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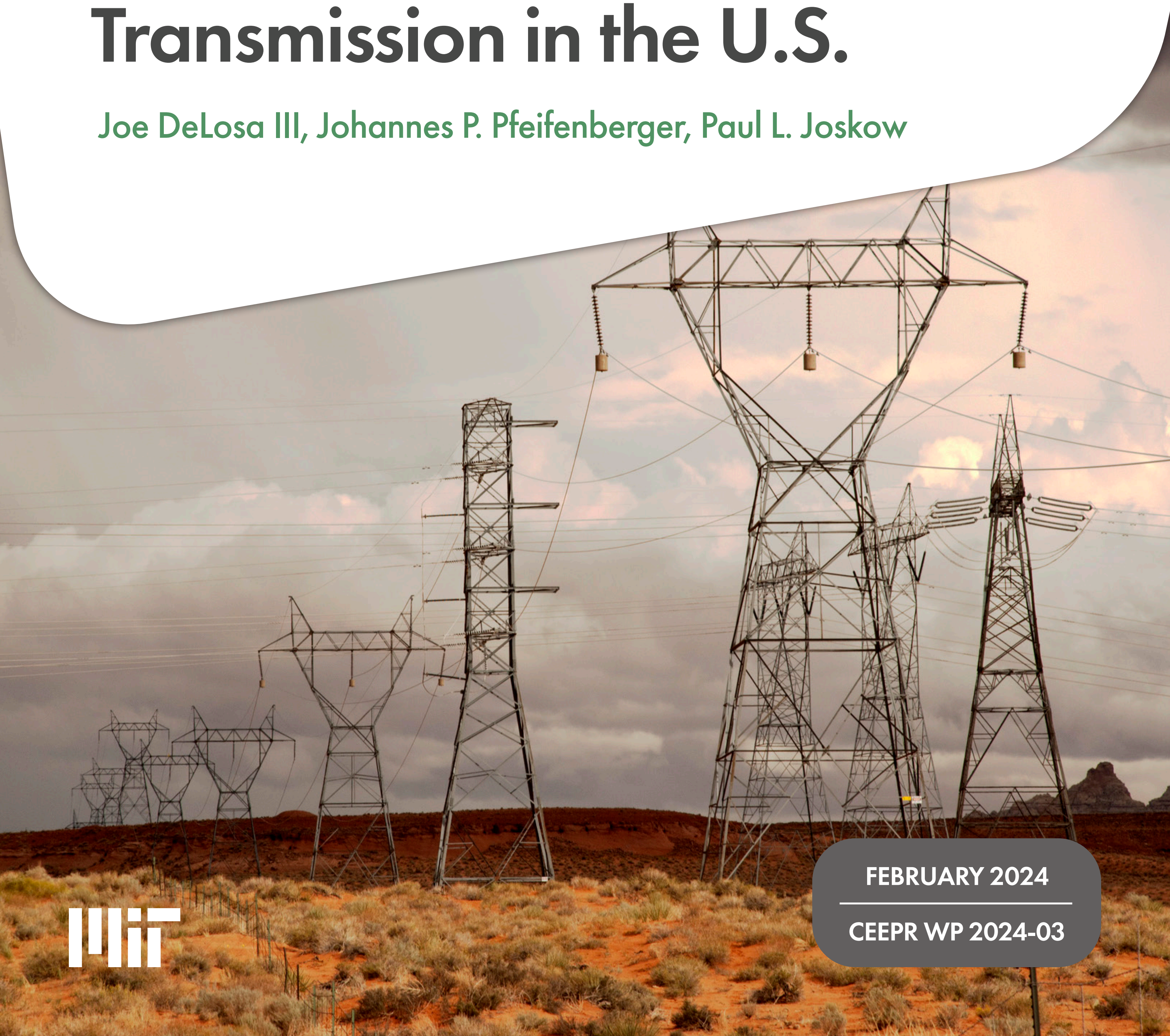

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Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S.[1]

Joe DeLosa III,[2] Johannes P. Pfeifenberger,[3] Paul L. Joskow[4]

Abstract

The U.S. regulation of high-voltage transmission is highly complex and, as a result, generally poorly understood. The complexity is created by separate, but overlapping, jurisdictional authorities of the U.S. federal regulators and those of individual states, districts, and territories. While U.S. federal regulators have authority over stand-alone transmission service and the regional wholesale power markets that use the transmission grid, state regulators have jurisdiction over both (1) retail electricity services that include the distribution network, the retail cost of transmission service, and often generation service; and (2) the permitting of most new transmission facilities within their states' boundaries. Some of these federal and state regulatory authorities overlap and some of them do not apply to non-jurisdictional transmission providers (such as certain municipal utilities, cooperatives, and federal power marketing agencies) and states (such as Texas) that are not synchronized with the larger regional grid. We summarize this complex structure of transmission regulation in the U.S. and the history of regulations that have created the industry structure and regulatory frameworks that exist today. We provide an overview of how transmission investments are priced and recovered and the planning processes that individual transmission owners and regional grid operators use to plan the necessary expansion of the high-voltage transmission grid. We also point out some of the economic inefficiencies that are created by a combination of balkanized regulatory structures and outdated industry planning practices.

I. Federal Regulation of the Electric Utility Industry and Transmission

Over the past century, electricity has become an increasingly important aspect of American life. Since the first power generator brought electric power to Wall Street in the late 1880s, the business of

[1] The final version of this paper will be published in the forthcoming *Handbook on Electricity Regulation* edited by Jean-Michel Glachant, Michael Pollitt, and Paul Joskow. We welcome comments to help us to improve the paper before then.

[2] The Brattle Group, Washington, DC, 20036, Joe.DeLosa@brattle.com, Conflicts: None, Funding: None

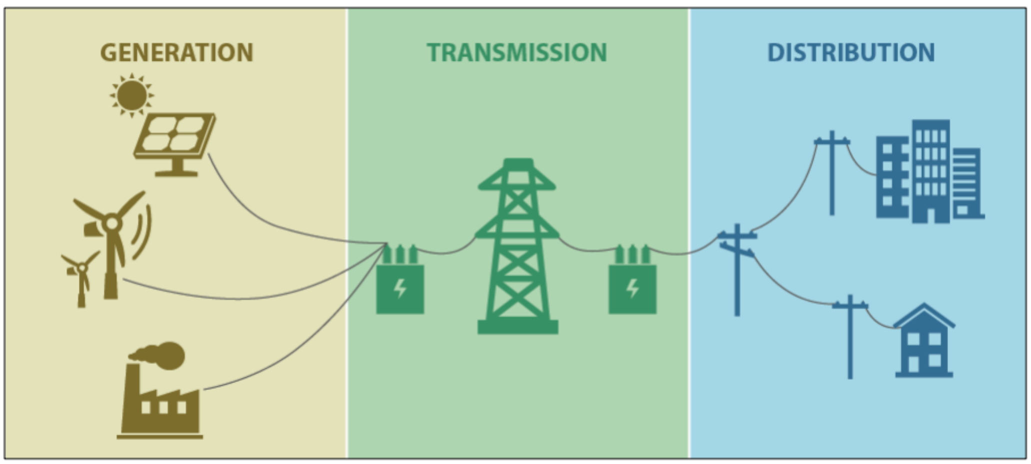
[3] MIT CEEPR and The Brattle Group, Boston, MA, 02108, USA, hannes.pfeifenberger@brattle.com, Conflicts: None, Funding: None.

[4] MIT Department of Economics, Cambridge, MA, 02139, USA, pjoskow@mit.edu, Conflicts: None, Funding: MIT Energy Initiative and the MIT Department of Economics, Economics of Energy Fund.

generating, transmitting, and distributing electricity in America has been in a state of constant evolution. In a similar fashion, the regulation of electric companies—or providers of public utility services "affected with a public interest"—has continued to evolve with the primary goals of capturing the efficiency benefits of natural monopolies by providing exclusive service areas while protecting the general public from monopoly conduct of utilities.[5]

Historically, electric power systems are made up of three component parts: generation, transmission, and distribution, as shown in Figure 1. Large, utility-scale generators provide electric power by converting a fuel source, including the sun, wind, geothermal heat, nuclear fuel, run-of-river, or a wide array of fossil fuels, into electricity. Typically, this electricity is injected into the high-voltage transmission system, which is an interconnected network of power lines that transmits electricity over long distances within and between states. Finally, the distribution system receives this electricity from the transmission system and distributes it locally to end-use customers.[6]

FIGURE 1: ELECTRIC POWER SYSTEM OVERVIEW



Source: Congressional Research Service, R45762 (August 4, 2022) at Figure 1.

A. Fundamentals of U.S. Power Systems Regulation

The first Public Utility Commissions ("PUCs"), or state regulatory agencies with jurisdiction over electric and gas utilities, were created by New York and Wisconsin in 1907, laying the foundation for more than two-thirds of U.S. states creating PUCs by 1920.[7] During this period, while subject to constitutional restrictions imposed by the Supreme Court, states retained a large degree of autonomy even in creating

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5 See, e.g., *Munn v. Illinois,* 94 U.S. 113 (1877).

6 Today, electricity supply from large generators connected to the transmission system is increasingly complemented (but not displaced) by "distributed energy resources" ("DERs"), such as smaller-scale solar plants, that are connected directly to the distribution system or are owned by end users.

7 J.P. Tomain, R.D. Cudahy, *Energy Law in a Nutshell*, 2nd Ed. (2011) at 153.

policies that impacted neighboring states.[8] In 1927, faced with the prospect of Rhode Island setting the rates for an in-state plant selling power across state lines to Attleboro, Massachusetts, the Supreme Court struck down the state regulation of this interstate service, explaining that the regulation had placed a "direct burden on interstate commerce," which could only be addressed "by the exercise of power vested in Congress."[9]

This ruling created the so-called "Attleboro gap" in electricity regulation, with certain matters remaining beyond the purview of state jurisdiction, and not yet covered by any federal law.[10] Congress closed this gap in 1935 with the passage of the Federal Power Act ("FPA").[11] Notably, the FPA placed under federal jurisdiction "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce;"[12] also requiring that all rates under federal jurisdiction be "just and reasonable" and not unduly discriminatory or preferential.[13] The FPA as subsequently amended multiple times remains the main regulatory framework upon which the transmission regulations effective today were built.

Following the FPA's passage in 1935, federal jurisdiction expanded to include interstate transmission of electric energy.[14] The remaining components, "generation" and "distribution," as well as intrastate transmission, remained within state jurisdiction.[15] As a result, the dominant 20th century regulatory paradigm featured large, "vertically-integrated" utilities, regulated under state law with exclusive service areas and that typically owned all generation facilities sufficient to serve the retail customers within their geographic franchise areas or their "native" loads, and delivered the electricity largely

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8 *Bluefield Waterworks v. Public Service Commission of West Virginia*, 262 U.S. 679, 690 (1923) ("Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service of the utility to the public are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment"); *New York v. FERC*, 535 U.S. 1 (2002) ("Prior to 1935, the States possessed broad authority to regulate public utilities, but this power was limited by our cases holding that the negative impact of the Commerce Clause prohibits state regulation that directly burdens interstate commerce" [*citing Pennsylvania Gas Co. v. Public Serv. Comm'n of N. Y.*, 252 U. S. 23 (1920), *Public Util. Comm'n of Kan. v. Landon*, 249 U. S. 236 (1919), *Missouri ex rel. Barrett v. Kansas Natural Gas Co*., 265 U. S. 298, 309 (1924)]).

9 *Public Util. Comm'n of R.I. v. Attleboro Steam & Elec. Co*., 273 U. S. 83, 89, 90 (1927). See *New York v. FERC*, 535 U.S. 1 (2002).

10 See *New York v. FERC*, 535 U.S. 1 (2002) ("Creating what has become known as the "Attleboro gap," we held that this interstate transaction was not subject to regulation by either Rhode Island or Massachusetts, but only "by the exercise of the power vested in Congress").

11 16 U.S.C. Chapter 12.

12 16 U.S.C. § 824(b).

13 16 U.S.C. § 824d(a), (b).

14 *FPC v. Florida Power & Light Co.*, 404 U.S. 453, 461, 467 (1972) ("Power supplied to the bus from a variety of sources is said to merge at a point and to be commingled just as molecules of water from different sources (rains, streams, etc.) would be commingled in a reservoir")(citing 16 U.S.C. § 824(b)).

15 16 U.S.C. § 824(b)(1) ("The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution…").

through their own transmission and distribution networks. This framework largely resulted in an institutional arrangement where each vertically-integrated utility planned its own generation, transmission, and distribution facilities to serve the utility's "native load" customers and (at times) embedded small municipal and cooperative distribution utilities—with only sales between utilities and third parties subject to federal jurisdiction.

These vertically-integrated utilities typically did not have an obligation to plan transmission to serve third parties, primarily municipal utilities and cooperatives at the time, nor did they have to provide wholesale transmission or generation services pursuant to generally-available transmission tariffs. This resulted in fairly limited federal involvement because only interstate transmissions of energy, and the rare occasion where an investment was made to enable such transmissions, were regulated by the federal government through the Federal Energy Regulatory Commission ("FERC" or "Commission").

It is important to note that FERC jurisdiction over transmission and power markets does not extend to certain publicly owned power companies, which include municipal power companies (such as the Los Angeles Department of Water and Power ("LADWP")) and federal power marketing agencies (such as the Bonneville Power Administration ("BPA"), the Tennessee Valley Authority ("TVA"), or the Western Area Power Administration ("WAPA")). FERC jurisdiction over transmission and electricity markets also does not apply to single-state power grids (the Electricity Reliability Council of Texas ("ERCOT")) that are not synchronized with the interstate transmission network. However, in the mid 1990s FERC established a "reciprocity principle" under which such non-jurisdictional entities can take advantage of FERC-jurisdictional entities' open access transmission policies only if they reciprocate—and offer open access service at terms comparable to FERC requirements. This reciprocity condition was highly successful in motivating non-jurisdictional U.S. transmission owners (as well as interconnected Canadian and Mexican transmission owners) to provide reciprocal open access to their transmission grid at terms comparable to FERC's open access requirements.

It was not until the 1990s, that some states (mostly on the east and west coast) sought to lower electricity rates by restructuring their utilities and creating organized competitive wholesale markets for electricity generation and related network support services.[16] Certain of these "restructuring" laws allowed retail customers, for the first time, to choose an energy supplier (i.e., of generation) other than their incumbent utility company. In many states, these same laws simultaneously required utilities to "unbundle" their generation assets from their existing utility business, creating a series of competitive independent generators and retail suppliers from which distribution utilities and retail customers could choose. Still other states embraced competitive wholesale power markets while retaining vertically-integrated utilities and limits on retail choice.

To support these restructuring efforts, FERC issued a number of orders that expanded access to transmission systems at FERC-regulated rates to support wholesale power sales by both integrated

[16] Limited competition to utility-owned generation was previously facilitated in the late 1970s under the Public Utilities Regulatory Policy Act ("PURPA"), which required utilities to buy power from certain types of generation plants owned by third parties at avoided-cost-based rates, see 16 U.S.C. Chapter 46. Similarly, prior to restructuring, markets consisting of bilateral wholesale power transactions existed throughout the U.S., going back to the early 20th century. See Joskow, P.L. and Schmalensee, R. (1983). Markets for Power: An Analysis of Electric Utility Deregulation, MIT Press. Cambridge, MA.

utilities and "unbundled" generators to third parties consistent with state restructuring policies. These FERC orders also created organized wholesale markets for energy, capacity, and ancillary services managed by Independent System Operators ("ISOs") or Regional Transmission Operators ("RTOs").

B. FERC Initiatives to Support Wholesale Power Markets, Transmission Access, and Reliability

To set the framework for wholesale power markets in response to state restructuring efforts of the 1990s, a series of landmark FERC orders overhauled the method of using, selling, and planning transmission facilities in the U.S.[17] By applying the FPA's requirement of "non-discrimination" to the bulk transmission system, FERC set the foundation for the modern energy industry, in which "open access" to the transmission system and lower-cost electric generation must be provided to all market participants, including competitive generators.

FERC issued **Order 888**, the first of these landmark orders, just prior to the state restructuring reform efforts in the late 1990s.[18] Order 888 responded in part to a wave of FERC litigation over insufficient and discriminatory transmission access provided by incumbent utilities.[19] Order 888 transitioned the industry into a new open-access transmission paradigm, and away from the prior industry practice where each transmission owner controlled the use and assignment of available transmission capacity. This new "open-access" framework provided non-discriminatory transmission system access to all market participants, including through the previously-discussed "reciprocity principle", with the goal to eliminate the ability for local utilities to provide preferential treatment to their own generation resources and setting the stage for a rapid growth in interstate trading of electricity.

The open access framework established through Order 888 also set the stage for state restructuring efforts in the 1990s, which depended on the ability to transmit competitively-priced generation. The subsequent development of RTOs further relied on the open and non-discriminatory access created by Order 888 to optimize and dispatch the most economically optimal set of resources to meet load, using network transmission facilities.

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17 Many of the landmark orders use the federal "rulemaking" process which requires the Commission to provide adequate opportunity for public notice and comment. See *American Medical Ass'n v. Reno*, 57 F.3d 1129, 1132 (1995).

18 *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, FERC Stats. & Regs. ¶ 31,036, at 31,783-84 (1996) ("Order 888"), *order on reh'g*, Order No. 888-A, 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 Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom*. *New York v. FERC*, 535 U.S. 1 (2002). The Order was named after FERC moved into its new location at 888 First Street in Washington, D.C.

19 See K. Rose et al., Summary of Key State Issues–Order 888 and 889, National Regulatory Research Institute (Rev. January, 1997) at 3–10.

In January 2000, FERC issued the (aptly-named) **Order 2000**, setting out minimum characteristics and functions necessary for RTOs/ISOs.[20] FERC promoted the creation of RTOs and ISOs to improve open access to the transmission grid envisioned through Order 888 and provide a framework and platform for newly deregulated utilities and generation companies to buy and sell electricity services in competitive wholesale power markets. The FERC envisioned these RTOs/ISOs implementing organized wholesale power markets to replace the previous power pools of interconnected utilities that would rely solely on bilateral transactions and did not offer transparent market pricing or efficient management of transmission constraints.[21]

Order 2000 set out four minimum characteristics and eight minimum functions of RTOs and ISOs.[22] The first minimum characteristic, RTOs' organizational independence from any class of market participant, is the bedrock principle "upon which the ISO [or RTO] must be built."[23] To ensure this independence, the Commission paid special attention to the governance and voting structures within each ISO and RTO. These voting structures directly implicate the rules that govern transmission development and wholesale markets, and are critical to maintaining the confidence of all market participants in the ability of the ISO and RTO to fulfill the other minimum characteristics and functions required by Order 2000. These governance provisions and other requirements for operating wholesale power markets and transmission (including planning and cost recovery), must be documented in Open Access Transmission Tariffs ("OATTs") filed and approved with the FERC by all transmission owners and RTOs/ISOs.[24]

In addition to independence, the Order 2000 framework specifies a number of other operational and market-maker responsibilities of RTOs/ISOs. Upon joining an RTO/ISO, a FERC-jurisdictional utility (or

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20 *Regional Transmission Organizations*, Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999)("Order 2000"); *order on reh'g*, Order No. 2000-A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom*. *Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

21 Order 2000 at 14 ("Open access transmission and the opening of wholesale competition in the electric industry have brought an array of changes in the past several years: divestiture by many integrated utilities of some or all of their generating assets; significantly increased merger activity both between electric utilities and between electric and natural gas utilities; increases in the number of new participants in the industry in the form of both independent and affiliated power marketers and generators as well as independent power exchanges; increases in the volume of trade in the industry, particularly sales by marketers; state efforts to introduce retail competition; and new and different uses of the transmission grid"); see also National Association of Regulatory Utility Commissioners, National Regulatory Research Institute, *A Review of FERC Order 2000* (April, 2000).

22 The four minimum characteristics are 1) independence; 2) scope and regional configuration; 3) operational authority; and 4) short-term reliability. The eight minimum functions are 1) tariff administration and design; 2) congestion management; 3) parallel path flows; 4) ancillary services; 5) OASIS and transmission capability management; 6) market monitoring; 7) planning and expansion; and 8) interregional coordination. See Order 2000 at 5, 151–496.

23 Order 2000 at 193.

24 This requirement is known as the Commission's "Rule of Reason" policy that states that utilities must file "only those practices that affect rates and service significantly, that are reasonably susceptible of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous" in their Commission-approved Tariff, *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985). Other items that do not significantly affect rates, or can "better be classified as implementation details" are included in RTOs' business practice manuals, 162 FERC ¶ 61,296 (2018) at P 103.

utility affiliate, often called a "Transmission Owner" or "TO") cedes operational control of the facilities they own to the RTO/ISO.

The combined geographical area served by RTO/ISO transmission owners sets the boundaries and service areas of the RTO/ISO. Throughout this service area, RTOs/ISOs are granted responsibility for ensuring grid reliability. RTOs/ISOs are further responsible for operating the regional spot markets for electric energy, managing transmission congestion, and identifying and procuring the necessary "ancillary services" that are required to maintain grid reliability and the ongoing matching of generation and load.[25] All of these overlapping market, procurement, and reliability functions of RTOs/ISOs are monitored on an ongoing basis by internal and external market monitoring committees and ultimately by FERC. This process is supposed to ensure competitive outcomes and prevent manipulation of market prices or other types of fraud that would negatively impact electric ratepayers or other market participants. In addition to these market and operational functions, Order 2000 required RTOs/ISOs to take "ultimate responsibility" for transmission planning within their region.[26] Along with Order 888, Order 2000 was one of the most significant FERC actions that modernized the rules governing the expansion, enhancement, replacement, and future planning of the nation's transmission system. A number of other orders (as summarized in Appendix A) subsequently built on these milestones orders.

C. FERC Evolving Regional Transmission Policy

Less than 10 years after the issuance of Order 2000, FERC issued **Order 890** to further advance transmission reform.[27] Order 890 responded to shortcomings in the RTOs' system planning under Order 2000 by requiring more open, transparent, and coordinated frameworks to evaluate necessary transmission expansions or enhancements. These reforms set the underlying standards for transmission expansion planning processes used by all FERC-jurisdictional utilities today.[28] Notably, transmission planning processes were now required to include region-wide coordination,[29] early opportunities for open stakeholder and customer engagement[30] (including an opportunity to review the underlying

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25 See FERC, *Energy Primer: A Handbook of Energy Market Basics*, (December, 2023).

26 Order 2000 at 485 ("We reaffirm the NOPR proposal that the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities").

27 *Preventing Undue Discrimination and Preference in Transmission System Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007)("Order 890"), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

28 Order 890 instituted nine principles for transmission planning processes: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. Order 890 at PP 435–561. Note that "…to the extent that … asset management projects and activities do not expand the grid, they do not fall within the scope of Order 890," see 164 FERC ¶ 61,160 at PP 31–34 (2018).

29 Order 890 at PP 523–528.

30 Order 890 at PP 451–454.

assumptions relied on to plan transmission facilities)[31], and a method of regionally allocating the costs of resulting transmission projects.[32] All transmission expansion planning processes under FERC jurisdiction are subject to the requirements of Order 890, whether or not the transmission owner resides within an RTO.[33]

Less than five years following the issuance of Order 890, FERC sought to address identified shortcomings of regional planning processes through the issuance of **Order 1000**.[34] Building on Order 890, Order 1000 required affirmative participation of transmission providers in developing regional plans with the participation of stakeholders. Notably, FERC required that RTOs/ISOs, including transmission providers in their service territories, select the most efficient solutions available to solve identified regional transmission needs.[35] In these cases, the transmission projects are also selected "for the purposes of regional cost allocation,"[36] with the costs of these projects shared between the ratepayers throughout the planning region using a FERC-approved cost allocation method.[37] To introduce competition in the identification and selection of transmission projects, FERC removed the long-held federal "right-of-first-refusal" by incumbent utilities, enabling competitive transmission developers to bid on regionally-cost-allocated transmission expansions in competition with incumbent transmission owners.[38] Order 1000 also required that transmission plans address state and federal public policy needs,[39] although various regions have responded to this directive to varying degrees as discussed in Section II.B.

A significant portion of transmission projects planned in the footprint of RTOs/ISOs are not subject to regional cost sharing. They therefore are not subject to competition, nor to other rigorous transmission planning analysis by the RTOs/ISOs to determine whether the selected project is indeed the most cost-effective solution. In practice, transmission planning processes are split between (1) "regional"

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31 Order 890 at PP 471–472.

32 Order 890 at PP 557–561.

33 Order 890 at PP 135–142.

34 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011)("Order 1000"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and 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).

35 Order 1000 at P 331 ("Whether or not public utility transmission providers within a region select a transmission facility in the regional transmission plan for purposes of cost allocation will depend in part on their combined view of whether the transmission facility is an efficient or cost-effective solution to their needs").

36 Order 1000 at P 331.

37 Order 1000 at PP 482–779.

38 Order 1000 at PP 313–340. Historically, the incumbent (local) transmission owner would retain the rights to build all transmission facilities within its service territories under the federal right-of-first refusal. Order 1000 removed only *federal* rights-of-first refusal. Various state laws, undisturbed by Order 1000, effectively leave in place a right-of-first refusal in many states, even within RTO/ISO regions. See Order 1000 at P 287 ("The Commission acknowledges that there may be restrictions on the construction of transmission facilities by non-incumbent transmission providers under rules or regulations enforced by other jurisdictions. Nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities").

39 Order 1000 at PP 146–148.

transmission planning, where RTOs/ISOs identify needs and select the transmission solutions and (2) "local" transmission planning, where incumbent transmission owners identify transmission needs and solutions with only limited review by the RTOs/ISOs.[40] Since Order 1000, the share of regionally-planned transmission has fallen while the share of locally-planned transmission has increased, as shown further below.

When recovering the cost of transmission investments from customers, the costs allocated to certain groups of customers (i.e. in different utility service territories within a region) must be roughly aligned with the benefits received by these customers from the transmission investments. All cost allocation methodologies for transmission projects under FERC jurisdiction must satisfy this requirement, which is known as the cost causation principle. Cost causation requires that "all approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them."[41] Ahead of FERC's Order 1000, federal courts issued a number of decisions refining the scope of the cost causation principle, explaining that "causing" or "benefiting from" a transmission project both satisfied the requirements of the cost causation principle to serve as justification for the assignment of transmission costs.[42] Order 1000 and subsequent federal court precedent further clarified cost allocation principles, specifically requiring that the costs assigned must be "roughly commensurate" with the benefits received by each party.[43] This accounting of benefits does not need to be done with exacting precision,[44] but must be backed with substantial evidence of the burdens caused or benefits received by the party

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[40] Order 1000 at P 63 ("A local transmission facility is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation"); Order 1000 at P 7, referencing "transmission facilities in local transmission plans that are merely "rolled up" and listed in a regional transmission plan without going through an analysis at the regional level, and therefore, not eligible for regional cost allocation;" Order 1000 at P 64 ("In some regions, transmission facilities not selected for purposes of regional or interregional cost allocation nonetheless may be in a regional transmission plan for informational purposes, and the presence of such transmission projects in the regional transmission plan does not necessarily indicate an evaluation of whether such transmission facilities are more efficient or cost-effective solutions to a regional transmission need").

[41] *KN Energy, Inc. v. FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992).

[42] See *Illinois Commerce Commission v. FERC,* 576 F.3d 470 at 476 (7th Cir. 2009) ("FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members … 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); *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004)("[W]e evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party").

[43] *Illinois Commerce Commission v. FERC*, 576 F.3d 470 at 476 (7th Cir. 2009).

[44] Order 1000 at P 586 (citing *Illinois Commerce Commission v. FERC*, 576 F.3d 470 at 476-77 (7th Cir. 2009) (stating that "[w]e do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars"); *MISO Transmission Owners v. FERC*, 373 F.3d 1361 at 1369 (D.C. Cir. 2004) (stating that "we have never required a ratemaking agency to allocate costs with exacting precision").

being allocated transmission costs,[45] allowing for the significant variation of regional cost allocation methods used by the various RTOs/ISOs today.

In May 2024, FERC issued **Order 1920** on regional transmission planning and cost allocation.[46] The Order, which as of this writing is still subject to rehearing requests and potential legal challenges, is intended to improve planning processes to make them more holistic and proactive by addressing anticipated long-term transmission needs over at least 20 years, considering long-term uncertainties through at least three plausible scenarios.[47] It requires grid planners "… to conduct and periodically update long-term transmission planning to anticipate future needs; … to consider a broad set of benefits when planning new facilities; … to identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, known as 'right-sizing'; customers [to] pay only for projects from which they benefit;" it also expands states' role in planning, selecting, and determining how to pay for transmission.[48] These scenarios must incorporate categories of factors identified by the Commission including resource retirements, integrated resource plans, utility needs, and federal, state, and local laws regarding the future resource mix and decarbonization.[49] The planning process must include a process for the transmission planner to select long-term projects,[50] based on an assessment of at least seven mandatory benefits identified by the Commission.[51] To allocate the costs of these long-term projects, planning regions must have a default allocation method to recover the costs from various states.[52]

D. Market-based Congestion Management and Locational Market Pricing

While transmission facilities primarily enable the transfer of electricity at high voltages over relatively long distances, the interconnected transmission network enables a wide array of other functions critical to operating an efficient and reliable electricity system. For instance, transmission networks facilitate reliable operation of the power system by enabling the second-to-second matching of generation and load over large geographic areas. Larger interconnected networks of transmission facilities, centrally

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[45] 5 U.S.C. § 706. Under the Administrative Procedures Act, the Commission's Orders will be upheld unless found to be "arbitrary and capricious," or unsupported by "substantial evidence" and not the product of "reasoned decisionmaking," which requires "a rational connection between the facts found and the choice made." S*outh Carolina Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 54–55 (D.C. Cir. 2014); *Electricity Consumers Resource Council v. FERC,* 747 F.2d 1511, 1513-14 (D.C. Cir. 1984)(internal citations omitted).

[46] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Order No. 1920, 187 FERC ¶ 61,068 (2024) ("Order 1920").

[47] Order 1920 at P 559.

[48] FERC, Fact Sheet | Building for the Future Through Electric Regional Transmission Planning and Cost Allocation (2024).

[49] Order 1920 at P 387.

[50] Order 1920 at P 911.

[51] Order 1920 at P 667.

[52] Order 1920 at P 1291.

managed and operated, provide access to a wider array of generating facilities to meet the system's electricity demands. As the geographic size of interconnected transmission grids increases, customer costs for generation will tend to decrease, other things equal, because the transmission system provides access to lower-cost generation from across the region and is able to reduce the cost of maintaining reliability by taking advantage of load and resource diversity in the larger geographic areas—particularly when the geographic areas of the interconnected grid exceeds the size of large weather systems that can create reliability challenges.

The interconnected transmission network combined with open access transmission regulations established by FERC Orders 888 and 2000 and with state restructuring efforts, led to the voluntary formation of RTOs/ISOs in most regions except in the Southeast and the non-California portions of the Western U.S.[53] These RTOs/ISOs in turn created organized bid-based spot markets for wholesale power that integrated the management of transmission congestion with the determination of market clearing hourly day-ahead and real-time prices for energy. As a result, the organized wholesale energy markets in the U.S. lead to prices that may vary by location when there is congestion on the network. Thus, these voluntarily organized FERC-regulated U.S. wholesale power markets set prices for electricity in each location based on the current marginal cost of generating electricity in that area, efficiently managing congestion created by transmission constraints that may prevent access to the region's lowest marginal cost resources. When an area cannot access the lowest-cost electricity supply in the region, that constrained area must instead rely on more expensive local generators to meet the next increment of energy. When this occurs, the more expensive local generator sets a higher location-specific price (relative to the rest of the system) to serve load in the constrained area, making the congestion costs associated with the transmission constraint visible in the market.

This system of location-specific pricing of electricity is called "nodal pricing" or Locational Marginal Pricing ("LMP") and forms the foundation for pricing electricity for all RTO/ISO markets in the U.S. Because higher LMPs are a direct result of insufficient transmission capacity, expanding transmission capacity to constrained areas will necessarily relieve the congestion, reduce wholesale LMPs, and make lower-cost generation accessible to customers. High observed or projected congestion costs on transmission paths between generation and load areas provides valuable information for transmission planning processes that are targeted to increase market efficiency and reduce total customer costs. Congestion costs observed in locational power markets are, however, an incomplete picture of transmission-related impacts on total electricity costs as they do not fully indicate the extent to which transmission expansion can reduce generation investment costs (e.g., by allowing the integration of additional resources in areas with low-cost generation) and address resource adequacy and grid reliability challenges. Congestion charges in LMP-based spot markets are not generally high enough to provide for the full recovery of the capital and operating costs incurred by TOs simply because a regionally efficient expansion of the transmission system will tend to reduce congestion below the levels necessary for such cost recovery. As a result, the recovery of transmission-related cost is thus based mostly on cost-of-service regulations governing the recovery of TOs' capital and operating costs as discussed in Section III below. These organized wholesale energy markets are also co-optimized with markets establishing the prices for ancillary services such as frequency regulation and spinning reserves.

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53 Several municipal utilities in California, including the relatively large Los Angeles Department of Water and Power, are not members of the California ISO.

Overall, these wholesale market reforms have led to a significant increase in the efficiency of how the electricity system is operated.[54]

II. Transmission Planning

A. Distinguishing between Transmission and Distribution

While the rates, terms, and conditions governing facilities used in the interstate transmission of electricity generally fall under the jurisdiction of FERC, the local distribution system remains fully under state jurisdiction.[55] Forty-nine (49) states created state public utility commissions to regulate the local electric distribution systems owned by investor-owned utilities ("IOUs").[56] Transmission facilities under FERC purview are subject to the reliability standards developed by the North American Electric Reliability Corporation ("NERC," now regulated by FERC), while distribution facilities are instead subject to the reliability requirements of the utilities bound by state regulation. FERC and the federal courts have provided guidance as to which facilities fall into each of these categories and therefore which authority retains regulatory jurisdiction.

In Order 888, FERC instituted a 7-factor test to distinguish between state-regulated distribution facilities and federally-regulated transmission.[57] Whether grid facilities were considered distribution or transmission is a "case-by-case" fact-specific determination of the Commission informed by these

54 The initiatives to implement organized wholesale power markets originated regionally. For example, PJM implemented LMP-based markets as part of its Order 888 Compliance Filing, see 81 FERC ¶ 61,257 at 42-56 (1997); New York implemented Locational Based Marginal Pricing ("LBMP") in phases throughout the early 2000s, see, e.g., 99 FERC ¶ 61,126 (2001); the Midwestern ISO implemented LMP pricing on April 1, 2005, see D. Patton, 2005 State of the Market Report for MISO, Potomac Economics (June, 2006).

55 16 U.S.C. § 824(b)(1) ("The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution…."). States also retain jurisdiction over siting and permitting of transmission facilities, as well as over bundled retail rates (i.e., rates that combine cost recovery for generation, transmission, and distribution).

56 Texas was the last state to introduce state public utility commission regulation in 1975. Prior to that date Texas relied on municipalities to regulate electric utilities pursuant to their franchise agreements. Nebraska has no IOUs and customers are served solely by municipal and cooperative utilities and public power districts.

57 Order 888 at page 402. The seven factors are (1) Local distribution facilities are normally in close proximity to retail customers; (2) Local distribution facilities are primarily radial in character; (3) Power flows into local distribution systems; rarely, if ever, flowing out; (4) When power enters a local distribution system, it is not resold or transported on to some other market; (5) Power entering a local distribution system is consumed in a comparatively restricted geographical area; (6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system; (7) Local distribution systems will be of reduced voltage.

factors.[58] In Order 743, the Commission required that NERC further clarify which facilities constitute bulk electric facilities under federal jurisdiction, setting a 100kV threshold for networked (i.e. non-radial) facilities paired with an exemption process that relies on the 7-factors when deciding exemption requests.[59]

However, other sovereign powers of states impact the development even of FERC-jurisdictional transmission facilities. Various state laws require permitting and siting approvals before construction on transmission facilities can begin within the boundaries of a state. Often, these approvals are in the form of a "Certificate of Public Convenience and Necessity" ("CPCN").[60] These authorities can also provide the state regulator with the ability to re-evaluate the "need" for a project in the CPCN application process, even when the project need has been determined in FERC-jurisdictional regional and local transmission planning processes. These overlapping state and federal authorities often cause tension, particularly in cases where state regulators disagree with FERC-jurisdictional planning authorities on whether the project is a worthwhile investment. An example of such a disagreement has recently been litigated in federal court.[61]

B. Planning for Different "Drivers" of Transmission Needs

The transmission grid is composed of a number of different types of transmission facilities that support different "needs" for transmission capability. Large high-voltage regional transmission facilities are the 'highway' for electricity. They form the bulk-power grid to which large generating plants are connected. Also connected to the bulk-power grid are lower-voltage transmission facilities that provide the necessary on-ramps for smaller generation facilities as well as off-ramps to enable delivery of wholesale power to local distribution systems. As discussed earlier, these transmission facilities are often said to be "regional" (i.e., regionally planned in an Order 1000 planning process and selected for the purposes of regional cost allocation) or "local" (planned by the local TOs).

Significant investments in transmission are occurring throughout the United States in the last decade, with annual capital expenditures by FERC-jurisdictional transmission owners of $20–25 billion since 2013

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[58] Order 888 at page 401; Order No. 743-A*,* 134 FERC ¶ 61,210 at P 67 (2011) ("Order 743-A"); 133 FERC ¶ 61,018, at n. 59 (2010) ("The Supreme Court has determined that whether facilities are used in local distribution is a question of fact to be decided by the Commission") (*citing FPC v. Southern California Edison Co*., 376 U.S. 205, 210 n. 6 (1964)).

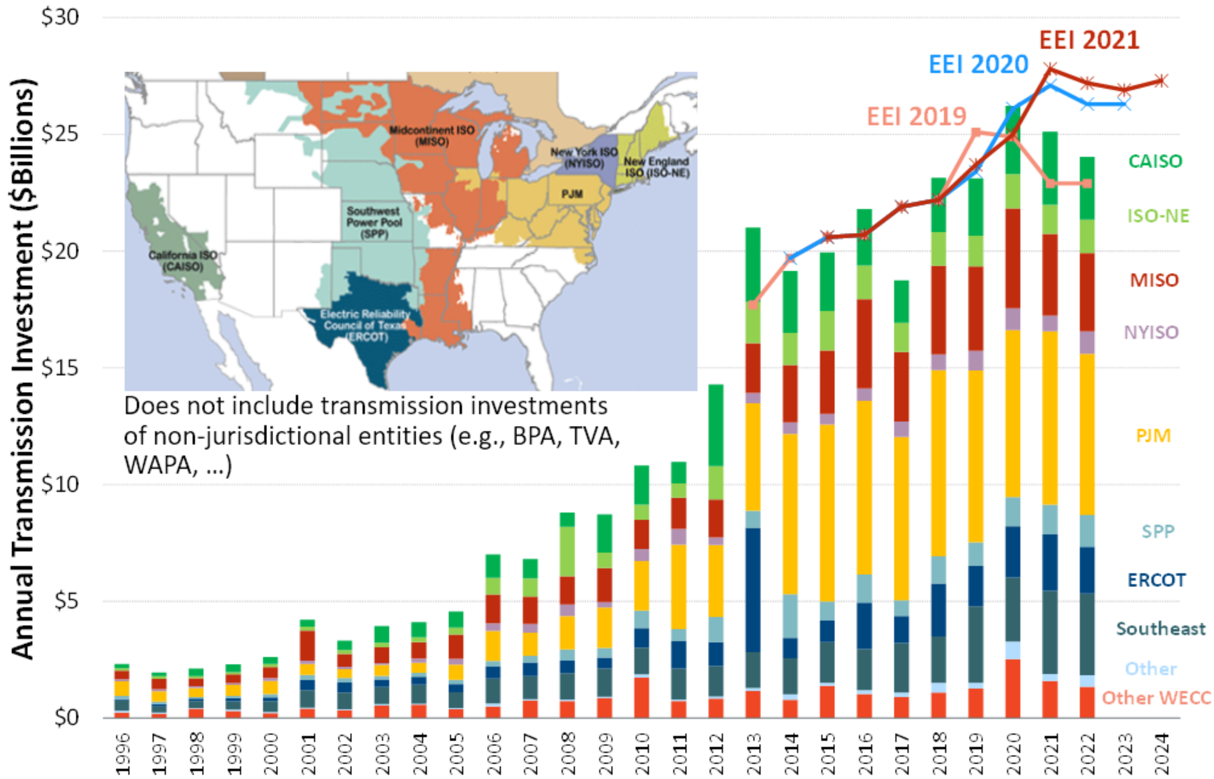
[59] Order 743-A at P 67.

[60] See, e.g., 220 ILCS 5/8406(a) (Illinois), Ky. Rev. Stat. § 278.020(1) (Kentucky), Maryland Annotated Code, Public Utilities, § 7-207(b)(3)(i) (Maryland), 66 Pa. Stat. and Cons. Stat. Ann. § 1102(a)(1) (Pennsylvania).

[61] See *Transource v. Dutrelle,* Memorandum Opinion (December 6, 2023), Case No. 1:21-cv-01101-JPW (U.S.D.C. M.D.PA), *appeal pending.*

as shown in Figure 2.[62] Today, the vast majority of these annual investments occur through development of local transmission projects, based on the plans of local TOs with a smaller portion of the investment resulting from RTO/ISO's regional planning processes. For instance, of the total $4.2 billion in new transmission approved through MISO's 2022 transmission expansion plan, over 74%, or $3.2 billion, were locally planned.[63] Similarly, each year since 2014 the PJM reliability planning process has approved more local (so-called "supplemental") projects than regionally-planned projects, with $38.3 billion invested in supplemental and only $6.4 billion of regional projects approved from 2014 through 2022.[64]

FIGURE 2: ANNUAL TRANSMISSION INVESTMENT AS REPORTED TO FERC BY REGION



Source: J. Pfeifenberger, The Value of Interregional Transmission: Grid Planning for the 21st Century (September, 2023) at 15 (with permission).

62 Not included in these historical transmission investments are (1) grid upgrades built by the transmission owners for interconnecting generators (funded, for the most part, directly by the generators) and (2) transmission investments by non-jurisdictional transmission owners, such as BPA, WAPA, LADWP, and TVA. It is estimated that these non-jurisdictional transmission providers own approximately 40% of the transmission system in the Western U.S. and Texas and approximately 20% of the transmission in the Eastern U.S. (see Pfeifenberger et al., *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada* (May, 2011) at Figure 10.

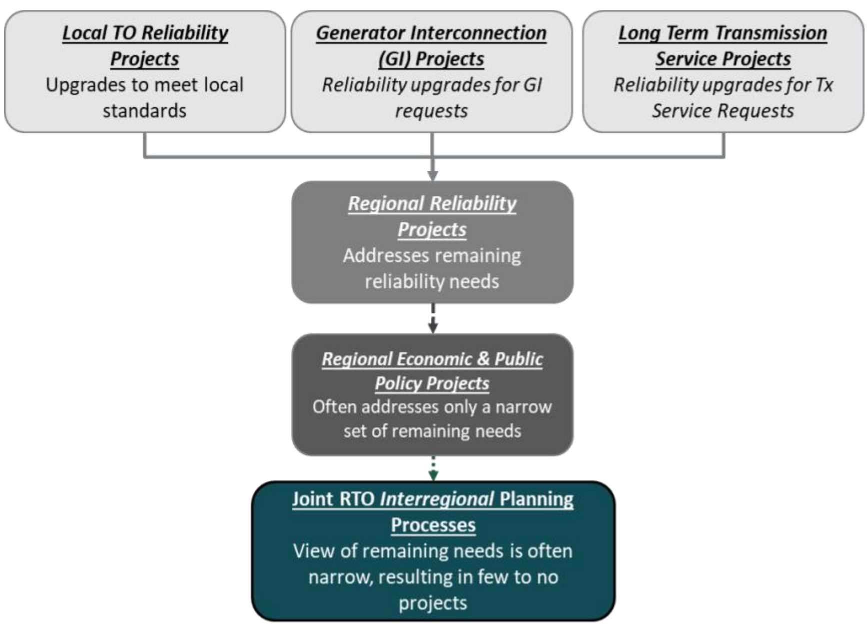
63 See MISO, 2022 MTEP, at 17.

64 See PJM 2022 RTEP at 286 (comparing "Supplemental" cost in Figure 5.2 to "NERC/PJM Criteria" cost in Figure 5.3).

As required by FERC, transmission planning is supposed to address reliability, economic, and public policy needs.[65] In most regions, this means that separate planning processes are used to: (1) address local reliability-driven transmission needs; (2) enable the reliable interconnection of new generators; (3) reliably enable requests for long-term transmission service; (4) address region-wide reliability needs; (5) improve market efficiency (i.e., economic congestion relief) so lower-cost resources can be used to serve customers; (6) to address state or federal public policy needs; and (7) contemplate interregional transmission projects. As shown in Figure 3, this leads to a siloed set of planning processes that address these various needs incrementally rather than holistically and is inefficient.

It is estimated that planning solely for **reliability** needs (i.e., the top four blocks in Figure 3 below) accounts for 90–95% of all U.S. transmission investment, with planning for economic and public policy accounting for most of the remainder.[66] Interregional transmission planning processes remain largely ineffective. Some interregional transmission expansion is being addressed through "merchant transmission facilities" [67] that rely on at-risk cost recovery through bilateral contracts (i.e. without regulated cost recovery), as discussed further below. These projects are not selected through an RTO/ISO driven planning process and must apply for interconnection authorization from the RTO/ISO and pay for the associated interconnection costs.

FIGURE 3: TYPICAL U.S. TRANSMISSION PLANNING PROCESSES



Source: J. Pfeifenberger, The Benefits of Interregional Transmission: Grid Planning for the 21st Century (March 15, 2022) at 3 (with permission).

65 See Order 1000 at P 148.

66 See J. Pfeifenberger, The Benefits of Interregional Transmission: Grid Planning for the 21st Century (March 15, 2022).

67 See Order 1000 at P 119; see also, e.g., *Opinion No. 503,* 129 FERC ¶ 61,161 (2009).

Considered separately from the regional projects planned by RTOs/ISOs, **local transmission projects** are planned and constructed by the incumbent TOs, with the costs of these facilities typically assigned directly to the local utility's ratepayers. Such facilities are primarily intended to meet, not expand, the local needs of the regional electric grid.[68] Local enhancements often include, but are not limited to, the repair, maintenance, and replacement of transmission facilities at the end of their useful life. However, in certain areas, transmission owners can identify and address local system needs that have not been otherwise identified through the regional planning process. These local projects carry different names: for example, PJM refers to them as "supplemental projects;"[69] in MISO's transmission plan they are categorized as "other projects;"[70] ISO-NE lists them in the "Local System Plan;"[71] and CAISO refers to them as "asset management projects."[72]

Transmission expansions to accommodate **generator interconnection** and **long-term transmission service** requests are usually evaluated individually with the costs of identified necessary transmission upgrades usually recovered from the interconnecting generator or long-term transmission service customers. Due to the large number of generator interconnection requests associated with the growth of clean-energy resources and battery storage technology, generator interconnection queues have grown exponentially, resulting in large backlogs and multi-year delays. These generator interconnection related challenges are discussed in more detail in Section II.C below.

FERC Order 1000 mandated that **economic and public policy needs** are addressed by regional planning processes and based on benefit-cost analyses. While some RTOs/ISOs are already holistically addressing economic and public policy needs (along with regional reliability needs), many are addressing these needs incrementally and often based on narrow definitions of such needs. For example, economic or "market efficiency" needs are often limited to relieving transmission congestion with benefits narrowly quantified through forward-looking market simulations that are highly normalized and do not consider challenging market conditions such as cold snaps, heat waves, and transmission and generation outages during which a lack of sufficient transmission capability can result in disproportionately high costs. It is not surprising that these types of narrowly-defined economic planning processes have not resulted in the approval of many economic or market efficiency transmission projects. Narrowly defined public-policy transmission planning processes have a similarly poor track record. Fortunately, some regions are now addressing economic and public policy needs more holistically along with reliability and generator interconnection needs through multi-driver (also called multi-value) planning as discussed further below.

Interregional transmission projects serve to enable power transfers and improve reliability by connecting multiple ISO/RTOs and non ISO-planning regions. Order 1000 only required improved interregional coordination between neighboring planning regions to allow them to identify interregional

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[68] See 164 FERC ¶ 61,160 at PP 31–34 (2018) ("…to the extent that … asset management projects and activities do not expand the grid, they do not fall within the scope of Order 890…").

[69] See PJM Tariff, Attachment M-3.

[70] See 2022 MISO Transmission Expansion Plan at 17.

[71] See ISO-NE Tariff, Attachment K.

[72] See So Cal Edison Tariff, Attachment XI; see also supra n. 56.

facilities that could serve regional violations more cost-effectively than identified regional solutions.[73] However, despite Order 1000's requirement for increased *coordination*, the Commission did not require interregional *planning*, and left in place several challenges for identifying and making interregional transmission investments actionable in transmission plans. Notably, Order 1000 requires any interregional project seeking to be included in regional plans to respond to a separate need in each region, and agree on cost allocation.[74] These challenges, in combination with a siloed transmission planning process that addresses local and regional needs before considering interregional needs, make the selection of interregional transmission facilities in regional transmission plans extremely rare.[75] Most of the interregional projects being developed are, as a result, merchant projects that are not included in regional plans (e.g. New England Energy Connect, Champlain-Hudson, Grain Belt Express, SOO-Green, TransWest, Sun Zia).

The compartmentalization of transmission planning into separately addressing different types of transmission needs yielding incremental investments that foreclose more efficient (e.g., larger scale) solutions that could address multiple needs. But this is not the only source of planning inefficiencies. The **sequencing of individual planning processes** also makes it very difficult to identify cost effective transmission solutions. Local projects that are planned and approved before regional needs are considered can pre-empt more efficient regional solutions that can simultaneously address local needs. And regional projects approved before interregional needs are studied can pre-empt more efficient interregional solutions that can simultaneously address regional needs. Inefficiencies are created by the sequencing of **planning for near-term and long-term needs**: near-term needs within the next 3 years that are considered "urgent," while long-term reliability needs are typically evaluated for the next 10 years. Economic and public policy needs typically are evaluated over a longer-term period, such as 20 years. Inefficient planning outcomes may occur because near-term needs are typically addressed without consideration of longer-term needs—which means the projects approved to address near-term needs may pre-empt more efficient solutions that could simultaneously address longer-term needs. To overcome these planning inefficiencies requires proactive planning processes that more holistically consider transmission needs and available solutions over both near- and long-term time frames.[76]

A number of **national transmission studies** have found that doubling or tripling the available regional and interregional transmission could provide significant cost savings and reliability benefits, particularly as the grid transitions to clean resources at geographic locations different from the bulk of thermal

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73 Order 1000 at P 435.

74 Order 1000 at P 436.

75 See J. Pfeifenberger, et al., A Roadmap to Improved Interregional Transmission Planning (November 30, 2011).

76 For example, assume term transmission needs can be addressed by adding a single-circuit transmission line. The consideration of longer-term needs may suggest that a higher-capacity, double-circuit transmission line may ultimately be required. Proactive planning that addresses near-term needs, while also considering long-term needs, may find that building a single circuit line with double circuit towers (which would create the option to inexpensively add a second circuit in the future if and when needed) would yield a more robust plan to address near-term needs—particularly when considering long-term uncertainties.

generators.[77] These studies show that expanding transmission nationally can reduce costs, lower electricity costs to customers, and reduce the risk of high-cost outcomes and power outages during extreme weather events and challenging market conditions. These benefits go beyond allowing for the development of lower-cost clean energy resources and delivering their output to load, they include resource and load diversification, increased system reliability and resilience, and a broader set of wholesale power market benefits. However, despite the net benefits of expanded interregional transmission demonstrated through these studies, they have failed to yield the identified regional and interregional transmission expansion simply because their study approach is separate from those of the RTOs/ISOs and misaligned with the transmission planning processes discussed above.[78]

C. Planning for Generator Interconnections

Certain transmission upgrades are necessary to enable the connection of new generating resources. This infrastructure includes the transmission facilities between the generator and the closest transmission line or substation on the existing grid, which is called the "Point of Interconnection" ("POI"). Facilities between the generator and the POI are called "generator lead lines" and are typically constructed by the generation project developer (i.e., not the owner of the existing grid facilities). By interconnecting its facility, the generator is seeking to inject power on the existing grid facilities owned by the local TO and the broader regional grid operated by the RTO/ISO. Upgrades to the local grid around the POI may be necessary to accommodate the interconnection requests, the cost of which are typically assigned to the interconnecting generators.

To determine the feasibility of these power injections and identify any grid reliability problems the new generators could cause, both RTOs/ISOs and local transmission owners study the power grid with the new generator or clusters of multiple generator interconnection requests. These reliability assessments typically distinguish between "non-firm" (energy-only) and "firm" (energy plus capacity) interconnection requests. Any reliability concerns identified in these generator interconnection studies for the new generator(s) must then be addressed prior to the generator being allowed to inject its full power output onto the system (although non-firm injections may be allowed until upgrades needed for firm interconnection service are completed).

[77] See Table 1 in A Roadmap to Improved Interregional Transmission Planning and U.S. Department of Energy, National Transmission Needs Study (October, 2023), summarizing the results of several national studies undertaken in recent years by the National Renewable Energy Laboratory ("NREL"), M.I.T., and Princeton, among others.

[78] As noted in A Roadmap to Improved Interregional Transmission Planning, these studies have not been successful in motivating improved interregional planning or actual transmission project developments because: (1) many of the national studies tend to analyze aspirational clean energy targets (e.g., 100% by 2050) not the actual policies for the next 10−15 years; (2) the studies do not identify specific transmission projects that could be built; (3) the studies fail to identify how benefits and costs are distributed across jurisdictions; (4) there has not been an analysis of the state-by-state economic impact and job creation from interregional transmission development; and (5) most studies do not propose solutions to address the barriers inherent in existing planning processes that stymie the development of new interregional transmission projects.

Upgrades to transmission facilities that transmit power over longer distances to serve load are called "network upgrades." If such network upgrades are deemed necessary to reliably transmit the interconnecting generator's output to load, most grid operators will allocate the cost of these network upgrades on a pro-rata share to the interconnecting generators that contribute to the need for the upgrade. Thus, in most regions the cost of all transmission upgrades related to generator interconnection requests (both local and distant network upgrades) is allocated to the interconnecting generators.[79]

The generator interconnection processes used by grid operators today were designed decades ago for the interconnection of a limited number of large generating plants. These processes are unable to handle the large number of interconnection requests associated with the (often smaller-scale) renewable generation and battery storage development efforts necessary to support the clean energy goals of U.S. states, utilities, and large commercial customers. As a result, the size of RTOs/ISOs' generator interconnection queues has grown exponentially, causing substantial (multi-year) delays[80] and a sharp increase in the cost of generator-interconnection-related grid upgrades.[81]

To address the generator-interconnection-related delays, FERC issued Order 2023 in June of 2023.[82] With this order, FERC aims to streamline and speed up generator interconnection processes by: (1) transitioning from a first-come, first-served serial process to a first-ready, first-served cluster study process; (2) facilitating public interconnection information access; (3) imposing 150 day time limits on interconnection studies; (4) increasing generation developers' financial readiness and site control requirements; (5) imposing timeliness requirements on "affected system studies" by impacted neighboring grid operators; (6) requiring grid operators to allow projects to co-locate on a shared site behind a single POI and share a single interconnection request; and (7) requiring that grid operators consider alternative transmission technologies as solutions to address the identified needs.[83] If actually implemented by grid operators, some of these reforms have the potential to significantly speed up generator interconnection processes, particularly at existing POIs and new POIs that do not require significant network upgrades—although additional reforms, such as integrating generator

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79 Regions that differ from cost allocation to generators include ERCOT (where the cost of all network upgrades are recovered from load) and CAISO (where network upgrades are initially funded by generators but then reimbursed through cost allocations to load).

80 Lawrence Berkeley National Laboratory (Rand, et al), Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022 (April, 2023). As of the end of 2022, "Over 10,000 projects representing 1,350 gigawatts (GW) of generator capacity and 680 GW of storage [are] actively seeking interconnection. …The typical project built in 2022 took 5 years from the interconnection request to commercial operations, compared to 3 years in 2015 and <2 years in 2008" (at 3).

81 Lawrence Berkeley National Laboratory (Seel, et al), Generator Interconnection Costs to the Transmission System (June, 2023). "Average interconnection costs have grown across regions and request types: Often doubling for projects that have completed all studies [and] increasing even more for active projects currently moving through the queues" (at 12).

82 FERC, Improvements to Generator Interconnection Procedures and Agreements (July 28, 2023).

83 FERC, Explainer on the Interconnection Final Rule | Federal Energy Regulatory Commission (ferc.gov)

interconnection needs into more proactive and holistic transmission planning will be necessary to achieve more timely and cost-effective outcomes.[84]

Incrementally constructing network upgrades alone in response to generator interconnection requests without considering other transmission needs has been demonstrated to be inefficient. A number of examples show that more proactive and holistic planning for generator interconnection in combination with other transmission needs can reduce the cost of transmission upgrades associated with generator interconnection needs by 50% to 80%.[85]

D. Holistic and Proactive Transmission Planning

FERC has recognized in its Order 1920 that holistic long-term transmission planning is desirable to avoid the inefficiencies created by the siloed current planning processes.[86] Planning holistically considers more than one transmission driver simultaneously is referred to as "multi-value" or "multi-driver" planning, enabling solutions that enhance the existing grid, upsize existing lines, or add new lines to simultaneously and more cost-effectively address multiple needs.

Holistic planning is particularly valuable now as the need to refurbish or replace transmission infrastructure originally deployed during the rapid expansion of the U.S. electric grid during the middle of the 20th century logically drives a significant portion of today's high level of local transmission investments. The large number of transmission facilities built in the 1950s, 1960s, and 1970s are now reaching the end of their useful lives and must be refurbished to maintain reliability. This growing need for investment would present an opportunity for transmission planners to evaluate holistic solutions that may be more cost-effective than simply replacing a facility with the same type. Through more holistic and forward-looking analyses, planners could evaluate a wide range of transmission needs, including local or asset replacement needs, and identify solutions—including grid-enhancing technologies—that can more cost effectively address the various types of transmission needs and better utilize the existing grid and the rights of way of aging existing lines.

To account for all transmission needs in the most efficient manner, planning processes will have to move beyond today's siloed, reactive planning processes that respond to each need as they arise, often with local solutions.[87] Instead, efficient regional transmission planning will need to proactively look at both the near-term and long-term transmission needs that arise as system conditions evolve. Through such

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84 J. Pfeifenberger, How Resources Can Be Added More Quickly and Effectively to PJM's Grid (October 17, 2023).

85 See J. Pfeifenberger, J. DeLosa III, et al., The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals (January 24, 2023). Section II summarizes examples of cost savings associated with proactively planning of transmission needs for interconnecting both onshore and offshore renewable generation.

86 See *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Order 1920, 187 FERC ¶ 61,068 (2024); see also J. Pfeifenberger, R. Gramlich, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (October, 2021).

87 See Transmission Planning for the 21st Century at 14.

proactive, holistic planning processes, regions can not only evaluate multiple needs simultaneously; but when evaluating alternative transmission solutions that can address the identified needs, they can also evaluate the extent to which benefits provided (including avoided generation and other transmission costs) differ across the alternative solutions. The so chosen transmission solutions will be those that address the identified multiple needs at the highest benefit-cost ratio (or highest net benefits), while also considering long-term uncertainties and non-monetary considerations such as community impacts. While most U.S. planning regions currently do not, or only partially employ many of these best practices into their planning processes, a number of successful holistic planning process examples already exist.[88] As a result, FERC's most recent order requires that transmission planning regions consider transmission needs holistically and proactively over at least a 20-year time horizon, based on benefit-cost analyses that consider a wide range of transmission-related benefits and a broader set of solutions that include grid-enhancing technologies and the upsizing of aging existing lines.[89]

The mandatory subset of transmission-related benefits that FERC Order 1920 requires include: (1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme weather events and unexpected system conditions; and (7) capacity cost benefits from reduced peak energy losses.[90] As FERC previously recognized, but not mandated in Order 1920, additional benefits of transmission investment may also include: (8) diversification of weather and load uncertainty; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity.[91] This list of benefits is derived from successful examples of existing multi-value transmission planning efforts by RTOs/ISOs (as shown in Table 1 below) and a growing amount of industry experience.[92]

While U.S. transmission planners are still planning most of their transmission upgrades solely based on reliability needs and are only beginning to develop and refine existing planning processes, many of the available best practices are already utilized (for example) by the Australian Energy Market Operator ("AEMO") in the preparation of its Integrated System Plans, which evaluate both near- and long-term transmission needs based on a variety of drivers across a range of long-term scenarios.[93] In addition, the Integrated System Plan (ISP) includes the ability to efficiently sequence planning, permitting, and construction phases, such that transmission projects can be developed to be "shovel-ready" so they can

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88 See Transmission Planning for the 21st Century at 15.

89 See *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Order No. 1920, 187 FERC ¶ 61,068 (2024).

90 Order 1920 at P 667.

91 *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022), at P 185.

92 Transmission Planning for the 21st Century (2021) at 31, Table 4 and Appendices B, C, and D for examples of benefits that have been quantified for use in evaluating transmission projects.

93 See Draft 2024 Integrated System Plan for the National Electricity Market ("ISP").

later be constructed quickly when needed (but not before) to maximize overall benefits.[94] Europe and some of the U.S. system operators have implemented similar planning processes that are more proactive and more holistic than the traditional planning methods.[95]

TABLE 1. EXAMPLES OF MULTI-VALUE TRANSMISSION BENEFITS ANALYSES BY U.S. RTOs/ISOs

SPP **2016 RCAR, 2013 MTF**	**MISO** **2011 MVP Analysis**	**CAISO** **2007 TEAM Analysis of DPV2 Project**	**NYISO** **2015 PPTN Study of AC Upgrades**
Quantified Production Cost Savings - A. Reduced Emissions - B. Reduced as Costs Avoided Transmission Project Costs Reduced Transmission Losses - A. Capacity Benefit - B. Energy Cost Benefit Lower Transmission Outage Costs Value of Reliability Projects Value of Meeting Policy Goals Increased Wheeling Revenues	**Quantified** Production Cost Savings Reduced Operating Reserves Reduced Planning Reserves Reduced Transmission Losses Reduced Renewable Generation Investment Costs Reduced Future Transmission Investment Costs	**Quantified** Production Cost Savings and Reduced Energy Prices From Both a Societal And Customer Perspective Mitigation of Market Power Insurance Value for High-Impact Low-Probability Events Capacity Benefits Due to Reduced Generation Investment Costs Operational Benefits (RMR) Reduced Transmission Losses* Emissions Benefit	**Quantified** Production Cost Savings (Includes Savings Not Captured by Normalized Simulations) Capacity Resource Cost Savings Reduced Refurbishment Costs for Aging Transmission Reduced Costs of Achieving Renewable & Climate Goals
Not Quantified Reduced Cost of Extreme Events Reduced Reserve Margin Reduced Loss of Load Probability Increased Competition/Liquidity Improved Congestion Hedging Mitigation of Uncertainty Reduced Plant Cycling Costs Societal Economic Benefits	**Not Quantified** Enhanced Generation Policy Flexibility Increased System Robustness Decreased Nat. Gas Price Risk Decreased CO_2 Emissions Decreased Wind Volatility Increased Local Investment and Job Creation	**Not Quantified** Facilitation of the Retirement of Aging Power Plants Encouraging Fuel Diversity Improved Reserve Sharing Increased Voltage Support	**Not Quantified** Protection Against Extreme Market Conditions Increased Competition and Liquidity Storm Hardening and Resilience Expandability Benefits

Sources: Transmission Planning for the 21st Century (with permission), referring to: SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016; SPP Metrics Task Force, Benefits for the 2013 Regional Cost Allocation Review, July, 5 2012; Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011; CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a

94 See ISP at 38 ("A major challenge for planners is to balance the risks of investment that is 'too early' or 'too late' in an uncertain future. Too early may mean over-investing in things that in the end are not needed. Too late, after waiting for certainty, may mean the system is less able to maintain reliable, secure and affordable power if unpredictable events occur").

The ISP distinguishes between different types of transmission project based on the certainty of their future need. It identifies: (1) future projects that are likely needed at some point in the future; and (2) actionable projects for which the need is certain enough now to move forward. Because projects that are more capable of adapting to different future market conditions and drivers are more valuable, the ISP can add "optionality" to actionable ISP projects to create flexibility—such as staging the overall size or timing of the project (splitting a project into smaller sizes, and retaining the flexibility to deliver subsequent stages if and when needed), using non-transmission options that manage the immediate need (and enable ISP projects to be delivered if and when needed in future), and undertaking early works (to develop shovel-ready projects that can be constructed quickly in the future if required).

95 See Pfeifenberger, Proactive Transmission Planning for a Clean Energy Transition, Presented at an Atlantic Council Global Energy Center Roundtable, March 28, 2024.

Certificate of Public Convenience and Necessity; S. Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015.

E. Merchant and Competitive Transmission

Seeking to overcome the inadequacies in planning interregional transmission projects through existing planning processes, merchant transmission developers have been proposing to develop transmission projects outside of RTO planning processes, using at-risk development capital without regulated cost-recovery from FERC. Such merchant transmission projects are not developed in response to RTO/ISO-identified reliability, market-efficiency, public policy, local, or interregional transmission "needs," but in response to market opportunities identified by the transmission developer that can be captured through construction of new transmission facilities paid through bilateral contracts for transmission service on the lines. The regional grid operators essentially treat interconnection requests from merchant lines similarly to generators, typically charging them for the costs of grid upgrades identified at each end of the line and placing them in an interconnection queue. Although merchant transmission facilities typically are interregional lines designed to interconnect neighboring RTO/ISOs, intra-regional opportunities of sufficient size occasionally exist (e.g., in conjunction with long-term contracts to deliver renewable generation to load centers) to motivate capital investment in merchant facilities within a single region. The capital utilized to develop these merchant facilities faces market risks for cost recovery as the investment is not recovered through regulated rates imposed on electricity customers.

For certain regional needs, Order 1000 has enabled non-incumbent transmission providers to compete with incumbents to construct transmission facilities with regulated cost recovery. The exact structure of this competition for the construction of regulated transmission varies across regions, with some RTOs/ISOs (such as NYISO and PJM) soliciting bids for solutions designed and constructed to address an identified transmission need, while other regions (such as CAISO, MISO, and SPP) solicit bids for just the construction of projects already designed through the planning process. Competitively procuring solutions for identified needs is generally thought to offer larger benefits (i.e., through innovative solutions) than the bidding out of projects that reflect solutions preselected by the grid planners.[96]

In practice so far, only a very limited set of transmission needs is open for competition, however, with planning regions excluding a wide array of transmission projects from competition.[97] When transmission projects are competitively bid, experience shows that the competitive process can result in reduced costs, with savings estimated between 20% to 30% on average.[98] As noted, the solutions-based model of transmission procurement unlocks additional ratepayer value, "because developers are also competing

[96] See P. Joskow, Competition for Electric Transmission Projects in the U.S.: FERC Order 1000 (March, 2019) at 26–48, discussing structure of each region's competitive procurements and early results of Order 1000 competitive solicitations.

[97] See P. Joskow, Competition for Electric Transmission Projects in the U.S.: FERC Order 1000 (March, 2019) at 42, see also e.g., PJM Operating Agreement, Sch. 6 § 1.5.8 (l), (m), (n), (p) (excluding transmission owner/supplemental, immediate need, < 200kV, and thermal substation equipment needs from competition).

[98] J. Pfeifenberger, J. Chang, et al., Cost Savings Offered by Competition in Electric Transmission (April, 2019) at 10. See also Initial Comments of the California Public Utilities Commission in FERC Docket RM21-17-000, filed August 17, 2022 (providing an update of the state's experience with competitive transmission procurement).

on broader design ideas, which can yield significant additional cost benefits when innovative solutions can more cost-effectively meet identified system needs."[99] Certain incumbent transmission owners claim that competitive processes do not provide any such benefits, but these incumbent-sponsored analyses are based on invalid comparisons.[100]

Competition for the design and construction of transmission projects with regulated cost recovery was made possible by Order 1000's removal of the federal "Right of First Refusal" ("ROFR"), which previously provided incumbent utilities the sole right to construct and own all transmission in their service territory. As part of Order 1000, FERC removed the federal ROFRs, finding that ROFRs "deprive customers of the benefits of competition in transmission development, and associated potential savings."[101] However, even with the federal ROFR eliminated, U.S. states are still allowed to decide who is authorized to build transmission within its boundaries. After FERC eliminated the federal ROFR, incumbent TOs have worked with many states legislatures to pass "state ROFR laws" specifying that only the incumbent utility or an affiliated transmission company is allowed to construct transmission in that state. In 2023, twelve central U.S. states (in MISO, SPP, and ERCOT) had ROFRs that prohibited competition for the construction of transmission projects by excluding non-incumbent transmission developers,[102] although the legality of these restrictions has now been challenged successfully in some of them.[103]

III. Transmission Cost Recovery

The annual costs of regulated transmission facilities are expressed as "revenue requirements," which are then allocated to the utilities and wholesale transmission customers. Precisely how the cost of regulated transmission facilities are allocated to utilities and users within a region typically varies by the type, driver, or voltage level of the transmission facility. A utility's own transmission costs and its share of allocated regional transmission costs is then translated into a wholesale rate for transmission service charged to loads in its service area. These wholesale transmission costs are ultimately recovered from end-use customers through state-jurisdictional retail rates. We discuss each of these steps in more detail below.

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[99] J. Pfeifenberger, J. Chang, et al., Cost Savings Offered by Competition in Electric Transmission (April, 2019) at 11.

[100] See, e.g., J. Chang, J. Pfeifenberger, et al., Response to Concentric Energy Advisors' Report on Competitive Transmission (August, 2019).

[101] Order 1000 at P 285.

[102] See Inside Climate News, Utilities Seize Control of the Coming Boom in Transmission Lines (April 26, 2023). See also J. Neely, How ROFR Laws Increase Electric Transmission Costs in Midwestern States (March 7, 2023). ("…while a state's ROFR requirement increases the costs of projects built in that state, not all of those additional costs are borne by ratepayers in that state. This is because the costs of a project are often divided up between multiple states … This means that if a state ROFR law makes transmission projects in that state unnecessarily expensive, it is not just electricity customers in that state who will bear the burden. Residents of other states—who are not a part of the ROFR state's electorate—will pay some of the higher cost as well").

[103] E&E News, Transmission Rulings Pave Path for Renewable Energy (December 12, 2023) summarizing successful challenges of state ROFR laws in Texas and Iowa.

A. Transmission Cost Allocation Methodologies

The initial step in recovering the costs for any transmission investment is identifying the universe of customers that will be responsible for funding the cost of a specific transmission facility. As noted above, precedent requires that the costs borne by different groups of ratepayers for each transmission facility are roughly commensurate with the benefits the facility provides to those customers.[104] In light of this standard, FERC and the courts have allowed for significant regional variation in the particular methods of identifying beneficiaries and allocating costs associated with facilities selected in the regional plan for purposes of regional cost allocation (pursuant to Order 1000).[105] The initial step of selecting a cost allocation method is mandated by Order 1000, as facilities cannot be selected in a regional plan without an approved regional cost allocation method for the particular type of transmission facility.[106]

Generally, cost allocation approaches tend to share the costs of regional projects more or less broadly throughout the region.[107] This tendency is enforced by recent court decisions, which have applied the cost causation principle in determining that large, high-voltage network transmission facilities provide regional benefits, limiting cost allocations that are too narrowly applied to only one set of customers.[108] For example, reliability projects in the Southwest Power Pool (SPP) RTO are allocated using a "highway-byway" approach, with 100% of the cost of "highway" facilities operating at 300 kV or above spread fully across all local transmission providers in the SPP region (on a load-ratio share basis), and "byway" facilities between 100 kV and 300 kV shared 33% across the region with 67% allocated to the local transmission zone.[109] In CAISO, the cost of transmission projects operating at voltage levels below 200 kV are recovered from each transmission owner's customers, while the cost of transmission for facilities above 200 kV are recovered from transmission customers on a CAISO footprint-wide basis. PJM assigns the costs of double-circuit 345 kV or larger facilities such that 50% are allocated based on a load-ratio shared across the region and 50% are assigned based on an engineering analysis of which zones cause power flows on the facility (measured solution-based distribution factors or DFAX). In PJM, the costs of smaller "regional" facilities are assigned 100% based on zones' use of the facility as measured by DFAX, while the cost of local projects are allocated directly to the local transmission owners.[110]

The methods for allocating the costs of transmission projects can vary by the drivers behind these projects. For example, MISO, NYISO, and PJM allocate costs of market efficiency projects to areas for

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104 Supra nn. 37–40.

105 For a summary of regional cost allocations used by RTOs/ISOs, see Review of Regional Cost Allocation Methods, Organization of MISO States Cost Allocation Principles Committee (September 12, 2022) at pdf p. 7–24.

106 See Order 1000 at P 690 ("…a public utility transmission provider must have a regional cost allocation method for any transmission facility selected in a regional transmission plan for purposes of cost allocation. It may not designate a type of transmission facility that has not had a regional cost allocation method applied to it…").

107 Supra n. 91.

108 See *ODEC v. FERC*, 898 F.3d at 1261 (D.C. Cir. 2018) (overturning a FERC order that would have "shift[ed] a grossly disproportionate share of [the] costs of these high-voltage projects into a single zone")(internal citations omitted).

109 131 FERC ¶ 61,252 (2010), *reh'g denied,* 137 FERC ¶ 61,075 (2011).

110 142 FERC ¶ 61,214 (2013).

which market simulations projected benefits from the upgrade. Approaches to allocating costs of local transmission projects are similar across regions,[111] with project costs typically allocated 100% to the local transmission zone's customers.

Because the costs of transmission upgrades assigned to generator interconnection requests can be significant, FERC recently provided guidance through Order 2023 that costs be shared within a "cluster" of generator interconnection requests that are moving through the process together, based on each generator's estimated use of the needed facility.[112]

B. Annual Transmission Revenue Requirements

The costs associated with transmission investments must be translated into an annualized cost, a wholesale rate for transmission service charged to transmission users and, ultimately, a rate for retail electricity ratepayers. FERC applies traditional cost of service regulation (COSR) or rate of return (ROR) regulation to determine the transmission "revenue requirement," which is the annual amount of revenues that must be recovered from transmission customers to recover the full cost of transmission projects.[113] These costs include not only the recovery of the capital costs of the project (including but not limited to planning, engineering, site preparation, equipment purchases, installation, etc.), but also operating and maintenance costs, taxes, and a FERC-allowed return of investment based on estimates of the TOs' cost of capital.

As shown in the example of Figure 4 below, the annual transmission revenue requirement is equal to the sum of the depreciation expense of transmission assets, an allowed return on equity and debt on the remaining rate base (i.e., the depreciated net capital cost of transmission investments), operating and maintenance costs, and property and income taxes. The initially high book value of transmission assets that are depreciated over time results in investment returns being front-loaded and recovered at a higher annual cost during the earlier part of the asset's useful life, as shown in Figure 4. Accelerated depreciation available for tax purposes results in the shown kinked (convex) annual cost recovery pathway.

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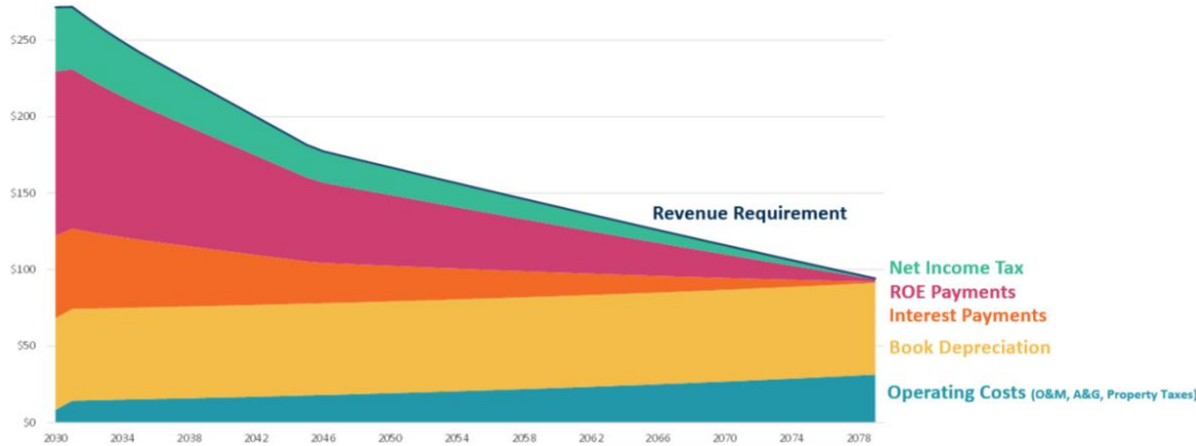
[111] Although the method for allocating the costs of these projects is similar, they have unique names in each region, as discussed supra nn. 57–60 (i.e., PJM, they are called "supplemental projects," in MISO, "other projects," in ISO-NE, projects specified in the "Local System Plan," and in CAISO, "asset management projects."

[112] *Improvements to Generator Interconnection Procedures and Agreements,* Order No. 2023, 184 FERC ¶ 61,054 at PP 416–418 (2023).

[113] Revenue requirements are often calculated for the entire group of a transmission owner's projects rather than for individual projects. Consistent with region-wide cost allocation frameworks, a transmission owner's revenue requirements may be the revenue requirements for all projects owned by the TO, plus payments to other transmission owners, less payments from other transmission owners in the region.

FIGURE 4 ANNUAL TRANSMISSION REVENUE REQUIREMENTS OVER THE LIFE OF AN ASSET



$$\text{Revenue Requirement} = \overbrace{OC_t + TAX_t + DEP_t}^{\text{Expenses}} + \overbrace{(r_e \times P_e)\overbrace{(K_t - ADEP_t)}^{\text{Rate Base}}}^{\text{Return on Equity}} + \overbrace{(r_d \times P_d)\overbrace{(K_t - ADEP_t)}^{\text{Rate Base}}}^{\text{Return on Debt}}$$

OE_t	= Operating Costs
TAX_t	= Effective Income Tax
DEP_t	= Annual (Book) depreciation
Rate Base:	
K_t	= First Year Rate Base (capital cost + AFUDC)
$ADEP_t$	= Book depreciation (annual) × years in-service
r_e	= Return on Equity
r_d	= Return on Debt
Capital structure:	
P_e	= Percent Equity
P_d	= Percent Debt

Source: J. Pfeifenberger, et al., New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report, Public Report, prepared for New Jersey Board of Public Utilities (October 26, 2022) at Appendix C.1 (used with permission).

C. Transmission Rates

The total revenue requirements of a TO is used to develop per-unit rates for transmission service. Depending on the RTO/ISO, these per-unit rates are charged based on the energy delivered to load, the amount of peak load served, or the amount of transmission capability reserved. These transmission rates are set to recover the total annual revenue requirements of TOs, offset by contributions from and contributions to other regional TOs based on regional cost allocations as described above. The transmission rates are charged only to withdrawals of power from the transmission grid by regional loads and exports to neighboring regions. Generators typically have to pay for the transmission upgrades deemed necessary to enable the interconnection of their plant, but are not subject to any ongoing transmission charges.

As power is traded across multiple transmission service providers (RTO/ISO or utilities in non-RTO regions), the transmission charges imposed on exports are generally additive. This adding up of transmission charges as power is transmitted across several areas is referred to as **"pancaking"** of transmission charges. Given that much of the grid's cost reflects the fixed cost of sunk investment, applying pancaked transmission charges to individual short-term transactions can create a significant uneconomic barrier to the efficient short-term use of the grid. To reduce the inefficiency created by pancaked transmission rates, some of the regional system operators have consequently "de-pancaked" transmission charges between them to increase market efficiency. For example, NYISO and ISO-NE do not impose charges for transmission service between them and the same is true for most of the transmission services available between MISO and PJM. Transmission charges have also been depancaked regionally between TOs located within individual RTO/ISO service areas and between TOs who joined a regional energy imbalance market, such as the Western Energy Imbalance Market[114]—although in that case, only imbalance-market transactions, not bilateral transactions, are de-pancaked.

The process of determining transmission rates takes one of two forms: "stated rates" or "formula rates." The transmission-owning utility chooses which type of rate setting process it will use at FERC to determine its revenue requirements and associated transmission rates. FERC has expressed a preference for formula rates, noting that they encourage "certainty of recovery that is conducive to large transmission expansion programs."[115] As a result, most TOs utilize formula rates, particularly in ISO/RTO regions but also in areas outside organized wholesale markets.[116]

Stated rates require that a utility files a "rate case" with FERC under which rates are developed based on the current snapshot (or projected) revenue requirements. Once determined in the rate case, these rates then remain in effect until a new rate case is filed by the TO.[117] The development of stated rates typically occurs through regulatory proceedings adjudicated initially by a FERC Administrative Law Judge, who makes findings of fact and recommendations of law to the full Commission. The utility and intervenors can elect to settle the case prior to the ALJ decision, if consensus can be reached on disputed issues. The new stated rates take effect (often retroactively to the date on which the rate case was filed), after the full Commission approves the new transmission rates.

Under **formula rates**, a utility initially submits a spreadsheet template (the "formula"), designed as a framework to annually calculate updated revenue requirements. This template is subject to FERC review and approval when initially filed, similar to a typical change in a utility's Tariff. After this initial approval, the underlying formula remains unchanged (until the utility elects to change it). However, each year, the

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114 Western Energy Imbalance Market (westerneim.com)

115 *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 at P 386, n. 207 (2006) (*citing* approval of PJM Transmission Owner formula rates, 111 FERC ¶ 61,308 at P 51 (2005), 106 FERC ¶ 61,003 at P 32 (2004)).

116 For example, Black Hills, Basin Electric, and Powder River file a formula rate for service in Wyoming and South Dakota, see 148 FERC ¶ 61,035 (2014). Southern Company files a formula rate for service in Alabama, Georgia, and Mississippi, see 178 FERC ¶ 61,207 (2022).

117 See Cost of Service Rate Filings, FERC Staff. Stated rates are more often used outside of RTO/ISO regions, but also exist within RTOs/ISOs, such as in California where the TOs have agreed to update their transmission revenue requirement and associated rates every three years through the filing of a rate case with FERC.

utility updates the formula rate "inputs," resulting in an annual update of its transmission revenue requirements and associated per-unit transmission rates. These updated inputs, which need to adhere with FERC's standardized accounting practices, reflect any new transmission investments placed in service that year as well as all other projects previously placed into service and covered by the formula rate. These annual updates do not receive the same level of scrutiny as the initial formula rate application, because "the formula itself is the rate, not the particular components of the formula."[118] However, FERC has noted that certain protections must be in place to "ensure that the input data is the correct data, that calculations are performed consistent with the formula," and ultimately develop just and reasonable rates.[119] Formula rate protocols are supposed to be the "safeguard that has often been employed."[120]

In the early 2010s, FERC clarified its standards for formula rate protocols in a series of cases related to MISO TOs, which share a single formula rate for the entire RTO.[121] Specifically, FERC identified three areas of potential concern: "(1) scope of participation—who can participate in the information exchange; (2) the transparency of the information exchange—what is exchanged; and (3) the ability to challenge the transmission owners' implementation of the formula rate as a result of the information exchange—how the parties may resolve their potential dispute."[122] In the years following, the Commission has initiated several investigations into other utilities, using the standard set in the MISO formula rate orders to determine whether existing formula rate protocols remain just and reasonable.[123] Despite these efforts by FERC, many commenters continue to highlight shortcomings in these formula rate safeguards, and the generally limited level of review that is applied to the significant transmission expenses added by TOs and recovered through formula rates.[124] Because transmission expenses are rarely questioned, it means that transmission developers typically are able to recover all costs associated with their transmission projects, including a full return on investments, through the FERC-approved stated or formula rates.

In addition to the transmission rates, the terms for available types of transmission services are similarly standardized by FERC in its "pro-forma" OATT, but can vary significantly across regions. Transmission rates range from simple volumetric rates (such as the $/MWh rate used in in CAISO) to rates that are differentiated by the type of service (e.g., "point-to-point" vs. "network" transmission service), the

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[118] 69 FERC ¶ 61,146, at 61,544 (1994).

[119] [148 FERC ¶ 61,035]() at P 3 (2014).

[120] [148 FERC ¶ 61,035]() at P 3 (2014).

[121] [178 FERC ¶ 61,207]() at P 4 (2022) (*citing* [139 FERC ¶ 61,127]() (2012), 143 FERC ¶ 61,149 (2013) (MISO Investigation Order), *order on reh'g*, 146 FERC ¶ 61,209, 146 FERC ¶ 61,212 (2014), *order on reh'g*, 150 FERC ¶ 61,024, 150 FERC ¶ 61,025 (2015)).

[122] [139 FERC ¶ 61,127]() at P 8 (2012).

[123] See, e.g., 178 FERC ¶ 61,207 at n.10 (2022) (citing *Black Hills Power, Inc.,* 148 FERC ¶ 61,035 (2014)*; UNS Elec., Inc.,* 148 FERC ¶ 61,032 (2014)*; The Empire Dist. Elec. Co.,* 148 FERC ¶ 61,030 (2014); *Kansas City Power & Light Co.,* 148 FERC ¶ 61,034 (2014); *Louisville Gas & Elec. Co.,* 148 FERC ¶ 61,031 (2014); *Westar Energy, Inc.,* 148 FERC ¶ 61,033 (2014)).

[124] See [185 FERC ¶ 61,198]() *Christie, Comm'r, Concurring* at n. 4 (2023); D. Hartman, K. Chandler, [Stakeholder Soapbox: A Transmission Planning Resolution Emerges]() (December 13, 2022).

duration of service (long-term, annually, monthly, daily, or hourly), and the quality of service (e.g., firm vs. non-firm transmission service).

"Network service" is usually available for providing transmission service to load-serving entities, including those that are transmission-dependent, with charges determined based on the coincident peak loads of the load-serving entities in the TOs' service area. "Point-to-point service" is typically utilized for trades between and across RTOs/ISOs (and individual TOs outside of RTO/ISO regions). These "wheeling through and out" rates (from the specified point of receipt to the point of delivery) are typically used by power traders buying or selling electricity from utilities and generators in one region to load-serving entities other regions. Firm point-to-point transmission service is generally required for trading firm energy and "capacity" across regions, while non-firm point-to-point service is used for trades of economy energy on an as available basis. In contrast, Network service is offered to load-serving entities (e.g., utilities) within regions as a firm service to supply load from dedicated "network resources," with the option to redirect the service to receive power from other resources on a non-firm basis. To encourage efficient use of the transmission grid, FERC allows RTOs/ISOs and TOs to discount non-firm transmission service based on market conditions.

D. The Prudence and Reasonableness of Transmission Costs

Utilities that file proposed rates and rate changes with FERC bear the burden of proving that the proposed rates are just and reasonable,[125] including the "charge resulting from its application of the formula" rate.[126] The Commission allows recovery of all prudently incurred costs as determined by the Commission's "reasonable utility management test." This test presumes that the expenditures a reasonable utility manager would have made in good faith are prudent in the absence of a challenge raising "serious doubt" about the expense.[127] To raise serious doubt, a challenger must include a showing of "reliable, probative, and substantial evidence."[128]

In practice, however, formula rate protocols can create limits on which information can be obtained and which aspects of the formula rates can be subject to a challenge. It has proven exceptionally difficult for challengers to rebut the Commission's presumption of prudence, in part due to the information

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[125] *Sierra Pac. Power Co. v. FPC*, 223 F.2d 605, 607 (D.C. Cir. 1955) ("In modifying a filed rate…the new rate will take effect if the utility sustains the burden of proving that it is 'just and reasonable'").

[126] "[T]he transmission owner bears the ultimate burden of demonstrating that the justness and reasonableness of the charge resulting from its application of the formula." 178 FERC ¶ 61,207 at n.5 (2022) (citing 123 FERC ¶ 61,098 at P 47 (2008); 124 FERC ¶ 61,306 at P 36 (2008)).

[127] See 172 FERC ¶ 61,175 at P 15, n.28 (2020), *citing* 31 FERC ¶ 61,047 at 61,084 (1985), *aff'd sub nom., Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986); see also 87 FERC ¶ 61,295 at 62,168 (1999) (explaining the serious doubt standard); see also *Indiana Mun. Power Agency v. FERC*, 56 F.3d 247, 253 (D.C. Cir. 1995) (complainant must "present evidence sufficient to raise serious doubt that a reasonable utility manager, under the same circumstances and acting in good faith, would not have made the same decision and incurred the same costs") (internal citations omitted).

[128] 172 FERC ¶ 61,175 at P 15 (2020)(internal citations omitted).

asymmetry between challengers (typically representing state commissions and transmission service customers) and the TOs. In one survey, the California Public Utility Commission found only one case in the past 20 years where FERC had partially disallowed a utility's transmission expenditure for imprudence.[129]

E. Flow-through of FERC's Wholesale Transmission Rates to Retail Customers

As part of their jurisdiction over distribution utilities, states retain regulatory authority over the retail electric bills sent to end-use customers. While wholesale transmission service is FERC-jurisdictional, ultimately, the revenues and costs associated with transmission service provided and received pursuant to FERC-approved wholesale transmission rates must be recovered in state-jurisdictional retail rates paid by retail customers in various states. Because federal rates pre-empt state authority, and a state cannot limit recovery of a federally-approved rate,[130] transmission charges are explicitly or implicitly included in every end-use customer's state-regulated electricity bill. While state regulators can participate in the transmission planning process and FERC transmission rate cases as stakeholders and retain authority to decide how transmission costs are recovered from different retail rate classes (e.g., commercial, industrial, residential, etc.), state utility commissions ultimately do not retain the authority to disallow recovery of transmission investment approved by FERC.

The amount of flexibility that states have with respect to translating FERC-approved wholesale transmission rates into retail rates depends on whether transmission service is "bundled" or "unbundled" for the purpose of determining a state's retail rates. In all restructured (and some vertically-integrated) states, transmission charges are clearly separated from other charges in customers' retail electricity bills. These unbundled retail transmission charges need to be designed to fully recover the FERC-approved annual revenue requirements, but may do so through retail rate designs (e.g., $/kWh) that differ from the wholesale transmission rate design (e.g., $/kW-month). In states with vertically-integrated utilities that have not unbundled transmission service in their retail rates, the states continue to regulate the utilities' total revenue requirement, which covers the sum of generation, transmission, and distribution rates and applies a state-regulated return to all of the utilities' investments. In these states, a state's determination of bundled retail rates can essentially "undo" FERC-allowed rates of return and other aspects of FERC-jurisdictional transmission rates—although the FERC-

[129] California Public Utilities Commission, Brief on Exceptions, Docket No. ER16-2320-002 at 57 (Oct. 31, 2018), *citing* 152 FERC ¶ 63,025 at P 86 (2015) (partial disallowance only of a transmission developer's in-house legal fees and services because of missing documentation).

[130] See *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 373 (1988), *citing Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 965-966 (1986) ("a state utility commission setting retail prices must allow, as reasonable operating expenses, costs incurred as a result of paying a FERC-determined wholesale price. . . . Once FERC sets such a rate, a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable. A State must rather give effect to Congress' desire to give FERC plenary authority over interstate wholesale rates, and to ensure that the States do not interfere with this authority"). See also *Narragansett Electric Co. v. Burke*, 119 R.I. 559, 381 A.2d 1358 (1977), *cert. denied*, 435 U.S. 972 (1978); C. Hobelman, *The Narragansett Decision and its Aftermath*, Energy Law Journal, Volume 6:1.

jurisdictional transmission rates still apply to all wholesale (i.e., beyond bundled retail or native load) use of the transmission system, such as when the utility provides transmission service to other utilities or wholesale market participants. Any third-party transmission revenues from such wholesale use of the utility's transmission system, however, will be credited against the utility's bundled revenue requirements in the utility's state rate cases and (if any) automatic retail rate adjustments that can be made (e.g., annually) between the state rate cases.

Appendix A: Landmark FERC Orders

Adapted from FERC's Major Orders and Regulations.

Order No. 2023	July 27, 2023	Improvements to Generator Interconnection Procedures and Agreements, reform interconnection queues | News Release | Fact Sheet | Presentation
RM21-17-000	April 21, 2022	Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection
AD21-15-000	June 17, 2021	State-Federal Task Force on Transmission Planning
Order No. 2222 (RM18-9-00)	September 17, 2020	Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators (Final Rule)
Order No. 773 (RM12-6-000 & RM12-7-000) Order No. 773-A (RM12-6-001 & RM12-7-001)	December 20, 2012 (effective March 5, 2013) April 18, 2013 (effective May 17, 2013)	Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure (Final Rule)
Order No. 1000 (RM10-23-000) Order No. 1000-A (RM10-23-001)	July 21, 2011 (effective October 11, 2011) May 17, 2012	Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (Final Rule) Visit FERC's Order No. 1000 Section
Order No. 717-D (RM07-1-003)	April 8, 2011 (effective May 16, 2011)	Standards of Conduct for Transmission Providers (Order on Rehearing and Clarification)
Order No. 745 (RM10-17-000) Order No. 745-A (RM10-17-001)	March 15, 2011 (effective April 25, 2011) December 15, 2011	Demand Response Compensation in Organized Wholesale Energy Markets (Final Rule)
Order No. 743 (RM09-18-000) Order No. 743-A (RM09-18-001)	November 18, 2010 (effective January 25, 2011) March 17, 2011 (effective March 23, 2011)	Revision to Electric Reliability Organization Definition of Bulk Electric System (Final Rule)
Order No. 717-C (RM07-1-002)	April 16, 2010	Standards of Conduct for Transmission Providers (Order on Rehearing and Clarification)
Order No. 719-B (RM07-19-002)	December 17, 2009	Wholesale Competition in Regions with Organized Electric Markets (Order Denying Rehearing And Providing Clarification)
Order No. 717-B (RM07-1-002)	November 16, 2009	Standards of Conduct for Transmission Providers (Order on Rehearing and Clarification)
Order No. 717-A (RM07-1-001)	October 15, 2009	Standards of Conduct for Transmission Providers (Order on Rehearing and Clarification)
Order No. 719 (RM07-19-000)	October 17, 2008 July 16, 2009	Wholesale Competition in Regions with Organized Electric Markets (Final Rule)

Order No. 719-A (RM09-17-001)		Improving the operation of organized wholesale electric markets in the areas of: (1) demand response and market pricing during periods of operating reserve shortage; (2) long-term power contracting; (3) market-monitoring policies; and (4) the responsiveness of RTOs/ISOs.
Order No. 717 (RM07-1-000)	October 16, 2008	Standards of Conduct for Transmission Providers (Final Rule)
Order No. 890 (RM05-17-000 & RM05-25-000) Order No. 890-A Order No. 890-B	February 16, 2007 December 28, 2007 June 23, 2008	Preventing Undue Discrimination and Preference in Transmission Service (Final Rule)
Order No. 2006-B (RM02-12-002)	July 20, 2006	Standardization of Small Generator Interconnection Agreements and Procedures (Order on Clarification)
Order No. 2006-A (RM02-12-001)	November 22, 2005	Standardization of Small Generator Interconnection Agreements and Procedures (Order on Rehearing)
Order No. 2003-C	June 16, 2005	Standardization of Generator Interconnection Agreements and Procedures, Order on Rehearing (Final Rule)
Order No. 2006	May 12, 2005	Standardization of Small Generator Interconnection Agreements and Procedures (Final Rule)
Order No. 2004-C	December 21, 2004	Standards of Conduct for Transmission Providers (see Standards of Conduct for Transmission Providers section for more detail) (Final Rule)
Order No. 2003-B	December 20, 2004	Standardization of Generator Interconnection Agreements and Procedures, Order on Rehearing and Directing Compliance (Final Rule)
Order No. 2004-B	August 2, 2004	Standards of Conduct for Transmission Providers (see Standards of Conduct for Transmission Providers section for more detail)
Order No. 2004-A	April 16, 2004	Standards of Conduct for Transmission Providers (Order on Rehearing) (Final Rule) (see Standards of Conduct for Transmission Providers section for more detail)
Order No. 2003-A	March 5, 2004	Standardization of Generator Interconnection Agreements and Procedures (Order on Rehearing) (Final Rule)
Order No. 2004	November 25, 2003	Standards of Conduct (Final Rule) (see Standards of Conduct for Transmission Providers section for more detail)
Order No. 2003	July 24, 2003	Standardization of Generator Interconnection Agreements and Procedures (Final Rule)
Order No. 2000 (Complete Version) » Part 1 of 4 » Part 2 of 4 » Part 3 of 4 » Part 4 of 4	December 20, 1999 February 25, 2000	Establishment of Regional Transmission Organizations proposals (Final Rule)

Order No. 2000-A Bookmarked version		
Order No. 889-B	November 25, 1997	Final Order: Order Denying Rehearing of Order 889-A in Regards to Open Access Same-Time Information System & Standards of Conduct (OASIS)
Order No. 889-A	March 4, 1997	Order Revising Rules Governing Transmission Information Networks, Standards of Conduct and Policy on Posting Discounts consistant with changes under Order 888-A
Order No. 889	April 24, 1996	OASIS: Open Access Same-Time Information System (formerly Real- Time Information Networks) and Standards of Conduct (Final Rule)
Order No. 888 Order No. 888-A Order No. 888-B Order No. 888-C	April 24, 1996 March 4, 1997 November 25, 1997 January 20, 1998	Transmission Open Access. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (Final Rule)

Contact.

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Center for Energy and
Environmental Policy Research

MIT Center for Energy and
Environmental Policy Research
Massachusetts Institute of Technology
77 Massachusetts Avenue, E19-411
Cambridge, MA 02139-4307
USA

ceepr.mit.edu

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