

**United States Court of Appeals**  
**FOR THE DISTRICT OF COLUMBIA CIRCUIT**

---

Argued April 26, 2007

Decided July 20, 2007

No. 04-1414

WISCONSIN PUBLIC POWER INC.,  
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,  
RESPONDENT

WPS RESOURCES CORPORATION, ET AL.,  
INTERVENORS

---

Consolidated with  
05-1006, 05-1007, 05-1198, 05-1203, 05-1358, 05-1427,  
05-1428, 05-1429

---

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

---

*Mark S. Hegedus* argued the cause for petitioners Midwest Transmission Dependent Utilities and Wisconsin Public Power Inc. With him on the briefs were *Cynthia S. Bogorad*, *David E. Pomper*, *Louis R. Cohen*, *Jonathan J. Frankel*, *Heather Zachary*, and *Michael R. Postar*.

*Jeffrey L. Landsman* argued the cause for petitioners National Rural Electric Cooperative Association and Dairyland Power Cooperative on grandfathered agreement issues. With him on the briefs was *Wallace F. Tillman*.

*John N. Estes, III* argued the cause for petitioners Duke Energy Shared Services, Inc. and Xcel Energy Services Inc. With him on the briefs were *Noel H. Symons, John L. Shepherd, Jr., J. Alexander Cooke, Floyd L. Norton, IV, Stephen M. Spina,* and *Joseph C. Hall*.

*Elizabeth E. Rylander*, Attorney, and *Judith A. Albert*, Senior Attorney, Federal Energy Regulatory Commission, argued the cause for respondent. With them on the brief was *Robert H. Solomon*, Solicitor.

*Stephen L. Teichler* argued the cause for intervenor Midwest Independent Transmission System Operator, Inc. With him on the brief were *Ilia Levitine* and *Stephen G. Kozey*.

*Cynthia S. Bogorad, David E. Pomper, Mark S. Hegedus, Louis R. Cohen, Jonathan J. Frankel, Heather Zachary, Jeffrey L. Landsman, Alan I. Robbins,* and *Debra D. Roby* were on the brief for intervenors Wisconsin Public Power Inc., et al. in support of respondent.

*John N. Estes, III, Noel H. Symons,* and *John L. Shepherd, Jr.* were on the brief for intervenor Duke Energy Shared Services, Inc. in support of respondent.

Before: GINSBURG, *Chief Judge*, and GARLAND and KAVANAUGH, *Circuit Judges*.

Opinion for the Court filed PER CURIAM.

PER CURIAM: The Midwest Independent System Operator, known as MISO, is a nonprofit corporation that controls the transmission of electricity over a grid spanning 15 Midwestern states. Its original tariff was approved by the Federal Energy Regulatory Commission and went into effect in 2002. Under that tariff's terms, MISO approved transmission requests, scheduled service, monitored the grid to manage congestion, and provided various ancillary services to support the regional electricity market.

On March 24, 2004, MISO filed a revised tariff with FERC. Under the new tariff, MISO administers two competitive wholesale power markets: a "day-ahead" market that allows transmission to be scheduled in advance, and a real-time or "spot" market. Among other improvements over MISO's original operations, these markets incorporate more sophisticated pricing and congestion-management mechanisms that increase the efficiency and reliability of the transmission grid. In a series of orders issued between May 2004 and September 2005, the Commission accepted the proposed tariff with modifications, and MISO's new market began operating on April 1, 2005. Three groups of petitioners now seek review of various aspects of the Commission's orders: the Transmission Dependent Utilities, who rely on MISO's transmission system and markets to buy and sell electric power to retail customers; the Transmission Owners, who are electricity sellers in MISO's markets subject to the new tariff's rules and liabilities; and the Cooperatives, who are electricity buyers under contracts predating the establishment of MISO. For the reasons that follow, we deny the petitions of the Transmission Dependents and the Transmission Owners, and we dismiss those of the Cooperatives for lack of standing.

Section 201(b) of the Federal Power Act (FPA) grants the Federal Energy Regulatory Commission exclusive jurisdiction over the transmission and wholesale sale of electricity in interstate commerce. *See* 16 U.S.C. § 824(b). Section 205 of the FPA provides that “[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission . . . shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.” *Id.* § 824d(a). Section 205 also prohibits undue discrimination in rates, charges, or terms of service. *See id.* § 824d(b). To enforce these requirements, Section 205 requires that utilities file tariffs reflecting their rates and service terms with the Commission, which must in turn ensure that those rates and terms are just and reasonable and not unduly discriminatory. *Id.* § 824d(c).

## A

In the mid-1990s, FERC determined that longstanding structural barriers to competition in the wholesale power market constituted undue discrimination. Since then, it has been the Commission’s policy to eliminate those barriers and promote competition. This policy required a significant shift in the Commission’s regulatory approach, which has in turn produced dramatic changes in the electricity industry. Because the tariff at issue in these petitions is part of that transformation, we begin with some background on the development of FERC’s policy. Rather than reinventing the wheel, we borrow the following account from our opinion in *Midwest ISO Transmission Owners v. FERC*:

In the bad old days, utilities were vertically integrated monopolies; electricity generation, transmission, and distribution for a particular geographic area were generally provided by and under the control of a single regulated utility. Sales of those services were “bundled,” meaning consumers paid a single price for generation, transmission, and distribution. As the Supreme Court observed, with blithe understatement, “[c]ompetition among utilities was not prevalent.” *New York v. FERC*, 535 U.S. 1, 5 (2002).

In its pathmarking Order No. 888, FERC required utilities that owned transmission facilities to guarantee all market participants non-discriminatory access to those facilities. *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, FERC Stats. & Regs. ¶ 31,036, 31,635-36 (1996) (Order No. 888). That is, FERC required all transmission-owning utilities to provide transmission service for electricity generated by others on the same basis that they provided transmission service for the electricity they themselves generated. To effectuate this introduction of competition, FERC required public utilities to “functionally unbundle” their wholesale generation and transmission services by stating separate rates for each service in a single tariff and offering transmission service under that tariff on an open-access, non-discriminatory basis. *See New York*, 535 U.S. at 11; *see generally California Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 397 (D.C. Cir. 2004).

As the next step toward the goal of a more competitive electricity marketplace, Order No. 888

encouraged – but did not require – the development of multi-utility regional transmission organizations (RTOs). The concern was that the segmentation of the transmission grid among different utilities, even if each had functionally unbundled transmission, contributed to inefficiencies that impeded free competition in the market for electric power. Combining the different segments and placing control of the grid in one entity – an RTO – was expected to overcome these inefficiencies and promote competition. Order No. 888 at 31,730-32; *see also Public Util. Dist. No. 1 of Snohomish County v. FERC*, 272 F.3d 607, 610-11 (D.C. Cir. 2001). Better still if the RTO were run by an independent system operator – an ISO. As envisioned by FERC, an ISO would assume operational control – but not ownership – of the transmission facilities owned by its member utilities, thereby “separat[ing] operation of the transmission grid and access to it from economic interests in generation.” Order No. 888 at 31,654; *see also id.* at 31,730-32. The ISO would then provide open access to the regional transmission system to all electricity generators at rates established in “a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.” *Id.* at 31,731; *see also California Indep. Sys. Operator Corp.*, 372 F.3d at 397. FERC called this type of separation of generation and transmission “operational unbundling,” a step beyond “functional unbundling.” Order No. 888 at 31,654. Although several parties to the 1996 rulemaking had requested that FERC require “operational unbundling” or even divestiture of transmission assets, it was FERC’s considered judgment that “the less intrusive functional unbundling

approach . . . is all that we must require at this time.”  
*Id.* at 31,655.

By 1999, FERC had come to a less sanguine view of the curative powers of functional unbundling. In FERC’s view, inefficiencies in the transmission grid and lingering opportunities for transmission owners to discriminate in their own favor remained obstacles to robust competition in the wholesale electricity market. FERC concluded that these problems could be remedied through the establishment of RTOs, explaining that “better regional coordination in areas such as maintenance of transmission and generation systems and transmission planning and operation” was necessary to address regional reliability concerns and to foster regional competition. *See Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, 30,999 (1999) (Order No. 2000) (codified at 18 C.F.R. § 35.34) (citing Staff Report to FERC on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998, at 5-8 (Sept. 22, 1998)). FERC concluded that RTOs would: “(1) improve efficiencies in transmission grid management; (2) impose grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation.” Order No. 2000 at 30,993; *Public Util. Dist. No. 1*, 272 F.3d at 611. To further encourage RTO development, FERC directed transmission-owning utilities either to participate in an RTO or to explain their refusal to do so. *Public Util. Dist. No. 1*, 272 F.3d at 612. Importantly, though, Order No. 2000 still did not *require* utilities to join

RTOs; participation remained voluntary. *See id.* at 616.

For those utilities opting to join an RTO, Order No. 2000 retained a flexible approach, allowing the RTOs to employ a variety of ownership and operational structures, so long as the RTO established that it had certain required characteristics and functional capabilities. *Id.* at 611. FERC required, *inter alia*, that an RTO be regional in scope, 18 C.F.R. § 35.34(j)(2); “have operational authority for all transmission facilities under its control,” *id.* § 35.34(j)(3); “be the only provider of transmission service over the facilities under its control,” *id.* § 35.34(k)(1)(i); and “have the sole authority to receive, evaluate, and approve or deny all requests for transmission service,” *id.* Thus, whatever its structure, once a utility made the decision to surrender operational control of its transmission facilities to an RTO, any transmissions across those facilities were subject to the control of that RTO.

373 F.3d 1361, 1363-65 (D.C. Cir. 2004) (alterations in original).

## B

MISO developed in response to Order No. 888 and Order No. 2000. On January 15, 1998, pursuant to Order No. 888, a group of Midwestern transmission owners sought FERC’s approval of their agreement establishing an Independent System Operator. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 84 F.E.R.C. ¶ 61,231, at 62,139 (1998) (“MISO Formation Order”). Under the MISO Agreement, “[t]he participating transmission owners . . . transfer[red] to the Midwest ISO



functional control over all network transmission facilities” above a specified voltage. *Id.* The transmission owners retained ownership and physical control over the facilities, but operated them according to MISO’s instructions. MISO, in turn, was “authorized to provide non-discriminatory open access transmission service,” “to receive and distribute transmission revenues” to the transmission owners, and “to be responsible for regional system security.” *Id.*; *see also E. Ky. Power Coop., Inc. v. FERC*, No. 06-1003, slip op. at 5 (D.C. Cir. June 15, 2007) (“MISO was responsible for functional control over the transmission system, which included managing transmission availability and capacity, requests for transmission service, available ancillary services, and security.”). Along with the MISO Agreement, the transmission owners also filed an Open Access Transmission Tariff (OATT), which established the terms and rates of transmission service on the MISO grid. Under the proposed OATT, “all customers would pay a single rate to use the entire MISO transmission system, based on the volume of power the customer carried on the system.” *Midwest ISO Transmission Owners*, 373 F.3d at 1365.

FERC conditionally approved the MISO Agreement and the OATT on September 16, 1998, but suspended the tariff pending a hearing to determine whether its terms were just and reasonable. *See* MISO Formation Order, 84 F.E.R.C. ¶ 61,231, at 62,181-82. While these proceedings were still ongoing, FERC issued Order No. 2000, which directed all FERC-approved ISOs to show that they had met the requirements for RTO status. *See* 18 C.F.R. § 35.34(h). When MISO made the required filing, the Commission found that it had satisfied Order No. 2000’s requirements and granted it RTO status. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,326, at 62,500 (2001) (“RTO Formation Order”). The Commission also approved the OATT, and MISO began providing transmission service on February 1, 2002. *See*

*Midwest Indep. Transmission Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,033, at 61,177 (2001) (“Opinion No. 453”), *order on reh’g*, 98 F.E.R.C. ¶ 61,141 (2002) (“Opinion No. 453-A”).

MISO’s development was complicated by the existence of several hundred pre-existing bilateral contracts between its transmission owners and other utilities. *Midwest ISO Transmission Owners*, 373 F.3d at 1365. These long-term contracts, known as grandfathered agreements (GFAs), obligated the transmission owners to provide transmission service under terms and rates that were inconsistent with the OATT. *See id.* In order to balance the contract rights and expectations of the parties to the GFAs with the benefits of open-access service provided by an ISO, the MISO transmission owners “proposed to not place . . . grandfathered wholesale load under the Midwest ISO’s Tariff for at least a six year transition period.” Opinion No. 453, 97 F.E.R.C. ¶ 61,033, at 61,169.<sup>1</sup> In other words, under the original version of the MISO Agreement, two different types of transmission service would have coexisted on the MISO grid: independent service provided by the transmission owners under the terms of their bilateral GFAs, and open-access service provided by MISO under the terms of the OATT.

FERC accepted this proposed treatment of the GFAs when it initially approved the formation of the Midwest ISO, but had to revisit the issue in light of Order No. 2000. As the Commission explained, “Order No. 2000 and Section 35.34(k) of the Commission regulations require that an RTO be the only provider of transmission services over the facilities under its control.” Opinion No. 453, 97 F.E.R.C. ¶ 61,033, at 61,170

---

<sup>1</sup> “Load” simply refers to demand for service on a transmission grid. *See Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 725 n.11 (D.C. Cir. 2000).

(citing 18 C.F.R. § 35.34(k)). The proposed MISO Agreement and OATT did not satisfy this requirement because they allowed transmission owners to provide independent transmission service to fulfill their obligations under the GFAs. FERC therefore directed that, “to the extent that certain transmission-owning members of the Midwest ISO serve . . . grandfathered load, those transmission-owning members will have to take transmission service under the Midwest ISO Tariff for their use of the Midwest ISO transmission system to serve . . . grandfathered agreement customers.” Opinion No. 453-A, 98 F.E.R.C. ¶ 61,141, at 61,413. MISO complied. Under the revised MISO Agreement, a transmission owner providing service under a GFA took service from MISO under the terms of the OATT and then re-sold the same service to the GFA customer (this is known as providing “back-to-back” transmission service).

Order No. 2000 demanded this formal integration of the GFAs into MISO, but in financial terms the transmission owners – with FERC’s approval – preserved the separate status of the GFAs. The final version of the OATT provided that MISO transmission owners “will be exempt, during the [six-year] transition period, from rates under the Midwest ISO Tariff for services provided pursuant to the existing [GFA] agreements.” *Id.* Thus, although the transmission owners took service under the OATT when serving GFAs, they did not pay MISO for that service – financially, grandfathered load was effectively kept outside of the OATT.<sup>2</sup>

---

<sup>2</sup> FERC did, however, require that *all* load using the grid contribute to MISO’s administrative costs, which are recovered by Schedule 10 of the OATT. *See* Order No. 453-A, 98 F.E.R.C. ¶ 61,141, at 61,413. As we explained in the course of affirming FERC’s determination, the imposition of Schedule 10 charges on grandfathered load was consistent with the Commission’s “cost-

Under MISO's original OATT, MISO managed transmission congestion primarily through the Transmission Line Loading Relief procedure (TLR). The TLR procedure required MISO to monitor real-time power flows and to order the physical curtailment of any transactions that threatened to exceed the system's transmission capacity. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,236, at 62,279 PP 27-30 (2004) ("GFA Order"). This system of congestion management was highly inefficient. "[R]eliance on TLRs for congestion management inherently leaves transmission capacity under-utilized because the TLR approach relies on imprecise flow estimates" and because "each TLR curtailment . . . may curtail too many or too few transactions." *Id.* at 62,279 P 30. The uncertainty of the TLR process also undermined the reliability of the grid because it made it "more difficult to maintain power flows within operating security limits." *Id.* at 62,280 P 32.

FERC recognized these shortcomings in the OATT, and it granted MISO's request for RTO status on the condition that MISO begin planning a transition to more "dynamic" operations, including more efficient market-based congestion management. RTO Formation Order, 97 F.E.R.C. ¶ 61,326, at 62,512, 62,522. On March 31, 2004, MISO filed a revised Open Access Transmission and Energy Markets Tariff (Tariff) that is the subject of these petitions for review. The Tariff provides for a "security-constrained, centralized bid-based scheduling and dispatch system" similar to those currently operating in three

---

causation principle" because even transmission owners serving grandfathered load "draw benefits from being a part of the MISO regional transmission system." *Midwest ISO Transmission Owners*, 373 F.3d at 1371.

other RTOs. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163, at 61,916-17 PP 2-6 (2004) (“TEMT II Order”). In these systems, the ISO “administers two sets of bid-based energy markets. First is the ‘Day-Ahead Market,’ in which the [ISO] derives a market-clearing price from the sellers’ and buyers’ price and quantity indications for the next day; sales are then made at the market-clearing price. Second is the ‘Real-Time Market,’ designed to ensure system reliability by calculating hourly clearing prices and allowing sellers to offer supplies to meet additional demand and even to revise day-ahead bids.” *Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 965 (D.C. Cir. 2005).

As directed by FERC, the Tariff includes a market-based approach to congestion management. The Tariff establishes markets based on a mechanism known as locational marginal pricing (LMP), which incorporates the cost of congestion into the price of energy. Under the LMP system, MISO takes into account the limits on available transmission capacity when determining the price of energy at each node in its transmission grid. This results in higher energy prices at nodes that require the use of congested transmission lines and lower prices in less congested areas. *See Prepared Direct Testimony of Dr. Ronald R. McNamara* 33. LMP reduces the need for inefficient TLRs by giving market participants incentives to avoid congestion-causing transactions. *See id.* It is also more economically efficient: scarce transmission capacity is allocated to those who value it most instead of being physically rationed by TLRs. *See id.* at 35.

In order to protect market participants from variations in congestion costs, the Tariff provides for a system of Financial Transmission Rights (FTRs), which are financial instruments that entitle their holders to be paid the congestion costs associated with transmitting a given quantity of electricity

between two specified points. *See* TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,935-36 P 139. A party planning a transmission can thus hedge its exposure to congestion costs by acquiring a corresponding FTR. At the time of the transmission, the party will pay MISO the applicable congestion costs, but will then receive the same amount back from MISO in its capacity as the holder of the FTR. MISO proposed annual allocations of FTRs to existing users of the transmission grid, supplemented by periodic adjustments and secondary auctions. *See id.*

Two additional features of the Tariff are relevant to the petitions before us: market power mitigation measures and marginal loss refunds. First, MISO recognized that, during periods of transmission congestion and high demand, sellers might be able to exercise market power and drive prices in MISO's markets to unreasonable levels. The Tariff therefore provides for two types of market power mitigation: one for Narrow Constrained Areas (NCAs) and one for Broad Constrained Areas (BCAs). NCAs are determined annually and are defined as areas where transmission constraints are expected to be binding for at least 500 hours during a given year and where at least one seller is "pivotal." *See id.* at 61,955 P 276. "A supplier is pivotal when the output of some of its generation resources must be changed to resolve the transmission constraint during some or all hours when the constraint is binding." *Id.* BCAs are areas where competitive conditions are generally present but where transmission constraints may create occasional opportunities for the exercise of market power. BCAs are defined dynamically: when a transmission constraint becomes active, MISO's independent market monitor defines those generators that affect the constraint as being within the BCA. *See id.* at 61,953 PP 264-65.

The consequence of being within an NCA or BCA is that a generator's bids are subject to mitigation if they exceed

“conduct” and “impact” thresholds. These thresholds are defined in relation to the seller’s “reference level,” which is based on an estimate of its marginal cost. In BCAs, the “conduct” threshold is equal to either \$100 per megawatt hour above the seller’s reference level or 300 percent above the reference level, whichever is less. *See id.* at 61,959 PP 307-12. If a seller’s bid fails the conduct test, then it is subject to the impact test. A bid fails the BCA impact test if it causes the market-clearing price to increase by either \$100 per megawatt-hour or 200 percent above the price that would have resulted if the seller had bid its reference level. *See id.* If a seller’s bid fails both the conduct and impact tests, then it is “mitigated” – that is, it is reduced to the reference level. FERC approved MISO’s BCA mitigation measures, but imposed a “sunset” provision requiring that they terminate after one year unless MISO filed for an extension. *See id.* at 61,954-55 P 275.

Because of the greater risk of market power in NCAs, the conduct and impact thresholds are lower than in BCAs. In NCAs, both thresholds are the same: the seller’s reference price plus a “fixed cost adder” equal to the “net annual fixed cost divided by the constrained hours” expected that year. *Id.* at 61,959 PP 307-12. Net annual fixed cost is defined as “the fixed cost of a new peaking generator minus revenue from applicable resource reserve adequacy payments.” *Id.* at 61,959 n.209. The purpose of the fixed-cost adder is to preserve incentives for suppliers to enter the market (and to discourage existing suppliers from exiting) by ensuring that market revenues cover a generator’s fixed costs. *See id.* at 61,960 PP 316-17. FERC approved MISO’s NCA mitigation measures without imposing a sunset provision.

The second relevant feature of the Tariff is its marginal loss refund mechanism. In addition to accounting for congestion costs, the Tariff’s LMP mechanism includes a component for

transmission losses. When electricity is transmitted across power lines, some portion of the energy is lost as heat. The loss is a function of (among other things) the length of the transmission and the square of the amount of current being transmitted. *See Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 2 (D.C. Cir. 2002). Under the OATT, transmission losses within MISO were determined on an average system-wide basis and allocated to all users pro rata. This system did not account for the length of the transmission required for each transaction, and thus led to “cross-subsidies” between market participants – parties that scheduled long-distance transmissions paid too little, while those that scheduled shorter transmissions paid too much. *See* TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,925-26 PP 66, 71. Therefore, FERC instructed MISO to adopt “marginal loss pricing.” *Id.* at 61,925 P 66. Marginal loss pricing recovers transmission losses on a transaction-by-transaction basis by incorporating them into the LMP. In order to do so, however, it treats every transmission as if it were the last (marginal) transmission on the system. This pricing scheme sends more efficient signals to market participants, but because transmission losses increase with the amount of current in the system, treating every transmission as the marginal transmission produces revenue in excess of actual losses – the “marginal loss surplus.”

In order to provide transitional protection for market participants who faced higher costs as a result of the new marginal loss system, FERC required MISO to use this surplus to “refund the difference between the marginal loss charge and either an average loss or a historical loss charge to all existing transmission customers” for the first five years of the Tariff. *Id.* at 61,926 PP 73-74. MISO proposed, and FERC approved, a refund mechanism that distributes marginal loss surpluses through groups of market participants known as “Balancing Authority Areas.” *See Midwest Indep. Transmission Sys.*



*Operator, Inc.*, 109 F.E.R.C. ¶ 61,285, at 62,364 P 160 (2004) (“Compliance Order I”). The surpluses are distributed pro rata within each Area, but “customers in Balancing Authority Areas that have the highest actual losses . . . receive a greater proportion of the Marginal Loss Surplus share than customers in Balancing Authority Areas with relatively lower losses.” *Id.*

## D

The Commission approved the Tariff in two parallel proceedings. In the first set of orders, FERC considered the justness and reasonableness of the terms of the Tariff, including the features described above. These orders accepted the Tariff with some modifications and subject to ongoing compliance filings. *See* TEMT II Order, 108 F.E.R.C. ¶ 61,163, *order on reh’g*, 109 F.E.R.C. ¶ 61,157 (2004) (“TEMT II Reh’g Order”), *order on reh’g*, 111 F.E.R.C. ¶ 61,043 (2005) (“Compliance Order III”), *reh’g denied*, 112 F.E.R.C. ¶ 61,086 (2005) (“Compliance Order V”).<sup>3</sup>

In the second set of orders, the Commission considered the relationship between MISO’s new markets and the GFAs, which – as during the formation of MISO – posed special difficulties. In the original MISO Agreement, the transmission owners agreed to preserve the rates and terms of the GFA contracts for at least a six-year transition period. But under the Tariff, with its system of markets and centralized dispatch, the GFA parties could only “exercise the scheduling and energy management provisions of their GFAs in the same manner they did before” if

---

<sup>3</sup> Petitioners also seek review of three related compliance orders. *See* Compliance Order I, 109 F.E.R.C. ¶ 61,285, *order on reh’g*, 111 F.E.R.C. ¶ 61,053 (2005) (“Compliance Order IV”); *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 F.E.R.C. ¶ 61,049 (2005) (“Compliance Order II”).

MISO reserved or “carved out” transmission capacity from its day-ahead market to allow for the possibility that it would be used by the GFA transactions. GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,289 P 90. In its initial filing, MISO estimated that GFAs accounted for up to 40 percent of the total load on its transmission grid. *Midwest Indep. Transmission Sys. Operator, Inc.*, 107 F.E.R.C. ¶ 61,191, at 61,776 P 16 (2004) (“Procedural Order”). MISO argued that carving out such a large fraction of its transmission capacity would significantly reduce the efficiency of the new markets, jeopardize reliability, and impose significant costs on other market participants. *See id.* at 61,777 P 17. Therefore, MISO proposed that those GFA parties that did not voluntarily agree to convert to service under the Tariff be required to choose one of three options for scheduling their transactions and settling transmission charges.

All three options proposed by MISO required the GFA parties to designate a GFA Responsible Entity (GFA-RE), which would be financially responsible for charges under the Tariff, and a GFA Scheduling Entity (GFA-SE), which would submit schedules for GFA transactions to MISO. *See id.* at 61,777 P 19 & nn.23-24. Under Option A, the GFA-RE would pay congestion charges and loss charges under the Tariff and would also be eligible for FTR allocations, just like any other market participant. *See id.* at 61,777-78 P 20. Under Option B, as under Option A, the GFA-RE would pay congestion and loss charges. But instead of being required to obtain FTRs to hedge congestion costs like other market participants, these GFA-REs would receive a guaranteed reimbursement of congestion costs and loss charges as long as their GFA-SEs provided MISO with a day-ahead schedule of GFA transmissions. *See id.* at 61,778 P 21. Finally, under Option C, the GFA-RE would pay congestion costs and marginal loss charges but would not be eligible for refunds or FTRs. *See id.* at 61,778 P 22.

The Commission responded to MISO's proposal by instituting a three-step process to gather additional information about the GFAs and their impact on the new markets. Step one, the "paper hearing," required utilities to provide information about their GFA contracts and sought additional information from MISO on the impact of a "carve out" of GFA load on the efficiency and reliability of the new markets. *See id.* at 61,785-86 P 68. Step two was a "trial-type" hearing before two administrative law judges to settle any disputes between GFA parties about the information sought in step one. *See id.* at 61,787 P 75; *see also Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 63,013 (2004) ("ALJ Findings"). Finally, in step three the Commission issued an order on the merits of MISO's proposal. *See* Procedural Order, 107 F.E.R.C. ¶ 61,191, at 61,787 P 78. FERC also encouraged GFA parties to avoid the time and expense of the three-step process by voluntarily agreeing to convert to Tariff service or selecting one of MISO's proposed options. *Id.* at 61,787 P 77.

The Commission issued its order on the merits on September 16, 2004. *See* GFA Order, 108 F.E.R.C. ¶ 61,236, *order on reh'g*, 111 F.E.R.C. ¶ 61,042 (2005) ("GFA Reh'g Order"), *order on reh'g*, 112 F.E.R.C. ¶ 61,311 (2005). Based on the paper hearing and the ALJ findings, FERC determined that MISO's initial estimate of the scope of the problem had been somewhat exaggerated. A total of 229 GFAs would be in existence when the Tariff went into effect, representing 23 percent of MISO's total load rather than 40 percent. *See id.* at 62,275 P 4. Furthermore, 52 of those GFAs – representing nine percent of MISO's total load – had voluntarily settled before the Commission issued its order on the merits. *See id.*; *see also id.* at 62,318 P 275. The largest group, representing roughly five percent of MISO's total load, selected Option B. *See id.* at 62,318 P 275.

The Commission concluded that carving out the relatively small number of remaining GFAs would not threaten the reliability of MISO's grid or seriously compromise the efficiency of its markets. *See id.* at 62,288-91 PP 89-102. FERC also explained that, if the GFAs were not carved out, the result would "impose changes to the manner in which transmission service is provided for transactions under the GFAs" and could alter the original bargain between the GFA parties by shifting costs between them. *Id.* at 62,296-97 P 138. The Commission agreed with MISO, however, that any carve out for GFAs "has the potential to result in additional costs for non-GFA transactions." *Id.* at 62,290 P 99.

In order to balance these competing considerations, the Commission determined that the treatment of non-settling GFAs should depend on the standard of review in each GFA contract. FPA section 205 allows utilities to file changes to their rates at any time and requires FERC to approve them as long as the new rates are "just and reasonable." 16 U.S.C. § 824d(d), (e). "Under the Supreme Court's *Mobile-Sierra* doctrine," however, "parties may negotiate a fixed-rate contract with a provision relinquishing their right to file for a unilateral change in rates." *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 11 (D.C. Cir. 2002); *see also FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956); *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956). If the parties to a contract adopt the *Mobile-Sierra* standard of review, "FERC may abrogate or modify" the contract "only if required by the public interest." *Atl. City Elec.*, 295 F.3d at 14. This standard "is much more restrictive than the just and reasonable standard of section 205." *Id.*

FERC concluded that all non-settling GFA contracts that were subject to unilateral modification under the "just and reasonable" standard should be required to "choose between the scheduling and settlement provisions of Option A or Option C."

GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,297 P 139.<sup>4</sup> The Commission explained that the risk of imposing additional costs on non-GFA parties made it “unjust and unreasonable to allow GFAs that are subject to a just and reasonable standard of review to remain outside the Midwest ISO Energy Markets.” *Id.* at 62,296 P 137. The risk of unfair cost shifts between the GFA parties was reduced, moreover, because “the terms and conditions of GFAs subject to a just and reasonable standard of review allow the parties to propose appropriate modifications to reflect such new costs.” *Id.* at 62,297 P 138. These “just and reasonable” GFAs accounted for another 4.5 percent of total MISO load.

By contrast, the Commission directed MISO to “carve [the *Mobile-Sierra*] GFAs out of the Energy Markets for the remainder of the six-year transition period.” *Id.* at 62,297 P 143. The Commission explained that it “cannot find today that the public interest requires that [the *Mobile-Sierra*] GFAs be modified” in the same manner as the just-and-reasonable GFAs because the new energy markets “can be operated reliably, with net benefits to the public, notwithstanding a carve-out” of these GFAs. *Id.* at 62,297 P 142. FERC also explained that a carve out of the *Mobile-Sierra* GFAs was needed to maintain the bargain of the original MISO Agreement, in which the MISO transmission owners agreed that GFAs would be kept outside of

---

<sup>4</sup> FERC determined that both of these options were just and reasonable, and that Option B was just and reasonable for those parties that had already settled. *See* GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,316 P 264. But the Commission explained that “Option B was an incentive to settle,” and that “[i]t would be unfair to allow this option” – with its guaranteed reimbursement of congestion and marginal loss charges – “to those that did not settle first and [a]waited (and even litigated) the outcome of this proceeding.” *Id.*

MISO for a six-year transition period. *See* GFA Reh’g Order, 111 F.E.R.C. ¶ 61,042, at 61,134 P 94. In total, the 127 carved-out *Mobile-Sierra* GFAs accounted for approximately 9.5 percent of MISO’s total load. GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,297 P 141.<sup>5</sup>

The Commission also addressed the designation of GFA-REs and GFA-SEs. Unless the parties agreed otherwise, the Commission determined that the transmission owner responsible for providing service under the GFA should be both the GFA-RE and the GFA-SE. *See id.* at 62,300-01 PP 161, 165.

Finally, the Commission addressed the assessment of MISO charges on GFA agreements. It concluded that the administrative costs associated with the new markets – known as Schedule 17 charges – should be assessed on all load using the MISO grid, including carved-out GFAs. *See id.* at 62,321-22 PP 297-98. Applying the “cost-causation” principle, the Commission found that the new markets would “produce more reliable service and more efficient Energy Markets that will benefit all [parties] transacting over the Midwest ISO grid,” and concluded that “GFAs should pay for the benefits they receive.” *Id.* at 62,322 P 298. But the Commission concluded that carved-out GFAs should not pay Schedule 16 charges, which cover the cost of administering the market in FTRs, because carved-out GFAs “do not benefit from the FTR Service.” *Id.* at 62,321 P 295.

---

<sup>5</sup> These figures include contracts that did not specify a standard of review, which the Commission decided to treat as if they had incorporated the *Mobile-Sierra* standard. *See* GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,298 PP 147-49. They also include a small number of non-jurisdictional GFAs. FERC explained that these GFAs had to be carved out because it “has no authority to make any modifications to these contracts.” *Id.* at 62,298 P 150.

Three groups of petitioners now seek review of the 11 orders approving the Tariff and addressing the treatment of the GFAs. The first group, led by the Midwest Transmission Dependent Utilities, is made up of buyers of power in the new markets. They argue that FERC should have required more stringent market power mitigation measures and that the Commission's approval of MISO's marginal loss refund mechanism was arbitrary and capricious. The second group, led by the National Rural Electric Cooperative Association and the Dairyland Power Cooperative (the Cooperatives), is composed of buyers of power under GFA agreements. They argue that the imposition of Schedule 17 charges on carved-out GFAs was arbitrary and capricious and that the Commission's denial of their request for an evidentiary hearing violated the Administrative Procedure Act and the Due Process Clause of the Constitution. The third group consists of Duke Energy Shared Services, Inc., and Xcel Energy Services Inc. – transmission owners who sell power in the new markets. They argue that *all* GFAs should have been required to choose between conversion to the Tariff, Option A, or Option C, and that FERC acted arbitrarily by carving out some GFAs entirely and granting others favorable treatment under Option B. In addition, Xcel challenges FERC's designation of the GFA-RE and GFA-SE.<sup>6</sup>

The remainder of this opinion addresses the issues raised by each group of petitioners in turn. At the outset, however, we set

---

<sup>6</sup> The Transmission Dependents intervened in support of FERC on the issues raised by Duke and Xcel, while Duke (but not Xcel) intervened to support FERC on the issues raised by the other two groups of petitioners. Finally, MISO intervened to support FERC on the issues raised by the Transmission Dependents and the Cooperatives.

forth the standard of review that is common to the objections asserted by all three. We review FERC's orders by applying the Administrative Procedure Act's "arbitrary and capricious" standard. *See* 5 U.S.C. § 706(2)(A); *Midwest ISO Transmission Owners*, 373 F.3d at 1368. Under this deferential standard, we must affirm the Commission's orders as long as it has "examine[d] the relevant data and articulate[d] a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)). We treat the Commission's factual findings as conclusive as long as they are supported by substantial evidence. *See* 16 U.S.C. § 825l(b). Finally, we recognize that "matters of rate design . . . are technical and involve policy judgments at the core of FERC's regulatory responsibilities. Hence, the court's review of whether a particular rate design is just and reasonable is highly deferential." *Me. Pub. Utils. Comm'n v. FERC*, 454 F.3d 278, 287 (D.C. Cir. 2006).

## II

The Transmission Dependent Utilities buy power for resale to retail customers in the new markets overseen by the Midwest Independent System Operator (MISO). These petitioners challenge two aspects of MISO's operations under the Tariff. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 (2004) ("TEMT II Order"), *order on reh'g*, 109 F.E.R.C. ¶ 61,157 (2004) ("TEMT II Reh'g Order"). First, the Transmission Dependents challenge MISO's market power mitigation measures, which seek to prevent electricity suppliers from unduly raising prices above competitive levels in certain areas of MISO's grids where transmission constraints sometimes give suppliers the power to influence prices. Second, the



Transmission Dependents challenge MISO's allocation of refunds for marginal loss charges, which account for the extra energy that generators must inject into a grid to supply electricity to faraway buyers (because electricity dissipates the further it travels from its source). We hold that FERC's conclusions on these points were reasonable, and we therefore deny the Transmission Dependents' petitions for review.

#### A

When electricity demand is high and the grids become congested, the possibility arises that sellers in some transmission constrained areas will be able to exercise their market power and charge higher-than-competitive prices. The Tariff separated these areas into Narrow Constrained Areas (NCAs), which pose more persistent competitive concerns, and Broad Constrained Areas (BCAs), which pose only intermittent competitive concerns. Under the Tariff, the independent market monitor compares bids in constrained areas to reference levels calculated from suppliers' historical costs. If those bids exceed the reference level by a certain increment and fail a market impact test, the independent market monitor mitigates the bids – replacing them with lower amounts designed to give sellers an appropriate but not higher-than-competitive investment return. *See* TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,949-50 PP 242, 245, 247. “The conduct screen sifts out prices that by some amount or percentage exceed a reference price. . . . The impact screen tests whether that price increment actually would cause market-clearing prices to rise a certain amount or percentage over the price that would prevail in the event of mitigation.” *Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 965-66 (D.C. Cir. 2005) (internal quotation marks omitted).

FERC concluded that the Tariff's approach to the mitigation of sellers' market power in the NCAs and BCAs

adequately responded to the market power problem by avoiding under-mitigation, and at the same time, not over-mitigating and squelching suppliers' incentives to invest in additional capacity in those areas. Challenging that conclusion, the Transmission Dependents focus on features of FERC's choices concerning the NCAs (Parts 1 and 2 below) and BCAs (Parts 3 and 4 below).

## 1

NCAs are areas where transmission constraints are expected to be binding for at least 500 hours during a given year, and where at least one seller is "pivotal" in that the constraint can only be resolved if the seller increases its generation output. *See* TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,955 P 276. The NCA definition thus focuses on individual seller conduct. *See id.* The NCA definition does not account for the possibility that even where a single seller lacks the influence over output necessary to be pivotal, a group of sellers in collusion may exercise such influence. More specifically, the NCA definition does not take into consideration how concentrated the relevant geographic section of the market is – even though there is a connection between market concentration and the likelihood of anticompetitive collusion: "Significant market concentration makes it easier for firms in the market to collude, expressly or tacitly, and thereby force price above or farther above the competitive level." *FTC v. H.J. Heinz Co.*, 246 F.3d 708, 724 (D.C. Cir. 2001) (internal quotation marks omitted); *see also Brooke Group Ltd. v. Brown & Williamson Tobacco Corp.*, 509 U.S. 209, 227 (1993) ("Tacit collusion . . . describes the process, not in itself unlawful, by which firms in a concentrated market might in effect share monopoly power, setting their prices at a profit-maximizing, supracompetitive level by recognizing their shared economic interests and their interdependence with respect to price and output decisions.").

The Transmission Dependents challenge the omission of market concentration analysis from the NCA definition. They proposed that MISO focus on multilateral conduct and use a market concentration metric – such as the Herfindahl-Hirschmann Index (HHI), which “is calculated by totaling the squares of the market shares of every firm in the relevant market.” *H.J. Heinz Co.*, 246 F.3d at 716 n.9. (When the Department of Justice and Federal Trade Commission review proposed mergers, those agencies treat a market with an HHI value exceeding a certain level (1,800) as highly concentrated, meaning the merger warrants careful attention because of the risk of abuse of market power that might result from increased concentration. *See id.*). FERC rejected that proposal, concluding that market concentration analysis was not mandatory in defining NCAs. *See* TEMT II Reh’g Order, 109 F.E.R.C. ¶ 61,157, at 61,704-05 PP 235, 241-44. FERC did, however, note that the independent market monitor could use the HHI to identify areas where market power is enough of a concern to warrant designation as NCAs; FERC thus deemed HHI analysis optional, not compulsory. *See* TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,956 P 283.

We conclude that FERC reasonably refused to direct MISO to define NCAs using the HHI or another market concentration measure. Petitioners’ argument that FERC precedent required a different determination errs in two respects: first, in misreading a prior FERC order in one case concerning market-based rates, and second, in mistaking the binding force of a subsequent FERC order in another case concerning the Pennsylvania-New Jersey-Maryland (PJM) Regional Transmission Organization (RTO).

First, in *AEP Power Marketing, Inc.*, FERC addressed aspects of its market-based rate evaluation framework, which applies to electricity suppliers that have received FERC’s

permission to charge market-based rates (rather than rates subject to “traditional cost-based rate ceilings”). See 107 F.E.R.C. ¶ 61,018, at 61,054-70 PP 30-127 (2004); *Grand Council of the Crees v. FERC*, 198 F.3d 950, 953 (D.C. Cir. 2000). FERC requires an applicant that wants to charge market-based rates to establish, among other things, “that it, and its affiliates, either do not have, or have adequately mitigated, market power in both generation and transmission.” *Grand Council of the Crees*, 198 F.3d at 953. To help determine which suppliers exercise market power and therefore ought not be given the latitude to charge market-based rates, FERC decided in *AEP* to use two analytical screens, one of which focuses on the generator’s seasonal market share. Generators with a market share of 20 percent or more are presumed to have market power, but they can produce evidence rebutting the presumption. See 107 F.E.R.C. ¶ 61,018, at 61,060-61 PP 71-72, 61,065-66 PP 101-03.

Because the *AEP* order did not embrace use of the HHI, it cannot be taken as precedent requiring its use here. Looking at a single firm’s individual market share, as FERC did in *AEP*, is obviously not the same thing as looking at all of the market shares of all of the firms in the market, which is what a concentration metric such as the HHI does – and which is what petitioners demanded MISO *had* to do in defining NCAs. Moreover, the market-based rate framework used in *AEP* is concerned with *shifting* the burden of proof on market power to generators with seasonal market shares of 20 percent or more; in contrast, *all* supplier bids in NCAs are reviewed under the conduct and impact tests, and suppliers have no opportunity to forestall application of those tests by offering evidence that they do not possess market power. Thus, as FERC properly noted, the market-based rates framework and the NCA concept are sufficiently distinct that “pieces of one should not automatically

be used as precedent for the other.” TEMT II Reh’g Order, 109 F.E.R.C. ¶ 61,157, at 61,705 P 242.

Second, petitioners are mistaken in relying on a subsequent proceeding in which FERC asked the PJM RTO to explain why it did not use the market power tests described in FERC’s *AEP* order. See *PJM Interconnection, LLC*, 110 F.E.R.C. ¶ 61,053, at 61,249 PP 80, 84 (2005). FERC issued the *PJM* order after FERC issued the rehearing order approving the MISO Tariff (dated November 8, 2004); it is that rehearing order that is challenged in this case. See TEMT II Reh’g Order, 109 F.E.R.C. ¶ 61,157, at 61,663. Agencies are ordinarily not required to “explain alleged inconsistencies in the resolution of subsequent cases,” when the subsequent case is not “part of a pattern of arguably inconsistent decision-making that began before the challenged action.” *AT&T Inc. v. FCC*, 452 F.3d 830, 839 (D.C. Cir. 2006) (internal quotation marks omitted). Petitioners have not established that there was any such pattern of inconsistency beginning before FERC’s original order approving the MISO tariff, so the ordinary rule governs, and in this case we cannot require FERC to square the *PJM* order with its decision concerning MISO.

In any event, the *PJM* order simply reflected a line of inquiry by FERC concerning the reasonableness of the RTO’s proposed concentration metric, but it in no way required *all* RTOs to use concentration metrics in *all* market power mitigation frameworks. In fact, the PJM proceedings ended in a settlement that decided nothing. As FERC noted: “The Commission’s approval of the settlement agreement does not constitute approval of, or precedent regarding, *any* principle or issue in this proceeding.” *PJM Interconnection, LLC*, 114 F.E.R.C. ¶ 61,076, at 61,282 P 3 (2006) (emphasis added). And this Court has already held that neither FERC nor challengers may rely on an uncontested settlement as precedent. *Kelley ex*

*rel. Mich. Dep't of Natural Res. v. FERC*, 96 F.3d 1482, 1490 (D.C. Cir. 1996).

FERC's orders in the *AEP* and *PJM* proceedings, then, did not compel it to direct MISO to perform market concentration analysis in defining NCAs. And FERC reasonably explained that market concentration analysis carried too great a risk of over-mitigation in the context of this market power mitigation scheme. See *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (“[T]he agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.”) (internal quotation marks omitted). Requiring the market power mitigation framework to focus on market concentration carried the risk of over-mitigation, and FERC reasonably took that into account. In sum, FERC's conclusion that market concentration analysis was not necessary to properly identify areas warranting NCA treatment was reasonable.

Within an NCA, the conduct test compares (i) a supplier's bid to (ii) the supplier's reference price – calculated from historical cost data – plus a “fixed cost adder” set at the supplier's “net annual fixed cost divided by the constrained hours” for the given year. See *TEMT II Order*, 108 F.E.R.C. ¶ 61,163, at 61,959 P 312. The Tariff defined the net annual fixed cost to be “the fixed cost of a new peaking generator minus revenue from applicable resource reserve adequacy payments.” *Id.* at 61,959 n.209. The fixed cost adder is designed to ensure that suppliers earn enough money not only to pay for generation of each additional unit of electricity within the NCA, but also to recover fixed costs such as the cost of

building generation facilities. The premise is straightforward: If sellers are unable to recover fixed costs, they will have little reason to remain in the area or to invest in new capacity for the area. *See id.* at 61,960 PP 316-17.

The Transmission Dependents seek to invalidate the fixed cost adder. They contend that the adder was vaguely defined and overly generous to suppliers at the expense of buyers such as the Transmission Dependents. According to petitioners, in those few NCAs where recovery of fixed costs poses a genuine problem, MISO should simply have set the adder at the supplier's marginal cost plus a 10-percent booster. FERC rejected that approach, concluding that the fixed cost adder as defined in the Tariff "provides a careful balance between the need to mitigate market power and to provide an efficient incentive to invest." *Id.* at 61,960 P 317.

Petitioners fail to convince us that FERC's approval of the fixed cost adder was unsupported by the evidence or inadequately explained. FERC's overall task, of course, was to ensure, based on record evidence, that the rates and practices set forth in the MISO Tariff were just, reasonable, and not unduly discriminatory. *See* 16 U.S.C. § 824d(a), (b). "The burden," however, "is on the petitioners to show that the Commission's choices are unreasonable and its chosen line of demarcation is not within a zone of reasonableness as distinct from the question of whether the line drawn by the Commission is precisely right." *ExxonMobil Gas Mktg. Co. v. FERC*, 297 F.3d 1071, 1084 (D.C. Cir. 2002) (internal quotation marks omitted).

Petitioners' argument that the appropriate investment incentive should have been limited to marginal-cost-plus-10-percent certainly casts no doubt upon the reasonableness of the adder that FERC approved. "[T]he just and reasonable standard," the Supreme Court has explained, "does not compel

the Commission to use any single pricing formula.” *Mobil Oil Exploration & Producing Se., Inc. v. United Distribution Cos.*, 498 U.S. 211, 224 (1991). Petitioners essentially submit that fixed cost recovery is *universally* guaranteed by setting the adder at marginal cost (as estimated from historical cost data) plus 10 percent, but that mistakenly presupposes the existence of a “single pricing formula” for fixed cost recovery that meets the just and reasonable standard. *Id.* Petitioners’ argument goes astray, in other words, by substituting a pinpoint (marginal cost plus 10 percent, and not a penny more) for a zone of reasonable options FERC can choose from. *See ExxonMobil Gas Mktg.*, 297 F.3d at 1084.

Moreover, FERC’s conclusion that the fixed cost adder was necessary “to provide an efficient incentive to invest” was a judgment about the future behavior of entities FERC regulates. TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,960 P 317. This forecast – that approval of the fixed cost adder would help ensure that electricity suppliers continue to invest in NCAs – was a reasonable predictive judgment that warrants judicial deference. It is well established that an “agency’s predictive judgments about areas that are within the agency’s field of discretion and expertise are entitled to particularly deferential review, as long as they are reasonable.” *EarthLink, Inc. v. FCC*, 462 F.3d 1, 12 (D.C. Cir. 2006) (internal quotation marks omitted and emphasis altered); *see Env’tl. Action, Inc. v. FERC*, 939 F.2d 1057, 1064 (D.C. Cir. 1991) (“[I]t is within the scope of the agency’s expertise to make . . . a prediction about the market it regulates, and a reasonable prediction deserves our deference notwithstanding that there might also be another reasonable view.”).

Petitioners contend that FERC’s predictive judgment failed to account for the testimony of two experts, who essentially opined that not *every* supply-constrained area of a power grid –



a load pocket – needs an investment incentive like the fixed cost adder.

The expert testimony that petitioners rely on, however, did not refute FERC’s conclusion that a fixed cost adder was appropriate for NCAs. The analysis by the Transmission Dependents’ witness, Laurence Kirsch, was not anchored in the particular terms used in the Tariff (such as the NCA definition or the fixed cost adder definition); rather, Kirsch made claims at a high level of generality. He stated, for example, that FERC “should be aware that there *may be* some times and places” where the “efficiency justification for high electricity prices is lacking.” Kirsch Aff. at 7 (emphasis added). That testimony fell short of establishing that the fixed cost adder was inappropriate for the NCAs as defined in the Tariff. The testimony from the market monitor’s witness, David Patton, likewise did not contradict FERC’s conclusion. He stated that “new investment is not always necessary in the load pocket.” Protest of Midwest [Transmission Dependent Utilities], FERC Docket No. ER04-691-000, at 134 (May 7, 2004) (internal quotation marks omitted and emphasis altered). That statement made the undisputed point that an effective market power mitigation scheme is one that seeks to distinguish between price increases attributable to resource scarcity (which signal a need for investment to reduce the scarcity) and price increases attributable to exercise of market power (which do not signal investment need and instead reflect lack of competition). If anything, the portion of Patton’s testimony that petitioners quote suggests that interference with market prices should be avoided: “Markets,” he testified, “should establish transparent price signals that accurately reveal the marginal value of resources in the load pockets.” *Id.* (internal quotation marks omitted). That statement did not cast doubt upon the logic of the fixed cost adder – which, by affording suppliers latitude in setting prices, embraces rather than undermines the notion that transparent

price signals are good for the market. In short, petitioners have not identified relevant record evidence that compelled FERC to invalidate the fixed cost adder.

Petitioners' final argument concerning the fixed cost adder is that FERC unreasonably declined to require MISO to revise the Tariff to clarify that the fixed cost adder calculation takes into account ("nets") all sources of fixed cost recovery – such as retail rates approved by state authorities. But petitioners informed FERC that they understood how the calculations would be performed, noting their understanding that the independent market monitor would "net any retail rate recovery against the numerator of the fixed cost adder." *Id.* at 129. So even assuming that the Tariff was imprecise in explaining how the adder would be calculated, petitioners' argument on this point does not warrant relief; they have admitted that they understand the very Tariff term they deem confusing.

Supplier bids in constrained areas may exceed reference levels by a certain amount under the conduct test before they are subject to the impact test for mitigation. In NCAs that certain amount is the fixed cost adder. BCAs are structured differently to account for their more robust competitive conditions. A supplier's bid in a BCA fails the conduct test if it exceeds the reference level by the lesser of \$100 per megawatt hour or 300 percent. The bid goes on to fail the impact test if it would cause the market-clearing price to rise – by the lesser of \$100 per megawatt-hour or 200 percent – above the price that would have prevailed had the supplier bid at the reference level. *See* TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,959 PP 307-12.

The Transmission Dependents urged FERC to revise those numbers, arguing that they afford suppliers in BCAs too much

leeway to charge high prices before mitigation kicks in. FERC rejected those arguments. *See* TEMT II Reh’g Order, 109 F.E.R.C. ¶ 61,157, at 61,700-01 PP 215-21.

Petitioners fear that suppliers in BCAs will hike their prices to just below the specified limits – to rake in as much money as they can without triggering mitigation. But FERC reasonably concluded that petitioners’ scenario is not likely to become reality. In BCAs, concerns about market power are “minimal” or “not expected to be significant on an on-going basis.” TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,953 P 264; TEMT II Reh’g Order, 109 F.E.R.C. ¶ 61,157, at 61,701 P 221. That means – *by definition* – that suppliers in these areas ordinarily face competition and must therefore charge what the market will bear, but suppliers may not charge more than that without risking the loss of customers to competing suppliers. Rivals will quickly undercut a supplier that insists on pushing its permissible pricing to the limit (by charging an amount just below mitigation-triggering levels). Again, most of the time a BCA is a competitive market. And in “a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that price is close to marginal cost, such that the seller makes only a normal return on its investment.” *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990).

Equally unavailing are the other arguments advanced against FERC’s approval of the BCA mitigation framework. In deciding that the BCA ceilings are just and reasonable, FERC emphasized that approving the MISO market power mitigation scheme required striking a balance between, on the one hand, detecting and dampening exercises of market power and, on the other hand, allowing generators to charge prices that are high enough for them to recover their fixed costs. *See* TEMT II

Reh'g Order, 109 F.E.R.C. ¶ 61,157, at 61,701 P 221. Mitigation within NCAs takes fixed cost recovery into account through the fixed cost adder. But in BCAs, there is no fixed cost adder. Rather, in these areas, the more lenient ceilings to which prices may rise above reference before triggering mitigation allow for fixed cost recovery.

Those ceilings, FERC concluded, reflect an appropriate trade-off between the interests of buyers and sellers – and, of course, setting a just and reasonable rate necessarily “involves a balancing of the investor and the consumer interests.” *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (quoted in *Grand Council of the Crees*, 198 F.3d at 956). As FERC recognized in this case, “[t]he potential for over-mitigation would increase as BCA thresholds are tightened,” and petitioners have failed to show that FERC acted unreasonably in choosing precisely what degree of over-mitigation risk was appropriate. TEMT II Reh'g Order, 109 F.E.R.C. ¶ 61,157, at 61,701 P 221. Indeed, this choice is a classic example of ratemaking that “involves policy determinations in which the agency is acknowledged to have expertise,” and, of course, our review of such determinations “is particularly deferential.” *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004, 1006 (D.C. Cir. 2005) (internal quotation marks omitted).

The Transmission Dependents next challenge FERC's decision to authorize mitigation within BCAs one year at a time, rather than to make such mitigation a permanent feature of the BCA landscape.

To begin with, we reject the suggestion that the claim is nonjusticiable because it is either moot or not ripe. A federal court must satisfy itself that the party invoking federal

jurisdiction has presented a justiciable case or controversy. *See* U.S. CONST. art. III, § 2, cl. 1. The mootness doctrine ensures that judicial relief can still redress the asserted injury. *See Spencer v. Kemna*, 523 U.S. 1, 7 (1998). The ripeness doctrine prevents the court from prematurely deciding a question. *See Ohio Forestry Ass'n v. Sierra Club*, 523 U.S. 726, 733 (1998); *see also Nevada v. Dep't of Energy*, 457 F.3d 78, 83-85 (D.C. Cir. 2006).

FERC authorized BCA mitigation for only one year. *See* TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,954-55 P 275. But after initially declining to renew that authority, FERC renewed it for a second year ending August 1, 2007. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 116 F.E.R.C. ¶ 61,068, at 61,403 PP 22-24, *reconsidering* 115 F.E.R.C. ¶ 61,158, at 61,549-50 PP 22-25 (2006). Because mitigation authority exists at this moment, the justiciability argument goes, the Transmission Dependents are not being injured, and the case is amenable to judicial resolution only when the mitigation authority has actually expired.

That theory overlooks, however, the continuing economic injury that the one-year sunset provision causes petitioners in planning *future* transactions – in an industry where long-term transactions are a matter of course. *Cf.* Protest of Midwest [Transmission Dependent Utilities] 115 (“MISO retail utilities typically obtain their power supply either from their owned generation facilities or from generation purchased under *long-term contracts*.”) (emphasis added). Although FERC may repeatedly renew the mitigation authority after August 1, 2007, such renewal is not guaranteed, and the lack of such a guarantee has an effect now. *Cf. S. Co. Servs., Inc. v. FERC*, 416 F.3d 39, 42-43 (D.C. Cir. 2005) (challenge to FERC order regarding petitioner’s one-year agreement with third party not moot where agreement, as renewed or “rolled-over,” remained in effect).

When the Transmission Dependents negotiate long-term wholesale power contracts with generators, the sunset provision requires petitioners to factor into the negotiations the fact that they could be subject to unmitigated prices – reflecting potential abuse of market power rather than legitimate supply costs – when transmission constraints are active within the BCAs.

Petitioners' inability to rely on mitigation after the expiration of mitigation authority thereby reduces their bargaining power in the here-and-now; that reduction of bargaining power is an economic injury that vacatur of the one-year limitation would certainly help redress. We are satisfied that this aspect of the Transmission Dependents' claim cannot be considered moot or unripe. *See Ohio Forestry Ass'n*, 523 U.S. at 733; *Calderon v. Moore*, 518 U.S. 149, 150 (1996). Petitioners' challenge to the sunset provision therefore is justiciable.

On the merits, the Transmission Dependents challenge FERC's decision to impose the one-year sunset because there was no evidence in the administrative record that market power abuse would be a problem within BCAs for only one year. On the contrary, the Transmission Dependents emphasize, BCAs are by definition those in which a transmission constraint raises market power concerns at least some of the time (although less often than in NCAs).

Petitioners' argument has a surface appeal. It is logical to believe that a time limit on the solution to a problem should be adopted only if the problem itself is time-limited. But this does not render FERC's determination either irrational or unsubstantiated. FERC adopted the sunset provision as a response to concerns that the Tariff vested the independent market monitor with excessive discretion in mitigating conduct within BCAs – which, again, are not listed as such in advance,

but rather designated dynamically by the monitor when transmission constraints become active. “Should we find problems” with the monitor’s discretion, FERC noted, “we will take appropriate action including consideration of terminating the BCA provision before the end of the one-year period.” TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,955 P 275.

Again, BCAs are competitive most of the time. And as this Court recognized in evaluating FERC’s decisions concerning the market power mitigation framework of a different RTO, “the presence of workable competition would suggest that many, perhaps most, possibly all, of the bids triggering mitigation will be due not to market power but to temporary scarcity.” *Edison Mission Energy*, 394 F.3d at 968. The power conferred on the monitor to impose mitigation is a substantial one, and it accordingly is reasonable for FERC to limit the discretion to use that power.

Although the order approving the Tariff may have been less than crystal clear on the point, it is evident that FERC concluded that limiting the monitor’s discretion would help attain the proper balance between under- and over-mitigation – by making it less likely that the monitor would be too aggressive in mitigating high bids attributable not to market power but to legitimate supply costs. It is also evident from context that FERC concluded that adopting a one-year time limitation on the mitigation authority was one means to cabin the discretion. The sunset provision made MISO responsible for seeking and adequately justifying renewal of BCA mitigation authority if necessary. FERC indicated as much on rehearing. “We are concerned that the application of mitigation” in BCAs “could result in excessive mitigation. This is especially true,” FERC noted, to the extent that the independent market monitor “may have some discretion in applying that mitigation.” Therefore, FERC concluded that “the need for mitigation within BCAs

should be re-evaluated after there is some *operational market experience*,” while noting that MISO could “file to continue such mitigation” in the future. TEMT II Reh’g Order, 109 F.E.R.C. ¶ 61,157, at 61,703 P 231 (emphasis added).

We find reasonable FERC’s concern about over-mitigation and the contribution of unfettered discretion on the part of the independent market monitor to that over-mitigation. Thus, we conclude that placing a one-year limitation on the BCA mitigation authority was a permissible response to the excessive discretion problem FERC sought to solve – a choice that satisfies the requirement of “reasoned decisionmaking” that the arbitrary or capricious standard embodies. *Allentown Mack Sales & Serv., Inc. v. NLRB*, 522 U.S. 359, 374 (1998) (internal quotation marks omitted).

## B

The amount of electricity a supplier injects into the grid always exceeds the amount the customer receives; some electricity dissipates as heat during transmission (and is referred to as transmission loss). *See Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 2 (D.C. Cir. 2002). MISO’s initial practice was to calculate the average transmission losses for the entire system and then to charge each market participant a pro rata share; at FERC’s prompting, MISO’s Tariff replaced that allocation scheme with “marginal loss pricing” for transmission losses, as reflected in the Locational Marginal Pricing (LMP) concept. TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,925 P 66; *see also supra* Part I.C. For present purposes, the most significant point is FERC’s recognition that marginal loss charges would exceed the average loss charges that utilities previously paid. To soften the blow from the new marginal loss pricing policy, FERC accordingly directed MISO to give refunds to market participants so that they would pay no more



than their average losses for a five-year transition period. *See id.* at 61,926 P 73 (refund directive aimed “to give market participants more time to adjust to the LMP approach for setting prices and to develop confidence in market processes”).

In particular, FERC ordered MISO to “refund the difference between the marginal loss charge and either an average loss or a historical loss charge to all existing transmission customers.” *Id.* at 61,926 P 74. “Entities will be given this refund,” FERC directed, “based either on historical loss charges associated with existing transmission service, or otherwise on average loss charges calculated by the Midwest ISO.” *Id.*

The Transmission Dependents interpret those sentences to mean that FERC required MISO to issue refunds based on the average losses incurred by *each individual* transmission customer. Petitioners insist that directive cannot be reconciled with FERC’s subsequent approval of MISO’s “Balancing Authority” approach to the refunds – which groups transmission customers by geographic territory and computes average losses on a grouped rather than an individual basis. *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,285, at 62,364 n.76, 62,365 PP 171-72 (2004) (“Compliance I”). That inconsistency, petitioners contend, makes FERC’s decisions arbitrary and capricious.

At the outset, FERC urges us not to reach the merits of this contention, on the theory that FERC has not made a final decision on the matter. In FERC’s view, a compliance order issued *after* the last of the orders challenged in this case directed MISO to continue entertaining petitioners’ suggested method for computing average losses, therefore deferring for another day a final FERC endorsement of MISO’s method for those computations. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 117 F.E.R.C. ¶ 61,142, at 61,765 P 28 (2006).

But the very compliance order on which FERC relies squarely refutes the jurisdictional argument. As that order explains, in an *earlier* compliance order – one challenged in this case – FERC concluded that MISO’s “method for allocating the refund of marginal loss surplus revenue is just and reasonable.” *Id.* at 61,765 P 25 & n.17 (citing *Compliance I*, 109 F.E.R.C. ¶ 61,285, at 62,365 P 171 (2004)). The Transmission Dependents’ claim focuses on precisely that just and reasonable conclusion in *Compliance I*. Although FERC has instructed MISO to consider the Transmission Dependents’ proposals for further refining MISO’s method for computing average losses, FERC has never stated it is willing to revisit the conclusion that the method is just and reasonable. *See id.* at 61,765 PP 25-31. And FERC has clarified that “any revisions in the future will be prospective in nature.” *Midwest Indep. Transmission Sys. Operator, Inc.*, 112 F.E.R.C. ¶ 61,086, at 61,595 n.16 (2005). Therefore, that conclusion is reviewable “final” agency action because, under Supreme Court precedent, it embodies “the consummation of the agency’s decisionmaking process” on what is just and reasonable, and it carries “legal consequences” for petitioners who have been denied refunds calculated according to the exact method they believe FERC initially promised them. *Bennett v. Spear*, 520 U.S. 154, 177-78 (1997) (internal quotation marks omitted). The mere fact that FERC has continued to allow fine-tuning through additional compliance filings does not affect the finality of *Compliance I*: “Commission rate orders often appear to leave detail issues to ‘compliance’ filings, without anyone supposing that this deprives them of finality.” *Pub. Utils. Comm’n of Cal. v. FERC*, 894 F.2d 1372, 1378 (D.C. Cir. 1990).

On the merits, we reject the Transmission Dependents’ arguments concerning MISO’s average loss computation method. In approving that method, FERC reasonably

interpreted its initial instructions that refunds be distributed “based either on historical loss charges associated with existing transmission service, or otherwise on average loss charges calculated by the Midwest ISO.” TEMT II Order, 108 F.E.R.C. ¶ 61,163, at 61,926 P 74.

We review FERC’s interpretation of its own orders for reasonableness. *See Natural Gas Clearinghouse v. FERC*, 108 F.3d 397, 399 (D.C. Cir. 1997). Petitioners point to no textual commitment by FERC to require individual, rather than group, calculation of the average losses; the initial order was simply silent on that individual-versus-group question. There is nothing unreasonable about FERC’s interpretation of that silence as permission for MISO to take a group loss approach.

Even apart from the asserted conflict with the initial order, petitioners also argue that approval of the “Balancing Authority” approach was arbitrary. To that end, petitioners have identified various ways in which they believe average loss computations tailored to individual transmission customers would be more equitable than those tailored by geographic sorting. Some of these assertions may have merit, as FERC itself appears to have recognized. In requiring MISO to make ongoing compliance filings on the subject, FERC has noted, for example, that under the group approach large entities within a group might receive more of a refund than deserved, while small entities might receive less than deserved. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 111 F.E.R.C. ¶ 61,053, at 61,252 PP 49-50 (2005).

FERC’s acknowledgment that the computation method can and should be refined does not, however, undercut FERC’s conclusion that the overall method affords a just and reasonable rate for the transmission customers. Merely because petitioners can conceive of a refund allocation method that they believe

would be superior to the one FERC approved does not mean that FERC erred in concluding the latter was just and reasonable. Again, reasonableness is a zone, not a pinpoint. *See ExxonMobil Gas Mktg.*, 297 F.3d at 1084 (“The burden is on the petitioners to show that the Commission’s choices are unreasonable and its chosen line of demarcation is not within a zone of reasonableness as distinct from the question of whether the line drawn by the Commission is precisely right.”) (internal quotation marks omitted). Of course, the “question is not whether record evidence supports petitioners’ version of events, but whether it supports FERC’s.” *Ariz. Corp. Comm’n v. FERC*, 397 F.3d 952, 954 (D.C. Cir. 2005) (internal quotation marks and alterations omitted). FERC explained its conclusion that the allocation method it approved furthered the purpose of the refunds, and that reasoned explanation warrants judicial deference.

### III

The Cooperatives’ petitions challenge FERC’s treatment of Schedule 17 of the TEMT, which recovers the administrative costs of MISO’s energy market services. *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 F.E.R.C. ¶ 61,042, at 61,147 P 176 (2005) (“GFA Reh’g Order”). Applying the cost-causation principle – “under which costs are to be allocated to those who cause the costs to be incurred and reap the resulting benefits,” *NARUC v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007) – the Commission concluded that the services paid for by Schedule 17 “will have both economic and reliability benefits” for all parties using the MISO grid, “including parties transacting under GFAs.” GFA Reh’g Order, 111 F.E.R.C. ¶ 61,042, at 61,148 P 181. FERC therefore concluded that Schedule 17 charges should be assessed on the transmission owners providing service under GFA agreements, including carved-out GFA agreements. *See id.*

The Cooperatives dispute FERC's finding that the parties to GFA transactions benefit from the TEMT markets. They argue that the Commission's ultimate conclusion was unsupported by substantial evidence, that its acceptance of some of the supporting material filed by MISO constituted an unexplained reversal, and that its refusal to hold an evidentiary hearing violated the Administrative Procedure Act and the Due Process Clause.

Before reaching the merits of these arguments, we consider Intervenor Duke's assertion that the Cooperatives lack standing to raise them. We must address this threshold question of the jurisdiction of the court, notwithstanding that FERC does not raise it. *See Steel Co. v. Citizens for a Better Env't*, 523 U.S. 83, 101-02 (1998). For the reasons stated below, we conclude that the Cooperatives have not been aggrieved by the orders under review, and we therefore dismiss their petitions without reaching the remaining issues.

"[A] party seeking judicial review of a FERC order must be aggrieved by that order." *N.M. Att'y Gen. v. FERC*, 466 F.3d 120, 121 (D.C. Cir. 2006); *see* 16 U.S.C. § 8251(b). "A party is aggrieved within the meaning of [§ 8251(b)] if it can establish both the constitutional and prudential requirements for standing." *Pub. Util. Dist. No. 1 of Snohomish County v. FERC*, 272 F.3d 607, 613 (D.C. Cir. 2001). The test for constitutional standing has three elements. "First, the plaintiff must have suffered an injury in fact – an invasion of a legally protected interest which is (a) concrete and particularized, and (b) actual or imminent, not conjectural or hypothetical. Second, there must be a causal connection between the injury and the conduct complained of – the injury has to be fairly traceable to the challenged action of the defendant, and not the result of the independent action of some third party not before the court. Third, it must be likely, as opposed to merely speculative, that

the injury will be redressed by a favorable decision.” *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 560-61 (1992) (citations, internal quotation marks, footnote, and alterations omitted).

Intervenor Duke argues that the Cooperatives cannot satisfy the injury-in-fact requirement because the orders under review did not approve the imposition of any additional charges on them. As explained above, the orders approve the imposition of Schedule 17 charges on the GFA providers – the transmission owners that provide service under GFA contracts. None of the Cooperatives, however, is a GFA provider. Instead, they are GFA customers – utilities that purchase power from the GFA providers under those contracts. The orders before us therefore do not inflict any injury on the Cooperatives. Any injury to them would arise only out of a subsequent proceeding in which the GFA providers submitted – and FERC approved – a modified tariff providing for a “pass-through” of Schedule 17 charges to GFA customers.

The Cooperatives freely concede that the injury they seek to avoid is the pass-through of Schedule 17 charges from GFA providers to customers like themselves. *See* Cooperatives’ Reply Br. 17-19. They nonetheless argue that they have been aggrieved by the orders under review because those orders conclusively determined that the TEMT markets provide benefits to both GFA providers *and* GFA customers. *See id.* at 17-18 (citing GFA Reh’g Order, 111 F.E.R.C. ¶ 61,042, at 61,147 P 175). The Cooperatives argue that, because of the cost-causation principle, this finding predetermined the outcome of any proceeding on a pass-through of Schedule 17 charges. *See id.* They also claim that the orders under review signaled FERC’s intention to approve a pass-through. *See id.* at 18-19.

As a threshold matter, the Cooperatives’ arguments rest on an untenable reading of the Commission’s orders. Far from

predetermining the outcome of a pass-through proceeding, the orders under review explicitly rejected requests that FERC approve a pass-through of Schedule 17 charges from providers to customers. The Commission instead reserved the issue for future proceedings, explaining that it lacked a “concrete proposal” for a pass-through and that the issue therefore was “not ripe for consideration.” *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,236, at 62,322 P 302 (2004) (“GFA Order”). On rehearing, FERC was even more explicit: “[I]n the GFA Order, the Commission did not predetermine the outcome of future proceedings involving proposals to pass TEMT related costs through to customers under particular GFAs.” GFA Reh’g Order, 111 F.E.R.C. ¶ 61,042, at 61,143 P 151.

But even if the Cooperatives were correct, and FERC’s reasoning in the orders under review would govern subsequent proceedings on a pass-through, we have repeatedly held that this sort of “injury” is insufficient to establish standing. A petitioner’s “interest in the Commission’s legal reasoning and its potential precedential effect does not by itself confer standing where, as here, it is ‘uncoupled’ from any injury in fact caused by the substance of [FERC’s] adjudicatory action.” *Telecomms. Research & Action Ctr. v. FCC*, 917 F.2d 585, 588 (D.C. Cir. 1990). Indeed, “mere precedential effect within an agency is not, alone, enough to create Article III standing, no matter how foreseeable the future litigation.” *Sea-Land Serv., Inc. v. DOT*, 137 F.3d 640, 648 (D.C. Cir. 1998); *see also Ala. Mun. Distributions Group v. FERC*, 312 F.3d 470, 473 (D.C. Cir. 2002); *Shell Oil Co. v. FERC*, 47 F.3d 1186, 1201-02 (D.C. Cir. 1995); *Crowley Caribbean Transp., Inc. v. Peña*, 37 F.3d 671, 674 (D.C. Cir. 1994).

As it turns out, MISO’s transmission owners did file a “concrete proposal” for a pass-through of Schedule 17 charges

to certain carved-out GFA customers, and FERC approved it in orders that are not before us in these petitions. *See Transmission Owners of the Midwest Indep. Transmission Sys. Operator, Inc.*, 110 F.E.R.C. ¶ 61,339, at 62,343 P 1 (2005), *reh'g denied*, 113 F.E.R.C. ¶ 61,122 (2005). Those orders allow a GFA provider to pass-through Schedule 17 charges to a carved-out GFA customer if it “affirmatively demonstrate[s]” that those charges are not “otherwise being recovered from the GFA customer.” *Id.* at 62,352 P 54. And this Court has denied a separate petition seeking review of those orders. *See E. Ky. Power Coop., Inc. v. FERC*, No. 06-1003, slip op. at 3 (D.C. Cir. June 15, 2007).

The fact that the Commission approved a pass-through of Schedule 17 charges to GFA customers in orders not currently before us does not alter our standing analysis. The Cooperatives may be aggrieved by *those* orders, but a petitioner must show that it has been aggrieved by the final order under review. *See* 16 U.S.C. § 825l(b) (“Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the . . . [D.C. Circuit].”). The fact that a petitioner may be aggrieved by other, related orders does not cure a failure to show an injury in fact caused by the order actually under review. *See N.M. Att’y Gen.*, 466 F.3d at 121-22 (holding that a petitioner lacked standing to challenge an order that was conditional on a further compliance filing, and that “[t]he fact that FERC accepted [the] compliance filing after the Petitioners sought judicial review of the [conditional] orders is insufficient, of itself, to cure the defect in the Petitioners’ request for judicial intervention”); *see also DTE Energy Co. v. FERC*, 394 F.3d 954, 960-61 (D.C. Cir. 2005) (same). The place to challenge this pass-through was in the petition to review the orders that permitted it.

Finally, the Cooperatives argue that, even if they are barred from raising their substantive claims in this proceeding, they



have standing to raise their procedural challenges here. Cooperatives' Reply Br. 21-22. It is true that we apply a modified standing analysis to procedural claims: "[a] person who has been accorded a procedural right to protect his concrete interests can assert that right without meeting all the normal standards for redressability and immediacy." *Defenders of Wildlife*, 504 U.S. at 572 n.7. That is, "[a petitioner] who alleges a deprivation of a procedural protection to which he is entitled never has to prove that if he had received the procedure the substantive result would have been altered. All that is necessary is to show that the procedural step was connected to the substantive result." *Massachusetts v. EPA*, 127 S. Ct. 1438, 1453 (2007) (quoting *Sugar Cane Growers Coop. of Fla. v. Veneman*, 289 F.3d 89, 94-95 (D.C. Cir. 2002)). But a petitioner asserting a procedural right "must nonetheless show [that] it has itself 'suffered personal and particularized injury'" because of the challenged substantive result. *Int'l Bhd. of Teamsters v. TSA*, 429 F.3d 1130, 1135 (D.C. Cir. 2005) (quoting *Fla. Audubon Soc'y v. Bentsen*, 94 F.3d 658, 664 (D.C. Cir. 1996) (en banc)); see *Defenders of Wildlife*, 504 U.S. at 572 n.7; *Ctr. for Law & Educ. v. Dep't of Educ.*, 396 F.3d 1152, 1157 (D.C. Cir. 2005). And that is what is lacking here.

As explained above, the Cooperatives have not shown that they have suffered a concrete and particularized injury caused by the orders under review. Consequently, they cannot satisfy either Article III's standing requirements, or 16 U.S.C. § 825l's requirement that a party seeking review of a FERC order be "aggrieved" by that order. We are therefore barred from considering their claims, including their procedural arguments.

The Transmission Owners are two utilities (Duke Energy Shared Services, Inc., and Xcel Energy Services Inc.) that provide transmission service under the Midwest Independent System Operator (MISO) Tariff. They maintain that FERC's solution to the problem of contracts pre-dating MISO's formation (the grandfathered agreements, or GFAs) has impermissibly shifted to ordinary market participants – including the Transmission Owners – the congestion costs that GFA transactions cause. The Transmission Owners accordingly seek to vacate FERC's decision approving as just and reasonable MISO's solution to the GFA problem. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,236 (2004) (“GFA Order”), *order on reh'g*, 111 F.E.R.C. ¶ 61,042 (2005) (“GFA Reh'g Order”), *order on reh'g*, 112 F.E.R.C. ¶ 61,311 (2005).

The tension between GFA terms and practices on the one hand and the MISO Tariff on the other hand was from the very beginning a “fundamental problem in the proposed design and operation” of MISO. *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,033, at 61,169 (2001) (“Opinion No. 453”), *order on reh'g*, 98 F.E.R.C. ¶ 61,141 (2002). FERC's solution to the problem hinged on sorting the GFAs into different classes and reaching appropriate accommodations for each.

Specifically, 229 GFAs remained in effect in March 2005. GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,275 P 4. FERC approved the settlement of 22 GFAs that are not at issue here. One settlement option – which petitioners do challenge in this Court – was Option B, under which MISO reimbursed the GFA parties for congestion costs linked to transactions scheduled through the Day-Ahead market. *See id.* at 62,316 P 264, 62,318

P 275. MISO shifts the costs of reimbursing the 30 GFAs that settled under Option B to the ordinary market participants, who bear them pro rata.

For the GFAs that did not settle, FERC's response varied according to the applicable standard for contract modification. One set, consisting of 50 GFAs, was subject to the "just and reasonable" standard of review. *See id.* at 62,295 P 130. FERC ordered that set to conform to the MISO Tariff under Options A or C, after finding that it was just and reasonable to do so. *See id.* at 62,296 P 137 & n.104, 62,297 P 139. For a distinct set of 127 GFAs whose transactions represented about 10 percent of MISO's peak load, FERC took a different course. Those GFAs allow modification or abrogation only when necessary in the "public interest" under the *Mobile-Sierra* doctrine. *See id.* at 62,297 P 141 & n.108. FERC concluded that compelling those GFAs to obey the MISO Tariff terms would not be necessary in the public interest, and FERC therefore concluded that they had to be carved out – essentially exempting the parties to that narrow class of GFAs from Tariff requirements, including congestion costs and scheduling rules, for a six-year transition period. *See id.* at 62,297 P 143. (The 127 GFAs carved out include some that did not specify a standard of review, and some that were outside FERC's jurisdiction; we will refer to all of them as GFAs protected by the *Mobile-Sierra* doctrine and subject to the public interest standard of review. *See id.* at 62,298 PP 147-50; *see also supra* Part I.D & n.5).

In this Court, the Transmission Owners first claim that FERC erred in approving the carve out of the 127 GFAs subject to the public interest standard. Second, they claim that FERC erred in approving the Option B settlement terms for 30 GFAs. Third, they assert that even if the carve out and Option B settlements were adequately supported as individual decisions, FERC erred in approving the carve out and Option B settlements

together as just and reasonable. (Xcel presses a fourth claim concerning FERC's designation of entities responsible in the first instance for paying GFA charges.) We hold that these claims are unsound, and we therefore deny the Transmission Owners' petitions for review.

## A

In the companion cases for which the *Mobile-Sierra* doctrine is named, the Supreme Court interpreted the Federal Power Act to substantially preserve the rights of federally regulated utilities to make private contracts among themselves, subject to only limited FERC intervention. *See United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 337-38, 347 (1956); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348, 352-55 (1956). The parallel Federal Power Act and Natural Gas Act struck a balance between “contract stability on the one hand and public regulation on the other.” *Mobile*, 350 U.S. at 344. As the Supreme Court has explained, Congress pre-supposed in enacting those statutes that in the wholesale market “the party charging the rate and the party charged were often sophisticated businesses enjoying presumptively equal bargaining power, who could be expected to negotiate a ‘just and reasonable’ rate as between the two of them.” *Verizon Communications Inc. v. FCC*, 535 U.S. 467, 479 (2002); *see generally id.* at 479-81 (describing historical difference between federal regulation of wholesale transactions and state or local regulation of retail transactions in energy and telephone markets). Facing such rate contracts, “the principal regulatory responsibility was not to relieve a contracting party of an unreasonable rate,” but instead “to protect against potential discrimination by favorable contract rates between allied businesses to the detriment of other wholesale customers.” *Id.* at 479 (citing *Sierra*, 350 U.S. at 355).

Thus, under the *Mobile-Sierra* doctrine, if and only if the public interest requires, FERC may “abrogate or modify freely negotiated private contracts that set firm rates or establish a specific methodology for setting the rates for service, and deny either party the right to unilaterally change those rates.” *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 14 (D.C. Cir. 2002). FERC’s abrogation or modification of an existing contract rate may not hinge on the mere fact that one of the parties finds it unprofitable. Rather, to meet the public interest standard – gleaned from Section 201(a)’s recital that the Federal Power Act “is necessary in the public interest,” 16 U.S.C. § 824(a) – FERC must make a finding that the existing rate “might impair the financial ability of the public utility to continue its service,” or that the rate would “cast upon other consumers an excessive burden, or be unduly discriminatory,” among other “circumstances of unequivocal public necessity.” *Sierra*, 350 U.S. at 355; *Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968); *see also Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 582 (1981) (FERC “lacks affirmative authority, absent extraordinary circumstances, to abrogate existing contractual arrangements.”) (internal quotation marks omitted).

The public interest standard is “much more restrictive than the just and reasonable standard” that FERC applies to rates not contractually shielded. *Atl. City Elec.*, 295 F.3d at 14. In any event, as FERC’s *Mobile-Sierra* analysis hinges on interpretation of utility contracts, our review of that analysis is deferential. *See, e.g., Vt. Dep’t of Pub. Serv. v. FERC*, 817 F.2d 127, 134-35 (D.C. Cir. 1987).

The first step in the *Mobile-Sierra* analysis is to determine whether the challenged regulatory action constitutes an abrogation or modification of the contracts protected by the

doctrine. The Transmission Owners insist that requiring the GFA parties to obey MISO Tariff terms would not abrogate or modify the GFAs. We reject that view. The central flaw in petitioners' argument is its radical oversimplification of the GFA problem. Giving short shrift to the tensions between the GFAs and the MISO Tariff, petitioners essentially claim that instead of carving out GFA transactions (thereby shifting the congestion costs they create onto all other market participants), FERC should have required MISO to simply impose a congestion charge on each GFA transaction – which, petitioners contend, would have placed the GFA and non-GFA transactions on equal footing. As FERC recognized in the orders at issue here, however, subjecting GFA transactions to Tariff terms would be far more disruptive for the GFA parties than that account of the problem suggests.

A critical concern that petitioners' account omits is the direct collision between GFA scheduling practices and the MISO Tariff's scheduling requirements. “‘Carving out’ GFAs,” FERC explained, “means that parties to GFAs are allowed to exercise the *scheduling* and energy management provisions of their GFAs in the same manner they did” before MISO's new markets started up. GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,289 P 90 (2004) (emphasis added). Were their transactions not exempted, the GFA parties would have been pressed to conform to the MISO Tariff scheduling provisions of the Day-Ahead market. Centralized transmission markets, such as those the Tariff established, cannot function unless market participants provide the central coordinator with *advance* information about the timing and amount of electricity they intend to transmit. The extent of advance notice required depends on the kind of market (e.g., day-ahead versus real-time); and the centralized coordinator must receive information on the transactions early enough to be able to compile and process that information. *Cf. Midwest Indep. Transmission Sys. Operator, Inc.*, 107 F.E.R.C.

¶ 61,191, at 61,784 n.53 (2004) (“Procedural Order”) (even in hour-ahead markets bids cannot simply be submitted last minute because “significant computing time is necessary to produce final hour-ahead schedules”) (internal quotation marks omitted).

But centralized scheduling in the Day-Ahead market is utterly foreign to the GFAs, some of which date back to the 1950s and 1960s and certainly are out of sync with FERC’s post-1990 efforts to spur the development of competitive bulk power markets. In particular, a number of the GFAs do not spell out the quantity of electricity to be purchased or the precise time when the buyer will take delivery; those details have often been worked out in the course of dealing on a real-time (not a day-ahead) basis between the GFA parties. “[S]pecific details of the contracts, such as usage, *scheduling requirements* and megawatt quantity or capacity, are not readily apparent on the face of some of the contracts.” *Id.* at 61,776 P 16 (emphasis added). That is why FERC could only discern “the number and location of megawatts represented under GFAs, and *how the GFAs are used in practice*” after conducting a factual investigation. *Id.* at 61,785-86 P 68 (emphasis added).

FERC’s investigation led it to conclude that “while the [MISO Tariff] does not rewrite the GFAs, it would impose significant changes in the manner in which transmission service is provided for [in] transactions under the GFAs that could result in cost shifts between the parties to the individual GFAs and thus affect the bargain between the parties to the individual GFAs.” GFA Reh’g Order, 111 F.E.R.C. ¶ 61,042, at 61,133 P 87 (2005). Because GFA commercial practices – including the scheduling terms developed through the parties’ course of dealing – are not all set forth in the text of the contracts themselves, FERC accurately determined that subjecting the GFA parties to MISO Tariff terms would not “rewrite” the plain text of the GFAs. Nevertheless, the scheduling problem

justified FERC's conclusion that subjecting the GFA parties to Tariff terms – in particular, coercing them through congestion charges to conform to the scheduling requirements of the Day-Ahead market – would result in “significant changes . . . affect[ing] the bargain between the parties to the individual GFAs.” *Id.*

Although FERC's wording may have been less than precise on this point, “the agency's path may reasonably be discerned,” as FERC's “significant changes” conclusion was tantamount to a finding that *not* carving out this narrow class of GFAs would modify them, thereby triggering application of *Mobile-Sierra's* public interest standard. See *Alaska Dep't of Env'tl. Conservation v. EPA*, 540 U.S. 461, 497 (2004) (“Even when an agency explains its decision with less than ideal clarity, a reviewing court will not upset the decision on that account if the agency's path may reasonably be discerned.”) (internal quotation marks omitted); *Nat'l Ass'n of Home Builders v. Defenders of Wildlife*, No. 06-340, slip op. at 11 (U.S. June 25, 2007). FERC's conclusion on the point was reasonable. The Commission determined that not carving out the GFAs at issue would have changed the terms of the GFA parties' bargain, in part by pervasively disrupting the GFA parties' scheduling practices – which as we have explained is an aspect of the problem petitioners completely omit from their account. Under this reasonable view, rejecting the proposed carve out would have not only affected the contracts but modified them – requiring FERC to satisfy the public interest standard under the *Mobile-Sierra* doctrine. Cf. *Am. Gas Ass'n v. FERC*, 428 F.3d 255, 263 (D.C. Cir. 2005) (if after FERC action terms of “service for which the parties have bargained remain unchanged,” then action “does not modify contracts, even if it affects them,” and public interest standard does not apply).



The second step in the *Mobile-Sierra* analysis is to determine whether the challenged modification or abrogation of the contracts protected by the doctrine is necessary in the public interest. If not, then FERC had no choice but to carve out these 127 GFAs. FERC decided that it could not meet the public interest standard: Because “the Energy Markets . . . can be operated reliably, with net benefits to the public” even with the *Mobile-Sierra* GFAs carved out, FERC determined that “unequivocal public necessity” did not support subjecting the relevant GFAs to the MISO Tariff. See GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,297 P 142; *Permian Basin Area Rate Cases*, 390 U.S. at 822. The Transmission Owners maintain FERC’s reasoning was erroneous, but we disagree.

In *Sierra*, although the Supreme Court did not purport to enumerate all the circumstances in which the public interest standard may be satisfied, the Court did provide three concrete examples of such circumstances: where the contract rate FERC aims to modify “might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory.” 350 U.S. at 355. To succeed in their challenge to FERC’s conclusion that the public interest standard was not met, petitioners must show FERC ignored relevant record evidence establishing one of these circumstances, or another similarly extraordinary circumstance of “unequivocal public necessity.” *Permian Basin Area Rate Cases*, 390 U.S. at 822.

But petitioners have demonstrated nothing like that. Although petitioners complain that the carve out will impermissibly shift congestion costs to everyone else in the market (except for those GFA parties that took the Option B settlement), petitioners do not claim – let alone prove – that the

cost shift was so severe as to threaten the “financial ability” of any utility “to continue its service,” or that the cost shift amounted to an “excessive” burden on any other market participants.

Moreover, although petitioners’ argument about the cost shift might be construed as presenting a claim that the cost shift was “unduly discriminatory” within *Sierra*’s meaning, that claim fails. Even when conduct amounts to undue discrimination in violation of Section 205 of the Federal Power Act, *see* 16 U.S.C. § 824d(b), such conduct is not automatically “unduly discriminatory” within the meaning of the *Mobile-Sierra* doctrine, thereby justifying a rate modification: “[I]t is possible to have discrimination that violates § 205(b) but does not dismantle the protection generally afforded to fixed-rate contracts under *Mobile-Sierra*.” *Town of Norwood v. FERC*, 587 F.2d 1306, 1314 n.21 (D.C. Cir. 1978). In other words, a claim of undue discrimination under *Mobile-Sierra* must overcome a *higher* hurdle than a claim of discrimination under Section 205. *See* 16 U.S.C. § 824d(b) (prohibiting utilities from showing “undue preference” or “unreasonable difference” among ratepayers). If the discrimination alleged does not constitute an “undue preference” forbidden by Section 205, then it also does not constitute undue discrimination permitting contract modification or abrogation in the public interest. That is the situation here: The alleged discrimination did not violate Section 205, so it did not justify contract modification under *Mobile-Sierra*.

To be sure, exempting the GFA parties from Tariff requirements was in some loose sense discriminatory, in part because it allows GFA parties to “schedule on short notice, with greater flexibility than non-GFA transmission users.” Procedural Order, 107 F.E.R.C. ¶ 61,191, at 61,784 P 61. And it is true that exempting some GFA transactions from congestion

costs means that remaining market participants subject to the Tariff must bear the congestion costs pro rata. FERC reasonably concluded, however, that such discrimination was inherent in the solution to the GFA problem, and that the extent of the discrimination was relatively small and not “undue.” Carving out the GFAs protected by *Mobile-Sierra*, FERC explained, “is possible only because of the small number of megawatts involved; larger carve-outs, in contrast, would require us to reevaluate this treatment.” GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,297 P 143; *see id.* at 62,290 P 99.

Forcing the public-interest GFA parties to conform to the MISO Tariff would thus have had comparatively small advantages, compared to the distinct *disadvantages* that would result from not exempting them. On this point, again, petitioners’ analysis gives virtually no weight to the settled expectations of the parties to GFAs protected by *Mobile-Sierra*; FERC, of course, could not afford to be so dismissive. Thus, the discrimination alleged by petitioners was not undue discrimination forbidden by Section 205 – and necessarily fell short of establishing that the public interest required modifying or abrogating the narrow class of GFAs at issue. *See Town of Norwood*, 587 F.2d at 1314 n.21.

Finally, there was yet another reason FERC reasonably determined that “unequivocal public necessity” did not mandate overriding the narrow class of GFAs at issue. *Permian Basin Area Rate Cases*, 390 U.S. at 822. Doing so would have disrespected the agreement between *all* the utilities that formed MISO to give the GFAs a transition period before subjecting them to the Tariff. MISO’s January 1998 formation agreement “proposed to not place existing bundled retail load and *any grandfathered wholesale load* under the Midwest ISO’s Tariff for at least a six year transition period.” Opinion No. 453, 97 F.E.R.C. ¶ 61,033, at 61,169 (emphasis added). In the course of its decisions concerning MISO, FERC sought to preserve to the

extent possible “the bargain that many of the transmission owners relied upon in creating” MISO by affording a transition period for the GFA parties before they become fully subject to the Tariff. GFA Reh’g Order, 111 F.E.R.C. ¶ 61,042, at 61,132 P 81. Having long ago approved a filing supporting the expectation that the GFAs would receive “special treatment” in the establishment of MISO’s new markets, FERC would have upset that settled expectation if it did not carve out those GFAs protected by the *Mobile-Sierra* doctrine. Procedural Order, 107 F.E.R.C. ¶ 61,191, at 61,776 P 15; *see* GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,294 P 125. We conclude that FERC permissibly weighed the need to preserve the terms of the formation bargain in deciding that “unequivocal public necessity” did not call for abrogating or modifying the GFAs protected by the *Mobile-Sierra* doctrine. Petitioners’ argument for a contrary result would essentially have FERC give no weight in its public interest analysis to the formation agreement’s promise of “special treatment” for the GFA parties, which we cannot accept. Procedural Order, 107 F.E.R.C. ¶ 61,191, at 61,776 P 15. The MISO formation agreement, after all, is itself a private contract, and we have previously cautioned FERC against “cavalierly disregarding private contracts.” *Union Elec. Co. v. FERC*, 890 F.2d 1193, 1195 (D.C. Cir. 1989) (internal quotation marks omitted).

To sum up: Petitioners have underestimated the disruption to the narrow class of GFAs protected by the *Mobile-Sierra* doctrine that would have resulted had FERC not approved the carve out. We therefore reject petitioners’ contention that FERC’s reasoning in this case threatened to expand that doctrine beyond its proper bounds; rather, FERC’s analysis was fully consistent with the doctrine. FERC reasonably concluded that the public interest standard was not satisfied here, and FERC therefore was not arbitrary or capricious when it determined that the GFAs protected by the *Mobile-Sierra* doctrine should not be

forced to comply with the MISO Tariff and instead should be carved out.

## B

FERC approved Option B only for those 30 GFA parties that settled before July 28, 2004, the end of a period FERC afforded for trial-type hearings to resolve factual disputes about the terms of the GFAs. *See* GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,316-17 P 264; Procedural Order, 107 F.E.R.C. ¶ 61,191, at 61,787 P 76. As FERC recognized, Option B presented the GFA parties with a meaningful advantage over the other options by reimbursing the GFA parties for congestion costs and loss charges as long as the parties provide MISO with a day-ahead schedule of their transmission service demands. That reimbursement gave GFA parties a distinct financial incentive to switch from real-time scheduling to the new, Day-Ahead market. FERC thus endorsed Option B as a “carrot” to give GFA parties a reason to settle. *See* GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,316 P 264 (“Option B was an incentive to settle and receive a hedge against congestion and marginal losses charges.”). The settlements, FERC explained, would help to “avoid the expensive and time-consuming hearing process that would otherwise be necessary and to provide all parties the benefits of a functional organized market in a more timely manner than would otherwise be possible.” Procedural Order, 107 F.E.R.C. ¶ 61,191, at 61,787 P 80. For GFAs that settled, FERC did not have to determine the applicable standard of review (that is, whether the *Mobile-Sierra* doctrine applied).

Petitioners contend that FERC erred in allowing the Option B settlements. We disagree. Contrary to petitioners’ claim, this is not a case in which FERC “failed to provide an adequate explanation for its decision to approve the settlement” under Option B’s terms. *Laclede Gas Co. v. FERC*, 997 F.2d 936, 945

(D.C. Cir. 1993). By giving an incentive for the GFA parties to voluntarily conform their transactions to MISO Tariff terms, the Option B settlements reduced the scope of the “fundamental problem” that the GFAs presented; increased GFA participation in the markets also increased the markets’ reliability (by increasing the accuracy of MISO’s estimates of how much electricity would flow through the grids each day).

To be sure, petitioners and other ordinary market participants bore the cost of that incentive. For example, GFA parties that settled under Option B transmit electricity over MISO grids, but those parties receive compensation for congestion costs on transmissions scheduled through the Day-Ahead market – forcing ordinary market participants to bear those congestion costs pro rata. But all market participants also reaped the benefit of having MISO’s new markets start up faster than would have been possible had FERC been forced into litigation with all of the settling GFA parties. Difficult issues might have arisen in that litigation (such as whether the *Mobile-Sierra* doctrine would have applied to each GFA, and if so, whether the public interest standard could be satisfied), and resolution of those issues would have delayed the commencement of market operations.

This Court previously has stated that FERC “must indicate why the interest in avoiding lengthy and difficult proceedings warrants acceptance” of a challenged settlement. *Laclede Gas*, 997 F.2d at 947. We have never, however, required FERC to *quantify* the length and difficulty of the proceedings to be avoided through settlement, and we see no basis for doing so. FERC’s *qualitative* description of the costs and benefits supporting approval of the Option B settlements reasonably explained why those settlements were warranted.

Petitioners next claim that *even if* FERC’s reasoning correctly supported its decision to carve out the GFAs protected by the *Mobile-Sierra* doctrine, and *even if* FERC reasonably offered the Option B settlement terms, FERC erred in approving the carve out and the Option B settlements in combination as just and reasonable. Although one might question whether the whole can be *less* than the sum of its parts as this argument seems to suggest, FERC explicitly tied its approval of the carve out and its approval of the Option B settlements together: “[W]hile we discussed the impact of the carve-out and Option B treatments separately . . . our assessment of the overall benefits of the Energy Markets considered both the carve-out and Option B treatments together.” GFA Reh’g Order, 111 F.E.R.C. ¶ 61,042, at 61,134 P 96. Petitioners’ claim, then, amounts to a challenge to the adequacy of FERC’s conclusion that the *combined* benefits of the carve out and Option B settlements outweighed their combined burdens.

That claim is unsound. FERC’s balancing of the interests was reasonable given the relatively small magnitude of the impact on the markets that the carve out and the Option B settlements were expected to create. FERC acknowledged “that a carve-out of GFAs has the potential to result in additional costs for non-GFA transactions. However, we expect those impacts to be minor, in light of the small percentage of capacity to be carved-out.” GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,290 P 99; *see also id.* at 62,297 P 143. The transmission volume transacted by the GFA parties who were carved out is indeed relatively small – representing about 10 percent of MISO’s peak load. *See id.* at 62,275 P 4. The impact of the Option B settling GFA parties, representing about an additional five percent of peak load transmission volume, likewise was small. The relatively low volume of electricity transmissions in question

rationality supported FERC's conclusion that the overall harms associated with the carve out and Option B – namely cost-shifting and reduced reliability – did not outweigh the benefits to be gained from FERC's solution to the GFA problem. In upholding FERC's approval of the carve out and Option B individually, we have already explained why FERC reasonably evaluated those benefits. The carve out respected, first and foremost, the bargain between the parties to GFAs protected by the *Mobile-Sierra* doctrine; it had the secondary benefit of preserving the promise of special treatment for GFAs set forth in the MISO formation agreement. For their part, the Option B settlements expanded the number of GFAs who abide by MISO Tariff terms while streamlining the administrative proceedings leading up to approval of the MISO Tariff.

Moreover, FERC's conclusion respected the principle of cost causation, "requiring that all approved rates reflect to some degree the costs actually caused by the customer who must pay them." *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (internal quotation marks and alteration omitted). "[G]iven the standard of review under the APA," this Court mandates only "that the cost allocation mechanism not be 'arbitrary or capricious' in light of the burdens imposed or benefits received." *Id.* at 1369. FERC met that requirement for the reasons we have already surveyed: Although the carve out and Option B settlements shifted congestion costs caused by GFA transactions to other market participants, the market participants benefited from earlier commencement of market operations (which protracted litigation would have delayed) and the greater reliability that resulted from having as many GFA parties as feasible participate in the new markets.

Nor was FERC's decision to approve the carve out (again, for a narrow class of GFAs) and the Option B settlements



inconsistent with its conclusion that *all* GFA parties should pay the Schedule 17 charges covering MISO's market operation and administrative costs. Schedule 17 charges pay for the market functions as a whole, and not for the costs created by a specific transaction. *See, e.g.*, GFA Reh'g Order, 111 F.E.R.C. ¶ 61,042, at 61,147 P 176. That sets Schedule 17 charges apart from the congestion charges that the GFA parties would have been forced to pay had they been either not carved out or not allowed to select Option B, which relieved settlers of congestion cost liability on transmissions scheduled through the Day-Ahead market. *See id.* at 61,134 n.111.

In short, FERC's approval of the carve out and Option B in combination was not "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(A).

#### D

Finally, Xcel Energy Services challenges the designation of several of its subsidiaries, rather than their customers, as GFA Responsible Entities (that is, the GFA parties liable in the first instance for MISO Tariff charges).

To review: FERC initially asked the GFA parties to agree among themselves which of them should be the Responsible Entity for each GFA. *See* GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,291 PP 103-04. Numerous GFA parties, including Xcel's subsidiaries, failed to amicably resolve the issue. For those recalcitrant GFA parties, FERC sought to streamline matters by adopting a default rule designating the GFA provider – namely, the utility that takes transmission service from MISO grids and supplies it to the GFA customer – as the Responsible Entity for each GFA. *See id.* at 62,300-01 PP 160-62. Although the provider takes the MISO Tariff-constrained service for the

ultimate benefit of the customer, FERC concluded that the provider should be responsible because it is the provider that interacts with MISO's grids, and it is the provider that is certified as a market participant "financially responsible" to MISO "for all of its Market Activities and obligations," whereas some GFA customers are not so certified. *Id.* at 62,299 P 152 & n.122 (internal quotation marks omitted).

Xcel falls short of demonstrating that FERC's determination was arbitrary or capricious. A GFA transaction may be described in two analytical steps. In the first of these analytical steps, the GFA provider receives electricity transmitted over the MISO grids. MISO is not involved in the second analytical step – the transmission of electricity on a "back-to-back basis" from the GFA provider to the GFA customer. *See* Transmission Owners' Br. 12 ("MISO provides TEMT service to the transmission owner that is a party to the GFA, and the transmission owner in turn, on a back-to-back basis, provides the GFA service to its GFA counterparty."); *see also id.* at 4. Because the Responsible Entity must pay charges to MISO, FERC reasonably concluded that the GFA provider – which *does* interact directly with MISO – should be responsible in the first instance. This is particularly so given FERC's refusal in the orders at issue here to in any way prevent GFA providers from passing their Tariff-related liability through to GFA customers where appropriate. FERC simply "did not predetermine the outcome of future proceedings involving proposals to pass [Tariff] related costs through to customers under particular GFAs." GFA Reh'g Order, 111 F.E.R.C. ¶ 61,042, at 61,143 P 151. Thus, Xcel's argument that FERC's designation rule deviated from cost-causation principles fails because that rule simply did not foreclose Xcel's subsidiaries and other Responsible Entities from shifting ultimate liability for the MISO charges onto the GFA customers.

Moreover, it made sound business sense to require that the Responsible Entity be a utility that was *already* required by the Tariff definition to be financially responsible to MISO. *See* GFA Order, 108 F.E.R.C. ¶ 61,236, at 62,299 P 152 & n.122. The Responsible Entity designation does no more than identify *who* will pay MISO's bill in the first instance; someone has to be on the hook to pay that bill, because otherwise MISO could not fund its operations. By linking the Responsible Entity designation to the definition of a market participant under the MISO Tariff, FERC simply presumed that market participant status ensured responsibility sufficient for administering the various charges associated with the Tariff – and that presumption was entirely rational.

## V

We dismiss the Cooperatives' petitions for review for lack of standing, and we deny the Transmission Dependents' and Transmission Owners' petitions for review.

*So ordered.*