GridStrategies

VOLUME 1

FEDERAL TRANSMISSION PRICING

The Evolution of Current Policies and Practices

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EXECUTIVE SUMMARY

As large electricity loads, including hyperscale data centers, connect to the transmission grid, many policymakers and technology companies have committed to minimizing impacts on other electricity consumers. Projects with gigawatt-scale demand are emerging faster and at greater concentration than the system was designed to accommodate, raising urgent questions about who should pay for expanding the shared transmission network. At the Federal Energy Regulatory Commission (FERC), these developments are challenging core assumptions underpinning bedrock transmission pricing policies, including whether current mechanisms adequately protect existing ratepayers from cost shifts and whether these mechanisms can take advantage of an era of high load growth to upgrade and expand a transmission system long in need of robust investment. As a result, transmission pricing—historically a relatively stable and technical domain—is now at the center of a broader policy debate about fairness, affordability, and the future of grid investment.

This report, ***Federal Transmission Pricing Volume 1: The Evolution of Current Policies and Practices***, is the first of two volumes and examines the evolution, current framework, and emerging challenges around federal transmission pricing in the United States, with a focus on how costs are allocated and recovered at the wholesale level. The second volume, ***Federal Transmission Pricing Volume 2: Options for Ensuring Affordability and Reliability in an Era of High Load Growth***, will take the next step of identifying, explaining, and assessing the merits of various policy options the industry and FERC could adopt to ensure all transmission customers are paying their "fair share" of transmission costs.

Federal transmission pricing is governed by the Federal Power Act's division of authority between FERC and state regulators. FERC oversees transmission in interstate commerce and wholesale electricity sales, while states regulate retail sales and determine how costs are ultimately distributed among end-use customers, such as new large load customers. This framework of "cooperative federalism" creates a two-step process: FERC allocates transmission costs to wholesale customers, and states incorporate those costs into retail rates, which may include large load-specific rate classes.

Several enduring principles guide FERC transmission pricing policy. FERC must ensure rates are just and reasonable and not unduly discriminatory or preferential, with cost allocation grounded in the cost causation and beneficiary pays principles—meaning those who drive or benefit from transmission investments should bear the associated costs. These principles define a zone of reasonableness within which multiple pricing approaches may be acceptable.

Historically, transmission pricing evolved from bundled, state-regulated cost-of-service ratemaking to a more complex system incorporating federal oversight, open access requirements, and regional coordination. Key policy milestones, including FERC Orders 888, 2000, 2003, 890, and 1000, introduced non-discriminatory open access, encouraged creation of regional transmission organizations (RTOs), and established standard requirements for generator interconnection and regional transmission planning and cost allocation. Over time, FERC shifted from a strict cost-of-service model toward greater emphasis on beneficiary-based cost allocation and regional efficiency to achieve economies of scale and cost savings for consumers.

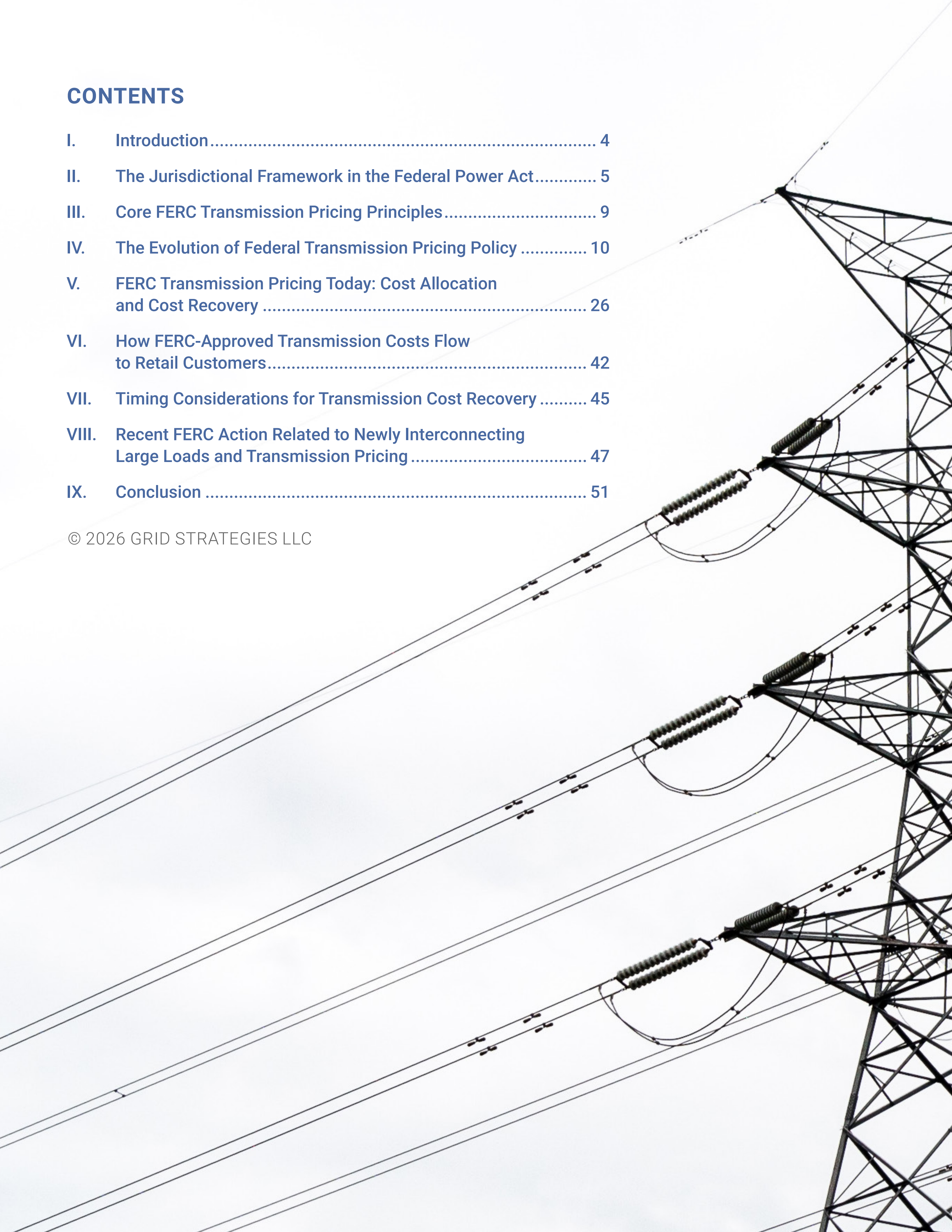
Today, most FERC-approved transmission costs are still recovered through embedded, cost-of-service-based transmission charges, typically implemented via formula rates that are updated annually. Costs are allocated using a variety of methods, depending on the type of transmission investment:

- Local transmission costs are generally allocated within a transmission owner's service territory using load ratio share cost allocation approaches.
- Regional transmission costs are allocated across utility zones in an RTO using more complex methods, including not only load ratio share, but also granular benefits-based, power flow-based, or hybrid cost allocation approaches, to reflect broader system benefits of regional transmission.
- Generator interconnection-related transmission network upgrade costs are typically assigned directly to the generators (interconnection customers) that trigger them, particularly in RTOs.

Incremental (marginal) cost-based transmission pricing, while permitted under FERC's "higher of" transmission pricing policy, remains relatively uncommon due to implementation complexity and cost support and documentation requirements. Its use is predominantly limited to generator interconnection in most RTOs.

Importantly, regardless of how costs are allocated and recovered from customers at the wholesale level (load serving entities), the rates actually charged to retail customers are, in most cases, decided by state regulators. Thus, states play a critical role in determining how costs are distributed among end-use customers and customer classes. Most state regulators in states with significant entry of new large loads have already updated policies, such as by adopting large load tariffs and minimum commitment and payment requirements, to protect existing customers from cost shifts associated with new, high-demand electricity users.

Looking ahead, the evolution of FERC transmission pricing policy will be central to balancing three competing objectives: maintaining reliability, ensuring affordability for new and existing customers, and enabling the infrastructure upgrade and expansion needed for improving resilience and enabling economic growth. Rather than viewing rising demand as a threat, this report and the second volume emphasize the opportunity to modernize and scale the grid while adhering to foundational principles that promote fairness, affordability, and efficient investment.



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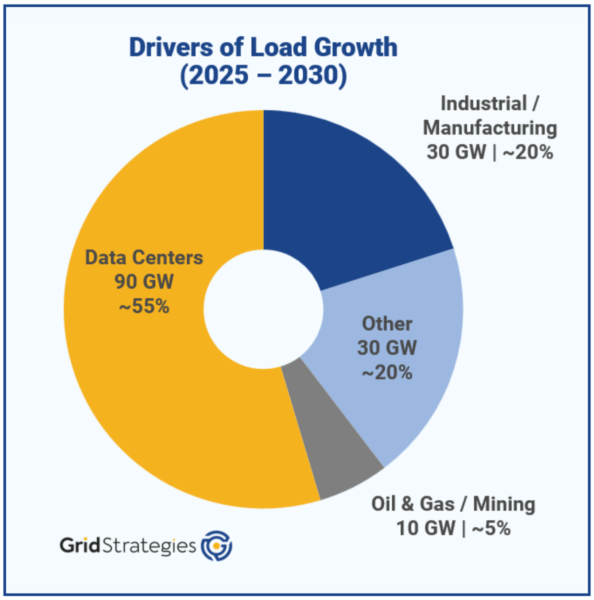
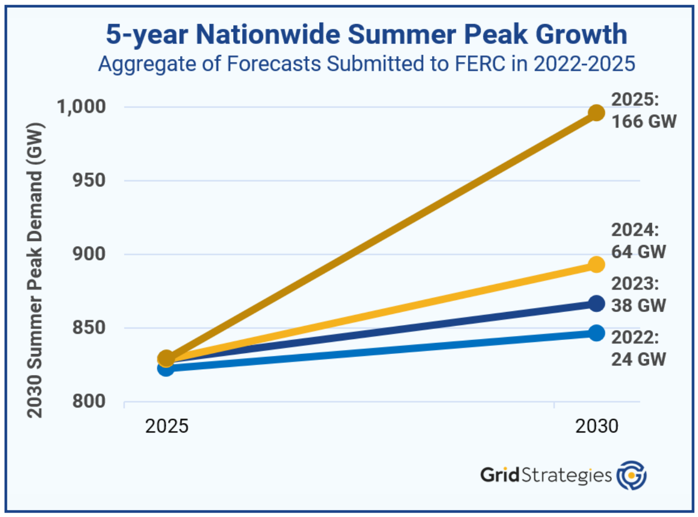
I. INTRODUCTION

One cannot read the news today without seeing headlines about data centers and rising electricity bills. The President is talking about the electric grid, the Mid-Atlantic's regional grid operator, and wholesale electricity markets. The President, governors, and the largest technology companies in the world have signed a Ratepayer Protection Pledge, committing new large load customers to pay for all the electricity and associated infrastructure needed to power their operations.[1] These developments are raising new questions about how electricity costs, including the costs of transmission infrastructure, are allocated to customers, and how ratepayer protection commitments play out under current cost allocation and cost recovery processes.





^ **FIGURE 1** - 5-year Nationwide Summer Peak Growth[2]

‹ **FIGURE 2** - Drivers of Load Growth[3]

This report, ***Federal Transmission Pricing Volume 1: The Evolution of Current Policies and Practices***, is aimed at bringing to the conversation a more fulsome background on the evolution of federal transmission pricing to inform the public, policymakers, and regulators about how we got to where we are today, and why the policies are the way they are.

The second volume of this report, ***Federal Transmission Pricing Volume 2: Options for Ensuring Affordability and Reliability in an Era of High Load Growth***, will take the next step of identifying guiding principles from the historic evolution of federal transmission pricing and applying those principles to test a series of potential actions FERC could take to ensure all transmission customers, including new data centers and other large electric system users, are paying their "fair share" of transmission costs.

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

2 Grid Strategies, ***Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers*** (Nov. 2025), https://gridstrategiesllc.com/project/load-growth-forecast/.

3 *Id.*

As rapid load growth raises new questions about how to timely meet demand reliably and affordably, without unfairly shifting costs to other customers, it is important to not lose grounding in fundamental policies that underpin America's growing grid. Rather than adopting a scarcity mindset, policymakers and regulators should see the opportunity of load growth to build the grid Americans need, to replace aging poles and wires, to leverage economies of scale, and to balance economic growth with consumer protection.

This report first discusses the jurisdictional framework as set forth in the Federal Power Act, and the roles of federal and state regulators under that framework in approving and allocating electricity costs to customers. Then it moves into core FERC transmission pricing principles that continue to govern what it means to pay a "fair share" of the costs of electric transmission infrastructure at the wholesale level. From there, this report traces the evolution of FERC transmission pricing from the inception of electric service to today, highlighting key FERC actions along the way and FERC's reasoning in each instance. Next, this report focuses on FERC transmission pricing today, including how FERC-approved transmission costs are allocated at the wholesale level, how costs allocated at the wholesale level are recovered from wholesale customers, and the use of what is called incremental cost-based transmission pricing. This report then briefly touches on how FERC-approved transmission costs flow to retail customers and key considerations around the timing of transmission cost recovery. Before closing, this report summarizes recent FERC actions related to newly interconnecting large loads and transmission pricing.

Neither this report nor Volume 2 cover generation costs (capacity, energy, ancillary services) or how they are allocated or recovered, or distribution facility cost recovery or allocation. Rather, these reports focus on transmission costs only.

II. THE JURISDICTIONAL FRAMEWORK IN THE FEDERAL POWER ACT

The Federal Power Act (FPA) separates authority over rates for transmission service in interstate commerce and wholesale electricity sales (FERC-jurisdictional) from authority over rates for sales to end-use customers and allocation of costs among those retail customers, in addition to authority over generation and other matters not specifically granted to FERC (state-jurisdictional).[4] The framework is one of cooperative federalism[5] and forms the statutory foundation for the long-standing "bright line" concept: FERC regulates transmission and wholesale

4 Specifically, FPA section 201 provides FERC with authority over transmission of electric energy in interstate commerce and wholesale sales of electric energy in interstate commerce and explicitly reserves to the states jurisdiction over any other sale of electric energy as well as over generation, local distribution, transmission in intrastate commerce, and transmission of electric energy consumed wholly by the transmitter. 16 U.S.C. § 824(a)–(b) (FPA § 201). FERC enjoys broad authority over transmission in interstate commerce. ***See, e.g.***, ***New York v. FERC***, 535 U.S. 1, 6 (2002) ("When it enacted the FPA in 1935, Congress authorized federal regulation of electricity in areas beyond the reach of state power," tasking FERC's predecessor agency with "effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce."); ***id.*** at 17 ("There is no language in the statute limiting FERC's ***transmission*** jurisdiction to the wholesale market, although the statute does limit FERC's ***sale*** jurisdiction to that at wholesale."); ***S.C. Pub. Serv. Auth. v. FERC***, 762 F.3d 41, 63 (D.C. Cir. 2014) (stating FERC "possesses greater authority over electricity transmission than it does over sales," "the FPA preserves for the States relatively more sales authority than transmission authority," and FERC "has relatively broader authority" over transmission).

5 ***E.g.***, ***FERC v. Elec. Power Supply Ass'n***, 577 U.S. 260, 281 (2016) (***EPSA***) (stating the FPA makes federal and state authorities "'complementary' and 'comprehensive,' so that 'there [will] be no 'gaps' for private interests to subvert the public welfare"—"[s]ome entity must have jurisdiction to regulate each and every practice that takes place in the electricity markets" (citations omitted)).

sales while states regulate generation, distribution, and retail sales.[6] In reality, there is no such bright line, and the jurisdictional divide is only becoming blurrier.[7]

WHO REGULATES WHAT?

State Regulators (PUCs, PSCs, etc.)	Federal Regulator (FERC)
Rates* for sales to end-use customers (i.e., retail sales)	Rates* for transmission in interstate commerce – rules for planning; approval of cost recovery and cost allocation to wholesale customers (i.e., load serving entities); sets utility's authorized return (cost of capital) on transmission assets, which is included in costs
Allocation of costs among retail customers/ customer classes	Rates for wholesale electricity sales
Generation planning	**Note:** There is no bright line in reality. E.g., FERC has declined to generically assert jurisdiction over transmission in bundled retail sales. FERC also sometimes approves rates for sales to end-use customers.
Local distribution	
Transmission service in intrastate commerce	
Transmission and generation construction	
Other matters not specifically granted to FERC	

** "Rates" is shorthand for rates, terms, and conditions and is not meant to encompass only the ultimate $/kWh rate but rather also the rules governing cost recovery, cost allocation, and rate design at the relevant regulatory level.*

This bright line framework typically produces a two-step pathway for how costs flow from a transmission provider to the electricity customer (aka load) in the rates they pay:

- FERC approves the recovery of transmission costs and their allocation among customers at the wholesale level (aka load serving entities, or LSEs), thus determining what FERC-jurisdictional transmission costs can be recovered and from which wholesale customers purchasing electricity for resale.

6 *See, e.g.*, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (referencing "the bright line drawn by Congress to fill the Attleboro gap for regulating wholesale sales of electric energy"), ***order on reh'g***, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, ***order on reh'g***, Order No. 888-B, 81 FERC ¶ 61,248 (1997), ***order on reh'g***, Order No. 888-C, 82 FERC ¶ 61,046 (1998), ***aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC***, 225 F.3d 667 (D.C. Cir. 2000), ***aff'd sub nom. New York v. FERC***, 535 U.S. 1 (2002).

7 *EPSA*, 577 U.S. at 281 ("It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other. To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level.").

- States approve retail electricity rates that include the FERC-approved transmission costs allocated to the relevant LSE and determine the allocation of those costs to end-use customers/customer classes. States are not permitted to reconsider whether FERC-approved transmission costs are recoverable in retail electricity rates or allocated appropriately to the LSE but can determine which individual customers/customer classes ultimately pay them.[8]

Thus, most "large load" differentiation that affects the end-use large load customer's bill (e.g., special rate classes, minimum bills, demand ratchets, contract tariffs, or commitment structures) is determined at the state level through state-jurisdictional ratemaking even when the underlying transmission costs originate from FERC-jurisdictional transmission cost recovery and cost allocation rules. The major limit on state authority is that states cannot "trap" costs by failing to provide the utility with a reasonable opportunity to fully collect those costs from their customers.[9]

Two-step pathway for costs to flow from transmission provider to electricity customer in end-use (i.e., retail) electricity rates:

1. FERC approves recovery of transmission costs and their allocation among wholesale customers (aka LSEs).
2. States approve retail electricity rates that include all FERC-approved transmission costs allocated to the relevant LSE and determine their allocation to end-use customers/customer classes (including large loads).

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But there is a wrinkle: for transmission providers outside regional transmission organizations and independent system operators (RTOs),[10] the federal regulation of transmission pricing differs from that just described. In these areas of the country, most transmission is sold as part of a bundled retail sale. In a bundled retail sale, an end-use customer purchases all required electricity services from a single seller—a vertically integrated utility that provides generation, transmission, and distribution—rather than engaging in separate transactions at wholesale and retail levels.

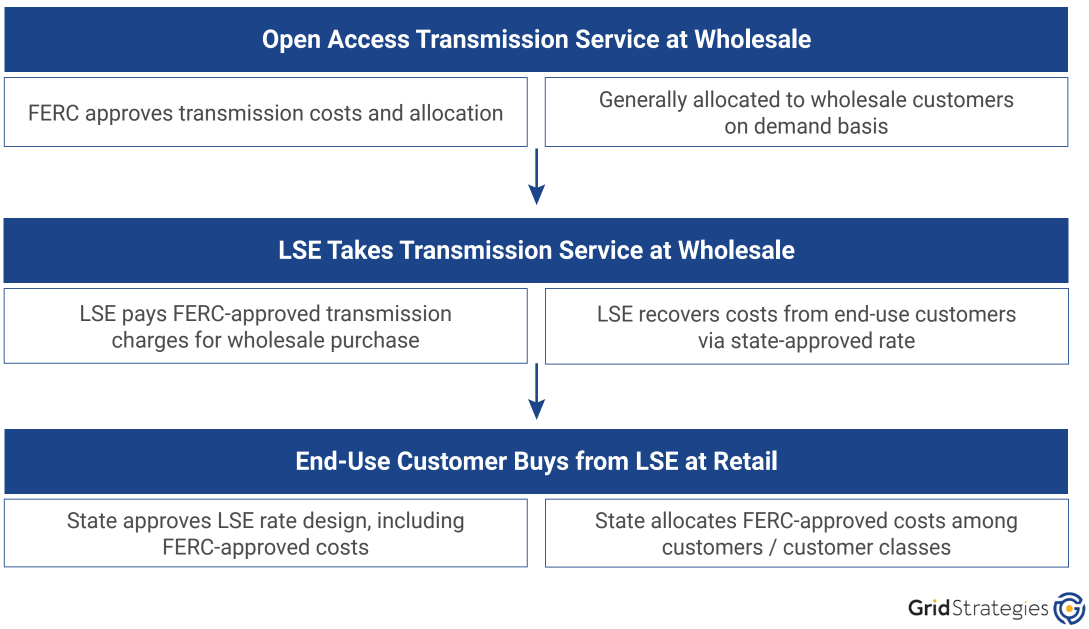
8 *See Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986) (finding state regulators must allow FERC-approved costs to be passed through to retail ratepayers).

9 *Id.* (explaining that a state may not, through its authority over retail sales, prevent a load serving entity "from recovering the costs of paying the FERC-approved rate" by "trapping" such costs).

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

FERC has, to date, declined to generically assert jurisdiction over the transmission used for bundled retail sales.[11] FERC reasoned that “when transmission is sold at retail as part and parcel of that delivered product called electric energy, the transaction is a sale of electric energy at retail.”[12] The U.S. Supreme Court, on appeal, affirmed FERC’s decision not to regulate bundled retail sales, finding FERC made a statutorily permissible choice.[13] FERC has since reaffirmed that decision, emphasizing “the need for heightened cooperation between federal and state regulators in areas where there are overlapping federal and state policy concerns.”[14] Bundled sales was the predominant structure prior to the 1990s and remains the norm for vertically integrated utilities in the Southeast and most of the West. As a result, transmission pricing for most[15] of the FERC-jurisdictional transmission costs outside RTOs is determined at the state level, primarily through cost-of-service ratemaking.[16]

TYPICAL UNBUNDLED TRANSMISSION SALE



11 Order No. 888-A, at 30,225-26 (explaining FERC’s belief that regulation of bundled retail transmission was unnecessary and that such unbundling would “raise serious jurisdictional questions” but not stating FERC had no power to regulate the transmission component of bundled retail sales); *New York*, 535 U.S. at 25 (“FERC chose not to assert such jurisdiction, but it did not hold itself powerless to claim jurisdiction. Indeed, FERC explicitly reserved decision on the jurisdictional issue . . . .”), 27 (noting that should FERC find undue discrimination in retail electricity markets, FERC would have to act to remedy that discrimination and could do so by regulating bundled retail transmission).

12 Order No. 888, at 31,781.

13 *New York*, 535 U.S. at 28.

14 *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, at P 94, ***order on reh’g***, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), ***order on reh’g and clarification***, Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), ***order on reh’g***, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), ***order on clarification***, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

15 Wholesale transmission service, such as wheeling through, into, or out of a utility’s transmission system by a wholesale customer (e.g., a municipal or cooperative utility, a neighboring utility, or an independent power producer), is still regulated at the federal level outside RTOs.

16 In many retail electric bills, there is no separate transmission line item, with transmission rates included in other bill components, such as energy usage charges. This makes it challenging to generalize about transmission pricing for bundled retail sales.

Importantly, FERC's decision to not broadly assert jurisdiction over the transmission component of bundled retail sales does not mean that FERC has not accepted proposals from transmission providers that blur the line. For example, California's investor-owned utilities use a FERC-approved transmission rate even for what they refer to as bundled retail sales and include cost allocation among end-use customers in their tariffs on file at FERC.[17] This dates back to the early years of the California Independent System Operator Corp.'s (CAISO) formation. This appears to be the only circumstance in which FERC routinely approves class-specific end-use rates for retail customers.

For discussion of recent action at FERC related to the jurisdictional divide and large loads specifically, see Section VIII below.

III. CORE FERC TRANSMISSION PRICING PRINCIPLES

There are a couple of key concepts that underpin all FERC-regulated transmission cost recovery and cost allocation.

Just and reasonable and not unduly discriminatory or preferential. FERC is charged with the responsibility, per the FPA, of ensuring that the rates, terms, and conditions of transmission service in interstate commerce are just and reasonable and not unduly discriminatory or preferential.[18] Thus, all rules governing how federally regulated transmission rates are set (i.e., which transmission costs are recoverable and from whom) must adhere to this overarching statutory standard. FERC has discretion, under this statutory standard, to approve rates within the "zone of reasonableness," which essentially means there is no single just and reasonable rate but rather a range of acceptable outcomes.[19]

17 For example, Pacific Gas and Electric's (PG&E) tariff states that end-user transmission rates are based on the transmission revenue requirement authorized by FERC. End-user transmission rates are set forth in Appendix III using specific retail schedules and associated transmission charge components. Pacific Gas & Electric Co., Transmission Owner Tariff and Service Agreements, § 5.3 (0.0.0), Appendix III (35.0.0). Furthermore, the section on "Retail Transmission Rates" establishes that where California Public Utilities Commission orders (and certain California Energy Commission requirements) change rate groups, rate schedules, or retail rate design in ways that cannot be reflected through normal formula operation, PG&E will make a filing at FERC to revise the relevant retail rate schedules to conform to the state-directed change. Pacific Gas & Electric Co., Transmission Owner Tariff and Service Agreements, Appendix VIII, Attach. 1 (2.1.0), § 10.2.

18 16 U.S.C. § 824d.

19 "The U.S. Supreme Court has recognized the Commission's broad latitude to fix rates. There is no single valid theory of ratemaking. Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed, which is controlling." ***Duquesne Light Co. v. Barasch***, 488 U.S. 299, 316 (1998); ***Fed. Power Comm'n v. Hope Natural Gas Co.***, 320 U.S. 591, 602 (1944). Indeed, "allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science." ***Colo. Interstate Gas Co. v. Fed. Power Comm'n***, 324 U.S. 581, 589 (1945).

Cost causation. In considering what just and reasonable means, courts established what is called the cost causation principle.[20] It essentially stands for the proposition that those who cause the costs to be incurred should also pay the costs.[21] In the transmission context, those who have caused the need for the transmission should pay for the costs of the transmission to meet such need. To do otherwise is to fail to meet the statutory just and reasonable standard.[22]

Beneficiary pays. An extension of the cost causation principle is the "beneficiary pays" principle, pursuant to which a customer who benefits from new facilities can be said to have "caused" the costs of developing those facilities to be incurred, such that those beneficiaries should share in paying the costs of the facilities from which they benefit.[23] FERC and associated court precedent prohibit cost allocation to entities that derive no or trivial benefits and, crucially, requires that costs must be allocated "roughly commensurate with estimated benefits."[24] These concepts essentially frame the "zone of reasonableness" in the transmission cost recovery context.

IV. THE EVOLUTION OF FEDERAL TRANSMISSION PRICING POLICY

The discussion below traces the evolution of transmission pricing, from the early days of regulation by states alone, to the creation of federal regulatory authority, through key decision points in federal transmission pricing policy through present day.

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20 *City of Lincoln v. FERC*, 89 F.4th 926, 930 (D.C. Cir. 2024) ("The FPA's just and reasonable standard incorporates a cost-causation principle."); ***Old Dominion Elec. Coop. v. FERC***, 898 F.3d 1254, 1255 (D.C. Cir. 2018) ("Under the [FPA], electric utilities must charge 'just and reasonable' rates. For decades, the Commission and the courts have understood this requirement to incorporate a 'cost-causation principle'—the rates charged for electricity should reflect the costs of providing it." (internal citations omitted)); ***K N Energy, Inc. v. FERC***, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("FERC and the courts have added flesh to these bare statutory bones [i.e., the just and reasonable standard], establishing what has become known in Commission parlance as the 'cost-causation' principle.").

21 ***E.g.***, ***BNP Paribas Energy Trading GP v. FERC***, 743 F.3d 264, 268 (D.C. Cir. 2014) ("[T]he cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit.").

22 ***El Paso Elec. Co. v. FERC***, 76 F.4th 352, 363 (5th Cir. 2023) ("No amount of emphasizing other competing interests permits FERC to sacrifice the foundational principle of cost-causation by refusing to allocate costs to those who cause the costs to be incurred and who reap the resulting benefits.").

23 FERC explained "beneficiary pays" as recognizing "the nature of power flows over an interconnected transmission system does not permit a public utility transmission provider to withhold service from those who benefit from those services but have not agreed to pay for them." ***Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.***, Order No. 1000, 136 FERC ¶ 61,051, at P 534 (2011), ***order on reh'g***, Order No. 1000-A, 139 FERC ¶ 61,132, ***order on reh'g & clarification***, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), ***aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC***, 762 F.3d 41 (D.C. Cir. 2014); ***see also id.*** P 535 (stating "the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them"); ***Ill. Commerce Comm'n v. FERC***, 576 F.3d 470, 476-77 (7th Cir. 2009) (***ICC v. FERC I***) ("All approved rates must reflect to some degree the costs actually caused by the customer who must pay them . . . To the extent that a utility benefits from the costs of new facilities, it may be said to have caused a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."); ***Neb. Pub. Power Dist. v. FERC***, 957 F.3d 932, 941 (8th Cir. 2020) ("[I]t is certain that to the extent that a utility benefits from the costs of new facilities, it may be said to have caused a part of those costs to be incurred.").

24 ***ICC v. FERC I***, 576 F.3d at 477 ("If [FERC] cannot quantify the benefits . . ., but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in [the] region, then fine; [FERC] can approve [the] proposed pricing scheme on that basis.").

HISTORY OF TRANSMISSION PRICING

Late 1800s	Bundled retail sales; no regulation
Early 1900s	State regulation of monopoly franchises; state cost-of-service ratemaking
1927	Supreme Court identifies “Attleboro Gap” (no regulation of transmission in interstate commerce)
1935	Public Utility Act grants Federal Power Commission jurisdiction over transmission in interstate commerce
1977	Congress establishes FERC; federal cost-of-service ratemaking
1994	FERC Transmission Pricing Policy Statement; “higher of” pricing allowed; corporate “and” pricing prohibited
1996	FERC Order 888 requires open access and non-discriminatory transmission service; “higher of” continues with introduction of “but for” test for incremental/direct assignment
1999	FERC Order 2000 on RTOs; requires RTOs to eliminate “rate pancaking;” some forms of “and” pricing allowed in RTOs
2003	FERC Order 2003 adopts standard generator interconnection procedures; maintains “higher of” pricing; again allows some form of “and” pricing in RTOs (participant funding)
2007	FERC Order 890 requires open, transparent, and coordinated transmission planning, clear cost allocation, and comparison of rates for “higher of” pricing with robust cost support
2011	FERC Order 1000 requires regional transmission planning and cost allocation; six regional cost allocation principles; emphasis on “beneficiary pays” principle
2023	FERC Order 2023 reforms standard generator interconnection procedures; applies same pricing policy to clusters of generators
2024	FERC Order 1920 on long-term regional transmission planning and cost allocation; moves away from single driver planning and cost allocation; increases role for states

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THE ORIGINAL TRANSMISSION PRICING POLICY: COST-OF-SERVICE

From the inception of electricity service in the late 1800s, electricity sales were bundled: a customer could only buy an inseparable electricity product, including generation, transmission, and distribution, from the local vertically integrated electric company operating under a state-granted monopoly franchise.[25] At first, the price

25 *New York*, 535 U.S. at 1 (When Congress enacted the FPA in 1935, “most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems. Although there were some interconnections among utilities, most operated as separate, local monopolies subject to state or local regulation. Their sales were ‘bundled,’ meaning that consumers paid a single

for that bundled product was set by the electric company. By the early 1900s, prices were increasingly regulated by the state that granted the monopoly franchise.[26] Utilities made rate proposals to state regulators, designed to recover the utility's "cost of service" for providing the electricity service (building, operating, and maintaining the needed system, including generation, transmission, and distribution) plus a reasonable return on investment for the utility's shareholders and debtors commensurate with their investment risks. The rates included a demand charge (or "load factor" rate) to recover the fixed costs of the system plus a return on those fixed costs and an energy charge to recover the variable costs (e.g., fuel) of supplying electricity.[27]

The customers of these utility franchises, located within the monopoly service territory, are known as native load customers. Utilities with such service territories have an obligation to serve native load customers, including by planning their systems to meet forecasted native load reliably. The backbone of our electric system was built for native load customers and those same native load customers paid for such legacy assets through state-approved rolled-in retail rates. Public power entities similarly build their systems primarily to serve native load, which, in turn, pays for the system costs.

As the electric system grew, vertically integrated utilities began to connect their systems, raising issues around power flowing not only between the systems but across state lines (i.e., in interstate commerce). States lacked authority over sales and deliveries of electricity in interstate commerce, leaving the rates and other terms of such service unregulated.[28] Congress addressed this growing gap in regulation with the Public Utility Act of 1935, granting FERC's predecessor agency, the Federal Power Commission, jurisdiction over transmission in interstate commerce. Thus, states continued to approve rates for bundled retail sales, but the federal government began to regulate the rates for wholesale power sales and transmission-only sales in interstate commerce, though federal-jurisdictional transmission pricing was uncommon at first. In 1977, Congress established FERC and bolstered its independent regulatory mandate.

Generally, in the early days of electricity service, transmission was priced on a cost-of-service basis, whether regulated by states or the federal government. Cost-of-service ratemaking for transmission service is aimed at allowing transmission providers to charge rates that yield revenues equal to the rolled-in, embedded costs[29] of providing service on their transmission system plus a reasonable rate of return on the transmission provider's capital investment, less depreciation, plus operation and maintenance expenses, taxes, and interest. The sum total of these inputs is called the revenue requirement. FERC must ensure rates are adequate to recover these costs, and must ensure that the rate of return portion is sufficient to attract future investment when needed, per

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charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent."); ***Midwest ISO Transmission Owners v. FERC***, 373 F.3d 1361, 1363 (D.C. Cir. 2003) ("In the bad old days, utilities were vertically integrated monopolies; electricity generation, transmission, and distribution for a particular geographic area were generally provided by and under the control of a single regulated utility. Sales of those services were 'bundled,' meaning consumers paid a single price for generation, transmission, and distribution. As the Supreme Court observed, with blithe understatement, '[c]ompetition among utilities was not prevalent.'") (quoting ***New York***, 535 U.S. at 1).

26 ***See*** NARUC, Comments, Docket No. RM26-4-000, at 4 (filed Nov. 21, 2025) (NARUC Comments on DOE ANOPR) (explaining that states regulated "electricity transactions and services long before Congress established FERC's predecessor, the Federal Power Commission").

27 ***E.g.***, ***Cities of Batavia v. FERC***, 672 F.2d 64 (D.C. Cir. 1982) (describing cost-of-service ratemaking).

28 ***See Public Util. Comm'n of R.I. v. Attleboro Steam & Elec. Co***., 273 U.S. 83 (1927) (creating what has become known as the "Attleboro Gap" in finding states lacked authority to regulate an interstate transaction).

29 Embedded costs are reflected in the utility's book of accounts and include the rolled-in total cost of a utility's capital investment in new facilities or upgrades that become part of the utility's integrated transmission system. ***Inquiry Concerning the Commission's Pricing Policy for Transmission Servs. Provided by Pub. Utils. Under the Fed. Power Act***, 59 FR 55031 (Nov. 3, 1994), FERC Stats. and Regs. ¶ 31,005 (1994) (Transmission Pricing Policy Statement).

longstanding Supreme Court precedent.[30] Under the traditional cost-of-service revenue requirement approach, ratemaking involves three steps:

- Utility determines its total revenue requirement (with the capital component traditionally measured by embedded, depreciated cost);
- Utility allocates that total revenue requirement among customers or classes of customers to reflect what portion is attributable to providing transmission services to such customers or classes of customers; and
- Utility designs rates to recover those allocated costs, such that the total collected revenues equal the utility's prudently incurred[31] embedded costs plus a reasonable return on its capital investment.

STANDARD RATEMAKING CONCEPTS

Cost-of-Service Ratemaking: Establishes the revenue requirement (total dollars the utility is allowed to collect) based on the cost to the utility of providing the transmission service, including a reasonable return

General Cost-of-Service Formula: $R = O + (r \times B) + D + T$

R = revenue requirement

O = operating expenses (fuel, labor, maintenance)

$r \times B$ = return on rate base

- r = allowed rate of return (sufficient to attract future investment when needed)
- B = rate base (value of invested capital, e.g., transmission lines, less accumulated depreciation over time)

D = depreciation expense

T = taxes

Three Steps to Traditional Cost-of-Service Revenue Requirement Approach:

1. Utility determines total revenue requirement (FERC approves wholesale and state approves retail).
2. Utility allocates that total revenue requirement among customer classes on the basis of cost causation principles (FERC approves wholesale and state approves retail).
3. Utility designs rates to recover those allocated costs, such that the rates are expected to recover revenues equal to the utility's prudently incurred embedded costs plus a reasonable return on its capital investment.

Prudence Review: Regulators review utility investments to determine whether they were reasonable costs for the utility to incur at the time the utility made the decision (i.e., were prudently incurred), based on what the utility knew or should have known then. Imprudent costs can be disallowed, meaning the regulator does not allow the utility to recover the costs in rates.

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30 ***See Duquesne***, 488 U.S. at 316; ***Hope***, 320 U.S. at 602; ***Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of WV***, 262 U.S. 679 (1923).

31 Note "prudence" is another important concept in ratemaking, developed, in part, to counteract utility monopoly power through the threat of a regulator disallowing recovery of imprudently incurred costs. Scott Hempling, ***Regulating Public Utility Performance: The Law of Market Structure,***

As electric systems began to expand and increasingly connect to one another,[32] FERC saw an uptick in rate proposals for transmission service across otherwise vertically integrated utility systems. And with it, FERC began to see innovation in ratemaking, departing from the strict traditional revenue requirement approach, particularly where providing the transmission service was triggering the need for transmission system expansion. FERC began to allow transmission providers to charge transmission-only customers the higher of embedded costs (traditional revenue requirement approach) or incremental expansion costs[33] (or legitimate and verifiable opportunity costs where utilities chose not to expand their system due to constraints, capped by incremental expansion costs).[34] This is called "or" pricing or "higher of" pricing. Sometimes incremental costs are higher than embedded costs; it tends to depend on whether new equipment is more costly than historical average costs.

FERC TRANSMISSION PRICING POLICY STATEMENT: "HIGHER OF" PRICING

In 1994, FERC issued its Transmission Pricing Policy Statement (Policy Statement) to bring clarity to its transmission pricing policy particularly because there were no requirements that vertically integrated utilities offer transmission service to third parties nor that they do so on a non-discriminatory or comparable basis to their use of the same transmission for their own bundled sales to native load customers.[35] The Policy Statement remains an important guide to FERC-jurisdictional transmission pricing. Although it is now over 30 years old, it has been repeatedly cited by current FERC Commissioners in their separate statements regarding transmission pricing related to large loads[36] and is essential context for potential changes to transmission pricing going forward.

Pricing and Jurisdiction, Am. Bar Ass'n, at 236 (2013). "The first prudence disallowances prompting judicial decisions were made during the rise (and fall) of nuclear power in the late 1960s and early 1970s." M. Wachpress, ***Dear Prudence: The Atomic Origins, Decarbonization Deployment, and Transformative Potential of a Regulatory Principle***, forthcoming, Utah L. Review, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=6308639.

32 ***See, e.g.***, ***S.C. Pub. Serv. Auth.***, 762 F.3d at 49-50 (describing the evolution of the electric system following the enactment of the FPA, from mostly vertically integrated utilities to "increasingly interconnected" systems where "long-distance transmission had become increasingly economical, and smaller, lower-cost power plants had begun to emerge as competitors to the vertically integrated utilities").

33 FERC described incremental expansion costs as the "cost of increasing the level of service provided" (such as the cost of additional needed facilities) to provide transmission service to the relevant customer or class of customers.

34 ***E.g.***, ***Penn. Elec. Co.***, 58 FERC ¶ 61,278 (1992) (describing the lost opportunity of using limited transmission capacity to serve a new customer rather than to access lower cost power, thereby foregoing the opportunity to reduce costs for native load customers to serve a third-party customer) (citing other precedent regarding opportunity cost pricing); ***Ne. Utils. Serv. Co. v. FERC***, 993 F.2d 937 (1st Cir. 1993) (discussing FERC's increasing openness to departing from traditional pricing principles to allow incremental cost pricing).

35 ***See*** 18 C.F.R. § 2.22.

36 ***E.g.***, ***Duke Energy Carolinas, LLC***, 193 FERC ¶ 61,237 (2025) (Chang, Comm'r, concurring); ***Commonwealth Edison Co.***, 194 FERC ¶ 61,183 (2026) (Swett, Chair & LaCerte, Comm'r, concurring).

In the Policy Statement, FERC aimed to ensure transmission pricing policies "promote economic efficiency, fairly compensate utilities for providing transmission services, reflect a reasonable allocation of transmission costs among transmission users, and maintain the reliability of the transmission grid." FERC adopted five principles with which transmission pricing proposals should seek to conform (see call out box below). The principles were especially important at the time FERC issued the Policy Statement as there were not yet RTOs independently operating transmission facilities and offering non-discriminatory access.[37]

In the Policy Statement, FERC generalized the policy of "higher of" pricing that it had begun allowing on a case-by-case basis. According to FERC, giving transmission providers the option to charge the "higher of" embedded or incremental costs has three aims: "hold native load customers harmless;" "provide the lowest reasonable cost-based price to third-party firm transmission customers;" and "prevent the collection of monopoly rents by transmission owners and promote efficient transmission decisions."[38] FERC noted, "[t]o the extent practicable, transmission rates should be designed to reflect marginal costs, rather than embedded costs" because, according to FERC, this promotes efficient decision-making on the part of both the transmission owners and users. In other words, if the cost of serving the new transmission customer is higher than the rolled-in embedded costs of the system, FERC thought the new transmission customer should pay that higher cost (though FERC left it up to the transmission provider to decide which to charge).

FERC benefitted from experience regulating natural gas transportation rates where similar considerations applied. Incremental pricing is used regularly in allocating and recovering costs of natural gas pipeline expansions.

In electricity, determining the marginal cost or incremental expansion cost for a new transmission customer can be challenging given complicated network interactions and "loop flow" where capacity can benefit every user across entire regional grids, so transmission providers have not frequently elected the "higher of" option, even where incremental costs indeed may have been higher.

While FERC was explicit about allowing "higher of" pricing, FERC was similarly explicit about disallowing certain forms of "and" pricing. Under "and" pricing, transmission providers charge both the embedded costs ***and*** the incremental costs of the same transmission service on the same system. FERC generally views "and" pricing as unfair because it can result in third-party transmission customers paying more than the costs they cause and effectively subsidizing native load customers. However, as discussed later, FERC does not have an absolute ban on all forms of "and" pricing—just where it is needed to prevent undue discrimination and unfair cost shifting.[39]

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37 ***See also Entergy Servs., Inc.***, 70 FERC ¶ 61,006 (1995) (rejecting Entergy's proposal to charge third-party customers for both system average costs and incremental costs of a system addition because it failed the "comparability" requirement). Congress had recently enacted the Energy Policy Act of 1992, P.L. No. 102-486, giving FERC new authority to require transmission access (called "wheeling" power) for a third party across a transmission owner's facilities, thereby enabling competition in generation and moving toward full open access transmission service.

38 ***See also Duke***, 193 FERC ¶ 61,237 (Chang, Comm'r, concurring) (stating that FERC's "higher of" transmission pricing policy "protects existing transmission customers by allowing transmission owners to charge new customers the higher of an incremental rate or the rolled-in rate for NITS or point-to-point transmission service," and "ensures that new customers or incremental demand from existing customers do not significantly and directly increase the cost of transmission for other customers and aims to hold native load customers harmless").

39 ***E.g.***, ***Jersey Cent. Power & Light Co.***, 72 FERC ¶ 61,298 (1995) (stating that while the prohibition on "and" pricing "applies to a particular method of combining average and embedded cost pricing, i.e., the sum of an average cost postage stamp rate with the direct assignment of opportunity cost or expansions costs that would not have been incurred 'but for' the transmission service," FERC "expressly permit[s] transmission rates to combine average cost pricing and opportunity cost pricing where the customer pays a pro rata share of average embedded costs and average opportunity costs"). In addition, as of 1994, FERC had not yet ruled on transmission pricing within independent RTOs. As explained later, FERC approved what looks like "and" pricing in RTOs as discrimination was not a concern in that context.

Another point to note from the Policy Statement is that FERC was clear that "[d]ifferent customers may pay different rates if they use the system in different ways." While FERC must ensure rates are not unduly discriminatory or preferential, the standard leaves room for "due" discrimination, such as where customers have cost-of-service differences based on their different peaking times and customer profiles.[40] In modern FERC parlance, discrimination is undue when similarly situated customers are treated differently without adequate justification.[41]

FERC'S 1994 TRANSMISSION PRICING POLICY STATEMENT

Five Principles for Transmission Pricing:

1. Meet the traditional revenue requirement;
2. Reflect comparability (third parties can take service on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider itself);
3. Promote economic efficiency, including in transmission expansion, generation and load locations, use of existing transmission, and efficient dispatch of generation;
4. Promote fairness (including third party customers not subsidizing existing customers); and
5. Be practical, such that customers are able to calculate the charges.

Endorsed "Higher of" Pricing: FERC allows (but does not require) transmission providers to charge customers the higher of embedded costs (traditional cost-of-service revenue requirement approach) or incremental expansion costs (or legitimate and verifiable opportunity costs) of serving the customer.

Prohibited Corporate "And" Pricing: FERC does not allow transmission providers to charge both the embedded costs and the incremental costs of the same transmission service on the same system because it can result in third-party customers paying more than the costs they cause and subsidizing native load customers (undue discrimination and unfair cost shifting).

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40 *See Cities of Bethany v. FERC*, 727 F.2d 1131, 1138 (D.C. Cir. 1984) (upholding FERC distinguishing between wholesale municipal customers and wholesale rural cooperative customers based on different load profiles: one general service customers with heavy air conditioning loads and one servicing mainly rural and farm customers) (citing *Ala. Elec. Coop. v. FERC*, 684 F.2d 20 (D.C. Cir. 1982) for the proposition that courts have upheld FERC's approval of separate customer categories when those categories reflected general factual characteristics of the customer classes with cost-of-service implications); *St. Michaels Utils. Comm'n v. FPC*, 377 F.2d 1020 (D.C. Cir. 1977) (allowing for different wholesale rates for classes of customers that reflect different costs of serving them).

41 *Mo. River Energy Servs. v. FERC*, 918 F.3d 954, 958 (D.C. Cir. 2019) ("A mere difference in the treatment of two entities does not violate that provision; instead, undue discrimination occurs only if the entities are 'similarly situated,' such that 'there is no reason for the difference.'").

OPEN ACCESS TRANSMISSION SERVICE AND PRICING

As noted above, at the time of the Policy Statement, FERC had not imposed any specific requirements on transmission providers to offer open and non-discriminatory access to their transmission system to third-party users. Yet the dramatic increase in the number of electricity suppliers necessitated action to prevent transmission owners from refusing "to deliver energy produced by competitors" or from delivering "competitors' power on terms and conditions less favorable than those they apply to their own transmissions."[42] FERC also wanted to foster competitive wholesale electricity markets.[43]

In 1996, FERC issued Order 888 to address the potential for undue discrimination by requiring FERC-jurisdictional transmission providers to offer open access transmission service consistent with the terms and conditions in FERC's *pro forma* open access transmission tariff (OATT). The *pro forma* OATT was designed to include primarily non-rate terms and conditions, with rates being proposed in FPA section 205 filings made subsequent to adopting the non-rate terms and conditions.[44]

While Order 888 significantly reshaped the transmission service landscape, FERC did not broadly reform transmission pricing in Order 888. Rather, FERC put in place rules to stop transmission owners from favoring their native load customers with better rates or better information access than the transmission owners offered to other customers. Otherwise, FERC maintained its existing "higher of" pricing policy from the Policy Statement and declined to generically assert jurisdiction over bundled retail sales, as discussed earlier.

The *pro forma* OATT adopted in Order 888 requires transmission providers to expand transmission capacity, if necessary, to meet the needs of firm transmission customers on a comparable basis as they do for native load customers.[45] In Order 888, FERC explained that "if the cost of expansion is directly attributable to a customer's request for transmission service and the expansion would not be undertaken 'but for' that customer's request, then it is reasonable to assign the cost of expansion to that customer." According to FERC, allowing this direct assignment avoids existing customers subsidizing new customers' use of the transmission system.

The decision to allow direct assignment of certain costs to new customers in Order 888 alongside charging rates for the embedded costs of the remaining system does not fully achieve "higher of" pricing (where the

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42 *New York*, 535 U.S. at 1; *Midwest ISO Transmission Owners*, 373 F.3d at 1364 ("As the next step toward the goal of a more competitive electricity marketplace, Order No. 888 encouraged—but did not require—the development of multi-utility" grid operators to address "segmentation of the transmission grid among different utilities" and the associated inefficiencies thereof.).

43 *S.C. Pub. Serv. Auth.*, 762 F.3d at 50 (describing FERC's conclusion that "the economic self-interest of electric transmission monopolists lay in denying transmission or offering it only on inferior terms to emerging competitors" and, thus, "[g]iven this intrinsic defect," FERC action was needed "to foster 'a successful transition to competitive wholesale electricity markets'"); ***see also*** Order No. 888 (discussing the goal of the Energy Policy Act of 1992 to "promote greater competition in bulk power markets by encouraging new generation entrants . . . and by expanding the Commission's authority under sections 211 and 212 of the FPA to approve applications for transmission services").

44 *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002) ("Section 205 of the Federal Power Act gives a utility the right to file rates and terms for services rendered with its assets.").

45 *E.g.*, *Pro forma* OATT § 13.5 (requiring for firm point-to-point customers, where there is insufficient transmission capacity, the transmission provider must "expand or upgrade its Transmission System" provided the customer "agree[s] to compensate the Transmission Provider for any necessary transmission facility additions"); *Pro forma* OATT § 28.2 (requiring for network service customers that the transmission provider must "plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service" and "endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers").

transmission provider could charge the customer the incremental costs attributable to serving that customer). Nonetheless, Order 888's approach advanced FERC's expressed preference for "marginal" cost pricing from the Policy Statement. As noted earlier, determining the incremental costs that would not be incurred "but for" the new customer is challenging and is not commonly used. In Order 888, FERC also repeated its admonition against "and" pricing (at least where discrimination is a concern) to avoid new customers subsidizing a transmission provider's native load customers.

TRANSMISSION PRICING IN REGIONAL TRANSMISSION ORGANIZATIONS

In Order 888, FERC set out a list of principes for ISOs and encouraged a move toward more regionalization of the electric system. FERC went a step further in 1999 when it issued Order 2000 to advance the voluntary formation of RTOs with the aim that all transmission owners place their transmission facilities under the control of an RTO to address operational and reliability issues, eliminate undue discrimination, and achieve efficiencies for the benefit of all consumers.[46] FERC established minimum characteristics and functions of an RTO and enumerated the anticipated benefits of RTO formation, including, as relevant here, "increased efficiency through regional transmission pricing and the elimination of rate pancaking." Pancaked transmission rates refer to separate charges assessed by individual transmission owners layering on top of one another—like pancakes—every time the contract path for a transmission service request crosses their system. Without an RTO, customers could face two or more compounding charges for longer contract paths that do not necessarily reflect the actual cost of providing the transmission service.

While traditional transmission pricing appropriately reflected an industry structure in which vertically integrated utilities designed their transmission systems to meet demand within their local service territory, FERC noted that RTOs are a different structure altogether and therefore require a potentially different transmission pricing approach—one that allows for transmission system design and operation to meet regional needs, including congestion management and regional expansion. FERC encouraged innovative ratemaking from RTOs, provided that the proposals eliminate rate pancaking across the RTO footprint, manage congestion, internalize parallel path flows, "deal effectively and fairly" with transmission owners that do not participate in RTOs, and provide incentives for transmission owners to efficiently operate and invest in their systems (with emphasis on the last point). FERC described performance-based regulation and other potential ratemaking practices RTOs could propose.

FERC specifically stated that RTOs could propose rate designs that combine elements of embedded and incremental cost rates, such as a non-pancaked access fee based on embedded costs of the existing transmission facilities that make up the regional system and an incremental charge based on opportunity or expansion costs for new transmission facilities.[47] FERC also accepted proposals from ISOs during their

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46 ***Regional Transmission Organizations***, Order No. 2000, 65 FR 809, FERC Stats. & Regs, Regs. Preambles ¶ 31,089 (Jan. 6, 2000), ***order on reh'g***, Order No. 2000-A, 90 FERC ¶ 61,201 (2000); ***see also Midwest ISO Transmission Owners***, 373 F.3d at 1364 (explaining that "FERC had come to a less sanguine view of the curative powers of functional unbundling" and found that the "inefficiencies in the transmission grid and lingering opportunities for transmission owners to discriminate in their own favor remained obstacles to robust competition in the wholesale electricity market").

47 Order No. 2000-A (adding 18 C.F.R. § 35.34(e), "Innovative transmission rate treatments for Regional Transmission Organizations," and explicitly stating that innovative transmission rate treatment that RTOs may adopt includes "Transmission rates that combine elements of incremental cost pricing for new transmission facilities with an embedded-cost access fee for existing transmission facilities"). The summary of Order No. 2000 around incremental pricing similarly states that FERC would allow "proposals to charge incremental rates for new investment while charging embedded rates for existing investment."

formation that allowed for customers scheduling transmission service on a firm basis to be charged an embedded cost rate and also for congestion charges because, according to FERC, the customer could use "fixed transmission rights" (FTRs) to receive congestion revenues to offset that additional incremental charge (i.e., the congestion charge), thus avoiding "and" payments.[48]

While technically forms of "and" pricing, FERC explained that the "and" pricing it banned in the 1994 Transmission Pricing Policy Statement (which FERC later called "corporate 'and' pricing") is aimed at making transmission costs higher for third-party customers than native load customers by charging third-party customers the sum of the embedded and incremental costs, and thus is a form of undue discrimination.[49] In contrast, the combined embedded and incremental cost pricing FERC entertains for RTOs "is intended to (1) reduce the cost of transmission over multiple utility systems in both constrained and unconstrained situations and (2) rely on congestion charges to provide a uniform price signal to all users in constrained situations."[50] Thus, FERC allowed what looks like "and" pricing in the RTO context because the potential for undue discrimination was moderated with an independent transmission system operator that lacks the incentive to discriminate in favor of native load customers (because RTOs do not have native load customers).[51] For all RTO transmission pricing proposals, FERC cautioned that new approaches should not enhance transmission owner revenues at the expense of transmission service customers nor stray from the fundamental principle that "transmission prices must reflect the costs of providing the service."[52]

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48 Every firm transmission service customer under the proposed tariff was awarded FTRs based on their specific reservations. FERC explained that "[u]sers with firm reservations if they schedule energy consistent with the points of receipt and delivery specified for their reservations" are sheltered from congestion charges via the revenues they receive from the FTRs. Under locational marginal pricing, transmission congestion charges reflect the differences between the marginal price of generation at each location on the regional transmission network. ***See Penn.-N.J.-Md. Interconnection***, 81 FERC ¶ 61,257 (1997), ***order on reh'g***, 82 FERC ¶ 61,047 (1998).

49 Order No. 2000 (explaining that in the Transmission Pricing Policy Statement, FERC "addressed 'and' pricing at the corporate level, i.e., proposals by individual transmission providers to assess certain customers both an embedded cost rate and an incremental cost rate, while assessing only an embedded cost rate to their own uses of the transmission system").

50 *Id.* (noting "unlike the corporate 'and' pricing prohibited under [the] Transmission Pricing Policy Statement, the objective of" RTO "and" pricing "is not to make the cost faced by one group of transmission users (i.e., the wholesale customer) higher than another's (i.e., native load)"); ***see also Pac. Gas & Elec. Co.***, 77 FERC ¶ 61,204 (1996), ***order on reh'g***, 81 FERC ¶ 61,122 (1997) (expressing concern that the original proposal to form the CAISO violated "and" pricing, which FERC described as "customers should not be required to pay prices equal to the sum of embedded and opportunity costs").

51 ***See Midwest Indep. Transmission Sys. Operator***, 84 FERC ¶ 61,231 (explaining that FERC's "***per se*** prohibition on pricing which combines incremental and average cost rates involves service provided by a single transmission provider and does not extend to regional rate proposals"), ***order on reconsideration***, 85 FERC ¶ 61,250, ***order on reh'g***, 85 FERC ¶ 61,372 (1998) (granting rehearing and not allowing MISO "to charge a customer both an average and incremental cost rate, unless it charges the same rate to all transmission customers, including the owners," during the seven-year transition period to ISO formation); ***see also Standardization of Generator Interconnection Agreements & Procs.*** Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at P 826 (2003) ("With respect to an RTO or ISO . . . we will allow it to seek 'independent entity variations' from the Final Rule . . . This is a balanced approach that recognizes that an RTO or ISO has different operating characteristics depending on its size and location and is less likely to act in an unduly discriminatory manner than a Transmission Provider that is a market participant."), ***order on reh'g***, Order No. 2003-A, 69 FR 15932, 106 FERC ¶ 61,220, ***order on reh'g***, Order No. 2003-B, 70 FR 265 (Jan. 19, 2005), 109 FERC ¶ 61,287 (2004), ***order on reh'g***, Order No. 2003-C, 70 FR 37661 (July 18, 2005), 111 FERC ¶ 61,401 (2005), ***aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC***, 475 F.3d 1277 (D.C. Cir. 2007).

52 Order No. 2000 (citing ***Hope*** and ***Bluefield***). Note that during the formation of RTOs, FERC generally allowed for grandfathering of existing bundled retail sale contracts with transmission owners joining the RTOs. Rather than requiring elimination of the existing contracts, FERC required that all transmission service under the contracts be taken under the non-rate terms and conditions of the RTO's OATT to ensure non-discriminatory access. But FERC did not touch the rate-related terms of the contracts. As a result, there remains a small though increasingly diminishing amount of bundled retail sales whereby FERC has not asserted jurisdiction over the transmission pricing component within RTOs. ***See, e.g.***, ***Sw.***

TRANSMISSION PRICING IN RTOS

FERC encouraged innovation and regional variation in RTO transmission pricing to:

- Eliminate "rate pancaking" across the RTO (i.e., avoid separate charges from individual transmission owners layering on top of one another—like pancakes—every time the contract path for a transmission service request crosses their system)
- Manage congestion
- Internalize parallel path flows
- "Deal effectively and fairly" with transmission owners that do not participate in RTOs
- Provide incentives for transmission owners to efficiently operate and invest in their systems

FERC allowed forms of "and" pricing in RTOs (e.g., combine non-pancaked access fee based on embedded costs of existing transmission and incremental charge based on opportunity or expansion costs of new transmission) because the potential for undue discrimination is moderated in RTOs.

FERC maintained that transmission prices still must reflect the costs of providing service.

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STANDARDIZED GENERATOR INTERCONNECTION PROCEDURES AND PRICING FOR TRANSMISSION UPGRADES

In 2003, FERC again acted to prevent undue discrimination and facilitate generation competition by issuing Order 2003, in which FERC adopted standard procedures and a standard agreement for transmission providers to use to study and interconnect large generators to their systems reliably.[53] FERC adopted specific rules regarding transmission pricing for interconnecting generators. Stepping back, when a transmission provider studies a request for a generator to interconnect to its system, it may identify the need for upgrades to its system—called network upgrades—to effectuate the interconnection reliably. This is the same type of transmission expansion discussed in Order 888, for example, where FERC noted that it may be appropriate to directly assign or employ incremental cost rates where the expansion would not be undertaken "but for" the customer's request for transmission service.

In Order 2003, FERC maintained the option of "higher of" pricing for transmission providers providing service to newly interconnecting generators, with the standard interconnection agreement contemplating embedded cost pricing but transmission providers having the option to seek FERC approval to charge the incremental cost rate instead.[54] But for interconnecting generators, distinct from load-side transmission service customers, when the embedded cost rate is used, FERC required initial funding from the interconnecting generator as construction costs are incurred, unless the transmission provider elects to upfront fund the network upgrade

Power Pool, Inc., 110 FERC ¶ 61,046, at PP 8, 14 (2005); ***Sw. Power Pool, Inc.***, 106 FERC ¶ 61,110 (2004); ***Midwest ISO Transmission Owners***, 373 F.3d at 1365.

53 FERC took similar action with regard to small generators (less than 20 MW) in Order 2006.

54 Order No. 2003, PP 694 & n.11.

construction itself.[55] The interconnecting generator that initially funds the network upgrade costs is then entitled to reimbursement, with interest, through transmission service credits against the embedded cost rate until fully repaid (called crediting).[56] The costs of those network upgrades go into the transmission provider's rate base as part of its embedded cost-based revenue requirement used to allocate costs to all users of its transmission system. This recognizes that network upgrades are part of the broader transmission system and produce benefits that extend beyond the single interconnecting generator.[57]

FERC allowed flexibility for RTOs to deviate from the standard pricing policy described above given the reduced concern about undue discrimination with an independent transmission provider. FERC stated that RTOs could directly assign network upgrade costs to interconnecting generators, in addition to charging the embedded cost rate (i.e., "and" pricing), where the RTO provided to the generator well-defined rights to capacity made available by the network upgrades.[58] This is called "participant funding" and FERC only allows it in RTOs where the concern about undue discrimination by non-independent transmission providers is diminished.[59] FERC reasoned that "under the right circumstances, a well-designed and independently administered participant funding policy for [n]etwork [u]pgrades offers the potential to provide more efficient price signals and a more equitable allocation of costs than [a] crediting approach."[60] Note that CAISO is the only RTO that did not opt to implement participant funding, instead using more of a "participant financing" approach whereby the generator provides upfront funding and, upon commercial operation, is reimbursed for the costs, with interest, over no more than five years, with the costs then included in the transmission owner's embedded cost-based revenue requirement.[61]

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55 *Id*. P 676; Order No. 2003-A, P 563; *Pro forma* LGIA Art. 11.3.

56 Note that the crediting cannot go longer than 20 years from the generator's commercial operation date. After 20 years, the transmission provider must repay any remaining unreimbursed balance. Order No. 2003-B, PP 34-41; Order No. 2003-C, P 9 & n.9 ("We remind petitioners that we continue to view the Interconnection Customer's upfront payment for Network Upgrades as essentially a loan from the Interconnection Customer to the Transmission Provider.").

57 *E.g.*, Order No. 2003, PP 21, 65 ("Most improvements to the Transmission System, including Network Upgrades, benefit all transmission customers" and "Facilities beyond the Point of Interconnection are part of the Transmission Provider's Transmission System and benefit all users."); Order No. 2003-A, P 585 (stating that "the Commission has long held that the Transmission System is a cohesive, integrated network that operates as a single piece of equipment, and that network facilities are not 'sole use' facilities but facilities that benefit all Transmission Customers").

58 Order No. 2003, PP 699-700. FERC has explained that "[t]here is no requirement that such well-defined rights must provide a dollar-for-dollar reimbursement, and the interconnection customer need not receive such rights where the network upgrades make no such capacity available." *Midcontinent Indep. Sys. Operator, Inc.*, 187 FERC ¶ 61,170, at P 5 n.15 (2024) (citing *Old Dominion Elec. Coop. v. PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,052, at P 18 (2007)).

59 Order No. 2003, PP 28, 696 ("[T]he Commission remains concerned that, when the Transmission Provider is not independent and has an interest in frustrating rival generators, the implementation of participant funding, including the 'but for' pricing approach, creates opportunities for undue discrimination . . . Therefore, the Commission continues in this Final Rule its current policy . . . of requiring a Transmission Provider that is not an independent entity to provide transmission credits for the cost of Network Upgrades needed for a Generating Facility interconnection.").

60 *Id.* P 695.

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

Note that FERC reformed its standard generator interconnection procedures and agreements in 2023, in Order 2023,[62] but largely maintained its pricing policy (assign network upgrade costs to interconnecting generators, with crediting, and participant funding allowed in RTOs—but now for clusters rather than individual generators).

FERC TRANSMISSION PRICING FOR INTERCONNECTING GENERATORS

Default Crediting Policy: The transmission provider has the option to charge the "higher of" embedded or incremental cost rate. Where the embedded cost rate is used, the interconnecting generator must upfront fund the network upgrade costs, unless the transmission provider elects to upfront fund the costs. If the interconnecting generator provides upfront funding, it must receive transmission service credits against the embedded cost rate until fully repaid, with interest (no longer than 20-year repayment).

Participant Funding: Only in RTOs, RTOs can directly assign network upgrade costs to interconnecting generators, in addition to charging the embedded cost rate (a form of "and" pricing), where the RTO provides the generators well-defined rights to capacity made available by the network upgrades.

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OPEN, TRANSPARENT, AND COORDINATED TRANSMISSION PLANNING

As part of FERC's steady march to foster competition in wholesale electric generation, in 2007, FERC issued Order 890. As the D.C. Circuit explained, "[g]rowth in demand without growth in transmission investment led to the Commission's adoption of the transmission planning reforms" in Order 890.[63] FERC amended the *pro forma* OATT to improve transmission planning and foster greater competition in wholesale power markets by, among other things, requiring transmission providers to conduct an open, transparent, and coordinated transmission planning process and strengthening compliance and enforcement efforts against undue discrimination in transmission service. FERC emphasized that many transmission providers have a "disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in the area," thus necessitating FERC rules to step in to remedy the potential for undue discrimination.[64] FERC also relied on the need to open planning processes, including underlying assumptions and data, to market participants as well as states so they can review the transmission plans.[65]

FERC did not broadly reform transmission pricing in Order 890. However, FERC did establish nine transmission planning principles with which all transmission planning processes must comply, the last of which requires

62 This is a good point to note for readers unfamiliar with FERC order naming conventions that the order number is chosen by FERC's chair. In this case, Order 2023 just happens to be named for the year in which it was issued. *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024).

63 *See S.C. Pub. Serv. Auth.*, 762 F.3d at 51 ("Noting that the United States had 'witnessed a decline in transmission investment relative to load growth,' the Commission found that the resulting grid congestion 'can have significant cost impacts on consumers.'").

64 Order No. 890, P 422.

65 *Id.* PP 424-25.

transmission providers to clearly specify in their OATT how the costs of new transmission facilities will be allocated. FERC did not impose a specific cost allocation method. Instead, FERC provided overall guidance, explaining that it would weigh several factors in reviewing proposed cost allocation proposals: whether the proposal fairly assigns costs among cost causers and beneficiaries; whether the proposal adequately incentivizes new transmission; and whether the proposal is generally supported by states and regional stakeholders.[66]

In Order 890, FERC also made important clarifications around incremental cost pricing as allowed by its "higher of" policy. It clarified that, "when the requested transmission service requires network upgrades, the transmission provider should calculate a monthly incremental cost transmission rate using the revenue requirement associated with the required upgrades and compare this to the monthly embedded cost transmission rate, including the expansion costs," deriving the incremental cost rate "by amortizing the cost of the upgrades over the life of the contract."[67] In other words, FERC clarified that a transmission provider seeking to charge a monthly incremental cost rate must compare that rate to the monthly embedded cost rate.

FERC also explained in Order 890 that it requires significant documentation for a transmission provider to charge a single transmission customer an incremental cost rate. FERC explained that transmission providers seeking to charge an incremental cost rate must provide "cost support indicating the derivation of the rate calculation consistent with the cost support that the transmission provider would provide to the Commission in a section 205 rate filing."[68] Alternatively, the transmission provider can charge the already FERC-approved embedded cost rate—clearly the less burdensome option for the transmission provider—and in either instance, the transmission provider recovers its costs.

REGIONAL TRANSMISSION PLANNING AND COST ALLOCATION

Following Order 890, electric industry estimates showed a need for nearly $300 billion of investment in new transmission between 2010 and 2030 to maintain reliability across the country in the face of growing demand and a changing generation mix,[69] a tall order without more robust transmission planning on a regional and interregional basis. FERC saw flaws and gaps in the existing transmission planning paradigm, particularly around the absence of regional planning processes that take a sufficiently broad view of transmission needs and solutions, including evaluating alternatives.

Order 1000. Thus, in 2011, FERC issued Order 1000, a landmark rule that required transmission providers to band together to form regions and conduct regional transmission planning. Such planning must have a process to identify regional transmission needs and select 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, with the end result being a regional transmission plan. Neighboring transmission planning regions must establish interregional coordination procedures for sharing information and planning

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66 *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010) (citing Order No. 890, P 559).

67 Order No. 890, P 870.

68 *Id.* P 884.

69 *S.C. Pub. Serv. Auth.*, 762 F.3d at 51 (noting the North American Electric Reliability Corporation (NERC) projected a 9.5–15% increase in transmission circuit miles would be needed to maintain reliability through 2019) (citing Marc Chupka, et al., *Transforming America's Power Industry: The Investment Challenge 2010–2030*, at 37 (Nov. 2008); NERC, *2009 Long-Term Reliability Assessment*, at 26 (Oct. 2009); NERC, *2008 Long-Term Reliability Assessment*, at 15 (Oct. 2008)).

data as well as identifying and jointly evaluating needs and solutions, though FERC did not require interregional transmission planning like it did for regional.[70] FERC also removed the federal right of first refusal for incumbent transmission developers (i.e., transmission owners in their franchise service territory) to construct new regional transmission facilities selected in a regional transmission planning process that complied with Order 1000.

Most relevant to this report, in Order 1000, FERC found that a lack of a clear and workable process for allocating and recovering the costs of transmission projects across a transmission planning region or more than one transmission planning region presented a barrier to needed transmission investment. So, FERC required each region to develop and include in the relevant regional tariff a method for ***ex ante***[71] allocating the costs of transmission projects planned through the regional transmission planning process. FERC has emphasized the importance of ***ex ante*** cost allocation repeatedly, explaining that transmission development requires a significant amount of capital investment, so it is essential for developers to have some up-front certainty around their cost recovery.[72] Similarly, those on the paying end—i.e., the beneficiaries—need some reasonable expectation around who will pay what.

By shifting from a focus almost exclusively on cost causation to more emphasis on the beneficiary pays principle, Order 1000 marked a key point in the evolution of FERC's transmission pricing policy. Cost causation requires transmission providers to charge customers based on the costs they caused the transmission provider to incur, whether rolled into embedded costs or separated into an incremental cost rate. The beneficiary pays principle more explicitly requires that the costs of new transmission investments be allocated to those who benefit.[73]

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70 This report does not dive into more detail on interregional transmission specifically as there are few requirements and very little commonality across the country, other than the general shared lack of interregional transmission development and cost sharing.

71 An ***ex ante*** cost allocation method is one established before the project is built. FERC has emphasized that predetermined cost allocation is critical for providing certainty about how the costs of a transmission project (or portfolio of projects) will be allocated. According to FERC, this allows all relevant stakeholders to understand the benefits along with the financial implications, improving the likelihood the transmission is ultimately built. ***See S.C. Pub. Serv. Auth.***, 762 F.3d at 70 (explaining FERC saw the cost allocation reforms as reducing conflicts by clarifying who is benefitting from, and who must pay for, the new transmission projects via an ***ex ante*** determination).

72 ***E.g.***, ***Sw. Power Pool, Inc.***, 131 FERC ¶ 61,252 at P 68 (explaining that in Order 890, FERC "recognized that knowing how the costs of new transmission facilities would be allocated is critical to the development of new infrastructure, because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs"); Order No. 1000, P 499 (agreeing with commenters "that the lack of clear ***ex ante*** cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of . . . transmission providers to implement more efficient or cost-effective transmission solutions" by failing to align cost allocation with evaluation of benefits).

73 ***NARUC***, 475 F.3d at 1285 (stating "costs are to be allocated to those who cause the costs to be incurred and reap the resulting benefits"); ***S.C. Pub. Serv. Auth.***, 762 F.3d at 85 (finding a "strong scientific basis" for FERC's conclusion that those "that contract for service on the transmission grid cannot 'choose' to affect only the transmission facilities for which they have entered into a contract' and 'cannot claim that they are not using or benefitting from such transmission facilities simply because they did not enter into a contract to use them").

FERC adopted a set of six principles that apply to the *ex ante* cost allocation method adopted by a region for allocating the costs of transmission projects that the region selects in its regional transmission planning process as solutions to meet regional transmission needs.[74] Other than adopting principles, FERC largely left the actual cost allocation method up to the transmission providers to propose, though FERC explicitly disallowed participant funding as a cost allocation method for regional transmission.[75] FERC reasoned that the use of participant funding for this type of transmission would "increase the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development," thereby slowing needed investment, adversely affecting ratepayers. FERC was clear that it was not preventing the use of participant funding, on a voluntary basis, for transmission projects not planned through the regional transmission planning process, though.[76]

FERC ORDER 1000 REGIONAL COST ALLOCATION PRINCIPLES

1. Costs must be allocated at least roughly commensurate with estimated benefits.
2. Those that receive no benefit must not be involuntarily allocated costs.
3. If a benefit to cost threshold is used, it cannot include a ratio that exceeds 1.25.
4. Cost allocation must be within the region unless an entity outside the region voluntarily agrees otherwise.
5. Cost allocation must be sufficiently transparent for stakeholders to determine how the method applies to a specific project.
6. Regions may choose different cost allocation methods for different types of projects (reliability, congestion relief, public policy driven).

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74 Order No. 1000, PP 622, 637, 646, 657, 668, 685.

75 *Id.* P 723.

76 *Id.* P 724.

Order 1920. In Order 1920, issued in 2024, FERC largely maintained these principles for cost allocation methods that apply to regional transmission projects that regions select in the longer-term regional transmission planning required by the new rule.[77] FERC required transmission providers to file one or more default, ***ex ante***, cost allocation methods, but revised its approach from Order 1000 by specifically prohibiting transmission providers from proposing to allocate costs of long-term regional transmission facilities based on project types, such as reliability, economic, or public policy requirements. FERC reasoned that such single driver planning and cost allocation resulted in underinvestment in large-scale, multi-value transmission that achieves the greatest economies of scale and efficiencies for customers. This is because, according to FERC, such planning ignores the combined set of economic and reliability benefits that transmission can provide, thereby undercounting benefits and, in some cases, allowing for free ridership in cost allocation.

Another change made in Order 1920 to prior practice is the enhanced role of state entities in both regional transmission planning and cost allocation. Significantly, transmission providers must include in their compliance filings with FERC any cost allocation method and/or state agreement process[78] agreed to by states in the region, even if the transmissio n provider has an alternative proposal. FERC then makes the ultimate determination as between competing alternatives.[79] Most Order 1920 compliance filings have not yet been filed or ruled upon by FERC.

V. FERC TRANSMISSION PRICING TODAY: COST ALLOCATION AND COST RECOVERY

Having explored the historic evolution of FERC transmission pricing policy, this section focuses on present day. What is FERC's transmission pricing policy today, and more specifically, how does FERC regulate transmission cost allocation and cost recovery at the wholesale level? Cost allocation refers to how FERC-approved transmission costs are shared among transmission system users (and which transmission system users). Cost recovery is about which costs FERC approves for recovery and the mechanisms by which those costs flow to paying customers (in FERC's case, at the wholesale level). Section VI will take the next step of discussing how FERC-approved transmission costs flow to retail customers.

COST ALLOCATION: HOW FERC-APPROVED TRANSMISSION COSTS ARE ALLOCATED AT THE WHOLESALE LEVEL

Cost allocation differs for local transmission, regional transmission, and transmission upgrades triggered by new generator interconnections. Each is discussed in turn below.

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77 ***Building for the Future Through Electric Regional Transmission Planning and Cost Allocation***, Order No. 1920, 187 FERC ¶ 61,068, at PP 1469-79, ***order on reh'g & clarification***, Order No. 1920-A, 189 FERC ¶ 61,126 (2024), ***order on reh'g & clarification***, Order No. 1920-B, 191 FERC ¶ 61,026 (2025).

78 A state agreement process allows states to propose an alternative cost allocation method for a specific long-term regional transmission facility. The process must be completed no later than six months after the regional planner selects the specific facility as the preferred solution. If the process fails, then the default regional cost allocation method is used to allocate costs.

79 Order 1920-A, P 659 (explaining that FERC will consider alternatives from the transmission provider and the states and, based on the entire record, set the replacement rate, i.e., accept one of the cost allocation proposals).

COST ALLOCATION METHOD	DESCRIPTION	WHO / WHICH TRANSMISSION COSTS
License Plate	Allocates costs to local area in which the transmission is located	• RTOs use for allocating costs of lower-voltage and local transmission to single pricing zone or transmission owner (costs may then be allocated within a single pricing zone using load ratio share where multiple LSEs take service in the zone)
Load Ratio Share (Postage Stamp)	Allocates costs based on amount of load served by wholesale customer in defined area (e.g., region or sub-region) at snapshot in time (e.g., monthly peak) compared to total load served in the area at that time	• Regional transmission • CAISO – regional load ratio share for transmission > 200 kV • ERCOT – regional load ratio share for transmission > 60 kV • ISO-NE – regional load ratio share for reliability + economic-driven regional, and 70% of public policy-driven regional • MISO – regional load ratio share for Multi-Value Projects, with some sub-regional load ratio share for Long Range Transmission Planning portfolios • PJM – regional load ratio share for 50% > $5M and > 500 kV (345 kV double circuit) baseline reliability and economic • SPP – regional load ratio share for 100% > 300 kV, and 33% > 100 kV and < 300 kV; zonal load ratio share 67% > 100 kV and < 300 kV, and 100% < 100 kV
Granular Benefits-Based	Allocates costs by identifying and quantifying specific benefits of transmission and allocating costs based on the quantified benefits to specific beneficiaries, completed through use of complex modeling tools	• Regional transmission • PJM – 100% market efficiency (economic) projects (production costs, congestion relief) • Other RTOs quantify benefits for project evaluation and selection but not for cost allocation, and others have used quantified benefits for a portion of their regional cost allocation in specific circumstances (e.g., NYISO in its Public Policy Transmission Planning Process)
Power Flow-Based (DFAX)	Allocates costs by quantifying distribution factors (the estimated power flows through a transmission facility) to determine who will use and benefit from the transmission and allocate costs to them	• Regional transmission • PJM – solution-based DFAX for 50% > $5M and > 500 kV (345 kV double circuit) baseline reliability, and 100% < $5M and < 500 kV (except stability-driven allocated based on zonal contribution to need)
Voluntary Supplement	Allows states to push a project across the required benefit-cost ratio by agreeing to be allocated any costs above the calculated benefits separate from the standard regional cost allocation method	• Regional transmission • In FERC Order 1920 • ISO-NE – Longer-Term Transmission Planning Process • PJM – State Agreement Approach

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COST ALLOCATION FOR LOCAL TRANSMISSION

Load Ratio Share. Historically, FERC allocated transmission costs using what is called a load ratio share or postage stamp cost allocation method. This cost allocation method determines the costs to be allocated to a load-serving transmission service customer based on the proportion of load it serves in the defined geographic area (e.g., transmission owner service territory) at a snapshot in time (e.g., when the relevant system is at its peak demand). Similar to a postage stamp needed to mail a letter, where the distance traveled and road used does not change the price (within a specified geography), load ratio share cost allocation assumes that all users of the transmission system receive benefits proportional to the load they serve, regardless of delivery path or distance. FERC endorsed this cost allocation method in the 1994 Transmission Pricing Policy Statement and again in Order 888, explaining that load ratio cost allocation for network transmission is reasonable because such service is load based.

Load ratio share cost allocation uses load-based allocation factors. At a high level, an allocation factor is the input on the bottom of the equation used to allocate costs among system users. It is the factor by which the total cost to be recovered is divided to determine the amount of costs allocated to specific entities. FERC allows for some variation in the allocation factor used, favoring an annual coincident peak[80] (1 CP) or average of three monthly peaks (3 CP) for systems with seasonally higher demand, or the average of all 12 monthly system peaks (12 CP) for systems with relatively constant demand.[81] The aim is to reflect cost causation, with the understanding that transmission infrastructure is built to serve peak demand. The load shares are then converted to transmission rates charged to transmission customers at the wholesale level—a $/kW-month or $/MW-year demand charge, for example—and applied uniformly, regardless of distance or path.

Transmission located within a single transmission owner’s service territory is typically planned by the transmission owner through a local transmission planning process, sometimes known by other names or incorporated into a broader integrated planning process outside RTOs. Local transmission refers to the transmission facilities 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.[82] A significant amount of transmission investment today is locally planned and zonally allocated.

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80 Briefly, 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.

81 *Golden Spread Elec. Coop., Inc.*, Opinion No. 501, 123 FERC ¶ 61,047, at P 66 (2008). FERC affirmed the use of 12 CP in Order 888 on the basis that most utilities plan their systems to meet their 12 monthly peaks.

82 Over the past several decades, most new customer load has connected to local distribution systems. The cost allocation associated with the interconnection—as well as the process governing such interconnection—has been a matter for state regulators. With larger manufacturing and data center loads emerging, however, more customers may seek to connect directly to the transmission system. Whether connected to the distribution or transmission system, new load can trigger needed upgrades on the transmission system.

License Plate. In RTOs, the costs of local transmission are allocated first using a license plate cost allocation method, whereby the costs are allocated to the local pricing zone in which the local transmission is located or to the transmission owner that planned the transmission specifically.[83] The license plate method is commonly used for new low-voltage and local transmission in RTOs under the assumption that modest benefits, if any, extend beyond the relevant zone for these types of transmission facilities, and thus the allocation satisfies the "roughly commensurate with estimated benefits" standard. If there is a single transmission owner or LSE in the zone, the allocation is simple: 100% of the costs are allocated to that single entity at the wholesale level. If there are multiple transmission owners and/or LSEs in a single local pricing zone, costs may be further allocated on a load ratio share basis among those entities. Transmission owners generally incorporate the allocated costs into their embedded cost rate that they charge on a load ratio share basis to the LSEs taking service in the zone. The LSEs then typically recover the costs through state-approved retail rates from end-use customers or customer classes.

In non-RTOs, there is no license plate cost allocation step as the costs for local transmission are incurred by and 100% allocated to the transmission owner that plans, builds, owns, and operates them. For vertically integrated utilities, a new customer, such as a data center, will most likely receive bundled retail service that incorporates transmission costs into the rates established using the utility's embedded cost-based revenue requirement. The utility will also determine whether it has enough generation capacity to serve the customer and recover generation, transmission, and distribution costs through its state-regulated bundled retail rates.

COST ALLOCATION FOR REGIONAL TRANSMISSION

A large share of transmission investment today is in local transmission and transmission needed to meet near-term reliability needs. But FERC has repeatedly found that multi-value, regional transmission projects can more efficiently and cost-effectively address multiple transmission needs, including local needs, reliability needs, and economic needs (e.g., congestion reduction) than local transmission or transmission planned just in time to meet the need. While the value of regional transmission is well-documented, allocating the costs of these projects is more complicated than for transmission in a single, local zone. These projects oftentimes have multiple drivers, many beneficiaries, and cross multiple transmission owner territories and jurisdictions. Thus, the costs of new regional transmission projects are allocated distinctly from other transmission investments and are subject to specific cost allocation principles, as discussed earlier in Section IV.

Common cost allocation methods for regional transmission projects include load ratio share, granular benefits-based, power flow-based, and a hybrid approach, such as highway/byway. (Regional cost allocation methods are currently undergoing reexamination in many regions as part of Order 1920 compliance proceedings.[84]) In some regions, costs are allocated on a project-by-project basis, whereas other regions allocate costs of a portfolio of projects. In all cases, the regional cost allocation method is aimed at satisfying the cost causation and beneficiary pays principles, thereby balancing region-wide benefits of high-voltage transmission with more

83 Amy Rose, et al., National Laboratory of the Rockies, ***Lessons Learned for Transmission Cost Allocation in U.S. Regional Markets***, at 9-10 (Feb. 2026), https://www.nlr.gov/docs/fy26osti/97370.pdf (identifying SPP, PJM, and MISO as regions in which the license plate method is used to allocate the costs of local transmission to the local pricing zone, and CAISO, NYISO, and ISO-NE as regions in which the license plate method is used to allocate such costs to the local transmission owner).

84 States in most transmission planning regions are currently meeting to talk about potential cost allocation methods to use for the new long-term regional transmission planning process required by FERC Order 1920. This may result in variations on existing methods or entirely new ones.

localized benefits.[85]

Load Ratio Share. The most common cost allocation method for regional transmission is load ratio share, sometimes called postage stamp.[86] The high-level details of the method are much the same as where this practice is used for local transmission cost allocation, as described in the previous subsection above. At the regional level, the charge to each LSE within the defined geographic area (whether regional or sub-regional) is determined in proportion to the load it serves using a load-based allocation factor. FERC generally prefers variations of a coincident system peak demand (MW) factor, although in some cases it has approved use of a usage (MWh) factor.[87] The factor may be calculated using historical, forecast, or a combination of data. Notably, the percentage share paid by different LSEs changes over time as the allocation factor is recalculated to reflect shifting demand or usage.

This method is generally transparent and simple to implement, including accounting for demand changes over time, and it can minimize free rider problems by implicitly incorporating benefits of regional transmission that are less capable of quantification.[88] But it can be more or less accurate depending on the choice of allocation factor and frequency of load share updates.

Several regions use load ratio share for all or most of their regionally planned transmission.

- CAISO uses regional load ratio share cost allocation for transmission over 200 kV, with the allocation factor based on gross energy usage (MWh).[89]
- The Electric Reliability Council of Texas (ERCOT) uses regional load ratio share cost allocation for transmission over 60 kV, with the allocation factor based on four coincident summer peak loads from June to September (4 CP). This cost allocation method is currently undergoing review by the Public Utility Commission of Texas in response to concerns that the 4 CP method allows large load customers to avoid paying their fair share.[90]

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85 ***See, e.g.***, ***Long Island Power Auth. v. FERC***, 27 F.4th 705, 709 (D.C. Cir. 2022) (ruling on a long-running dispute about cost allocation for high-voltage transmission facilities in PJM; noting "[t]he question is difficult because high-voltage projects afford 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," providing "'backbone infrastructure' that improves reliability and reduces congestion regionwide"); ***Old Dominion Elec. Coop.***, 898 F.3d at 1260 ("Application of the cost-causation principle is simple here, because this critical point is undisputed: high-voltage power lines produce significant regional benefits within the PJM network . . . .").

86 According to FERC, postage stamp cost allocation "refers to regionwide allocation of the cost of a transmission facility." Order No. 1000, P 741 n.543.

87 Southwest Power Pool, SPP Documents & Filings, CARE Team Meeting Materials 20260204, ***Overview of Cost Allocation Methodologies*** (Feb. 4, 2026), https://spp.org/spp-documents-filings/?id=552361 (in zip file). Historically, FERC and the courts have allowed variations so long as the utility has explained why the facts and circumstances support the relevant cost allocator. ***See, e.g.***, ***Cities of Bethany***, 727 F.2d at 1131 (affirming FERC's rejection of a cost allocator based on coincident peaks in three summer months, or 3 CP, based on evidence the utility did not have summer peak demand to justify the undue emphasis on summer peaks).

88 ***See Long Island Power Auth.***, 27 F.4th at 713 (explaining postage stamp cost allocation "takes account of 'the full spectrum of benefits associated with high-voltage facilities, including difficult to quantify regional benefits' such as improved reliability, reduced congestion, and greater carrying capacity").

89 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).

90 Pub. Util. Comm'n of Tex., ***Evaluation of Transmission Cost Recovery***, Case 58484, https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=58484&ItemMatch=Equal&DocumentType=ALL&SortOrder=Ascending.

- ISO New England (ISO-NE) uses regional load ratio share for most of its regionally planned transmission, including all reliability and economic-driven regional projects and 70% of its public policy-driven regionally planned projects. ISO-NE's allocation factor is based on 12 CP.[91]
- The Midcontinent Independent System Operator (MISO) uses regional load ratio share for its Multi-Value Projects (MVP), starting with those it approved in 2011 and now for its Long Range Transmission Planning (LRTP) process. For the first two LRTP portfolios, MISO revised its standard cost allocation method to allow for subregional cost allocation, still on a load ratio share basis within the MISO subregion(s).[92] MISO uses an allocation factor based on monthly net actual energy withdrawals, with the resulting usage rate charged based on system usage (i.e., MWh).[93]
- PJM Interconnection (PJM) uses regional load ratio share, based on 12 CP, for 50% of the costs of regionally planned higher-voltage baseline reliability projects (over $5 million in cost and over 500 kV, or over 345 kV if double circuit), with the other 50% allocated based on expected power flows using a solution-based method (discussed below).[94] PJM also uses regional load ratio share for 50% of the costs of higher-voltage baseline economic projects (same gating threshold).

Granular Benefits-Based. Granular benefits-based approaches to regional cost allocation are designed to align allocation of costs with specifically identified beneficiaries more precisely than other cost allocation methods. These approaches are commonly used for allocating the costs of economic or market efficiency projects, where the cost-saving benefits of the transmission projects can be quantified by comparing the system with and without the new transmission in service (e.g., congestion reduction) through production cost modeling. Under the granular benefits-based approaches, the regional planner identifies benefits and estimates the quantity of those benefits that specific zones or LSEs will receive for a specific transmission project or portfolio of projects. Regional planners quantify the estimated benefits using forward-looking scenarios and then allocate costs to zones or to specific LSEs in a manner that is "roughly commensurate" with those "estimated benefits" to the identified beneficiaries (i.e., LSEs).

Granular benefits-based approaches offer greater precision in quantifying benefits and aligning costs with beneficiaries than other cost allocation methods. While not used to allocate the costs of a significant amount regional transmission today, some regions are considering moving toward greater use of this approach as part of their compliance with FERC Order 1920. And as technological improvements make quantification of benefits and identification of beneficiaries easier and more accessible for stakeholders, more regional transmission costs may be allocated in this way.

There are several challenges with granular benefits-based approaches, though. For one, they are much more complex than other methods and difficult for many stakeholders to understand (i.e., less transparent) given the reliance on sophisticated modeling tools to estimate benefits oftentimes described with opaque industry terms.

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91 ISO New England Inc., Transmission, Markets and Services Tariff, II.21 (Rates and Charges) (8.0.0), Sched. 9 (Regional Network Service) (5.0.0), Sched. 12 (Transmission Cost Allocation On/After Jan 1 2004) (9.0.0).

92 ***See Midcontinent Indep. Sys. Operator, Inc.***, 179 FERC ¶ 61,124 (2022) (accepting MISO's proposal to revise its MVP cost allocation method for LRTP).

93 Midcontinent Indep. Sys. Operator, Inc., FERC Electric Tariff, Schedule 26A (Multi-Value Project Usage Rate) (37.0.0), Attachment MM (Multi-Value Project Charge).

94 PJM Interconnection, L.L.C., Intra-PJM Tariffs, Schedule 12 (15.0.0); Grace Niu, PJM Interconnection, L.L.C., ***Cost Allocation Education*** (Sept. 18, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/destf/2025/20250918/20250918-item-04---cost-allocation---presentation.pdf.

Attempting to precisely quantify benefits and align cost allocation with the flow of those benefits to specific beneficiaries (LSEs) is often highly contentious, and a frequent source of litigation.[95] Such attempts at exactitude commonly open cost allocation to debates about the appropriate benefits to quantify (there is no standard list of benefits),[96] methods to quantify those benefits (there is no standard method for quantifying benefits), and modeling assumptions and data used.

In addition, some benefits are not easily quantifiable.[97] This creates a mismatch between the identified benefits that drive project approval (e.g., for establishing benefit-cost ratios as part of evaluation processes) and subsequent allocation of the project costs to LSEs, which is by necessity a quantified process. A frequently cited example is resilience benefits, which can be significant and yet undervalued. When resilience is ignored, LSEs that benefit from the added insurance value provided by a new regional transmission project do not pay any of its costs.[98]

Critically, model-driven precision in quantification of benefits and associated cost allocation is not required by the cost causation or beneficiary pays principles.[99]

Power Flow-Based (Distribution Factor or DFAX). The power flow-based cost allocation method, sometimes referred to as distribution factor or DFAX, is currently used only by PJM for reliability-driven regional transmission projects (and some lower-voltage transmission facilities). This method allocates costs by quantifying so-called distribution factors. Distribution factors are, essentially, the estimated power flows through a transmission facility. PJM specifically uses "solution-based" DFAX, relying on how much electrical power moves through the specific transmission solution (i.e., newly planned transmission project) to determine who will use and

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95 For example, FERC recently voted to approve, over the objection of some states in the region, PJM's plan to regionally allocate the costs of transmission to address reliability concerns driven, at least in part, by Virginia's policy to encourage data center development in the state. ***See PJM Interconnection, L.L.C.***, 187 FERC ¶ 61,012 (2024); ***see also*** North Dakota Public Service Commission, et al., Complaint, Docket No. EL25-109-000 (filed July 30, 2025) (challenging MISO's selection of a Board-approved portfolio of transmission projects—LRTP Tranche 2.1—on the basis that MISO miscalculated benefits and relied on a defective business case); ***Transource Penn. LLC v. DeFrank***, No. 24-1045, 2025 WL 2554133 (3d Cir. Sept. 5, 2025) (affirming a lower court's ruling that the Pennsylvania Public Utility Commission could not second guess the FERC-approved benefit-cost method, even though the state body disagreed with the analysis and, thus, rejected a construction permit for the transmission project (Project 9A)).

96 FERC attempted to increase standardization in Order 1920, in which it required transmission planners to consider a specific list of benefits as part of long-term regional transmission planning. These benefits are: avoided or deferred reliability transmission facilities and aging infrastructure replacement; either reduced loss of load probability or reduced planning reserve margin; production cost savings; reduced transmission energy losses; reduced congestion due to transmission outages; mitigation of extreme weather events and unexpected system conditions; and capacity cost benefits from reduced peak energy losses. Order No. 1920, PP 719-39.

97 ***See Sw. Power Pool, Inc.***, 131 FERC ¶ 61,252 at P 76 (explaining that cost-benefit analyses evaluate benefits at a static point in time, which cannot capture all benefits over time, and may not accurately identify "true beneficiaries" of the transmission, "particularly because such tests do not consider any of the qualitative, (i.e., less tangible) regional benefits inherently produced by" a high-voltage network).

98 Order No. 1000, P 486 (explaining the risk of free rider problems with new transmission "is particularly high for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries" because individual beneficiaries necessarily have "an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development").

99 See discussion in Section III above regarding core FERC ratemaking principles. ***See also ICC v. FERC I***, 576 F.3d at 477 ("We do not suggest that [FERC] has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars . . . If it cannot quantify the benefits . . ., but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in [the] region, then fine; [FERC] can approve [the] proposed pricing scheme on that basis."); ***Coal. of MISO Transmission Customers v. FERC***, 45 F.4th 1004, 1009 (D.C. Cir. 2022) (finding that cost allocation can still satisfy the roughly commensurate standard if there are spillover benefits to other zones, so long as there is at least a "crude" attempt to match costs and benefits and a reasonable correlation thereof); ***Long Island Power Auth.***, 27 F.4th at 714 (disagreeing with appellant's contention that prior court precedent requires a cost-benefit analysis to quantify project benefits).

benefit from the new transmission facilities and allocate costs to them. The DFAX values are not recalculated continuously but may change when PJM updates its planning models (generally on an annual basis).

PJM allocates 50% of the costs of higher-voltage regionally planned baseline reliability projects (over $5 million in cost and over 500 kV AC, or over 345 kV AC if double circuit) using solution-based DFAX, with the other 50% allocated on a regional load ratio share basis, as discussed above. PJM allocates 100% of the costs of lower-voltage baseline reliability projects (less than $5 million in cost and less than 500 kV AC) on a solution-based DFAX basis. The exception is stability-driven facilities, which PJM allocates based on each zone's relative contribution to the issue. The power flow-based cost allocation method seeks to align cost allocation with users of the specific new transmission facilities.[100] It shares some of the challenges of granular benefits-based approaches to cost allocation in that it is complex and relies on modeling with assumptions that can open it up to disputes, though the DFAX method is generally less controversial than attempts at precise quantification of benefits and identification of beneficiaries.

Hybrid. Several regions use a hybrid cost allocation method for regional transmission that combines elements of the above approaches and/or uses novel approaches not commonly used elsewhere. For example, the highway/byway cost allocation method, used only by SPP, uses load ratio share but allocates costs on a regional or zonal basis depending on voltage threshold levels of the transmission at issue. "Highway" refers to higher-voltage transmission facilities, the costs of which are allocated on a regional load ratio share basis consistent with their broader regional benefits, whereas "byway" refers to lower-voltage transmission facilities, the costs of which are allocated to the zone in which the facilities are located consistent with their more localized benefits. This cost allocation method is transparent, simple to implement, and recognizes the relative breadth of beneficiaries of different voltages of transmission.[101]

In SPP, the specific breakdown of voltage and cost allocation was the result of extensive state and stakeholder negotiation.[102] Transmission costs are allocated in three categories:

- The costs of transmission facilities at 300 kV and above are allocated to the entire SPP region on a load ratio share basis;
- For transmission facilities above 100 kV and below 300 kV, 33% of the costs are allocated to the entire SPP region on a load ratio share basis, with the remaining 67% allocated to the SPP pricing zone in which the facilities are located; and
- The costs of transmission facilities at 100 kV and below are allocated to the relevant SPP pricing zone.[103]

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100 ***See Long Island Power Auth.***, 27 F.4th at 714 (explaining that the flow-based portion of PJM's regional cost allocation method looks "to usage data as a proxy for specific benefits . . . to identify the subset of customers that benefit from a facility simply through electrical proximity").

101 ***See Sw. Power Pool***, 131 FERC ¶ 61,252 (noting high-voltage transmission provides benefits that are difficult to quantify, such as enhanced "reliability by reducing loading on existing lines and circuits which increases their capacity to withstand emergency situations"—benefits that accrue to all SPP members).

102 ***Id.*** (first accepting SPP's highway/byway cost allocation method and describing the process SPP and its regional state committee undertook to arrive at the filed cost allocation method). FERC found the highway/byway method important for facilitating investment in new transmission "to integrate the eastern and western portions of the SPP grid, reduce congestion, efficiently integrate new resources, and accommodate new or growing loads."

103 ***See*** Sw. Power Pool, Inc., Open Access Transmission Tariff, Attach. J, § III (21.0.0). For network upgrades associated with certain designated resources where the upgrade is located in a different zone than the point of delivery, the costs of facilities 300 kV and above are allocated 100% to the region and the costs of facilities below 300 kV are allocated 67% to the region and 33% to the transmission customer. ***Id.*** §§ III.A.3, III.A.4.

Costs allocated to a pricing zone are then incorporated into the relevant transmission owners' embedded cost-based revenue requirement, recovered on a load ratio share basis from LSEs taking service in the zone. SPP has a tariff mechanism to revisit its cost allocation method on a regular basis (at least every six years).[104]

Voluntary Supplement. FERC Order 1920,[105] ISO-NE's Longer-Term Transmission Planning (LTTP) process,[106] and PJM's State Agreement Approach[107] provide an opportunity for states to voluntarily supplement cost allocation to push a transmission project forward that otherwise would not meet the required benefit-cost ratio but that is important to the relevant state(s) (e.g., to achieve state public policies). Essentially, the portion of the costs of the transmission project at issue that fall below the benefit-cost ratio are allocated to the state(s) that agree to voluntarily supplement the project, and the remainder is allocated using the applicable cost allocation method (e.g., regional load ratio share in ISO-NE's LTTP).

FERC broadly encouraged states to voluntarily agree to plan and pay for transmission in a 2021 policy statement, reaffirming that such agreements are not categorically precluded by any FERC rules or regulations.[108] This policy statement was broader than just voluntary supplements, noting such agreements "may allow state-prioritized transmission facilities to be planned and built more quickly than would comparable facilities that are planned through the regional transmission planning process(es)."[109] FERC also noted that, while the policy statement focuses on states, market participants are also able to pursue such arrangements without state involvement. Order 1920 similarly extends the voluntary supplement option to interconnection customers (rather than only states).

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104 ***Id.*** § III.D.

105 Order No. 1920, PP 1012-18.

106 ISO New Eng. Inc., Transmission, Markets and Services Tariff, Attach. K (34.0.0), § 16.3(j).

107 *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at PP 142-43 (2013), ***order on reh'g & compliance***, 147 FERC ¶ 61,128, at P 92 (2014) (accepting PJM's State Agreement Approach as supplementary to PJM's Order 1000 regional transmission planning process, under which one or more states may agree voluntarily to be responsible for the allocation of all costs of a proposed transmission facility); *PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,090 (2021) (approving a specific use of the State Agreement Approach in PJM).

108 *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 (2021).

109 ***Id.*** P 2.

COST RECOVERY: HOW COSTS ALLOCATED AT THE WHOLESALE LEVEL ARE RECOVERED FROM WHOLESALE CUSTOMERS

REVENUE REQUIREMENTS AND FORMULA RATES

Most transmission costs allocated at the wholesale level, using the methods described above for local, regional, and interconnection-related transmission, are recovered via transmission charges set using the traditional cost-of-service revenue requirement approach, whereby LSEs pay on an embedded cost basis for transmission service, essentially as has been the structure from the inception of the transmission system itself.[110]

Revenue requirement. The basics of the traditional revenue requirement approach (described in Section IV above) still apply to revenue requirements set in many state and federal rate proceedings today. The general formula provides for recovery of the transmission owner's operating expenses (fuel, labor, maintenance), return on rate base (rate of return sufficient to attract future investment when needed multiplied by the rate base, less accumulated depreciation), depreciation expense, and taxes.

At the federal level, FERC allows transmission owners to use either stated rates or formula rates to establish the revenue requirement to recover FERC-approved transmission costs.

Stated rates. Stated rates are set through periodic rate cases filed at FERC and the approved rate remains in effect until a subsequent rate case is filed and approved (usually after litigation or a settlement with intervenors) to set a new stated rate, even if the transmission provider's costs of service have changed in the interim. The result is a static rate that gives the transmission provider and customers pricing certainty for a period of time but does not reflect changes in the overall cost of service between rate cases.

Formula rates. Formula rates are exactly what the name suggests: a formula for how a transmission provider will set a specific rate based on specific cost inputs.[111] FERC approves the formula for calculating the cost-of-service-based rate, including definitions for each of the inputs to that formula to guide the transmission owner's implementation of the formula (and customers' ability to understand and challenge those inputs), as well as an annual process for the transmission owner to update its rates using the formula to reflect changing costs. The formula is based on the same categories used in stated rates. The formula stays constant but the resulting rate changes.

There are several aims of formula rates. One is to reduce the burden on FERC, as well as transmission owners and interested stakeholders, of annual or semi-annual stated rate cases, litigated potentially over several years at FERC and in the courts and typically ending in a "black box" settlement. Another is to reduce the regulatory lag before transmission owners can begin recovering the costs of new investments by moving from static stated rates to annually updated formula rates that allow cost recovery to begin much closer to when the costs are incurred. This can be particularly important for larger, capital-intensive transmission investments. While there is an advantage to lowering the financial risk, thereby incentivizing needed investments in the grid, there is a

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110 Though, note, whereas traditional revenue requirements originally did not include "adders" to incentivize certain behavior, FERC established incentive-based transmission rates in response to Congress's directive in the Energy Policy Act of 2005 in newly added Section 219 of the FPA. This essentially boils down to increases in transmission owners' return on equity in certain circumstances, such as joining an RTO. ***See*** 16 U.S.C. § 824s; ***Promoting Transmission Inv. through Pricing Reform***, Order No. 679, 116 FERC ¶ 61,057, ***order on reh'g***, Order No. 679-A, 117 FERC ¶ 61,345 (2006), ***order on reh'g***, 119 FERC ¶ 61,062 (2007); ***Promoting Transmission Inv. through Pricing Reform***, 141 FERC ¶ 61,129 (2012).

111 ***See*** Federal Energy Regulatory Commission, ***Formula Rates in Electric Transmission Proceedings: Key Concepts and How to Participate***, https://www.ferc.gov/formula-rates-electric-transmission-proceedings-key-concepts-and-how-participate (last updated July 5, 2022).

countervailing risk that transmission owners have less incentive to control costs or improve efficiency.

FERC has established standard formula rate protocols that utilities must adopt and follow in an effort to standardize oversight and provide an opportunity for interested entities to review and challenge formula rate inputs (i.e., the costs to be recovered).[112] FERC also routinely audits formula rates. The vast majority of FERC-regulated transmission providers have opted for formula rates rather than stated rates for transmission service.[113]

Prudence. As briefly discussed in Section IV above, regulators review utility investments to determine whether they were reasonable costs for the utility to incur at the time the utility made the decision (i.e., were prudently incurred). In a standard rate case, the transmission owner has the initial burden of proof to demonstrate the prudence of its investments to receive FERC approval for cost recovery. This can be challenged, in which case FERC typically sets the rate for hearing and settlement judge procedures that lead to a settlement. In the context of formula rates, FERC presumes the inputs made to the FERC-approved formula rates are prudent and does not examine those costs on a regular basis. Instead, the burden is on stakeholders and other interested entities (e.g., state regulators, consumer organizations) to raise a timely challenge to the formula rate inputs and show imprudence. Prudence review exists in both scenarios, but the burden shifts, though for both types of transmission rates FERC is largely reactive.

TRANSMISSION CHARGES IN RTOS

Many transmission owners have joined RTOs, and their revenue requirements are constituents of a regional cost recovery regime. In RTOs, transmission charges based on the member transmission owner's FERC-approved transmission revenue requirements, predominantly set via formula rates, are commonly collected by the relevant RTO through settlement functions outlined in the RTO tariff through which the RTO collects the amounts due from transmission customers at the wholesale level (LSEs) and turns the collections over to the transmission owners.[114] This is not true in all RTOs.[115] The LSEs then flow the transmission costs through to the load they serve in retail rates (with state regulators deciding how those costs are shared among end-use customers/customer classes).

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112 The formula rate protocols provide for notice, opportunity for intervention, and information request procedures, among other requirements designed to make the rate-setting process transparent. Many stakeholders contend there is room for improvement. FERC opened a proceeding to explore issues around transmission planning and cost management (Docket AD22-8) and recently reaffirmed the right of customers to reasonable information to assess the prudence of actual expenditures. ***ISO New Eng. Inc.***, 192 FERC ¶ 61,234 (2025) (affirming stakeholders are entitled to transmission investment information about asset condition projects through the transmission formula rate protocols that govern the New England Participating Transmission Owners' transmission rates); ***see also id.*** (Chang, Comm'r, concurring) (asserting that the order "should serve as a call to action for transmission owners across the country to provide greater transparency regarding their transmission investments" and suggesting more standardized information sharing would "increase consumer confidence," thereby providing "long-term regulatory certainty for transmission investors").

113 London Economics International, ***Primer on Transmission Formula Rates***, at 4 (Feb. 16, 2023), https://wiresgroup.com/wp-content/uploads/2023/02/LEI-Primer-on-Transmission-Formula-Rates.pdf (stating that transmission owners using formula rates have service territories in every state in the continental United States).

114 ***See, e.g.***, ISO New England Inc., ***Rate Development of Regional Transmission Charges***, https://www.iso-ne.com/markets-operations/settlements/rate-development (last visited Feb. 23, 2026) (explaining the annual rate-development process for regional transmission charges in the ISO-NE region).

115 ***See*** PJM Interconnection, L.L.C., ***Guide to Billing***, https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/guide-to-billing (last visited Apr. 6, 2026) (explaining which charges PJM collects versus the transmission owners); N.Y. Indep. Sys. Operator, Inc., NYISO Tariffs, § 2.7.2.1 (21.0.0) (explaining the transmission service charge will be payable to transmission owners, whereas transmission usage charges are payable directly to NYISO).

Diving deeper into ISO-NE as an example, LSEs in the region taking network integration transmission service (NITS) to serve their network load must pay multiple charges, one to cover the costs of the relevant local transmission and one to cover regional transmission. Starting with local transmission, LSEs taking NITS must pay a monthly charge that reflects costs allocated to the LSE based on the LSE's amount of coincident peak load for the month (the cost allocation factor) multiplied by the applicable local NITS rate (the NITS rate for the area in which the LSE's network load is located).[116] The monthly charge is separately computed for each local area (zone) in which the transmission customer (LSE) serves load. For regional transmission, LSEs taking NITS must also pay a monthly regional network service charge, established by aggregating the annual transmission revenue requirements of the transmission owners in ISO-NE for the regional "pooled" facilities and dividing the aggregate total by the average 12-month coincident peak (12 CP) for the region (the cost allocation factor).[117] This is then allocated to LSEs on a regional load ratio share basis, as discussed above. "Pooled" facilities in ISO-NE include both existing transmission assets that benefit the regional network as well as new regional transmission planned to meet reliability and economic needs, the costs of which are spread across the entire ISO-NE footprint.

The framework is similar in PJM, with NITS customers paying daily demand charges based on their daily peak load contribution (cost allocation factor), multiplied by the applicable zonal NITS rate, with each transmission owner's FERC-approved annual transmission revenue requirement used to derive the relevant zonal NITS rate.[118] Then those customers also pay PJM's Transmission Enhancement Charge to cover the cost of new regional transmission, planned through PJM's Regional Transmission Expansion Plan (RTEP) process. With other names for the charges, SPP and NYISO do the same—zonal NITS rate plus regional charge for regional projects.[119] MISO is similar as well.[120]

In CAISO, most participating transmission owners file transmission revenue requirements with FERC that reflect their cost of service, which are then recovered through two channels, based on voltage level. High-voltage facilities (at or above 200 kV) go into a regional transmission revenue requirement, recovered on a uniform basis across CAISO by dividing the total revenue requirement by the combined gross load of the local distribution companies and allocating on a load ratio share basis.[121] CAISO collects the charges through its billing process from the local distribution companies. Lower-voltage transmission facilities (below 200 kV but still under CAISO's

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116 ISO New England, Transmission, Markets and Services Tariff, § II.21.1–2 (8.0.0) (Rates and Charges, Regional Network Service, Determination of Network Customer's Regional Network Load).

117 ISO New England, Transmission, Markets and Services Tariff, Schedule 9 (5.0.0) (Regional Network Service) (providing for calculation of the NITS rate); ***id.*** Attach. F (23.0.0) (providing the current annual transmission revenue requirements of transmission owners in ISO-NE).

118 PJM Interconnection, L.L.C., Intra-PJM Tariffs, OATT, Attach. H (each transmission owner's annual transmission revenue requirement); PJM Interconnection, L.L.C., ***Guide to Billing***, https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/guide-to-billing (last visited Apr. 6, 2026); PJM Interconnection, L.L.C., ***Formula Rates***, https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates (last visited Mar. 30, 2026).

119 ***See Sw. Power Pool***, 182 FERC ¶ 61,141, at P 3 (2023) (describing SPP's Zonal Construct); Southwest Power Pool, Inc. OATT, Sched. 11 (Base Plan Zonal Charge and Region-wide Charge) (11.2.0) (describing that SPP will assess a zonal component to recover the annual transmission revenue requirement of facilities classified as Base Plan Upgrades and a regional component to recover the region-wide annual transmission revenue requirement); N.Y. Indep. Sys. Operator, Inc., NYISO Tariffs, § 2.7 (21.0.0) (Billing and Payment), 14.1 (32.0.0) (Transmission Service Charge), 14.2 (1.0.0) (NYPA Transmission Adjustment Charge); Mathangi Srinivasan Kumar, New York Independent System Operator, ***Transmission Charges*** (Mar. 17-20, 2026), https://www.nyiso.com/documents/20142/3037451/5-Transmission-Charges.pdf/16018410-3821-ae59-44be-64851148adda.

120 ***See*** Midcontinent Indep. Sys. Operator, FERC Electric Tariff, Schedule 26 (Network Upgrade Charge from Transmission Expansion Plan) (45.0.0) (describing zonal rates), Schedule 26-A (Multi-Value Project Usage Rate) (37.0.0) (describing the rate for regionally planned Multi-Value Projects).

121 Cal. Indep. Sys. Operator, CAISO eTariff, § 26 (Transmission Rates and Charges). This is called the Transmission Access Charge (TAC) in CAISO.

operational control) are recovered through utility-specific rates allocated within that utility's service territory, collected directly by the local distribution company from retail customers outside CAISO's billing process (with some exceptions for municipal and other specific CAISO participants).

TRANSMISSION CHARGES OUTSIDE RTOS

Outside RTOs, most transmission costs are included in bundled retail sales over which FERC has declined to generically assert jurisdiction. Where FERC approves the transmission cost recovery, the mechanism is typically a transmission revenue requirement, established via formula rate, similar to transmission costs within RTOs.

For non-RTO transmission planning regions formed to comply with Order 1000, there is no single, unified regional tariff that governs cost allocation and recovery. Instead, these regions complied with Order 1000 by including a cost allocation method in the individual transmission owners' OATTs.[122] To date, no regional project outside an RTO has ever been selected in an Order 1000-compliant regional transmission planning process. If that occurred, cost recovery would likely be through transmission owners' own rates given that there is no regional entity to collect and distribute payments.

USE OF INCREMENTAL COST-BASED TRANSMISSION PRICING

As explained in Section IV, FERC allows transmission providers to charge transmission service customers at wholesale based on the "higher of" the embedded costs of providing the service or the incremental costs (or opportunity cost). But also as noted earlier, incremental cost-based transmission pricing is the exception, with the vast majority of transmission priced at the wholesale level using embedded cost-based transmission revenue requirements. The "but for" test to discern incremental costs associated with new transmission investments is challenging and FERC requires significant cost support before it approves incremental cost rates. It can be particularly challenging to establish a reasonable comparison between incremental and embedded costs for customers whose load may vary over time.[123] That said, there are a few instances of incremental cost-based transmission pricing at the FERC level, discussed below.

GENERATOR INTERCONNECTION SERVICE

In RTOs, the costs of transmission upgrades identified through the generator interconnection process as necessary to interconnect a new or upgraded generator (i.e., the incremental expansion costs) are usually directly assigned to that generator, under the theory that those costs would not be incurred "but for" the request of that generator to interconnect to the transmission system. Thus, the generator pays the costs. FERC introduced this approach, called "participant funding," in Order 2003, as discussed earlier in Section IV. Where the generator pays the costs up front, transmission owners may not include the costs of the network upgrades in their rate base for establishing their revenue requirement allocated to other customers in their pricing zone.

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122 *E.g.*, *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206, at PP 1, 281-87, 306 (2013) (ruling on compliance filings related to the WestConnect region, explaining that the transmission owning members submitted revisions to the transmission planning processes in their respective OATTs to comply with Order 1000, including around regional cost allocation) (subsequent history omitted).

123 *E.g.*, *Sw. Power Pool, Inc.*, 112 FERC ¶ 61,319, at P 34 (2005) (addressing arguments on rehearing and compliance related to SPP's recognition as an RTO, explaining that "determining the appropriate monthly revenue requirement for the embedded transmission rate may be more difficult for network customers" because a "network customer's load ratio share automatically changes from month to month and determining the appropriate amount to include, if any, for a 'higher of' test may, in some cases, be difficult").

Outside RTOs, FERC does not allow "participant funding." Instead, while generators must pay up front for the costs of triggered network upgrades, unless the transmission provider opts to upfront fund them itself, the generators must be credited back over time for those upfront payments against embedded cost-based transmission service charges until they are made whole (with a balloon payment after 20 years for any remaining unreimbursed balance). The transmission owners include the costs of the network upgrades in their rate base for establishing their revenue requirement; thus, this is not incremental cost-based transmission pricing.

TRANSMISSION SERVICE OUTSIDE RTOS

Typically, new transmission needed to serve load additions is: planned and its costs allocated via regional transmission planning and cost allocation mechanisms, with cost recovery through embedded cost-based charges; and/or planned through nearer-term, locally focused transmission planning processes within the transmission owner's territory, with costs allocated only within that "local" area, with cost recovery through embedded cost-based charges. But there are some instances, which appear to all be outside RTOs, where transmission providers have charged a higher incremental cost rate in an unbundled transmission service sale. Incremental cost rates are also more common for point-to-point service than network (NITS) service.

For an example of an incremental cost rate, in 2014, FERC accepted two transmission service agreements filed by NorthWestern Corporation for firm point-to-point transmission service to a wind generation developer in NorthWestern's Montana service territory.[124] Note this is distinct from standard generator interconnection service. Interestingly, the transmission provider split the total transmission service request into three separate agreements, charging an embedded cost rate for the portions where the transmission service could be provided without significant upgrades and an incremental cost rate for the portion that required transmission expansion.[125] Responding to arguments that this violates FERC's policy against "and" pricing, FERC explained that transmission providers may charge the higher of the embedded or incremental cost rate (not both) and may also charge directly assignable, non-grid costs (such as interconnection or radial line costs).[126] Because each of NorthWestern's transmission service agreements reflected the transmission capacity associated with the respective pricing methodology, FERC found the approach consistent with its transmission pricing policies. FERC noted it was to the customer's advantage that NorthWestern exclude the significant upgrade costs from the embedded cost-based rate charged for the remaining transmission service.

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124 ***NorthWestern Corp.***, 147 FERC ¶ 61,171 (2014).

125 In particular, NorthWestern had to upgrade its 500 kV system at a cost of approximately $73 million. ***Id.*** P 18.

126 ***Id.*** P 53 (citing FERC precedent from the 1990s). In this case, non-grid is referring to facilities that FERC now calls Interconnection Customer's Interconnection Facilities, essentially those located between the generator and the point of change of ownership, and are solely used by the generator. ***Pro forma*** LGIA, Art. 1 (Definitions).

In the network transmission service customer context, in 2020, FERC approved Nevada Power Company and Sierra Pacific Power Company's (collectively, NV Energy) agreement with a municipal utility seeking transmission service.[127] The agreement covers NITS service for up to 30 MW of load over a 20-year term at an incremental cost rate based on the upgrades needed to provide the service as well as the operation and maintenance expenses on the facilities. NV Energy described the rate as a "single-customer version of an OATT rate, containing all the same cost components included in a standard cost-of-service rate."[128] NV Energy noted that a demand cap is important in the case of a single customer rate because it avoids a situation where the customer later increases load and shifts costs to other customers. NV Energy provided an expert affidavit and detailed cost support, as well as a comparison between the incremental and embedded cost rates, to satisfy FERC's requirements.[129]

But FERC does not always accept proposed incremental cost rates. In 2025, pointing to NV Energy's successful incremental cost rate filing, FERC rejected a NITS agreement related to a new data center load where the utility proposed an incremental cost rate due, in part, to the failure of the utility to provide sufficient cost support.[130] In addition, FERC was concerned that the customer would not be charged any transmission rate following the five-year term of the agreement, shifting ongoing costs to native load and other transmission customers and violating cost causation.[131] FERC explained what would be required to satisfy the incremental cost rate requirements should the utility choose to refile: detailed cost support, including underlying criteria, assumptions, or allocation methodology for the proposed incremental cost rate; and detailed explanation as to how the proposed incremental cost rate will avoid cost shifting, including after the term of the agreement, for ongoing costs such as operations and maintenance expenses, administrative and general costs, or other reasonably foreseeable costs of long-term service.[132]

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127 ***Nev. Power Co.***, Docket Nos. ER20-2813-000 & ER20-2814-000 (Oct. 23, 2020) (delegated order). Note the agreement was amended in 2023 but did not change the rate.

128 **Nev. Power Co.**, Transmittal Letter, Docket No. ER20-2813-000 (filed Sept. 4, 2020).

129 The network upgrade capital cost was estimated around $25 million, to be depreciated over the 20-year term of the agreement. The incremental cost rate was around $10/kW-month compared to around $2.50/kW-month for the embedded cost rate. Nev. Power Co., Jensen Aff., Docket No. ER20-2813-000 (filed Sept. 4, 2020); ***see also Pub. Serv. Co. of N.M.***, 175 FERC ¶ 61,111 (approving four transmission service agreements for point-to-point service over disputes that the utility miscalculated the embedded cost rate as compared to the incremental cost rate and should have charged an incremental cost rate because another transmission customer was taking service on an incremental cost basis), ***order on reh'g***, 177 FERC ¶ 61,094 (2021). NV Energy also clearly explained that the incremental cost rate covered only NITS and the customer is separately responsible for ancillary services.

130 ***Duke***, 193 FERC ¶ 61,237 at P 16 (citing Order 890, P 884) (stating the transmission provider failed to include cost support consistent with what it would provide to the Commission in an FPA section 205 rate filing).

131 ***Id.*** P 18.

132 ***Id.*** P 20.

WHAT IS “AND” PRICING AND DOES FERC ALLOW IT? MIXED SIGNALS.

1994 TRANSMISSION PRICING POLICY STATEMENT

FERC prohibits corporate “and” pricing but allows disaggregated pricing: FERC clearly prohibits transmission providers from charging both the embedded costs and the incremental costs of the same transmission service on the same system, reasoning it can result in third-party customers paying more than the costs they cause and subsidizing native load customers (i.e., concerns about undue discrimination and unfair cost shifting). But FERC explicitly allows transmission providers to account for costs on a disaggregated basis, separating pricing for separate facilities or groups of facilities (e.g., line-by-line pricing), so they could charge for some lines using embedded costs and others using incremental costs.

2000 ORDER 2000-A RE: RTOS

FERC allows some forms of “and” pricing in RTOs: FERC disagrees that it is allowing corporate “and” pricing like prohibited in the Policy Statement by allowing RTOs to combine elements of embedded cost rates and incremental cost rates (e.g., charging a non-pancaked access fee based on embedded costs for existing investment and an incremental cost-based charge for new investment; or charging firm transmission service customers an embedded cost rate and for incremental congestion charges). FERC emphasizes that prohibited “and” pricing is about the potential for undue discrimination by intentionally making the costs charged to one set of customers (e.g., wholesale) higher than those charged to another (e.g., native load), which is not a concern in RTOs.

2003 ORDER 2003 RE: GENERATOR INTERCONNECTION

FERC allows a form of “and” pricing in RTOs, again: FERC requires interconnecting generators that upfront fund the cost of network upgrades be credited back against embedded cost-based transmission charges until they are reimbursed, in which case the transmission owner can include the network upgrade costs in the embedded cost rate. This is important to avoid “and” pricing, FERC says. But for RTOs, FERC allows “participant funding,” whereby the interconnecting generators are not reimbursed. FERC states this is not “and” pricing if the generator receives well-defined capacity rights that are created by the network upgrades for which the generator has paid, even if the generator is also required to pay an embedded cost-based charge for transmission service. FERC views this as separate charges for separate services. FERC notes it is less concerned with undue discrimination in RTOs.

CONCLUSION

FERC has, at least arguably, remained consistent with its general prohibition on corporate “and” pricing where a non-independent transmission provider is involved, though the stated rationale may differ across FERC orders.

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VI. HOW FERC-APPROVED TRANSMISSION COSTS FLOW TO RETAIL CUSTOMERS

As discussed in Section II, FERC has jurisdiction over most transmission cost recovery. For unbundled retail sales, typical of RTO regions, FERC regulates allocation of transmission costs to LSEs. Transmission costs are then ultimately included in and recovered through state-jurisdictional retail rates, in most cases. For bundled sales, states typically regulate and allocate transmission costs. As a result, regardless of structure, 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 (see the end of this section for some exceptions).

According to the National Association of Regulatory Utility Commissioners (NARUC), state commissions "must determine the right balance between customer classes when determining retail rates."[133] Traditionally, most retail customer load has been assigned to residential, commercial, and industrial classes. Large loads can be "carved out" of existing rate structures in two ways. First, many jurisdictions are adopting new large load rate schedules, contained within existing commercial or industrial classes. Second, some states have created, or are considering creating, new large load or data center-specific classes.[134] While creating a new class involves greater change, it has the potential to assign costs caused by large loads to those customers more transparently and definitively.

Whether existing classes are used or a new large load class is created, large load tariff and contracts typically include provisions that can be grouped into three categories:

- **Commitment and assurance mechanisms,** such as long-term service commitments, contract demand requirements, milestone-based development obligations, deposits, or other collateral;
- **Minimum contribution mechanisms**, such as minimum bills or minimum demand charges; and
- **Exit and true-up mechanisms**, such as early termination charges, exit fees, or refund limitations where utilities initially fund certain facilities.[135]

To allocate FERC-approved transmission costs, some states have a rider that automatically passes the costs through to retail ratepayers. Other states allow LSEs to incorporate the FERC-approved transmission costs into their rate base, as part of their state-regulated revenue requirement, updated on a semi-annual basis. One common complaint from state regulators is that they lack transparency into some of the FERC-approved transmission costs, which makes it challenging to effectively allocate those costs to the appropriate end-use customers or customer classes.[136] Another issue is some states can only allocate the costs to customers

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133 NARUC Comments on DOE ANOPR at 4.

134 *See* Smart Electric Power Alliance & NC Clean Energy Technology Center, ***Database of Emerging Large-Load Tariffs (DELTa)***, https://sepapower.org/large-load-tariffs-database/ (tracking large load-related tariffs across the United States, updated quarterly).

135 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; Energy and Environmental Economics, Inc., ***Tailored for Scale: Designing Electric Rates and Tariffs for Large Loads*** (Dec. 2025), https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf.

136 Federal and State Current Issues Collaborative, Transcript, Docket No. AD24-7-000, at 17:11-14 (Feb. 11, 2026 Meeting), https://www.ferc.gov/media/transcript-ad24-7-000 (Kelsey Bagot, Chairman, Virginia Corp. Comm'n) (In Virginia, the state has to allocate costs that come from formula rates, but "we at the state need additional information or need to start thinking about how we can identify, once we get those dollars, that bucket of costs to us. You know, how do we identify and make sure we're allocating those costs to the drivers of that new transmission? And that is a place where I think additional collaboration and transparency at the FERC level with the states or at the RTO level to make sure we're

on default retail service and not to customers that use competitive retail suppliers. In those instances, the competitive retail suppliers pay the transmission charge at the wholesale level and allocate the costs to their customers.

Where a transmission provider provides both unbundled transmission service at FERC-regulated rates and bundled transmission service at state-regulated rates, states must determine how the costs of the same transmission facilities are divided among customers at the retail level. While the aim is generally for federal- and state-level transmission rates to be aligned, differences in rate design and inputs, such as how returns on equity are set, as well as timing differences in adjusting rates (e.g., regularity of rate cases or formula rate updates), mean there is usually a delta between the two prices.[137]

While the above framework is the most common, there are some exceptions for large customers, e.g., major casinos and manufacturers in Nevada connected at the transmission level were given the choice (via state law) to take unbundled transmission service, forcing the vertically integrated utility to offer unbundled transmission service to these end-use customers.[138] In addition, California has a distinct architecture around transmission cost recovery that creates a more explicit interface between FERC-jurisdictional transmission rate mechanisms and state retail class structures than is common in other regions. For example, retail rate classes are explicitly discussed in Pacific Gas & Electric's FERC-jurisdictional transmission owner tariff,[139] which states that end-user transmission rates are based on the transmission revenue requirement authorized by FERC and includes such rates in the tariff using specific retail schedules and associated transmission charge components.[140] The California Public Utilities Commission does not appear to have asserted jurisdiction over end-user transmission rates in the state, as is the case in other parts of the country.

able to do that, we have the information we need, I think is really, really critical."); ***id.*** at 26:16-25 (Philip Bartlett, Chair, Maine Pub. Util. Comm'n) ("The second big issue, I think, in the region where we're making some progress . . . is that there's been very little transparency into transmission costs of a particular type, and those are the asset condition or replacing sort of end-of-life assets. This is a problem in New England, and I think in many RTOs in other parts of the country where there's pretty, very little visibility. There's no real oversight at the RTO level."); Electricity Customer Alliance, Comments, Docket No. RM26-4-000, at 11 (filed Nov. 21, 2025) (noting "the costs of large load interconnections to the transmission system will flow down into retail sales and tariffs regulated by the states" and asking FERC to "require transmission providers to provide additional transparency of how costs incurred to interconnect to the FERC-jurisdictional transmission system will flow through to state retail tariffs").

137 For example, NV Energy will make both bundled and unbundled sales over its Greenlink Nevada Transmission Project. FERC approved transmission incentives that impact the transmission pricing at the wholesale level but does not regulate the transmission pricing over the same transmission facilities used for bundled retail sales. ***See Nev. Power Co.***, 182 FERC ¶ 61,186, at PP 1, 33 (2023) ("NV Energy also points out that the Petition only applies to NV Energy's wholesale (transmission-only) and large customers subject to the Commission's jurisdiction and that NV Energy's bundled retail customers are not impacted by the Petition.").

138 Nevada statute established a process whereby large customers can file an application to leave bundled retail service and build or procure their own generation and take transmission service unbundled from the local transmission provider. N.R.S. 704B, https://www.leg.state.nv.us/nrs/nrs-704b.html.

139 While the discussion focuses on PG&E, other California investor-owned utilities have similar FERC-jurisdictional transmission owner tariffs with end-use customer transmission rates.

140 Pacific Gas & Electric Co., Transmission Owner Tariff and Service Agreements, § 5.3 (0.0.0), Appendix III (35.0.0).

SIMPLIFIED EXAMPLE OF TYPICAL TRANSMISSION PLANNING, COST ALLOCATION, AND COST RECOVERY FOR TRANSMISSION TO ACCOMMODATE NEW LARGE LOAD CUSTOMER ADDITION

Assumed Facts:

- 1 GW data center requesting service in Zone A
- Zone A contains one transmission owner and one LSE
- Relevant transmission planning region uses load ratio share cost allocation method

5-10 Years Before Data Center Comes Online – New Regional Transmission Planned:

- New regional transmission need identified using inputs that include load forecast with new 1 GW data center in Zone A
- Region selects new transmission project to meet need (quantified reliability and economic benefits exceed costs)
- Region allocates costs of new regional transmission using load ratio share – 70% to Zone A (with new 1 GW data center),* 10% to Zone B, and 20% to Zone C
- State regulated tariff or utility contract determines rate (including transmission), minimum charge, etc., which determined what costs are recovered from customer

1-3 Years Before Data Center Comes Online – New Local Transmission Planned:

- Transmission owner in Zone A conducts interconnection study and identifies need for local transmission upgrades to accommodate customer requesting service
- If served by a vertically integrated utility, local upgrade costs recovered from customer through a combination of state-regulated rates and extra facility charges
- If located in an RTO region:
    - Upgrade costs added to transmission owner's embedded cost-based revenue requirement used to establish Zone A transmission service charge allocated to LSEs in the zone on load ratio share basis (100% to the LSE in Zone A)
    - LSE flows FERC-approved transmission costs allocated at wholesale to end-use customers, including new 1 GW data center, according to state-approved rate design (may include separate rate class for large load customers, like the data center)

** Caveat: Initial load ratio share cost allocation does not account for new 1 GW data center because it is not yet part of historic coincident peak-based allocation factor used, but as load shares update over time, the Zone A allocation will increase to account for increased load from the data center.*

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VII. TIMING CONSIDERATIONS FOR TRANSMISSION COST RECOVERY

There are several timing-related considerations that are important to keep in mind in considering transmission cost allocation and recovery, including when cost recovery in rates paid by customers begins, how long it lasts, and the relative length of customer commitments.

Rate Updates. Most commonly, FERC-approved transmission costs flow through a formula rate, as explained in Section V. These costs are typically updated on an annual basis via informational filings to FERC, with true-ups to actual expenses.[141] This means that new costs typically begin to flow through rates on an annual basis. If the transmission rates are stated rates, which remain in place until a new rate is filed and approved, cost recovery does not begin until FERC reviews and approves the costs and resulting rate, which could result in several years of lag between cost outlays and cost recovery beginning. Sometimes when FERC approves a rate increase, it delays the effective date or requires a transitional period to avoid rate shock (when rates change substantially between rate updates).[142] This can further delay the start of cost recovery. The timing of when cost recovery begins for transmission costs that either flow from FERC-approved charges to LSEs or are directly regulated by states varies by state laws and regulations.

Used and Useful. In principle, cost recovery cannot occur without a regulator approving the cost, typically by finding that it was prudently incurred. But the timing of when cost recovery for regulator-approved costs can begin looks to when the transmission facility is placed into service for purposes of ratemaking. This dates back to a longstanding regulatory ratemaking concept: “used and useful.” Briefly, the concept is that only a utility’s property currently providing service to customers can be included in the rate base on which the utility earns a rate of return (i.e., be part of the embedded cost-based revenue requirement). Thus, during the design and construction period for transmission, utilities cannot yet earn a return on the new investments. However, “used and useful” is often modified by the two following financing practices.

Allowance for Funds Used During Construction (AFUDC). The delay in cost recovery does not necessarily reduce utility earnings because regulators routinely allow cost recovery of AFUDC, which is essentially the financing costs incurred during the construction period. These costs are accrued and recovered after the project is placed in service. To reduce AFUDC or to improve utility cash flow, FERC has allowed utilities to begin recovering costs while projects are under construction, pending the new facilities meeting the “used and useful” test. States may employ similar mechanisms.

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141 London Economics International, ***Primer on Transmission Formula Rates***, at 4 (Feb. 16, 2023), https://wiresgroup.com/wp-content/uploads/2023/02/LEI-Primer-on-Transmission-Formula-Rates.pdf (explaining that utilities submit “ annual updates and supporting documentation to the Commission on an informational basis only, and share[] the updates with interested parties, who can review, verify, and challenge the inputs used in the calculations pursuant to approved protocols”). A true-up is where the utility reconciles what it expected to spend and collect with what it actually spent and collected. This is used to then adjust future rates to make up the difference. True-ups are particularly important where rates are set using historic data that may significantly differ from actual and future data (e.g., where there are significant changes on the system or unexpected costs, such as volatile fuel prices). True-ups also ensure ratepayers pay no more and no less than the actual cost of service approved by the regulator.

142 ***Id.*** (stating that the annual update process for formula rates reduces the risk of rate shock that can occur when stated rates are not updated for prolonged periods).

Construction Work in Progress (CWIP). FERC (and other regulators) also allow early cost recovery using a CWIP incentive.[143] Without going too far into the weeds, FERC allows utilities to include, where appropriate, 100% of prudently incurred transmission-related CWIP in rate base and earn a return on those costs while new transmission facilities are still under construction.[144] CWIP raises equity concerns, as customers who provide financing for projects during lengthy construction periods do not concurrently benefit from those projects.[145]

Depreciation. Another concept to note here is how long cost recovery takes for a transmission investment. This is where depreciation comes into the picture. Depreciation is essentially a return to utilities of the investment they made in capital assets over that asset's useful life, a period that is approved by the regulator. For transmission, the useful life is usually 40-50 years. Details about how depreciation periods are determined and applied are routine regulatory decisions.[146]

Length of Service. When considering new customers—especially large load customers—it is also important to keep in mind how long customers commit to and can be expected to take service, and therefore pay for such service. Historically, it has been expected that for those customers that stop taking service (e.g., go out of business), other similar customers will begin taking service, and the utility's assets will continue to be similarly used and useful.

However, because transmission asset life is much longer than any new customer's contractual commitment, this raises the risk that enough large load customers may depart the system to drive down energy use and hence revenues in the future. FERC's ***pro forma*** OATT establishes a minimum service term of one year for NITS[147] and one day for point-to-point,[148] whereas state large load tariffs are requiring service terms commonly around 10-20 years.[149] At the scale of these new large load customers' requested demand, replacement customers cannot be anticipated with the same certainty as was the case over the past few decades.

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143 FERC allows CWIP to be added to rate base as a transmission incentive under Section 219 of the FPA, so transmission owners must apply for FERC approval of the incentive for the specific transmission at issue, which FERC routinely grants.

144 Order No. 679, PP 29, 117; 18 C.F.R. Pt. 101 (FERC's Uniform System of Accounts), Account 107 (Construction work in progress—Electric).

145 ***See, e.g.***, ***Mont.-Dak. Utils. Co.***, 185 FERC ¶ 61,015 (2023) (Christie, Comm'r, concurring) (expressing concern with FERC's existing CWIP policy, explaining that it allows recovery of costs before a project is placed into service, "run[ning] the risk of making customers 'the bank' for the transmission developer").

146 ***See, e.g.,*** Order No. 2000 (stating that FERC believes it appropriate "to provide those willing to make new transmission investments with the flexibility to propose that such assets follow non-traditional depreciation schedules . . . to remove disincentives for the construction of new facilities").

147 ***Pro forma*** OATT § 29.2(vii).

148 ***Pro forma*** OATT § 13.1.

149 ***See*** Smart Electric Power Alliance & NC Clean Energy Technology Center, ***Database of Emerging Large-Load Tariffs (DELTa)***, https://sepapower.org/large-load-tariffs-database/ (tracking large load-related tariffs across the United States, updated quarterly).

VIII. RECENT FERC ACTION RELATED TO NEWLY INTERCONNECTING LARGE LOADS AND TRANSMISSION PRICING

While the above sections set out overarching FERC policy around transmission pricing and how it has evolved over time, as well as the general jurisdictional divide set forth in the FPA, the line between federal and state authority has increasingly been tested in the new era of large loads. Below is an overview of some of the key recent proceedings at FERC that raise many of the concepts described above related to newly interconnecting large loads specifically.

U.S. DEPARTMENT OF ENERGY ADVANCE NOTICE OF PROPOSED RULEMAKING

On October 23, 2025, pursuant to section 403 of the Department of Energy Organization Act,[150] the Secretary of Energy transmitted to FERC a proposed advance notice of proposed rulemaking (ANOPR) for FERC's consideration.[151] The ANOPR proposal asserts that FERC has jurisdiction over large loads when they interconnect directly to the FERC-jurisdictional transmission system. The ANOPR sets forth 14 principles that DOE believes should inform a FERC rulemaking to establish rules governing large load interconnection (loads greater than 20 MW) to the transmission system (as determined via FERC's existing seven-factor test).[152]

As relevant to this report, the 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's next steps in that proceeding could have significant implications for the jurisdictional divide, which is a topic hotly debated in the filed comments.[153] FERC has indicated it will act by June on the ANOPR.[154]

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150 42 U.S.C. § 7173.

151 Letter from Secretary of Energy Chris Wright to The Honorable David Rosner, et al., at 2 (Oct. 23, 2025), https://www.energy.gov/sites/default/files/2025-10/403%20Large%20Loads%20Letter.pdf (DOE ANOPR).

152 The seven-factor test determines whether a facility is subject to FERC's jurisdiction over transmission or whether it is local distribution under state jurisdiction based on its functional use. The seven factors are as follows: (1) local distribution facilities are normally close in proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems; it rarely, if ever, flows out; (4) when power enters a local distribution system, it is not re-consigned or transported on to some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographic area; (6) meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and (7) local distribution systems will be of reduced voltage. Lawrence Greenfield, et al., ***An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities***, at Slide 15 (June 2018), https://www.ferc.gov/sites/default/files/2020-07/ferc101.pdf.

153 ***E.g.***, NARUC Comments on DOE ANOPR (strongly asserting that FERC does not have jurisdiction to do what the DOE ANOPR suggests and arguing that, "from a policy perspective, the states are well positioned to make decisions on load interconnections necessary to support the best interests of their citizens"); Electricity Customer Alliance, Reply Comments, Docket No. RM26-4-000, at 5 (filed Dec. 5, 2025) (disagreeing that FERC regulating interconnection of large loads to FERC-jurisdictional transmission "would amount to regulation of retail sales or preemption of state authority over such sales").

154 ***Interconnection of Large Loads to the Interstate Transmission System***, 195 FERC ¶ 61,045 (2026) (Order Regarding Intent to Act).

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION LARGE LOAD TARIFF

On October 27, 2025, FERC rejected Tri-State Generation and Transmission Association's (Tri-State) proposed large load tariff and agreement, submitted pursuant to FPA section 205, on jurisdictional grounds.[155] Notably, Tri-State described its tariff proposal as "adapt[ing] several processes and principles borrowed from the Commission's standardized generator interconnection procedures to evaluate the feasibility of interconnecting large loads to the Tri-State system."[156] In other words, Tri-State's proposal was akin to the DOE ANOPR proposal, though some details differ.

Protestors raised jurisdictional concerns, arguing it infringes on retail sales subject to state jurisdiction, and FERC agreed, ruling that certain aspects of the proposal impermissibly intruded on retail rate regulation. FERC pointed to provisions of the proposed tariff that "require specific terms and conditions of service" by a utility to an end-use customer and make the standard agreement (that provides assurances of the viability of the large project and risk mitigation) a condition of wholesale service.[157] FERC concluded that "Tri-State has not provided a sufficient basis for the Commission to find that its proposal does not regulate the terms and conditions of a [large load customer's] retail service in ways that are beyond the Commission's authority."[158] FERC stated "it appears that Tri-State's proposal before us sets the terms of retail sales" and therefore declined to opine on questions about FERC's jurisdiction raised by protestors, "such as jurisdiction over the process of interconnecting loads to the Commission-jurisdictional transmission system."[159]

PJM CO-LOCATION ORDER TO SHOW CAUSE

On February 20, 2025, FERC initiated a show cause proceeding regarding the lack of rules in PJM's tariffs governing co-location of generation with loads, including the rates, terms, and conditions that apply to such co-location arrangements.[160] FERC initiated the proceeding following a series of filings at FERC that raised questions about co-location arrangements for large loads.

On December 18, 2025, FERC took the next step by directing PJM to establish new types of transmission service for co-located facilities—the first new transmission services FERC has established since it issued Order 888 in 1996.[161] Specific to the new transmission services, FERC also established a paper hearing to determine the just and reasonable rates, terms, and conditions that will apply. This proceeding remains pending. While ostensibly limited to co-location arrangements, larger issues around transmission rate design are implicated and FERC's rulings may indeed set precedent that reverberates beyond this narrow set of circumstances and in this one region.[162] For example, FERC raised questions about requiring co-located loads to pay for certain ancillary services regardless of the transmission service option they select and about whether co-located loads should pay a minimum transmission charge to cover the costs of maintaining the transmission system, even when they

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155 *Tri-State Generation & Transmission Ass'n, Inc.*, 193 FERC ¶ 61,070 (2025).

156 *Id.* P 5.

157 *Id.* P 45.

158 *Id.* P 49.

159 *Id.* P 50.

160 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,115 (2025).

161 *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,217 (2025)

162 *See id.* (Chang, Comm'r, concurring) (raising several issues around rate design, including the need for a minimum charge).

are not actively withdrawing power from the grid.

BESPOKE TRANSMISSION-RELATED AGREEMENTS

FERC recently approved a series of bespoke transmission-related agreements, negotiated between utilities and data center developers, and filed at FERC because the agreements contain terms that may affect FERC jurisdictional transmission service.[163] In each case, FERC decided not to address concerns about whether the negotiated agreements fairly protect native load customers, deferring such reviews to future formula rate cases.

For example, the AES Ohio-Amazon Construction Service Agreement (CSA) governs construction of new transmission facilities necessary to provide retail and transmission service to the Amazon data center; the data center will be a retail customer and not take transmission service directly under the PJM tariff.[164] The aim of the CSA is for Amazon to cover the costs of transmission upgrades needed to serve the data center, including substations and direct connection facilities (~$9 million), with the cost of network upgrades (~$22 million) to be later rolled into AES Ohio's formula rate, subject to a later proceeding. The CSA assumes Amazon will meet minimum load requirements for at least 10 years and therefore pay enough for transmission service using the rolled-in embedded cost rate to cover the costs of the network upgrades over time. The Office of the Ohio Consumers' Counsel (OCC) protested, arguing there is no evidence other customers have a need for or will benefit from the network upgrades. FERC ultimately approved the CSA using a deferential standard FERC applies to individually negotiated agreements.[165] FERC found the OCC's protest outside the scope of the proceeding as AES Ohio will later seek to recover the network upgrade costs in a formula rate update proceeding, at which time OCC can renew its protest.

FERC has also approved several Transmission Security Agreements (TSA) in PJM that similarly contain terms aimed at ensuring the data center developers pay an appropriate share of the utility's transmission revenue requirement, which is allocated to customers on a load ratio share basis. The data centers will be retail customers,[166] and the utilities will take transmission service under the regional transmission tariff (PJM) to serve the data centers, similar to their other retail customers. The TSAs contain terms meant to protect the utilities (and their other retail customers) if the data centers do not materialize, including readiness and credit obligations, committed revenue contributions, and a termination fee schedule.[167] The TSAs do not contain actual

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163 ***See Dayton Power & Light Co.***, 189 FERC ¶ 61,220 (2024) (AES Ohio-Amazon CSA Order); ***PECO Energy Co.***, 193 FERC ¶ 61,148 (2025) (PECO-Amazon TSA Order); ***Commonwealth Edison Co.***, 194 FERC ¶ 61,110 (2026) (Red Energy TSA Order); ***Commonwealth Edison Co.***, 194 FERC ¶ 61,113 (2026) (Karis TSA Order); ***Commonwealth Edison Co.***, 194 FERC ¶ 61,109 (2026) (Aligned TSA Order); ***Commonwealth Edison Co.***, 194 FERC ¶ 61,183 (2026) (Hillwood TSA Order); ***Commonwealth Edison Co.***, 194 FERC ¶ 61,181 (2026) (GCP TSA Order); ***Commonwealth Edison Co.***, 194 FERC ¶ 61,185 (2026) (QTS TSA Order); ***Commonwealth Edison Co.***, 194 FERC ¶ 61,184 (2026) (Equinix TSA Order).

164 AES Ohio states that it serves certain customers at high voltage delivery points under its state-regulated retail tariff and passes through the transmission charges incurred for service under the PJM tariff pursuant to its Transmission Cost Recovery Rider.

165 FERC used what is called the ***Mobile-Sierra*** presumption. ***See Devon Power LLC***, 134 FERC ¶ 61,208, at P 10 (2011) (citing ***Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty.***, 554 U.S. 527, 530 (2008)).

166 PECO states that it will provide retail service to the Amazon data center at 230 kV pursuant to PECO's retail tariff. In its answer, Equinix explains it will be subject to a rider in ComEd's retail tariff that establishes payments to cover transmission costs for large demand customers specifically. Equinix cites Commonwealth Edison Co., Schedule of Rates for Electric Service, Rider ZSS—Zero Standard Service (ILL. C. C. No. 10), Sheets 284-287. Presumably, the same is true for all of the data centers for which ComEd entered into the TSAs.

167 ComEd claims the TSA will ensure revenues from the data centers will equal or exceed the expected transmission costs under the PJM tariff associated with the load. To guard against uncertainty, the TSA requires the data centers to pay ComEd a minimum contribution to the revenue requirement, essentially 80% of the expected charge from PJM for transmission service to serve the data center, plus a fee for any early termination of the TSA. The PECO-Amazon TSA is similar.

costs of transmission facilities needed to serve the data centers, for which the utilities intend to seek recovery through their FERC-approved transmission formula rate. ComEd contends the TSAs should bring down overall costs for all customers because as more load is added, the overall system cost will be spread among more customers. The PJM independent market monitor protested the PECO-Amazon TSA, and the Illinois Attorney General protested nearly all the ComEd TSAs. FERC accepted the TSAs using the same deferential standard it used for the AES Ohio-Amazon CSA. FERC noted the TSAs do not upset the state commissions' authority to establish terms of retail service, including retail consumer protection provisions. FERC also stated that the Illinois Attorney General will have the opportunity to review the cost of transmission facilities associated with the data centers when ComEd seeks cost recovery through its formula rate process at FERC.

In concurrences, Commissioner Chang explained that "[m]anaging how costs are allocated among customer classes, particularly costs related to the addition of new load, has historically been the purview of state regulators, falling under their retail rate responsibilities."[168] But she asserted that concerns about the costs of interconnecting and serving these new large loads are "increasingly spilling into" FERC proceedings, raising complicated jurisdictional and policy questions with significant implications for both state and federal regulators."[169] Commissioner Chang encouraged complementary actions at the federal and state levels to protect customers against unjustified cost increases associated with specific large load additions.

In the FERC sphere, Commissioner Chang suggested FERC adopt a "higher of" policy that requires, rather than allows, the charging of the higher rate.[170] She then went on to test ComEd's theory regarding lowering overall costs, stating that if the system upgrade costs required to serve the data center are small relative to the size of the load, the transmission rates for other customers will not increase under the TSAs; but if those upgrade costs are instead substantial, the embedded cost rate will increase for all ComEd customers. According to Commissioner Chang, the embedded cost rate will increase based on the cost of the transmission upgrades (return of capital) plus the return on capital (equity and debt), income tax allowance and depreciation, and possibly additional operations and maintenance expenses, for the full useful life of the transmission assets (40+ years). She compares this to the 10-year TSA terms.

Chair Swett and Commissioner LaCerte, jointly concurring, emphasized FERC's existing transmission pricing policy: "'endorses transmission pricing flexibility,' not a linear analysis;" allows transmission providers to charge ***either*** the rolled-in embedded costs ***or*** the incremental expansion costs, "but not the sum of the two;" and "does not restrict the transmission provider to charging only the higher of those two rate structures."[171]

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168 PECO-Amazon TSA Order (Chang, Comm'r, concurring).

169 ***Id.***

170 Hillwood TSA Order (Chang, Comm'r, concurring).

171 ***E.g.***, Hillwood TSA Order (Swett, Chair & LaCerte, Comm'r, concurring).

IX. CONCLUSION

Transmission pricing policy has evolved over a century from locally regulated, bundled cost-of-service ratemaking into a complex, multi-layered paradigm shaped by shared federal and state oversight, regional markets and planning, and increasingly sophisticated cost allocation and cost recovery mechanisms. Throughout this evolution, FERC has maintained a consistent foundation: transmission rates must be just and reasonable, not unduly discriminatory or preferential, and aligned with the cost causation and beneficiary pays principles. These overarching standards continue to anchor how transmission costs are allocated and recovered at the wholesale level, even as the system around them grows more complex.

But the challenges of today raise questions about whether the current framework still strikes the right balance between critical and yet sometimes competing aims: maintaining reliability, ensuring affordability, and enabling needed infrastructure upgrade and expansion for improving resilience and supporting economic growth. The rapid growth of large loads, including data centers, is placing unprecedented pressure on both federal and state regulators. Recent FERC proceedings and policy discussions suggest that both regulators and industry stakeholders are actively grappling with whether existing tools, such as FERC's "higher of" transmission pricing policy, regional cost allocation methods, and state-regulated retail rate design, are sufficient to address these challenges.

At the same time, the core insight from the history of transmission pricing is that the framework has repeatedly adapted to new conditions while remaining grounded in its foundational principles. As load growth accelerates, those principles—ensuring cost recovery, safeguarding non-discriminatory access, promoting economic efficiency and growth, promoting fairness, and encouraging simple, transparent, and predictable rates—remain the most durable guideposts for future policy decisions.

Ultimately, rising demand should not be viewed solely as a risk to affordability, but also as an opportunity. Thoughtfully designed transmission pricing policies can enable the expansion and modernization of the grid, capture economies of scale, and ensure that costs are allocated fairly. The next phase of policy development will require coordinated action across federal and state jurisdictions to ensure that all customers, existing and new, contribute appropriately to the system on which they depend, while supporting reliability, affordability, and economic growth.

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Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in state regulation, transmission planning, and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations,the North American Electric Reliability Corporation, Congressional committees, the administration, and various stakeholders.