

**ORAL ARGUMENT SCHEDULED FOR FEBRUARY 26, 2008**

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**IN THE UNITED STATES COURT OF APPEALS  
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

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**Nos. 04-1090, *et al.***  
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**WESTERN AREA POWER ADMINISTRATION, *ET AL.*,  
PETITIONERS,**

**v.**

**FEDERAL ENERGY REGULATORY COMMISSION,  
RESPONDENT.**

\_\_\_\_\_

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

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**BRIEF FOR RESPONDENT  
FEDERAL ENERGY REGULATORY COMMISSION**

\_\_\_\_\_

**CYNTHIA A. MARLETTE  
GENERAL COUNSEL**

**ROBERT H. SOLOMON  
SOLICITOR**

**SAMUEL SOOPPER  
ATTORNEY**

**FOR RESPONDENT  
FEDERAL ENERGY REGULATORY  
COMMISSION  
WASHINGTON, D.C. 20426**

**OCTOBER 9, 2007  
FINAL BRIEF: JANUARY 18, 2008**

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## **CIRCUIT RULE 28(a)(1) CERTIFICATE**

### **A. Parties and Amici**

All parties and intervenors appearing in the proceedings below and in this are listed in the Petitioners' Circuit Rule 28(a)(1) certificates.

### **B. Rulings Under Review**

1. *California Independent System Operator Corp.*, 103 FERC ¶ 61,114 (2003) (Opinion No. 463), JA 338.

2. *California Independent System Operator Corp.*, 106 FERC ¶ 61,032 (2004) (Opinion No. 463-A), JA 587.

3. *California Independent System Operator Corp.*, 113 FERC ¶ 61,135 (Opinion No. 463-B), JA 748.

4. *California Independent System Operator Corp.*, 116 FERC ¶ 61,224 (2006) (Opinion No. 463-C), JA 918.

5. *California Independent System Operator Corp.*, 118 FERC ¶ 61,061 (2007), JA 948.

**C. Related Cases**

Counsel is not aware of any related cases pending before this or any other Court.

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Samuel Soopper  
Attorney

January 18, 2008

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## GLOSSARY

Cogeneration Association	Petitioners Cogeneration Association of California And Energy Producers and Users Coalition
Existing Contract Customers	Petitioners Western Area Power Administration, Northern California Power Agency, Sacramento Municipal Utility District, City of Santa Clara, California, and Modesto Irrigation District
FPA	Federal Power Act
Hearing Order	<i>California Independent System Operator Corp.</i> , 109 FERC ¶ 61,162 (2004)
Initial Decision	<i>California Independent System Operator Corp.</i> , 99 FERC ¶ 63,020 (2002)
ISO	Independent System Operator
January 2007 Order	<i>California Independent System Operator Corp.</i> , 118 FERC ¶ 61,061 (2007)
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Second Initial Decision	<i>California Independent System Operator Corp.</i> , 111 FERC ¶ 63,008 (2005)

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

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**BRIEF OF RESPONDENT  
FEDERAL ENERGY REGULATORY COMMISSION**

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**STATEMENT OF THE ISSUES**

1. Whether the Federal Energy Regulatory Commission (Commission or FERC) acted reasonably in holding that certain administrative costs of the California Independent System Operator Corporation (California ISO or ISO) could be recovered from its customers with pre-existing transmission contracts, who nonetheless benefit from the operation of the ISO.

2. Whether the Commission reasonably held that a portion of the California ISO's administrative costs should be allocated to all of its customers, who benefit

from ISO-administered services, except to the extent customers have load that does not cause the ISO to incur these particular administrative costs on their behalf.

## **STATUTORY AND REGULATORY PROVISIONS**

The pertinent statutes and regulations are contained in the Addendum to this brief.

## **COUNTERSTATEMENT OF JURISDICTION**

The Court does not have jurisdiction over one group of petitioners, Cogeneration Association of California and the Energy Producers and Users Coalition (collectively, Cogeneration Association), as their claim is time-barred under section 313 of the Federal Power Act (FPA), 16 U.S.C. § 8251(b). *See infra* Argument Section I.

## **INTRODUCTION**

This case arises from the filing in November 2000 by the California ISO of its Grid Management Charge, to recover the ISO's start-up, administrative and operating costs for the period from January 1, 2001, when it replaced a prior ISO rate recovering administrative costs, until January 1, 2004, when it was superseded by a new, more precisely allocated Grid Management Charge.<sup>1</sup> Thus, the issues in

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<sup>1</sup> *See California Independent System Operator Corp.*, 105 FERC ¶ 61,406 (2003). The revised Grid Management Charge, which subdivided the ISO's administrative costs into seven elements, became effective January 1, 2004, and is not on appeal.

this appeal solely apply to a limited, three-year locked-in period.

One group of petitioners, Western Area Power Administration, Northern California Power Agency, Sacramento Municipal Utility District, City of Santa Clara, California, and the Modesto Irrigation District (collectively, Existing Contract Customers), consists of electric transmission customers whose pre-ISO contracts with their pre-ISO transmission provider, Pacific Gas and Electric Company (PG&E), were still in effect for the period in question. The Existing Contract Customers appeal the Commission's decision authorizing the ISO to allocate certain administrative costs to them, which they are then charged by PG&E, their ISO Scheduling Coordinator. The Court addressed similar matters in *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) and *East Kentucky Power Cooperative v. FERC*, 489 F.3d 1299, 1301 (D.C. Cir. 2007).

The second group of petitioners, the Cogeneration Association, consists of two trade associations representing industrial facilities which are retail customers of PG&E or Southern California Edison Company. Both the Existing Contract Customers and the Cogeneration Association contest different aspects of the Commission's orders concerning the ISO's allocation of one element of the Grid Management Charge to its customers. These issues involve garden-variety cost causation principles, which the Court has also applied in the ISO context. *See*

*Midwest ISO Transmission Owners*, 373 F.3d at 1368-69.

While the factual matrix of this case is complex, the legal issues are quite straightforward. First, the Grid Management Charge is designed solely “to allow the ISO to recover its administrative and operating costs.” R 1 at 1, JA 86. Thus, the Grid Management Charge is not a charge for actual transmission service. During the period at issue, the California ISO charged a separate Transmission Access Charge to market participants for actual use of the grid.<sup>2</sup> The Existing Contract Customers continued to receive transmission on the ISO-controlled grid under their existing contracts with PG&E (sometimes referred to as Control Area Agreements) until the expiration of these contracts. However, any transmission service on the ISO-controlled grid above and beyond the contract terms (such as additional load) would be subject to the Transmission Access Charge.

Second, the contested orders also approved PG&E’s Grid Management Charge Pass-Through Tariff, which was designed “to collect the actual [Grid Management Charge] charges billed by the ISO” to PG&E, on a dollar-for-dollar basis. R 3 at 1, JA 1205. PG&E, one of the ISO’s original Participating

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<sup>2</sup> The Commission approved the California ISO’s Transmission Access Charge and the related congestion usage charge applicable during the relevant period in *California Independent System Operator Corp.*, 109 FERC ¶ 61,301 (2004) (Opinion No. 478), *reh’g denied*, 111 FERC ¶ 61,337 (2005), *appeal pending*, *State Water Contractors, et al. v. FERC*, 9th Cir No. 06-74506.



Transmission Owners, acted as the ISO's Scheduling Coordinator for transmission service on the ISO-controlled grid for the Existing Contract Customers pursuant to those contracts. Thus, the Grid Management Charge was assessed to PG&E in its role as Scheduling Coordinator, and PG&E passed these charges through to the Existing Contract Customers.

As noted above, the ISO filed its Grid Management Charge in 2000, followed by PG&E's filing of its Pass-Through Tariff. After a hearing, a FERC administrative law judge generally approved the ISO's proposed Grid Management Charge, as well as PG&E's tariff. *California Independent System Operator Corp.*, 99 FERC ¶ 63,020 (2002), JA 191 (Initial Decision).

In the first order on review here, Opinion and Order on Initial Decision, *California Independent System Operator Corp.*, 103 FERC ¶ 61,114 (2003), JA 338 (Opinion No. 463), the Commission largely affirmed the judge. The agency held that the relevant portions of the Grid Management Charge were for new services performed by the California ISO, which were not performed by PG&E under the existing contracts, and thus could be passed through by PG&E to the Existing Contract Customers. Additionally, the agency held that it was proper for the ISO to allocate the Control Area Services portion of the rate to all customers for the entire ISO Control Area (referred to as Control Area Gross Load allocation). However, the Commission attempted to craft an exception for what it

termed “behind-the-meter” generation with a more limited impact on the ISO’s grid.

In the second order on review, Order on Rehearing and Clarification and Dismissing Complaint, *California Independent System Operator Corp.*, 106 FERC ¶ 61,032 (2004), JA 587 (Opinion No. 463-A), the Commission denied, in most respects, requests for rehearing by various customers on the pass-through issues. It did, however, redefine the generating facilities that would be eligible for the behind-the-meter exemption from allocation of the Control Area Services charge on a gross-load basis.

Thereafter, the Commission set the issue of the behind-the-meter allocation for hearing, Order Deferring Rehearing Requests and Establishing Limited Hearing Procedures, *California Independent System Operator Corp.*, 109 FERC ¶ 61,162 (2004), JA 713 (Hearing Order). After a second Initial Decision by the administrative law judge, *California Independent System Operator Corp.*, 111 FERC ¶ 63,008 (2005), JA 724 (Second Initial Decision), the Commission established an exemption to gross-load allocation for the subset of generation for which the ISO did not incur the administrative costs at issue. Order Denying Rehearing and Affirming in Part and Reversing in Part Initial Decision, *California Independent System Operator Corp.*, 113 FERC ¶ 61,135 (2005), JA 748 (Opinion No. 463-B); Order Denying Rehearing, *California Independent System Operator*

*Corp.*, 116 FERC ¶ 61,224 (2006), JA 918 (Opinion No. 463-C).

On January 29, 2007, the Commission issued the final order on appeal, Order Rejecting Request for Rehearing, *California Independent System Operator Corp.*, 118 FERC ¶ 61,061 (2007), JA 948 (January 2007 Order).

## STATEMENT OF THE FACTS

### I. Statutory and Regulatory Background

Under Section 201(b) of the FPA, 16 U.S.C. § 824(b), the Commission has exclusive jurisdiction to regulate the transmission and sale at wholesale of electric energy in interstate commerce. Section 205(c) of the FPA, 16 U.S.C. § 824d(c), requires public utilities to file tariffs with the Commission showing their rates and terms of service, along with related contracts, subject to FERC jurisdiction. When those tariffs are filed, Sections 205(a)-(b) of the FPA, 16 U.S.C. §§ 824d(a)-(b), direct the Commission to assure that the rates and services described therein are just and reasonable and not unduly discriminatory. The Commission may also investigate existing rates and services on complaint or on its own motion. *See* FPA § 206(a), 16 U.S.C. § 824e(a).

This Court has described how the Commission presided over the transformation of the electric power industry from integrated monopolies to participants in a competitive marketplace. *See generally Midwest ISO Transmission Owners*, 373 F.3d at 1363 (describing the historic structure and

recent restructuring of the electric utility industry); *Wisconsin Public Power Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007), 2007 U.S. App. LEXIS 17257 at \*4-\*10 (same). *See also New York v. FERC*, 535 U.S. 1, 5-14 (2002) (describing technological advances and legislative initiatives promoting competitive wholesale electric markets).

To foster the development of competitive markets, the Commission issued Order No. 888, which directed transmission-owning utilities to offer non-discriminatory, open access transmission service.<sup>3</sup> Pursuant to this rule, the Commission required each jurisdictional utility to state separate rates for its wholesale generation, transmission and ancillary services, and to provide transmission service on a non-discriminatory basis. *See New York v. FERC*, 535 U.S. at 11.

As a means to accomplish the Commission's open access goals, Order No. 888 encouraged, but did not direct, the formation of independent system operators

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<sup>3</sup> *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), *clarified*, 76 FERC ¶ 61,009 and 76 FERC ¶ 61,347 (1997), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248, *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

(ISOs) to operate regional, multi-system transmission grids. *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730-32 (announcing certain principles to guide future consideration of ISO proposals).

## **II. Development of the California ISO**

As this Court is aware, in 1996, at the time the Commission was implementing Order No. 888, the State of California chartered the California ISO as “an independent entity that would take over transmission operations from the California utilities and file a new tariff with the Commission.” *Sacramento Municipal Utility District v. FERC*, 428 F.3d 294, 296-297 (D.C. Cir. 2005) (citing *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 397 (D.C. Cir. 2004)). In order “[t]o manage the transition to a new regulatory regime and a completely new service model, the Commission . . . declined to abrogate existing contracts and ordered customers to take service under the California ISO tariff upon contract expiration.” *Sacramento Municipal Utility District*, 428 F.3d at 297 (footnote and citation omitted).

In 1997, the California ISO filed its original proposed Grid Management Charge designed to collect the costs of operating the ISO, including start-up and development costs, as well as ongoing operation and maintenance costs. *See* R 1 at 1, JA 86. This rate took the form of a monthly charge assessed on all ISO Scheduling Coordinators. As indicated above, PG&E was the ISO Scheduling

Coordinator for the Existing Contract Customers during the period at issue.

### **III. Factual Background**

#### **A. The California ISO and PG&E Filings**

On November 1, 2000, as amended on December 15, 2000, the California ISO filed with the Commission a proposed new Grid Management Charge. R 1, JA 86. As mentioned previously, the Grid Management Charge at issue here was effective from January 1, 2001, until January 1, 2004, when it was replaced by a revised rate.

The California ISO's Grid Management Charge was designed to collect costs from "all ISO system users, and minimize cost subsidization among Market Participants." R 1 at 6, JA 91. Thus, it applied to all users of the Control Area operated by the ISO, "and not just those that use the ISO Controlled Grid," a smaller subset of the ISO's Control Area. *Id.* at 7, JA 92.

The ISO's 2000 filing was for an "unbundled" Grid Management Charge, dividing costs for various administrative services into three service categories (sometimes referred to as "buckets"), so that allocation of particular costs was more closely aligned to the appropriate ISO customers than under the earlier version of the charge. *See* R 1 at 8-9, JA 93-94. Two of these categories, the Control Area Services category and the Market Operations category, are relevant

on appeal.<sup>4</sup>

The ISO defined the Control Area Services category to include the ISO's costs, as the control area operator, associated with ensuring reliable, safe operation of the transmission grid and the entire ISO Control Area (including the cost of performing operation studies and system security analyses, monitoring and developing transmission maintenance standards, performing system planning to ensure overall reliability, and to provide integration services with other control areas). *See* Exh. ISO-1 at 19, JA 1001.

The Market Operations category, on the other hand, included the ISO's costs of market- and settlement-related services in the ISO Control Area (*e.g.*, the cost of operating an Ancillary Service market as well as the cost of billing). *Id.* at 20.

On November 13, 2000, as amended December 26, 2000, PG&E submitted its proposed Grid Management Charge Pass-Through Tariff, which would authorize it to pass through the ISO's Grid Management Charge to PG&E's existing wholesale contract customers. R 3, JA 1205.

On December 29, 2000, the Commission accepted for filing both the California ISO's Unbundled Grid Management Charge and PG&E's Pass-Through Tariff, and set them for hearing before an agency administrative law judge.

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<sup>4</sup> The third category, Inter-Zonal Scheduling, does not figure in the instant dispute.

*California Independent System Operator Corp., et al.*, 93 FERC ¶ 61,337 (2000),  
R 55, JA 153.

The hearing was held before the presiding judge from November 13, 2001,  
to December 20, 2001.



## **B. The Initial Decision**

On May 10, 2002, the presiding judge issued the Initial Decision, generally upholding both the Grid Management Charge and the Pass-Through Tariff as just and reasonable. While the judge considered and decided a substantial number of issues, only a relative few are relevant to the issues raised by petitioners on appeal.

The judge upheld the California ISO's proposal to unbundle its services into the previously identified categories. Initial Decision at 65,083-86, JA 206-209.

The judge also upheld the California ISO's proposal to allocate Control Area Service charges on all load within the ISO's control area, on the ground that these services were provided to all such load. *See* Initial Decision at 65,109-110, JA 232-233.<sup>5</sup> In so doing, the judge declined to grant an exception for load served by so-called "behind-the-meter" generation, as the record supported "treating all load the same for purpose of the allocation of the [Control Area Services] charge." *Id.* at 65,111, JA 234.

The judge then turned to the question of PG&E's Pass-Through Tariff, under which PG&E sought "to pass-through as a 'new service' those charges billed to it by the ISO as a result of loads attributable to its [Control Area Agreement]

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<sup>5</sup> "Load' simply refers to demand for service on a transmission grid." *Wisconsin Public Power Inc.*, 493 F.3d 239 (D.C. Cir. 2007) 2007 U.S. App. LEXIS 17257 at \*5 n.1 (citation omitted).

customers [*i.e.*, Existing Customers]” pursuant to their existing contracts “based on the ISO’s [Control Area Gross Load] allocation and assessment methodology for the recovery of [Control Area Services] costs.” Initial Decision at 65,164, JA 287. The judge determined that the Pass-Through Tariff for the Control Area Services category was appropriate, as that category included the ISO’s costs for providing new services, above and beyond the service that PG&E provided under the existing contracts. *Id.*

The judge rejected, however, PG&E’s Pass-Through Tariff to the extent it sought recovery for services provided under the Market Operations component of the Grid Management Charge. Initial Decision at 65,169, JA 292. She found that this component of the charge included the ISO’s cost of operating an ancillary services market, while ancillary services “can be and often are self-provided” by the Existing Contract Customers. *Id.*

### **C. Opinion No. 463**

After briefing, the Commission issued Opinion No. 463, addressing a number of matters resolved by the Initial Decision, including the two specifically at issue on appeal.

The Commission substantially affirmed the Initial Decision’s holding that the assessment of the Control Area Services charge on the basis of gross load was consistent with cost causation principles. Opinion No. 463 P 25-26, JA 342-343.

However, the Commission believed that “the judge cast too wide a net with the gross load approach” for customers with behind-the-meter generation “who primarily rely on that generation to meet their energy needs.” Opinion No. 463 P 28, JA 343. As a remedy, the agency determined that such customers

should be allocated [Control Area Services] costs on the basis of their highest monthly demand placed on the ISO's grid, rather than on gross load. In this manner, their more limited dependence on the ISO grid will be reflected in their allocation of the [Control Area Services] costs. Customers eligible for such treatment are those with generators with a 50 percent or greater capacity factor.

*Id.* (footnote omitted).

Opinion No. 463 sustained the Initial Decision’s holding that PG&E’s Pass-Through Tariff was for a new service. With respect to the issues raised on appeal, the Commission rejected the contention that “the judge’s approach evades the *Mobile-Sierra* doctrine in any manner.” Opinion No. 463 P 46, JA 346.<sup>6</sup> Opinion No. 463 also affirmed the Initial Decision’s holding that PG&E’s pass-through of the Control Area Services charge was consistent with cost causation principles. Opinion No. 463 P 50-53, JA 347-348.

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<sup>6</sup> The *Mobile-Sierra* doctrine, which was established by *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *FPC v. Sierra Power Co.*, 350 U.S. 348 (1956), generally prohibits a party to a FERC-jurisdictional contract from unilaterally proposing changes in rates and conditions that are not authorized by the contract. See, e.g., *Maine Pub. Util. Comm’n v. FERC*, 454 F.3d 278, 283 (D.C. Cir. 2006).

However, the Commission reversed the judge's determination that that the Market Operations component of the Grid Management Charge did not represent the cost of new services. Opinion No. 463 P 57, JA 348. Rather, the Commission held that the Market Operations component, like the Control Area Services component, represented the cost to the ISO of providing "a new and different service to the [Control Area Agreement] customers," with no duplication of functions by PG&E. *Id.* Thus, the Commission concluded, PG&E could pass through these costs to the Existing Contract Customers.

**D. Opinion No. 463-A**

A number of parties, including petitioners here, filed requests for rehearing of Opinion No. 463. In Opinion No. 463-A, JA 587, the Commission addressed both the new service and gross load allocation issues.

With respect to the former, the Commission rejected petitioners' argument that permitting PG&E to pass through the relevant Grid Management Charge components resulted in it collecting additional costs while failing to provide any service beyond that already provided by the existing contracts. In the Commission's view, this contention "fail[s] to confront the very foundation" of its decision that, with the establishment of the California ISO, "there have been 'massive' and 'fundamental changes' in the manner in which electricity is sold and distributed . . . so that 'the complexities of operating the transmission system have

increased exponentially.’” Opinion No. 463-A P 25 & n. 23, JA 592 (quoting Exh. S-1 at 29 (testimony of FERC staff witness Mr. Gross), JA 1335).

Opinion No. 463-A also addressed a number of requests for rehearing and clarification on the gross load allocation issue. The Commission did not disturb its determination that, as a general matter, all customers should pay the Control Area services charge. However, the Commission agreed with several of the parties that Order No. 463’s eligibility requirement for the limitation on this charge was not supported by the record and would create implementation problems. Opinion No. 463-A P 19, JA 592.

Nonetheless, the Commission continued to believe “that certain behind the meter generators should be subject to an exception from the use of [Control Area Gross Load] for the billing of [Control Area Services] charges.” Opinion No. 463-A P 20, JA 592. Accordingly, the Commission determined:

In light of the nature of the [Control Area Services] charges, in particular expenses incurred for the continued planning of operation of the transmission grid, it appears appropriate that generators which are not modeled by the ISO in its regular performance of transmission planning and operation should be exempted from the [Control Area Gross Load] charge. That is, those generators that will not cause the ISO to incur administrative or operating expenses should, therefore, have the load exempted from the [Control Area Services] charge.

*Id.*

### **E. The Hearing Order On The Behind-the-Meter Exception**

A number of parties to the proceeding filed requests for rehearing of Opinion No. 463-A, on the ground that the exception to gross load allocation of the Control Area Services charge for unmodeled generation was not supported by the record.

In the Hearing Order issued November 16, 2004, the Commission explained that it continued “to subscribe to the concept of an exception from [Control Area Gross Load] based on whether the generator and associated behind-the-meter load are modeled by the ISO.” Hearing Order P 15, JA 715. However, the agency agreed that the parties’ objections had made clear that the issue “cannot be resolved on the record before us.” *Id.* Therefore, the Commission set this sole issue for a trial-type, evidentiary hearing. *Id.*

### **F. The Second Initial Decision**

After a hearing, the presiding judge issued the Second Initial Decision on the issue of whether generation unmodeled by the ISO incurred Control Area Services costs. Second Initial Decision, JA 724.

The judge found that while the ISO did not itself actually model generating units, it “adopt[ed] the power flow models, including the representations of generating units, which are developed by the investor-owned [Participating Transmission Owners].” Second Initial Decision P 40, JA 732 (footnote omitted).

Thus, the judge concluded, the ISO employed “the models provided to it by the [Participating Transmission Owners] to conduct studies that examine the effects of different conditions under which the transmission system may have to operate and to determine the effects of the conditions on the transmission system.” *Id.* P 42, JA 733 (footnote omitted).

The ISO’s studies, the judge went on to explain, examine “the effects of different conditions under which the grid may have to operate, and determine the effects of those conditions on the grid.” Second Initial Decision P 60, JA 736 (footnote omitted). Thus, she concluded, these studies must take into account all generation based on its impact on the ISO-controlled grid, whatever type of load it may serve. *Id.* P 61, JA 736.

The judge determined that “neither the ISO or any other party has been able to present quantifiable evidence” concerning whether unmodeled generation did incur Control Area Services costs. Second Initial Decision P 85 (footnotes omitted), JA 740. Nonetheless, the judge stated, there was evidence that such load “benefits less directly” than other load “from transmission planning, maintenance and outage coordination,” provided by ISO Control Area Services. *Id.* (footnote omitted). Thus, she concluded, generation unmodeled by the ISO should be allocated the Control Area Services charge on a net usage basis, rather than a gross load basis. *Id.* P 92, JA 741-742.

### **G. Order No. 463-B**

A number of parties filed exceptions to the Second Initial Decision. On November 7, 2005, the Commission issued Opinion No. 463-B, which resolved these exceptions by largely affirming the presiding judge's conclusions, and denying outstanding requests for rehearing on the issue of behind-the-meter load. Opinion No. 463-B, JA 748.

At the outset, the Commission affirmed its determinations in Opinion No. 463 and Opinion No. 463-A that load-serving entities generally should pay their share of Control Area Services costs on the basis of gross load because they all share the benefits of the ISO-administered grid. Opinion No. 463-B P 58, JA 756.

The agency likewise reiterated its determination that behind-the-meter generators -- generators which are not modeled by the ISO in its regular performance of transmission, planning and operation -- should only pay such costs when they actually use the grid:

Our reasoning was that because such generators are not seen by the ISO, they could not cause the ISO to incur administrative or operating expenses reflected by the Control Area Services charge. The problem was that because there was no record evidence with respect to the ISO's generator modeling, we had no factual basis upon which to test our reasoning. The Initial Decision on review here provides that factual basis.

Opinion No. 463-B P 60, JA 756.

Turning to the question of how modeling should be defined, the Commission



agreed with the presiding judge that the ISO, while it does not itself model generation, uses the models provided by the Participating Transmission Owners to conduct studies to determine the effects of different conditions on its transmission system. Opinion No. 463-B P 73, JA 758.

However, the Commission did not agree with the judge that unmodeled generation does not incur Control Area Services costs simply because its load benefits less directly than other load from the services covered by the charge. Opinion No. 463-B P 78, JA 754. Rather, the Commission based its conclusion that the ISO does not incur administrative costs for unmodeled generation on evidence that it has no information concerning certain on-site, behind-the-meter generation. *Id.* P 78 & nn. 87-88 (citing Exh. ISO 12 at 6, JA 1048).<sup>7</sup>

#### **H. Opinion No. 463-C**

Several parties -- including certain petitioners here<sup>8</sup> -- filed requests for rehearing of Opinion No. 463-B. As relevant to these appeals, in Opinion No. 463-C, JA 918, the Commission denied these rehearing requests.

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<sup>7</sup> The Commission also directed the ISO to make a compliance filing reflecting the total universe of modeled generation for the locked-in period. Opinion No. 463-B P 81, JA 759. This compliance proceeding is continuing before the agency and is not at issue in these appeals.

<sup>8</sup> These were Silicon Valley Power (the electric power operator for the City of Santa Clara, California), the Cogeneration Association, Modesto Irrigation District and Sacramento Municipal Utility District.

The Commission rejected the contention that the behind-the-meter exemption established in Opinion No. 463-B was inconsistent with that originally contemplated in Opinion No. 463 and Opinion No. 463-A. In the Commission’s view, “while the mechanics of the exemption . . . has evolved in the course of this proceeding as the factual record has developed,” the agency had “held firm to its view that generators that will not cause the ISO to incur expenses should have their load exempted from [Control Area Services] costs.” Opinion No. 463-C P 25, JA 921.

The Commission once again held that the exemption for unmodeled generation was based on cost causation principles. Opinion No. 463-C P 28, JA 922. Additionally, the Commission rejected the contention that because the ISO “relies on information supplied by other parties. . . it does not model generation.” *Id.* P 31, JA 922. Finally, it denied claims by various parties that particular generating facilities should not be included in the exception, even if they were modeled by the ISO. *Id.* PP 26, 32-33, JA 921-923.

**I. The Order Rejecting Cogeneration Association’s Rehearing Request**

Petitioners Silicon Valley Power, Modesto Irrigation District and Sacramento Municipal Utility District thereupon filed their timely appeals with this Court (the Western Area Power Administration had previously appealed Opinion Nos. 463 and 463-A). The Cogeneration Association, however, on October 10,

2006, filed another request for rehearing before the Commission. R. 493, JA 925.

The Commission rejected the Cogeneration Association's rehearing request in the January 2007 Order, on the ground that the agency "does not allow rehearing of an order denying rehearing." January 2007 Order P 7, JA 949 (footnote omitted).

## SUMMARY OF ARGUMENT

1. The petition for review filed by the Cogeneration Association should be dismissed for lack of jurisdiction. The Cogeneration Association alleges that it is aggrieved by the Commission's determination concerning the allocation of Control Area Services costs. The Commission made its final aggrieving decision on this issue in Opinion No. 463-B, and denied requests for rehearing in Opinion No. 463-C. Because the Cogeneration Association, unlike the other affected petitioners, failed to seek review of those orders in a timely manner, and instead waited to appeal a later order that did not address the merits of the contested issue, its petition for review is time-barred.

2. The Commission's decision that the California ISO's Grid Management Charge was for new services performed by the ISO, which were not provided by PG&E under the Existing Contract Customers' pre-ISO contracts, was reasonable and supported by substantial evidence.

As in the Commission orders affirmed by the Court in *Midwest Transmission Owners* and *East Kentucky Power Cooperative*, the agency here determined that the ISO's administrative costs – the overarching costs of having an ISO and its transmission benefits – should be shared by all customers within the ISO Control Area benefiting from operation of the ISO. In so holding, the Commission relied on specific record evidence that PG&E had previously not

provided the services in question to the Existing Contract Customers, and that there were no double charges for the same service. While Existing Contract Customers adduced their own contrary evidence, this does not render the expert testimony relied on by the Commission less than substantial.

The Commission also reasonably concluded that the existing contracts did not preclude the costs of the ISO's new services from being passed through to the Existing Contract Customers via a new tariff. Exactly the same reasoning was endorsed by the Court in *East Kentucky Power Cooperative*, which Existing Contract Customers try in vain to distinguish.

3. The Commission reasonably decided that cost causation principles supported allocation of the Control Area Services charge on a gross load basis, as all ISO customers benefited from this service. This finding is based on substantial evidence in the record and should be affirmed.

The Commission also reasonably determined that Control Area Services charges should not be assigned to the load of unmodeled generation, for which the California ISO did not incur administrative costs. This reasonable conclusion, carving out a limited exception to allocation of Control Area Services on the basis of all load, was supported by substantial evidence that the ISO did not model (or study) such generation.

## ARGUMENT

### **I. THE COURT SHOULD DISMISS THE PETITION OF THE COGENERATION ASSOCIATION FOR LACK OF JURISDICTION BECAUSE IT IS TIME-BARRED.**

This Court has stated that under section 313(b) of the FPA, 16 U.S.C. § 825l(b), “a petition for review of an agency order must be filed within sixty days of that order.” *Cities of Batavia v. FERC*, 672 F.2d 64, 72 (D.C. Cir. 1982) (footnotes omitted). Thus, the Court later cited *Cities of Batavia* as an example of the rule that “statutory time limits on petitions for judicial review of agency action have been held ‘jurisdictional and unalterable’ in a parade of this circuit’s decisions.” *AFL-CIO v. OSHA*, 905 F.2d 1568, 1570 (D.C. Cir. 1990) (citing numerous cases).

Here, the Commission established in Opinion No. 463-B that the allocation of the Control Area Services charge would be on a Control Area Gross Load basis, with an exception for certain behind-the-meter generation unmodeled by the California ISO. Opinion No. 463-B PP 61, 75-76, 79, JA 756, 758, 759. Numerous parties, including the Cogeneration Association, R 486, JA 829, filed requests for rehearing of that determination before the Commission. In Opinion No. 463-C, the Commission rejected these rehearing requests in all respects, specifically referencing that of the Cogeneration Association. Opinion No. 463-C P 27-28, JA 922.

Following Opinion No. 463-C, all affected petitioners here except for the Cogeneration Association filed petitions for review of the Commission's orders. Cogeneration Association instead filed another rehearing request before the Commission, making the same arguments that it had made in its request for rehearing of Opinion No. 463-B. R 493, JA 925. Indeed, large portions of the Cogeneration Association's second rehearing request are simply a verbatim repetition of its earlier one. *Compare* R 486 at 10-12, JA 838-840, R 493 at 12-14, JA 936-938; R 486 at 15-18, JA 843-846, R 493 at 15-19, JA 939-943; R 486 at 18-20, JA 846-848, R 493 at 21-22, JA 945-946.

Thus, the Commission rejected the Cogeneration Association's second rehearing request on procedural grounds without reaching the merits, as it was a "neither required nor appropriate" request for rehearing of an order denying rehearing. January 2007 Order P 9, JA 949.

In these circumstances, the Cogeneration Association did not file a timely petition for review of Opinion Nos. 463-B and 463-C, which were the final aggrieving and rehearing orders concerning the extent that Control Area Services would be allocated to customers on a gross load basis. Instead, the Cogeneration Association is now attempting to appeal from a later agency order which does not address the merits of the Association's arguments, but rejected the Association's final filing as procedurally invalid (the Cogeneration Association's brief does not

contest the procedural finding in the Commission’s January 2007 Order).

Accordingly, the Cogeneration Association’s petition for review should be dismissed by this Court for lack of jurisdiction.<sup>9</sup> This Court has held that “an order denying rehearing does not necessarily constitute a new ‘order’ as to which a new petition for rehearing is required.” *Southern Natural Gas Co. v. FERC*, 877 F.2d 1066, 1072-1073 (D.C. Cir. 1989) (citing *Public Service Commission v. FPC*, 543 F.2d 757, 775 n.116 (D.C. Cir. 1974)). Another request for rehearing is appropriate only where the agency modifies the result reached, as opposed to the rationale employed. *E.g., Allegheny Power v. FERC*, 437 F.3d 1215, 1222 (D.C. Cir. 2006) (citing *Town of Norwood, Massachusetts v. FERC*, 906 F.2d 772, 775 (D.C. Cir. 1990)).

“To interpret the statute otherwise,” the Court has explained, “would be to permit an endless cycle of applications for rehearing and denials.” *Southern Natural Gas Co.*, 877 F.2d at 1073 (quoting *Boston Gas Co. v. FERC*, 575 F.2d 975, 978 (1st Cir. 1978)). A duplicative petition for rehearing before the agency serves only to delay the time for judicial review by other petitioners who filed

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<sup>9</sup> The Cogeneration Association has advanced arguments concerning the scope of the limitation on gross load allocation for the load of unmodeled generation that are not raised in the brief of the Existing Contract Customers, and would thus not be addressed by the Court. *See Cogeneration Association Br.* at 24-34.



timely petitions for review. It follows that “imposing an additional rehearing requirement in this situation would lead to infinite regress and serve no useful end.” *Canadian Ass’n of Petroleum Producers v. FERC*, 254 F.3d 289, 296 (D.C. Cir. 2001) (citations omitted).

Having chosen not to seek timely review of the order which allegedly aggrieved it (Opinion No. 463-B) and the relevant rehearing order (Opinion No. 463-C, which denied rehearing in all respects), Cogeneration Association cannot remedy this failure by seeking review of a later order. *See Canadian Ass’n of Petroleum Producers*, 254 F.3d at 296-97 (where an issue was finally resolved by a rehearing order, petitioner could not raise that issue on appeal of a later order). *See also Cities of Newark v. FERC*, 763 F.2d 533, 542-543 (3rd Cir. 1985) (noting that “repetitive petitions for rehearing can readily be remedied by Commission regulation”).

## II. STANDARD OF REVIEW

The Commission's orders are reviewed under the arbitrary and capricious standard of the Administrative Procedure Act. *See, e.g., Sithe/Independence Power Partners v. FERC*, 165 F.3d 944, 948 (D.C. Cir. 1999). Under this standard, the court "will affirm the Commission's orders so long as FERC 'examined the relevant data and articulated a . . . rational connection between the facts found and the choice made.'" *Midwest ISO Transmission Owners*, 373 F.3d at 1368 (quoting *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 26, 43 (1983)).

The Court "uphold[s] FERC's factual findings if supported by substantial evidence." *Florida Mun. Power Agency v. FERC*, 315 F.3d 362, 365 (D.C. Cir. 2003) (citing *Pacific Gas & Elec. Co. v. FERC*, 306 F.3d 1112, 1115 (D.C. Cir. 2002), and *Process Gas Consumers Grp. v. FERC*, 292 F.3d 831, 836 (D.C. Cir. 2002)). The substantial evidence standard "requires more than a scintilla, but can be satisfied by something less than a preponderance of the evidence." *Florida Mun. Power Agency*, 315 F.3d at 365-66 (quoting *FPL Energy Me. Hydro LLC v. FERC*, 287 F.3d 1151, 1160 (D.C. Cir. 2002) (internal citation omitted)).

Furthermore, "[w]hen FERC's orders concern ratemaking," as here, the Court is "particularly deferential to the Commission's expertise." *Midwest ISO Transmission Owners*, 373 F.3d at 1368 (quoting *Association of Oil Pipe Lines v.*

*FERC*, 83 F.3d 1424, 1431 (D.C. Cir. 1996) (internal quotation marks omitted)); *see also East Kentucky Power Cooperative*, 489 F.3d at 1301 (referring to the Court’s “particularly deferential standard of review for the Commission’s decisionmaking” in cost allocation cases).

**III. THE COMMISSION REASONABLY CONCLUDED THAT THE ISO’S ADMINISTRATIVE COSTS SHOULD BE ALLOCATED TO EXISTING CONTRACT CUSTOMERS.**

**A. The Commission’s Finding That The Grid Management Charge Was For New Services Not Covered By The Existing Contracts Is Consistent With Precedent And Supported By Substantial Evidence.**

At the heart of this case is the Commission’s holding that the relevant components of the Grid Management Charge were designed to recoup the costs of new services provided by the California ISO to its customers, which are “separate, distinct, and qualitatively different from the scheduling and related services” that PG&E provided to existing contract customers. Opinion No. 463-A P 28, JA 593.

The Commission explained that “[t]he [Grid Management Charge] is based on the ISO’s overarching costs of maintaining the reliability of the ISO transmission grid and operating that grid in the most efficient manner possible, rather than providing any specifically defined transmission.” Opinion No. 463-A P 26, JA 593. As the agency elaborated:

As we explained in Opinion No. 463, the charge includes costs to perform operation studies, system security analyses, emergency management, outage coordination, and transmission planning for the

combined ISO grid as opposed to the pre-existing individual control area. Additionally, by combining the pre-ISO control areas and eliminating pancaked rates, the ISO operations allow greater access to generation alternatives so that the ISO can provide ancillary services to the existing transmission contracts in the most cost-effective and efficient manner possible on a broad regional basis. Regional planning and operation of the combined ISO grid maximizes efficiencies when compared to the pre-existing utility operations. Consolidating scheduling maximizes transmission usage, reduces ancillary service requirements and provides greater reliability by allowing the operation of more facilities to respond to contingencies. The customers receiving these new services should pay their share of them.

*Id.* See also Order No. 463 P 50-53, JA 347-348.

Furthermore, this finding by the Commission was supported by specific record evidence, such as testimony of Commission staff witness Mr. Gross that the formation of the California ISO resulted in “massive” and “fundamental changes” in the manner in which electricity was sold and distributed, so that “the complexities of operating the transmission system have increased exponentially.” Opinion No. 463-A P 25 & n.23, JA 592 (quoting Exh. S-1 at 29, JA 1335). Therefore, as PG&E witness Mr. Bray explained, the “[ISO] performs certain activities in its role of control area operator which were not performed in the pre-ISO era,” and, as the ISO’s Scheduling Coordinator, PG&E performs “a new and unique function that it did not provide to the [Control Area Agreement] customers prior to the ISO.” Opinion No. 463-A P 29 & nn. 27-28, JA 593 (quoting PGE Exh. 32 at 16, JA 1257) (internal quotation marks omitted). See also Opinion No.

463-A P 30 & n.32, JA 593 (citing Exh. PGE-6B (Revised) at 3-9, JA 1229-1226) (testimony of PG&E witness Mr. King explaining that “no ISO operation costs billed to PG&E for ISO [Grid Management Charges] are included PG&E’s transmission operation and maintenance expense accounts or the [Control Area Agreements]”); Opinion No. 463-A P 30 & n.33, JA 593 (citing Exh. PGE-41 at 1-16, JA 1290-1305) (testimony of PG&E witness Mr. Doran explaining that it was “not possible for any of the ISO [Grid Management Charge] amounts to be included in these [Control Area Agreement] firm transmission rates.”).

In addition to being fully supported by record evidence, the Commission’s conclusions find firm legal support in this Court’s decisions in *Midwest ISO Transmission Owners* and *East Kentucky Power Cooperative*. In *Midwest ISO Transmission Owners*, the Court reviewed the Commission’s decision that the Midwest ISO transmission customers, taking transmission service under existing, pre-ISO, grandfathered contracts, could be charged for a portion of the Midwest ISO’s capital costs and expenses. *See Midwest ISO Transmission Owners*, 373 F.3d at 1369. The Court rejected the claim that the customers already were paying for such benefits pursuant to their existing contracts. Analogizing to the federal court system, the Court reasoned that contract (and other) customers benefit in many respects from “*having* an ISO,” and thus should share responsibility for the ISO’s administrative costs, “even if they are not in some sense *using* the ISO” to

administer additional transactions. 373 F.3d at 1371 (emphasis the Court's).

This is exactly the reasoning the Commission employed here concerning the analogous administrative costs of the California ISO being assigned to transmission customers with existing pre-ISO contracts. See Opinion No. 463-A P 28 & n.26, JA 593 (“recogniz[ing] similar benefits in [FERC] orders concerning the Midwest ISO”).

In *East Kentucky Power Cooperative*, the Court addressed the related question of whether the Midwest ISO's administrative costs could be passed through to the transmission customers with pre-existing contracts, just as PG&E passed through the same type of costs in the proceeding here.

In affirming the Commission's decision that the costs could be passed through, the Court explained that the agency “first set out to determine whether the grandfathered agreements in this case already provide for the [Midwest ISO] benefits identified by the Commission and by this Court in *Midwest ISO Transmission Owners*,” (such as regional grid planning and increased reliability and efficiency) “provided by the [Midwest ISO] to customers receiving service under grandfathered agreements.” 489 F.3d at 1307. As the Court further indicated, the Commission found that the costs for providing those benefits were “*separate and distinct from the costs that the Midwest ISO [transmission owners] recover under current provisions [of the grandfathered agreements].*” *Id.* at 1307-

08 (quoting *Transmission Owners of the Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,339 at 62,350 (2006) (emphasis the Court’s; internal quotation marks omitted). Here, based on the evidence cited above, the Commission made the same finding.

Thus, this Court has endorsed the assignment by the Commission of ISO administrative costs – costs essentially the same as those at issue here – to customers with grandfathered existing transmission contracts.

**B. Petitioners’ Arguments To The Contrary Are Without Merit.**

Despite the Commission’s reference to the Midwest ISO allocation orders (e.g., Opinion No. 463-A P 28, JA 593), Existing Contract Customers simply fail to mention *Midwest ISO Transmission Owners*. They do attempt to distinguish *East Kentucky Power Cooperative*, asserting that a “key fact[]” there, “not present here, [was] that the transmission owners had provided ‘sufficient evidence’ that the passthrough of the Midwest ISO’s administrative costs reflected the costs of providing a new service to those customers. . . .” Existing Contract Customers Br. 38 (a second allegedly “key” factual difference Existing Contract Customers identify concerns the *Mobile-Sierra* doctrine and respect for contracts, and is dealt with in part C, *infra.*).

However, as cited above, there was substantial evidence supporting the Commission’s conclusions that the ISO was performing new services, which

PG&E did not and could not perform under the existing contracts, and that PG&E was simply passing on the costs for these services to the existing contract customers. *See* Opinion No. 463-A P 31, JA 594 (“In sum, there was clear support in the record for Opinion No 463’s conclusion that PG&E’s [Pass-Through Tariff] costs were separate and distinct from the ongoing costs it was charging its customers under the existing contracts”).<sup>10</sup>

Existing Contract Customers never confront the evidence on which the Commission relied, preferring to deny that such evidence exists. *See, e.g.,* Existing Contract Customers Br. at 43-44. Instead, they cite their own evidence before the agency to the effect that the California ISO is not offering new services. *E.g.,* Existing Contract Customers Br. at 41, citing, *e.g.,* R 919 at 5, JA 1377 (testimony of Sacramento Municipal Utility District witness Mr. Jobson); R 964 at 5-6, JA 1523-1524 (testimony of Northern California Power Agency witness Mr. Cohen). However, the question for the Court is “not whether record evidence supports [petitioners’] version of events, but whether it supports FERC’s.” *Florida Mun. Power Agency*, 315 F.3d at 368 (citing *Ark. Elec. Energy Consumers v. FERC*, 290 F.3d 362, 367 (D.C. Cir. 2002)). As the Court recently explained, “where expert

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<sup>10</sup> Indeed, there was a substantially more detailed evidentiary basis for the Commission’s finding that the California ISO was performing new services here than in the orders affirmed in *East Kentucky Power Cooperative*, where the agency had not held an evidentiary hearing.



witnesses dispute a factual issue, the resolution of which implicates substantial agency expertise, our role is only to verify that the agency has relied upon sufficient expert evidence to establish a rational connection between the facts and the choice made.” *Petal Gas Storage v. FERC*, 496 F.3d 695, 702 (D.C. Cir. 2007), 2007 U.S. App. LEXIS 18656 at \*14-\*15 (quoting *Wis. Valley Improvement Co. v. FERC*, 236 F.3d 738, 746-47 (D.C. Cir. 2001), and *Marsh v. Or. Natural Res. Council*, 490 U.S. 360, 376 (1989)) (internal quotation marks omitted). As demonstrated above, the Commission has appropriately performed this task here.

Existing Contract Customers attempt to muddy the waters by arguing that the Commission has already ruled that “because pre-CAISO transmission contracts already provided for reliable firm transmission service, CAISO reliability charges could not simply be passed on to the existing customers.” Existing Customers Br. at 44-45 (citing *Pacific Gas and Elec. Co.*, 100 FERC ¶ 61,160 (2002) (Opinion No. 459). However, in Opinion No. 463-A, the Commission readily distinguished Opinion No. 459:

With respect to the [Existing Transmission Contract] customers, Opinion No. 459 explained that firm transmission contracts executed prior to the California restructuring inherently included reliability as part of that firm service. Thus, the Commission concluded that “PG&E’s proposal to add an allocation of [California ISO] [Reliability Service] charges to the unadjusted rates of the [Existing Transmission Contract] customers is not just and reasonable because it results in a double recovery.”

Opinion No. 463-A P 35 (quoting Opinion No. 459 P 20), JA 594 (footnote omitted). As the Commission went on to explain, “[w]hile the existing contracts at issue” in Opinion No. 459 “inherently included reliability as part of firm service, . . . the [existing transmission contracts] at issue here did not and could not have included the service represented by the ISO’s [Grid Management Charge].” *Id.* P 36, JA 595.

In other words, in Opinion No. 459, the Commission would not allow PG&E to add charges under its existing contracts for new costs it incurred in supplying reliable service. In this case, however, PG&E is not recovering additional costs under its contracts with the Existing Contract Customers. Rather, the Commission found that the ISO is providing totally new services, not provided by PG&E pursuant to the existing transmission contracts, and billing PG&E, which is then passing through these costs to the Existing Contract Customers.

Similarly, Existing Contract Customers are confused with respect to Market Operations costs. They argue that “a customer self-providing ancillary services cannot possibly benefit from [California ISO] provision of ancillary services that, by definition, are being provided by others.” Existing Contract Customers Br. 49. But as the Commission explained, “[t]he [Market Operations] charge is only assessed on a Scheduling Coordinator when it procures such services through the ISO markets.” Opinion No. 463-A P 42 & n.48, JA 595 (citing Exh. J-2, JA 100

(ISO Tariff § 8.3.3)). Thus, there is no possible double-recovery for any ancillary services the existing contract customers do self-provide, as the ISO Tariff “provides that a Scheduling Coordinator’s responsibility for these costs is reduced by other, self-provided ancillary services.” Opinion No. 463-A P 42 & n. 49, JA 595 (citing ISO Tariff § 2.5.20.2, JA 1149-50). In other words, to the extent the Existing Contract Customers do self-provide ancillary services, they are not subject to the Market Operations charge.

Existing Contract Customers then assert that if the California ISO’s Market Operations costs “are reduced by the self-provision of ancillary services, those self-providing should logically be exempt from the charge,” as they reduce the ISO’s costs. Existing Contract Customers Br. 49-50. In fact, they are exempt from this charge to the extent they do self-provide such services and do not cause the ISO to incur these costs.

**C. The Commission Properly Found That The *Mobile-Sierra* Doctrine Was Irrelevant Here.**

In Opinion No. 463, the Commission held that the *Mobile-Sierra* doctrine, concerning respect for contracts, had no application here because PG&E’s Pass-Through Tariff was to collect costs billed by the California ISO for new services not provided under the existing contracts. Opinion No. 463 P 46, JA 346. As the Commission explained, the doctrine bars a utility from unilaterally “fil[ing] a new rate under Section 205 [of the FPA, 16 U.S.C. § 824d] to *supersede the agreed-*

upon rate.” *Id.* P 46 & n.68, JA 346 (quoting *Boston Edison Co. v. FERC*, 233 F.3d 60, 65 (1st Cir. 2000) (emphasis the Commission’s)). Here, however, the agency determined, “the agreed-upon rate for PG&E’s [Control Area Agreement] services is not being superseded,” because PG&E’s customers “are receiving a new and different service in addition to the service they already receive” under their existing contracts. *Id.* See also Opinion No. 463-A P 31, JA 594.

The Commission’s reasoning here is identical to its reasoning in the *East Kentucky Power Cooperative* decision. In that case, the Court sustained the Commission’s decision that, because the Midwest ISO’s new services were not covered by the transmission owners’ existing grandfathered contracts, the *Mobile-Sierra* doctrine did not bar the ISO’s collecting the administrative costs of providing the new services from the contract customers:

FERC has concluded that Schedule 23 imposes a new rate to recover the costs of new benefits and services received from the Midwest ISO and its energy markets by customers to grandfathered agreements. . . . The disputed Schedule 23 tariff does not “modify the rates, terms or conditions of services provided under the [grandfathered agreements].”

489 F.3d at 1309 (quoting *Transmission Owners of the Midwest Independent System Operator, Inc.*, 113 FERC ¶ 61,122 at 61,476 (2006)) (citations omitted).

Existing Contract Customers attempt to distinguish the Court’s reasoning with respect to the *Mobile-Sierra* doctrine in *East Kentucky Power Cooperative* by

arguing that there, “the Court had no occasion to address whether utilities could recoup the costs of new ISO services from customers if their contracts barred or imposed conditions on such recovery.” Existing Contract Customers Brief 51. On the contrary, the Court addressed that exact question in *East Kentucky Power Cooperative*, but found that because the Midwest ISO’s new tariff reflected a new rate for new services, and thus did not upset existing contracts, “[t]he *Mobile-Sierra* doctrine, powerful though it may be where it applies, is not implicated in this case.” *East Kentucky Power Cooperative*, 489 F.3d at 1309.

Existing Customers then argue that “FERC never addressed the argument by several [Existing Contract] customers that their contracts with PG&E not only barred PG&E from charging a new rate for an existing service, but (unlike in *East Kentucky*) barred PG&E from offering a new service without the agreement of the customer.” Existing Contract Customers Br. 52.

We are unable to distinguish this argument from the one rejected in *East Kentucky Power Cooperative*. In any event, the Commission explained in Opinion No. 463, *Mobile-Sierra* was simply irrelevant in this situation:

[O]ur determination that PG&E's [Pass-Through Tariff] represents a rate change, subject to the suspension and refund provisions of FPA Section 205, is not dispositive of whether a new and different service is at issue for which a *new tariff* is appropriate. The excepting parties fail to recognize this distinction. However, as the Initial Decision discerned, we have previously taken this specific approach.

Opinion No. 463 P 44, JA 346 (emphasis in original; footnotes and internal

quotations omitted). Before the Court, Existing Contract Customers do not cite any precedent that the *Mobile-Sierra* doctrine can be employed as a defense where a new service is at issue, and we are not aware of any.

In sum, the ISO is not providing the same services that PG&E has continued to provide under the existing, pre-ISO contracts. PG&E is not altering the terms of its existing contracts, which remain unchanged, but rather is passing through the costs of new services provided by the California ISO. Thus, the Commission reasonably concluded – like the Court in *East Kentucky* – that the *Mobile-Sierra* doctrine did not apply here.

**IV. THE COMMISSION’S DETERMINATION OF THE APPROPRIATE ALLOCATION FOR THE CALIFORNIA ISO’S CONTROL AREA SERVICES COSTS SHOULD BE SUSTAINED.**

**A. The Commission’s Allocation Determinations Were Consistent With Cost Causation Principles And Supported By Substantial Evidence.**

As this Court has explained, “the cost causation” principle of ratemaking “requir[es] that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.” *Midwest ISO Transmission Owners*, 373 F.3d at 1368 (quoting *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992), and citing *Transmission Access Policy Study Group*, 225 F.3d at 708, and *Pacific Gas & Elec. Co. v. FERC*, 373 F.3d 1315 (D.C. Cir. 2004)). “Not surprisingly,” the Court has observed, it evaluates the Commission’s “compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens or benefits drawn by that party.” *Midwest ISO Transmission Owners*, 373 F.3d at 1368-69 (citing *KN Energy*, 968 F.2d at 1300-01, and *Alabama Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982)). “Also not surprisingly,” the Court “ha[s] never required a ratemaking agency to allocate costs with exacting precision,” so long as the agency’s decision is not arbitrary or capricious “in light of the burdens imposed or benefits received.” *Midwest ISO Transmission Owners*, 373 F.3d at 1369 (citing *Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002) (“FERC is not bound to reject any rate mechanism that

tracks the cost-causation principle less than perfectly.’’)).

Here, the Commission appropriately applied this well-established principle both in approving allocation of Control Area Services costs on a gross load basis and limiting this allocation to generation which actually incurs such costs.

The presiding judge found that it was appropriate to allocate the Control Area Services segment of the Grid Management Charge on a gross load basis because of both costs caused and “benefits received” by the ISO’s customers as a result of the ISO providing this service. Initial Decision at 65,109, JA 232 (citing *Midwest Independent System Operator, Inc.*, 98 FERC ¶ 61,141 (2002) (Opinion No. 453-A)). She also relied on evidence presented by the California ISO on the nature of Control Area Services. *Id.* at 65,110, JA 233 (citing Ex. ISO-10 at 18:15-29:4 (JA 1660-1666) (testimony of ISO witness Mr. Carlson) & Ex. ISO-29 at 12:11-20:19 (JA 1067-1076)).

The Commission affirmed the judge on this issue, relying on language in Opinion No. 453-A (subsequently affirmed by this Court in *Midwest ISO Transmission Owners*), which had analyzed the same issue in the context of the Midwest ISO’s rates. Opinion No. 463 P 25, JA 342. Thus, in rejecting the argument that “inclusion of bundled loads in the cost adder employed to calculate the Midwest ISO rates was improper because those loads were served by generation which did not use facilities controlled by the ISO,” *id.*, the Commission



explained:

Intervenors fail to consider the benefits all users of the regional grid will receive when that grid is operated and planned by a single regional entity instead of multiple local entities whose goals may often conflict. As a result of this move to unified planning and operation of the regional grid, we expect to see more efficient siting of transmission facilities from the regional perspective; *i.e.*, siting that follows need rather than arbitrary boundaries such as individual local service territories. This will result in enhanced reliability which will benefit all loads. This is because the non-Midwest ISO-operated facilities, such as those connected to local generation, in this region are integrated with the facilities operated by the Midwest ISO.

*Id.* P 25 & n.36, JA 342 (quoting Opinion No. 453-A, 98 FERC at 61,412). The Commission went on to identify further benefits to all customers using the integrated transmission grid:

[L]oad served from generation located on an individual transmission owner's system (*i.e.*, located on low-voltage transmission facilities that have not been transferred to Midwest ISO) can not be served reliably without the facilities operated by Midwest ISO. If those Midwest ISO-operated facilities were to disappear, service to all loads, including bundled retail loads, would suffer greatly. Similarly, more efficient operation of the regional grid, including an effective congestion management scheme, should result in the ability of the regional grid to accommodate greater power flows, and thus more transactions than otherwise possible. This should increase the supply of competing generation available to load-serving entities.

*Id.* P 25 & n.39, JA 343 (quoting Opinion No. 453-A, 98 FERC at 61,412).

Turning to the specific benefits provided by the California ISO, Opinion No. 463 also affirmed the judge's factual findings that Control Area Services "are not and could not be self-provided." Opinion No. 463 P 27, JA 343. In this regard, the

agency relied on the testimony of ISO witness Mr. Lyon, distinguishing between control area-wide services provided by the ISO and such services provided by a customer within a particular service territory. *Id.* P 27 & n.43, JA 343 (citing Tr. 955-58, JA 951-954).

With respect to the exception for behind-the-meter generation, the Commission agreed with the presiding judge that while the ISO itself does not model generating units, “it uses the models provided by the Participating Transmission Owners ‘to conduct studies that examine the effects of different conditions under which the transmission system may have to operate and to determine the effects of the conditions on the transmission system.’” Opinion No. 463-B P 72 & n.75, JA 758 (quoting Second Initial Decision P 42, JA 733 (footnote omitted)).

In support of this finding, the Commission relied on the testimony of Commission staff witness Mr. Gross and ISO witness Mr. Lyon that the ISO performed studies concerning transmission planning and operation, based on the models submitted by the Participating Transmission Owners. Opinion No. 463-B PP 73-74, JA 758 (citing Exh. ISO-54, JA 1131 (testimony of Mr. Lyon), and Exhs. S-79, JA 1342 (testimony of Mr. Gross) and S-80, JA 1369). The Commission found it irrelevant that the ISO itself does not model generation, because “[t]he important fact is that the generators were included in the models

which the ISO examines and on which it bases its studies.” *Id.* P 75, JA 758.

The Commission also referred to the testimony of ISO witness Mr. Price, who indicated that at least some on site behind-the-meter generation is not seen by the ISO, and would thus not incur Control Area Services costs. Opinion No. 463-B P 79 & n.87, JA 759 (citing Exh. ISO-12, JA 1042). Thus, the agency concluded:

[A]s the Commission predicted, there is indeed a small subset of generators for which the ISO incurs no Control Area Services costs whatsoever. It is these generators whose load should not be assessed Control Area Services costs on a gross load basis. Rather, the customers should only pay the Control Area Services charge when they actually use the ISO’s grid.

*Id.* P 79, JA 759.

**B. Petitioners Cannot Demonstrate Otherwise.**

Existing Contract Customers complain that “FERC never established a causal link” between customers with existing contracts and the California ISO’s incurrence of Control Area Services costs. Existing Contract Customers Br. 56.<sup>11</sup> But this ignores that the Commission specifically found that Control Area Services costs were incurred by these customers and that these services could not be

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<sup>11</sup> Existing Contract Customers incorrectly include Market Operations costs in their argument against gross load allocation. *E.g.*, Existing Contract Customers Br. 56. In the orders below, however, the Commission only approved gross load allocation for the Control Area Services segment of the Grid Management Charge. For Market Operations service, the charge is based on a “given [Scheduling Coordinator’s] total purchases and sales of ancillary service.” Opinion No. 463 P 54, JA 348.

self-provided. Opinion No. 463 P 25-27, JA 342-343.

Existing Contract Customers go on to assert that Control Area Services costs cannot be allocated to existing contract customers because the ISO did not seek to charge these costs “for the *use* of the ISO Controlled Grid,” so that its allocation of Control Area Services costs on a gross load basis “was not based on whether a [Control Area Agreement] customer caused it to incur costs.” Existing Contract Customers Br. 56-57 (quoting Initial Decision at 65,111, JA 234 (emphasis in original; internal quotation marks omitted)). This point, however, disregards the distinction recognized by the Court in *Midwest ISO Transmission Owners* between the costs of *using* the ISO grid and “the administrative costs of *having* an ISO.” 373 F.3d at 1371 (emphasis in original). The presiding judge made the same distinction here, explaining that “[t]he charges at issue here are solely to recover the ISO’s administrative costs for [Control Area Services], which are caused by and provided for the benefit of all load within the ISO Control Area” (with certain exceptions not relevant here). Initial Decision at 65,110, JA 233 (citing Exh. ISO-1 at 24, JA 1006, and Exh. ISO-10 at 15:1-18:9, JA 1657-1660). These were not, she emphasized, the costs for use of the grid for the actual delivery of transmission service. *Id.* at 65,110-111, JA 233-234.

The Cogeneration Association, for its part, complains that the Commission’s final conclusion in Opinion No. 463-B “that any generator modeled by a utility . . .

must pay the [Control Area Services charge] on a gross load basis is directly contrary” to the agency’s original view that customers with behind-the-meter generation who primarily rely upon such generation to meet their energy needs are allocated too great a share of these costs. Association Br. 25 (citing Opinion 463 P 28, JA 343).

But the Commission does not make any such determination at the cited passage, which merely sets out its initial theory that some behind-the-meter generation did not incur Control Area Services costs. However, once the Commission compiled a record on the issue, after holding a second hearing, it concluded that the only sustainable exception to gross load allocation for Control Area Services costs was for generators serving load not modeled by, and thus “unseen by the ISO – for which the ISO obviously does not provide Control Area Services.” Opinion No. 463-B P 63, JA 757.

Certainly the Commission would have avoided some confusion if it had discarded (or at least deemphasized) its “behind-the-meter” terminology, which was susceptible of different definitions by different parties, as well as by the agency. However, the fact remains that the Commission ended up with a rational limitation on allocation of Control Area Services costs – exempting those customers who do not cause the ISO to incur such costs when they are not using the ISO-controlled grid – which is supported by substantial evidence. *See, e.g.,*

*Williams Natural Gas Co. v. FERC*, 3 F.3d 1544, 1551 (D.C. Cir. 1993)

(Commission reexamination of issue and arriving at a different result does not diminish deference owed agency).

The Cogeneration Association also argues that the Commission's exception is arbitrary because it believes that "the great majority of generation serving retail behind-the-meter load," is "unseen by the ISO," does not cause the ISO to do any work, and thus receives no benefit from Control Area Services other than when using the California ISO grid, and yet is "still modeled in some form by the utilities and therefore would be excluded from the Commission's exception." Cogeneration Association Br. 26-27 (citing R 486 at 10, JA 838). First, this statement is internally contradictory, as the Commission found that the load of any generation that is unseen, unmodeled and not studied by the ISO does not cause the ISO to do any work (and accordingly should not be billed for this charge). In any event, the citation is to the Cogeneration Association's conclusory statement in its request for rehearing of Opinion No. 463-B, not to evidence. *See, e.g., National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 842-844 (D.C. Cir. 2006) (theory is no substitute for evidence).

The Cogeneration Association does attempt to garner evidentiary support for this proposition when it asserts that "[t]he unambiguous evidence in this proceeding demonstrates that retail behind-the-meter load, and the on-site

generation which serves it, does not cause the ISO to incur [Control Area Services] costs when it is not using the [California ISO] grid.” Cogeneration Association Br. at 28 (citing Opinion No. 463-B P 79, JA 759). But the citation here is to the Commission’s finding that there is evidence that with respect to “on-site behind-the-meter generation, the ISO has no information and must make estimates to figure gross load allocation.” Opinion No. 463-B P 79 & n.88, JA 759 (citing Exh. ISO-12 at 6 (testimony of Mr. Price)). The Commission relied on this evidence to support its finding that, at least for some generation, the ISO does not incur administrative expenses covered by the Control Area Services charge. But the Commission further decided that whether generation was modeled, and thus examined by the ISO in its transmission planning and operation studies, provided the only actual evidentiary basis for determining which generation caused the ISO to incur administrative expenses. Opinion No. 463-B P 79, JA 759.

The Cogeneration Association’s other attempts to undermine the Commission’s conclusion fare no better. The Cogeneration Association cites ISO witness Mr. Lyon’s testimony as somehow supporting its position that behind-the-meter load does not incur Control Area Services costs. Cogeneration Association Br. 29 (citing Exh. ISO-54 at 11, JA 1142). However, Mr. Lyon testified extensively that all load, including behind-the-meter load served by behind-the-meter generation, receives numerous Control Area Services from the ISO beyond

the actual real-time monitoring of the grid and delivery of energy. *See* Exh. ISO-54 at 11-15, JA 1142-1146. Similarly, the Cogeneration Association emphasizes that behind-the-meter retail load does not cause the ISO to incur administrative costs relating to supply and withdrawal of power from the ISO-controlled grid. Cogeneration Association Br. at 30-31. But as Mr. Lyon explained, the costs of the administrative services at issue were for the entire ISO Control Area, not just the smaller subset of the ISO-controlled grid. Exh. ISO-54 at 12-13, JA 1143-1144. Cogeneration Association also seems to maintain that the Commission’s standard permits the ISO to “arbitrarily or incorrectly” include a generator in its studies just to collect more costs. Cogeneration Association Br. 27. This contention ignores both that the ISO is an independent, non-profit entity, as well as the fact that whether particular generation was modeled by a utility, and thus studied by the ISO, would necessarily be based on practical engineering concerns.

At bottom, both the Existing Contract Customers (Br. 58-59) and the Cogeneration Association (Br. 35-36) are arguing that it would reasonable to allocate Control Area Services costs for all load, including wholesale and retail behind-the-meter load, solely on a net basis, *e.g.*, when those customers are actually using the ISO-Controlled grid. However, even if such a course might have been reasonable from a cost causation standpoint, this would not in any way invalidate the Commission’s reasonable and record-supported determination. As



the Court recently explained, “FERC is not required to choose the best solution” in this context, “only a reasonable one.” *Petal Gas Storage*, 496 F.3d at 703, 2007 U.S. App. LEXIS 18656 at \*16-\*17 (citing *Deaf Smith County Grain Processors, Inc. v. Glickman*, 162 F.3d 1206, 1215 (D.C. Cir. 1998)).

## CONCLUSION

For the reasons stated, the Commission's orders should be affirmed in all respects.

Respectfully submitted,

Cynthia A. Marlette  
General Counsel

Robert H. Solomon  
Solicitor

Samuel Soopper  
Attorney

Federal Energy Regulatory  
Commission  
Washington, DC 20426  
TEL: (202) 502-8134  
FAX: (202) 273-0901

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**CERTIFICATE OF COMPLIANCE**

In accordance with Fed. R. App. P. 32(a)(7)(C)(i), I certify that the Brief of Respondent Federal Energy Regulatory Commission contains 11,494 words, not including the tables of contents and authorities, the certificates of counsel and the addendum.

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Samuel Soopper  
Attorney

Federal Energy Regulatory  
Commission  
Washington, DC 20426  
TEL: (202) 502-8154  
FAX: (202) 273-0901

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