

ORAL ARGUMENT HAS NOT BEEN SCHEDULED

**In the United States Court of Appeals
for the Fifth Circuit**

No. 25-60127

ARKANSAS PUBLIC SERVICE COMMISSION;
MISSISSIPPI PUBLIC SERVICE COMMISSION,

Petitioners,

v.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

consolidated with

No. 25-60208

CLEAN GRID ALLIANCE; ADVANCED POWER ALLIANCE;
ADVANCED ENERGY UNITED; AMERICAN CLEAN POWER ASSOCIATION;
SOLAR ENERGY INDUSTRIES ASSOCIATION,

Petitioners,

v.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

ON PETITIONS FOR REVIEW OF ORDERS OF THE
FEDERAL ENERGY REGULATORY COMMISSION

**BRIEF OF RESPONDENT
FEDERAL ENERGY REGULATORY COMMISSION**

David L. Morenoff
Deputy General Counsel

Robert H. Solomon
Solicitor

Robert M. Kennedy
Deputy Solicitor

Federal Energy Regulatory
Commission

888 First Street, N.E.
Washington, DC 20426
(202) 502-6790

December 16, 2025

CERTIFICATE OF INTERESTED PARTIES

*Arkansas Public Service Commission, et al. v. Federal Energy
Regulatory Commission*, Nos. 25-60127, 25-60208

The undersigned counsel of record certifies that the following listed persons and entities, as described in the fourth sentence of Rule 28.2.1, have an interest in the outcome of this case. These representations are made in order that judges of this Court may evaluate possible disqualifications or recusal.

COUNSEL FOR MISSISSIPPI PUBLIC SERVICE COMMISSION

William D. Booth and Alex L. Peterson of Michael Best & Friedrich LLP

COUNSEL FOR ARKANSAS PUBLIC SERVICE COMMISSION

Bridgette M. Fraizer of Arkansas Public Service Commission

COUNSEL FOR CLEAN GRID ALLIANCE; ADVANCED POWER ALLIANCE;
ADVANCED ENERGY UNITED; AMERICAN CLEAN POWER ASSOCIATION;
SOLAR ENERGY INDUSTRIES ASSOCIATION

Nicholas M. Gladd, Steven Boughton, and Kelsy Catina of Wilson
Sonsini Goodrich & Rosati, P.C.

Gabriel Tabak of American Clean Power Association

COUNSEL FOR SOUTHWEST POWER POOL INC.

Matthew Binette and Vivian Chum of Wright & Talisman, P.C.

COUNSEL FOR INTERVENOR MISO TRANSMISSION OWNERS

Wendy Reed of Wright & Talisman, P.C.

COUNSEL FOR MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

Christopher Davies Supino of Midcontinent Independent System
Operator, Inc.

COUNSEL FOR FEDERAL ENERGY REGULATORY COMMISSION
David Morenoff, Robert Solomon and Robert Kennedy of the
Federal Energy Regulatory Commission

/s/ Robert M. Kennedy
Attorney of Record
For Federal Energy
Regulatory Commission

December 16, 2025

STATEMENT REGARDING ORAL ARGUMENT

In accordance with Circuit Rule 28.2.3 and Federal Rule of Appellate Procedure 34(a)(1), Respondent Federal Energy Regulatory Commission submits that oral argument would assist the Court's resolution of this case. Oral argument will enable counsel to answer any questions the Court might have regarding the Commission's interconnection policies, as well as its review of filings under Section 205 of the Federal Power Act, 16 U.S.C. § 824d.

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GLOSSARY

Commission or FERC	Respondent Federal Energy Regulatory Commission
Generators	Clean Grid Alliance, Advanced Power Alliance, Advanced Energy United, American Clean Power Association, and Solar Energy Industries Association, petitioners in Case No. 25-60208
Gen. Br.	Brief of Petitioners Clean Grid Alliance, Advanced Power Alliance, Advanced Energy United, American Clean Power Association, and Solar Energy Industries Association, filed October 17, 2025
Initial Order	<i>Midcontinent Indep. Sys. Operator, Inc.</i> , 189 FERC ¶ 61,108 (2025) (R.148)
Midcontinent or MISO	Respondent-Intervenor Midcontinent Independent System Operator, Inc.
MISO JTIQ Filing	Submission of Revisions to the MISO-SPP Joint Operating Agreement to Implement Joint Targeted Interconnection Queue Framework, filed by Midcontinent Independent System Operator, Inc. on August 16, 2024 (R.1)
MISO Tariff Filing	Proposed Revisions to MISO Tariff to Implement Joint Targeted Interconnection Queue Framework, filed by Midcontinent Independent System Operator, Inc. on August 26, 2024 (R.21)

Portfolio upgrades	The five 345-kilovolt transmission projects identified through the Joint Targeted Interconnection Queue study process
Protest	Protest of Clean Energy Associations, filed Sept. 19, 2024 (R. 117)
Rehearing Order	<i>Midcontinent Indep. Sys. Operator, Inc.</i> , 191 FERC ¶ 61,231 (2025) (R.166)
Southwest or SPP	Respondent-Intervenor Southwest Power Pool, Inc.
SPP JTIQ Filing	Submission of Revisions to the MISO-SPP Joint Operating Agreement to Implement Joint Targeted Interconnection Queue Framework, filed by Southwest Power Pool, Inc., on August 16, 2024 (R.2)
SPP Tariff Filing	Submission of Revisions to SPP Tariff, filed Aug. 21, 2024 (R.17)
States	Arkansas Public Service Commission and Mississippi Public Service Commission, petitioners in Case No. 25-60127
State Br.	Brief of Petitioners Arkansas Public Service Commission and Mississippi Public Service Commission, filed October 17, 2025

INTRODUCTION

Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc., operators of regional electricity transmission systems in the central United States, were facing a serious problem. For years, they had been receiving a massive number of interconnection requests from new generation projects seeking to plug into their grids, particularly projects planned for the central and upper Midwest where the two transmission systems share a border or “seam.” But the grid at the seam was at capacity.

To accommodate new generators, system upgrades would be needed. But these upgrades were often prohibitively expensive for any single generator or small group of generators to bear. As a result, developers would often cancel their generation projects late in the interconnection review process, leading to delays and increased costs for other proposed projects waiting to be evaluated. Even when upgrades were constructed, they only added enough capacity for a single interconnection, thereby leaving the same problems to recur when the next batch of interconnection requests were analyzed.

The Joint Targeted Interconnection Queue framework was the system operators' innovative solution. Rather than considering upgrades on a piecemeal basis in response to specific interconnection requests, Midcontinent and Southwest identified five large-scale network upgrade projects that would allow for the interconnection of numerous generation resources across many years. The projects are estimated to enable at least 28 gigawatts of new generation. (For perspective, that is the equivalent of adding the capacity of 14 Hoover dams.)¹

The upgrades will be initially paid for, and built, by the transmission owners in whose existing service territories the projects will be located. The collective capital costs of the upgrades will then be charged, on a pro rata basis, to those interconnecting generators making use of them.

Because these large-scale upgrades will provide enough transmission capacity to accommodate generator interconnections across a long time horizon, they could go into service before all their

¹ See Department of Energy, *How Much Power is 1 Gigawatt?*, <https://perma.cc/3CTA-S4A5>.

capacity has been subscribed. To address this, the Joint Targeted Interconnection Queue framework has a backstop funding mechanism whereby Midcontinent and Southwest transmission customers (local utilities serving retail “load”) will be charged for any funding shortfall. As new generators come online and make use of the upgrades, they will be backcharged for their share of the costs, and their payments will be used to refund transmission customers with interest. If the upgrades’ capacity is never fully subscribed, any funding shortfall will be for transmission customers’ accounts.

The Commission found that the proposed Joint Targeted Interconnection Queue framework was “just and reasonable” within the meaning of the Federal Power Act. The Commission determined that it was appropriate to allocate primary responsibility for the capital costs of the upgrades to interconnecting generators since they are the primary beneficiaries. The sole reason the upgrades are being constructed is to enable large amounts of generator interconnections. And before any generator is charged, power flow modelling will establish that it will be making use of the upgrades to deliver power to the market.

The Commission also accepted the proposed backstop funding mechanism. First, the uncontradicted evidence established that it was highly unlikely that transmission customers will ultimately incur unreimbursed costs given the large amount of pending interconnection requests. Second, the upgrades will benefit transmission customers by, among other things, promoting a more reliable grid and enabling timelier generator interconnections, which helps local utilities meet their power demands in a cost-efficient manner. The Commission found that these benefits would flow to transmission customers in the southern portion of Midcontinent’s transmission system, even though the upgrades will be built elsewhere. Thus, it was reasonable to include all Midcontinent transmission customers in the backstop funding mechanism.

Petitioners Clean Grid Alliance, *et al.*—the “Generators”—contend that the Commission’s decision is arbitrary because more costs should be allocated to transmission customers. The Public Service Commissions of Alabama and Mississippi—the “States”—challenge the Commission’s decision from the other direction, claiming that no costs

should be allocated to transmission customers in Midcontinent's southern region.

STATEMENT OF THE ISSUES

The issues presented for review are:

1. Did the Commission reasonably determine that it is "just and reasonable," as the Federal Power Act requires, to allocate primary funding responsibility to interconnecting generators since they are the primary beneficiaries of the network upgrades.
2. Did the Commission reasonably determine that transmission customers in Midcontinent's southern region will receive some benefits from the network upgrades, such that it is reasonable to allocate to them a backstop funding obligation which is highly unlikely to lead to any permanent costs.

STATUTES AND REGULATIONS

Pertinent statutes and regulations are reproduced in the Addendum to this brief.

STATEMENT OF THE CASE

I. Statutory Background

The Federal Power Act declares that federal regulation of “matters relating to generation ... and ... the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce” is “necessary in the public interest.” 16 U.S.C. § 824(a). To that end, section 201(b) of the Act gives the Commission jurisdiction over the “transmission of electric energy in interstate commerce,” the “sale of electric energy at wholesale in interstate commerce,” and “all facilities for such transmission or sale.” *Id.* § 824(b)(1); *see also FERC v. Elec. Power Supply Ass’n*, 577 U.S. 260, 266 (2016). This grant of jurisdiction extends to the interconnections of generation facilities to the electric grid—a necessary process for delivering energy to the wholesale market. *Nat’l Ass’n of Reg. Util. Comm’rs v. FERC*, 475 F.3d 1277, 1280 (D.C. Cir. 2007); *see also NextEra Energy Cap. Holdings, Inc. v. Lake*, 48 F.4th 306, 319 (5th Cir. 2022) (FERC has “jurisdiction to regulate ‘all facilities for [the interstate] transmission ... of electric energy.’”) (quoting 16 U.S.C. § 824(b)(1)).

The Act directs the Commission to ensure that all rates and charges for, or in connection with, transmission services or wholesale sales subject to its jurisdiction, and all rules, regulations, or practices affecting such rates and charges, are just and reasonable and not unduly discriminatory or preferential. *See* 16 U.S.C. §§ 824d, 824e; *see also El Paso Elec. Co. v. FERC*, 76 F.4th 352, 357 (5th Cir. 2023) (“*El Paso II*”).

II. Connecting to the Electric Grid

A. Overview of the Bulk Power System

The United States’ bulk power system consists of three principal components: generation, transmission, and local distribution.

Generation takes place at power plants where fuels such as coal, natural gas, uranium, or the energy inherent in wind, sunshine, or water, are used to generate electricity. A complex network of high-voltage transmission lines moves that electricity over long-distances.

Once it travels to the vicinity of the end user, local public utilities deliver the electricity to customers over distribution lines. The demand placed on the grid is called “load,” and that term is used to refer to transmission customers or end users of energy, depending on the context. *See Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239, 249 n.1 (D.C.

Cir. 2007); *see also* FERC, ENERGY PRIMER: A HANDBOOK OF ENERGY MARKET BASICS 44-52 (2023), <https://perma.cc/2Q46-DKQW>.

B. Operating The Transmission Grid

1. Unbundling transmission and generation

“In the bad old days,” power grids were run by “vertically integrated monopolies” that owned and operated generation, transmission, and distribution facilities. *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1363 (D.C. Cir. 2004). Utilities sold these services “as a ‘bundled’ package to wholesale and retail customers in a limited geographical service area.” *Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607, 610 (D.C. Cir. 2001). This practice resulted in artificially high prices for consumers. *See Transmission Access Pol’y Study Grp. v. FERC*, 225 F.3d 667, 685 (D.C. Cir. 2000).

In 1996, the Commission issued its Order No. 888 rulemaking, which required transmission owners to give other generators equal access to their facilities. *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996). The Commission directed transmission owners to “file open

access nondiscriminatory tariffs” for wholesale transmission service, thus effectively “unbundling” sale of the power itself from sale of the transmission service. *See Detroit Edison Co. v. FERC*, 334 F.3d 48, 50 (D.C. Cir. 2003); *see also Transmission Access*, 225 F.3d at 681 (upholding Order No. 888 in “nearly all respects”), *aff’d*, *New York v. FERC*, 535 U.S. 1 (2002).

2. Encouraging Regional Transmission Organizations

To reduce the technical inefficiencies associated with different utilities operating different parts of the grid, the Commission encouraged transmission providers to form multi-utility “Regional Transmission Organizations,” which would be operated by “Independent System Operators.” *See Morgan Stanley Cap. Grp. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 536-37 (2008). These not-for-profit entities assume operational control, but not ownership, of their member utilities’ transmission facilities. *Id.*; *see also Lake*, 48 F.4th at 311. They then provide open access to the regional transmission system “at rates established in a single, unbundled, grid-wide tariff.” *NRG Power Mktg., LLC v. Me. Pub. Utils. Comm’n*, 558 U.S. 165, 169 n.1 (2010) (internal quotation marks omitted).

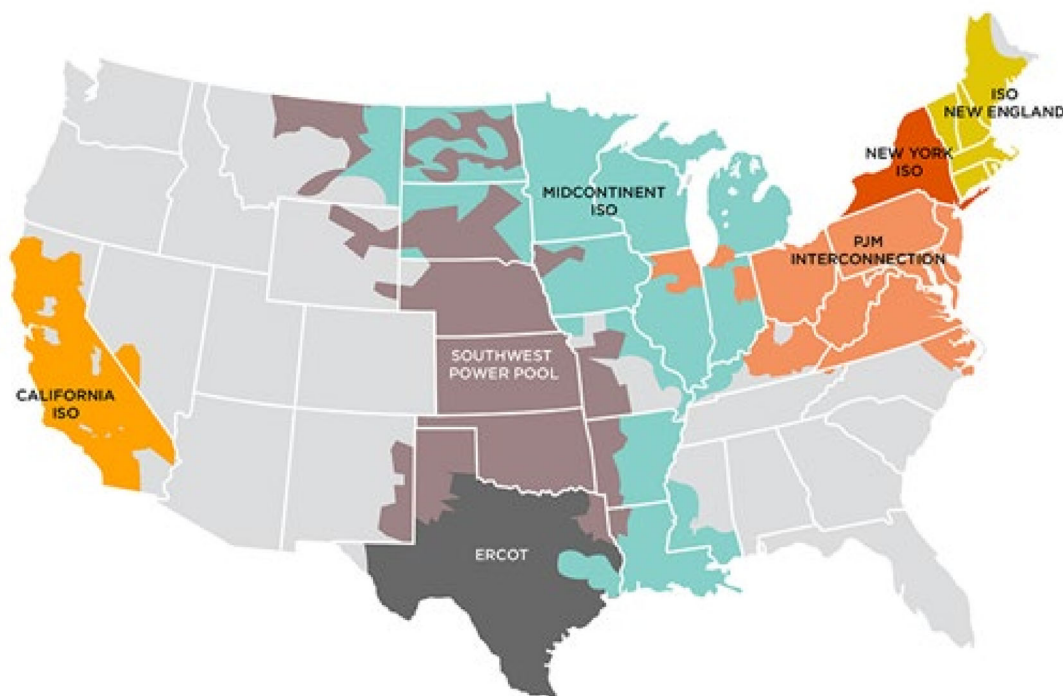
3. Southwest and Midcontinent

Two of the largest Regional Transmission Organizations (at least by geography) are Southwest and Midcontinent, and they happen to be adjacent to each other. *See Sw. Power Pool, Inc. v. FERC*, 736 F.3d 994, 995 (D.C. Cir. 2013).

Southwest exercises operational control over roughly 70,000 miles of electric transmission lines stretching from Arkansas to Montana and from Texas to North Dakota. *See FERC, Electric Power Markets: SPP* (Sept. 18, 2025), <https://www.ferc.gov/industries-data/electric/electric-power-markets/spp>. Midcontinent operates the transmission system in portions of 15 states, extending from Michigan to Montana and from the Canadian border to the southern extremes of Louisiana and Mississippi. *See FERC, Electric Power Markets: MISO* (June 26, 2025), <https://www.ferc.gov/industries-data/electric/electric-power-markets/miso>. Operationally, Midcontinent is divided into three subregions: MISO North (Minnesota, Iowa, North Dakota, and parts of Montana and South Dakota), MISO Central (Wisconsin, Michigan, and parts of Illinois, Indiana, Kentucky and Missouri), and MISO South (parts of Arkansas, Mississippi, Louisiana, and Texas). *See FERC,*

Participation in MISO Processes, <https://www.ferc.gov/participation-midcontinent-independent-system-operator-miso-processes>.

As illustrated below, Southwest and Midcontinent have largely distinct footprints. But their electrical systems connect to each other along numerous borders known as “seams.” *See, e.g., Constellation Energy Commodities Grp., Inc. v. FERC*, 602 F. App’x 536, 537 (D.C. Cir. 2015). Given the interconnected nature of their transmission systems, Midcontinent and Southwest have entered into a Joint Operating Agreement to coordinate power flows across their respective systems, and to engage in transmission planning along the seam.



See FERC, AN INTRODUCTORY GUIDE TO ELECTRICITY MARKETS (Apr. 3, 2025), <https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission>.

4. Expanding the grid to address demand

System operators, like Southwest and Midcontinent, are obligated to plan and manage the expansion of their transmission systems so they can continue to provide reliable and cost-effective transmission service. See, e.g., *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 50 (D.C. Cir. 2014); Energy Primer at 68, 92. This is accomplished through regional (*i.e.*, system-wide) and inter-regional (*i.e.*, with neighboring systems) studies that attempt to identify transmission projects that are necessary to either maintain compliance with reliability requirements, enable more cost-effective power to be delivered to consumers, or respond to public policy requirements. See, e.g., *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Advanced Notice of Proposed Rulemaking, 176 FERC ¶ 61,024, PP 8, 13-17 (2021) (“*Advanced Notice*”).

The need for projects identified through the transmission expansion planning process is deemed to arise from the demand placed on the system by transmission customers (*i.e.*, local utilities and their retail “load”). Accordingly, the costs for these projects are allocated to transmission customers “in a manner that is roughly commensurate with estimated benefits.” *Id.* P 11. No costs are assigned to generators, although they may benefit from such projects. *See* Southwest, Revisions to MISO-SPP Joint Operating Agreement, Test. of D. Kelley, Ex. No. SPP-0001, 44, R.2:133, filed Aug. 16, 2024 (“SPP JTIQ Filing”).²

5. Expanding the grid to address supply

To bring their electricity to the market, generators must establish an electric connection—*i.e.*, an interconnection—between their generation facilities and the transmission grid. The regional and inter-regional transmission planning processes generally do not consider the needs of future generation projects. *See* Advanced Notice, 176 FERC

² The parties have agreed to cite the challenged FERC orders as “short name P [Paragraph Number].” All other record items are cited as “R.[Record Item Number in Respondent’s Certified Index]:[Page Number of the Document],” with the page number representing the document’s overall PDF page number, even when the document has internal pagination.

¶ 61,024 at P 31. Instead, the infrastructure needed to accommodate new generators is identified through the “interconnection process.”

a. The interconnection process

Under that process, system operators typically open a window for interconnection requests. All requests received during that specified time period are grouped together in a “cluster” and placed in the “queue” behind earlier-received interconnection requests. *See Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 104 FERC ¶ 61,103, P 35 (July 24, 2003) (“*Order No. 2003*”), *aff’d sub nom. Nat’l Ass’n of Regul. Util. Comm’rs*, 475 F.3d 1277; *see also Tenaska Clear Creek Wind, LLC v. FERC*, 108 F.4th 858, 864-65 (D.C. Cir. 2024) (discussing Southwest’s cluster study process).

During the evaluation process, system operators conduct a series of power flow studies to assess the impact of adding a new generator on the preexisting electric grid. These studies identify any new facilities and equipment that may be needed to accommodate the new interconnection. *See, e.g., Pioneer Trail Wind Farm, LLC v. FERC*, 798 F.3d 603, 606 (7th Cir. 2015) (discussing Midcontinent interconnection process). In some instances, the interconnection has an impact on

neighboring grids. When this occurs, the neighboring grid operator will conduct an “affected system study” to identify the necessary upgrades to its own system. *See Tenaska*, 108 F.4th at 863-64.

b. “But for” cost allocation

Generators pay the cost of transmission system upgrades necessitated by their interconnection—either directly or by repaying the relevant transmission owner—under the so-called “but for” principle. *See* Order No. 2003, 104 FERC ¶ 61,103, at P 694 (“[I]t is appropriate for the Interconnection Customer to pay initially the full cost of Interconnection Facilities and Network Upgrades that would not be needed but for the interconnection”). Midcontinent’s tariff has a slight exception to this general rule: generators fund all of the up-front costs of low-voltage interconnections, and 90% of the costs of high-voltage interconnection-related upgrades, with the other 10% being allocated to transmission customers generally. *See* Midcontinent, Revisions to MISO-SPP Joint Operating Agreement, Test. of A. Johnson, Ex. No. MISO-0001, 32, R.1:114, filed Aug. 16, 2024 (“MISO JTIQ Filing”).

In exchange for funding network upgrades, generators are awarded transmission rights, which provide them with the opportunity

to recover their upgrade payments. *See* Order No. 2003, 104 FERC ¶ 61,103 at P 695 (Commission has approved system operator “pricing policies ... in which the Interconnection Customer bears the cost of all facilities and upgrades that would not be needed but for the interconnection of the new Generating Facility and receives valuable transmission rights in return”).

c. Queue delays and withdrawals

At various points of the study process, generators will be advised of the costs of any necessary upgrades. This enables them to decide whether to move forward or cancel their projects and withdraw from the interconnection queue. *See Pioneer Trail*, 798 F.3d at 606.

Withdrawals, particularly those occurring late in the process, “present a significant problem.” *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054, P 49, *on reh’g*, 185 FERC ¶ 61,063 (“*Order No. 2023*”). They often require system operators to re-do technical studies (since studies may incorporate anticipated upgrades associated with now-withdrawn projects), which “can result in significant increases to the interconnection costs attributed to those customers and the timeline for

completion of interconnection studies, which can result in further late-stage withdrawals, thus exacerbating the interconnection queue backlogs and delays.” *Id.*

In Midcontinent, queue delays and uncertainty regarding the cost of any necessary network upgrades have resulted in only 15% of interconnection requests, by capacity, reaching commercial operation between 2000 and 2018. *See* Joseph Rand *et al.*, Lawrence Berkely Nat’l Lab., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection* 29 (Apr. 2024), <https://perma.cc/B6WL-LRNG>. In Southwest, that figure was 14%. *Id.* The ultimate result is that consumers bear “[i]ncreases in energy rates” due to “limited access to new and more competitive supplies of generation.” Order No. 2023, 184 FERC ¶ 61,054 at P 43.

III. The Commission Proceedings

A. The Problem

For years, Midcontinent and Southwest have experienced an unprecedented volume of interconnection requests. *See* MISO JTIQ Filing, Johnson Test. 8, R.1:90; SPP JTIQ Filing, Kelley Test. 9, R.2:98. Both RTOs operate in regions with prime development potential for wind and solar generation projects. *See, e.g.*, SPP JTIQ Filing, Kelley

Test. 9, R.2:98. And consumer preferences, public policies, and technological advances have driven significant demand for such resources. *See* MISO JTIQ Filing 4-5, R.1:4-5. But the Southwest-Midcontinent seam is at capacity; the grid was not designed to accommodate geographically remote generation projects that will deliver electricity to distant locations. *See id.* 5; R.1:5; SPP JTIQ Filing, Kelley Test. 8-10, R.2:97-99.

These conditions have had a significant impact on the interconnection process. First, the next iteration of upgrades at the seam is exceedingly costly—a recent study estimated \$1 billion in necessary upgrades for a single interconnection cycle. These staggering costs lead many proposed projects to exit the queue, which results in re-studies and delay. *See* MISO JTIQ Filing 5, R.1:5; SPP JTIQ Filing 6, R.2:6.

Second, the upgrades identified through the interconnection study process are only sized to remedy the immediate impacts of a single generator or cluster. This is true even where the same upgrade could be scaled up to accommodate future interconnection requests. But because it would be inequitable to require a generator to pay the entire

cost of an upgrade designed to do more than address that generator's specific impacts, an inefficient, incremental upgrade process begins anew with each interconnection study cycle. *See* MISO JTIQ Filing, Johnson Test. 9-10, R.1:91-92; SPP JTIQ Filing, Kelley Test. 10-12; R.2:99-101.

B. The Proposed Solution: The Joint Targeted Interconnection Queue Framework

To address these issues, Midcontinent and Southwest proposed amendments to their tariffs and joint operating agreement to implement the Joint Targeted Interconnection Queue framework. Instead of piecemeal network upgrades constructed in response to particular interconnection requests, this innovative framework allows the system operators to proactively identify large-scale upgrades that will address transmission constraints that have been barriers to the development of new generation.

The framework outlined below is intended to be a general process that the system operators can reuse to assess future categories of network upgrades. The proposed cost allocation, however, will be reevaluated for any future suite of projects. *See, e.g.*, MISO JTIQ Filing 11, R.1:11.

1. The study

In 2020, Southwest and Midcontinent began working together to identify transmission projects that would comprehensively and efficiently address the significant capacity limitations hindering the interconnection of new generation near the Midcontinent-Southwest seam. The system operators evaluated 59 projects, assessing their economic benefits, impacts upon system reliability, and ability to enable generator interconnections. *See* MISO JTIQ Filing at 5-6, R.1:5-6; SPP JTIQ Filing at 6-7; R:2-6-7.

They ultimately identified five coordinated high-voltage transmission projects. The upgrades—known as JTIQ Portfolio #1 in the proceedings below and referred to herein as the “Portfolio upgrades”—consist of 4 new transmission line projects, and the expansion of an existing substation. Two of the projects will be in Midcontinent’s footprint, two within Southwest’s, and one will cross the seam.



See SPP JTIQ Filing, Test. of C. Locke, Ex. No. SPP-0003, 10, R.2:154.

Collectively, the upgrades will relieve 48 reliability constraints across both markets and enable the interconnection of over 28 gigawatts of additional generation near the seam. *See MISO JTIQ Filing, Johnson Test. 15, R.1:97.*

2. Who builds?

The responsibility to construct the upgrades is assigned to the transmission owners in whose existing service territory a particular upgrade will be located. After the Midcontinent and Southwest boards of directors give final approval of the Portfolio upgrades, the system operators will direct transmission owners to begin construction. *See*

MISO JTIQ Filing, Test. of A. Witmeier, Ex. No. MISO-0002, 11, R.1:130. Construction will commence even though all interconnecting generators who will ultimately make use of, and benefit from, the upgrades may not have been identified.

3. Who pays?

a. Initial funding

The Portfolio upgrades are expected to cost approximately \$1.7 billion dollars. *See* MISO JTIQ Filing 11, R.1:11. The constructing transmission owners will pay for the upgrades in the first instance. *See* SPP JTIQ Filing, Locke Test. 11, 13, 32, R.2:155, 157, 176.

b. The generator charge

Capital costs (*i.e.*, engineering, construction, and carrying expenses) will be reimbursed by the interconnecting generators pursuant to the Joint Targeted Interconnection Queue's subscription methodology. *See id.* 13, 32, R.2:157, 176; MISO JTIQ Filing, Witmeier Test. 34, R.1:153. Non-capital costs, like operation and maintenance expenses, will be recovered from transmission customers in the region where the upgrades are located. *See* MISO JTIQ Filing, Witmeier Test. 35, R.1:154.

i. “Target” and “Threshold” values

The first step in the subscription methodology is the establishment of “Target” and “Threshold” megawatt values for the Portfolio upgrades. The Target value is the total megawatts of generation capacity projected to be enabled by the upgrades (28,600 megawatts) and the Threshold is 85% of that figure (24,310 megawatts). *See id.* 12, R.1:131. To guard against the risk of oversubscription, the Portfolio upgrades will be deemed fully subscribed, and closed to future interconnection clusters, when the capacity of subscribing generation projects exceeds the Threshold value. *Id.*³

ii. The “Commitment Group”

A sequential winnowing process is used to identify subscribers to the Portfolio upgrades. Each year, the system operators create a “Screening Group” consisting of all interconnecting generators in a cluster window that closes after the Portfolio upgrades have been formally approved by the system operators’ boards of directors. *See, e.g.,* MISO JTIQ Filing 17, R.1:17.

³ Oversubscription would lead to supplemental upgrades, increased costs, and delay. *See, e.g.,* MISO JTIQ Filing 22, R.1:22; SPP JTIQ Filing 27, R.2:27.

The smaller “Participation Group” consists of those Screening Group projects that are shown via power flow modeling to have a specified level of impact on (i) transmission facilities in the neighboring transmission system (*e.g.*, a Midcontinent-based generation project affecting the Southwest system), and (ii) one or more of the Portfolio upgrades. *Id.* 18, R.1:18.

The final “Commitment Group” is made up of those Participation Group members that choose to execute transmission service agreements with Midcontinent and Southwest by April 30 of the relevant study year. And once those generators execute their interconnection agreements, they will be responsible for their share of the costs of the Portfolio upgrades. *See* MISO JTIQ Filing, Witmeier Test. 19-21, 24-25, R.1:138-40, 143-44. The Portfolio upgrades are expected to accommodate multiple Commitment Groups before reaching the Threshold value. *See* SPP JTIQ Filing, Locke Test. 18, R.2:162. The subscription period closes after 20 years. *See id.*, Kelley Test. 38, R.2:127.

iii. Calculating the charge

Each generator included in a Commitment Group will pay for a share of each Portfolio upgrade. The charge will be based on the generator's megawatts of interconnection service (*i.e.*, the amount of power it wants to be able to flow onto the grid) as a percentage of the Threshold value or the final subscribed amount, if larger. *See* MISO JTIQ Filing, Witmeier Test. 35-36, R.1:154-55. Thus, if 28 gigawatts of generation subscribed to the Portfolio upgrades, a 100-megawatt project would pay roughly 0.35% ($100\text{MW}/28,000\text{MW} \times 100$) of the capital costs.

The generator charges will be amortized over a twenty-year period and will be collected monthly by Midcontinent and Southwest. The charges commence when a Portfolio upgrade goes into service. *See* SPP JTIQ Filing 33, R.2:33.

iv. Generator compensation

As compensation for their capital cost funding, the Joint Targeted Interconnection Queue framework provides generators with “auction revenue rights” for their contributions to Portfolio upgrades located in Midcontinent's footprint. *See* Midcontinent, Proposed Revisions to Tariff 53-54, R.21:53-54, filed Aug. 26, 2024 (“MISO Tariff Filing”). The holders of these rights are entitled to the proceeds generated from the

sale of “Financial Transmission Rights”—a financial instrument that allows transmission customers to hedge against transmission congestion charges—derived from the capacity associated with the Portfolio upgrades. *See id.*, Test. of M. Bailey, Ex. MISO-0008, 7-11; R.21:1590-94; *see also Wis. Pub. Power*, 493 F.3d at 251 (discussing Financial Transmission Rights). Generators would receive a similar right to compensation—called Incremental Long-Term Congestion Rights—for Portfolio upgrades located in Southwest’s territory. *See* Southwest, Submission of Revisions to Tariff 29-31, R.17:29-31, filed Aug. 21, 2024 (“SPP Tariff Filing”).

c. Backstop funding

The Joint Targeted Interconnection Queue framework incorporates a backstop mechanism by which transmission customers in the region where an upgrade is being constructed will cover any funding shortfall. They serve as a temporary backstop when a Portfolio upgrade goes into service before full subscription is achieved. In that circumstance, the transmission customers will be charged for the unrecovered portion of the annual cost of the upgrade. Once full subscription is achieved, newly subscribed generators will be charged

for these earlier shortfalls and their payments will be used to refund transmission customers, with interest. *See, e.g.*, SPP JTIQ Filing, Locke Test. 35-36, R.2:179-80.

If full subscription is never achieved (*i.e.*, if, after 20 years, the committed megawatts do not exceed the Threshold value), then the annual shortfall payments from regional transmission customers would serve as permanent backstop funding. *Id.* 36, R.2:180. The need for any permanent backstop funding was deemed “highly unlikely” since Midcontinent and Southwest projected that the Portfolio upgrades would be fully subscribed in just a few years. *See, e.g.*, MISO JTIQ Filing, Johnson Test. 27, R.1:109, *id.* Witmeier Test. 38-39, R.1:157-58; SPP JTIQ Filing, Kelley Test. 39, R.2:128, *id.* Locke Test. 12, R.2:156.

d. Department of Energy funding

In 2023, the Department of Energy announced that it had selected the Portfolio upgrades for an award of \$464.5 million through its Grid Resilience and Innovation Partnerships Program. These funds will offset the capital costs of the Portfolio upgrades before calculating the generator charge. *See* MISO JTIQ Filing 11, 16, R.1:11, 16.

C. The Challenged Orders

In a November 2024 order, the Commission accepted the tariff and joint operating agreement revisions implementing the Joint Targeted Interconnection Queue framework. *Midcontinent Indep. Sys. Operator, Inc.*, 189 FERC ¶ 61,108 (2025), R.148 (“Initial Order”). The Commission observed that the framework addressed a “unique” challenge posed by the lack of transmission capacity at the seam, massive amounts of interconnection requests, and the ineffectiveness of the standard interconnection process. *Id.* P 196. It found that the “novel” forward-looking planning and subscription methodology would ease the way for new generation projects to connect to a historically congested portion of the grid in an efficient and timely manner. *Id.* P 199; *see also id.* P 198. In addition, the use of a per-megawatt usage rate to assess cost responsibility for the Portfolio upgrades will provide interconnecting customers with a greater degree of cost certainty, which should reduce late-stage withdrawals and concomitant delays. *Id.* P 199.

The Commission also approved the proposed cost allocation. New generators are the primary beneficiaries of the Portfolio upgrades,

which are being built for the specific purpose of removing system constraints blocking the interconnection of large amounts of generation capacity. It is thus consistent with the cost causation principle to allocate them primary responsibility for Portfolio upgrades' capital costs. *Id.* P 198.

The Commission likewise found the proposed backstop funding mechanism to be appropriate. The Portfolio upgrades will provide benefits to transmission customers, such as increased resilience and access to cheaper generation resources. *Id.* P 201. These benefits are roughly commensurate with the potential costs associated with the limited risk that the Portfolio upgrades will not be fully subscribed. *Id.* P 202.

Finally, the Commission rejected the contention that it was inappropriate to assign backstop funding responsibility to transmission customers in the MISO South subregion when none of the facilities would be located there. The record established that the entirety of the Midcontinent region, including MISO South, would receive some benefits from the Portfolio upgrades. *Id.* P 203.

The Commission affirmed its findings on rehearing. *See*

Midcontinent Indep. Sys. Operator, Inc., 191 FERC ¶ 61,231 (2025), R.166 (“Rehearing Order”).

D. Post-Order Events

The Midcontinent and Southwest boards of directors approved the Portfolio upgrades in December 2024. *See* Midcontinent, *Fact Sheet*, <https://perma.cc/6UUN-AN53>. Nearly a year later, reports emerged that the Department of Energy had revoked its grant of funding for the Portfolio upgrades. *See* State Br. 38. The Commission understands, however, that no such cancellation has occurred.

SUMMARY OF ARGUMENT

Primary Cost Allocation: The Commission reasonably found that interconnecting generators are the primary beneficiaries of the Portfolio upgrades. The sole reason the upgrades are being built is to respond to the massive demand for interconnection of new generation resources at the Midcontinent-Southwest seam. The Portfolio upgrades will enable those new generators to deliver their power to the market. And the Joint Targeted Interconnection Queue framework will also promote more timely interconnection, greater certainty regarding the costs of network upgrades, and reduced upgrade costs—all of which should help more generation projects move from mere proposals to

market participants.

As the primary beneficiaries of the Portfolio upgrades, it is consistent with the cost causation principle to allocate interconnecting generators primary cost-responsibility. And while the Joint Targeted Interconnection Queue framework is a novel approach to generator interconnection, its constituent parts—analyzing groups of projects as a portfolio, using projected power flows as a proxy for benefits, and assigning cost responsibility to a class of customers based on projected use—are consistent with established precedent.

Generators’ contention that transmission customers (local utilities serving retail “load”) should pay more starts from a faulty legal premise—*i.e.*, that the Federal Power Act demands perfect cost allocation—and is supported by various distortions of the record. But Generators cannot avoid the fact that the Portfolio upgrades could not be justified based on their benefits to transmission. Moreover, Generators utterly ignore the costs that transmission customers do bear. They have backstop funding responsibility, and liability for all operation and maintenance expenses, and their payments through various market mechanisms will allow generators to recoup at least a

portion of their capital cost contributions to the Portfolio upgrades.

The case law establishes that a cost allocation decision is arbitrary and capricious only if it reflects a wholesale departure from cost causation principles. Nothing in the record supports such a claim.

Backstop Funding: The Commission reasonably found that it was appropriate to include MISO (Midcontinent) South transmission customers in the system-wide assignment of backstop funding responsibility. Notwithstanding the limitations on power flows into the MISO South subregion, the Portfolio upgrades will still impart benefits to the subregion by enabling more timely generator interconnections (and associated electricity cost reductions), potential congestion payment relief, and increased grid resiliency.

The States challenge the Commission's benefits analysis by pointing to the Midcontinent Multi-Value Project proceeding where costs were not allocated to the MISO South subregion. But the Commission explained why that precedent did not govern here. It involved a different portfolio of projects with different aims. And the record there showed that, in fact, some benefits would still flow to the MISO South subregion, notwithstanding transfer capacity limitations.

Finally, the question in the Multi-Value Project proceeding was primary cost responsibility, not backstop funding.

On the cost side, the Commission found—and the States do not challenge—that the administrative record established that it was “highly unlikely” that transmission customers would incur any unreimbursed costs. The benefits that will flow to the MISO South subregion are thus roughly commensurate to the burdens imposed by the backstop funding mechanism, which is not expected to result in any permanent costs. The States cannot avoid this conclusion by relying on post-decisional events.

ARGUMENT

I. Standard of Review

The Court reviews Commission orders under the Administrative Procedure Act’s arbitrary-and-capricious standard, 5 U.S.C. § 706(2)(A). *See El Paso Elec. Co. v. FERC*, 832 F.3d 495, 503 (5th Cir. 2016) (“*El Paso I*”). That standard is “deferen[tial],” and a court “may not substitute [its] own judgment for that of the agency.” *Elec. Power Supply Ass’n*, 577 U.S. at 292 (cleaned up). The Commission’s decision “must” be upheld if it “has examined the relevant considerations and articulated a satisfactory explanation for its action, including a rational

connection between the facts found and the choice made.” *Id.* (cleaned up). “And nowhere is that more true than in a technical area like electricity rate design.” *Id.* (citing *Morgan Stanley*, 554 U.S. at 532.) The Commission is thus afforded “great deference” in its rate decisions. *Id.*; see also *La. Pub. Serv. Comm’n v. FERC*, 771 F.3d 903, 910 (5th Cir. 2014) (same).

Similarly, “FERC’s factual findings are conclusive if supported by substantial evidence,” *El Paso I*, 832 F.3d at 503; 16 U.S.C. § 825l(b)—*i.e.*, “more than a mere scintilla,” *Capstone Logistics, L.L.C. v. NLRB*, 122 F.4th 194, 200 (5th Cir. 2024) (cleaned up). The question “is not whether record evidence supports petitioner’s version of events, but whether it supports FERC’s.” *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 94 (3d Cir. 2014) (quoting *Fla. Mun. Power Agency v. FERC*, 315 F.3d 362, 368 (D.C. Cir. 2003)) (cleaned up).

Finally, “agency decisions are presumptively valid; the petitioner bears the burden of showing otherwise.” *Texas v. EPA*, 156 F.4th 523, 537 (5th Cir. 2025).

II. The Commission Reasonably Approved the Joint Targeted Interconnection Queue Framework

The Commission’s determination that the Joint Targeted Interconnection Queue framework is “just and reasonable” and not “unduly discriminatory,” as the Federal Power Act requires, is well-supported by the record and consistent with precedent.

A. The Joint Targeted Interconnection Queue Framework Reasonably Allocates Primary Cost Responsibility to Generators

1. Benefits conferred

The Commission correctly found that interconnecting generators are the primary beneficiaries of the Joint Targeted Interconnection Queue framework. *See* Initial Order P 198.

First, and fundamentally, the Portfolio upgrades will “enable their interconnection” so they can deliver their product to the market. *Id.* The Generators acknowledge that “transmission scarcity” at the Midcontinent-Southwest seam results in “high interconnection costs that prevent projects from moving forward,” thereby “inhibit[ing] new market entrants.” Clean Energy Assocs., Protest 2, R.117:2, filed Sept. 19, 2024. They concede that the Portfolio upgrades are “critically needed” to “interconnect[] much-needed generation at the seam[].” *Id.*

This is consistent with the record, which “reflects more than sufficient—indeed excess—demand for interconnection service” near the seam. Rehearing Order P 32 n.127. For example, in Midcontinent alone, projects seeking to interconnect near the seam have grown from 7.9 gigawatts in the 2020 cycle, to 14.6 gigawatts in the 2021 cycle, 27.9 gigawatts in the 2022 cycle, and 21.1 gigawatts in the 2023 cycle. *See* Initial Order P 77 (citing MISO JTIQ Filing, Witmeier Test. 39-40, R.1:158-59). Undisputed testimony established that the Portfolio upgrades would likely be fully subscribed within just a few planning cycles. *Id.* P 201 (citing MISO JTIQ Filing 11, R.1:11; SPP JTIQ Filing 38-40, R.2:38-40).

Second, the Joint Targeted Interconnection Queue framework will promote more timely interconnections. *See* Initial Order P 193; *see also* Rehearing Order P 24. The framework “streamlines the interconnection process by” eliminating the “existing affected system process.” MISO JTIQ Filing, Johnson Test. 6, R.1:88. And it also allows construction of the Portfolio upgrades to commence without waiting for every potential beneficiary to complete the interconnection queue process. *Id.*, Witmeier Test. 12, R.1:131. Faster interconnection is critical since

delays “can disrupt numerous aspects of generating facility development.” Order No. 2023, 184 FERC ¶ 61,054 at P 43; *see also id.* P 43 n.127 (developer comment explaining that “delays can be significant and costly, including liquidated damages if compliance with a commercial operation deadline is at risk”).

Third, by identifying upgrades upfront and specifying a precise cost contribution formula, the Joint Targeted Interconnection Queue framework provides generators with greater cost certainty. *See* Rehearing Order P 24 & n.87; *see also* SPP JTIQ Filing, Kelley Test. 14-15, R.2:103-04; MISO JTIQ Filing, Johnson Test. 12-13, R.1:94-95. This too is a crucial benefit: “[c]ost uncertainty poses an especially significant obstacle because interconnection customers may not be able to finance substantial increases in unexpected interconnection costs.” Order No. 2023, 184 FERC ¶ 61,054 at P 42; *see also Tenaska*, 108 F.4th at 865-66 (network upgrade costs balloon from \$31 million to \$99 million during interconnection study process).

Fourth, the Joint Targeted Interconnection Queue framework should reduce upgrade costs. *See* Rehearing Order P 24. The record established that a recent affected systems study found that a single

Midcontinent cluster of projects would necessitate \$1.4 billion in network upgrades on Southwest’s grid to accommodate just 7.7 gigawatts of generation. *See* MISO JTIQ Filing, Johnson Test. 10; R.1:92. By contrast, for a similar cost, the Portfolio upgrades will enable 28 gigawatts of generation. *Id.*; *see also* SPP JTIQ Filing, Kelley Test. 11-12, R.2:100-101.

2. Costs imposed

Traditionally, interconnection-related upgrade costs are allocated to generators under a “but for” analysis—that is, generators pay the full costs of upgrades that would not be needed but for their interconnection. *See* Initial Order P 197; *see also* *Tenaska*, 108 F.4th at 870 (discussing “but for” analysis). The Portfolio upgrades, however, are not being constructed in response to any specific interconnection request. Instead, they were identified through a forward-looking planning process to address the needs of generators as a class. *See* Initial Order P 197. Accordingly, the Commission declined to apply its standard “but for” analysis. In its place, the Commission used a broader lens to assess whether the costs of the Portfolio upgrades are being allocated “in a manner that is at least roughly commensurate

with estimated benefits.” *Id.*

In answering that question in the affirmative, the Commission observed that the Portfolio upgrades “would not exist” without the demand for interconnection by proposed generation projects. Rehearing Order P 31; *see also id.* P 24. The record established that “none of the five projects” could be justified based on the benefits they provided to transmission customers. *Id.* P 31; *see also* P 42 (none “were justified apart from the interconnection customers’ need for them”); Initial Order P 198 (same). Accordingly, allocating interconnecting generators with primary cost responsibility is consistent with “the cost causation principle, which requires that ‘all approved rates reflect, to some degree, the costs actually caused by the customer who must pay them.’” Rehearing Order P 26 (quoting *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

The proposed generator charge methodology is also “consistent with ‘beneficiary pays’ cost allocation.” Initial Order P 199; *see supra* p. 22 (describing generator charge process). By using power flow modeling to identify those interconnecting generators that will be making use of the Portfolio upgrades to deliver their electricity to the market, the

system operators’ proposal “ensur[es] that the interconnecting customers that will pay” the generator charge “are benefitting from the JTIQ Upgrades.” Rehearing Order P 32; *see also id.* PP 37-38.

The record is clear that a “massive influx of interconnection requests,” particularly along the Midcontinent-Southwest seam, drove the need for the Portfolio upgrades. Rehearing Order P 35; *see also* MISO JTIQ Filing, Johnson Test. 11, R.1:93 (same). And since “interconnection customers are the primary beneficiaries” of the upgrades, they “should bear the primary responsibility” for their “capital costs.” Rehearing Order P 24.

B. The Commission Appropriately Found That Transmission Customers Are Incidental Beneficiaries

The Commission reasonably found that the benefits conferred on transmission customers by the Portfolio upgrades were roughly commensurate with the potential costs imposed under the backstop funding mechanism.

1. Benefits conferred

Although the benefits to transmission customers (*i.e.*, local utilities serving retail load) alone are not enough to justify construction of the Portfolio upgrades, there are benefits nonetheless. *See* Initial

Order P 201-02; Rehearing Order P 44.

The record showed that, over a 20-year period, the Portfolio upgrades would reduce electric costs by about \$175 million (so-called Adjusted Production Costs savings). *See* Initial Order P 201 (citing, *inter alia*, Southwest, *Cost Allocation Working Group-JTIQ Benefits and Cost Allocation Update* (Oct. 3, 2023)); *see also* *Entergy Ark., LLC v. FERC*, 40 F.4th 689, 693 (D.C. Cir. 2022) (discussing Adjusted Production Cost Savings metric). The Portfolio upgrades could also lead to increased “wheeling” revenues. *See* Initial Order P 201; *see also* *Otter Tail Power Co. v. United States*, 410 U.S. 366, 368 (1973) (explaining that “wheeling” is transmitting “electric power from one utility to another over the facilities of an intermediate utility”). In addition, the upgrades will reduce transmission congestion, which should lower congestion charges to transmission customers. *See* SPP JTIQ Filing 40, R.2:40. The upgrades will also impart qualitative benefits, such as increased system resiliency and more timely interconnection of new generation, which helps transmission customers meet their energy needs. *See* Initial Order P 201 (citing SPP JTIQ Filing 40, R.2:40); *see also* MISO JTIQ Filing, Johnson Test. 30, R.1:112.

2. Costs imposed

On the cost side of the scale, the record established that, given the demand for interconnection, it was “highly unlikely” that transmission customers would need to provide any permanent funding. Rehearing Order P 58 (citing *inter alia* MISO JTIQ Filing, Witmeier Test. 38-40, R.1:157-58; SPP JTIQ Filing, Locke Test. 12, R.2:156). The Commission thus concluded that the “costs, if any, are likely to be within a narrow range ... and will not exceed a small portion of total costs.” Initial Order P 201. On this basis, the Commission found “that the backstop funding mechanism satisfies the cost causation principle” since “costs are allocated in a manner that is at least roughly commensurate with estimated benefits.” *Id.*; see also *Ill. Com. Comm’n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (FERC need only provide “an articulable and plausible reason to believe that the benefits are at least roughly commensurate” with project costs) (“*Illinois I*”).

C. The Commission’s Approval Is Consistent with Precedent

The Joint Targeted Interconnection Queue framework is a novel solution to a pressing problem. But the Commission’s approval of the proposed cost allocation is firmly rooted in precedent.

First, requiring generators to bear the cost of network upgrades being built to satisfy their demand for interconnection is the standard rule. *See, e.g., Old Dominion Elec. Coop., Inc. v. FERC*, 518 F.3d 43, 51 (D.C. Cir. 2008) (upholding cost allocation of network upgrades to interconnection customers “when facilities would not have been built but for the interconnection request”). Courts have recognized—like the Commission did here—that the “primary beneficiaries” of network upgrades should be primarily responsible for their costs. *See, e.g., N.Y. Power Auth. v. FERC*, 109 F.4th 550, 561 (D.C. Cir. 2024) (“FERC reasonably explained that its decision adhered to cost-causation principles when it identified the *primary beneficiary* and cost-driver of a project and explained why costs were appropriately assigned to that party.”) (cleaned up; emphasis added); *Pioneer Trail*, 798 F.3d at 608 (upholding allocation of network upgrade costs to generators since they “are the *primary utilities that stand to benefit* from being connected to the grid”) (emphasis added); *Ill. Com. Comm’n v. FERC*, 756 F.3d 556, 564 (7th Cir. 2014) (“The incidental-benefits tail mustn’t be allowed to wag the *primary-benefits dog*.”) (emphasis added).

Using a portfolio approach to study a group of upgrades, assess

their benefits, and allocate costs is also well-established. *See Ill. Com. Comm’n v. FERC*, 721 F.3d 764 (7th Cir. 2013) (upholding FERC approval of Midcontinent’s multi-value project methodology which analyzes and assigns cost responsibility on a portfolio basis). Indeed, courts have repeatedly held that the Commission need not consider “cost-allocation rules on a project-by-project basis.” *Long Island Power Auth. v. FERC*, 27 F.4th 705, 715 (D.C. Cir. 2022); *see also LSP Transmission Holdings II, LLC v. FERC*, 45 F.4th 979, 994 (D.C. Cir. 2022) (same); *Coal. of MISO Transmission Customers v. FERC*, 45 F.4th 1004, 1021 (D.C. Cir. 2022) (“the validity of an overall cost-allocation rule need not be determined on a project-by-project basis”) (cleaned up).

Assigning cost responsibility to a general class of customers based on an expectation of future use—and thus future benefits—is also standard practice. As this Court has recognized, FERC-jurisdictional utilities are required to have *ex ante* cost allocation methodologies in place for regional transmission projects. *El Paso II*, 76 F.4th at 357; *see also S.C. Pub. Serv. Auth.*, 762 F.3d at 82-83 (upholding framework of *ex ante* tariffs established by the Commission in Order No. 1000).

Those projects are developed in response to demand projections. *See*

Energy Primer 78. Costs are assigned to classes of future customers whose projected demand led to construction, even though their specific identity is unknown and they “are not a static group.” Rehearing Order P 32 n.128.

The Joint Targeted Interconnection Queue framework follows a similar pattern. The Portfolio upgrades were identified in response to projections of interconnection demand by generators as a class. *See, e.g.,* MISO JTIQ Filing 5, R.1:5 (discussing JTIQ Study process). Power flow modeling will ensure that the specific generators ultimately assigned cost responsibility are making use of, and benefiting from, the Portfolio upgrades. *See, e.g.,* Rehearing Order PP 32, 38. It is settled that the Commission may “reasonably look[] to usage data as a proxy for specific benefits.” *Long Island*, 27 F.4th at 713.

In short, the system operators’ proposal employs established planning and cost allocation principles to an innovative interconnection construct. *See* Initial Order P 196; Rehearing Order P 24. Despite its novelty, the Joint Targeted Interconnection Queue framework comports with “foundational principles of cost-causation” by placing principal cost responsibility on “those who cause the costs to be incurred and who reap

the resulting benefits.” *El Paso II*, 76 F.4th at 363 (quoting *Nat’l Ass’n of Reg. Util. Comm’rs*, 475 F.3d at 1285).

III. The Generators’ Cost Allocation Objections Lack Merit

Generators argue that the Joint Targeted Interconnection Queue framework is unjust and unreasonable because, in their view, more of the Portfolio upgrade capital costs should be allocated to transmission customers (*i.e.* local utilities serving retail load).⁴ Their various arguments proceed from an incorrect legal standard and are supported by distortions of the record. Their claims should be rejected.

A. Generators Use The Wrong Legal Standard

1. The purported two-step inquiry

Generators assert that “the cost-causation principle and beneficiary-pays must be analyzed separately,” with a causation determination coming first. Gen. Br. 45. They cite no authority for this

⁴ Generators use “load” to mean “end-use customers.” *See, e.g.*, Gen. Br. 10, 15, 26. But transmission customers are the “load” providing backstop funding under Joint Targeted Interconnection Queue framework. *See, e.g.*, MISO JTIQ Filing, Exh. No. MISO-0003 27, R.1:188 (“MISO region-wide transmission customers will provide temporary and permanent backstop funding”); Rehearing Order P 32 (analyzing cost allocation to “transmission customers (load)”). The challenged orders did not address the pass through of any costs to end users.

proposition because there is none. Looking at project benefits is simply “another prism through which to view the question of cost causation.”

KN Energy, 968 F.2d at 1302; *see also* Rehearing Order P 29 (explaining that “beneficiary approach can be an acceptable *proxy* for cost causation”). That is because “[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have ‘caused’ a part of those costs to be incurred.” *Illinois I*, 576 F.3d at 476; *see also Neb. Pub. Power Dist. v. FERC*, 957 F.3d 932, 941 (8th Cir. 2020) (same).

More fundamentally, neither the Federal Power Act nor precedent requires the Commission to “utilize a particular formula” when assessing cost allocation. *El Paso II*, 76 F.3d at 357 (quoting *Old Dominion Elec. Coop. Inc. v. FERC*, 898 F.3d 1254, 1260 (D.C. Cir. 2018)). The Commission “may even ‘emphasize other, competing policies and approve measures that do not best match cost responsibility and causation.’” *Id.* (quoting *Carnegie Nat. Gas Co. v. FERC*, 968 F.2d 1291, 1294 (D.C. Cir. 1992)).

In any event, the Commission explicitly found that interconnecting generators as a class were the “cause” of the Portfolio upgrades: “[t]he un rebutted evidence proved that the need to construct

transmission to facilitate the interconnection of generation at the MISO-SPP seam is the driving force behind” the Portfolio upgrades. Rehearing Order P 54; *see also id.* P 31 (Portfolio upgrades “were justified for construction based on the need to interconnect generating facilities,” not their benefits to transmission customers). And because costs will only be assigned after power flow modeling establishes that an interconnecting generator is making use of the Portfolio upgrades, the framework “ensures that ... [they] are benefitting” from the upgrades and thus “may be said to have ‘caused’ ... those costs to be incurred.” Rehearing Order P 32 (quoting *Illinois I*, 576 F.3d at 476).

2. The purported mandatory allocation

Generators also assert that if transmission customers benefit from the Portfolio upgrades at all, then “they must be allocated costs commensurate with those benefits.” Br. 40. That is not the law.

“Ratemaking is much less a science than an art.” *Consol. Edison Co. of N.Y., Inc. v. FERC*, 45 F.4th 265, 286 (D.C. Cir. 2022) (cleaned up). And “FERC has no duty” to take a “hyper-granular” “customer-by-customer approach” to “weighing costs and benefits.” *Paragould Light & Water Comm’n v. FERC*, 144 F.4th 287, 293 (D.C. Cir. 2025).

“[E]xacting precision” is not required, *El Paso II*, 76 F.4th at 362; instead, “costs need only be ‘roughly commensurate’ to benefits under the cost causation principle.” *Id.* at 360. And of course, transmission customers here are not free riders; they will be required to backstop any capital funding shortfalls temporarily and possibly even permanently. *See* Rehearing Order P 47; *see also infra* pp. 52-53 (discussing other Portfolio upgrade costs imposed on transmission customers).

B. Generators Rely on Distortions of the Record

Generators rely on a series of distortions of the record to buttress their claim that, as a matter of law, transmission customers must be allocated more of the Portfolio upgrade costs.

1. “One billion” in benefits

Generators begin by claiming the record “indicates that consumers will likely receive over \$1 billion in benefits” from the Portfolio upgrades. Gen. Br. 3; *see also id.* 17 (“nearly \$1 billion in benefits to SPP and MISO”); *id.* 30 (\$247 million in benefits to SPP and \$724 million in benefits to MISO”). This is not true.

The touted figures relate to a larger suite of projects and outdated study assumptions. Some of those projects were stripped out of the Joint Targeted Interconnection Queue framework and constructed

pursuant to Midcontinent’s regional transmission planning process (and thus paid for entirely by transmission customers). *See* Rehearing Order P 48. As a result, “much of the then-projected benefits to load were reduced.” *Id.*

2. “Consumers caused” the Portfolio upgrades

a. The record evidence

Generators go on to assert that the Commission “acknowledge[ed] that consumers on the demand side ... cause[d] the need for” the Portfolio upgrades. Gen. Br. 1. But again, the Commission found that the Portfolio upgrades “were justified for construction based on the need to interconnect generating facilities more efficiently and cost-effectively.” Rehearing Order P 31. That determination is supported by undisputed evidence establishing that “none of the projects included in the current [Portfolio upgrades] would be built but for interconnection customers” and that they “are intended to benefit interconnection customer[s].” MISO JTIQ Filing, Johnson Test. 29, R.1:111; *see also* Rehearing Order P 31.

Generators suggest that interconnection demand could not have triggered the need for the Portfolio upgrades because “it is the transmission facility that causes the generator to come into existence in

that location ... rather than the generators that causes the transmission facility.” Gen. Br. 47. The record says otherwise.

The Generators are a collection of renewable resource advocacy groups. *See id.* i-ii, 6. Renewable resources—particularly wind and solar—are “location-constrained” due to “the immobility of their fuel sources.” *Sw. Power Pool, Inc.*, 127 FERC ¶ 61,283, P 29 (2009).

Midcontinent and Southwest “are located in areas with prime development potential for” renewable generation, given abundant wind and solar resources and low-density populations. SPP JTIQ Filing, Kelley Test. 9, R.2:98. The Portfolio upgrades, in turn, were “aimed at addressing transmission system limitations preventing the interconnection of large amounts of generation, particularly location constrained renewable generation resources.” MISO JTIQ Filing, Johnson Test. 29, R.1:111; *see also* Rehearing Order P 31 n.121 (same). Those resources pose unique challenges because the “transmission system was simply not designed to interconnect mass quantities of location-constrained renewable resources for potential delivery to far removed load centers.” MISO JTIQ Filing, Johnson Test. 8, R.1:90.

This is not a case of “if you build it, they will come.” Gen. Br. 46.

The Joint Interconnection Queue framework, and resulting Portfolio upgrades, were developed to address the “massive amounts of interconnection requests between the two [Regional Transmission Operators].” MISO JTIQ Filing, Johnson Test. 6, R.1:88; *see also* SPP JTIQ Filing, Kelley Test. 6, R.2:95. Interconnection customers have come to the seam; the Portfolio upgrades are being built in response.

b. The costs borne by load

Generators similarly argue that, as a metaphysical matter, “end customers are the legally relevant cause of the transmission system.” Gen. Br. 45. This proves too much as it would eviscerate the established rule that generators are responsible for the transmission upgrades necessitated by their interconnection. *See, e.g., Tenaska*, 108 F.4th at 869 (noting “longstanding policy” that a generator is responsible for the cost of network upgrades “that would not be needed ‘but for’” its “request to reliably interconnect its generating facility”) (cleaned up). And using Generators’ economic observation as a basis for cost allocation is particularly inappropriate here, where the record indisputably establishes that the benefits to customer load could not justify construction of the Portfolio upgrades. *See* Initial Order P 198.

Moreover, Generators ignore the costs that transmission customers already bear in connection with the Portfolio upgrades. First, they have backstop funding obligations. *Id.* P 201. Second, they pay the upgrades’ operation and maintenance expenses. *Id.* P 74. Third, as compensation for funding the Portfolio upgrades, interconnecting generators are given auction revenue rights. *See id.* P 89. Any revenues recovered through those rights—which effectively reimburse capital cost outlays—will come from transmission customer payments. Generators have never challenged the Commission’s determination that the granting of these rights “further balances benefits and costs among interconnection customers and load.” *Id.* P 202. Fourth, as Generators note, their capital cost outlays will also be recovered through power sales to load. *See* Protest 25, R.117:25 (“If generators do subscribe, higher costs will need to be reflected in power purchase agreements with offtakers.”). Fifth, transmission customers bear sole cost responsibility for all transmission expansions built in response to load-driven needs, even though generators “may realize some benefits from those regional projects.” MISO JTIQ Filing, Johnson Test. 31, R:1:113.

3. “Ignoring” benefits to load

Generators charge that the Commission “ignored the benefits to” load (Gen. Br. 30), “irrationally assum[ed]” there would be no benefits (*id.* 23), and “did not attempt to estimate or value the benefits” to load. *Id.* 32; *see also id.* 2 (same). None of that is true.

The Commission walked through the various “quantitative and qualitative” benefits that transmission customers would receive from the Portfolio upgrades. *See, e.g.,* Initial Order P 201; *see also supra* p. 40 (discussing benefits to load). And while Generators assert there was no “attempt to quantify” any benefits (Gen. Br. 31), the Commission expressly addressed evidence projecting “a combined \$175.87 million of Adjusted Production Cost benefits to MISO and SPP.” Rehearing Order P 64. In addition, the Commission repeatedly cited Southwest’s Cost Allocation Working Group study, which estimated resiliency and wheeling revenue benefits to transmission customers. *See, e.g.,* Initial Order P 201; Rehearing Order PP 24, 31, 32, 49, 59. Finally, the Commission also addressed the qualitative benefits of increased system reliability and more timely interconnection of new generation. *See e.g.,* Initial Order P 201; Rehearing Order P 24; *see also Paragould*, 144

F.4th at 295 (cost allocation can be based on “[q]ualitative benefits” even if they are not “amenable to precise tabulation”).

The Commission then balanced these benefits against its estimation of the risks—and thus the costs—associated with backstop funding. *See, e.g.*, Initial Order P 201; Rehearing Order P 44. This more than satisfied the Commission’s burden to articulate a “plausible reason to believe” that Portfolio upgrade’s benefits to load are “roughly commensurate” with the backstop funding costs. *Long Island*, 27 F.4th at 714-15 (cleaned up).

4. “Presuming” no benefits due to lack of selection in the regional planning process

Generators spill much ink on the Commission’s recognition that the Portfolio upgrades were not selected for construction through the Midcontinent or Southwest regional planning processes—*i.e.*, they could not be justified by their benefits to transmission customers. *See* Gen. Br. 31-36, 43-44. Generators contend that the Commission used that “rejection” to “presume[] the absence of benefits to load.” *Id.* 34; *see also id.* 44 (claiming FERC used “selection in a regional planning process as a proxy for benefits”). But again, the Commission did not “presume” the absence of benefits to transmission customers. It identified and

analyzed those benefits. *See supra* pp. 40-41, 54-55.

The Commission pointed to the fact that the Portfolio upgrades were not selected in the regional planning processes as additional evidence that their benefits “are *not sufficient* to require load to bear primary cost allocation responsibility.” Rehearing Order P 43 (emphasis added); *see also* Initial Order P 198 (same). Non-selection also buttressed the Commission’s causal finding that the upgrades were “developed primarily to interconnect generation” and not to respond to “reliability, economic, or public policy needs [of] load.” Rehearing Order P 42.

Generators also assert that the Commission “offers no explanation why it was just and reasonable” to rely on the lack of selection in the regional planning process given it is more difficult to meet the necessary cost-benefit ratio when “benefits to load are split between customers in two [Regional Transmission Operators].” Gen. Br. 33, 34. Generators did not raise this argument on rehearing to the agency, and the reviewing court thus lacks jurisdiction to consider it. *See* 16 U.S.C. § 825l(b) (“No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged

before the Commission in the application for rehearing.”); *see also La. Pub. Serv. Comm’n*, 771 F.3d at 918 (argument “not raised before FERC ... cannot be considered here”); *NICOR Expl. Co. v. FERC*, 50 F.3d 1341, 1346-47 (5th Cir. 1995) (holding that Federal Power Act’s rehearing requirement is jurisdictional).

Anyway, Generators are wrong on the facts. Only one of the Portfolio upgrades spans the seam; four of the five are located and evaluated within a single system operator’s footprint. *See* Initial Order P 6 n.11.

C. Generators’ Remaining Arguments Fail to Establish That the Commission Acted Unreasonably

1. The Commission’s reasoning is internally consistent

Generators argue that it was “contradictory” for the Commission to find, on the one hand, that the Portfolio upgrades benefit transmission customers enough to justify allocating them backstop funding, and to project, on the other, that it is unlikely they will bear any permanent costs (*i.e.*, the Portfolio will be fully subscribed). Gen. Br. 38. Not so.

The Commission assessed the record evidence of benefits to transmission customers and found them to be “minor and incidental.”

Rehearing Order P 45; *see also* Initial Order P 201. And then it assessed the potential costs imposed through the backstop funding mechanism and found them unlikely to “exceed a small portion of the total costs.” Initial Order P 201. On that basis, the Commission compared the “costs load will likely pay” with the expected benefits and found them to be “roughly commensurate.” *Id.*

Generators contend that if transmission customers benefit from the upgrades at all, then they must be assigned costs. Gen. Br. 40. But “nothing requires the Commission to ensure full or perfect cost causation.” *S.C. Pub. Serv. Auth.*, 762 F.3d at 88. And transmission customers were assigned costs. The backstop funding mechanism burdens them with the risk of undersubscription. While the Commission assessed that risk to be low, it is not zero. *See, e.g.*, Rehearing Order P 45 n.189; *see also supra* p. 52 (discussing costs borne by transmission customers).

2. The Commission did not depart from precedent

Generators charge that the Commission “depart[ed] from its own precedent” in approving the Joint Targeted Interconnection Queue framework. Gen. Br. 41. The relevant section of Generators’ brief (41-

44) does not cite any Commission precedent at all—much less any contradictory precedent—but the claim appears to be grounded in Generators’ belief that the Federal Power Act requires that all beneficiaries “must bear costs commensurate to the benefits [they] receive.” *Id.*; *see also id.* 48.

From the start, the Commission acknowledged that the system operators’ filing presents a “unique set of facts and circumstances.” Initial Order P 196. The Commission thus “decline[d] to apply” its standard but-for precedent “for interconnection-related network upgrades.” *Id.* P 197. Instead, the Commission “evaluated whether the proposal is just and reasonable consistent with the cost causation principle and allocates the costs ... in a manner that is at least roughly commensurate with estimated benefits.” *Id.* That is precisely what the law requires. *See, e.g., El Paso II*, 76 F.4th at 362 (“exacting precision” is not required; rates must “reflect to some degree the costs actually caused by the customer” and be “at least roughly commensurate with costs”) (cleaned up).

3. Generators have waived their undue discrimination claim

Generators argue that the Joint Targeted Interconnection Queue framework is unduly discriminatory because it purportedly treats interconnection customers at the Midcontinent-Southwest seam differently than customers in other areas of the country. Gen. Br. 47-48. This argument was not raised to the agency on rehearing, *see* Clean Energy Ass'ns. Reh'g Req. 6-7, R.153:6-7, and the Court lacks jurisdiction to consider it. *See* 16 U.S.C. § 825l(b); *see also supra* p. 56-57 (citing cases).

D. Generators Have Failed to Establish a Wholesale Departure from the Cost Causation Principle

All of Generators' arguments boil down to a single proposition: the benefits conferred on transmission customers warrant the imposition of a larger cost burden. But a cost allocation decision is arbitrary and capricious only where the costs are "grossly disproportionate" to the benefits. *Long Island*, 27 F.4th at 713; *see also MISO Transmission Customers*, 45 F.4th at 1018 (cost-causation principle violated if "Zone A is paying 100% of a project's costs, but Zone B is receiving 58%, 64%, or even 69% of the benefits"); *MISO Transmission Owners v. FERC*, 819 F.3d 329, 336 (7th Cir. 2016) ("modest" "spillover of ... benefits" does

not run afoul of cost-causation principle). Generators cannot point to any record evidence establishing that the Joint Targeted Interconnection Queue framework “produces a severe misallocation” of costs or a “wholesale departure from the cost-causation principle.” *Old Dominion*, 898 F.3d at 1261.

In the end, they simply want a different cost sharing arrangement. But the Commission’s role is to assess whether the system operators’ proposal was, as the Federal Power Act requires, just and reasonable; “it does not extend to determining” whether some alternative proposal might be “more appropriate.” *Neb. Pub. Power Dist.*, 957 F.3d at 943 (cleaned up). The Commission may only “accept or reject the proposal”; it cannot “impose a new [rule or rate] of its own making” by unilaterally modifying the utility’s proposal. *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114 (D.C. Cir. 2018).

IV. The States Have Failed to Establish That Imposing a Backstop Funding Obligation on MISO South Transmission Customers Is Unreasonable

Pursuant to a 2016 settlement agreement among Midcontinent, Southwest, and others, Midcontinent’s right to “firm” energy transfer capacity—*i.e.*, uninterruptable—on that portion of the grid connecting

the MISO Midwest⁵ and MISO South subregions is set at 1,000 megawatts. Midcontinent is also authorized to use, on an “as-available” basis, 3,000 megawatts in capacity for transfers from MISO Midwest to MISO South, and 2,500 megawatts for transfers from MISO South to MISO Midwest. *See* Rehearing Order P 66 n.77; *see also Midcontinent Indep. Sys. Operator, Inc.* 154 FERC ¶ 61,021 (2016) (approving settlement).

The Midcontinent-based Portfolio upgrades will be located in the MISO Midwest subregion. *See* Rehearing Order P 9. The Commission found that, notwithstanding the transfer capacity limits, “transmission customers in MISO South will receive minor and incidental benefits” from the Portfolio upgrades. Rehearing Order P 59; *see also* Initial Order P 203 (transmission customers throughout the Midcontinent region, “including MISO South, will benefit to some degree” from the upgrades). It was therefore reasonable to include MISO South

⁵ The States’ brief refers to “MISO Midwest,” which is a subregion designated in Midcontinent’s tariff for purposes of allocating costs associated with Multi-Value Projects. *See, e.g., Invenenergy Transmission LLC v. Midcontinent Indep. Sys. Operator, Inc.*, 193 FERC ¶ 61,033, P 7 (2025) (discussing cost allocation subregions). Geographically, MISO Midwest essentially overlaps with Midcontinent’s MISO North and MISO Central operational subregions. *See supra* p. 10.

transmission customers in the region-wide backstop cost allocation. *Id.* That determination was reasonable and reasonably explained. *See FCC v. Prometheus Radio Project*, 592 U.S. 414, 423 (2021) (“The APA’s arbitrary-and-capricious standard requires that agency action be reasonable and reasonably explained.”).

A. The Commission Reasonably Found That the Portfolio Upgrades Will Benefit the MISO South Subregion

1. Timelier generator interconnection

Although limited, the transfer capability between the MISO Midwest and MISO South subregion “is not trivial.” Rehearing Order P 66 n.270. Nor would it prevent the benefits of the Portfolio upgrades from flowing to the MISO South subregion. Midcontinent’s witness testified that “[t]he existence of this constraint does not indicate ... that the MISO South Subregion would not benefit from more expeditious interconnection of generation along the MISO-SPP seam.” MISO Tariff Filing, Test. of A. Witmeier, Ex. MISO-0006, 15, R.21:1535. And as the Commission explained, Southwest’s Cost Allocation Working Group analysis found that “the more expeditious interconnection of generation” would “result in a combined \$175.8 million of Adjusted Production Cost benefits to MISO and SPP, including \$76.4 million to

MISO.” Rehearing Order P 64.

2. Congestion payment reductions

The Commission also found that the Portfolio upgrades will reduce congestion at the seam. *Id.* P 59. “[C]ongestion on the electrical grid is like a traffic jam.” *Citadel FNGE Ltd. v. FERC*, 77 F.4th 842, 849 (D.C. Cir. 2023). It prevents system operators from meeting demand “in certain areas through the transmission of low-cost generation, forcing the grid to instead draw on more expensive generation closer to the areas of high demand, which ultimately raises costs to consumers.” *Int’l Transmission Co. v. FERC*, 988 F.3d 471, 473 (D.C. Cir. 2021).

Southwest and Midcontinent engage in “market-to-market” coordination of congestion at their shared borders whereby one operator can request the other to reduce flows on an overloaded facility. This can result in payments from one system operator to the other (after netting out any payments going the other way). *See* MISO Tariff Filing, Witmeier Test. 16, R.21:1536. When Midcontinent incurs such charges, they are recovered from all of its transmission customers system-wide. *Id.*

The Commission acknowledged that it could not project with certainty that Midcontinent (as opposed to Southwest) would be the “net beneficiary of the reduction in market-to-market congestion payments.” Rehearing Order P 60. But any “reduced congestion at the seam should reduce market-to-market charges to MISO load,” and “this benefit ... would accrue to the entire MISO footprint because market-to-market charges are recovered on a system-wide basis.” *Id.*

3. Consistency with existing cost allocation methodology

The Commission also observed that Midcontinent’s existing tariff allocates 10% of the capital costs of high-voltage interconnection-related network upgrades to transmission customers on a system-wide basis. *See* Initial Order P 203. This cost allocation recognizes that high-voltage network upgrades, like the Portfolio upgrades, “provide broad regional benefits to load.” Rehearing Order P 61.

4. Qualitative benefits

Finally, the Commission explained that Portfolio upgrades would increase the resiliency of the entire Midcontinent transmission system. *See* Initial Order P 201; *see also* Rehearing Order 58-59. This benefit, just like all the rest, will enure to MISO South to the same degree “as

the rest of MISO, up to the contractual transfer limits.” Rehearing Order P 62; *see also Paragould*, 144 F.4th at 295 (“Qualitative benefits such as improved integration and reliability are sufficient to sustain a cost shift.”).

B. The States’ Objections to the Commission’s Benefits Analysis Lack Merit

1. The States waived any substantial evidence challenge

The States’ primary argument is that the Commission’s benefits determination is not supported by substantial evidence. State Br. 24-29. The claim rests on two pillars: (1) the Commission’s purportedly faulty reliance upon Southwest’s Cost Allocation Working Group analysis (the so-called “CAWG Analysis”), and (2) the Commission’s supposed erroneous projections of lower congestion costs. *Id.*

But neither the broad substantial evidence argument, nor the particular objections to the Commission’s findings, were raised on agency rehearing. *See* State Comm’n Reh’g Req. 2-3, R.149:2-3. Indeed, the States’ rehearing request makes no mention whatsoever of the Cost Allocation Working Group analysis or congestion costs. And it is not enough for the States to point to earlier pleadings in the administrative proceeding where these issues were touched upon. *See, e.g.,* State Br.

19 (discussing arguments made in support of protest). “[A] party must include its objection in a rehearing petition despite the fact that the point sought to be appealed was raised, considered and rejected in the original proceeding.” *Save Our Sebasticook v. FERC*, 431 F.3d 379, 382 (D.C. Cir. 2005); *see also Ind. Util. Reg. Comm’n v. FERC*, 668 F.3d 735, 739 (D.C. Cir. 2012) (“our purview [is] limited to the four corners of the ... request for rehearing”); *Allegheny Power v. FERC*, 437 F.3d 1215, 1220 (D.C. Cir. 2006) (issues must be preserved “specifically” in a request for agency rehearing, “an objection cannot be preserved indirectly” by referring to earlier arguments).

The States have failed to comply with their statutory obligation to “set forth” their rehearing arguments “specifically.” 16 U.S.C. § 825l(a). As a result, the Court lacks jurisdiction to consider their substantial evidence claim on review. *See id.* § 825l(b).

2. In any event, the States’ substantial evidence argument lacks merit

Even if the Court could reach the issue, the States’ argument lacks merit.

a. The Cost Allocation Working Group analysis

The States contend that the Cost Allocation Working Group analysis “was not in the record” and the Commission “violated the substantial evidence standard” by relying upon it. State Br. 27. But the analysis was discussed in the system operators’ initial filings and linked via an internet address. *See, e.g.*, MISO JTIQ Filing 33, R.1:33; SPP JTIQ Filing 40, R.2:40; MISO Tariff Filing 20, R.21:20; SPP Tariff Filing 41, R.17:41.

It stands on precisely the same footing as the Brattle Group testimony relied upon by the States. *See* Initial Order P 143 (discussing States’ argument); Rehearing Order P 65 (same); State Br. 31-32 (discussing Brattle Group analysis and testimony). That testimony was not filed separately in the underlying agency proceeding; it was cited to and discussed in the States’ filings. *See, e.g.*, State Comm’n Reh’g Req. 2 n.8, 3, 5, R.149:2, 3, 5.

The Commission reviewed the Cost Allocation Working Group analysis and discussed it in the orders below. *See, e.g.*, Initial Order P 201 (addressing Cost Allocation Working Group analysis). It was plainly part of the administrative record, which “includes ‘the decision

of the agency’ and ‘the evidence on which it was based.’” *Texas*, 156 F.4th at 537 (quoting *Fed. Power Comm’n v. Transcon. Gas Pipe Line Corp.*, 423 U.S. 326, 331 (1976)); *see also James Madison Ltd. by Hecht v. Ludwig*, 82 F.3d 1085, 1095 (D.C. Cir. 1996) (record “includes all materials compiled by the agency, that were before the agency at the time the decision was made”) (cleaned up).

Next, the States complain that the Cost Allocation Working Group analysis failed to break down the Portfolio upgrade benefits by subregion. State Br. 26-27. But they offer nothing to call into question the Commission’s finding that the identified benefits should flow to the MISO South region “up to the contractual transfer limits.” Rehearing Order P 6; *see also Medina Cnty. Env’t Action Ass’n v. Surface Transp. Bd.*, 602 F.3d 687, 699 (5th Cir. 2010) (“Where an agency’s particular technical expertise is involved, we are at our most deferential in reviewing the agency’s findings.”).

b. Congestion relief benefits

The States conceded that “there is evidence that [the Portfolio upgrades] will reduce congestion at the seam.” State Br. 28. They claim, however, that the Commission cannot rely on that undisputed

fact because there may not be a “net-decrease” in payments from Midcontinent. *Id.* Of course, it is theoretically possible that the Portfolio upgrades will reduce congestion on the Southwest and Midcontinent grids in precisely the same amount. But the States do not dispute that transmission customers in the MISO South subregion would benefit from *any* reduction in Midcontinent’s market-to-market payments to Southwest. *See* Rehearing Order P 60. This supports the Commission’s finding that Portfolio upgrades will confer “minor and incidental benefits” on the subregion. *Id.* P 59.

c. Existing cost allocation methodology

Reprising an argument that actually was made to the agency on rehearing, the States challenge the Commission’s reliance on Midcontinent’s existing cost allocation methodology for high-voltage interconnection-related upgrades as evidence of regional benefits. State Br. 29; *see also supra* p. 15 (discussing methodology). The States correctly note that this methodology was established before the MISO South subregion was created. *Id.* But it has remained in place for the ensuing 12 years in recognition of the fact that high-voltage network facilities, like the Portfolio upgrades, “provide sufficient benefits to

regional load to warrant allocation of some share of costs to that load.”

Initial Order P 203; *see also* Rehearing Order P 61 (same); *Midwest ISO Transmission Owners*, 373 F.3d at 1368, 1371 (network upgrades that “enhance[] transmission security and reliability” are “presumed to benefit the entire system”) (cleaned up).

3. The States’ reliance on Multi-Value Project precedent is misguided

In 2022, the Commission approved Midcontinent’s proposal to allocate the costs of a certain category of high-voltage transmission projects—termed Multi-Value Projects—on a subregional basis. Rather than having the costs of these projects allocated equally across the entire Midcontinent footprint, the costs of a portfolio of Multi-Value Project sited in the MISO Midwest subregion would be allocated to transmission customers in that region alone, and the costs of a portfolio sited in MISO South would be allocated to MISO South transmission customers. *See Midcontinent Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,124, P 68. *reh’g denied*, 181 FERC ¶ 61,219 (2022). The Commission found that the proposal was reasonable because the record in that case established that the transfer limits between the MISO Midwest and MISO South subregions would cause the benefits of Multi-

Value Projects to “be concentrated in a single Subregion.”

Midcontinent, 179 FERC ¶ 61,124 at P 69.

The States assert these earlier orders “prohibit[]” allocating backstop funding responsibilities to MISO South transmission customers because they held “that MISO South does not benefit from transmission portfolios like” the Portfolio upgrades. State Br. 34. But the Commission reasonably explained why the Multi-Value Project orders do not govern here.

First, those orders addressed a different portfolio of projects. *See* Initial Order P 203. This distinction matters because, unlike the Multi-Value Projects, the Portfolio upgrades are specifically designed to “relieve congestion at the seam,” and thereby potentially reduce market-to-market congestion payments. Rehearing Order P 60 n.253. The Portfolio upgrades will also “expedite the interconnection of generation facilities.” Rehearing Order P 66. And the timely interconnection of new generation at the seam “will allow load in MISO Midwest and MISO South to be served by lower cost generating facilities.” *Id.* As witnesses explained, “[l]oad generally benefits from having access to more generation resources.” MISO JTIQ Filing,

Johnson Test. 30, R.1:112.

Second, the Multi-Value Project proceeding did not establish that *no* benefits flow to the MISO South subregion from network upgrades sited elsewhere. Instead, the testimony was that the transfer limits prevent the MISO South subregion from benefitting “*significantly*” and that that “economic and reliability benefits ... remain *mostly concentrated* within the Subregion in which the projects are located.” Rehearing Order P 66 (quoting J. Pfeifengerger Testimony from Multi-Value Project proceeding). That is entirely consistent with the Commission’s finding here that the Portfolio upgrades should provide “minor and incidental benefits” to MISO South transmission customers. *Id.* P 59; *see also id.* P 68.

Third, the question in the Multi-Value Project proceeding was whether the benefits of those projects could justify a region-wide primary cost allocation obligation. *Id.* P 67. Here, the question was whether the benefits flowing to the MISO South subregion were roughly commensurate with any costs that might ultimately emerge from the backstop funding mechanism—a mechanism that is “highly unlikely” to result in any permanent costs. *Id.*; *see also* Initial Order P 201.

C. The States Do Not Challenge the Commission's Cost Projection

Neither on agency rehearing, nor in their opening brief, do the States challenge the Commission's finding that the administrative record established that "it is 'highly unlikely' that load, including load in MISO South, will be allocated backstop costs on a permanent basis." Rehearing Order P 58 (citing record evidence); *see also* Initial Order P 201 (same); Rehearing Order P 67 ("No party, including [the States] has rebutted this evidence."). And it is too late for them to do so now. *See United States v. Elashyi*, 554 F.3d 480, 494 n.6 (5th Cir. 2008) ("An appellant that fails to adequately brief an issue in his opening brief waives that issue."); *see also* 16 U.S.C. § 825l(b).

Given the undisputed likelihood that MISO South transmission customers will not have to bear *any* unreimbursed costs at all, the States' claim that the Commission's backstop allocation decision violates the cost causation principle falls away. *See* State Br. 35-36. After all, the "benefits justifying a cost shift do not need to be tangible, nor must they be amenable to precise tabulation." *Paragould*, 144 F.4th at 295. The Commission need only articulate a "plausible reason to believe that the benefits are at least roughly commensurate" with

allocated costs. *Illinois I*, 576 F.3d at 477; *see also El Paso II*, 76 F.4th at 357 (benefits need only be “roughly commensurate” with projected costs). It did so here by explaining why the Portfolio upgrades will impart “minor and incidental benefits” to MISO South transmission customers, Rehearing Order P 59, which justify the imposition of a backstop funding obligation that is “highly unlikely” to result in any permanent costs. *Id.* P 67.

D. The States’ Resort to Post-Order Events Is Unavailing

In a last-ditch attempt to show that the Commission’s backstop funding decision was arbitrary, the States claim that “[r]ecent activities” increase the risk that Midcontinent transmission customers will incur actual, unreimbursed costs in connection with the Portfolio upgrades. State Br. 37. They contend that in Fall 2025—long after the November 2024 Initial Order and June 2025 Rehearing Order—the Department of Energy cancelled its funding contribution and that Midcontinent observed “substantial withdrawals” from its interconnection queue. *Id.* 38. Two problems foreclose the State’s argument.

First, the Commission understands that the Department of

Energy has not terminated its Portfolio upgrade funding. The Commission further understands that Midcontinent’s intervenor brief will address the current state of its interconnection queue.

Second, and most fundamental, the States’ argument is legally barred. The Administrative Procedure Act directs courts to review the “whole record” when assessing the lawfulness of agency action. 5 U.S.C. § 706. “[T]he focal point for judicial review should be the administrative record already in existence, not some new record made initially in the reviewing court.” *Camp v. Pitts*, 411 U.S. 138, 142 (1973). “To review more than the information before the [Commission] at the time” of its decision “risks our requiring administrators to be prescient.” *Texas*, 156 F.4th at 537. It is thus “black-letter administrative law that in an Administrative Procedure Act case, a reviewing court should have before it neither more nor less information than did the agency when it made its decision.” *Hearth, Patio & Barbecue Ass’n v. EPA*, 11 F.4th 791, 802 (2021) (cleaned up).

Accordingly, the States’ argument premised on post-decisional events “is procedurally foreclosed.” *CTS Corp. v. EPA*, 759 F.3d 52, 64 (D.C. Cir. 2014); *see also Del. Dep’t of Nat. Res. & Env’t Control v. EPA*,

895 F.3d 90, 102 (D.C. Cir. 2018) (“a reviewing court cannot consider information that was unavailable to the agency when it made its decision”). In any event, these subsequent events fail to show that the Commission’s decision, based on the record before it, was arbitrary or capricious. That is the only question in this case.

CONCLUSION

For the foregoing reasons, the petitions for review should be denied, and the Commission orders on review should be affirmed in all respects.

Respectfully submitted,

David L. Morenoff
Deputy General Counsel

Robert H. Solomon
Solicitor

/s/ Robert M. Kennedy
Robert M. Kennedy
Deputy Solicitor

Federal Energy Regulatory
Commission
888 First Street, N.E.
Washington, DC 20426
(202) 502-8904
robert.kennedy@ferc.gov

December 16, 2025

CERTIFICATE OF COMPLIANCE

Pursuant to Fed. R. App. P. 32(g), Circuit Rule 32.3, and this Court's August 20, 2025 order setting a 18,500-word limit for Respondent, I certify that this brief complies with the type-volume limitation of Fed. R. App. P. 32(a)(7)(B) and this Court's order because it contains 13,508 words, excluding the parts of the brief exempted by Fed. R. App. P. 32(f) and Circuit Rule 32.2.

I further certify that this brief complies with the type-face requirements of Fed. R. App. P. 32(a)(5) and the type-style requirements of Fed. R. App. P. 32(a)(6) because this brief has been prepared in a proportionally spaced typeface using Microsoft Office 365 in Century Schoolbook 14-point font.

/s/ Robert M. Kennedy

Robert M. Kennedy

Deputy Solicitor

Federal Energy Regulatory
Commission
888 First Street, N.E.
Washington, DC 20426
(202) 502-8904
robert.kennedy@ferc.gov

December 16, 2025

ADDENDUM

STATUTES AND REGULATIONS

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vides that the action meanwhile is inoperative, for an appeal to superior agency authority.

(Pub. L. 89–554, Sept. 6, 1966, 80 Stat. 392.)

HISTORICAL AND REVISION NOTES

<i>Derivation</i>	<i>U.S. Code</i>	<i>Revised Statutes and Statutes at Large</i>
.....	5 U.S.C. 1009(c).	June 11, 1946, ch. 324, §10(c), 60 Stat. 243.

Standard changes are made to conform with the definitions applicable and the style of this title as outlined in the preface of this report.

§ 705. Relief pending review

When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, the reviewing court, including the court to which a case may be taken on appeal from or on application for certiorari or other writ to a reviewing court, may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve status or rights pending conclusion of the review proceedings.

(Pub. L. 89–554, Sept. 6, 1966, 80 Stat. 393.)

HISTORICAL AND REVISION NOTES

<i>Derivation</i>	<i>U.S. Code</i>	<i>Revised Statutes and Statutes at Large</i>
.....	5 U.S.C. 1009(d).	June 11, 1946, ch. 324, §10(d), 60 Stat. 243.

Standard changes are made to conform with the definitions applicable and the style of this title as outlined in the preface of this report.

§ 706. Scope of review

To the extent necessary to decision and when presented, the reviewing court shall decide all relevant questions of law, interpret constitutional and statutory provisions, and determine the meaning or applicability of the terms of an agency action. The reviewing court shall—

(1) compel agency action unlawfully withheld or unreasonably delayed; and

(2) hold unlawful and set aside agency action, findings, and conclusions found to be—

(A) arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law;

(B) contrary to constitutional right, power, privilege, or immunity;

(C) in excess of statutory jurisdiction, authority, or limitations, or short of statutory right;

(D) without observance of procedure required by law;

(E) unsupported by substantial evidence in a case subject to sections 556 and 557 of this title or otherwise reviewed on the record of an agency hearing provided by statute; or

(F) unwarranted by the facts to the extent that the facts are subject to trial de novo by the reviewing court.

In making the foregoing determinations, the court shall review the whole record or those parts of it cited by a party, and due account shall be taken of the rule of prejudicial error.

(Pub. L. 89–554, Sept. 6, 1966, 80 Stat. 393.)

HISTORICAL AND REVISION NOTES

<i>Derivation</i>	<i>U.S. Code</i>	<i>Revised Statutes and Statutes at Large</i>
.....	5 U.S.C. 1009(e).	June 11, 1946, ch. 324, §10(e), 60 Stat. 243.

Standard changes are made to conform with the definitions applicable and the style of this title as outlined in the preface of this report.

Statutory Notes and Related Subsidiaries

ABBREVIATION OF RECORD

Pub. L. 85–791, Aug. 28, 1958, 72 Stat. 941, which authorized abbreviation of record on review or enforcement of orders of administrative agencies and review on the original papers, provided, in section 35 thereof, that: “This Act [see Tables for classification] shall not be construed to repeal or modify any provision of the Administrative Procedure Act [see Short Title note set out preceding section 551 of this title].”

CHAPTER 8—CONGRESSIONAL REVIEW OF AGENCY RULEMAKING

<i>Sec.</i>	
801.	Congressional review.
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807.	Exemption for monetary policy.
808.	Effective date of certain rules.

§ 801. Congressional review

(a)(1)(A) Before a rule can take effect, the Federal agency promulgating such rule shall submit to each House of the Congress and to the Comptroller General a report containing—

(i) a copy of the rule;

(ii) a concise general statement relating to the rule, including whether it is a major rule; and

(iii) the proposed effective date of the rule.

(B) On the date of the submission of the report under subparagraph (A), the Federal agency promulgating the rule shall submit to the Comptroller General and make available to each House of Congress—

(i) a complete copy of the cost-benefit analysis of the rule, if any;

(ii) the agency’s actions relevant to sections 603, 604, 605, 607, and 609;

(iii) the agency’s actions relevant to sections 202, 203, 204, and 205 of the Unfunded Mandates Reform Act of 1995; and

(iv) any other relevant information or requirements under any other Act and any relevant Executive orders.

(C) Upon receipt of a report submitted under subparagraph (A), each House shall provide copies of the report to the chairman and ranking member of each standing committee with jurisdiction under the rules of the House of Representatives or the Senate to report a bill to amend the provision of law under which the rule is issued.

(D) For any rule submitted under subparagraph (A), if the Federal agency promulgating

(g) Qualifying criteria for closed-loop pumped storage projects

(1) In general

The Commission shall establish criteria that a pumped storage project shall meet in order to qualify as a closed-loop pumped storage project eligible for the expedited process established under this section.

(2) Inclusions

In establishing the criteria under paragraph (1), the Commission shall include criteria requiring that the pumped storage project—

- (A) cause little to no change to existing surface and ground water flows and uses; and
- (B) is unlikely to adversely affect species listed as a threatened species or endangered species under the Endangered Species Act of 1973 [16 U.S.C. 1531 et seq.].

(h) Savings clause

Nothing in this section affects any authority of the Commission to license a closed-loop pumped storage project under this subchapter.

(June 10, 1920, ch. 285, pt. I, § 35, as added Pub. L. 115–270, title III, § 3004, Oct. 23, 2018, 132 Stat. 3865.)

Editorial Notes

REFERENCES IN TEXT

The Fish and Wildlife Coordination Act, referred to in subsec. (c)(2), (3)(A), is act Mar. 10, 1934, ch. 55, 48 Stat. 401, which is classified generally to sections 661 to 666c–1 of this title. For complete classification of this Act to the Code, see section 661(a) of this title, Short Title note set out under section 661 of this title, and Tables.

The National Environmental Policy Act of 1969, referred to in subsec. (e), is Pub. L. 91–190, Jan. 1, 1970, 83 Stat. 852, which is classified generally to chapter 55 (§ 4321 et seq.) of Title 42, The Public Health and Welfare. For complete classification of this Act to the Code, see Short Title note set out under section 4321 of Title 42 and Tables.

The Endangered Species Act of 1973, referred to in subsec. (g)(2)(B), is Pub. L. 93–205, Dec. 28, 1973, 87 Stat. 884, which is classified principally to chapter 35 (§ 1531 et seq.) of this title. For complete classification of this Act to the Code, see Short Title note set out under section 1531 of this title and Tables.

§ 823g. Considerations for relicensing terms

(a) In general

In determining the term of a new license issued when an existing license under this subchapter expires, the Commission shall take into consideration, among other things—

- (1) project-related investments by the licensee under the new license; and
- (2) project-related investments by the licensee over the term of the existing license.

(b) Equal weight

The determination of the Commission under subsection (a) shall give equal weight to—

- (1) investments by the licensee to implement the new license under this subchapter, including investments relating to redevelopment, new construction, new capacity, efficiency, modernization, rehabilitation or replacement of major equipment, safety improvements, or

environmental, recreation, or other protection, mitigation, or enhancement measures required or authorized by the new license; and

- (2) investments by the licensee over the term of the existing license (including any terms under annual licenses) that—

(A) resulted in redevelopment, new construction, new capacity, efficiency, modernization, rehabilitation or replacement of major equipment, safety improvements, or environmental, recreation, or other protection, mitigation, or enhancement measures conducted over the term of the existing license; and

(B) were not expressly considered by the Commission as contributing to the length of the existing license term in any order establishing or extending the existing license term.

(c) Commission determination

At the request of the licensee, the Commission shall make a determination as to whether any planned, ongoing, or completed investment meets the criteria under subsection (b)(2). Any determination under this subsection shall be issued within 60 days following receipt of the licensee's request. When issuing its determination under this subsection, the Commission shall not assess the incremental number of years that the investment may add to the new license term. All such assessment shall occur only as provided in subsection (a).

(June 10, 1920, ch. 285, pt. I, § 36, as added Pub. L. 115–270, title III, § 3005, Oct. 23, 2018, 132 Stat. 3867.)

SUBCHAPTER II—REGULATION OF ELECTRIC UTILITY COMPANIES ENGAGED IN INTERSTATE COMMERCE

§ 824. Declaration of policy; application of subchapter

(a) Federal regulation of transmission and sale of electric energy

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

(b) Use or sale of electric energy in interstate commerce

(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted

across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

(2) Notwithstanding subsection (f), the provisions of sections 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824o, 824o-1, 824p, 824q, 824r, 824s, 824t, 824u, and 824v of this title shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this chapter with respect to such provisions. Compliance with any order or rule of the Commission under the provisions of section 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824o, 824o-1, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title, shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence.

(c) Electric energy in interstate commerce

For the purpose of this subchapter, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) “Sale of electric energy at wholesale” defined

The term “sale of electric energy at wholesale” when used in this subchapter, means a sale of electric energy to any person for resale.

(e) “Public utility” defined

The term “public utility” when used in this subchapter and subchapter III of this chapter means any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter (other than facilities subject to such jurisdiction solely by reason of section 824e(e), 824e(f),¹ 824i, 824j, 824j-1, 824k, 824o, 824o-1, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title).

(f) United States, State, political subdivision of a State, or agency or instrumentality thereof exempt

No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 et seq.) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing act-

¹ So in original. Section 824e of this title does not contain a subsec. (f).

ing as such in the course of his official duty, unless such provision makes specific reference thereto.

(g) Books and records

(1) Upon written order of a State commission, a State commission may examine the books, accounts, memoranda, contracts, and records of—

(A) an electric utility company subject to its regulatory authority under State law,

(B) any exempt wholesale generator selling energy at wholesale to such electric utility, and

(C) any electric utility company, or holding company thereof, which is an associate company or affiliate of an exempt wholesale generator which sells electric energy to an electric utility company referred to in subparagraph (A),

wherever located, if such examination is required for the effective discharge of the State commission’s regulatory responsibilities affecting the provision of electric service.

(2) Where a State commission issues an order pursuant to paragraph (1), the State commission shall not publicly disclose trade secrets or sensitive commercial information.

(3) Any United States district court located in the State in which the State commission referred to in paragraph (1) is located shall have jurisdiction to enforce compliance with this subsection.

(4) Nothing in this section shall—

(A) preempt applicable State law concerning the provision of records and other information; or

(B) in any way limit rights to obtain records and other information under Federal law, contracts, or otherwise.

(5) As used in this subsection the terms “affiliate”, “associate company”, “electric utility company”, “holding company”, “subsidiary company”, and “exempt wholesale generator” shall have the same meaning as when used in the Public Utility Holding Company Act of 2005 [42 U.S.C. 16451 et seq.].

(June 10, 1920, ch. 285, pt. II, §201, as added Aug. 26, 1935, ch. 687, title II, §213, 49 Stat. 847; amended Pub. L. 95-617, title II, §204(b), Nov. 9, 1978, 92 Stat. 3140; Pub. L. 102-486, title VII, §714, Oct. 24, 1992, 106 Stat. 2911; Pub. L. 109-58, title XII, §§1277(b)(1), 1291(c), 1295(a), Aug. 8, 2005, 119 Stat. 978, 985; Pub. L. 114-94, div. F, §61003(b), Dec. 4, 2015, 129 Stat. 1778.)

Editorial Notes

REFERENCES IN TEXT

The Rural Electrification Act of 1936, referred to in subsec. (f), is act May 20, 1936, ch. 432, 49 Stat. 1363, which is classified generally to chapter 31 (§901 et seq.) of Title 7, Agriculture. For complete classification of this Act to the Code, see section 901 of Title 7 and Tables.

The Public Utility Holding Company Act of 2005, referred to in subsec. (g)(5), is subtitle F of title XII of Pub. L. 109-58, Aug. 8, 2005, 119 Stat. 972, which is classified principally to part D (§16451 et seq.) of subchapter XII of chapter 149 of Title 42, The Public Health and Welfare. For complete classification of this Act to the Code, see Short Title note set out under section 15801 of Title 42 and Tables.

mental orders in the premises as it may find necessary or appropriate, and may by any such supplemental order modify the provisions of any previous order as to the particular purposes, uses, and extent to which, or the conditions under which, any security so theretofore authorized or the proceeds thereof may be applied, subject always to the requirements of subsection (a) of this section.

(c) Compliance with order of Commission

No public utility shall, without the consent of the Commission, apply any security or any proceeds thereof to any purpose not specified in the Commission's order, or supplemental order, or to any purpose in excess of the amount allowed for such purpose in such order, or otherwise in contravention of such order.

(d) Authorization of capitalization not to exceed amount paid

The Commission shall not authorize the capitalization of the right to be a corporation or of any franchise, permit, or contract for consolidation, merger, or lease in excess of the amount (exclusive of any tax or annual charge) actually paid as the consideration for such right, franchise, permit, or contract.

(e) Notes or drafts maturing less than one year after issuance

Subsection (a) shall not apply to the issue or renewal of, or assumption of liability on, a note or draft maturing not more than one year after the date of such issue, renewal, or assumption of liability, and aggregating (together with all other then outstanding notes and drafts of a maturity of one year or less on which such public utility is primarily or secondarily liable) not more than 5 per centum of the par value of the other securities of the public utility then outstanding. In the case of securities having no par value, the par value for the purpose of this subsection shall be the fair market value as of the date of issue. Within ten days after any such issue, renewal, or assumption of liability, the public utility shall file with the Commission a certificate of notification, in such form as may be prescribed by the Commission, setting forth such matters as the Commission shall by regulation require.

(f) Public utility securities regulated by State not affected

The provisions of this section shall not extend to a public utility organized and operating in a State under the laws of which its security issues are regulated by a State commission.

(g) Guarantee or obligation on part of United States

Nothing in this section shall be construed to imply any guarantee or obligation on the part of the United States in respect of any securities to which the provisions of this section relate.

(h) Filing duplicate reports with the Securities and Exchange Commission

Any public utility whose security issues are approved by the Commission under this section may file with the Securities and Exchange Commission duplicate copies of reports filed with the Federal Power Commission in lieu of the re-

ports, information, and documents required under sections 77g, 78l, and 78m of title 15.

(June 10, 1920, ch. 285, pt. II, § 204, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 850.)

Executive Documents

TRANSFER OF FUNCTIONS

Executive and administrative functions of Securities and Exchange Commission, with certain exceptions, transferred to Chairman of such Commission, with authority vested in him to authorize their performance by any officer, employee, or administrative unit under his jurisdiction, by Reorg. Plan No. 10 of 1950, §§ 1, 2, eff. May 24, 1950, 15 F.R. 3175, 64 Stat. 1265, set out in the Appendix to Title 5, Government Organization and Employees.

§ 824d. Rates and charges; schedules; suspension of new rates; automatic adjustment clauses

(a) Just and reasonable rates

All 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, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) Preference or advantage unlawful

No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Schedules

Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Notice required for rate changes

Unless the Commission otherwise orders, no change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein pro-

vided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Suspension of new rates; hearings; five-month period

Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint, at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such period, but in case of a proposed increased rate or charge, the Commission may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

(f) Review of automatic adjustment clauses and public utility practices; action by Commission; “automatic adjustment clause” defined

(1) Not later than 2 years after November 9, 1978, and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine—

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are—

(i) subject to periodic fluctuations and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to—

(A) modify the terms and provisions of any automatic adjustment clause, or

(B) cease any practice in connection with the clause,

if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

(4) As used in this subsection, the term “automatic adjustment clause” means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.

(g) Inaction of Commissioners

(1) In general

With respect to a change described in subsection (d), if the Commission permits the 60-day period established therein to expire without issuing an order accepting or denying the change because the Commissioners are divided two against two as to the lawfulness of the change, as a result of vacancy, incapacity, or recusal on the Commission, or if the Commission lacks a quorum—

(A) the failure to issue an order accepting or denying the change by the Commission shall be considered to be an order issued by the Commission accepting the change for purposes of section 825/(a) of this title; and

(B) each Commissioner shall add to the record of the Commission a written statement explaining the views of the Commissioner with respect to the change.

(2) Appeal

If, pursuant to this subsection, a person seeks a rehearing under section 825/(a) of this title, and the Commission fails to act on the merits of the rehearing request by the date that is 30 days after the date of the rehearing request because the Commissioners are divided two against two, as a result of vacancy, incapacity, or recusal on the Commission, or if the Commission lacks a quorum, such person may appeal under section 825/(b) of this title.

(June 10, 1920, ch. 285, pt. II, § 205, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 851; amended Pub. L. 95-617, title II, §§ 207(a), 208, Nov. 9, 1978, 92 Stat. 3142; Pub. L. 115-270, title III, § 3006, Oct. 23, 2018, 132 Stat. 3868.)

Editorial Notes

AMENDMENTS

2018—Subsec. (g). Pub. L. 115–270 added subsec. (g).
 1978—Subsec. (d). Pub. L. 95–617, § 207(a), substituted
 “sixty” for “thirty” in two places.
 Subsec. (f). Pub. L. 95–617, § 208, added subsec. (f).

Statutory Notes and Related Subsidiaries

**STUDY OF ELECTRIC RATE INCREASES UNDER FEDERAL
POWER ACT**

Section 207(b) of Pub. L. 95–617 directed chairman of Federal Energy Regulatory Commission, in consultation with Secretary, to conduct a study of legal requirements and administrative procedures involved in consideration and resolution of proposed wholesale electric rate increases under Federal Power Act, section 791a et seq. of this title, for purposes of providing for expeditious handling of hearings consistent with due process, preventing imposition of successive rate increases before they have been determined by Commission to be just and reasonable and otherwise lawful, and improving procedures designed to prohibit anti-competitive or unreasonable differences in wholesale and retail rates, or both, and that chairman report to Congress within nine months from Nov. 9, 1978, on results of study, on administrative actions taken as a result of this study, and on any recommendations for changes in existing law that will aid purposes of this section.

§ 824e. Power of Commission to fix rates and charges; determination of cost of production or transmission

(a) Unjust or preferential rates, etc.; statement of reasons for changes; hearing; specification of issues

Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. Any complaint or motion of the Commission to initiate a proceeding under this section shall state the change or changes to be made in the rate, charge, classification, rule, regulation, practice, or contract then in force, and the reasons for any proposed change or changes therein. If, after review of any motion or complaint and answer, the Commission shall decide to hold a hearing, it shall fix by order the time and place of such hearing and shall specify the issues to be adjudicated.

(b) Refund effective date; preferential proceedings; statement of reasons for delay; burden of proof; scope of refund order; refund orders in cases of dilatory behavior; interest

Whenever the Commission institutes a proceeding under this section, the Commission shall establish a refund effective date. In the case of a proceeding instituted on complaint, the refund effective date shall not be earlier

than the date of the filing of such complaint nor later than 5 months after the filing of such complaint. In the case of a proceeding instituted by the Commission on its own motion, the refund effective date shall not be earlier than the date of the publication by the Commission of notice of its intention to initiate such proceeding nor later than 5 months after the publication date. Upon institution of a proceeding under this section, the Commission shall give to the decision of such proceeding the same preference as provided under section 824d of this title and otherwise act as speedily as possible. If no final decision is rendered by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant. At the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: *Provided*, That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding. The refunds shall be made, with interest, to those persons who have paid those rates or charges which are the subject of the proceeding.

(c) Refund considerations; shifting costs; reduction in revenues; “electric utility companies” and “registered holding company” defined

Notwithstanding subsection (b), in a proceeding commenced under this section involving two or more electric utility companies of a registered holding company, refunds which might otherwise be payable under subsection (b) shall not be ordered to the extent that such refunds would result from any portion of a Commission order that (1) requires a decrease in system production or transmission costs to be paid by one or more of such electric companies; and (2) is based upon a determination that the amount of such decrease should be paid through an increase in the costs to be paid by other electric utility companies of such registered holding company: *Provided*, That refunds, in whole or in part, may be ordered by the Commission if it determines that the registered holding company would not experience any reduction in revenues which results from an inability of an electric

utility company of the holding company to recover such increase in costs for the period between the refund effective date and the effective date of the Commission's order. For purposes of this subsection, the terms "electric utility companies" and "registered holding company" shall have the same meanings as provided in the Public Utility Holding Company Act of 1935, as amended.¹

(d) Investigation of costs

The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.

(e) Short-term sales

(1) In this subsection:

(A) The term "short-term sale" means an agreement for the sale of electric energy at wholesale in interstate commerce that is for a period of 31 days or less (excluding monthly contracts subject to automatic renewal).

(B) The term "applicable Commission rule" means a Commission rule applicable to sales at wholesale by public utilities that the Commission determines after notice and comment should also be applicable to entities subject to this subsection.

(2) If an entity described in section 824(f) of this title voluntarily makes a short-term sale of electric energy through an organized market in which the rates for the sale are established by Commission-approved tariff (rather than by contract) and the sale violates the terms of the tariff or applicable Commission rules in effect at the time of the sale, the entity shall be subject to the refund authority of the Commission under this section with respect to the violation.

(3) This section shall not apply to—

(A) any entity that sells in total (including affiliates of the entity) less than 8,000,000 megawatt hours of electricity per year; or
(B) an electric cooperative.

(4)(A) The Commission shall have refund authority under paragraph (2) with respect to a voluntary short term sale of electric energy by the Bonneville Power Administration only if the sale is at an unjust and unreasonable rate.

(B) The Commission may order a refund under subparagraph (A) only for short-term sales made by the Bonneville Power Administration at rates that are higher than the highest just and reasonable rate charged by any other entity for a short-term sale of electric energy in the same geographic market for the same, or most nearly comparable, period as the sale by the Bonneville Power Administration.

(C) In the case of any Federal power marketing agency or the Tennessee Valley Authority, the Commission shall not assert or exercise any regulatory authority or power under paragraph (2) other than the ordering of refunds to achieve a just and reasonable rate.

(June 10, 1920, ch. 285, pt. II, § 206, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 852; amended Pub. L. 100-473, § 2, Oct. 6, 1988, 102 Stat. 2299; Pub. L. 109-58, title XII, §§ 1285, 1286, 1295(b), Aug. 8, 2005, 119 Stat. 980, 981, 985.)

Editorial Notes

REFERENCES IN TEXT

The Public Utility Holding Company Act of 1935, referred to in subsec. (c), is title I of act Aug. 26, 1935, ch. 687, 49 Stat. 803, which was classified generally to chapter 2C (§ 79 et seq.) of Title 15, Commerce and Trade, prior to repeal by Pub. L. 109-58, title XII, § 1263, Aug. 8, 2005, 119 Stat. 974. For complete classification of this Act to the Code, see Tables.

AMENDMENTS

2005—Subsec. (a). Pub. L. 109-58, § 1295(b)(1), substituted "hearing held" for "hearing had" in first sentence.

Subsec. (b). Pub. L. 109-58, § 1295(b)(2), struck out "the public utility to make" before "refunds of any amounts paid" in seventh sentence.

Pub. L. 109-58, § 1285, in second sentence, substituted "the date of the filing of such complaint nor later than 5 months after the filing of such complaint" for "the date 60 days after the filing of such complaint nor later than 5 months after the expiration of such 60-day period", in third sentence, substituted "the date of the publication" for "the date 60 days after the publication" and "5 months after the publication date" for "5 months after the expiration of such 60-day period", and in fifth sentence, substituted "If no final decision is rendered by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision" for "If no final decision is rendered by the refund effective date or by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, whichever is earlier, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision".

Subsec. (e). Pub. L. 109-58, § 1286, added subsec. (e).

1988—Subsec. (a). Pub. L. 100-473, § 2(1), inserted provisions for a statement of reasons for listed changes, hearings, and specification of issues.

Subsecs. (b) to (d). Pub. L. 100-473, § 2(2), added subsecs. (b) and (c) and redesignated former subsec. (b) as (d).

Statutory Notes and Related Subsidiaries

EFFECTIVE DATE OF 1988 AMENDMENT

Pub. L. 100-473, § 4, Oct. 6, 1988, 102 Stat. 2300, provided that: "The amendments made by this Act [amending this section] are not applicable to complaints filed or motions initiated before the date of enactment of this Act [Oct. 6, 1988] pursuant to section 206 of the Federal Power Act [this section]: *Provided, however,* That such complaints may be withdrawn and refiled without prejudice."

LIMITATION ON AUTHORITY PROVIDED

Pub. L. 100-473, § 3, Oct. 6, 1988, 102 Stat. 2300, provided that: "Nothing in subsection (c) of section 206 of the Federal Power Act, as amended (16 U.S.C. 824e(c)) shall be interpreted to confer upon the Federal Energy Regulatory Commission any authority not granted to it elsewhere in such Act [16 U.S.C. 791a et seq.] to issue an order that (1) requires a decrease in system production or transmission costs to be paid by one or more electric utility companies of a registered holding company; and (2) is based upon a determination that the amount of such decrease should be paid through an increase in the

¹ See References in Text note below.

ices. The amounts collected under this section shall be deposited in the Treasury to the credit of miscellaneous receipts. All printing for the Federal Power Commission making use of engraving, lithography, and photolithography, together with the plates for the same, shall be contracted for and performed under the direction of the Commission, under such limitations and conditions as the Joint Committee on Printing may from time to time prescribe, and all other printing for the Commission shall be done by the Director of the Government Publishing Office under such limitations and conditions as the Joint Committee on Printing may from time to time prescribe. The entire work may be done at, or ordered through, the Government Publishing Office whenever, in the judgment of the Joint Committee on Printing, the same would be to the interest of the Government: *Provided*, That when the exigencies of the public service so require, the Joint Committee on Printing may authorize the Commission to make immediate contracts for engraving, lithographing, and photolithographing, without advertisement for proposals: *Provided further*, That nothing contained in this chapter or any other Act shall prevent the Federal Power Commission from placing orders with other departments or establishments for engraving, lithographing, and photolithographing, in accordance with the provisions of sections 1535 and 1536 of title 31, providing for interdepartmental work.

(June 10, 1920, ch. 285, pt. III, § 312, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 859; amended Pub. L. 113–235, div. H, title I, § 1301(b), (d), Dec. 16, 2014, 128 Stat. 2537.)

Editorial Notes

CODIFICATION

“Sections 1535 and 1536 of title 31” substituted in text for “sections 601 and 602 of the Act of June 30, 1932 (47 Stat. 417 [31 U.S.C. 686, 686b])” on authority of Pub. L. 97–258, § 4(b), Sept. 13, 1982, 96 Stat. 1067, the first section of which enacted Title 31, Money and Finance.

Statutory Notes and Related Subsidiaries

CHANGE OF NAME

“Director of the Government Publishing Office” substituted for “Public Printer” in text on authority of section 1301(d) of Pub. L. 113–235, set out as a note under section 301 of Title 44, Public Printing and Documents.

“Government Publishing Office” substituted for “Government Printing Office” in text on authority of section 1301(b) of Pub. L. 113–235, set out as a note preceding section 301 of Title 44, Public Printing and Documents.

§ 825I. Review of orders

(a) Application for rehearing; time periods; modification of order

Any person, electric utility, State, municipality, or State commission aggrieved by an order issued by the Commission in a proceeding under this chapter to which such person, electric utility, State, municipality, or State commission is a party may apply for a rehearing within thirty days after the issuance of such order. The application for rehearing shall set forth specifically the ground or grounds upon which such ap-

plication is based. Upon such application the Commission shall have power to grant or deny rehearing or to abrogate or modify its order without further hearing. Unless the Commission acts upon the application for rehearing within thirty days after it is filed, such application may be deemed to have been denied. No proceeding to review any order of the Commission shall be brought by any entity unless such entity shall have made application to the Commission for a rehearing thereon. Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b), the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.

(b) Judicial review

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 United States court of appeals for any circuit wherein the licensee or public utility to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. A copy of such petition shall forthwith be transmitted by the clerk of the court to any member of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of title 28. Upon the filing of such petition such court shall have jurisdiction, which upon the filing of the record with it shall be exclusive, to affirm, modify, or set aside such order in whole or in part. No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do. The finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive. If any party shall apply to the court for leave to adduce additional evidence, and shall show to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for failure to adduce such evidence in the proceedings before the Commission, the court may order such additional evidence to be taken before the Commission and to be adduced upon the hearing in such manner and upon such terms and conditions as to the court may seem proper. The Commission may modify its findings as to the facts by reason of the additional evidence so taken, and it shall file with the court such modified or new findings which, if supported by substantial evidence, shall be conclusive, and its recommendation, if any, for the modification or setting aside of the original order. The judgment and decree of the court, affirming, modifying, or setting aside, in whole or in part, any such order of the Commission, shall be final, subject to review by the Supreme Court of the United States

upon certiorari or certification as provided in section 1254 of title 28.

(c) Stay of Commission's order

The filing of an application for rehearing under subsection (a) shall not, unless specifically ordered by the Commission, operate as a stay of the Commission's order. The commencement of proceedings under subsection (b) of this section shall not, unless specifically ordered by the court, operate as a stay of the Commission's order.

(June 10, 1920, ch. 285, pt. III, § 313, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 860; amended June 25, 1948, ch. 646, § 32(a), 62 Stat. 991; May 24, 1949, ch. 139, § 127, 63 Stat. 107; Pub. L. 85-791, § 16, Aug. 28, 1958, 72 Stat. 947; Pub. L. 109-58, title XII, § 1284(c), Aug. 8, 2005, 119 Stat. 980.)

Editorial Notes

CODIFICATION

In subsec. (b), “section 1254 of title 28” substituted for “sections 239 and 240 of the Judicial Code, as amended (U.S.C., title 28, secs. 346 and 347)” on authority of act June 25, 1948, ch. 646, 62 Stat. 869, the first section of which enacted Title 28, Judiciary and Judicial Procedure.

AMENDMENTS

2005—Subsec. (a). Pub. L. 109-58 inserted “electric utility,” after “Any person,” and “to which such person,” and substituted “brought by any entity unless such entity” for “brought by any person unless such person”.

1958—Subsec. (a). Pub. L. 85-791, § 16(a), inserted sentence to provide that Commission may modify or set aside findings or orders until record has been filed in court of appeals.

Subsec. (b). Pub. L. 85-791, § 16(b), in second sentence, substituted “transmitted by the clerk of the court to” for “served upon”, substituted “file with the court” for “certify and file with the court a transcript of”, and inserted “as provided in section 2112 of title 28”, and in third sentence, substituted “jurisdiction, which upon the filing of the record with it shall be exclusive” for “exclusive jurisdiction”.

Statutory Notes and Related Subsidiaries

CHANGE OF NAME

Act June 25, 1948, eff. Sept. 1, 1948, as amended by act May 24, 1949, substituted “court of appeals” for “circuit court of appeals”.

§ 825m. Enforcement provisions

(a) Enjoining and restraining violations

Whenever it shall appear to the Commission that any person is engaged or about to engage in any acts or practices which constitute or will constitute a violation of the provisions of this chapter, or of any rule, regulation, or order thereunder, it may in its discretion bring an action in the proper District Court of the United States or the United States courts of any Territory or other place subject to the jurisdiction of the United States, to enjoin such acts or practices and to enforce compliance with this chapter or any rule, regulation, or order thereunder, and upon a proper showing a permanent or temporary injunction or decree or restraining order shall be granted without bond. The Commission may transmit such evidence as may be available

concerning such acts or practices to the Attorney General, who, in his discretion, may institute the necessary criminal proceedings under this chapter.

(b) Writs of mandamus

Upon application of the Commission the district courts of the United States and the United States courts of any Territory or other place subject to the jurisdiction of the United States shall have jurisdiction to issue writs of mandamus commanding any person to comply with the provisions of this chapter or any rule, regulation, or order of the Commission thereunder.

(c) Employment of attorneys

The Commission may employ such attorneys as it finds necessary for proper legal aid and service of the Commission or its members in the conduct of their work, or for proper representation of the public interests in investigations made by it or cases or proceedings pending before it, whether at the Commission's own instance or upon complaint, or to appear for or represent the Commission in any case in court; and the expenses of such employment shall be paid out of the appropriation for the Commission.

(d) Prohibitions on violators

In any proceedings under subsection (a), the court may prohibit, conditionally or unconditionally, and permanently or for such period of time as the court determines, any individual who is engaged or has engaged in practices constituting a violation of section 824u of this title (and related rules and regulations) from—

- (1) acting as an officer or director of an electric utility; or
- (2) engaging in the business of purchasing or selling—
 - (A) electric energy; or
 - (B) transmission services subject to the jurisdiction of the Commission.

(June 10, 1920, ch. 285, pt. III, § 314, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 861; amended June 25, 1936, ch. 804, 49 Stat. 1921; June 25, 1948, ch. 646, § 32(b), 62 Stat. 991; May 24, 1949, ch. 139, § 127, 63 Stat. 107; Pub. L. 109-58, title XII, § 1288, Aug. 8, 2005, 119 Stat. 982.)

Editorial Notes

CODIFICATION

As originally enacted subsecs. (a) and (b) contained references to the Supreme Court of the District of Columbia. Act June 25, 1936, substituted “the district court of the United States for the District of Columbia” for “the Supreme Court of the District of Columbia”, and act June 25, 1948, as amended by act May 24, 1949, substituted “United States District Court for the District of Columbia” for “district court of the United States for the District of Columbia”. However, the words “United States District Court for the District of Columbia” have been deleted entirely as superfluous in view of section 132(a) of Title 28, Judiciary and Judicial Procedure, which states that “There shall be in each judicial district a district court which shall be a court of record known as the United States District Court for the district”, and section 88 of Title 28 which states that “the District of Columbia constitutes one judicial district”.

AMENDMENTS

2005—Subsec. (d). Pub. L. 109-58 added subsec. (d).

CERTIFICATE OF SERVICE

I hereby certify that, on December 16, 2025, I electronically filed the foregoing brief with the Clerk of the Court using the CM/ECF system. I certify that all participants in the case are registered CM/ECF users and that service will be accomplished by the CM/ECF system.

/s/ Robert M. Kennedy
Robert M. Kennedy
Deputy Solicitor

Federal Energy Regulatory
Commission
888 First Street, N.E.
Washington, DC 20426
(202) 502-8904
robert.kennedy@ferc.gov