

# **TIME TO CLOSE THE LOOP: FEDERAL JURISDICTION OVER TRANSMISSION AND THE “BUNDLED TRANSMISSION” EXEMPTION**

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**Synopsis:** As electricity demand surges due to data centers, advanced manufacturing, and electrification in nearly every aspect of American life – recent projections anticipate electricity use will more than double by 2050<sup>1</sup> – the United States will need a far more robust transmission system to make the most of every electron that can be generated. However, the regulatory framework governing transmission rates remains fragmented and incomplete, thereby leading to a less robust grid. By declining jurisdiction over rates for bundled transmission service provided by utilities that have not opted in to RTOs, the Federal Energy Regulatory Commission (FERC) has allowed a gap to persist in the oversight Congress intended when it enacted the Federal Power Act (FPA). This Article argues that closing that gap is both legally compelled and essential to ensuring that transmission rates remain just, reasonable, and not unduly discriminatory.

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1. NATHAN SHREVE ET AL., FEWER NEW MILES: STRATEGIC INDUSTRIES HELD BACK BY SLOW PACE OF TRANSMISSION 4 (Grid Strategies 2025), [https://gridstrategiesllc.com/wp-content/uploads/ACEG\\_Grid-Strategies\\_Fewer-New-Miles-2025\\_vF.pdf](https://gridstrategiesllc.com/wp-content/uploads/ACEG_Grid-Strategies_Fewer-New-Miles-2025_vF.pdf) (citing U.S. DEP’T OF ENERGY, NATIONAL TRANSMISSION PLANNING STUDY EXECUTIVE SUMMARY 2 (2024)).

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## I. INTRODUCTION

**Need for transmission:** While transmission development was robust in the early 2010's, it has slowed considerably in recent years.<sup>2</sup> Meanwhile, the transmission system has become more interconnected, highlighting the value of and need for regional transmission projects.<sup>3</sup> As load growth has accelerated in the past few years, this need for transmission has grown exponentially.<sup>4</sup> In October 2023, the U.S. Department of Energy (DOE) released its National Transmission Needs Study, which found the U.S. will need to more than double intra-regional transmission capacity and quadruple interregional transmission capacity by 2035 to meet projected load growth.<sup>5</sup> In October 2024, DOE's National Transmission Planning Study found a similar need to double or triple regional transmission capacity and quadruple interregional transmission capacity.<sup>6</sup> At the same time, the transmission grid is aging: 70% of transmission lines are over twenty-five years old and approaching the end of their typical 50–80-year lifecycle.<sup>7</sup>

In response to these factors, FERC issued a notice of proposed rulemaking and subsequent final rule asserting that existing transmission planning and cost allocation rules are insufficient to meet the growing need for transmission.<sup>8</sup> The insufficiency was highlighted by a report which demonstrated that fewer than sixty miles of new high-capacity transmission lines were built in 2023.<sup>9</sup> Meanwhile the Interregional Transfer Capability Study by the North American Electric Reliability Corporation (NERC), submitted to FERC in November 2024, finds that the United

2. NATHAN SHREVE, ZACHARY ZIMMERMAN & ROB GRAMLICH, GRID STRATEGIES, FEWER NEW MILES: THE US TRANSMISSION GRID IN THE 2020S 4 (2024), [https://cleanenergygrid.org/wp-content/uploads/2024/07/GS\\_ACEG-Fewer-New-Miles-Report-July-2024.pdf](https://cleanenergygrid.org/wp-content/uploads/2024/07/GS_ACEG-Fewer-New-Miles-Report-July-2024.pdf).

3. Order No. 1920, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P 101 (2024) [hereinafter Order No. 1920], *order on reh'g*, Order No. 1920-A, 186 FERC ¶ 61,126 (2024) [hereinafter Order No. 1920-A].

4. Order No. 1920, *supra* note 3, at P 95.

5. U.S. DEP'T OF ENERGY (DOE), NATIONAL TRANSMISSION NEEDS STUDY vii-xi (2023), [https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final\\_2023.12.1.pdf](https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf) [hereinafter NATIONAL TRANSMISSION NEEDS STUDY].

6. U.S. DEP'T OF ENERGY GRID DEPLOYMENT OFF. (GDO), NATIONAL TRANSMISSION PLANNING STUDY: EXECUTIVE SUMMARY 2 (2024), <https://www.energy.gov/gdo/national-transmission-planning-study> [hereinafter NATIONAL TRANSMISSION PLANNING STUDY].

7. AM. SOC. OF CIV. ENG'RS, 2021 REPORT CARD FOR AMERICA'S INFRASTRUCTURE: ENERGY 45 (2021), <https://2021.infrastructurereportcard.org/wp-content/uploads/2020/12/Energy-2021.pdf>.

8. See generally Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 26,504 (2022); Order No. 1920, *supra* note 3.

9. SHREVE, ZIMMERMAN & GRAMLICH, *supra* note 2, at 4 fig. 1.

States needs as many as thirty-five GW of interregional transfer capability to meet resource adequacy needs in the coming years.<sup>10</sup>

**Economic value of transmission:** Apart from unlocking economic opportunities by fueling new manufacturing and data centers, well planned regional and interregional transmission can replace aging facilities, reduce congestion, provide access to low-cost power, and enhance reliability. Recent analysis has shown that a significant expansion of the system could provide nearly \$5 in economic and reliability benefits for every \$1.00 spent on transmission.<sup>11</sup> The report further found that investing in high-capacity transmission expansion saves residential consumers \$6.3-10.4 billion per year across the United States, net of transmission costs, and even more for commercial and industrial customers.<sup>12</sup> While this report estimates the impact of future transmission, ongoing analyses of major transmission development shows that benefits often exceed initial estimates; for instance, a later review of the MISO Multi-Value Project Portfolio showed that benefits grew by 50%, and that additional benefits were provided to each local resource zone.<sup>13</sup>

**Obstacles to building transmission:** The process of deploying regional and interregional transmission is multi-faceted and complex. As early as 2019, grid advocates identified the three P's that challenge the development of transmission: Planning, Permitting, and Paying.<sup>14</sup> In the United States, most FERC-jurisdictional transmission is paid for by allocating infrastructure costs to utilities that benefit, that then collect those costs from electricity bills to retail customers.<sup>15</sup> Not surprisingly, the debate over who pays for transmission can impact the development of regional and interregional transmission infrastructure, where states want to be held harmless from rising infrastructure costs driven by a range of needs and providing a range of benefits.<sup>16</sup> At bottom, despite reform efforts, transmission cost allocation remains complex, rife with disputes and bereft of timely solutions.

10. *North American Electric Reliability Corporation Interregional Transfer Capability Study as Directed in the Fiscal Responsibility Act of 2023*, FERC Docket No. AD25-4-000, at 3 (Nov. 19, 2024) [hereinafter *North American Electric Reliability Corporation Study*].

11. ZACH ZIMMERMAN ET AL., *LARGE-SCALE TRANSMISSION DEVELOPMENT SAVES CONSUMERS MONEY* 8 (Grid Strategies 2025), <https://cleanenergygrid.org/portfolio/report-transmission-deployment-saves-customers-money/>.

12. See also Leila Safavi et al., *Interregional Electricity Transmission in the United States: Realized Savings and Opportunities for Increased Value, 2014 to 2023*, 47 ENERGY J. 51, 51 (2026) (noting that interregional transmission saved \$1.226 billion per year, but could have saved even more if better optimized); Tim Meehan & Madeline Geocaris, *How to Realize the Maximum Value of Interregional Transmission*, NAT'L LAB'Y OF THE ROCKIES (June 4, 2024), <https://www.nlr.gov/news/detail/program/2024/how-to-realize-the-maximum-value-of-interregional-transmission>.

13. MTEP14 MVP Triennial Review 2 (MISO Sep. 2014), <https://cdn.misoenergy.org/MTEP14%20MVP%20Triennial%20Review%20Report117061.pdf>.

14. Rob Gramlich, Grid Strategies LLC, *Testimony to Roundtable on Electricity Transmission Infrastructure 5-6* (June 20, 2019), <https://gridstrategiesllc.com/wp-content/uploads/2024/05/testimony-to-roundtable-on-electricity-transmission-infrastructure-.pdf>.

15. Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 at P 586 (2011) [hereinafter Order No. 1000], *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012) [hereinafter Order No. 1000-A].

16. See generally *N.D. Pub. Serv. Comm'n v. Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket No. EL25-109 (July 30, 2025); see also *PJM Interconnection L.L.C.*, 187 FERC ¶ 61,012 at PP 13-14 (2024).

**Implications of bifurcated rates:** Because vertically integrated utilities outside regional transmission organizations (RTO) do not have a shared tariff through which to recover costs of regional lines, and because state commissions evaluate only in-state benefits, regional projects rarely advance. These fractured cost-recovery mechanisms ultimately produce a mismatch between planning authority and cost-recovery authority, which leads to underinvestment in large-scale lines and the potential for inefficient and duplicative local projects. Ultimately, this can also raise barriers to interregional transfer capability, which can impair reliability.<sup>17</sup>

**Legal framework:** Congress established the limits of the Commission's jurisdiction in section 201 of the FPA.<sup>18</sup> Under this section, the Commission has jurisdiction to regulate “the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce;” however, this federal regulation “extend[s] only to those matters which are not subject to regulation by the States.”<sup>19</sup> The Commission has no jurisdiction over “facilities used for the generation of electric energy.”<sup>20</sup>

Just as Congress granted FERC broad transmission jurisdiction under the FPA, the U.S. Supreme Court confirmed the breadth of that jurisdiction, including to regulate the transmission component of rates assessed to a utility's retail customers carved out as a service (“unbundled transmission services”).<sup>21</sup> To date FERC has not fully exercised that jurisdiction. When FERC asserted federal jurisdiction over the provision of transmission service and required open access in Order No. 888, it also asserted jurisdiction over cost recovery of transmission in federal tariffs – with an exception for transmission used for bundled service, in which a utility may use a portion of the capacity on a transmission line to provide retail service to its customers.<sup>22</sup>

That exception became less relevant as utilities joined RTOs, and transmission costs were passed through FERC-jurisdictional regional tariffs. For those utilities that did not join RTOs, significant shares of their transmission costs remain outside federal tariffs and are still recovered through state rate cases. As a result, the exception has swallowed the rule in those regions and has significantly impaired the Commission's attempts to expand regional and interregional transmission development through Order Nos. 890, 1000, and most recently, 1920.<sup>23</sup> In fact, no regionally-cost allocated transmission lines have been developed outside RTOs; the only successful multi-state lines outside RTOs have been customer-supported subject to negotiated rates, or have undergone multiple

17. *North American Electric Reliability Corporation Study*, *supra* note 10, at xix-xx.

18. 16 U.S.C. § 824.

19. *Id.* § 824(a).

20. *Id.* § 824(b)(1).

21. *Id.*; *New York v. FERC*, 535 U.S. 1, 26 (2002).

22. See generally Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, 75 FERC ¶ 61,080 (1996) [hereinafter Order No. 888], *order on reh'g*, Order No. 888-A, 78 FERC ¶ 61,220 (1997) [hereinafter Order No. 888-A], *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997) [hereinafter Order No. 888-B], *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998) [hereinafter Order No. 888-C], *aff'd in relevant part sub nom.* Transmission Access Pol'y Study Grp. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* *New York v. FERC*, 535 U.S. 1 (2002).

23. See generally Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 ENERGY L.J. 1 (2021).

state rate cases.<sup>24</sup> FERC’s recent Order No. 1920 might have been intended to address the problem of building more transmission, but it did not address cost allocation outside RTOs. In a letter to FERC,<sup>25</sup> the U.S. DOE Secretary Wright brought this jurisdictional dichotomy to the forefront: FERC has jurisdiction over all transmission even where it has not chosen to exercise it.<sup>26</sup>

With this article, we propose that FERC assert jurisdiction over all transmission rates for all new projects. No additional Congressional direction is required, as the FPA clearly states – and the Supreme Court has confirmed – that transmission, without qualification, is subject to federal jurisdiction. As the grid has evolved over the last twenty years, and new loads are seeking to interconnect, FERC should revisit its earlier decision to exempt bundled transmission service from federal tariffs. As DOE stated, to argue otherwise would conflict with “the core purposes” of the FPA<sup>27</sup> – including a greater buildout of regional and interregional transmission for the most cost-effective and reliable electric system for every customer.

## II. HISTORICAL AND LEGAL FOUNDATIONS

The electric industry initially developed as islanded utilities, each seeking to serve their own customers.<sup>28</sup> But as early as World War II, industry and the Federal Power Commission (predecessor to FERC) recognized the value of a more connected grid.<sup>29</sup> As technology and markets have evolved and the benefits of

24. Latif Nurani, *Time Will Tell if New Transmission Planning Rule Achieves Its Purpose*, Am. Pub. Power Ass’n (July 1, 2024), <https://www.publicpower.org/periodical/article/time-will-tell-if-new-transmission-planning-rule-achieves-its-purpose>.

25. 42 U.S.C. § 7173(a) (“The Secretary . . . [is] authorized to propose rules, regulations, and statements of policy of general applicability with respect to any function within the jurisdiction of the Commission under section 7172 of this title.”).

26. Advance Notice of Proposed Rulemaking, *Ensuring the Timely and Orderly Interconnection of Large Loads*, FERC Docket No. RM26-4-000, at P 4 (Oct. 23, 2025) [hereinafter DOE ANOPR].

27. *Id.* at P 16.

28. *New York v. FERC*, 535 U.S. 1, 5 (2002).

29. *See e.g., Wis. Elec. Power Co.*, FPC Docket No. IT-5805, 3 F.P.C. 889, 889 (Dec. 31, 1942) (providing for interconnection of a 132kV transmission line between two utilities without conferring federal jurisdiction “to make available to either system a substantial portion of their combined reserve capacity and afford material protection in emergencies in an area having a heavy concentration of vital war loads and a low margin of operating reserves.”) The interconnection was further required by “an increase in demands for electric energy, restrictions on the construction and installation of additional electric generating and transmission facilities, and emergencies in the maintenance of an adequate supply of electric energy essential to the war effort, necessitating the interconnection of electric facilities.” *Id.* at 890; *see also Ga. Power & Light Co. & Ga. Power Co.*, FPC Docket No. IT-5707, 2 F.P.C. 993, 993 (June 27, 1941) (providing for interconnection under FPA section 202(c) between Florida Power Corp. and the Georgia Power Corp. “by reason of a sudden increase in the demand for electric energy coupled with a shortage of electric energy, a shortage of facilities for the generation and transmission of electric energy, a shortage of water for generating facilities, and other causes”); *Tex. Elec. Serv. Co.*, FPC Docket No. IT-6077, 6 F.P.C. 859, 860 (Aug. 19, 1947) (providing for interconnection under FPA section 202(d) due to “(1) a sudden and unprecedented increase in the demand for electric energy; (2) the inability to secure generating and related equipment on order to complete the program of construction designed to meet the increased load; (3) the demand for service by industries in the area resulting from their inability to procure essential equipment for power purposes, which industries have heretofore utilized their own prime movers; and (4) until such time as the point applicants are enabled to procure and install the necessary generating and related equipment to alleviate the present emergency. . .”). *See also* Horace M. Gray, *The Integration of the Electric Power Industry*, 41 AM. ECON. REV. 538, 538 (1951) (“By 1935, fifteen years of intensive criticism, beginning with the Keller report and

greater coordination, and the worsening harms of a fractured grid, have become more clear the grid has become more interconnected, though strong fractures remain – at a high cost to customers.

#### A. FERC Jurisdiction Over Transmission

FERC's movement towards transmission open access policies began in the 1980s and 1990s with deregulation and the creation of market-based rates for electric utilities.<sup>30</sup> The Energy Policy Act of 1992 broadened FERC's authority to order transmission service,<sup>31</sup> and resulted in a series of case-by-case adjudications of individual complaints.<sup>32</sup>

In 1996, FERC decided to act in a more widespread manner, tackling discriminatory practices across the U.S. By issuing Order No. 888 to “remedy undue discrimination” in accessing transmission,<sup>33</sup> FERC required vertically integrated public utilities that transmit electricity in interstate commerce to “functionally unbundle” their transmission services from generation services and offer non-discriminatory open access transmission to competitive generators and other load-serving utilities.<sup>34</sup> In implementing this mandate, Order No. 888 required public utilities to file open access non-discriminatory transmission tariffs with the terms and conditions of such wholesale transmission service.<sup>35</sup>

In Order No. 888, FERC addressed its finding of a “fundamental generic problem,” where control of transmission by vertically-integrated utilities was facilitating unduly discriminatory practices against third-party transmission customers in comparison to the level of transmission service afforded to the transmission provider's use of its own system for power sales and purchases.<sup>36</sup> In doing so, FERC took an opportunity to address its jurisdiction over transmission, finding that it extends over the rates, terms, and conditions of “the transmission component of an *unbundled* interstate retail wheeling transaction.”<sup>37</sup> FERC explained that “where states unbundle retail sales, we will give deference to their determinations as to which facilities are transmission and which are local distribution,” because in its view, “there is an element of local distribution service in any unbundled retail transaction.”<sup>38</sup> To determine whether a facility constituted

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terminating with the *National Power Survey*, had exposed the defective organization of the electric power industry and delineated the essential features of an integrated power system.”) (internal citations omitted).

30. Harvey Reither, *The Contrasting Policies of the FCC and FERC Regarding the Importance of Open Transmission Networks in Downstream Competitive Markets*, 57 FED. COMM'NS L.J. 243, 249-51, 255-56 (2005).

31. Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (codified as amended at scattered sections of 42 U.S.C.).

32. Reiter, *supra* note 30, at 256.

33. Order No. 888, *supra* note 22.

34. *Id.* slip op. at 1, 57, 61.

35. *Id.* slip op. at 3-4.

36. *See id.* slip op. at 128.

37. Order No. 888, *supra* note 22, slip op. at 428 (emphasis added).

38. *Id.* slip op. at 429.

FERC-jurisdictional transmission lines, as opposed to local distribution lines, FERC created a seven-factor test.<sup>39</sup>

Despite asserting authority to regulate unbundled retail transmission services, FERC did not explain why it chose not to assert jurisdiction over the transmission aspect of bundled retail service arrangements. In response to commenters, FERC reaffirmed its FPA section 201 jurisdiction over all transmission in interstate commerce, and explained that transmission sold at retail is “part and parcel” of the delivery of electricity, thus constituting a sale of electric energy at retail.<sup>40</sup> FERC further refrained from unbundling retail transmission and generation because it did not believe it to be “necessary,” and instead found that the “numerous difficult jurisdiction issues” presented would be better considered on a case-by-case basis.<sup>41</sup> FERC reiterated this point in Order No. 888-A, but clarified that “[t]o the extent the transmission takes place on the interstate facilities of other public utilities, [FERC] would have jurisdiction over such transmission.”<sup>42</sup>

Petitioners appealed Order No. 888 arguing that FERC exceeded its jurisdiction by applying open access principles to unbundled retail transmission service, while others argued that under FPA section 206, FERC was required to apply the open access principles to the bundled retail transmission service.<sup>43</sup> The D.C. Circuit held that FERC has jurisdiction over *all* transmission in interstate commerce, explaining that “the FPA gives FERC the authority to regulate the transmissions at issue here, whether retail or wholesale.”<sup>44</sup> With respect to the other petitioner’s arguments, the court upheld “FERC’s decision to characterize bundled transmissions as part of retail sales subject to state jurisdiction,” finding that although FPA section 201 is unclear, FERC’s interpretation “represents a statutorily permissible policy choice” under *Chevron*.<sup>45</sup>

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39. The elements of FERC’s seven-factor test are: “(1) [l]ocal distribution facilities are normally close in proximity to retail customers. (2) [l]ocal distribution facilities are primarily radial in character. (3) [p]ower flows into local distribution systems; it rarely, if ever, flows out. (4) [w]hen power enters a local distribution system, it is not reconsigned or transported on to some other market. (5) [p]ower entering a local distribution system is consumed in a comparatively restricted geographic area. (6) [m]eters are based at the transmission/local distribution interface to measure flows into the local distribution system. (7) [l]ocal distribution systems will be of reduced voltage.” *Id.* slip op. at 402. This determination is not a bright-line rule, but instead a “starting point” because FERC may consider “other case-specific factors in particular situations.” *See S. Cal. Edison Co.*, 153 FERC ¶ 61,384 PP 3-4 (2015). In application, the test requires a “comprehensive consideration of how the totality of the circumstances bears on each of the seven factors.” *Id.* at P 19. Only after considering the totality of the circumstances may FERC decide whether a facility is local distribution or transmission under its jurisdiction. *Id.* at PP 33, 37. If a facility is determined to be local distribution, then the state in which it is located has jurisdiction. Order No. 888, *supra* note 22, slip op. at 429.

40. Order No. 888, *supra* note 22, slip op. at 430; *see also id.* slip op. at 433 (holding that “[s]tate regulation of most power production and virtually all distribution and consumption of electric energy is clearly distinguishable from this Commission’s responsibility to ensure open and non-discriminatory interstate transmission service.”).

41. *Id.* slip op. at 188 (holding that “[i]n addition, it raises numerous difficult jurisdictional issues that we believe are more appropriately considered when [FERC] reviews unbundled retail transmission tariffs that may come before us in the context of a state retail wheeling program.”).

42. Order No. 888-A, *supra* note 22, slip op. at 127, n. 128.

43. *See generally* Transmission Access Pol’y Study Grp. v. FERC, 225 F.3d 667 (D.C. Cir. 2000).

44. *Id.* at 694.

45. *Id.* at 694-695.

This decision was eventually appealed to the U.S. Supreme Court.<sup>46</sup> In *New York v. FERC*, the Court addressed two questions: (1) whether FERC exceeded its jurisdiction by including unbundled retail transmission within the scope of the open access requirements promulgated in Order No. 888, and (2) whether FERC was obligated under FPA section 206 to apply open access requirements to bundled retail transmission given its findings of undue discrimination.<sup>47</sup> In addressing the first question, the Court explained that “the landscape of the electric industry has changed since the enactment of the FPA”, and agreed with the D.C. Circuit’s finding that the “clear statutory language” in FPA section 201(b) supports FERC’s claim of jurisdiction.<sup>48</sup> The court further concluded that the FPA authorizes FERC’s jurisdiction over interstate transmission, without regard to whether the transmission service is sold to a reseller or directly to a consumer.<sup>49</sup>

With respect to the second question, the Court explained that in Order No. 888, FERC chose not to assert jurisdiction over bundled retail transmission service, but “it did not hold itself powerless to claim jurisdiction,” and instead reserved decision on this issue.<sup>50</sup> The Court also agreed with FERC’s statement that regulating bundled transmission “raises numerous difficult jurisdictional issues” and found this as “valid support” for refraining from regulating this type of service.<sup>51</sup> The Court further found that “[b]ecause FERC determined that the remedy it ordered constituted a sufficient response to the problems FERC had identified in the wholesale market, FERC had no [FPA] § 206 obligation to regulate bundled retail transmissions or to order universal unbundling.”<sup>52</sup>

Justice Thomas, joined by Justices Scalia and Kennedy, penned a dissent arguing that the majority failed to appropriately scrutinize FERC’s jurisdictional analysis and provide adequate reasoning for excluding bundled retail transmission from the open access requirements under Order No. 888.<sup>53</sup> The dissenting Justices asserted that the majority improperly characterized FERC’s “post-hoc rationalization” as a policy choice,<sup>54</sup> and argued that FERC should have been held to a higher standard in explaining why “regulation of transmission is not necessary when used in connection with one type of transaction but is necessary when used for another.”<sup>55</sup> Further, the dissent found that FERC’s conclusory statements on its decision to exclude the transmission component in bundled retail service “appears to make little sense,” and explained that such decision may conflict with its mandate to regulate when it finds unjust, unreasonable, unduly discriminatory, or preferential treatment is present.<sup>56</sup>

In summary, the dissent argued that the “difficulty” of determining how to regulate the transmission component of bundled retail service is not a basis for

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46. *See generally* *New York v. FERC*, 535 U.S. 1.

47. *Id.* at 16, 25.

48. *Id.* at 16-17.

49. *Id.* at 20.

50. *New York v. FERC*, 535 U.S. at 25.

51. *Id.* at 26 (quoting Order No. 888, *supra* note 22, slip op. at 150).

52. *Id.* at 27.

53. *Id.* at 28-42 (Thomas, J., dissenting).

54. *New York v. FERC*, 535 U.S. at 30 (Thomas, J., concurring in part and dissenting in part).

55. *Id.* at 30-31 (Thomas, J., concurring in part and dissenting in part).

56. *Id.* at 33 (Thomas, J., concurring in part and dissenting in part).

avoiding an undue discrimination analysis as to the implementation of bundled retail service arrangements in the first instance or adoption of a remedy if undue discrimination is determined to be present.<sup>57</sup> The dissent asserted that FERC was raising an ambiguity (as to the line between bundled and unbundled retail service) that is irrelevant to jurisdictional authorities under the FPA noting that “the terms ‘bundled’ and ‘unbundled’ are not found in the statute.”<sup>58</sup> Further, the dissent explained that the sole jurisdictional line for transmission is whether the transmission is occurring in interstate or intrastate commerce.<sup>59</sup> On this point, Justice Thomas argued that the system, as it existed in 1996, already was inherently interstate because the electric grid consisted of a series of interconnected transmission facilities over which electricity free flows between generation and load based on a path of least resistance.<sup>60</sup> Addressing situations in which there is a contract path established for a participant transmission (i.e., point-to-point transmission service), the dissent responded saying that transactional arrangements “bear little resemblance to the physical behavior of electricity transmitted on a power grid and, as such, it is impossible for either a utility or FERC to isolate or distinguish between the transmission used for bundled or unbundled wholesale or retail sales.”<sup>61</sup>

At a minimum, the dissent believed the majority should have remanded the order so that FERC could “engage in reasoned decisionmaking to determine whether there is undue discrimination with respect to transmission associated with retail bundled sales.”<sup>62</sup> And, if FERC found that undue discrimination was present, it would have been required to provide such a remedy.<sup>63</sup> As discussed herein, the *New York v. FERC* dissent has taken on greater importance recently given DOE’s reliance on this dissent in asserting that FERC must take jurisdiction over the interconnection of data centers to the transmission grid.<sup>64</sup>

## B. Federal Transmission Planning Exposes the Gaps

### 1. Order No. 890

In 2007, over a decade after issuing Order No. 888, FERC issued Order No. 890 that amended the regulations and *pro forma* open access transmission tariff adopted in Order No. 888 to, among other revisions, emphasize the importance of transmission planning by requiring transmission providers to share their transmission planning process with customers and coordinate this process with future system plans.<sup>65</sup> In this order, FERC retained its finding of “jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce,” and the “need for heightened cooperation between federal and state

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57. *Id.* at 41-42 (Thomas, J., concurring in part and dissenting in part).

58. *New York v. FERC*, 535 U.S. at 37 (Thomas, J., concurring in part and dissenting in part).

59. *Id.* at 37-38 (Thomas, J., concurring in part and dissenting in part).

60. *Id.* at 31-32 (Thomas, J., concurring in part and dissenting in part) (internal citations omitted).

61. *Id.* at 33 (Thomas, J., concurring in part and dissenting in part).

62. *New York v. FERC*, 535 U.S. at 42 (Thomas, J., concurring in part and dissenting in part).

63. *Id.* (Thomas, J., concurring in part and dissenting in part).

64. DOE ANOPR, supra note 26, at PP 1, 5.

65. Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, 118 FERC ¶ 61,119 P 3 (2007) [hereinafter Order No. 890].

regulators in areas where there are overlapping federal and state policy concerns.”<sup>66</sup> With respect to the order’s transmission planning requirements, FERC explained that these “do not reopen or otherwise change the existing jurisdictional divide for transmission facilities.”<sup>67</sup>

## 2. Order No. 1000

In 2011, FERC built upon the transmission planning and cost allocation requirements established in Order No. 890 and proposed a framework for regional transmission planning under a similar set of principles.<sup>68</sup> These reforms applied to all public utilities, regardless of whether they participated in an organized wholesale electricity market.<sup>69</sup> FERC explained that although “[FERC] do[es] not intend our reforms to preclude the ability of states to actively plan at the local level,” such reforms were needed because the Order No. 890 transmission planning and cost allocation requirements were “insufficient to ensure that the evolution of transmission planning processes will . . . ensure[] that the rates, terms and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential.”<sup>70</sup>

Numerous commenters questioned whether FERC had the legal authority to apply its Order No. 1000 reforms to all public utilities, especially those that utilize bundled transmission rates. The Southern Companies (Southern) argued that the rule’s mandates could not be implemented without preempting or undermining state law when applied to vertically integrated transmission companies that plan their transmission systems under state supervision and recover costs through bundled rates.<sup>71</sup> The North Carolina Agencies also argued that the rule should “recognize the indispensable role of state regulatory authorities” and only apply to unbundled transmission rates.<sup>72</sup> In response, FERC explained that its jurisdiction is “clearly broad enough” to allow it to ensure that the beneficiaries of transmission facilities absorb the costs whether or not they have a contractual relationship with the owner of such facilities.<sup>73</sup> FERC, again, used FPA section 201 to justify its authority to regulate the use of transmission facilities in the provision of transmission service, which it believes includes the consideration of benefits derived from such facilities, regardless of the relationship between the beneficiaries and the owner or operator of such facilities.<sup>74</sup>

Other questions were raised as to how the rule’s regional and interregional cost allocation methodologies would apply to public utilities that do not participate in RTOs. The American Wind Energy Association (AWEA) warned that the

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66. *Id.* at PP 92, 94 (internal citation omitted).

67. *Id.* at P 94.

68. *See generally* Order No. 1000, *supra* note 15.

69. *Id.* at P 19 (noting that requirements in Order No. 890 applied to “all public utility transmission providers, including Commission-approved RTOs and ISOs”); *id.* at P 80 (comparing how RTOs and ISOs plan transmission to how other transmission planning regions move forward and finding the need to “enhance the transmission planning-related requirements imposed in Order No. 890”).

70. *Id.* at P 84.

71. Order No. 1000, *supra* note 15, at P 527.

72. *Id.* at P 529.

73. *Id.* at P 531.

74. *Id.* at P 532.

market structure and cost allocation mechanisms outside RTOs “needs to mature further” before transmission providers could fully comply with the proposed mandates, and suggested the FERC consider an “interim method to address cost allocation in those regions.”<sup>75</sup> NextEra encouraged FERC to include an “adder on the transmission rates of public utility transmission providers” and non-jurisdictional utilities, while Southern disagreed, explaining that this concept would not work for them because their federal tariff “recovers only the share of the cost attributable to their provision of wholesale transmission service,” limited to approximately 15% of their costs.<sup>76</sup> In response, FERC refrained from adopting a fixed methodology, and instead established flexible principles for the costs of new projects that were to be allocated regionally.<sup>77</sup>

On rehearing, some commenters queried how FERC’s new transmission planning and cost allocation requirements would apply where states make resource planning and siting decisions, arguments made only by states that were wholly or in part outside an organized energy wholesale market.<sup>78</sup> Again, FERC refrained from directly answering such comments, and justified the rulemaking by pointing out that it does not “intrud[e] on state jurisdiction” or undermine state authority to site, permit, and construct transmission facilities or integrated resource planning and similar processes.<sup>79</sup> With respect to a question by Edison Electric Institute on how FERC would share transmission costs among a region in the absence of a voluntary agreement and what mechanism would be used in such an instance,<sup>80</sup> FERC sidestepped the issue and stated that the order does not “contemplate[ ] the recovery of costs from a beneficiary in the absence of an applicable tariff or agreement.”<sup>81</sup>

With respect to the rule’s application to bundled retail rates, the North Carolina Agencies resurfaced its earlier concerns, and the Ad Hoc Coalition of Southeastern Utilities agreed that the planning and cost allocation revisions preempted state authority over bundled retail rates, and asserted that FERC “must recognize that the applicability of any cost allocation methods that result from Order No. 1000 is limited to unbundled transmission and cannot impinge on state jurisdiction with respect to bundled retail rates.”<sup>82</sup> FERC disagreed that the rule infringes on state authority, and reiterated that it did not seek to regulate bundled retail rates; rather, it reaffirmed its finding in Order No. 1000 that such arguments are premature, and “in this generic rulemaking proceeding, these issues are not presented for [FERC] determination.”<sup>83</sup>

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75. Order No. 1000, *supra* note 15, at P 596.

76. *Id.* at P 597.

77. *Id.* at PP 603-05.

78. Order No. 1000-A, *supra* note 15, at PP 180-84.

79. *Id.* at PP 186-88.

80. *Id.* at P 602.

81. *Id.* at P 618.

82. Order No. 1000-A, *supra* note 15, at P 597.

83. *Id.* at P 621.

### 3. Order No. 1920

In 2024, FERC issued Order No. 1920, which sought to further evolve the transmission planning landscape by requiring transmission planning regions to undertake long-term transmission planning and closing loopholes created by Order No. 1000 by revising the local transmission planning process.<sup>84</sup> In addition to concerns about FERC impinging on states' authority to choose their generation mix, other commenters worried that the rule would regulate transmission processes typically regulated by states. For example, the Nevada Commission argued that FERC's rule "may cross the line from regulating interstate transmission to regulating intrastate processes—particularly because [FERC] has not asserted jurisdiction over bundled retail transmission."<sup>85</sup> Other commenters asserted that the rule's proposal would intrude on siting and construction of transmission reserved to states under FPA section 201.<sup>86</sup>

In its general discussion over its jurisdiction to pass the final rule, FERC cited to *New York v. FERC* and again reminded commenters that the FPA provides FERC the authority "over the transmission of electric energy in interstate commerce, which includes transmission on the interconnected national grids,"<sup>87</sup> concluding that the "[t]ransmission planning and cost allocation processes are practices affecting the rates charged by public utilities in connection with the [FERC]-jurisdictional transmission of electric energy in interstate commerce."<sup>88</sup>

Further, FERC stated that the final rule did not actually "regulate, aim at, or otherwise attempt to influence . . . decisions related to the siting and construction of transmission facilities or generation resources, or any other matters reserved to states under FPA section 201."<sup>89</sup> FERC also clarified that the final rule "directly regulates only [transmission planning and cost allocation] practices, and it does not directly regulate any matter reserved to the states by FPA section 201."<sup>90</sup> On rehearing, FERC revised the Order No. 1920 reforms to provide state regulators an even larger role in the transmission planning and cost allocation processes, reiterating its arguments advanced in Order No. 1920 that the order does not "infringe on the authority reserved to the states by FPA section 201."<sup>91</sup> However, FERC did not address how the split between cost recovery at the state and federal levels would impact regional transmission planning in regions outside RTOs.

### III. THE CURRENT BIFURCATED JURISDICTIONAL FRAMEWORK IS CONTRARY TO LAW AND CONGRESSIONAL INTENT

The current regulatory framework for utilities that do not belong to RTOs and whose transmission rates are recovered through both state and federal mechanisms is complex, problematic, and fundamentally leads to less development of high-

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84. Order No. 1920, *supra* note 3, at P 1.

85. *Id.* at P 191 (internal citation omitted).

86. *Id.* at PP 197-99 (noting that The Alabama Commission, Kansas Ratepayer Advocates, NARUC, Nevada Commission, Southern, and the Mississippi Commission all provided comments on this issue).

87. *Id.* at P 253 (citing *New York v. FERC*, 535 U.S. 1, 16-17 (2002) (citing 16 U.S.C. § 824(b))).

88. Order No. 1920, *supra* note 3, at P 253 (internal citations omitted).

89. *Id.* at P 254.

90. *Id.* at P 263 (internal emphasis omitted).

91. Order No. 1920-A, *supra* note 3, at PP 125-31 (internal citations omitted).

capacity regional transmission outside organized markets. The complexity of these structures leaves open the possibility of rate under-recovery, discouraging cost-effective investment, or over-recovery, adding unnecessary costs to customer bills at a time when electricity costs are rising.<sup>92</sup> Most significantly, this bifurcated approach is contrary to the plain language of the FPA, and creates barriers to implementing key energy policy objectives, including transmission development and large load interconnection.

*A. FERC's Disclaimer of Jurisdiction over Bundled Transmission Is Inconsistent with the Plain Language of the Federal Power Act*

Section 201 of the FPA states clearly that transmission service is subject to federal regulation; however, FERC chose to apply the law more narrowly in Order No. 888 and affirmed by the Supreme Court. Despite the statute's plain language, this choice was a reasonable political nod to the significant changes underway at the time, as the transmission system moved from a small part of a system built largely on vertically-integrated utilities serving their own customers with lines they built, to the means of creating robust markets, moving power from generating facilities owned by utilities and independent generators alike under open-access tariffs.<sup>93</sup> First, Order No. 888 provided for open access, compensating transmission owners for allowing generators to access the grid pursuant to a *pro forma* agreement.<sup>94</sup> In response to a lack of cohesive transmission planning, FERC promulgated the next step, Order No. 2000, which required a number of transmission pricing reforms to be included in regional tariffs.<sup>95</sup>

FERC was optimistic that allowing voluntary participation in RTOs would move transmission providers to engage in non-discriminatory behavior, including better transmission planning.<sup>96</sup> However, not all utilities joined RTOs, particularly those in the West and Southeast. The tariffs of utilities outside RTOs remained bifurcated—with (i) a federal tariff that governs the portion of the transmission facilities that serve wholesale customers subject to federal regulation,<sup>97</sup> and (ii) the portion that provides bundled service to native load customers subject to state regulation.<sup>98</sup>

Further, as a legal matter, FERC's current interpretation of the bounds of its regulatory authority is incompatible with the clear mandate set forth in FPA section 201, the Congressional intent behind it, and the evolving needs of the grid.

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92. Ryan Wiser et al., *Factors Influencing Recent Trends in Retail Electricity Prices in the United States. What Do We Know? Where are the Gaps?*, LAWRENCE BERKELEY NAT'L LAB'Y (Oct. 2025), [https://eta-publications.lbl.gov/sites/default/files/2025-10/full\\_summary\\_retail\\_price\\_trends\\_drivers.pdf](https://eta-publications.lbl.gov/sites/default/files/2025-10/full_summary_retail_price_trends_drivers.pdf).

93. See Order No. 888, *supra* note 22, slip op. at 13-50.

94. See *id.* slip op. at 51-52.

95. Order No. 2000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285, slip op. at 505-77 (1999) [hereinafter Order No. 2000]. In fact, "Industrial Consumers" in that proceeding urged the Commission to assert jurisdiction over the transmission component of bundled sales to encourage vertically-integrated utilities to join RTOs. *Id.* slip op. at 113. The Commission declined, relying on the value proposition of RTOs to encourage voluntary participation. *Id.* slip op. at 115-17.

96. Order No. 2000, *supra* note 95, slip op. at 100-01.

97. See 16 U.S.C. § 824.

98. In 1976, the Supreme Court held that the Commission could not alter the rates set by a state regulator. Rather, the Commission could only alter the rate that it set for the wholesale service. *FPC v. Conway Corp.*, 426 U.S. 271, 281-82 (1976).

The Supreme Court said as much in *New York v. FERC*, when concluding that section 201 “unambiguously authorizes FERC to assert jurisdiction over two separate activities -- transmitting and selling” and that its jurisdiction over transmission contains “no [] limitation[s].”<sup>99</sup> The Court concluded that FERC’s language limiting federal powers in this section is “a mere ‘policy declaration’ that ‘cannot nullify a clear and specific grant of jurisdiction, even if the particular grant seems inconsistent with the broadly expressed purpose.’”<sup>100</sup> Additionally, the Court held “even if we assume ... that ... the FPA gives FERC the authority to regulate the transmission component of a bundled retail sale, we nevertheless conclude that the agency had discretion to decline to assert such jurisdiction in this proceeding in part because of the complicated nature of the jurisdictional issues.”<sup>101</sup>

This gap – between the jurisdiction provided to FERC and the jurisdiction that FERC chose to assert – was highlighted in October 2025, when DOE issued an ANOPR emphasizing the broad nature of the federal jurisdiction over transmission.<sup>102</sup> The ANOPR cited the majority opinion in *New York v. FERC*, as well as the dissent which disagreed with the majority on whether FERC adequately explained why it was not necessary to regulate transmission connected to bundled retail rates.<sup>103</sup> The dissent stated, “[w]hile Congress understood that transmission is a necessary component of all energy sales, it granted FERC jurisdiction over all interstate transmission, without qualification.”<sup>104</sup> DOE relied on this broad understanding of FERC jurisdiction over transmission in proposing that FERC regulate large load interconnection to transmission lines at the federal level.<sup>105</sup>

The ANOPR justified its proposal on the federal regulation of transmission, noting that, “[t]he FPA has vested [FERC] with exclusive authority to ensure that wholesale rates are just and reasonable and not unduly discriminatory or preferential,” and asserting jurisdiction over the transmission system “does not impinge on States’ authority over retail electricity sales.”<sup>106</sup> Moreover,

any contrary view ... conflicts with the FPA’s core purposes. [FERC] has exclusive jurisdiction over the transmission of electric energy in interstate commerce, including the rates, terms, and conditions of transmission service, and all facilities for such transmission or sale of electric energy at wholesale in interstate commerce.<sup>107</sup>

When analyzing what constitutes “interstate commerce” courts have taken a very broad view. The FPA defines interstate commerce as energy “transmitted

99. *New York v. FERC*, 535 U.S. 1, 19-20 (2002) (emphasis added).

100. *Id.* at 22 (internal citations omitted).

101. *Id.* at 27-28.

102. Letter from Chris Wright, Sec’y of Energy, to FERC, FERC Docket No. RM26-4-000 (Oct. 23, 2025) (directing initiation of rulemaking procedures and proposals regarding the interconnection of large loads); DOE ANOPR, *supra* note 26.

103. DOE ANOPR, *supra* note 26, at PP 3-5.

104. *Id.* at P 5 (quoting *New York v. FERC*, 535 U.S. 1, 42 (Thomas, J., concurring in part and dissenting in part)).

105. *Id.* at PP 13-16.

106. *Id.* at PP 14-15.

107. DOE ANOPR, *supra* note 26, at P 16.

from a State and consumed at any point outside thereof.”<sup>108</sup> In a case between the predecessor to FERC, the Federal Power Commission, and a Florida utility, the Supreme Court found that anytime energy commingles on transmission facilities, regardless of whether that line crosses a state border, that act establishes federal jurisdiction over the transmission, in contrast to “facilities used in local distribution” of energy, which are left to state jurisdiction.<sup>109</sup> In that case, the utility provided power to Florida Power Corp., which then interconnected with, and exchanged power with, Georgia Power Co.<sup>110</sup> The Court noted that this interconnection contributed to the reliability of the broader system.<sup>111</sup> This clear threshold to showing whether transmission is conveying energy in interstate commerce has been repeatedly cited by FERC in determining whether transmission lines across the seam of the region governed by the Electric Reliability Council of Texas (ERCOT) convey federal jurisdiction over that grid.<sup>112</sup>

Legal precedent supports the framework of federally regulated costs for transmission to be passed through to utility customers rather than decided separately by state public utility commissions. The Supreme Court’s decision in *Nantahala Power & Light Co. v. Thornburg* supports the notion that there must be a FERC jurisdictional tariff to pass-through transmission costs at the retail level.<sup>113</sup> In *Nantahala*, the Court found that state commissions setting retail rates must allow utilities to pass through costs incurred paying wholesale rates approved by FERC.<sup>114</sup> To do otherwise would result in unjust and unreasonable rates as wholesale costs would be “trapped,” and the utility would not be able to recover its costs of a FERC approved rate.<sup>115</sup> Importantly, under *Nantahala*, it is only the FERC approved rate that must be passed through at the retail level. However, to date, FERC has not asserted jurisdiction over “bundled” transmission rates, so there is no FERC-approved rate to pass through to retail customers.

#### *B. Bifurcated Approach to Jurisdiction over Transmission Rates Complicates Cost Recovery for Regionally Significant Transmission*

In addition to legal gaps, this system gives rise to gaps in cost recovery for a single transmission line, particularly if that line crosses utility footprints or regions. For bundled service, states retain full jurisdiction over rate-setting, including the bundled transmission component. When a utility serves both wholesale (FERC-jurisdictional) and retail (state-jurisdictional) customers, it must

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108. 16 U.S.C. § 824(e).

109. FPC v. Fla. Power & Light Co., 404 U.S. 453, 467 (1972) (quoting 16 U.S.C. § 824(b)(1)).

110. *See id.* at 457.

111. *Id.* (“when a midwestern utility sustained a 580-megawatt generating loss, a regularly scheduled 8-megawatt FP&L contribution to the Florida Pool coincided with an 8-megawatt contribution from the pool to the ISG system.”).

112. *See generally* *AEP Energy Partners, Inc.*, 164 FERC ¶ 61,056 (2018); *City of College Station, TX*, 137 FERC ¶ 61,230 (2011); *Brazos Elec. Power Coop.*, 118 FERC ¶ 61,199 (2007); *Kiowa Power Partners, LLC & Oncor Elec. Delivery Co.*, 99 FERC ¶ 61,251 (2002); *Central Power and Light Co.*, 40 FERC ¶ 61,077 (1987); *Central Power and Light Co.*, 17 FERC ¶ 61,078 (1981).

113. *See generally* *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986).

114. *Id.* at 965.

115. *Id.* at 970-71.

allocate total transmission costs between jurisdictions using allocation factors approved through regulatory proceedings.<sup>116</sup> These factors are typically determined through cost-of-service studies based on peak demand contributions, energy consumption, load ratios, or customer classes.<sup>117</sup> FERC determines the transmission revenue requirement for the wholesale portion;<sup>118</sup> the utility then files a rate case with the state PUC, which implements cost recovery mechanisms to incorporate FERC-jurisdictional transmission costs into bundled retail rates, as well as recover costs for the portion of the line that provides bundled service.<sup>119</sup> The primary cost recovery mechanisms include: (1) base rate inclusion during general rate cases, (2) automatic adjustment clauses or riders, and (3) formula-based trackers.<sup>120</sup> The mechanism chosen significantly affects cost transparency, regulatory lag, utility earnings risk, and customer bill volatility.

Under the current approach, federally approved transmission costs are embedded in the utility's overall revenue requirement during general state rate cases.<sup>121</sup> Costs remain fixed between state rate cases, which typically occur every two to five years – but in some cases can take many more years, even decades.<sup>122</sup> This creates regulatory lag, where the utility bears risk if FERC-approved costs increase between state rate cases, and consumers bear risk if FERC-approved costs decrease between state rate cases.<sup>123</sup> This approach provides less transparency because transmission costs are not separately identified on customer bills.<sup>124</sup>

Additionally, state rate cases address the revenue requirement for the bundled portion of the transmission line. Through this separate process, there can be a gap in cost recovery that can leave a single investment being subject to multiple inconsistent rates of return for a transmission line, or a developer vulnerable to not being able to recover the whole cost of a transmission line.

One notable example of differing cost recovery outcomes is the Energy Gateway projects, a complex of projects that is expected to ultimately total approximately 2,300 miles of high-capacity transmission lines across Wyoming,

116. JIM LAZAR, PAUL CHERNICK & WILLIAM MARCUS, *ELECTRIC COST ALLOCATION FOR A NEW ERA: A MANUAL* 73-74 (Mark Lebel eds., Regulatory Assistance Project 2020).

117. *Id.*

118. *Nantahala Power & Light Co.*, 476 U.S. at 956.

119. Joe DeLosa III, Johannes P. Pfeifenberger & Paul L. Joskow, *Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S.* 31-32 (MIT Ctr. for Energy & Env't Pol'y Rsch., Working Paper No. 2024-03, 2024).

120. RAYMOND LAWTON ET AL., *MODEL STATE PROTOCOLS FOR CRITICAL INFRASTRUCTURE PROTECTION COST RECOVERY* at 4 figs. 1-2, 7-10 (NARUC 2004).

121. DeLosa III, Pfeifenberger & Joskow, *supra* note 119, at 31-32.

122. For example, the most recent rate case in Alabama was in 1982 – over 40 years ago. See Dennis Pillion, *How George Wallace and Bull Connor Set the Stage for Alabama's Sky-High Electric Rates*, *INSIDE CLIMATE NEWS* (Dec. 26, 2025), <https://insideclimatenews.org/news/26122025/george-wallace-bull-connor-set-stage-for-alabama-sky-high-electric-rates>

123. KEN COSTELLO, *NAT'L REGUL. RSCH. INST., FORMULA RATE PLANS: DO THEY PROMOTE THE PUBLIC INTEREST?* 1 (2010). Regulatory lag is defined as the time period between when a cost is incurred and when a utility is able to recover it. *Id.* at 1 n. 1.

124. Unlike FERC-jurisdictional rates, which are publicly filed and governed by standardized formula rate procedures, state retail rates embed transmission costs in a bundled figure, making cross-utility comparison of embedded transmission costs infeasible without accessing each utility's individual state commission rate case records. RMI, *Retail Electricity Prices: It's Time to Unbundle the Package* (June 12, 2013), [https://rmi.org/blog\\_06\\_12\\_2013\\_retail\\_electricity\\_prices\\_its\\_time\\_to\\_unbundle\\_the\\_package](https://rmi.org/blog_06_12_2013_retail_electricity_prices_its_time_to_unbundle_the_package).

Idaho, Utah and Oregon.<sup>125</sup> Cost recovery for specific segments have been primarily addressed through annual rate proceedings at state public utility commissions, with inconsistent results. For instance, the Idaho Public Utilities Commission (Idaho PUC) engaged in cost recovery review for the Gateway Central segment extending from Downey, Idaho to Salt Lake City, Utah.<sup>126</sup> In a May 2010 application, Rocky Mountain Power proposed to include its share of Gateway Central capital investment costs in updated electric service rates before the Idaho Public Utilities Commission (Idaho PUC).<sup>127</sup> Citing record evidence, the Idaho PUC disallowed 27% of the costs of the facilities based on its interpretation of state law.<sup>128</sup> More recently, the Public Utility Commission of Oregon (Oregon PUC) addressed a proposal to include a share of the Gateway South transmission project in rates for Oregon customers.<sup>129</sup> Due to a dispute over provision of evidence the Oregon PUC disallowed \$16.2 million of the revenue requirement associated with the transmission line.<sup>130</sup> These variable outcomes and uncertainty of rate recovery make it difficult for investors and developers to pursue regional and interregional transmission.

In the absence of unified cost recovery for multi-state or multi-utility footprints outside RTOs, few regional lines have been considered in the planning process.<sup>131</sup> Regional lines outside RTOs have largely relied on participant

125. *Energy Gateway*, PACIFICORP (last updated Jan. 2026), <https://www.pacificorp.com/transmission/transmission-projects/energy-gateway.html>.

126. *See generally Application of PacifiCorp dba Rocky Mountain Power for Approval of Changes to its Electric Service Schedules*, No. PAC-E-10-07, 2011 WL 770798 (Idaho Pub. Utils. Comm'n 2011), [https://puc.idaho.gov/fileroom/PublicFiles/elec/PAC/PACE1007/ordnotc/20110228FINAL\\_ORDER\\_NO\\_32196.PDF](https://puc.idaho.gov/fileroom/PublicFiles/elec/PAC/PACE1007/ordnotc/20110228FINAL_ORDER_NO_32196.PDF).

127. *Id.* at \*51.

128. *Id.* at \*38. Notably, one year later, the Idaho commission and Rocky Mountain Power agreed to a dismissal of an appeal challenging the Idaho commission's decision based on a settlement between the parties. *See generally Application of PacifiCorp dba Rocky Mountain Power for Approval of Changes to its Electric Service Schedules*, No. PAC-E-1112, 2012 WL 112290 (Idaho Pub. Utils. Comm'n 2012).

129. *See generally PacifiCorp*, No. UE 433 (Or. Pub. Utils. Comm'n 2024), <https://apps.puc.state.or.us/orders/2024ords/24-447.pdf>.

130. *Id.* at 41-42.

131. *See e.g., Regional Planning: 2018-2019 Regional Planning Cycle*, WESTCONNECT REG'L PLAN., [https://regplanning.westconnect.com/2018\\_19\\_regional\\_plng\\_cycle.htm](https://regplanning.westconnect.com/2018_19_regional_plng_cycle.htm) (last visited Apr. 27, 2026) (identifying no regional transmission needs in the 2018-19 planning cycle); *Regional Planning: 2020-2021 Regional Planning Cycle*, WESTCONNECT REG'L PLAN., [https://regplanning.westconnect.com/2020\\_21\\_regional\\_plng\\_cycle.htm#:~:text=Report%20\(.pdf\)-.Identify%20Regional%20Needs,open%20for%20this%20planning%20cycle](https://regplanning.westconnect.com/2020_21_regional_plng_cycle.htm#:~:text=Report%20(.pdf)-.Identify%20Regional%20Needs,open%20for%20this%20planning%20cycle) (last visited Apr. 27, 2026) (identifying no regional transmission needs in the 2020-21 planning cycle); *Regional Planning: 2022-2023 Regional Planning Cycle*, WESTCONNECT REG'L PLAN., [https://regplanning.westconnect.com/2022\\_23\\_regional\\_plng\\_cycle.htm#:~:text=Identify%20Regional%20Needs%20\\*%20Regional%20Needs%20Assessment,will%20not%20open%20for%20this%20planning%20cycle](https://regplanning.westconnect.com/2022_23_regional_plng_cycle.htm#:~:text=Identify%20Regional%20Needs%20*%20Regional%20Needs%20Assessment,will%20not%20open%20for%20this%20planning%20cycle) (last visited Apr. 27, 2026) (identifying no regional transmission needs in the 2022-23 planning cycle); *Regional Planning: 2024-2025 Regional Planning Cycle*, WESTCONNECT REG'L PLAN., [https://regplanning.westconnect.com/2024\\_25\\_regional\\_plng\\_cycle.htm](https://regplanning.westconnect.com/2024_25_regional_plng_cycle.htm) (last visited Apr. 27, 2026) (identifying no regional transmission needs in the 2024-25 planning cycle). This stands in stark contrast to neighboring region SSP, which found significant transmission needs to be addressed every year in 2023-2025. *See generally K* (2023), <https://spp.org/documents/70584/2023%20itp%20assessment%20report%20v1.0.pdf>; *Integrated Transmission Planning*, SPP, <https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/> (last visited Apr. 27, 2026).

funding, where the customers of the line pay directly to use the facility.<sup>132</sup> However, the Commission has repeatedly rejected reliance on participant funding as the primary means of developing regional transmission. In Order No. 1000, FERC noted that participant funding would not satisfy its cost allocation principles, because it “increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development.”<sup>133</sup> Although participant funding is permitted, the Commission refused to allow it to be relied upon as a regional cost allocation methodology because “it is likely that some transmission facilities identified as needed in the regional transmission planning process would not be constructed in a timely manner, adversely affecting ratepayers.”<sup>134</sup> In rejecting arguments made by the Ad Hoc Coalition of Southeastern Utilities and the Arizona Corporation Commission, the Commission reiterated that cost causation principles require that those who benefit from new facilities “may be said to have ‘caused’ a part of those costs to be incurred,”<sup>135</sup> underscoring the fact that shared cost allocation principles govern outside RTOs.

*C. Transmission Planning is Less Effective When Subjected to a Bifurcated Approach to Jurisdiction Over Transmission Rates*

FERC’s broad jurisdiction over transmission provides the basis for its regulations on regional transmission planning. However, the Commission’s decision in Order No. 888 to divide the rates, terms, and conditions of transmission service into two different regimes has contributed to uneven transmission expansion outside RTOs. Organized markets have independent transmission planners that plan the transmission lines, which encourages the development of a broader grid than in non-organized markets. Outside RTOs, vertically integrated utilities serve bundled customers, and except for a small percentage of the transmission revenue requirement that is recovered under the FERC OATT, transmission costs are primarily recovered through state approved rates and will reflect only the bundled transmission costs of the individual utility, leading to conflicting incentive structures.

This complicates transmission planning. In RTO regions, transmission planners consider regional transmission needs and how to best serve the individual needs of each utility on an aggregated basis.<sup>136</sup> But where transmission cost recovery by vertically integrated utilities outside RTOs is primarily driven through a state approved process, individual utilities are motivated to only propose transmission facilities that will be approved by the state—frequently leading to proposal of smaller local transmission lines where the utility can more easily show

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132. See, e.g., SunZia Transmission, LLC, 160 FERC ¶ 61,074 (2017) (modifying the authority granted in SunZia Transmission, LLC, 135 FERC ¶ 61,169 (2011)); MATL LLP & BHE U.S. Transmission, LLC, 170 FERC ¶ 61,297 (2020).

133. Order No. 1000, *supra* note 15, at P 715.

134. *Id.* at P 723.

135. *Id.* at P 726 (citing Ill. Com. Comm’n v. FERC, 576 F.3d 470, 476 (7th cir. 2009) (internal emphasis omitted)).

136. Order No. 1920, *supra* note 3, at PP 101-02.

the benefits to customers in its service territory and avoiding regional projects that cross multiple utility footprints.<sup>137</sup>

Because transmission costs for large transmission projects would only be recovered by the utility planning and building the transmission project where a utility serves mostly bundled customers, this results in fewer large transmission lines being built in non-RTO regions.<sup>138</sup> The result is that transmission development outside RTOs has either been merchant transmission (paid for by the entity building it) or local projects where transmission costs are recovered through retail rates approved by state commissions.<sup>139</sup> Sole reliance on local transmission project planning, to avoid cost allocation to a neighboring utility, is inefficient and does not address the regional and interregional planning needs of today.<sup>140</sup>

Southern explained the complexities of regional planning through state-based transmission rates in its Order No. 1000 comments, criticizing FERC's proposed transmission planning rule as assuming that transmission development could "simply be recovered under [a] single RTO/regional Tariff."<sup>141</sup> Southern explained:

Southern Companies do not even recover all of their transmission revenue requirements under their OATT but only recover that amount attributable to wholesale service – which is approximately fifteen percent (15%). Retail consumers in the franchised service territories served on a vertically integrated basis by Southern Companies fund the great majority of the Southern electric transmission service – the remaining eighty five percent (85%) – through State-regulated bundled retail rates.

In this context it is unclear what the NOPR proposes as to vertically integrated transmission providers like Southern Companies who recover the bulk of their transmission revenue requirements from bundled retail customers pursuant to State regulations. Since the bulk of the recovery is at retail, this treatment is not an issue of federal comparability. At best, "comparability" would only allow a

137. *Industrial Energy Consumers of America v. Avista Corp.*, FERC Docket No. EL25-44-000, at \*8 (Dec. 19, 2024) (arguing that the tariffs of the named utilities and RTO/ISOs inappropriately permit them to plan FERC-jurisdictional transmission at levels above 100 kV as local planning without considering whether the local planning approach is the most cost-effective or efficient approach for the grid and consumers).

138. See ZACH ZIMMERMAN & ROB GRAMLICH, 2024 STATE OF REGIONAL TRANSMISSION PLANNING 1-3 (Grid Strategies 2024) (noting that the non-RTOs in the northwest, southwest, west, and southeastern regions of the United States have lagged in regional transmission planning while RTO/ISOs CAISO, MISO, SPP, ERCOT, NYISO, and ISO-NE have generally done more regional transmission planning).

139. See ZACHARY ZIMMERMAN, MICHAEL GOGGIN & ROB GRAMLICH, READY-TO-GO TRANSMISSION PROJECTS 2023, at 10-16 (Grid Strategies 2023) (describing transmission lines under development under development, including merchant and "local" projects); Zack Hale, *Merchant Developers Fill "Void" in US Interregional Grid Build-Out*, S&P GLOB. (Oct. 6, 2023), <https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/merchant-developers-fill-void-in-us-interregional-grid-build-out-76447354> (identifying 13 interregional transmission lines, 10 of which are merchant developed).

140. John D. Wilson et al., *Power Demand Forecasts Revised Up for Third Year Running*, Led by Data Centers, GRID STRATEGIES, at 6 (Nov. 2025), <https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf>; see also Brattle Grp., *Annual U.S. Transmission Investments 1996-2023*, BRATTLE (June 13, 2024), <https://www.brattle.com/wp-content/uploads/2023/07/Annual-US-Transmission-Investments-1996%E2%80%932023.pdf>.

141. Southern Co. Servs., Inc., Comment Letter to Proposed Rule on Transmission Planning Processes and Cost Allocation by Transmission Owning and Operating Public Utilities, FERC Docket No. RM10-23, at 74 (Sep. 29, 2010) [hereinafter Southern Co. Servs., Inc. Comment Letter].

nonincumbent to recover fifteen percent (15%) of its transmission costs under a federal OATT. For the remainder, it would need State approval.<sup>142</sup>

The Southern Companies' OATT includes Alabama Power Co., Georgia Power Co., and Mississippi Power.<sup>143</sup> Under its OATT, Attachment M "Formula Rate Manual" establishes the procedures and methodology for deriving charges for services under the OATT on Southern Companies' bulk transmission facilities, including the derivation of the Annual Revenue Requirement, which is the total authorized transmission cost recovery amount for the Transmission Provider's bulk and sub-transmission facilities.<sup>144</sup> Attachment M appropriately excludes from the formula rate base investment in physically radial bulk transmission facilities used exclusively to serve retail load.<sup>145</sup> This means that infrastructure built solely for retail customers falls outside the OATT cost recovery mechanisms. Instead, those costs are recovered through state retail rates.<sup>146</sup>

In a section 205 filing submitted to FERC on July 3, 2018, Southern Companies filed Exhibit A, "Statement Comparing OATT Revenues," which quantifies the allocation of transmission cost recovery between these two channels.<sup>147</sup> The Total Company Revenue Requirement for 2018 was \$1,131,530,134, with an OATT Customer Projected Revenue of \$178,875,111.<sup>148</sup> The OATT revenue was roughly 15.8% of the Company's revenue requirement, leaving roughly 84.2% to flow through bundled retail rates set in separate proceedings before the Alabama, Georgia, and Mississippi Public Service Commissions.<sup>149</sup> The result of this imbalance is a system that favors certainty over who will pay the costs of needed transmission facilities and smaller projects whose benefits are concentrated within a single utility's service territory, rather than attempts to coordinate amongst multiple public utility transmission providers seeking support across multiple state jurisdictions.

Southern's experience is echoed by vertically-integrated transmission owners outside organized wholesale markets across the country. As shown in Figure 1 below, the authors analyzed data included in EIA's 2023 Form 861 Report submitted by a sampling of public utilities that are not located in an RTO to determine what percentage of their use of their transmission system is for wholesale sales pursuant to their OATT versus retail sales regulated by their state public utility commission – meaning bundled retail sales.<sup>150</sup>

142. *Id.* at 74-75.

143. *Id.* at 1.

144. *Filing to Amend Southern Companies' OATT*, FERC Docket No. ER18-1934-000, at Attach. M (July 3, 2018), [https://www.oasis.oati.com/SOCO/SOCOdocs/Southern\\_OATT\\_Filing\\_7\\_3\\_18.pdf](https://www.oasis.oati.com/SOCO/SOCOdocs/Southern_OATT_Filing_7_3_18.pdf) [hereinafter *Filing to Amend Southern Companies' OATT*].

145. *Id.* Bulk or Subtransmission Retail Radial Facilities are facilities used exclusively to serve the Transmission Provider's retail load that are placed into service in Rate Year 2011 and after.

146. Southern Co. Servs., Inc. Comment Letter, *supra* note 141, at 74-75.

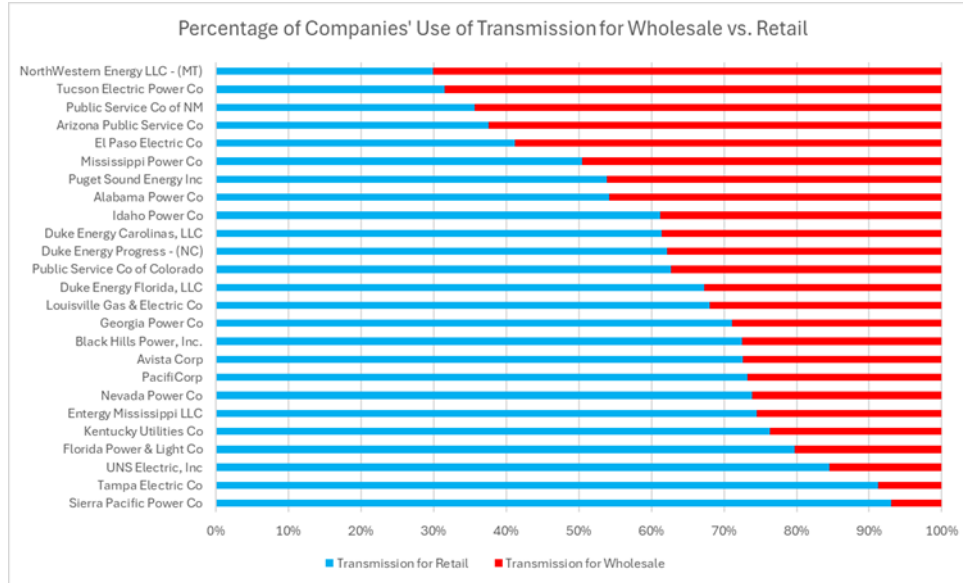
147. *Filing to Amend Southern Companies' OATT*, *supra* note 144, at exhibit A.

148. *Id.*

149. *Id.*

150. *Annual Electric Power Industry Report, Form EIA-861 Detailed Data Files*, U.S. ENERGY INFO. ADMIN. (last updated Oct. 7, 2025), <https://www.eia.gov/electricity/data/eia861/#:~:text=Form%20EIA%2D861%2C%20Annual%20Electric,all%20United%20States%20electric%20utilities.> This analysis relies on the data published in the Operational Data tab of the 2023 EIA-861 Report and assumes that the data identified as (1) Wheeled Power Received represents

Fig. 1. Percentage of Utility Companies' Use of Transmission for Wholesale vs. Retail.



Approximately 62% of the uses of those transmission systems represent bundled retail sales where the transmission component is regulated by state authorities.<sup>151</sup> The remaining 38% of the utilities' transmission usage reflects wholesale power sales where transmission is provided under the FERC OATT.<sup>152</sup> That percentage demonstrates that outside of RTO regions, a significant percentage of transmission system usage is tied to bundled retail sales – and a potentially significant gap exists. This gap is highlighted in the map below that shows the limited number of longer transmission projects connecting multiple utility footprints in the Southeast.

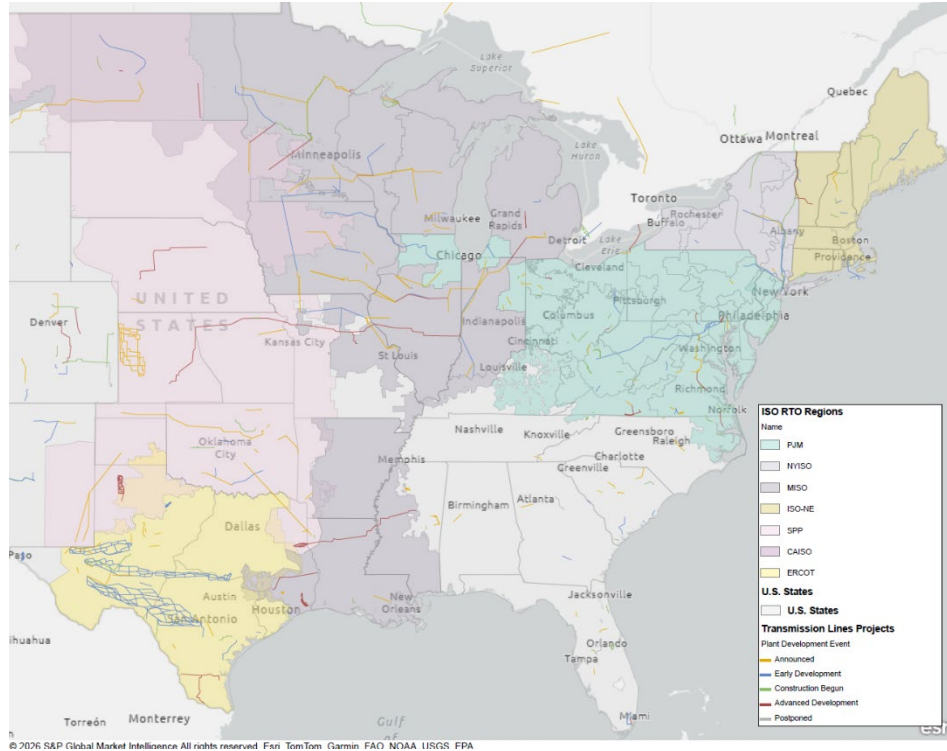
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power transmitted over, within or through a utility's transmission system under its FERC OATT; (2) Sales to Ultimate Customers represents the utility's retail power sales delivered over the utility's transmission system where the state regulated the transmission aspects of those sales; and (3) Sales for Resale represents transmission wholesale of the utility's wholesale power sales delivered over the utility's transmission system under its FERC OATT.

151. This percentage reflects the average for the 24 utilities we analyzed. The actual percentages for individual utilities ranged from 29.9% to 93%. *Id.*

152. The actual percentages for the 24 individual utilities ranged from 7% to 70.1%. *Id.*

Fig. 2. S&P Global Map of Transmission Line Projects in the Midwest and Eastern Region.<sup>153</sup>



The transmission planning provisions adopted by Order No. 1000 tried to resolve this gap but did not entirely succeed. FERC recognized the benefit of transmission owners proactively cooperating with one another to identify and plan for cost-effective transmission solutions across the region, rather than each transmission owner identifying smaller local solutions.<sup>154</sup> FERC described the challenges associated with cost allocation, particularly in regions that encompass several states, and that the lack of tariff defined cost allocation methods to identify beneficiaries of proposed regional and interregional transmission facilities was leading to inefficient and not cost-effective transmission solutions being identified during the transmission planning process.<sup>155</sup> To effectuate regional transmission planning and cost-allocation methodologies, FERC required transmission providers to participate in a regional transmission planning process and submit tariff amendments incorporating regional planning procedures and cost-allocation

153. S&P Global Market Intelligence and Capital IQ Domain: *Transmission Line Projects by Stage of Development*, S&P GLOB., <https://www.capitaliq.spglobal.com/web/client?auth=inherit#mapping/map?mapId=3c7903dc-835c-4e05-931a-51c88f0e0caf&share=1&bbox=-104.6426%2C45.482%2C-68.4141%2C25.5542%2C4326> (last visited Mar. 18, 2026) (using basemap sources such as Esri, TomTom, Garmin, FAO, NOAA, USGS, and EPA to create map).

154. Order No. 1000, *supra* note 15, at PP 68, 81.

155. *Id.* at PP 488-99.

methods.<sup>156</sup> But it did not squarely address, nor solve for, the problem of bifurcated jurisdiction over rates.

For RTOs, amending their tariffs to cover regional planning and cost allocation is relatively straightforward because regional tariffs already exist. Order No. 1000 required that each transmission provider adopt the same cost allocation method in its tariff as every other transmission provider in the region,<sup>157</sup> so RTOs only needed to amend their regional transmission tariffs that covered participating transmission owners in their regions.<sup>158</sup> Transmission providers outside RTOs each have their own individual tariffs, however, so transmission providers in these regions each submit revisions to their own tariffs on a regional basis.<sup>159</sup>

In Order No. 1920, FERC again sought to address multi-value transmission planning, whereby local transmission planning needs would be incorporated into regional planning,<sup>160</sup> but parties in that proceeding did not raise the concern regarding FERC's lack of assertion of federal jurisdiction over rates for bundled transmission outside RTOs. Public power entities – such as the Large Public Power Council and Six Cities<sup>161</sup> – expressed concern that the federal government would delegate its ratemaking powers to states through the Relevant State Entity process<sup>162</sup> but FERC sought to assuage those concerns, noting that ultimately FERC was acting under its own jurisdiction by setting forth procedures under which it would “establish a just and reasonable replacement rate.”<sup>163</sup> Under the existing framework, it is unclear how such multi-value transmission will be cost allocated outside RTOs.

The lack of a federal tariff that provides for comprehensive cost recovery for transmission also presents a significant impediment to development of interregional transmission that would connect a region outside RTOs. If FERC sought to initiate an interregional planning process that included regions outside RTOs, as has been considered,<sup>164</sup> there is no readily available tariff through which to flow through costs. It's not that it couldn't be done – FERC addressed that issue in Order No. 1000, when it rejected arguments that, for a utility to allocate costs to a beneficiary, there must be privity of contract or an already existing tariff.<sup>165</sup> FERC asserted that its jurisdiction is broad enough to allow beneficiaries to pay for transmission facilities in the absence of a contractual relationship between the

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156. *Id.* at P 792.

157. *Id.* at P 500.

158. *Order No. 1000 Regional Compliance Orders*, FERC (last updated Jan. 10, 2022), <https://www.ferc.gov/industries-data/electric/overview/order-no-1000-regional-compliance-orders> (listing Order No. 1000 compliance filing orders).

159. For example, there were 10 utilities in the WestConnect planning region, that each filed separate tariffs in compliance with Order No. 1000. *Order on Compliance Filings*, 142 FERC ¶ 61,206 (2013).

160. Order No. 1920, *supra* note 3, at P 1569.

161. Six Cities refers to The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California. Public power utilities generally are not-for-profit, community-owned electric systems operated by local governments. *Id.* at App. A.

162. *Id.* at P 1424.

163. *Id.* at P 1428.

164. Miranda Willson, *Glick Fleshes Out Plans for New FERC Grid Rules*, E&E News (Oct. 20, 2021), <https://www.eenews.net/articles/glick-fleshes-out-plans-for-new-ferc-grid-rules/>.

165. Order No. 1000, *supra* note 15, at P 540.

parties, which applies equally to interregional transmission.<sup>166</sup> But without a regional tariff to allocate costs that benefit the region broadly, large transmission projects linking regions would have to either seek application of a whole new tariff in the first instance or seek cost recovery from the interconnecting utility, which would then have to pass costs along through its state rate case, even if benefits are more broadly spread.

Consider the North Plains Connector, a four hundred and twenty mile transmission project connecting Montana and North Dakota that will be the first high-voltage transmission line to connect MISO, the Western Interconnection, and SPP.<sup>167</sup> A high voltage direct current transmission line connecting the western and eastern transmission systems is anticipated to provide significant interregional reliability benefits.<sup>168</sup> Theoretically, such an interregional line would be able to recover costs from all who benefit, throughout each neighboring region – in this case, SPP, which is an organized market,<sup>169</sup> and Northern Grid, which is a transmission planning region that encompasses at least eight utilities across six states.<sup>170</sup> However, Northern Grid does not have a regionwide cost recovery tariff, leaving North Plains Connector to only interconnect with a single utility's system in Montana.<sup>171</sup> Even though the transmission line would provide access to additional power for the entire Northern Grid region, the Montana Public Utility Commission focuses on impacts “affecting consumers in a utility's service area” when adjudicating a rate case.<sup>172</sup> Because only the benefits to the utility could be considered in such a rate case, and not the benefits to the entire Northern Grid region, it is not clear whether the entire cost of the line could be recovered, making it more difficult to develop such a line with broader regional benefits. To circumvent this challenge the developer of North Plains Connector is seeking investment from individual utilities around the region, and each utility must seek cost recovery in their individual state rate cases – an inefficient work around to share the benefits of a transmission line that would bridge the eastern and western interconnections.<sup>173</sup> In contrast, if such a line planned and developed within a single organized market region and provided significant net benefits, it would be able to allocate its costs to those that benefitted within the region.<sup>174</sup>

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166. *Id.* at P 395

167. *BHE U.S. Transmission Joins Grid United for North Plains Connector Transmission Project*, BUS. WIRE (Jan. 8, 2025), <https://www.businesswire.com/news/home/20250108279171/en/BHE-U.S.-Transmission-Joins-Grid-United-for-North-Plains-Connector-Transmission-Project>.

168. See generally Aaron Bloom et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, 37 IEEE TRANSACTION ON POWER SYS. 1760 (2022).

169. *About Us*, SPP, <https://spp.org/about-us/> (last visited Apr. 27, 2026).

170. *Purpose*, N. GRID, <https://www.northerngrid.net/northerngrid/purpose/> (last visited Apr. 27, 2026).

171. The North Plains Connector ends at the Colstrip substation. *Frequently Asked Questions: What is the Proposed Route of the Transmission Line?*, N. PLAINS CONNECTOR, <https://northplainsconnector.com/frequently-asked-questions/> (last visited Apr. 27, 2026). The Colstrip substation is owned and operated by Northwestern Energy. *Our Company*, NW. ENERGY, <https://northwesternenergy.com/about-us/our-company/2024/12/12/northwestern-energy-to-participate-in-regional-transmission-projects#> (last visited Apr. 27, 2026).

172. MONT. CODE ANN. § 69-3-303(1) (2025).

173. *Frequently Asked Questions: Who Will Maintain and Operate the Line Once It's Built?*, N. PLAINS CONNECTOR, <https://northplainsconnector.com/frequently-asked-questions/> (last visited Apr. 14, 2026).

174. See Order No. 1000, *supra* note 15, at P 622.

Even as North Plains Connector anticipates being able to move forward through participant funding and other similar projects seek to build support through individual customers, it is worth remembering that even FERC does not view this participant-funding model as sufficient to build out much-needed regional and interregional transmission, as discussed above.

*D. The Bifurcated Approach to Jurisdiction over Transmission Leads to Unduly Discriminatory Rates*

When a vertically-integrated transmission owner transmits electricity for both unbundled customers and bundled customers over the same transmission line, two different transmission cost allocation schemes arise—the unbundled customers are served under the terms of the transmission owner’s FERC jurisdictional tariff; whereas the bundled customers are served under the state-jurisdictional retail tariff. This differing treatment, and potentially different rate for the same service, has the potential of being unduly discriminatory.<sup>175</sup> Undue discrimination arises when similarly situated customers are treated differently;<sup>176</sup> here, bundled and unbundled transmission customers use the transmission line in the same manner, and are therefore similarly situated.<sup>177</sup> There is no material difference between types of customers using a high-voltage transmission line.<sup>178</sup> Under these circumstances, having different rate treatment for customers of the same transmission line would appear to be the very definition of undue discrimination.<sup>179</sup>

The current discriminatory treatment is exacerbated when incentives are applied. FPA section 219 directed the Commission to establish incentives providing beneficial transmission rates in order to promote capital investment in transmission infrastructure to enhance reliability and lower congestion costs.<sup>180</sup> Not only have states applied a different transmission rate to their own retail rate regulated customers that is different than that applied to wholesale customers, utilities have also claimed revenues associated with the wholesale transmission portion of the line and credited them to retail rates. Specifically, in seeking transmission rate incentives for their Energy Gateway projects, PacifiCorp stated that it would:

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175. 16 U.S.C. §§ 824d, 824e; Order No. 888, *supra* note 22, slip op. at 3 (“Indeed, it is our statutory obligation under sections 205 and 206 of the Federal Power Act to remedy undue discrimination.”).

176. *Dynegy Midwest Generation v. FERC*, 633 F.2d 1122, 1125-1129 (D.C. Cir. 2011); *Mass. Mun. Wholesale Elec. Co. v. Northeast Utils. Serv. Co.*, 57 FERC ¶ 61,306, at 61,997 (1991) (“Section 206 of the FPA clearly permits challenges to the justness and reasonableness of existing rates. Because various circumstances may change over time, rates which have been accepted for filing under Section 205 of the FPA later may be shown to be unjust and unreasonable. In this regard, Section 206 operates to ensure that a utility’s current rates are just and reasonable by permitting the Commission and others to challenge such current rates.”).

177. *New York v. FERC*, 535 U.S. 1, 7 (2002) (“any electricity that enters the grid immediately becomes part of a vast pool of energy that is constantly moving in interstate commerce.”).

178. *See id.* at 30-32 (Thomas, J., concurring in part and dissenting in part) (internal citations omitted).

179. *Tri-State Generation and Transmission Ass’n*, 186 FERC ¶ 61,183 at P 129 (2024) (noting that all transmission customers benefit from integrated transmission planning “by gaining access to a wider pool of resources and the collective benefits of shared investments in reliability and capacity enhancements” and it is therefore not unduly discriminatory to charge all transmission customers the same rate for transmission service).

180. Order No. 679, *Promoting Transmission Investment Through Pricing Reform*, 116 FERC ¶ 61,057 at PP 1-6 (2006) [hereinafter Order No. 679].

compensate its retail customers by crediting the transmission-related revenues, inclusive of any incentives granted by [FERC], against its retail revenue requirement. PacifiCorp expects that the requested incentives will be an important consideration in obtaining state regulator support for including the reliability and future growth elements of the Project in retail rates.<sup>181</sup>

Intervenors in the proceeding noted that PacifiCorp only received approximately 10% rate recovery for its transmission through federal rates and 90% through state rates,<sup>182</sup> and argued that reducing retail rates through incentives on the wholesale portion of the transmission line was a condition for state regulators to approve investment in the transmission.<sup>183</sup> FERC declined to address the argument, stating that it was beyond the scope of the proceeding.<sup>184</sup> Yet reducing state-recovered transmission rates by the amount of incentives recovered from wholesale customers would, on its face, appear discriminatory.<sup>185</sup>

Even more significantly, this shows how bifurcating jurisdiction over transmission rates thwarts Congressional intent behind transmission incentives. Section 219 was added to the FPA through EPAct 2005 to require FERC “to establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.”<sup>186</sup> Such incentives, whether in the form of adders on return on equity within the zone of reasonableness or risk-reducing incentives such as providing for recovery of costs related to abandoned plant and construction work in progress, applied to federal transmission rates to foster the buildout of high-capacity transmission.<sup>187</sup> Applying the incentives unevenly, where FERC elected not to assert jurisdiction over some transmission rates, leads to a more uneven buildout of transmission lines.<sup>188</sup>

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181. *PacifiCorp*, 125 FERC ¶ 61,076 at P 12 (2008) (internal citation omitted).

182. *Id.* at PP 31, 31 n.39.

183. *Id.* at PP 30-32.

184. *Id.* at PP 49, 62.

185. *Tex-La Electric Coop. of Texas, Inc. & W. Tex. Utils. Co.*, 69 FERC ¶ 61,269, at 62,035 (1994) (finding that it was unduly discriminatory for the transmission owner to charge two different rates to different transmission customers).

186. Order No. 679, *supra* note 180, at P 7 (2006).

187. *See id.* at P 3 (“We are particularly attuned to the need for flexibility to support long-distance interstate projects that significantly reduce the cost of delivered power by reducing transmission congestion on the interstate grid.”).

188. The effectiveness of transmission incentives has been robustly debated, but it is worth noting that the incentives serve as a kind of revenue sharing mechanism where the incentivized behavior – here, the buildout of high-capacity transmission – is intended to save customers money, and a portion is reserved to the developer, akin to a performance-based ratemaking incentive. *See Joint Supplemental Comments of WIRES, The Edison Electric Institute, and GridWise Alliance*, FERC Docket No. RM20-10-000, at 4 (Apr. 3, 2025) (arguing FERC should terminate the transmission incentive reform proceeding); *see generally WATT Coalition & AEE Shared Savings Proposal*, FERC Docket Nos. RM20-10-000 & AD19-19-000 (Sept. 3, 2020) (proposing a shared savings incentive for grid-enhancing technologies).

#### IV. FERC SHOULD EXERCISE ITS JURISDICTION OVER TRANSMISSION RATES

In keeping with the reasoning provided in *New York v. FERC*, and as discussed above, FERC has jurisdiction over all transmission rates.<sup>189</sup> FERC should extend its reasoning supporting regional planning to find that its current approach to the jurisdictional framework is leading to rates that are not just and reasonable, and assert its full jurisdiction over transmission rates for future transmission projects. Similar to its finding in Order No. 888 that the old framework led to rates, terms, and conditions that were not just and reasonable under FPA section 206, FERC can make a similar finding here based on its findings in support of Order No. 1000 and 1920, and the examples set forth in this article that the current framework has led to outcomes in conflict with the legal prohibition against unduly discriminatory rates, the Congressional intent behind incentives, and the plain language of the Federal Power Act providing for federal jurisdiction over transmission.

Such an argument could be made *sua sponte* in a FERC rulemaking or policy statement, or through an outside entity filing a region-specific complaint or broad-based petition for rulemaking. Transitions between old and new forms of regulation are never neat, and here, the possibility of double-recovery of costs – through state and federal tariffs for the same transmission assets – would require scrutiny of how to apply its jurisdiction over new and existing lines. FERC should commence a proceeding to consider the issue independently so that, as new transmission lines are proposed, the issue has been clearly vetted and jurisdiction established, and developers have greater clarity as they moved forward with new projects. FERC would need to re-examine the cost recovery of current facilities in conjunction with their recovery under state tariffs, and balance a wide-range of factors to ensure that moving those facilities to federal tariffs would be necessary in the public interest. Despite these complexities, it is imperative that, to improve planning efficiency and ensure just and reasonable rates, all transmission that moves into rates on a prospective basis should be solely under federal jurisdiction.

FERC must complete its move towards federal jurisdiction over transmission rates in order to more successfully develop a larger grid by more readily applying new regional and interregional projects to the new tariffs that would be planned to meet future needs. As noted above, FERC already has the authority to provide for cost allocation pursuant to the existing FPA and does not require any additional Congressional authority. Indeed, FERC ordered cost allocation frameworks to be included in tariffs in Order Nos. 1000 and 1920.<sup>190</sup> But by continuing to disclaim jurisdiction over a portion of transmission rates, the cost allocation to get much needed transmission built will remain elusive given the false interim step of seeking rate approval from state regulators that may have conflicting incentives.

Just as transmission planning applies to transmission owners around the country where FERC has jurisdiction – everywhere except Alaska, Hawaii, and

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189. *New York v. FERC*, 535 U.S. 1, 17 (2002) (“There is no language in the statute limiting FERC’s transmission jurisdiction to the wholesale market. . .”).

190. See generally Order No. 1000, *supra* note 15; See generally Order No. 1920, *supra* note 3.

ERCOT<sup>191</sup> – federal jurisdiction over transmission rates should also apply everywhere. This will enhance federal oversight of transmission, and close gaps that arise between federal jurisdiction over transmission and vestigial state jurisdiction over bundled transmission rates. Federal transmission incentives, cost containment, and any other federal policies would likewise apply in total. Unbundling all transmission will also implement the FPA as it was intended – asserting federal jurisdiction over interstate transmission and transactions, in contrast to state jurisdiction over generation. Federal oversight over all transmission facilities and planning will also better position FERC and NERC to ensure reliability of the bulk power electric system and make the system more efficient and cost-effective.

Should FERC assert jurisdiction over all transmission, the most likely administrative framework would require all transmission service to be provided under a FERC-jurisdictional OATT. Such service could be administered through newly created Independent Transmission Providers (ITPs), joint tariffs, or through enhanced individual utility OATTs.

One prospective model would be an ITP that offers a more flexible mechanism for ensuring open access across the transmission systems of all FERC-jurisdictional utilities. ITPs would assume transmission responsibilities analogous to those of RTOs and ISOs but without the requirement of an expansive regional market. Under this structure, a utility or group of utilities would form an ITP and administer an OATT. To address rate pancaking concerns when transmission service spans multiple systems, FERC could require that customers purchasing transmission beginning in one ITP region and terminating in another be charged only the access charge of the destination ITP—that is, the system where electricity is delivered to load. Such a pricing structure would expand competitive opportunities by eliminating the cumulative access charges that currently impede long-distance transmission of electricity supply.

An alternative approach would preserve existing utility OATTs while enhancing the current framework under which utilities outside RTOs file individual tariffs. Under this option, bundled retail load would also be required to take service under the tariff, with each utility filing its own OATT at FERC. Bundled retail load would be treated as a “network customer” under the OATT, with the utility effectively paying itself for transmission service at the same rate as applies to all customers. FERC could further permit joint OATT filings by groups of utilities coordinating transmission service within a similarly enhanced framework.

As FERC looks to move the energy industry into the future, clarity of jurisdiction will ensure a smoother transition and greater equity around opportunities to participate in wholesale markets and provide just and reasonable rates, terms, and conditions for all customers.

Moreover, states will still have an important role in the energy system should FERC assert its jurisdiction over transmission rates. Pursuant to Order Nos. 1920 and 1920-A, states inform cost allocation methods in their regions, and they can

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191. 16 U.S.C. § 824(c); *New York v. FERC*, 535 U.S. at 31 (Thomas, J., concurring in part and dissenting in part) (citing ENERGY INFO. ADMIN., RESTRUCTURING OF THE ELECTRIC POWER INDUSTRY: A CAPSULE OF ISSUES AND EVENTS 6 (2000)).

continue to advocate before FERC on planning, cost allocation, and other transmission policies that affect their customers.<sup>192</sup> States will also continue to exercise their traditional authority over the siting and permitting of transmission facilities. In other words, while transmission rates would be addressed on a uniform federal basis, states would remain essential participants in shaping how transmission is planned, paid for, and built.

#### V. CONCLUSION: FERC MUST FINISH THE JOB

While challenges remain, after nearly thirty years of bifurcated transmission rates, the inadequacies of the system have become quite clear. Nearly seventy-five years ago, an energy professional wrote that, “[i]n the perilous years ahead a nonintegrated electric power industry is a luxury which the nation can scarcely afford.”<sup>193</sup> That warning still holds true today; America needs a grid to power America. Asserting federal jurisdiction over transmission rates is critical to developing that grid.

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192. See generally Order No. 1920-A, *supra* note 3 (describing provisions in the order on rehearing on the rule that provide a strong state role).

193. Gray, *supra* note 29, at 549.