This is a common allocation factor approach (e.g., Electric Reliability Council of Texas [ERCOT] uses 4CP, ISO-New England [ISO-NE] uses 12CP, and PJM uses 12CP).

Principle 3: Promote economic efficiency on the electric system. Coincident peak-based allocation factors can incentivize load-side flexibility because peak-avoidance behaviors can be rewarded with cost savings. These behaviors may reduce transmission congestion and other grid strain during key hours of reliability risk, which may, in turn, lower the amount of infrastructure needed to meet that peak and the costs allocated to LSEs.[136] However, these efficiency benefits can only be reflected if they are considered in system planning; otherwise, there is a risk of overbuild. Moreover, the specific coincident peak used matters for assessing economic efficiency. Some coincident peak-based allocation factors may over-reward peak avoidance by allowing large loads to reduce cost responsibility through limited curtailment during anticipated peak intervals (currently under examination in ERCOT),[137] while other methods may under-reward flexibility by relying on allocators that do not reflect actual load patterns.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. Coincident peak-based allocation factors may better reflect the transmission costs caused by loads that materially contribute to peak demand for which the transmission system has been built than alternatives. On the other hand, depending on the specific coincident peak used, sophisticated large loads may be able to curtail at peak to avoid cost allocation. While flexibility is valuable, the resulting savings may not be commensurate with the value the load flexibility is actually providing to the system, given that the loads would still have significant, year-round reliance on the transmission system that result in few cost savings. This concern could be reduced if peak-avoidance savings are paired with enforceable flexibility obligations or non-firm transmission service arrangements, so that lower cost responsibility reflects a corresponding reduction in firm service rights or verifiable peak-period performance that translate into avoided transmission upgrade costs. Also, it should be noted that this concern

135 *See* California Independent System Operator, *Review Transmission Access Charge Structure: Revised Straw Proposal*, at 15-16 (Apr. 4, 2018), https://www.caiso.com/documents/revisedstrawproposal-reviewtransmissionaccesschargestructure.pdf (explaining that CAISO proposed a 12CP approach because it "strikes an appropriate balance" in reflecting how the system is planned and used, reflects capacity and reliability benefits on a monthly basis, and provides advantages over 1CP or 4CP by reducing anomalous outcomes and cost shifts associated with lower-frequency peak measurements).

136 Brattle Group Untapped Grid Report at 4-7, 10-13 (explaining that much electric infrastructure is built to meet short periods of peak demand and that flexibility, efficiency, and operational strategies that reduce peak demand can lower the amount of supporting infrastructure needed to serve new load).

137 Public Utility Commission of Texas Staff, *Draft Evaluation of Transmission Cost Recovery*, Project No. 58484, at 11-12 (filed Mar. 16, 2026), https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=58484 (raising concerns with 4CP and the growth of sophisticated flexible large loads).

may be more significant in the context of 1CP or 4CP than 12CP methodologies.[138] Finally, entirely coincident peak-based allocation factors that do not include some hybridization, such as with an energy usage-based allocation factor, may not sufficiently reflect the benefits received by high load factor loads like data centers.

SUB-OPTION 8B: FORECASTED COINCIDENT PEAK-BASED ALLOCATION FACTOR

Under this sub-option, transmission planning regions would use a coincident peak-based allocation factor derived in whole or in part from forecasted peak demand rather than relying exclusively on historical peak demand data (as is common and envisioned by Sub-Option 8A). In practice, this could mean allocating regional transmission costs based on each LSE's projected contribution to system peaks over a defined planning period, such as the forecast years used in the regional transmission planning process or a multi-year average of projected peak contributions over the relevant planning horizon, rather than waiting for those load changes to appear in historical peak demand data.

Principle 3: Promote economic efficiency on the electric system. On the one hand, a forecasted coincident peak-based allocation factor could promote economic efficiency by disincentivizing over-forecasting because forecasts would be tied to actual cost consequences. This could discipline reliance on uncertain load forecasts. On the other hand, a forecast-based allocation factor could incentivize under-forecasting, particularly by LSEs, to avoid cost allocation. This could have the perverse outcome of under-planning more efficient and cost-effective regional transmission and having to rely more on piecemeal local transmission upgrades triggered when load materializes and the system has inadequate capacity to accommodate the new load.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. In an era of rapid load growth, such as we are seeing today, historical data can significantly lag reality. Thus, basing at least a portion of load shares for regional cost allocation on forecasted peak demand could better align with cost causation and beneficiary pays principles, particularly because the transmission is being planned based on forecasted load. While there is uncertainty in load forecasts, particularly using current load forecasting methods, improvements are on the horizon. That said, based on prevailing uncertainty today, looking at forecasted peak demand could result in over-allocation of costs to LSEs in which large loads fail to materialize, resulting in unfair cost shifting to other customers, at least until the load shares are updated.[139]

SUB-OPTION 8C: ENERGY USAGE-BASED ALLOCATION FACTOR

Under this sub-option, transmission planning regions would use an energy usage-based allocation factor, thus establishing load shares based on how much energy each LSE currently uses as a percentage share of total energy usage across the relevant region or sub-region. This means load shares would be proportional to energy consumption, so those who consume more energy as a total would pay a larger share of the costs. There is not necessarily any relationship to coincident peak demand contribution, though an alternative approach could be a hybrid of coincident peak-based and energy usage-based allocation factors (e.g., measure total energy consumption and contribution to system peaks and weight each). The below pros and cons assume a non-hybrid, energy usage-based only approach.

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138 *Id.*; *see also* NRG Energy, Inc., *Comments on Transmission Cost Recovery* [PUCT staff RFC], at 1, 21-23, 31 (filed Sept. 9, 2025); NRG Energy, Inc., *ERCOT Transmission Costs and Rate Design: Remarks on February 25, 2025 Workshop*, at 2-3 (Feb. 25, 2025).

139 *See* ESIG Load Forecasting Report at 2-4, 8-10 (explaining that large load forecasting methods currently lack transparency and consistency and that customer-supplied and historical data are often insufficient for accurate forecasting).

This approach could be adapted to utilize an allocation factor derived in part or in whole from forecasted energy usage, as Sub-Option 8B discusses for coincident peak-based allocation factors. However, energy usage forecasts are subject to even greater uncertainty than peak load forecasts given their reliance on load factor/load shape assumptions that are often low confidence.[140]

Principle 3: Promote economic efficiency on the electric system. Energy usage-based allocation factors may more accurately capture the benefits that flexible loads or loads with on-site generation that partially supply their energy needs receive from the broader transmission system than coincident peak-based allocation factors. But using this type of factor alone could, at minimum, fail to incentivize, and possibly disincentivize, load-side flexibility at peak that allows for more efficient use of the grid.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. Energy usage-based allocation factors may better reflect the more intensive grid usage of high load factor loads, such as hyperscale data centers, than coincident peak-based allocation factors. That said, given that much of the transmission system is designed to meet system peak needs, energy usage-based allocation factors could result in cost allocation misaligned with cost causation. This may be lessened for economic-driven as compared to purely reliability-driven regional transmission, as the benefits of economic projects may be more closely tied to throughput than to system peak needs.

SUB-OPTION 8D: INCREMENTAL LOAD GROWTH-BASED ALLOCATION FACTOR

Under this sub-option, transmission planning regions would use allocation factors based on the incremental amount of load growth projected between a specified future planning year and the current year. For instance, incremental load growth could be calculated as the difference between a 10-year load forecast and current load for each LSE. Load growth could be defined using either coincident peak load or total annual energy usage. This option would ensure that transmission costs are allocated to LSEs with high future demand, regardless of either their current demand or the driver of the load growth (e.g., data centers, EV adoption, manufacturing). Under this framework, a zone with small current load but projected high future demand would be allocated more costs than a zone with high current load but flat projected load growth. This approach could be hybridized with other allocation factor options to reflect that regional transmission costs are driven by both existing and forecasted load. The result of this cost allocation method would likely be very similar to Option 6 (Targeted Cost Allocation of Large Load-Driven Regional Transmission Costs), but without the burden of a with/without analysis.

Principle 3: Promote economic efficiency on the electric system. Same analysis as Sub-Option 8B.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. This option would align with cost causation and beneficiary pays principles where the costs of new regional transmission meant to serve future load would be allocated to the LSEs that host the load growth. It raises similar concerns as Sub-Option 8B with regard to uncertain load forecasts. In addition, high-voltage regional transmission provides many benefits besides serving new load, such that focusing too narrowly on incremental load growth could allow for free ridership by other beneficiaries, misaligning with the beneficiary pays principle.

140 *Id.* at 4, 18, 34-35 (noting that forecasters often express low confidence in customer-provided load factor and load shape information, even while relying on it, and that load shapes can vary materially across large load types).

Treatment of Co-Located Load in Determining Transmission Cost Allocation Factors

Methods for allocating FERC-approved transmission costs that rely on energy usage or coincident peak-based allocation factors, whether for allocating local or regional transmission costs, must grapple with how to treat load with onsite generation ("co-located" load). This can be complicated because, while a load that is partially served by on-site generation may have lower net withdrawals from the grid, it may still rely on the broader transmission system for reliability, backup service, balancing, and other grid services.

Although FERC-approved transmission costs are allocated to wholesale customers (LSEs), rather than directly to end-use customers, the treatment of co-located load is increasingly relevant where large loads make up a significant share of an LSE's total load. In those circumstances, the choice "load" to measure—whether gross load, net withdrawals, contract demand, or some other proxy—can materially affect what goes into the load-based cost allocation factor and, in turn, the load share that forms the basis of cost allocation.

There are several ways co-located load can be assessed. For an energy usage-based allocation factor, one option is to look at gross energy usage, as CAISO does today for certain regional transmission charges.[141] This approach would look at the total load, without discounting for the on-site generation, which means it could over-account for co-located load and shift costs unfairly in comparison to the usage of and benefits from the relevant transmission.

Another option is to look at net load. This approach would only count the portion of co-located load that is not served by on-site generation for purposes of cost allocation, which would more directly reflect the extent to which on-site generation reduces the need for energy withdrawals from the transmission system. At the same time, this approach could under-account for co-located load's reliance on the transmission system and shift costs unfairly in the opposite direction to the use of gross energy usage.

Industrial customers have emphasized that netting is not new. Many have long relied on behind-the-meter generation and net load treatment, and they have urged FERC not to let PJM co-location reforms for new data center load disrupt those existing arrangements.[142]

FERC is exploring another possible model as part of its open proceeding related to co-location in PJM, wherein FERC has directed PJM to develop "Firm Contract Demand" and "Non-Firm Contract Demand" transmission service options for co-located load, along with rates, terms, and conditions for such services.[143] Under that approach, a co-located load would elect or reserve a specified level of transmission service, and PJM would plan for, charge for, and limit service based on that reserved amount rather than treating gross load or net withdrawals alone as dispositive.

It may be appropriate to assess co-located load based on contract demand or another elected service level or minimum bill determinant more generally, as well, especially in circumstances where reliance on the grid is limited to a specified withdrawal level. This approach would tie cost allocation more directly to the amount of transmission service reserved by the co-located load. This approach could be used with either energy usage-based or peak-based allocation factors.

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141 Cal. Indep. Sys. Operator, CAISO eTariff, § 26 (Transmission Rates and Charges) (0.0.0), App. F, Sched. 3 (Regional Access Charge and Wheeling Access Charge) (30.0.0).

142 PJM Industrial Customer Coalition et al., Request for Clarification or Rehearing, Docket No. EL25-49-000, at 16, 24-25 (filed Jan. 20, 2026).

143 *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,217 (2025); *see also* Volume 1 Report, Section VIII (summarizing recent FERC action related to newly interconnecting large loads and transmission pricing).

OPTION 9: VOLUNTARY SUPPLEMENT AND EXPEDITED SERVICE

This option would allow LSEs, on behalf of large loads, to voluntarily pay to offset costs of regional transmission projects that fail to meet the benefit-cost threshold but provide value to those customers, in exchange for service benefits. This approach is modeled on the voluntary supplement option that Order 1920 provides for states. This could allow an LSE serving a large load to support a regional project that provides a more efficient path to service than piecemeal local upgrades or customer-specific facilities, while also preserving broader regional benefits. The supplement amount would be based on the extra costs above the quantified benefits required to meet the benefit-cost ratio for the region. In return for voluntary contributions, customers would receive tariff-defined service benefits, such as expedited processing or access to incremental withdrawal capability enabled by the project.

Principle 1: Ensure opportunity for appropriate cost recovery. This option provides for cost allocation among LSEs in the region for the costs not voluntarily supplemented by the LSE on behalf of the large loads they serve, and the remaining costs allocated to the voluntarily supplementing LSE. Even if the large loads did not materialize or did not remain customers long enough for full cost recovery for the LSE, the transmission provider could still recover the costs from the LSE.

Principle 2: Safeguard non-discriminatory open access. It is hard to raise a discrimination argument around an option to voluntarily supplement, but the tie to certain service benefits could result in a claim that a court finds violates the FPA. For example, in the absence of additional reforms and ongoing investments in expanding grid capacity, there is risk that "voluntary" supplements become the only viable route for large loads to be connected in a timely manner, rendering "voluntary" supplements not truly voluntary in practice. In addition, this option could advantage only the best-capitalized customers, erecting a barrier to open access.

Principle 3: Promote economic efficiency on the electric system. This option could leverage willing capital to move much-needed grid investments forward and support speed-to-power goals. Presumably the supplement would be applied to projects that are already close to meeting the benefit-cost metric, and hence require the least amount of supplemental investment, potentially catalyzing projects that have broad regional value beyond a single large load or LSE. By allowing an LSE serving a large load to help close the funding gap for a regional project, this option could support a more efficient regional solution where the alternative would be slower, more expensive, or more fragmented local upgrades. In addition, this approach would better preserve incentives for robust multi-value regional transmission planning than the options that separate out large load-driven regional transmission costs.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. A voluntary supplement approach would recognize that regional transmission with potentially significant benefits but also significant costs may fail to proceed for years while there are private entities willing to pay extra to move the project forward. This envisions a blended model that matches regulated cost recovery with private capital to the benefit of all involved.

Principle 5: Be administratively feasible, fast, and transparent. A voluntary supplement approach would be relatively simple to implement so long as the regional planner has already conducted a benefit-cost analysis and knows the delta of costs to be covered to move the project forward. There may be near-term challenges with establishing a standard agreement and set of assurances that the private capital will come through.

INNOVATIVE APPROACHES

These options require more substantial changes to the status quo as they approach the era of high load growth more holistically. Options 10 and 11 are both proactive capacity allocation models that would move away from a purely reactive, queue-based approach for serving new large loads and toward a framework in which the transmission provider would identify available or developable capacity in advance of the need arising and then allocate access to that capacity through a structured process (planning-led designation of preferred capacity areas in Option 10 and an open season model in Option 11). Option 12 is a consolidated load and generation framework.

OPTION 10: PLANNING-LED ZONAL CAPACITY RESERVATION MODEL

Under this option, transmission providers would proactively identify electrically coherent zones or other defined geographic areas where existing capacity or a planned portfolio of upgrades could support additional large load interconnection. The transmission provider would identify a defined quantity of incremental withdrawal capability within those areas and establish a structured pathway for qualifying projects that satisfy standardized location, readiness, and financial commitment requirements. This approach is most similar to planning-led generator interconnection frameworks in which transmission planning first identifies preferred locations and available capacity, and interconnection opportunities are then structured around those pre-identified areas.[144] Potential features of this option include:

- The framework could be initiated through a periodic transmission provider assessment or through a standardized request process under which qualifying customers, LSEs, or states may request evaluation of available or developable capacity.
- The transmission provider would identify zones or designated areas where large loads could be accommodated using existing capacity, planned upgrades, or a combination of the two.
- The transmission provider would specify the amount of incremental withdrawal capability available in each area and the basic terms under which that capability would be made available.
- Large loads seeking service in those areas would be required to satisfy standardized readiness requirements and make binding financial commitments.
- Large loads would then receive accelerated interconnection and standardized rights to transmission service up to a specified quantity and at specified locations within the zone, in exchange for binding financial commitments that would fund the zonal upgrade portfolio. Payments could be upfront or standardized monthly charges over a defined period.
- If later projects benefit from the same facilities, the tariff or planning framework could provide for cost sharing or crediting to earlier participants where appropriate.

144 This load-side concept is analogous to CAISO's recent generator interconnection reforms. In its 2024 Interconnection Process Enhancements Track 2 proposal, CAISO adopted a "zonal approach" intended to prioritize interconnection in areas with available or planned transmission capacity, using Transmission Plan Deliverability zones, available-capacity information, project-readiness scoring, and limits on the volume of projects that advance to study. CAISO, *Decision on Interconnection Process Enhancements 202 - Track 2*, at 3, 5-6 (June 6, 2024); CPUC President Alice Reynolds, Letter to CAISO Board of Governors Re: Interconnection Process Enhancements Track 2 Proposal, at 1-2 (May 23, 2024).

Principle 1: Ensure opportunity for appropriate cost recovery. Because the approach is proactive and incorporates binding financial commitments, it provides strong assurance of cost recovery.

Principle 2: Safeguard non-discriminatory open access. On the one hand, this type of approach to allocating scarce capacity avoids undue discrimination and ensures open access by transparently providing information to all interested customers and allocating capacity to those that satisfy standardized requirements. But the devil is in the details. Also, binding financial commitments applied only to large loads raise discrimination concerns that a court could find violate the FPA. In addition, depending on the structure, these requirements could become a barrier to accessing transmission service for smaller, less established large load developers. There is also risk of discrimination where demand exceeds the identified capacity in a given area if there is no clear process for an independent transmission developer or its proxy to select among competing customers (though this is less of a concern with large loads directly participating as opposed to LSEs).

Principle 3: Promote economic efficiency on the electric system. Properly implemented, proactive capacity allocation models, like Option 10, could improve transparency, speed to power, and cost discipline relative to ad hoc serial interconnection study processes. This option could also improve load forecasting accuracy by increasing certainty around committed large loads and could send strong price signals to promote efficient load configurations, flexibility, and location by identifying where the system can most efficiently accommodate new demand. Where designated areas include existing transmission capacity, this option could help reduce rate pressure by pairing better use of existing capacity with binding commitments for any needed expansion. In addition, this approach could support more efficient transmission development by creating a framework for planning around likely clusters of new load rather than around individual customer requests. On the other hand, this approach depends heavily on the transmission provider making credible ex ante judgments about where load will materialize and how much capacity should be identified in advance. Incorrect assumptions could result in delayed upgrade portfolios and large load interconnections. Moreover, if designated zones are too rigid, poorly chosen, or slow to update, the model could steer projects inefficiently or focus planning attention on areas that prove less valuable than expected.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. Depending on the details, binding financial commitments under this option could address timing concerns associated with large loads driving transmission costs, including stranded cost risk and unfair cost shifting.

Principle 5: Be administratively feasible, fast, and transparent. Where regions are already moving toward a more zonal or area-based planning construct, this approach may be administratively feasible in the near term. Where regions are not moving towards zonal planning, this option would demand a substantial increase of institutional effort to plan and allocate transmission capacity, with potential for more disagreement. This would also increase federal involvement in large load interconnection administration. In short, implementation of this option would be complex and technically demanding, as it represents a significant departure from current transmission planning practices and would raise implementation and governance questions.

OPTION 11: OPEN SEASON MODEL FOR LARGE LOAD INTERCONNECTION

Under this option, transmission providers would identify available capacity or a portfolio of upgrades capable of supporting additional large load interconnection and would then allocate access to that capability through a structured open season or auction-like process. Rather than relying primarily on queue position or administrative priority rules, the transmission provider would award interconnection and withdrawal rights based on financially binding bids evaluated under a transparent, pre-established methodology.[145] Potential features of this option include:

- The framework could require transmission providers to conduct open seasons on a regular schedule or allow qualifying customers, LSEs, or states to request an open season, subject to standardized response timelines and criteria.
- The transmission provider would develop an initial plan to interconnect large loads using existing system capacity and upgrades that can be completed on a relatively short timeline, segmented geographically as appropriate.
- The transmission provider would conduct an open season or similar competitive allocation process for that capacity.
- Bids submitted by large loads, or by LSEs acting on their behalf, could be evaluated based on net present value or another posted methodology that takes account of factors such as quantity, term, price, speed to energization, and operational flexibility.
- Winning large loads, or LSEs acting on their behalf, would make binding financial commitments and obtain the right to interconnect and withdraw a defined amount of power at a specified location.
- Those rights could potentially be transferable or re-assignable, subject to anti-hoarding rules and use requirements.
- Subsequent open seasons could be used for later rounds of upgrades requiring greater capital investment.
- Investment would move forward if sufficient revenue were raised by the bids.

Principle 1: Ensure opportunity for appropriate cost recovery. Same as Option 10.

Principle 2: Safeguard non-discriminatory open access. Similar to Option 10, direct participation by large loads could make the allocation process more commercially transparent, but binding financial commitments applied only to large loads could raise discrimination concerns and, depending on structure, could become a barrier to accessing transmission service for smaller, less established large load developers. In addition, how operational flexibility is weighted in bid evaluation could result in undue discrimination against continuous industrial and technology load customers. However, risk of undue discrimination may be reduced for this option to the extent there are less discretionary measures for a bidder to secure capacity than in Option 10.

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145 This approach is similar to the model advocated by Travis Kavulla and NRG to FERC, under which the allocation process would be designed to direct scarce interconnection capability to higher-valued uses. NRG Energy, Inc., Initial Comments, Docket No. RM26-4-000, at 15-29 (filed Nov. 19, 2025).

Principle 3: Promote economic efficiency on the electric system. Similar strengths as Option 10 plus this option relies on a strong market-based mechanism for allocating scarce transmission capacity, distinguishes among competing projects using financially binding bids and a posted evaluation methodology rather than relying solely on readiness screens, and creates clear commercial signals regarding the relative value of speed, flexibility, and location. On the other hand, this option would create a transferable or property-like interconnection right, which could raise concerns about speculation, warehousing, or inconsistent treatment across regions, depending on the details of the model implemented.

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. While the details of the long-term financial commitments are important, this approach is entirely aimed at aligning costs with causers/beneficiaries (projected large loads). That said, to the extent large loads shoulder the costs of network upgrades that benefit the broader system, there may be misalignment with the beneficiary pays principle.

Principle 5: Be administratively feasible, fast, and transparent. Similar to Option 10. In addition, in highly networked AC systems, it may be difficult to define the relevant product and associated rights with sufficient clarity to support a durable open season structure. One possible approach would be to define the product as injection and/or withdrawal rights at specified points on the system, with associated quantity, duration, firmness, transferability, and curtailment terms. Even then, the rights would need to be carefully designed to reflect the physical and operational interdependence of the transmission network and to operate alongside other transmission service products.

OPTION 12: CONSOLIDATED LOAD AND GENERATION INTEGRATION FRAMEWORK

Under this option, transmission providers would adopt a more integrated planning framework for new large loads, modeled in part on SPP's Consolidated Planning Process (CPP).[146] Rather than addressing large load service needs solely through stand-alone interconnection studies, or through transmission planning processes that proceed largely separately from new load-side service requests, transmission providers would evaluate large load interconnection needs through a coordinated set of assessments. Those assessments would consider large load needs alongside broader transmission and resource development needs, with the aim of identifying more efficient, multi-driver transmission solutions earlier and reducing duplicative study processes.[147] Additionally, this framework would include standardized contribution and commitment structures for interconnecting large loads.[148] This option would not replicate SPP's CPP universally but would extend its basic planning-and-interconnection integration logic to large loads. Potential features of this option could include:

- Coordinated assessment of large load service requests, generator interconnection, and transmission expansion needs;
- Earlier identification of transmission upgrades that address multiple drivers, including reliability, economics, generator interconnection, and large load integration;

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146 *See* Southwest Power Pool, Consolidated Planning Process, https://www.spp.org/engineering/consolidated-planning-process/ (last visited June 4, 2026).

147 *See Southwest Power Pool, Inc.*, 194 FERC ¶ 61,192 (2026).

148 Conversations about an expansion of CPP to incorporate large loads into the planning process, including the potential for a standardized rate for large loads, referred to as GRID-LL, are underway at SPP, but details have not yet been determined. *See* SPP, CPP Task Force, Draft Minutes, at 1-3 (Feb. 19, 2026); SPP, Cost Allocation Working Group, Minutes, at 2 (Mar. 11, 2026).

- More transparent information regarding where large loads can be accommodated and what transmission implications they would create;
- Use of a standardized $/MW contribution to cover costs of transmission and generation development;[149] and
- Integration of large load development assumptions into regional planning and restudy processes through more formalized milestones or financial commitments.

This option aligns with the third principle outlined in the Large Load ANOPR: "[T]o the extent practicable, load and hybrid facilities should be studied together with generating facilities."[150] The Large Load ANOPR explains that joint study can support efficient siting of loads and generation and minimize the need for costly network upgrades, including where siting a large load near or at the same point of interconnection as a new generating facility could reduce the upgrades needed to interconnect either facility separately.

Principle 1: Ensure opportunity for appropriate cost recovery. A standardized $/MW contribution ensures cost recovery from participants.

Principle 2: Safeguard non-discriminatory open access. If the framework uses transparent eligibility criteria, standardized study assumptions, defined milestones, and comparable terms for similarly situated large loads, it could improve open access and reduce dependence on bespoke utility negotiations. Without sufficient consistency and transparency into how upgrades are planned and prioritized, however, the framework could introduce new discrimination risks. Also, as in the case of Option 10, requiring binding financial commitments only from large loads could raise discrimination concerns and, depending on structure, could become a barrier to accessing transmission service for smaller, less established large load developers.

Principle 3: Promote economic efficiency on the electric system. As emphasized by FERC in approving SPP's CPP—and individual Commissioner statements—this approach could encourage a more integrated and efficient transmission buildout by allowing transmission providers to identify upgrades that solve for multiple needs at once.[151]

Principle 4: Promote fairness in line with cost causation and beneficiary pays principles. If paired with meaningful milestones, security, or crediting mechanisms, this option could help mitigate stranded cost risk while still supporting more proactive planning. Otherwise, this type of proactive planning could expose other customers to risk if projected large loads fail to materialize.

Principle 5: Be administratively feasible, fast, and transparent. On the one hand, this approach could support speed-to-power goals by reducing duplicative or serial study processes for large load interconnection through allowing transmission and generation-related assessments to inform each other earlier in the planning process. This approach may provide a more workable framework for standardized large load treatment than today's utility-by-utility and state-by-state bespoke arrangements. But note that SPP's CPP is, at present, principally a transmission planning and generator interconnection process. Extending comparable concepts to large loads

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149 Note that, in CPP, generation interconnection customers pay a standardized contribution, called GRID-C, with regional and subregional rate components calculated from the CPP-20 Transmission Portfolio and projected generation MWs at the 10-year and 20-year planning horizons. *See* SPP, Submission of Response to Request for Additional Information, Docket No. ER26-414-001, at 6, 9, 30-31 (filed Jan. 12, 2026).

150 Large Load ANOPR, at P 20.

151 *See Southwest Power Pool, Inc.*, 194 FERC ¶ 61,192, P 54 (2026) (Chang, Comm'r, concurring; Rosner, Comm'r, concurring).

would require additional design choices and additional tariff development, even in SPP (which is underway).[152] Planning processes for large loads are less well developed than those for generator interconnection, so implementation may be technically challenging as well as delayed by reasonable policy disagreements, particularly around the identification of large load-driven needs, cost allocation, and structuring rates to avoid double billing. As generator interconnection and transmission planning processes vary substantially between regions, the opportunity to adopt models from other regions would be limited. In addition, because this option would require closer coordination among RTOs, transmission owners, LSEs, and large loads, governance could be difficult.

V. CONCLUSION

The scale, timing, and concentration of new large load requests are creating real pressure on existing transmission planning, cost allocation, and cost recovery frameworks. The challenge is not simply that large loads may require new transmission investment; it is that the size and timing of some requests can require major infrastructure commitments before the load has fully materialized, while existing customers and state regulators may lack clear visibility into which costs are driven by large load growth and how those costs will ultimately be recovered. These conditions can undermine confidence that existing federal transmission cost allocation and recovery mechanisms are assigning costs fairly, even where the underlying transmission investments may provide broader system benefits.

Before embarking on major changes to federal transmission pricing, policymakers should carefully define the problem they are trying to solve. In some places, existing transmission cost allocation and recovery mechanisms may already be reasonably well suited to address high load growth, especially where state retail large load tariffs, transparent planning inputs, and regional cost allocation methods work together effectively. In others, the more urgent need may be better load forecasting, more disciplined interconnection and planning processes, changes to generation or capacity procurement, or stronger state-level mechanisms.

That is especially important because different transmission costs are allocated and recovered in different ways. Adjusting one aspect of transmission pricing may not achieve the intended goals unless policymakers consider how the pieces fit together as a full package. For example, directly assigning upgrade costs to a large load customer may better align some incremental costs with the customer that caused them, but the process of identifying those costs can create disputes, uncertainty, and delay. Direct assignment can also, if designed poorly, forfeit the opportunity for that customer to contribute to the fixed costs of the existing system (and potentially drive down rates for others) by paying an embedded cost rate. Similarly, singling out large load-driven regional transmission costs may appear to improve alignment with the cost causation principle in the near term, but could undermine more efficient, multi-value regional planning that produces broader long-term benefits for consumers.

Cost recovery timing matters nearly as much as the ultimate allocation of costs. On the front end, policymakers must decide how to manage rate impacts when transmission projects needed to serve large loads enter rates before those loads have fully materialized or reached expected demand. On the back end, they must decide who bears the risk if the customer downsizes or leaves the system before infrastructure costs are recovered. For that reason, upfront payments, long-term service commitments, minimum billing obligations, exit charges, and financial assurance requirements may be among the most important consumer protection tools in the large

152 SPP, Cost Allocation Review & Evaluation Team, *Summary of Motions and Action Items*, at 8-10 (May 6, 2026)

load context. Many of these tools are already being developed through retail large load tariffs, which are likely to remain a primary mechanism for addressing customer-specific commitments and stranded cost risk.

The federal role is therefore not necessarily to upend existing transmission pricing policies. In many cases, the more important federal task may be to ensure that the FERC-jurisdictional transmission pricing framework works effectively with state retail reforms. States can do a great deal through large load tariffs, but they cannot always protect customers alone where transmission planning regions and cost allocation boundaries cross state lines, or where the relevant costs are first approved and allocated under FERC-jurisdictional tariffs. Federal policy can help by improving transparency into large load-related transmission costs, maintaining confidence that those costs are being assigned fairly, ensuring regional cost allocation remains aligned with cost causation and beneficiary pays principles, and supporting planning processes that identify efficient transmission solutions earlier and at broader scale. Strong federal-state coordination is critical so both federal and state regulators have the information and tools they need to do their jobs. A new commitment from FERC and the states to regular coordination and collaboration (going beyond high-level policy discussions to, potentially, specific cost allocation questions in some cases) may be necessary.

Finally, this is a period of rapid change, and policy should leave room for innovation. Bottom-up proposals from states, utilities, RTOs, large load customers, and other stakeholders should be encouraged, especially where they reflect regional differences and pursue more holistic approaches to how the system is planned and paid for. More opportunities for large load customers to directly signal their willingness to pay for needed transmission capacity and contract to do so, whether through open seasons or other innovative market-responsive approaches, would directly address concerns about cost shifts to existing customers.

The most durable path is likely to combine strong state retail tariffs, better and more granular federal-state alignment, improved transparency, targeted federal reforms where transmission costs, planning processes, or cost allocation decisions are beyond the reach of state retail regulation, alongside innovative new customer-centric approaches to transmission planning and expansion outside traditional approaches.

GLOSSARY OF ACRONYMS

AI – Artificial Intelligence

ANOPR – Advance Notice of Proposed Rulemaking

CAISO – California Independent System Operator

DOE – U.S. Department of Energy

ERCOT – Electric Reliability Council of Texas

FERC – Federal Energy Regulatory Commission

FPA – Federal Power Act

IMM – Independent Market Monitor

ISO – Independent System Operator

ISO-NE – ISO New England

LSE – Load Serving Entity

MISO – Midcontinent Independent System Operator

NERC – North American Electric Reliability Corp.

PJM – PJM Interconnection

RTO – Regional Transmission Organization

SPP – Southwest Power Pool

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gridstrategiesllc.com

info@gridstrategiesllc.com

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