United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued March 14, 2022 Decided August 9, 2022

No. 15-1183

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

HUDSON TRANSMISSION PARTNERS, LLC, ET AL.,
INTERVENORS

Consolidated with 15-1188, 16-1153, 19-1002, 20-1074, 20-1077, 20-1082, 20-1269, 20-1351, 20-1382

On Petitions for Review of Orders
of the Federal Energy Regulatory Commission

Richard P. Bress argued the cause for petitioners. With him on the joint briefs were *Neil H. Butterklee*, *Susan J. LoFrumento, Sebrina M. Greene, Gary D. Levenson, William R. Hollaway, Lucas C. Townsend, David L. Schwartz, Eric J. Konopka, Shannon M. Grammel, Lawrence G. Acker, Gary D. Bachman,* and *Michael Diamond. Elias G. Farrah* and *Andrew F. Neuman* entered appearances.

Kevin M. Lang, John Sipos, John C. Graham, and *Alina Buccella* were on the joint brief for intervenors City of New York and New York State Public Service Commission in support of petitioners.

Elizabeth E. Rylander, Attorney, Federal Energy Regulatory Commission, argued the cause for respondent. With her on the brief were *Matthew R. Christiansen*, General Counsel, *Robert H. Solomon*, Solicitor, and *Susanna Y. Chu*, Attorney.

David M. Gossett argued the cause for intervenors American Electric Power Service Corporation, et al. in support of respondent. With him on the joint brief were *John Longstreth, Donald A. Kaplan, Richard P. Sparling, Stacey Burbure, Cara J. Lewis,* and *Steven M. Nadel. Kenneth R. Carretta, Amanda R. Conner, Vilna W. Gaston, William M. Keyser III, Morgan Parke*, *Bradley Miliauskas*, and *P. Nikhil Rao* entered appearances.

No. 20-1079

NEW JERSEY BOARD OF PUBLIC UTILITIES,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY, ET AL.,
INTERVENORS

Consolidated with 20-1080, 20-1081

On Petitions for Review of Orders
of the Federal Energy Regulatory Commission

Alec Schierenbeck, Deputy State Solicitor, Office of the Attorney General for the State of New Jersey, argued the cause for petitioner. With him on the briefs were *Andrew J. Bruck*, Acting Attorney General, and *Paul Youchak* and *Nathaniel Levy*, Deputy Attorneys General. *Alex Moreau*, Deputy Attorney General, entered an appearance.

Susanna Y. Chu, Attorney, Federal Energy Regulatory Commission, argued the cause for respondent. With her on the brief were *Matthew R. Christiansen*, General Counsel, *Robert H. Solomon*, Solicitor, and *Elizabeth E. Rylander*, Attorney.

Lucas C. Townsend argued the cause for intervenors Consolidated Edison Company of New York, Inc., et al. in support of respondent. With him on the brief were *Neil H. Butterklee, Susan J. LoFrumento, Richard P. Bress, David L. Schwartz, Eric J. Konopka, Gary D. Levenson, William R. Hollaway, Lawrence G. Acker, Gary D. Bachman,* and *Brian M. Zimmet.*

Before: KATSAS and RAO, *Circuit Judges*, and SILBERMAN, *Senior Circuit Judge*.

Opinion for the Court filed PER CURIAM.

PER CURIAM: Part of the electricity transmission grid in northern New Jersey was aging, storm-damaged, and vulnerable to short circuits. In response, PJM Interconnection, LLC ("PJM")—the regional transmission organization responsible for managing the grid in New Jersey—authorized a series of upgrades to facilities owned by the Public Service Electric and Gas Company ("PSE&G"). One set of improvements centered on the transmission corridor between PSE&G's Bergen and Linden switching stations; a second involved repairs to and around PSE&G's Sewaren substation. Together, these two projects cost around $1.3 billion. Initially, PJM assigned most of the projects' costs to entities that reroute electricity from northern New Jersey into the New York market. Thereafter, the New York-based entities gave up their rights to withdraw electricity from New Jersey, and PJM reassigned their costs to PSE&G.

The Federal Energy Regulatory Commission ("FERC" or "the Commission") approved both rounds of cost allocations. The petitions for review in these two cases are about whether these cost allocations were "just and reasonable" under the Federal Power Act, 16 U.S.C. §§ 824d(a), 824e(a), and whether FERC's orders were "arbitrary [and] capricious" in violation of the Administrative Procedure Act ("APA"), 5 U.S.C. § 706(2)(A). In effect, they are about who must pay the bill.

I.

The thirteen petitions for review before us challenge twenty FERC orders, involve numerous parties, implicate a series of related legal issues, and arise from a complex procedural history. We begin by setting out the regulatory and factual background needed to understand these petitions.

A.

The Federal Power Act gives FERC "jurisdiction over facilities that transmit electricity in interstate commerce," *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255 (D.C.

Cir. 2018), and requires that the rates charged for such transmission be "just and reasonable," 16 U.S.C. § 824d(a). "For decades, the Commission and the courts have understood this requirement to incorporate a 'cost-causation principle'—the rates charged for electricity should reflect the costs of providing it." *Old Dominion*, 898 F.3d at 1255. "[A]lthough the Commission need not allocate costs with exacting precision, the costs assessed against a party must bear some resemblance to the burdens imposed or benefits drawn by that party." *Pub. Serv. Elec. & Gas Co. v. FERC* ("*Artificial Island*"), 989 F.3d 10, 13 (D.C. Cir. 2021) (cleaned up).

Utilities, independent system operators, and regional transmission organizations must seek approval from FERC for new rates through the process outlined in section 205 of the Federal Power Act. *See* 16 U.S.C. § 824d(d)–(e). Section 206 permits "the Commission [to] investigate—on its own initiative or based on a third-party complaint—whether an existing rate is 'unjust, unreasonable, [or] unduly discriminatory.'" *Artificial Island*, 989 F.3d at 13 (quoting 16 U.S.C. § 824e(a)). "[U]ndue discrimination occurs [where] entities [that] are similarly situated" are charged different rates for no discernable reason. *Mo. River Energy Servs. v. FERC*, 918 F.3d 954, 958 (D.C. Cir. 2019) (cleaned up). In a section 206 proceeding, if FERC finds the existing rate is "unjust, unreasonable, [or] unduly discriminatory," it must "determine the just and reasonable rate." 16 U.S.C. § 824e(a).

B.

These petitions arise out of the legal relationships between the parties as well as the FERC-approved method by which PJM allocates the costs of major infrastructure projects on its transmission grid.

1.

PJM is the regional transmission organization responsible for coordinating the transmission of electricity in the mid-Atlantic region, which stretches from North Carolina to New Jersey. The dominant electricity provider in northern New Jersey is PJM-member PSE&G. Across the Hudson River, the New York grid is managed by the New York Independent System Operator, Inc. ("NYISO"). Electricity in New York City is transmitted and sold by the Consolidated Edison Company of New York, Inc. ("ConEd") and the New York Power Authority ("NYPA"), among other utilities.

The PJM and NYISO grids are interconnected, with large quantities of electricity flowing between New Jersey and New York across the jurisdictional line. Two of the longstanding connections between these grids are central to the petitions before us. First, beginning in the 1970s, PSE&G entered into an electricity swapping agreement with ConEd. The parties clarified the terms of this "wheeling agreement" most recently in a 2009 settlement. *See PJM Interconnection, LLC*, 132 FERC ¶ 61,221 (2010) [ConEd-PSE&G Settlement Order]. Under the settlement, ConEd agreed to redirect 1,000 megawatts of electricity from upstate New York into PSE&G's transmission network in northern New Jersey; in return, PSE&G agreed to route the same amount of electricity from New Jersey into New York City. *Id.* at P 23. This wheeling agreement allowed ConEd to serve its customers in New York City without having to build a new transmission line into the city. *See id.* at P 2.

Second, because the prices of electricity on the PJM and NYISO grids sometimes diverge, a handful of "merchant transmission facilities" have sprung up to capitalize on the arbitrage opportunity. Two such facilities—Linden VFT, LLC

("Linden") and Hudson Transmission Partners, LLC ("Hudson")—are petitioners here. When prices in New Jersey are lower, Linden and Hudson reroute electricity from New Jersey into the New York market and resell it at a profit.[1] In order to provide reliable, on-demand service to their New York customers, Linden and Hudson have historically held "firm transmission withdrawal rights," which permit them to extract an agreed-upon amount of electricity from the PJM grid at (almost) any time.

2.

One of PJM's primary responsibilities is overseeing the coordinated development of the mid-Atlantic grid and apportioning the costs of major grid improvements among its member utilities.

In 2011, FERC's "Order No. 1,000" directed each planning region to select an *ex ante* "method, or set of methods, for allocating the costs of new transmission facilities selected in [its] regional transmission plan," and to submit their chosen method for FERC's approval. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 at P 558 (2011) [Order No. 1,000]; *see id.* at P 603. The Commission gave each region leeway to design its own cost allocation method, *id.* at PP 605–06, but set out six general cost allocation principles that are binding on all planning regions. As relevant here, Order No. 1,000 requires that every region's cost allocation method reflect the Federal Power Act's cost causation principle (Principle 1), and that the costs of any new project be assigned

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[1] Hudson's primary customer is NYPA. By contract, NYPA is responsible for the full costs of any improvements to the PJM grid that are assigned to Hudson.

only to parties within the project's planning region, unless a party outside the region agrees to assume costs (Principle 4). *Id.* at PP 622, 657. Order No. 1,000 required each region to use its *ex ante* cost allocation method only for "regional plan" projects—that is, projects undertaken to meet the region's minimum transmission capacity and grid reliability criteria. *See Old Dominion*, 898 F.3d at 1256.

Pursuant to Order No. 1,000, PJM developed an *ex ante* cost allocation method and incorporated it into its Open Access Transmission Tariff. For projects that improve grid reliability, PJM's method allocates half the costs of high-voltage facilities, and all the costs of low-voltage facilities, through a "flow-based method" called "solution-based distribution-factor analysis," or "DFAX." *See* PJM Tariff, Sched. 12(b)(iii). As explained further below, *see infra* Part IV.A.1, "[t]he flow-based method assigns costs based on how much each utility uses the facility in question over time," *Long Island Power Auth. v. FERC*, 27 F.4th 705, 711 (D.C. Cir. 2022); *see Artificial Island*, 989 F.3d at 14. Using proprietary software, the DFAX method models how electricity will flow across a new transmission facility at moments of peak grid use (i.e., at "peak load"), and assigns costs proportionally, based on the projected use of the facility by utilities in each "zone" of the PJM grid. PJM spreads the DFAX costs of regional plan projects over a number of years, to account for utilities' evolving use of the grid.

The DFAX method also assigns costs to entities that withdraw electricity from the PJM grid. Merchant transmission facilities like Linden and Hudson are assigned DFAX costs based on their firm withdrawal rights. *See* PJM Tariff, Sched. 12(b)(iii)(A)(3). In other words, the DFAX method assumes that when the grid is running at peak load, merchant transmission facilities will extract the full amount of electricity to which they are entitled. Similarly, the DFAX method assigns ConEd costs based on the assumption that, pursuant to its wheeling agreement with PSE&G, ConEd will withdraw 900 megawatts from the PJM grid when it is at peak load. *See id.* Sched. 12(b)(xi); ConEd-PSE&G Settlement Order, 132 FERC ¶ 61,221 at P 13.

FERC approved PJM's cost allocation method in 2013. *See PJM Interconnection, LLC*, 142 FERC ¶ 61,214 (2013).

C.

This brings us to the two projects at issue here. In 2013, PJM approved 26 related improvements to the transmission corridor between PSE&G's Bergen and Linden switching stations (collectively, "the Bergen project" or "Bergen"). The purpose of the Bergen project was not to increase the total amount of electricity that can flow across the PJM grid; rather, the project was approved to mitigate the risk of short circuits on PSE&G's facilities. Because the anticipated short circuits would overwhelm any commercially available circuit breaker, PJM directed PSE&G to expand the corridor into a double-circuit line capable of transmitting electricity at higher voltages. This solution to PSE&G's short-circuit issue incidentally protected the corridor against thermal overloads.

Around the same time, PJM approved three low-voltage subprojects to repair aging infrastructure in and around PSE&G's Sewaren substation ("the Sewaren project" or "Sewaren"). Hurricane Sandy had exposed Sewaren's vulnerability to inclement weather. These upgrades were meant to harden it against future storms and protect it from short circuits. Like Bergen, the Sewaren project was not approved to increase the overall transmission capacity of the PJM grid. Rather, both were "reliability projects" intended to make the grid's existing infrastructure more resilient.

D.

In 2014, PJM first assigned the costs of the Bergen and Sewaren projects in two section 205 filings. Those initial cost allocations triggered a long-running series of FERC proceedings that only recently concluded, giving rise to the petitions under review.

1.

We begin at the beginning, with PJM's 2014 rate filings. Pursuant to its Tariff, PJM allocated most of the costs of the Bergen project ($763 million, out of a total cost of $1.2 billion), and all the costs of the Sewaren project ($125 million), via DFAX.[2] PJM's 2014 filings assigned most of the DFAX costs for Bergen to ConEd ($629 million), with the remainder spread between Hudson ($69 million), PSE&G ($52 million), and Linden ($13 million). The costs of Sewaren, meanwhile, were split between ConEd ($64 million) and Linden ($61 million). In two subsequent 2015 and 2016 filings, PJM reallocated Bergen's DFAX costs to reflect the project's evolving design and updated grid-use data.[3]

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[2] Most of the Bergen subprojects were high-voltage; a few were low-voltage. For the former, half the costs were allocated on a *pro rata* basis—"based on the level of customer demand within each zone" on the PJM grid—rather than through DFAX. *Old Dominion*, 898 F.3d at 1256; *see* PJM Tariff, Sched. 12(b)(i)(A)(1). Those *pro rata* cost allocations are not at issue in the petitions before us.

[3] In early 2015, PJM changed its Tariff's cost allocation method for projects, like Sewaren, that are added to the regional plan to meet the planning standards of individual utilities. *See PJM Interconnection, LLC*, 154 FERC ¶ 61,096 at PP 2, 12 (2016). Beginning in 2015, therefore, PJM ceased assigning Sewaren's costs via DFAX.

Over the protests of ConEd, Linden, Hudson, and NYPA, FERC accepted each of the four cost allocations. The protestors argued that the DFAX method was built on certain modeling conventions that systematically distorted the cost assignments for the Bergen and Sewaren projects, minimizing PSE&G's cost responsibility and magnifying theirs.[4] *See infra* Part IV. More fundamentally, they argued that PJM's rate filings violated the cost causation principle: the goal of these projects was to make PSE&G's infrastructure more reliable, yet parties other than PSE&G had been assigned the vast majority of the costs. Finally, they protested that the Tariff gave PJM discretion to adjust any "objectively unreasonable" DFAX cost allocation, but that PJM had unfairly declined to exercise that discretion in the filings at issue. PJM Tariff, Sched. 12(b)(iii)(G).

In response, FERC explained that it had previously approved DFAX as a just and reasonable cost allocation method. PJM had properly applied this cost allocation method in the contested filings, so they were *per se* just and reasonable. Because "[t]he reasonableness of the Solution-Based DFAX methodology is beyond the scope of [a section 205] proceeding," FERC declined to scrutinize the DFAX method's modeling conventions. *PJM Interconnection, LLC*, 147 FERC ¶ 61,028 at P 43 (2014). Finally, FERC agreed with PJM that

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[4] The protestors argued that, by design, the DFAX method arbitrarily favors large utilities like PSE&G at the expense of smaller entities. More specifically, they insisted that it was not just and reasonable for PJM's Tariff (1) to exempt from DFAX costs any utility whose flows across a facility are *de minimis* compared to its overall flows on the PJM grid; (2) to "net" total flow, such that a utility's positive and negative electric flows cancel each other out; and (3) to base DFAX costs on how electricity flows across the grid at peak load.

the Tariff did not give it the discretionary authority to adjust DFAX costs *ex post*.

2.

Meanwhile, shortly after PJM made its initial 2014 filings, ConEd and Linden each lodged section 206 complaints. First, they again objected to the structural assumptions on which the DFAX method was built. Second, they argued that it was not just and reasonable to use DFAX to assign the Bergen and Sewaren projects' costs. Most projects selected for PJM's regional plan are "flow-based"—they are approved in response to pent-up transmission demand and expand the total amount of electricity that can flow across the PJM grid. DFAX was designed with such projects in mind, on the grounds that utilities should pay for grid expansions based on their use of the grid's increased capacity. But Bergen and Sewaren were categorically distinct; they are "non-flow-based." The short-circuit issues they resolved were not caused by excessive electricity flows across PSE&G's facilities, and the utilities who benefited from their resolution were different from those whose electricity flows across the upgraded facilities. The DFAX method therefore failed to match the costs of these projects to their beneficiaries, as required by the Federal Power Act.

FERC addressed ConEd's complaint first. The policy behind Order No. 1,000, it explained, was to establish a clear, *ex ante* cost allocation method for major infrastructure projects in each planning region. To that end, PJM's Tariff did not give it discretion to apply different cost allocation methods to different kinds of reliability projects. FERC also found that the DFAX method reasonably identified the beneficiaries of non-flow-based projects, and so rejected the argument that the DFAX method was unsuited to Bergen and Sewaren. *See*

Consol. Edison Co. of N.Y., Inc., 151 FERC ¶ 61,227 at PP 54–55 (2015) [ConEd Complaint Order].

In 2016, FERC reaffirmed this position on rehearing, *see Consol. Edison Co. of N.Y., Inc.*, 155 FERC ¶ 61,088 at PP 40–42 (2016) [ConEd Complaint Rehearing Order], and rejected Linden's complaint for the same reasons, *see Linden VFT, LLC*, 155 FERC ¶ 61,089 at PP 54–58 (2016) [First Linden Complaint Order]. In addition, FERC upheld the DFAX method's modeling conventions as just, reasonable, and not unduly discriminatory. *See* ConEd Complaint Rehearing Order, 155 FERC ¶ 61,088 at PP 45–46, 49.

Importantly, at the same time it rejected ConEd and Linden's complaints, FERC also affirmed the use of DFAX in a closely related proceeding, which concerned the costs of a third non-flow-based project in southern New Jersey ("the Artificial Island project" or "Artificial Island"). *See Del. Pub. Serv. Comm'n*, 155 FERC ¶ 61,090 at PP 65–73 (2016) [Artificial Island Order].

3.

Soon after FERC denied its rehearing application, ConEd notified PSE&G that it planned to allow their wheeling agreement to lapse. PJM thereafter submitted a fifth cost allocation, to take effect after the wheeling agreement ended. This 2017 filing eliminated ConEd's cost liability entirely, placing Bergen's DFAX costs onto Hudson ($634 million), Linden ($132 million), and PSE&G ($128 million). The New Jersey Board of Public Utilities ("the Board") objected to the filing on behalf PSE&G's customers; Linden, Hudson, and NYPA objected as well. Linden also lodged a section 206 complaint, protesting the cost reallocation. FERC preliminarily accepted PJM's 2017 filing, but did not substantively address the cost allocation or Linden's second complaint for another three years.

Meanwhile, Hudson and Linden also took steps to extricate themselves from cost liability for the Bergen project. PJM's Tariff assigns DFAX costs to merchant transmission facilities only if they hold firm withdrawal rights, which entitle them to extract electricity from the PJM grid on demand. *See* PJM Tariff, Sched. 12(b)(iii)(A)(3). Hudson and Linden asked PJM to convert their firm withdrawal rights to non-firm ones, which would absolve them of DFAX costs for Bergen going forward. The New Jersey Board intervened in the ensuing proceedings, protesting that the proposed conversions would unfairly foist Bergen's entire cost onto PSE&G. But FERC found "no reasonable basis" for preventing Hudson and Linden from converting their withdrawal rights to non-firm ones. *Linden VFT, LLC*, 161 FERC ¶ 61,264 at P 24 (2017) [Linden Conversion Order]; *PJM Interconnection, LLC*, 161 FERC ¶ 61,262 at P 42 (2017) [Hudson Conversion Order].

Soon thereafter, the New Jersey Board brought a section 206 complaint. It argued that although ConEd, Linden, and Hudson were Bergen's primary beneficiaries, PJM had unfairly allowed them to evade cost responsibility after construction had begun, leaving local ratepayers to foot the bill. FERC disagreed. Under Order No. 1,000, PJM had no authority to place Bergen's costs on ConEd—a utility based outside the PJM region—after the wheeling agreement lapsed. FERC also approved the part of PJM's Tariff allocating DFAX costs only to merchant transmission facilities with firm withdrawal rights. Since PJM does not have to account for non-firm withdrawal rights in planning its grid, it made sense to exempt facilities with such rights from DFAX costs. FERC concluded that the Tariff's cost allocation method was just and reasonable and had been properly applied in the circumstances. *See N.J. Bd. of*

Pub. Utils., 163 FERC ¶ 61,139 at P 50 (2018) [Board Complaint Order], *reh'g denied*, 170 FERC ¶ 61,180 (2020) [Board Complaint Rehearing Order].

4.

In 2018, FERC granted rehearing in the Artificial Island proceeding—the same complaint it had earlier rejected. *See Artificial Island*, 989 F.3d at 15–16 (recounting FERC's volte-face). The Artificial Island project was intended to stabilize three nuclear generators in southern New Jersey. Like the short-circuit issues remedied by the Bergen and Sewaren projects, the stability issue that prompted the Artificial Island project was not caused by pent-up transmission demand. All three projects, in other words, were "non-flow-based." After reconsidering its initial Artificial Island order, FERC determined that the beneficiaries of at least some non-flow-based projects—namely, those addressing stability issues—are "not necessarily captured" by the DFAX method. *Del. Pub. Serv. Comm'n*, 164 FERC ¶ 61,035 at P 41 (2018) [Artificial Island Rehearing Order], *reh'g denied*, 166 FERC ¶ 61,161 (2019) [Artificial Island Second Rehearing Order]. It therefore directed PJM to adopt a different cost allocation method for stability related projects. *See* Artificial Island Rehearing Order, 164 FERC ¶ 61,035 at P 42; Artificial Island Second Rehearing Order, 166 FERC ¶ 61,161 at P 43.

In 2020, FERC disposed of the outstanding filings and complaints related to the Bergen and Sewaren projects. First, it denied rehearing of Linden's first complaint, which challenged PJM's 2014 cost allocations. FERC continued to find that the DFAX method's modeling conventions were just, reasonable, and nondiscriminatory, and that DFAX reasonably captured the beneficiaries of short-circuit projects like Bergen and Sewaren. *See Linden VFT, LLC*, 170 FERC ¶ 61,122 at

PP 41, 44, 47 (2020) [First Linden Complaint Rehearing Order].

Second, FERC approved PJM's 2017 cost reallocation—the cost distribution that came into effect after the end of ConEd's wheeling agreement—and denied Linden's second complaint (protesting the same cost allocation). *See PJM Interconnection, LLC*, 170 FERC ¶ 61,124 at PP 33–35 (2020) [Cost Reallocation Order]; *Linden VFT, LLC*, 170 FERC ¶ 61,123 at PP 31–35 (2020) [Second Linden Complaint Order]. In a rehearing application contesting both orders, Linden argued that "the use of the solution-based DFAX method to allocate costs for a non-flow-based project was unjust and unreasonable." *PJM Interconnection, LLC*, 172 FERC ¶ 61,176 at P 14 (2020) [Second Linden Complaint Rehearing Order]. The Bergen project "addresses a non-flow related reliability issue," just like the non-flow-based stability issue in Artificial Island, but FERC had treated the two projects differently. *Id.* at P 22. In response, FERC explained that it had made a one-time exception in Artificial Island for stability related projects, and that no such carve-out was warranted for short-circuit projects. *See id.* at PP 22–24. FERC also reiterated that the DFAX method's modeling conventions were just, reasonable, and nondiscriminatory. *See id.* at PP 27–29.

E.

As FERC successively denied their rehearing applications, ConEd, Linden, Hudson, and NYPA (collectively, "the New York entities") petitioned for review of FERC's orders approving PJM's five cost allocations from 2014 to 2017, as well as its orders denying ConEd's complaint and Linden's two complaints. Before they had extricated themselves from cost liability for the Bergen and Sewaren projects, the New York entities had been assessed approximately $115 million in costs.

The petitions in *Consolidated Edison Co. of New York, Inc. v. FERC* ("*ConEd v. FERC*") challenge FERC's approval of those already-paid costs. The City of New York and the New York State Public Service Commission have intervened on behalf of the New York entities, arguing against the cost allocations; a group of transmission owners, including PSE&G, have intervened on behalf of FERC, arguing in favor of the cost allocations.

The New Jersey Board petitioned for review of FERC's orders permitting Linden and Hudson to convert their firm withdrawal rights to non-firm ones, as well as its orders denying the Board's complaint. The petitions in *New Jersey Board of Public Utilities v. FERC* ("*New Jersey Board v. FERC*") concern PJM's reassignment of Bergen's DFAX costs to PSE&G—and, by extension, New Jersey ratepayers—beginning in 2017. ConEd, Linden, Hudson, NYPA and NYISO have intervened on FERC's behalf, in favor of the post-2017 cost allocations; PSE&G has intervened on the Board's behalf, arguing against the post-2017 cost allocations.

The New York entities and New Jersey Board both claim that FERC's myriad orders ran afoul of the APA and violated the Federal Power Act's cost causation and nondiscrimination principles. With two inconsequential exceptions, we have jurisdiction over their petitions under 16 U.S.C. § 825*l*(b).[5]

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[5] The petition in No. 20-1269 sought review of the Second Linden Complaint Order after the parties' application for rehearing was deemed denied by operation of law. *See* 16 U.S.C. § 825*l*(a). Because that petition was untimely filed, we dismiss it for lack of jurisdiction. *See id.* § 825*l*(b). That dismissal has no practical consequence, however, because after FERC affirmatively rejected the parties' application for rehearing of the same order years later,

II.

This court must set aside any order of the Commission that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(A). "In matters of ratemaking, our review is highly deferential, as issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission." *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1347 (D.C. Cir. 2009) (cleaned up). FERC's ratemaking orders will not stand, however, if they are "either unreasonable or inadequately explained." *Artificial Island*, 989 F.3d at 17 (cleaned up). FERC's reasoning must be grounded in "substantial evidence," 16 U.S.C. § 825*l*(b), which is "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion," *Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1309 (D.C. Cir. 2015) (cleaned up).

III.

The New York entities argue that FERC failed to reasonably explain why the DFAX method should be used to

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they again petitioned for review—this time in a timely fashion, in No. 20-1351.

Similarly, we dismiss the petition in No. 20-1077, which seeks review of FERC's orders preliminarily accepting PJM's 2017 cost reallocation, for lack of jurisdiction. "The decision to accept a rate filing" without approving its lawfulness "is undeniably interlocutory" and therefore unreviewable. *Papago Tribal Util. Auth. v. FERC*, 628 F.2d 235, 240 (D.C. Cir. 1980). Again, however, this dismissal is inconsequential, since FERC's final approval of PJM's 2017 filing is properly before us in No. 20-1382, which seeks review of the Cost Reallocation Order.

allocate the costs of the Bergen and Sewaren projects, but should not be used to allocate the costs of a similar project in Artificial Island. We agree.

A.

In 2016, FERC determined that DFAX was an appropriate method of assigning costs for all the projects selected for PJM's regional plan, whether they were flow-based or non-flow-based. Within that latter category, FERC specifically found that DFAX was appropriate even if "a short-circuit or stability violation is the [project's] primary driver." ConEd Complaint Rehearing Order, 155 FERC ¶ 61,088 at P 41. It therefore reasoned that PJM had properly used the DFAX method to assign the costs of the three non-flow-based projects before it—Bergen and Sewaren (short-circuit projects) and Artificial Island (a stability project). "The solution-based DFAX method," FERC explained, does not turn on "the immediate [problem] that drove the need for the project." *Id.* at P 40. While "the initial nature of the problem may not necessarily be related or entirely related to flows," DFAX still identifies the utilities that will use the new facilities and appropriately assigns them costs. *Id.* FERC therefore refused to create new cost allocation methods for different kinds of non-flow-based projects (stability projects, short-circuit projects, etc.). "[S]uch a case-by-case … approach," it found, "would create the same uncertainty that *ex ante* cost allocation is intended to avoid." ConEd Complaint Order, 151 FERC ¶ 61,227 at P 55.

By the time FERC issued its 2020 orders regarding the cost allocations for Bergen and Sewaren, however, it had reversed its position regarding the Artificial Island project. On rehearing in 2018, FERC distinguished between flow-based projects on the one hand and stability related projects like Artificial Island on the other. Flow-based problems, such as "thermal overload and voltage related reliability issues," are caused by excessive electricity flows across a facility, and are therefore resolved by expanding the grid's transmission capacity. Artificial Island Rehearing Order, 164 FERC ¶ 61,035 at P 39. As a result, "the change in power flows [is] consistent with the intended solution." *Id.* (quoting a PJM filing). DFAX reasonably picks out the beneficiaries of such a project because the utilities that use the upgraded facility are the same ones whose ability to transmit electricity was formerly constrained. *See id.*

By contrast, FERC explained that a stability related problem like the one in Artificial Island is not caused by excessive demand (i.e., it is "non-flow-based"). While such a problem can be solved by expanding the grid's overall transmission capacity, the utilities that use that new capacity are not necessarily the beneficiaries of a stability related project. Thus, although the "DFAX method will reveal parties' use of the new transmission facility, such use is neither connected with the need for the project, nor provides benefits to the parties being assigned cost responsibility." Artificial Island Second Rehearing Order, 166 FERC ¶ 61,161 at P 38. FERC therefore concluded that while DFAX is just and reasonable for allocating the costs of flow-based projects, it was not similarly appropriate for allocating the costs of non-flow-based projects addressing stability issues. Artificial Island Rehearing Order, 164 FERC ¶ 61,035 at PP 38–41.

B.

The New York entities argue that FERC should have extended this same logic to the Bergen and Sewaran projects. FERC, they say, failed to explain why it continued to apply the DFAX method to Bergen and Sewaren, even after directing PJM to use a different method for Artificial Island. All three projects addressed non-flow-based issues, so their costs should all have been allocated similarly.[6] "A fundamental norm of administrative procedure requires an agency to treat like cases alike. If the agency makes an exception in one case, then it must either make an exception in a similar case or point to a relevant distinction between the two cases." *Westar Energy, Inc. v. FERC*, 473 F.3d 1239, 1241 (D.C. Cir. 2007).

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[6] The New York entities raised this objection directly in their application for rehearing of the Second Linden Complaint Order and the Cost Reallocation Order. *See* Second Linden Complaint Rehearing Order, 172 FERC ¶ 61,176 at P 22. However, they did not similarly cite Artificial Island when applying for rehearing of the First Linden Complaint Order, instead arguing generally that "a flow-based method is the wrong way to measure benefits for non-flow based reliability concerns, such as the short-circuit concerns underlying [Bergen and Sewaren]." First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 41.

Ordinarily, we lack jurisdiction to consider an argument not raised before FERC on rehearing "with specificity." *Ameren Servs. Co. v. FERC*, 893 F.3d 786, 793 (D.C. Cir. 2018) (cleaned up). In this case, however, FERC did not change its position in Artificial Island until after the parties had applied for rehearing of the First Linden Complaint Order, so they have a "reasonable ground" for failing to specifically raise the issue. 16 U.S.C. § 825*l*(b). At the time FERC issued the First Linden Complaint Rehearing Order, it had been considering Artificial Island's cost allocations alongside Bergen's and Sewaren's for six years and had only recently changed its approach in Artificial Island. In that context, the parties' general argument that DFAX is unsuited to non-flow-based projects was sufficient to alert FERC to the need to distinguish its recent decision in Artificial Island from the position it initially took with respect to Bergen and Sewaren in 2016. We therefore have jurisdiction to consider whether, in the First Linden Complaint Rehearing Order, FERC acted arbitrarily in treating Bergen and Sewaren differently from Artificial Island.

In attempting to distinguish the Bergen and Sewaren projects from Artificial Island, FERC claimed it had "not ma[de] a generalized finding regarding all non-flow-based constraints," Second Linden Complaint Rehearing Order, 172 FERC ¶ 61,176 at P 23, but instead had made a narrow exception for stability related projects, which are "analytically unique," *id.* at P 24 (citing Artificial Island Rehearing Order, 164 FERC ¶ 61,035 at P 40). FERC explained that in order to resolve the short-circuit issues on the Bergen-Linden corridor, PSE&G had expanded the corridor into a double-circuit line capable of greater electricity flows. This "reconfigur[ation] [of] the transmission system" was "similar to the planning process for resolving thermal overloads," which are flow-based. *Id.*; *cf.* First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 41. According to FERC, in other words, the solution PJM adopted for Bergen made it *like* a flow-based project, and DFAX was therefore an appropriate way to assign its costs. Second Linden Complaint Rehearing Order, 172 FERC ¶ 61,176 at P 24.

But in Artificial Island, FERC did not find that stability projects are "analytically unique" in the abstract. Rather, it found that "stability is analytically unique *compared to voltage or thermal overload problems*," which are both flow-based. Artificial Island Rehearing Order, 164 FERC ¶ 61,035 at P 38 (emphasis added). In other words, FERC contrasted the mine-run of flow-based projects on the PJM grid on the one hand with the specific, non-flow-based stability project at Artificial Island on the other. But in the Artificial Island proceeding FERC said nothing about whether—like stability projects—short-circuit projects should also be treated differently from flow-based projects. In fact, the testimony on which it relied recognized *both* "the short circuit issue and the stability issue" as awkward fits for the DFAX method, because neither are flow-based. J.A. 1091–92.[7] Therefore, FERC could not rationally explain its decision to treat Bergen and Sewaren differently from Artificial Island by simply pointing to its earlier finding that "stability is analytically unique compared to voltage or thermal overload problems." Instead, FERC needed to explain why stability is "analytically unique" *compared to short-circuit issues*.

FERC failed to do so. It conceded that, like the stability issue at Artificial Island, "short-circuit problems are not directly caused by flow overloads on a facility." First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 41. Nonetheless, FERC reasoned that DFAX should still be used to assign Bergen's costs because Bergen was similar to a thermal overload project. FERC did not adequately explain why that similarity mattered. Short-circuit issues, not thermal overloads, were the primary impetus for Bergen. While Bergen expanded the grid's overall capacity, the same is true of Artificial Island. In both cases, the increased capacity incidentally benefited the utilities whose electricity flows across the new facilities. Critically, however, other parties also benefited in both cases. After Bergen's completion, PSE&G benefited from facilities that are resistant to short circuits, while other grid users also benefited from protection against the second-order effects of short circuits. Likewise, in Artificial Island, FERC recognized that the utilities that relied on the generators at issue benefited from their improved stability. *See* Artificial Island Second Rehearing Order, 166 FERC ¶ 61,161 at P 39.

Pointing to those other beneficiaries, FERC concluded in Artificial Island that the utilities whose electricity flows across

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[7] In this Part and Part IV, citations to the joint appendix refer to the one in *ConEd v. FERC*.

facilities built to address stability issues should not be assigned costs via DFAX; instead, it reallocated Artificial Island's DFAX costs to the utilities that depended on the newly stabilized nuclear generators. *See id.* at PP 13, 43. Here, by contrast, FERC used DFAX to assign the costs of Bergen and Sewaren to the utilities whose electricity flows across PSE&G's facilities—even though, like Artificial Island, those projects also conferred non-flow-based benefits to other entities. Given the similarities between the projects, basic rule of law principles required FERC to justify its different treatment of the projects. It needed to explain why, in contrast to Artificial Island, the costs of Bergen and Sewaren should be assigned via DFAX to the utilities whose electricity flows across the upgraded facilities, rather than to the projects' other beneficiaries.

We do not hold that the use of the DFAX method for short-circuit projects violates the cost causation principle *per se*. On remand, FERC may be able to provide a more satisfactory explanation of the distinction between stability related projects and those that address short-circuit issues and to articulate why DFAX cost allocations are appropriate for the latter but not the former. But the Commission "must provide an adequate explanation to justify treating similarly situated parties differently." *Comcast Corp. v. FCC*, 526 F.3d 763, 769 (D.C. Cir. 2008). It failed to do so here.

IV.

In addition to challenging the application of the DFAX method generally, the New York entities attack three specific conventions used in it: the *de minimis* threshold, netting, and the peak-load assumption.

A.

We begin with the *de minimis* threshold.

1.

The DFAX method divides the costs of a transmission facility among zones in proportion to each zone's use of the facility. *See* First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 7. For the facility in question, PJM first uses certain models, which estimate the flow of electricity at peak demand, to determine what it calls the "distribution factor" of each zone. The distribution factor for a zone represents the zone's use of the facility divided by the zone's total load or use of all facilities on the PJM grid. PJM Tariff, Sched. 12(b)(iii)(A). For example, if a zone uses 1,000 megawatts of electricity from a facility and its total load is 10,000 megawatts, then its distribution factor for the facility is 0.1 or 10%.

PJM then performs various arithmetic calculations to assign costs based on each zone's use of the facility at issue. First, it multiplies the distribution factor of a zone by its total load, which yields the zone's use of the facility. *Id.* Sched. 12(b)(iii)(B)(1). In the example above, the zone's use of the facility would be 1,000 megawatts. Second, PJM divides that number by all zones' use of the facility. *Id.* Sched. 12(b)(iii)(B)(2). For example, if a zone uses 1,000 of the 5,000 megawatts from a facility, PJM calculates a quotient of 0.2. Third, PJM multiplies that quotient by the total cost of the facility to produce the relevant cost allocation. *Id.* Sched. 12(b)(iii)(B)(5). If the facility in this example costs $1 million, PJM would allocate $200,000 in costs to the zone.

The *de minimis* threshold adds an important qualification to this process. In FERC's view, zones that receive very small benefits from a facility should be assigned no costs for it. First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 44. To that end, zones with a distribution factor below 1% are deemed to have no flows over the facility and thus are assigned no costs. PJM Tariff, Sched. 12(b)(iii)(A)(6). Because distribution factors measure a zone's use of a facility *relative to its total load*, the *de minimis* exception depends on the size of the zone, not on the zone's share of the facility's total flow. For example, suppose a zone uses 9 megawatts of a facility's total flow of 30 megawatts. Although the zone uses nearly a third of total flow, its use will be deemed *de minimis* if, say, the zone itself has a total load of 1,000 megawatts (which corresponds to a distribution factor of 0.9%). In that event, the sheer size of the zone will cause it to be assigned no costs.

2.

As implemented through distribution factors, the *de minimis* threshold thus operates as a too-big-to-pay rule. We agree with the New York entities that this violates the cost causation principle and causes undue discrimination. The cost causation principle requires "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004). And undue discrimination occurs when similarly situated entities are charged different rates for no good reason. *Mo. River Energy Servs.*, 918 F.3d at 958. As explained above, the *de minimis* threshold exempts zones from bearing any costs based on their load size—a quality unrelated to the burdens they impose on or the benefits they receive from any individual facility. And in so doing, it unduly discriminates against small zones, which must absorb higher cost allocations after large zones are exempted.

Peak load sizes vary greatly across the relevant zones, which makes the *de minimis* exception border on absurd. For instance, the peak load of PSE&G is about 11,000 megawatts, whereas PJM assigned Linden and Hudson peak loads of only 330 and 320 megawatts respectively. So if PSE&G used 100 megawatts of flow across a transmission facility (yielding a distribution factor slightly under 1%), and if Hudson had 4 megawatts of flow across the same facility (yielding a distribution factor slightly over 1%), then PSE&G but not Hudson would be exempt from paying any of the facility's costs, even though PSE&G derived 25 times more of the benefits. And because the large PSE&G would not have to pay any costs of the facility, the small Hudson would have to bear a substantially greater share of those costs.

PJM's allocations for the Bergen project illustrate this dynamic. For one subproject, the DFAX method determined that PSE&G received 65.5% of the benefits, while ConEd and Hudson together received only about 16%. Yet after applying the *de minimis* threshold, PSE&G was removed from the cost allocation, and so ConEd and Hudson were assigned 99.98% of the upgrade costs. J.A. 1018–20. And after ConEd withdrew from its wheeling agreement, PSE&G received 72.7% of the subproject's benefits and Hudson only 6%. Yet the *de minimis* threshold excluded PSE&G from any cost allocation, and Hudson then became responsible for 99.98% of the upgrade costs. *Id.* at 1404–07. Other examples abound. *See*, *e.g.*, *id.* at 1022–23 (PSE&G received 46% of a subproject's benefits and ConEd only 27%, yet ConEd was allocated 100% of its costs); *id.* at 1295 (listing nine subprojects for which Hudson received between 6% and 16% of the benefits, but was allocated over 99% of the costs); *id.* at 1408–09 (subproject for which Linden and Hudson received 33% of the benefits, but were allocated 100% of the costs). This scheme plainly violates the rule that FERC "may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse." *Old Dominion*, 898 F.3d at 1255 (cleaned up). Because the *de minimis* threshold regularly produces "wholesale departure[s] from the cost-causation principle," it cannot be considered just and reasonable. *See id.* at 1261.

3.

FERC asserted three justifications for the *de minimis* threshold, but none is persuasive.

First, it observed that the threshold identifies "entities that have relatively little use of the transmission facility relative to their load." First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 44. Similarly, the intervenors supporting FERC characterize the threshold as a measure of relative reliance—i.e., the degree to which a zone depends on one facility instead of others—as opposed to relative use. These are accurate statements of how the threshold works, but they are not justifications for a threshold keyed to the relative size of the zone, rather than to the relative use of the facility.

Second, FERC denied that the *de minimis* threshold depends on a zone's size. *Id.* at P 45. The Commission is correct that the threshold is keyed to a distribution factor, which measures the shift in power over a transmission facility when a zone's peak load is increased by one megawatt, regardless of its size. PJM Tariff, Sched. 12(b)(iii)(A). But this measurement is done precisely because the resulting distribution factor will measure "use *by the load* of each Zone." *Id.* (emphasis added). FERC's second rationale is thus wrong as well as inconsistent with its first, which claimed support from the fact that the *de minimis* threshold identifies zones with small use relative to their load.

Third, FERC noted that the DFAX analysis is performed annually, so "the zones that qualify for the *de minimis* exemption may change" over time. First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 45. We are at a loss to understand how that fact, reflecting the truism that things change, bears on whether the exception here is reasonably related to project costs or benefits.

B.

We now turn to netting. For zones with many delivery points, PJM "nets" the flows to each delivery point to calculate total flow. PJM Tariff, Sched. 12(b)(iii)(A)(4). Electricity can flow in both positive and negative directions. PJM assigns a negative value to flows in the negative direction, which decreases a zone's total flow. For instance, a zone with one delivery point that receives +100 megawatts and another that receives +50 megawatts will be deemed to have net flows of +150 megawatts. But a zone with one delivery point that receives +100 megawatts and another that receives −50 megawatts will be deemed to have net flows of only +50 megawatts. The New York entities challenge this offsetting of positive and negative flows.

1.

The New York entities contend that netting violates the cost causation principle and unduly discriminates against them. Transmission facilities benefit zones by bringing electricity to their delivery points, and this benefit is the same regardless of whether the electricity flows in the positive or negative direction. But netting causes markedly different cost allocations. If a zone with one delivery point receives +150 megawatts, while another with two delivery points receives flows of +100 and −50 megawatts at each point respectively, the former zone will pay three times as much as the latter for the same benefit. The New York entities contend that this discrepancy systematically favors large zones like PSE&G, which have many delivery points and so are more likely to have offsetting positive and negative flows. In contrast, each merchant transmission facility has only one delivery point and so cannot benefit from netting.

FERC approved netting because it produces a different benefit by creating extra capacity for the transmission line. Because "power flows in opposite directions offset each other," a zone's "negative flows decrease the amount of power flowing over the line and make additional capacity available." First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 49. For instance, a transmission facility with 75 megawatts of capacity cannot accommodate +100 megawatts of flows in the absence of counterflows. But with the addition of −50 megawatts of counterflows, the net flow is only +50 megawatts, and the facility can accommodate all the flows. FERC concluded that zones with flows in only one direction should bear more costs for using up more capacity.

This conclusion is reasonable. Because counterflows increase capacity, FERC could reasonably treat them as benefits that the zones confer on the facility, rather than benefits that they derive from it. So understood, counterflows can reasonably be considered a basis for discounting rather than increasing a zone's cost allocation. On this point, we do not suggest that FERC's approach is the only reasonable one. But because it is reasonable, we must uphold it on deferential review. *See Old Dominion*, 898 F.3d at 1260.

The New York entities raise two further objections. They contend that FERC's defense of netting is inconsistent with PJM's rationale for replacing its previous cost allocation method with the present DFAX method. And they claim it is unduly discriminatory to net *within* a zone but not *across* zones. The entities did not raise either objection in their applications for rehearing, so we do not have jurisdiction to consider them. 16 U.S.C. § 825*l*(b); *see Ameren Servs. Co. v. FERC*, 893 F.3d 786, 793 (D.C. Cir. 2018).

2.

After FERC issued the orders under review, another merchant transmission facility owner filed a section 206 complaint challenging the netting and *de minimis* provisions of PJM's Tariff. *Neptune Reg'l Transmission Sys., LLC*, 175 FERC ¶ 61,247 at PP 1, 4, 8 (2021). Following its preliminary review in Neptune, FERC undertook to "look anew" at whether both provisions "have become unjust and unreasonable," and it ordered further proceedings to do so. *Id.* at PP 45–46.

The New York entities request a remand for FERC to reconsider netting here, given its Neptune order. But we evaluate agency action "at the time of decision," *PBGC v. LTV Corp.*, 496 U.S. 633, 654 (1990), and an agency decision "is not arbitrary or capricious merely because it is not followed in a later adjudication," *MacLeod v. ICC*, 54 F.3d 888, 892 (D.C. Cir. 1995). Despite this, the entities note, we have sometimes remanded if the agency has changed the rule underlying a decision pending review. *See Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 62–63 (D.C. Cir. 1999). But FERC did not reject netting in Neptune; it merely ordered further proceedings to examine the practice in greater detail. A remand here is thus unwarranted.

We hold only that FERC reasonably explained its decision to approve netting in these proceedings. In doing so, we do not prejudge Neptune, and we do not foreclose the Commission from reconsidering its position on netting given whatever evidence and arguments may be developed in that case.

C.

Finally, we address the peak-load assumption. When modeling the flow of electricity, PJM assumes that each zone is at its peak demand. For merchant transmission facilities, this means PJM assumes that they are exercising their full firm withdrawal rights. PJM Tariff, Sched. 12(b)(iii)(A)(3). The merchant transmission facilities object that this assumption overestimates their use of the transmission facilities, because they generally do not reroute electricity into New York City when demand in New Jersey is at its peak. FERC acknowledged that merchant transmission facilities may be less likely than other zones to exercise full delivery rights at times of peak demand. Nonetheless, it found the assumption reasonable because PJM must be able to meet peak load to guarantee system reliability. First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 15. The entities complain this explanation is inconsistent with FERC's defense of netting, which the Commission justified as "realistically reflect[ing] how energy flows on an integrated transmission system." *Id.* at P 14. If FERC evaluates netting based on how electricity realistically flows, the challengers contend, it should do the same for the peak-load assumption.

We see no inconsistency. Maintaining grid reliability is one of a system operator's most important goals, *Blumenthal v. FERC*, 552 F.3d 875, 879 (D.C. Cir. 2009), so PJM could reasonably plan for a worst-case scenario in which all zones exercise their full delivery rights. But even under that scenario, positive and negative flows still would offset each other and thus create additional capacity. As explained above, FERC may reasonably take that fact into account in deciding whether to add or subtract opposite-direction flows.

V.

Finally, the New York entities challenge FERC's interpretation of the PJM Tariff. They contend that the Tariff requires a departure from the DFAX method if its application would violate the cost causation principle. We disagree.

The interpretive dispute centers on the interplay between Schedule 12(b)(iii) of the Tariff, which outlines how to carry out the DFAX analysis, and paragraph (G) of that provision, which confers some discretion to depart from the prescribed methodology. Under that paragraph, if PJM "determines in its reasonable engineering judgment that … the DFAX analysis cannot be performed or that the results of such DFAX analysis are objectively unreasonable," it "may use an appropriate substitute proxy for the Required Transmission Enhancement in conducting the DFAX analysis." The New York entities maintain that "objectively unreasonable" results include ones that do not conform to the cost causation principle. And in their view, an "appropriate substitute proxy" includes a different cost allocation methodology.

FERC read paragraph (G) differently. It objects that the New York entities invite an *ex post* allocation inquiry that is both standardless and contrary to Order No. 1,000's requirement that costs be assigned *ex ante*. First Linden Complaint Rehearing Order, 170 FERC ¶ 61,122 at P 55. According to FERC, results of the DFAX analysis are "objectively unreasonable" only if the flows it models "are not consistent with the normal expected flow results that an engineer would expect to see." *Id.* And because PJM engineers "had no difficulty determining flows across" the Bergen and Sewaren projects, the DFAX analysis results were not objectively unreasonable. *Id.* Moreover, paragraph (G) gives PJM discretion only to use "'an appropriate substitute proxy for the Required Transmission Enhancement in conducting the DFAX analysis,'" not general discretion to modify the method's "cost responsibility assignments." *Id.* at P 56 (quoting PJM Tariff, Sched. 12(b)(iii)(G)).

We review FERC's tariff interpretations with a "*Chevron*-like analysis." *La. Pub. Serv. Comm'n v. FERC*, 10 F.4th 839, 845–46 (D.C. Cir. 2021) (cleaned up). Under that framework, we enforce unambiguous tariff language but defer to FERC's reasonable interpretation of ambiguous text. *Id.* at 846.

FERC's interpretation is permissible. Any determination of unreasonableness by PJM must be "objective[]" and the product of PJM's "engineering judgment," which suggests a purely technical determination. Judging whether the method accurately models the flow of electricity fits that description. Ensuring compliance with the cost causation principle does not. Aligning project costs and benefits necessarily includes questions of fairness and the need to balance "competing goals." *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 88 (D.C. Cir. 2014) (per curiam). And courts have long recognized that ratemaking is "much less a science than an art," *Ala. Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982), requiring "both technical understanding and policy judgment," *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 295 (2016).

Moreover, even when PJM finds objectively unreasonable results, it does not have discretion to abandon the DFAX method. Paragraph (G) allows PJM to use a "substitute proxy" only "for the Required Transmission Enhancement," i.e., the transmission facility, and only "in conducting the DFAX analysis." It does not permit a proxy *method*. In other words, PJM can look past modeled flows that seem objectively unreasonable, replace them with flows from a comparable facility that the DFAX analysis can more accurately model, and then rerun the analysis. Nothing more.

Two other textual clues reinforce this view. The immediately preceding paragraph of the Tariff speaks of using a "proxy" in precisely this way. When the facility to be modeled is a direct-current facility, it "shall be replaced in the model with a comparable proxy [alternating-current] facility." PJM Tariff, Sched. 12(b)(iii)(F)(1). Additionally, whenever PJM uses a proxy under paragraph (G), it must "state in a written report … a recommendation as to what changes, if any, should be considered *in conducting the DFAX analysis*." *Id.* Sched. 12(b)(iii)(G) (emphasis added). This presupposes that even if PJM uses a proxy facility, it will not abandon the DFAX method altogether.

Finally, FERC's interpretation fits better with the principle of *ex ante* cost allocation established by Order No. 1,000. Under FERC's reading, PJM must apply all the existing cost allocation rules unless doing so is infeasible because the DFAX analysis does not accurately model flows. When that is the case, PJM's discretion is limited to identifying a proxy facility to which the existing rules will otherwise apply. Under the New York entities' reading, PJM must decide in each case whether to apply the existing rules or entirely new ones, based on its own view of the fairness of the results produced by the existing rules. Such an approach is *ex ante* in name only.

VI.

For its part, the New Jersey Board seeks review of FERC's order affirming the reallocation of the New York entities' costs for the Bergen project to PSE&G after they relinquished their rights to withdraw electricity from the PJM grid, as well as its orders permitting Linden and Hudson to convert their firm withdrawal rights to non-firm ones. The Board raises three main arguments. First, the Board claims that FERC erred in determining that ConEd's cost responsibility for the project ended when its transmission service agreements ceased. This was so since the project was built to benefit ConEd and ConEd previously agreed to accept its share of costs. Second, it is argued that Linden unreasonably evaded cost allocations for the project by the device of pairing non-firm transmission withdrawal rights and firm point-to-point transmission service, which ensures Linden retains the same benefits from the project. Third, the Board also contends that FERC did not properly consider whether the cumulative effect of relieving the New York entities of cost responsibility resulted in an unjust and unreasonable rate.

A.

We start with the New Jersey Board's first argument that ConEd was obliged to continue to pay project costs even after it ceased receiving service upon the termination of the ConEd-PSE&G power exchange transmission service—"wheeling"—agreement.

The 2009 settlement between PSE&G and ConEd, which clarified the parties' rights and obligations under the wheeling agreement, was signed by the New Jersey Board, ConEd, PJM, NYISO, and PSE&G. Under that agreement, ConEd "shall pay Transmission Enhancement Charges during the term of its … service." J.A. 614.[8] But the agreement makes clear that "ConEd shall have no liability for Transmission Enhancement Charges … after the termination of[] said term of service." *Id.*

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[8] In this Part, citations to the joint appendix refer to the one in *New Jersey Board v. FERC*.

FERC approved the settlement.[9] *See* ConEd-PSE&G Settlement Order, 132 FERC ¶ 61,221 at P 23. Here, ConEd's service agreements expired on April 30, 2017, and it did not renew them.

Under the PJM Tariff, ConEd's cost responsibility for PJM regional plan projects "shall be in accordance with the terms and conditions of the settlement" and "shall be adjusted at the … termination of service under the ConEd Service Agreements." PJM Tariff, Sched. 12(b)(xi)(A)–(B). FERC relied on the settlement agreement and its incorporation into the PJM Tariff to support its cost allocation decision. *See* Board Complaint Order, 163 FERC ¶ 61,139 at P 56 & n.94.

Similarly, FERC recognized that the Joint Operating Agreement ("JOA") between PJM and NYISO, which established protocols to improve the reliability and market operations of their systems, precluded the continued allocation of the Bergen project's costs to ConEd. *Id.* at PP 2, 54–55. FERC noted that, under JOA section 35.10.6, "neither the NYISO Region nor the PJM Region shall be responsible for compensating another region" for project costs unless both NYISO and PJM jointly decide to undertake an interregional project together. *Id.* at P 54; Board Complaint Rehearing Order, 170 FERC ¶ 61,180 at PP 12, 14. FERC correctly explained that the Bergen project was planned solely by PJM. Board Complaint Order, 163 FERC ¶ 61,139 at P 54; Board Complaint Rehearing Order, 170 FERC ¶ 61,180 at P 12. That cost allocation provision applies even where, as here, PJM and NYISO share mutual benefits between their systems that derive

[9] We note that the New Jersey Board participated in the settlement negotiations and signed the settlement agreement. If the Board took issue with these provisions, it should not have agreed to the settlement.

simply from their interconnection. Board Complaint Order, 163 FERC ¶ 61,139 at P 55. FERC recognized that "the JOA specifically states that 'PJM and NYISO shall not charge one another for such [mutual benefits].'" *Id.*

Accordingly, under these three agreements, FERC correctly determined that ConEd did not have to pay project costs after the termination of the service agreements.

The New Jersey Board contends that all of this misses the point. The relevant question, it says, is not whether a cost allocation complies with previously approved agreements or orders, but whether the resulting cost allocation, notwithstanding those agreements, is unjust and unreasonable. And, it points out that previously approved cost allocation *methods* can be unjust and unreasonable as applied to a particular rate decision.

As a general principle, under FERC's Order No. 1,000, which implements the cost causation principle, costs must be allocated roughly in accordance with benefits. Order No. 1,000, 136 FERC ¶ 61,051 at P 612. But that order also provides—in Principle 4—that "[t]he allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs." *Id.* at P 657. Here, after ConEd's service agreements expired, it no longer agreed to pay costs. And, as noted, the Bergen project was planned solely by PJM.

The New Jersey Board responds that there is tension between Principle 4 and the general cost causation principle because it may allow some project beneficiaries—here, ConEd—to avoid all cost responsibility. That is true. But it appears to us that Principle 4 is a permissible limitation on the cost causation principle. Indeed, we have concluded as much, as FERC points out. Board Complaint Order, 163 FERC ¶ 61,139 at P 54 n.83.

In *South Carolina Public Service Authority v. FERC*, Petitioners argued that Principle 4 was inconsistent with the cost causation principle because it did not fully allocate costs to out-of-region entities who still received some benefits. 762 F.3d at 88. We held that, even if Principle 4 "may lead to some beneficiaries escaping cost responsibility," there are other geographic policy considerations in play and FERC may permissibly approve a rate that does not perfectly track cost causation. *Id.*; *see also Carnegie Nat. Gas Co. v. FERC*, 968 F.2d 1291, 1293–94 (D.C. Cir. 1992) (noting that there is "no requirement in the Act itself that rates precisely match cost causation and responsibility" and that instead "the Commission may rationally emphasize other, competing policies and approve measures that do not best match cost responsibility and causation"). We noted that FERC developed Principle 4 in light of concerns about the monitoring costs, efficiency, and feasibility of involuntary interregional cost allocation. *S.C. Pub. Serv. Auth.*, 762 F.3d at 88–89. Accordingly, we concluded that Principle 4 is an important qualification on the cost causation principle. It reflects FERC's reasonable considered judgment about how best to balance its competing policy goals on a ratemaking matter, which we review with deference. *Id.*; *see also Artificial Island*, 989 F.3d at 17.

Therefore, we think that FERC reasonably relied on Order No. 1,000 and its Principle 4 to determine that it was just and reasonable for ConEd to be released from costs for the Bergen project going forward.

B.

Next, the New Jersey Board contends that "FERC's decision to allow Linden to avoid cost allocations for the Corridor Project" was "arbitrary" because "the Commission did not grapple with the interaction between firm Point-to-Point service and non-firm Withdrawal Rights." The Board notes that, at the same time Linden renounced its firm withdrawal rights, it separately bargained for and received firm "point-to-point" transmission service from utilities on the PJM grid. The Board therefore argues—and it is a powerful argument—that, as a practical matter, Linden's relinquishment of its firm withdrawal rights and its election of firm point-to-point service allowed Linden to receive the same benefits from the Bergen project without any of the costs.[10] FERC insists that we cannot consider this argument because it was not adequately presented in its requests for rehearing.

Under 16 U.S.C. § 825*l*(b), "[n]o objection to [an] order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing …." The argument the New Jersey Board makes before us, unfortunately, appears nowhere in its requests for rehearing before FERC. Instead, the Board's

[10] That is because PJM, despite being able to curtail service to a customer with non-firm withdrawal rights, cannot curtail service to that same customer if it has firm point-to-point rights. So even though Linden does not have to pay costs under PJM's Tariff because DFAX cost allocations are linked to firm withdrawal rights, it continues to receive the same service as it did when it held firm withdrawal rights by subscribing to firm point-to-point service. Once that power is transmitted to Linden's facility, PJM cannot prevent Linden from exporting that power in the exact same way as it had before converting from firm to non-firm withdrawal rights, including into NYISO's market.

rehearing requests generally challenge FERC's handling of the cost allocation issue. But we have held that a petitioner "must raise each argument with 'specificity'; objections may not be preserved either 'indirectly,' or 'implicitly.'" *Ameren Servs. Co.*, 893 F.3d at 793 (citations omitted). Accordingly, we lack jurisdiction to consider the Board's challenge to Linden's cost allocations.[11]

C.

Finally, it will be recalled, the New Jersey Board claims that FERC conducted a "siloed analysis" that did not consider the "total effect" of its orders on the rates for New Jersey ratepayers. Taken together, that the project was built in part to serve New York customers, ConEd did not renew its transmission service agreements, and Hudson and Linden converted their withdrawal rights have led to an unjust and unreasonable cost allocation, the Board says. Essentially, the Board protests that its ratepayers pay an "exceedingly disproportionate share" of the costs of the project.

But FERC did perform the kind of back-end analysis that the New Jersey Board claims was required. FERC recognized that the Bergen project was planned by PJM, and relied on PJM's statement that the project would still be needed in New Jersey "even if there were no flows on the transmission facilities interconnecting New York and New Jersey." Board Complaint Order, 163 FERC ¶ 61,139 at P 54 n.85. In its order denying the Board's complaint, FERC, applying Principle 4,

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[11] Although the New Jersey Board generally seeks judicial review of FERC's orders concerning Hudson's post-2017 cost allocation, it does not make this particular argument as to Hudson. Instead, the Board asks us to consider the Hudson cost allocation only as part of its "total effect" claim, which we address in Part VI.C.

concluded that because the Bergen project "was planned by a single region, i.e., PJM, and without a voluntary commitment to share cost responsibility by the other region, i.e., NYISO, it is just and reasonable for the costs of the project to be allocated solely within that region, PJM." *Id.* at P 54. And, in denying rehearing on this very argument, FERC noted that "[t]he fact that New Jersey ratepayers now pay higher rates as a result of a combined set of permissible circumstances does not by itself render such rates unjust and unreasonable." Board Complaint Rehearing Order, 170 FERC ¶ 61,180 at P 12.

Thus, looking at the matter from the stratosphere, FERC did consider the "total effect" of its decision and permissibly concluded—after evaluating who incurred the costs and who reaped the benefits of the project—that the overall cost allocation for the New York entities was not unjust or unreasonable. FERC's cost allocation determination was therefore neither "unreasonable" nor "inadequately explained." *Artificial Island*, 989 F.3d at 17.

VII.

In light of the foregoing, we deny the petitions for review in *New Jersey Board v. FERC*, and we grant in part and deny in part the petitions in *ConEd v. FERC*.

In denying the New York entities' applications for rehearing of both the First and Second Linden Complaint Orders, FERC failed to adequately distinguish its decision in Artificial Island from its treatment of the Bergen and Sewaren projects. In addition, FERC upheld the *de minimis* threshold, which we have found to be unlawful, in its orders denying rehearing of the First and Second Linden Complaint Orders and the ConEd Complaint Order. We therefore vacate FERC's denial of Linden's two complaints and remand for further proceedings on both issues. We likewise vacate its denial of ConEd's complaint and remand for further proceedings solely on the *de minimis* issue.

With one exception, we leave in place all the section 205 orders approving PJM's cost allocations. In all but one of those orders, FERC determined that when PJM files cost allocations under section 205, its role is limited to determining whether PJM correctly applied the methodology required by its Tariff rather than examining the lawfulness of that methodology. The New York entities do not challenge this procedural ruling, which forms an independent basis for rejecting their challenges.[12] We do vacate, however, the Cost Reallocation Order and remand on both the Artificial Island and *de minimis* issues. FERC did not raise a procedural bar to the New York entities' challenges there, instead rejecting them on the merits for reasons we have found defective. *See* Cost Reallocation Order, 170 FERC ¶ 61,124 at P 32; Second Linden Complaint Rehearing Order, 172 FERC ¶ 61,176 at P 18. On remand, FERC may consider in the first instance whether the challenges to PJM's 2017 cost reallocation are procedurally barred.

So ordered.

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[12] FERC argues that we lack jurisdiction over the petitions in Nos. 15-1183 and 15-1188—which seek review of its 2014 order approving PJM's initial cost allocations for Bergen—because that order was nonfinal. But we indisputably have jurisdiction over at least one "companion case" raising the same objections as those in Nos. 15-1183 and 15-1188, and so may reject those petitions on the merits without reaching the jurisdictional argument FERC presses. *Steel Co. v. Citizens for a Better Env't*, 523 U.S. 83, 98 (1998) (emphasis omitted) (citing *Norton v. Mathews*, 427 U.S. 524, 530–31 (1976)).