ORAL ARGUMENT IS SCHEDULED FOR SEPTEMBER 12, 2011

In the United States Court of Appeals for the District of Columbia Circuit

Nos. 09-1231 and 10-1395

BRAINTREE ELECTRIC LIGHT DEPARTMENT, HINGHAM MUNICIPAL LIGHTING PLANT, HULL MUNICIPAL LIGHT PLANT, MANSFIELD MUNICIPAL ELECTRIC DEPARTMENT, MIDDLEBOROUGH GAS AND ELECTRIC DEPARTMENT, AND TAUNTON MUNICIPAL LIGHTING PLANT,
***PETITIONERS*,**

V.

FEDERAL ENERGY REGULATORY COMMISSION,
***RESPONDENT*.**

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

BRIEF FOR RESPONDENT FEDERAL ENERGY REGULATORY COMMISSION

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JUNE 30, 2011

CIRCUIT RULE 28(A)(1) CERTIFICATE

A. Parties and Amici

To counsel's knowledge, the parties and intervenors before this Court and before the Federal Energy Regulatory Commission in the underlying docket are as stated in the Brief of Petitioners.

B. Rulings Under Review

1. Order on Complaint, *Braintree Electric Light Department, et al. v. ISO New England Inc.*, Docket No. EL08-48, 124 FERC ¶ 61,061 (July 18, 2008) ("Complaint Order"), R. 28, JA 491;

2. Order on Rehearing, *Braintree Electric Light Department, et al. v. ISO New England Inc.*, Docket No. EL08-48, 128 FERC ¶ 61,008 (July 2, 2009) ("2009 Rehearing Order"), R. 35, JA 583;

3. Order on Compliance Filing, *Braintree Electric Light Department, et al. v. ISO New England Inc.*, Docket No. EL08-48, 129 FERC ¶ 61,077 (Oct. 28, 2009) ("Compliance Order"), R. 44, JA 810; and

4. Order Denying Request for Rehearing, *Braintree Electric Light Department, et al. v. ISO New England Inc.*, Docket No. EL08-48, 132 FERC ¶ 61,248 (Sept. 21, 2010) ("2010 Rehearing Order"), R. 47, JA 852.

C. Related Cases

This case has not previously been before this Court or any other court. Counsel is not aware of any other related cases pending before this or any other court.

s/ Carol J. Banta
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2009 Rehearing Order	Order on Rehearing, *Braintree Electric Light Department, et al. v. ISO New England Inc.*, 128 FERC ¶ 61,008 (July 2, 2009), R. 35, JA 583
2010 Rehearing Order	Order Denying Request for Rehearing, *Braintree Electric Light Department, et al. v. ISO New England Inc.*, 132 FERC ¶ 61,248 (Sept. 21, 2010), R. 47, JA 852
Commission or FERC	Federal Energy Regulatory Commission
Complaint Order	Order on Complaint, *Braintree Electric Light Department, et al. v. ISO New England Inc.*, 124 FERC ¶ 61,061 (July 18, 2008), R. 28, JA 491
Compliance Order	Order on Compliance Filing, *Braintree Electric Light Department, et al. v. ISO New England Inc.*, 129 FERC ¶ 61,077 (Oct. 28, 2009), R. 44, JA 810
FERC Orders	Collectively, Complaint Order, 2009 Rehearing Order, Compliance Order, and 2010 Rehearing Order
ISO Compliance Report	Compliance Report of ISO New England (filed July 17, 2009), R. 36, JA 606
ISO New England	ISO New England Inc., the independent system operator of an integrated transmission network spanning six northeastern states
LSCPR	Acronym used in the Settlement and the FERC Orders: "Local Second Contingency Protection Resource" is a designation under the ISO New England tariff for a generation resource identified as necessary to meet reliability criteria

GLOSSARY

Municipals	Petitioners Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Light Plant, Mansfield Municipal Electric Department, Middleborough Gas And Electric Department, and Taunton Municipal Lighting Plant
SEMA	Acronym used in the FERC Orders to denote the Southeastern Massachusetts Reliability Region/Load Zone within ISO New England's service area
Settlement or Sett.	FERC-approved Settlement Agreement among the Municipals, ISO New England, and other parties, reproduced in full at JA 205 and excerpted in the Addendum to this Brief

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

BRIEF FOR RESPONDENT
FEDERAL ENERGY REGULATORY COMMISSION

STATEMENT OF THE ISSUE

Whether the Federal Energy Regulatory Commission ("Commission" or "FERC") reasonably denied a complaint by utilities that sought to reduce or reallocate charges for the operation of generation resources used to ensure regional system reliability, where the Commission agreed with the independent system operator's determinations (1) that alternative contingency measures would not have met accepted reliability standards and (2) that the reliability region should not be subdivided into localized cost-sharing zones.

STATUTORY AND REGULATORY PROVISIONS

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

INTRODUCTION

This case concerns the efforts by a group of municipal-owned utilities ("Municipals")[1] in Southeastern Massachusetts to reduce or reallocate charges for operation of certain generation resources used to ensure system reliability within that region. Because a settlement resolved all such disputes for earlier years and because system upgrades and operational changes largely eliminated the disputed charges going forward, the reliability charges in dispute are limited to a locked-in period from March 2008 to June 2009.

The disputed charges arose from the operation of two oil-fired generation plants in Cape Cod, Massachusetts, known as the Canal Units. Though increased fuel prices raised their costs above market-clearing rates in the New England energy markets, the independent system operator designated the Canal Units as

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[1] Petitioners Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Light Plant, Mansfield Municipal Electric Department, Middleborough Gas and Electric Department, and Taunton Municipal Lighting Plant refer to themselves collectively as "Massachusetts Public Systems" or "MPS." For simplicity and consistency with the FERC Orders, this Brief refers to the Petitioners as "Municipals."

necessary to avoid a risk of blackouts on Cape Cod in the event of more than one transmission failure. As a result, all loads within the Southeastern Massachusetts reliability region, including those served by the Municipals outside Cape Cod, were assessed reliability charges for operation of the Canal Units as a contingency measure.

In a 2007 settlement agreement approved by the Commission, the Municipals, ISO New England Inc., and other parties resolved all disputes regarding those reliability charges, except two specific issues reserved by the Municipals. First, the Municipals retained their right to challenge whether the reliability charges could or should be reduced by using an alternative contingency arrangement. The Municipals also reserved the right to seek redefinition of the boundaries of the Southeastern Massachusetts reliability region through ISO New England's stakeholder process or before the Commission.

Accordingly, the Municipals filed a complaint asserting their reserved claims, which the Commission denied in the orders now on review. First, the Commission denied the Municipals' claim to reduce the Canal Units charges, concluding that ISO New England had properly determined that the alternative contingency plans would pose an unacceptable risk of forced outages, inconsistent with established reliability standards. *Braintree Elec. Light Dep't v. ISO New England Inc.*, 124 FERC ¶ 61,061 (2008) ("Complaint Order"), R. 28, JA 491, *reh'g denied*, 128 FERC ¶ 61,008 (2009) ("2009 Rehearing Order"), R. 35, JA 583.[2] Following a stakeholder process that considered whether to redefine the reliability region, the Commission agreed with ISO New England's proposal to retain the existing boundaries, and thus denied the Municipals' reallocation claim. *Braintree Elec. Light Dep't v. ISO New England Inc.*, 129 FERC ¶ 61,077 (2009) ("Compliance Order"), R. 44, JA 810, *reh'g denied*, 132 FERC ¶ 61,248 (2010) ("2010 Rehearing Order"), R. 47, JA 852.

STATEMENT OF FACTS

I. STATUTORY AND REGULATORY BACKGROUND

Section 201 of the Federal Power Act gives the Commission jurisdiction over the rates, terms, and conditions of service for the transmission and sale at wholesale of electric energy in interstate commerce. 16 U.S.C. §§ 824(a)-(b). This grant of jurisdiction is comprehensive and exclusive. *See generally New York v. FERC*, 535 U.S. 1 (2002) (discussing statutory framework and FERC jurisdiction). All rates for or in connection with jurisdictional sales and transmission services are subject to FERC review to assure they are just and reasonable, and not unduly discriminatory or preferential. FPA § 205(a), (b), (e), 16 U.S.C. § 824d(a), (b), (e).

[2] "R." refers to a record item. "JA" refers to the Joint Appendix page number. "P" refers to the internal paragraph number within a FERC order.

Section 206 of the FPA, 16 U.S.C. § 824e, authorizes the Commission to investigate whether existing rates are lawful. If the Commission, on its own initiative or on a third-party complaint, finds that an existing rate or charge is "unjust, unreasonable, unduly discriminatory or preferential," it must determine and set the just and reasonable rate. FPA § 206(a), 16 U.S.C. § 824e(a).

The Commission's efforts to foster wholesale electricity competition over broader geographic areas in recent decades led to the creation of independent system operators ("ISOs") and regional transmission organizations. *See Morgan Stanley Capital Group v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 536-37 (2008). These independent regional entities operate the transmission grid on behalf of transmission-owning member utilities and are required to maintain system reliability. *See NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 130 S. Ct. 693, 697 & n.1 (2010) (explaining responsibilities of an ISO).

II. THE COMMISSION PROCEEDINGS AND ORDERS

A. Operation of Canal Units

ISO New England administers energy markets and operates the bulk power transmission system across six states (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont). *See generally NSTAR Elec. & Gas Corp. v. FERC*, 481 F.3d 794, 796 (D.C. Cir. 2007). The Municipals serve loads in the Southeastern Massachusetts Reliability Region, one of eight such regions — three in Massachusetts alone — within the ISO New England footprint. *See* Compliance Order at P 18 n.17, JA 816.[3]

As previously noted, the Municipals' claims center on charges related to the operation of generation resources in Cape Cod. The Canal Units are oil-fired generating plants that have provided the primary generation for Cape Cod since 1968 (Unit 1) and 1976 (Unit 2). *See* Complaint Order at P 2, JA 492. According to ISO New England, the total peak load in Cape Cod is 950 megawatts. *Id.* The Canal Units produce up to 1,126 megawatts, while four smaller generating plants within Cape Cod produce a total of 152 megawatts. *Id.* Until recently, transmission import capability into Cape Cod was limited, with two 345-kilovolt lines and two smaller, 115-kilovolt lines. *See* Complaint at 14, R. 1, JA 10, 23.

Until 2006, at least one of the Canal Units typically would clear the bid-determined market price, so it would be operated "in-merit," with that price charged to wholesale customers in its load zone. *See id.* In 2006, however, rising fuel oil costs made the Canal Units more expensive to operate than gas-fired units in the ISO New England region, and the Canal Units no longer cleared the market price. *See* Complaint Order at P 3, JA 492. In late January 2006, NSTAR Electric Company, which owns transmission facilities in Southeastern Massachusetts,

[3] Massachusetts is divided into Southeastern, Northeastern, and West Central reliability regions. *Id.*

asked ISO New England to operate the Canal Units "out-of-merit order" for reliability purposes. *Id.* ISO New England initially designated the costs to be allocated solely to NSTAR, believing it had requested out-of-merit dispatch to exceed reliability standards, but later agreed with NSTAR that operation of the Canal Units was necessary to meet regional reliability criteria. *Id.* Accordingly, in April 2006, ISO New England reclassified the Canal Units as a Local Second Contingency Protection Resource ("LSCPR"[4]) under its tariff, which defines such resources as those "identified by the ISO on a daily basis as necessary for the provision of Operating Reserve Requirements and adherence to [North American Electric Reliability Council], [Northeast Power Coordinating Council], and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region." ISO New England Tariff § III.6.1 (included in Addendum at A-11).

B. 2007 Settlement

ISO New England's reclassification of the Canal Units resulted in the proportional allocation of the out-of-merit costs to all load in the Southeastern Massachusetts Reliability Region, in the form of reliability or "uplift" charges, both prospectively and retroactive to January 2006. *See* Complaint Order at P 3,

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[4] To minimize the use of acronyms, this Brief uses "LSCPR" only when quoting the Settlement or the FERC Orders.

JA 492. Therefore, ISO New England and the affected parties, including transmission owners and load-serving entities (such as the Municipals) in the region, participated in an extended mediation that culminated in a Settlement Agreement, which was approved by the Commission on June 21, 2007. *See* Letter Order, FERC Docket No. ER07-921 (June 21, 2007). (A copy of the Settlement was attached to NSTAR's answer to the complaint (R. 10) and is included in the Joint Appendix (JA 205); in addition, the sections relevant to the instant appeal are excerpted in the Addendum to this Brief.)

Under the Settlement, the transmission owners agreed to reimburse a portion of the Canal out-of-merit charges for 2006, including $3.77 million to the Municipals and $20.5 million to other load-serving entities. Sett. § 3.1, JA 209. The Settlement further provided that all reliability charges going forward, including Local Second Contingency Protection Resource charges in the Southeastern Massachusetts Reliability Region, would be allocated in accordance with ISO New England's tariff, but the Settlement established a new tariff mechanism by which sudden increases in those charges would trigger a partial reallocation of costs to transmission customers. Sett. §§ 4.1, 5, JA 214, 215-16. *See also* 2009 Rehearing Order at P 28 & n.34 (noting that the Settlement's new allocation mechanism apparently "mitigated the risk" of high reliability charges by "provid[ing] relief from LSCPR costs" when triggered), JA 594. (Though the

Municipals now contend that the negotiated reallocation mechanism was "useless" to them (Br. 6, 17 n.7), they did not make that argument before the Commission.)

In addition, ISO New England committed to study the possibility of implementing Post-First Contingency Switching or a Special Protection System in Southeastern Massachusetts, as well as potential projects to ensure reliability in the lower part of the region without operating the Canal Units out-of-merit and without relying on load-shedding arrangements. *See* Sett. § 6.1(b) (requiring ISO, within 60 days after execution of the Settlement, to submit to the parties a "Short Term Report" on alternative contingency arrangements), JA 218-20; Sett. § 6.2(c) (requiring "Long Term Report" within 18 months concerning potential projects), JA 220-21.

Relevant to the instant appeal, several interrelated provisions of the Settlement committed the parties to support the revised allocation mechanism and to oppose any other allocation methods; each such provision, however, referenced an express reservation, in § 7 (quoted *infra*), of the Municipals' rights to litigate certain issues:

- Sett. § 4.1, JA 214:

> Subject to . . . [Section 7], no Party shall seek or support a different allocation mechanism prior to the end of the Moratorium Period, or

> seek or support reclassification of [ISO New England]'s designation of Canal as an LSCPR for service during the Moratorium Period.[5]

- Sett. § 8(c), JA 226:

> No Party shall propose, or argue, either to the Commission or within the [ISO New England] or [New England Power Pool Participants Committee] process, or vote within either process, for Market Rule amendments that would provide for a different mechanism for allocation of [reliability] Charges for LSCPR, or shall seek or support reclassification of [ISO New England]'s designation of Canal as a LSCPR during the Moratorium Period other than as provided in Sections 4, 5, or 7 of this Settlement.

- Sett. § 9.2, JA 228:

> It is the intent of the Parties that this Settlement agreement resolve all issues relating to the classification of Canal as LSCPR during its operation Out-of-Merit and to the allocation of [reliability] Charges for LSCPR during the period from January 1, 2006, through May 31, 2010. . . . This provision does not limit the rights established by Section[] . . . 7 of this Settlement.

See also Addendum at A-6, A-9, and A-10 (excerpts from Settlement).

Section 7 of the Settlement, which was the basis for the Municipals' complaint and is at the core of this appeal, specified two issues that the Municipals reserved the right to litigate:

> 7.1 (a) Nothing in this Settlement is intended to prevent one or more of the Municipals, as of January 2, 2008, from seeking relief from [Southeastern Massachusetts reliability] Charges for LSCPR through **litigation against [ISO New England] or the Transmission Owners over whether consistent with Applicable**

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5 The "Moratorium Period" ran from January 1, 2007 through May 31, 2010. Sett. § 1, JA 207, *cited in* 2009 Rehearing Order at P 4 n.7, JA 585.

Criteria as defined in Section 6.1(b)[6] **such charges could be or should be reduced through implementation of [a Special Protection System] or Post-First Contingency Switching arrangement**. However, any financial relief from such excess charges shall be limited to the difference between the [Southeastern Massachusetts reliability] Charges for LSCPR imposed on the Municipals and the charges that would have been imposed if [a Special Protection System] or Post-First Contingency Switching arrangement had been implemented. Such relief shall be prospective from the date of filing of a proceeding seeking such relief (which date shall not be prior to January 2, 2008), except that the Municipals are entitled to seek relief for the three-month period prior to the date of initiating such proceeding.

(b) This Section 7.1 does not create any rights that would not exist in the absence of the Settlement.

(c) Each Party retains all rights to respond in opposition or to remain silent, as it sees fit, to any such actions taken or proceeding initiated by one or more Municipals under this Section 7.1.

7.2 The Parties, other than the Municipals, agree not to **seek a change (in [the New England Power Pool Participants Committee] or before the Commission) in the [ISO New England] definition of the [Southeastern Massachusetts] Reliability Region** to become effective prior to June 1, 2010; provided that the

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6 Section 6.1(b) of the Settlement defined "Applicable Criteria" as, collectively, "[Northeast Power Coordinating Council]/[North American Electric Reliability Corporation] criteria and applicable [ISO New England] planning criteria and/or operating procedures." JA 218.

The North American Electric Reliability Corporation is the national organization charged with establishing and enforcing mandatory electric reliability standards under 16 U.S.C. § 824o(a)(2). *See North American Electric Reliability Corporation*, 116 FERC ¶ 61,062 (2006). The Northeast Power Coordinating Council is the regional organization that oversees electric power grid reliability for the northeast region of the United States and Canada.

> Municipals may seek such a change to become effective no earlier than January 1, 2008.

Sett. § 7 (emphases added), JA 224-25 (Addendum at A-7 to A-8).

C. Later System Improvements

Beginning in 2006, ISO New England and the transmission owners in Southeastern Massachusetts worked together to upgrade the regional transmission system. As a result, an additional 115 kilovolt line was placed into service in June 2008 and several infrastructure additions were placed into service from April to September 2009. *See* Compliance Report of ISO New England at 12 (filed July 17, 2009) ("ISO Compliance Report"), R. 36, JA 606, 617. Those upgrades were expected to enable the system to respond to a second contingency without shedding load in the area and without running the Canal Units except at New England-wide peak periods on some summer days. *Id.* at 13, 15, JA 618, 620. *See also id.* at 16 (stating that uplift charges for the Canal Units "were greatly reduced" in April-June 2009 and "should be virtually eliminated" with the completion of an additional upgrade in July 2009), JA 621.

D. Complaint Order

On March 28, 2008, the Municipals filed a complaint against ISO New England before the Commission. The Municipals claimed that, due to the classification of Canal Units as Local Second Contingency Protection Resources, they had been overcharged nearly $24 million in 2006 and 2007, and anticipated being overcharged more than $13.5 million in 2008. Complaint at 2, R. 1, JA 10, 11; *see also* Br. 16 (explaining calculations based on Municipals' proportion of regional load multiplied by total out-of-merit Canal Unit charges).[7] The Municipals claimed that the Canal out-of-merit charges could be reduced through implementation of an alternative arrangement and that Southeastern Massachusetts should be subdivided so that customers in the upper part of that zone (including the Municipals' loads) would not share the costs of ensuring reliability in the lower part (*i.e.*, Cape Cod).

On July 18, 2008, the Commission denied the Municipals' first claim and set the second for hearing. Order on Complaint, *Braintree Elec. Light Dep't v. ISO New England Inc.*, 124 FERC ¶ 61,061 (2008) ("Complaint Order"), R. 28, JA 491. The Commission began by recognizing that the Settlement "narrows the scope of the complaint to two issues": (1) whether an alternative switching arrangement "can replace the utilization of the Canal Units as [a Local Second Contingency Protection Resource]"; and (2) "whether the Commission should

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7 Because Section 7 of the Settlement provided that the Municipals could not file a claim before January 2, 2008 (*see supra* pp. 10-11), and because the Commission established the refund effective date as of March 28, 2008 (the date the complaint was filed) (Complaint Order at Ordering Para. B, JA 501), the Municipals could not seek refunds for such charges paid in 2006 and 2007.

direct a change" in ISO New England's definition of the Southeastern Massachusetts Reliability Region. *Id.* at P 22 (citing Sett. § 7), JA 497.

On the first issue, the Commission agreed with ISO New England's conclusion that reliance on an alternative (Post First Contingency Switching or Special Protection System) arrangement would make the involuntary shedding of firm load the next step after a first contingency, which "would inappropriately degrade reliability." *Id.* at P 26, JA 498. For that reason, the Commission concluded that ISO New England had properly followed established reliability standards by running the Canal Units out-of-merit. *Id.*

On the second issue, the Commission found that, because ISO New England had adopted the reliability regions from existing New England Power Pool boundaries that were based on engineering considerations, "whether or not the cost allocations resulting from the boundaries of the current . . . region are just and reasonable raises issues of material fact" that warranted investigation. *Id.* at P 30, JA 500. The Commission held the hearing in abeyance, however, because it determined that the issues raised by the Municipals and numerous other parties were "more appropriately addressed in the [ISO New England] stakeholder process." *Id.* The Commission defined the issues to be addressed as including whether (and, if so, how) the Southeastern Massachusetts Reliability Region should be divided and the effects of any proposal on electricity markets or other reliability regions in New England. *Id.* The Commission directed ISO New England to submit a filing by July 17, 2009, describing the stakeholder process and indicating how the ISO would address the cost allocation issues set for hearing. *Id.*

E. 2009 Rehearing Order

The Municipals filed a timely request for rehearing. R. 29, JA 502. (The transmission owners in Southeastern Massachusetts also filed a request for rehearing, raising arguments that are not at issue in this appeal. R. 30.) On July 2, 2009, the Commission issued its Order on Rehearing, *Braintree Elec. Light Dep't v. ISO New England Inc.*, 128 FERC ¶ 61,008 (2009) ("2009 Rehearing Order" and, together with the Complaint Order, "Complaint Orders"), R. 35, JA 583. In denying rehearing, the Commission reaffirmed that the Municipals had "failed to demonstrate" that a switching arrangement "represented an acceptable alternative" to reliance on the Canal Units; the Commission had found the alternative plans "lacking because they involved an unacceptable risk of forced outage after the first contingency, and would be inconsistent with applicable planning criteria." *Id.* at P 25, JA 592; *see also id.* at PP 29-30 (Municipals failed to address risk of involuntary load shedding and its inconsistency with reliability criteria), JA 594-95. The Commission rejected the Municipals' attempt to recast their claim as a challenge to ISO New England's classification of the Canal Units as Local Second

Contingency Protection Resources under its tariff, finding that the Settlement had resolved the classification issue and limited the Municipals' reserved claim to the question of alternative arrangements. *Id.* at PP 26-27, JA 593.

The Commission also addressed both the Municipals' and the transmission owners' concerns about the stakeholder process, assuring that the Commission would ultimately review any resulting proposal and make its own determination. *See id.* at PP 50, 55, JA 600-01, 602. The Commission clarified that the Settlement moratorium would not preclude parties from taking positions on the boundary issue. *See id.* at PP 51-54, JA 601-02.

The Municipals filed a petition for review of the Complaint Orders in Case No. 09-1231.

F. Compliance Order

On July 17, 2009, ISO New England filed its Compliance Report describing the stakeholder process and presenting the resulting proposal. JA 606. In that process, ISO New England worked with the New England Power Pool Markets Committee to develop guidelines for evaluating whether to change reliability zones; in general, the guidelines would focus on:

- providing a significant notice period — usually at least one year — with detailed information, including the specific revised boundaries;
- the presence of certain triggering events, such as changed market conditions or changes in the transmission system that are expected to

persist for well beyond the year of advance notice, that warrant separating a subregion (or integrating a previously separate zone); and

- whether the resulting zone would be of sufficient size to provide a reasonably predictable pricing zone and to include sufficient resources to meet reliability needs.

See ISO Compliance Report at 22-26, JA 627-31.

Applying those guidelines, the Markets Committee and ISO New England recommended, and the New England Power Pool Participants Committee agreed (over the objection of the Municipals), that the Southeastern Massachusetts Reliability Region should not be changed. *See id.* at 16-33, JA 621-38. The stakeholders decided against a prospective change largely because transmission upgrades were expected to eliminate the need for out-of-merit Canal Unit operations by mid-2009. *Id.* at 27-28, JA 632-33. The stakeholders also chose not to split Southeastern Massachusetts retroactively because they were concerned about creating zones that might be too small to provide price stability, and also concluded that market participants lacked sufficient (*i.e.*, one-year) advance notice, with details, of a potential change, given the March 28, 2008 refund effective date. *See id.* at 30, JA 635.

On October 28, 2009, the Commission issued its Order on Compliance Filing, *Braintree Elec. Light Dep't v. ISO New England Inc.*, 129 FERC ¶ 61,077 (2009) ("Compliance Order"), R. 44, JA 810. The Commission agreed with ISO New England's proposal, resulting from the stakeholder process, to leave the reliability region unchanged, both prospectively and for the past locked-in period. *Id.* at PP 47, 50-51, 53, JA 824-25. The Commission rejected the Municipals' objections to the guidelines (*id.* at P 49, JA 824) and explained that regionalization of reliability costs was consistent with cost causation principles (*id.* at P 54, JA 825). The Commission also ruled that the Settlement barred the Municipals from seeking reallocation of reliability charges except through a boundary change. *Id.* at P 48, 52, JA 824, 825.

G. 2010 Rehearing Order

The Municipals again filed a timely request for rehearing. R. 45, JA 829. On September 21, 2010, the Commission issued its Order Denying Request for Rehearing, *Braintree Elec. Light Dep't v. ISO New England Inc.*, 132 FERC ¶ 61,248 (2010) ("2010 Rehearing Order"), R. 47, JA 852, denying rehearing on all issues.

The Municipals filed a petition for review of the Compliance Orders in Case No. 10-1395. This Court subsequently consolidated that petition with Case No. 09-1231.

SUMMARY OF ARGUMENT

Reliable operation of the power grid is a central responsibility of a transmission system operator such as ISO New England. Under Commission policy, the network's users share the costs of reliability planning and operations on a regional basis. In this case, the Commission reasonably denied the Municipals' request to reduce or reallocate their share of past network reliability costs.

First, the Municipals sought additional reimbursement for reliability charges, beyond that paid under the Settlement, as though the regional system had used a load-shedding backup plan for contingencies. The Commission appropriately focused on the actual operation of the regional system and concluded that such alternative arrangements would have posed an unacceptable risk of forced service outages — *i.e.*, blackouts — inconsistent with established reliability standards. In addition, the Commission reasonably construed the Settlement to bar the Municipals' claim that the Canal Units charges were improperly classified under ISO New England's tariff, because the Settlement precluded arguments about reclassification and reserved only the specific question about using alternative contingency arrangements.

The Municipals also sought redistribution of reliability charges based on a theoretical, retroactive bifurcation of the reliability region. No party advocated splitting the region going forward, because transmission upgrades had eliminated out-of-merit dispatch of the Canal Units by mid-2009. The Commission, on its own review after the system's stakeholders rejected a retroactive split, reasonably concluded that reallocation of selected past charges based on temporary cost conditions would undermine the predictability that enables long-term contracting. Moreover, regional sharing of reliability costs provides price stability (as localized costs around the region may fluctuate) and appropriately allocates such costs to users who benefit from network reliability. The Commission also reasonably construed the Settlement to bar Municipals' claim for reallocation of reliability charges absent a change in the regional boundary.

ARGUMENT

I. STANDARD OF REVIEW

The Court reviews FERC orders under the Administrative Procedure Act's arbitrary and capricious standard. *See, e.g., Sithe/Independence Power Partners, L.P. v. FERC*, 165 F.3d 944, 948 (D.C. Cir. 1999); *Braintree Elec. Light Dep't v. FERC*, 550 F.3d 6, 10 (D.C. Cir. 2008). A court must satisfy itself that the agency "articulate[d] a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs. Ass'n of United States, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).

The Commission's decisions regarding rate issues are entitled to broad deference, because of "the breadth and complexity of the Commission's responsibilities." *Permian Basin Area Rate Cases*, 390 U.S. 747, 790 (1968); *see also Pub. Utils. Comm'n of Cal. v. FERC*, 254 F.3d 250, 254 (D.C. Cir. 2001) ("Because issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission, our review of whether a particular rate design is just and reasonable is highly deferential.") (internal quotation marks and citations omitted); *accord NSTAR*, 481 F.3d at 802. *See also Morgan Stanley*, 554 U.S. at 532 ("The statutory requirement that rates be 'just and reasonable' is obviously incapable of precise judicial definition, and we afford great deference to the Commission in its rate decisions."); *ExxonMobil Oil Corp. v. FERC*, 487 F.3d 945, 951 (D.C. Cir. 2007) ("In reviewing FERC's orders, we are 'particularly deferential to the Commission's expertise' with respect to ratemaking issues.") (citation omitted).

Moreover, under the *Chevron* standard, this Court gives substantial deference to the Commission's interpretation of settlements it previously approved, even where the issue simply involves the proper construction of language. *See Transcont'l Gas Pipe Line Corp. v. FERC*, 922 F.2d 865, 869 (D.C. Cir. 1991) (Court "affords a high degree of deference to the Commission's interpretation of a settlement agreement"); *Ameren Servs. Co. v. FERC*, 330 F.3d 494, 498 (D.C. Cir. 2003) (employing "a variation of the now familiar 'two-step'" set forth in *Chevron*).

The Commission's factual findings are conclusive if supported by substantial evidence. FPA § 313(b), 16 U.S.C. § 825*l*(b). The substantial evidence standard "'requires more than a scintilla, but can be satisfied by something less than a preponderance of the evidence.'" *La. Pub. Serv. Comm'n v. FERC*, 522 F.3d 378, 395 (D.C. Cir. 2008) (quoting *FPL Energy Me. Hydro LLC v. FERC*, 287 F.3d 1151, 1160 (D.C. Cir. 2002)). Substantial evidence means "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion."

Universal Camera Corp. v. NLRB, 340 U.S. 474, 477 (1951) (internal quotation marks and citation omitted); *accord Consol. Oil & Gas, Inc. v. FERC*, 806 F.2d 275, 279 (D.C. Cir. 1986). If the evidence is susceptible of more than one rational interpretation, the Court must uphold the agency's findings. *See Consolo v. Fed. Mar. Comm'n*, 383 U.S. 607, 620 (1966); *accord Fla. Mun. Power Agency v. FERC*, 315 F.3d 362, 368 (D.C. Cir. 2003) ("The question we must answer . . . is not whether record evidence supports [petitioner]'s version of events, but whether it supports FERC's."). Moreover, the Commission's "conclusions on conflicting engineering and economic issues" must be upheld "so long as its judgment is reasonable and based on evidence . . . ." *Sierra Pac. Power Co. v. FERC*, 793 F.2d 1086, 1088 (9th Cir. 1986) (citing *City of Cleveland v. FPC*, 525 F.2d 845, 849 n.36 (D.C. Cir. 1976)); *see also Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 645 (D.C. Cir. 2010).

II. THE COMMISSION PROPERLY DENIED THE MUNICIPALS' CLAIM THAT RELIABILITY CHARGES COULD HAVE BEEN REDUCED BY USING A LOAD-SHEDDING ARRANGEMENT

The Municipals first contend that the reliability charges should have been reduced because ISO New England could, theoretically, have used an alternative arrangement in planning for a second contingency. Br. 21, 37-38. The Commission disagreed, finding that the alternative backup plans would depend on involuntary load shedding and pose a risk of blackouts, inconsistent with accepted standards for reliability operations and planning.

A. The Commission Reasonably Determined That Alternative Load-Shedding Arrangements Would Have Been Inconsistent With Established Reliability Standards

The Municipals believe that the theoretical possibility of using an alternative contingency arrangement is all they need show to obtain refunds of the Local Second Contingency Protection Resource charges incurred under ISO New England's actual backup plan. *See* Br. 38-39. The Commission, however, agreed with ISO New England's assessment that either of the proposed alternatives would pose an unacceptable risk of blackouts, inappropriately degrading reliability, and thus could not have replaced operation of the Canal Units as an acceptable contingency plan under established reliability standards. Complaint Order at PP 23-26, JA 497-99; 2009 Rehearing Order at P 25, JA 592; 2010 Rehearing Order at PP 35-36, JA 865-66.

1. The Alternative Arrangements Would Rely On Involuntary Load Shedding

In the Settlement, the Municipals reserved their right to argue, and ISO New England committed to evaluate, whether, consistent with accepted reliability standards, either of two alternative arrangements — Post-First Contingency Switching or a Special Protection System — could or should have been implemented to ensure system reliability instead of operating the Canal Units out-of-merit. *See* Sett. § 6.1(b) (requiring ISO report), § 7.1 (reserving Municipals' right to litigate), JA 217-20, 224-25. *See supra* pp. 10-11.

Both of the alternative arrangements were premised on "involuntary load shedding" — which, given the structure of the Southeastern Massachusetts system before the upgrades went into service (*see supra* pp. 6, 12), would mean blackouts. Complaint Order at P 24, JA 498; *see also* Sett. § 6.1(b) (noting that both arrangements "can entail load shedding upon the occurrence of a second contingency"), JA 219. Post-First Contingency Switching is the opening of various circuit breakers following the occurrence of the first failure. *See* Complaint Order at P 1 n.1, JA 491. In the Cape Cod area, that arrangement would be, essentially, a plan for coordinating blackouts as the next step. *See* Testimony of Peter T. Brandien (ISO New England's witness) at 15 ("Actions would need to be implemented *to disconnect customer load* pre-second contingency or immediately upon the occurrence of the contingency to prevent equipment damage and public safety risks. *The resulting effect is often referred to as a 'blackout.'*") (emphases added), R. 17 (Answer of ISO New England Inc., Att. 1), JA 326; Testimony of Whitfield Russell (Municipals' witness) at 23 (switching arrangement "involves a pre-planned set of procedures that would be initiated after a first contingency outage event in order to position the system *to shed load* *automatically* upon the occurrence of the second contingency") (emphasis added), R. 1 (Complaint, Exh. MPS-1), JA 77.

A Special Protection System is a system designed to detect abnormal system conditions and take automatic, pre-planned corrective action. *See* Complaint Order at P 1 n.2, JA 491. Again, in the event of a loss of one of the transmission paths into Cape Cod, such a system would rely on controlled blackouts in the event of a second failure. *See* Direct Testimony of Whitfield Russell at 41 (system "would enable the ISO *to shed automatically* some Lower [Southeastern Massachusetts] loads and delivery facilities almost instantaneously after the loss of the second 345 [kilovolt] transmission line") (emphasis added), JA 95; *id.* at 43 (system should be designed to "take remedial actions *to remove loads* in Lower [Southeastern Massachusetts]") (emphasis added), JA 97.

Put differently, the question before the Commission was whether, in the event of a sudden outage of one of the two large transmission lines into Cape Cod, ISO New England's backup plan for any further failure should be to black out all or most of Cape Cod, rather than to draw power from the only substantial generation resource in the area (the Canal Units). The Commission noted that such a blackout could last up to 24 hours, as "it would take that long to bring the Canal Units on-line from a cold start." Complaint Order at P 26, JA 499.

ISO New England did, as the Municipals contend (Br. 21), find that a switching arrangement could be implemented — but ISO New England *also* found that relying on such an arrangement as a backup plan "would expose Cape Cod to the risk of involuntary load shedding if a 345 [kilovolt] line was lost." Complaint Order at P 24, JA 498. The total peak load in Cape Cod is 950 megawatts, and the remaining 345 kilovolt line would be able to import at most 400 megawatts. *Id.* Therefore, under any load conditions, only the operation of one or both Canal Units would avoid a forced blackout in the event of a second failure:

> [U]nder low load conditions in Cape Cod, the second 345 [kilovolt] line protects against the involuntary shedding of load under N-1 (first) contingency, while running a single Canal unit protects against the involuntary shedding of load under N-2 (second) contingencies. Under high load conditions in Cape Cod, running both Canal Units protects against involuntary shedding of load under N-1 and N-2 contingencies.

Id.

By contrast, "reliance on a [Post-First Contingency Switching] or [a Special Protection System] arrangement would make the involuntary shedding of firm load *the next step after a first contingency*" under all load conditions. *Id.* at P 26 (emphasis added), JA 498; *see also* 2010 Rehearing Order at P 36 (such alternative arrangements "would have [ISO New England] rely on setting up to disconnect the Cape Cod area as the next step post-first contingency 365 days a year") (citing testimony of ISO New England witness), JA 866; ISO Compliance Report at 14 ("given the design of the system in that area," using a switching arrangement instead of out-of-merit dispatch would mean "setting up for load shedding of the entire Cape Cod area would be the only available next step for operators in almost all hours of all days of the year if a first contingency were to occur"), JA 619. In other areas of New England, load shedding arrangements are used for contingencies only in circumstances (such as day-ahead operations or voluntary curtailment) "where many other steps would be utilized" before forced interruption of firm service. ISO Compliance Report at 8, JA 613; *cf.* Br. 37 (citing areas where ISO New England has relied on controlled load-shedding as a backup plan).[8]

2. Relying On Involuntary Load Shedding Is Disfavored Under Reliability Standards For Contingency Planning

In reviewing ISO New England's findings, the Commission turned to the applicable reliability standards, which strongly disfavor blackouts as contingency plans. For example, one of the Northeast Power Coordinating Council's seven basic objectives in formulating emergency operating plans is "[t]o avoid, to the

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[8] Ultimately, due to the transmission upgrades put into service in Southeastern Massachusetts by mid-2009 (*see supra* p. 12), a switching arrangement became an acceptable contingency plan — that is, no longer premised on forced blackouts — under most load conditions. *See* Compliance Order at PP 14-15, JA 815; ISO Compliance Report at 14-15 (following upgrades, second contingency would require "much less load" to be shed, and system would allow "selective[]" shedding rather than full blackout of Cape Cod area, with faster restoration of service), JA 619-20. At that point, out-of-merit dispatch of the Canal Units was largely eliminated. Compliance Order at P 15, JA 815.

extent possible, the interruption of service to firm load." Complaint Order at P 25, JA 498. Another Council document, providing guidance for transmission design and operation, sets forth a preferred sequence of actions to address contingencies, favoring "readjustment of generation" over other measures such as load-shedding. *Id.* (also citing the North American Electric Reliability Corporation's direction that system operators follow regional reliability requirements); 2009 Rehearing Order at P 30 (emphasizing "the applicable reliability criteria preference for generator redispatch over load shedding"), JA 594.

Accordingly, the Commission concluded that ISO New England had "properly followed" established reliability standards by running the Canal Units instead of relying on load-shedding arrangements, which the Commission agreed "would inappropriately degrade reliability." Complaint Order at P 26, JA 498; 2009 Rehearing Order at P 25 (Commission found such arrangements "lacking because they involved an unacceptable risk of forced outage after the first contingency, and would be inconsistent with applicable planning criteria"), JA 592; *see also id.* ("the resulting blackout could extend unacceptably long [up to 24 hours]"). This was a reasonable conclusion, based on the Commission's assessment of electrical engineering considerations, that should not be disturbed lightly on review. *See, e.g.*, *Washington Gas Light Co. v. FERC*, 532 F.3d 928, 930 (D.C. Cir. 2008) ("extreme" deference afforded to Commission's "evaluation of scientific data within its technical expertise") (internal quotation marks and citations omitted).

3. The Commission Properly Considered Actual, Rather Than Theoretical, Reliability Planning And Operations

In response, the Municipals contend that they never suggested that ISO New England should *actually* adopt a load-shedding arrangement — rather, they sought, in essence, a hypothetical arrangement for purposes of billing, so the Municipals could avoid their share of the costs for actual reliability operations. *See, e.g.*, Br. 9, 23, 24, 32, 38-39. Indeed, on appeal, they repeatedly object to any suggestion that they advocated implementing load-shedding arrangements in reality, and accuse the Commission, in its focus on actual system planning in light of applicable reliability standards, of dwelling on "strawman" and "red herring" arguments. Br. 39.

The Commission, however, appropriately considered the configuration and operation of the real-world transmission system, its service to real-world customers, and the well-established reliability standards that govern its planning and operation. The Commission found that the Municipals, focusing on the theoretical feasibility of implementing a switching arrangement, failed adequately to address ISO New England's crucial finding that, in the Southeastern Massachusetts system as it was configured (before recent upgrades), such a plan would necessarily rely on forced blackouts — nor did the Municipals refute the

Commission's determination that established reliability standards disfavor blackouts as contingency plans. *See* 2009 Rehearing Order at P 29, JA 594; *id.* at P 30 ("Municipals . . . fail to address the fact that, by posturing the system for load shedding on the occurrence of a first contingency when there is a high load in Cape Cod, such an arrangement runs afoul of the applicable reliability criteria preference for generator dispatch over load shedding"), JA 594; *see also id.* at P 29 (agreeing with ISO New England that "an acceptable solution must avoid exposing the system to problems from other contingencies"), JA 594.[9]

Therefore, the Commission reasonably determined that the Municipals, having exercised their Settlement-reserved right to litigate the question, "failed to demonstrate that either [a Special Protection System] or [Post-First Contingency Switching] represented an acceptable alternative" to out-of-merit dispatch of the Canal Units. 2009 Rehearing Order at P 25, JA 592. *See, e.g.*, *Elec.Consumers Res. Council v. FERC*, 407 F.3d 1232, 1236, 1239-40 (D.C. Cir. 2005) (deferring to Commission's "resolution of factual disputes between expert witnesses").

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9 The Municipals' supporting witness did not dispute that blackouts would be the backup plan under either of the alternative arrangements; instead, he minimized the likelihood of a second contingency occurring and concerns about blackouts, explaining that "even where 100% load shedding is needed," some of Cape Cod's load might be restored using the smaller transmission lines, and at least the blackout would be "limited to a maximum 24 hours . . . ." Testimony of Whitfield Russell at 25, JA 79. He went on to dismiss "the unpopularity of service curtailments" as "not relevant" to reliability standards. *Id.* at 29, JA 83.

B. The Commission Properly Construed The Settlement To Preclude Reclassifying The Canal Units Under The Tariff

The Municipals also contend that their claim was based on an interpretation of the ISO New England tariff: that the Canal Units were improperly designated as Local Second Contingency Protection Resources because they were not "necessary" to meet reliability criteria. Br. 36-37; *see supra* p. 7 (tariff definition). The Commission, however, properly denied that tariff dispute as beyond the scope of the issues reserved to the Municipals in Section 7 of the Settlement. *See* 2009 Rehearing Order at PP 24-27, JA 592-93; 2010 Rehearing Order at PP 17-19, JA 858-59.

The Municipals argue that, in Settlement provisions barring the parties from seeking reclassification of ISO New England's designation of the Canal Units (*see* Sett. §§ 4.1, 8(c), JA 214, 226), references to the separate reservation of issues (§ 7) demonstrate that the Municipals were entitled to seek that very reclassification. Br. 41-43; *see* Br. 42 (contending that Municipals' "reservation of their litigation rights in Section 7 takes priority over the more generalized moratorium language in those provisions [§§ 4.1 and 8(c)]").[10] Put differently, the

[10] The Municipals also rely on another section — which they failed to raise before the Commission — that states: "In this Settlement Agreement, subject to the rights reserved to the Municipals in Section 7, the Parties are agreeing that they will not challenge [ISO New England]'s flagging of Canal as LSCPR . . . ." Sett. § 10.1, JA 232. *See* Br. 43.

Municipals suggest that the language "subject to" (in §§ 4.1 and 10.1) and "other than as provided in" (in § 8(c)) effectively reserved the otherwise-barred reclassification claim to the Municipals by negative inference. *But see*, *e.g.*, *Michelin Tires (Canada) Ltd. v. First Nat'l Bank of Boston*, 666 F.2d 673, 677 (1st Cir. 1981) ("There is nothing in the use of the words 'subject to,' in their ordinary use, which would even hint at the creation of affirmative rights.") (citation omitted), *cited in* Br. 42.

The Commission properly rejected the Municipals' interpretation, holding that Section 7 itself defined the claims specifically reserved therein: "Section 7.1 permits Municipals to seek relief from LSCPR charges because such charges could or should be reduced through implementation of a switching or special protection arrangement. Municipals did so, and their claims were fully addressed in the Order on Complaint as affirmed in the [2009] Rehearing Order." 2010 Rehearing Order at P 19 & n.22 (citing Complaint Order at P 24, JA 498, and 2009 Rehearing Order at PP 24-31, JA 592-95), JA 859; *see also* Sett. § 7.1, JA 224-25, *quoted supra at* pp. 10-11. Section 7 contains no language reserving a right to seek reclassification of the Canal Units, as expressly precluded by Sections 4.1 and 8(c). *See* 2009 Rehearing Order at PP 26-27 (ruling that Sett. § 4.1 barred reclassification claims), JA 593; 2010 Rehearing Order at P 17 (same), JA 859. Accordingly, the Commission's interpretation of the Settlement moratorium and the Municipals' specific exceptions thereto is reasonable and entitled to deference. *See also N. Mun. Distribs. Group v. FERC*, 165 F.3d 935, 943 (D.C. Cir. 1999) ("Once the Commission has approved a settlement, the court will defer to the Commission's interpretation of it").

III. THE COMMISSION PROPERLY DENIED THE MUNICIPALS' CLAIM SEEKING REALLOCATION OF RELIABILITY CHARGES BASED ON SUBDIVIDING THE SOUTHEASTERN MASSACHUSETTS RELIABILITY REGION

The Municipals also contend that the reliability charges should have been reallocated to Cape Cod customers (and refunded to the Municipals) based upon a theoretical, temporary bifurcation of the Southeastern Massachusetts Reliability Region. Br. 44, 49. The Commission denied the reallocation claim, based on its own review of ISO New England's findings from an extended stakeholder process and on the analysis of cost allocation principles and precedents in the context of reliability operations.

A. The Commission Reasonably Denied The Municipals' Request To Subdivide The Reliability Region

Neither the Municipals nor any other party advocated changing the Southeastern Massachusetts Reliability Region prospectively — that is, after transmission upgrades began operating in mid-2009, effectively eliminating system reliance on out-of-merit dispatch of the Canal Units. *See* Compliance Order at PP 33, 47, 50, JA 820, 824; 2010 Rehearing Order at PP 39, 68, JA 867, 877.

Accordingly, ISO New England in the stakeholder process, and the Commission in ruling on the Municipals' complaint, considered whether to alter the regional boundaries retroactively and temporarily, for the locked-in period from the date of the complaint, March 28, 2008, to June 28, 2009. The Commission approved the guidelines that ISO New England proposed to apply in this and future cases (Compliance Order at P 49, JA 824), but did not rest its own determination simply on those guidelines or on ISO New England's analysis. Rather, the Commission went on to explain its own reasons for agreeing with the stakeholders' conclusion that the Southeastern Massachusetts Reliability Region is appropriately sized, and thus should not be changed retroactively. *Id.* at PP 50-54, JA 824-25; 2010 Rehearing Order at P 44, JA 869-70; *see also id.* at PP 34-48, JA 865-72.

1. Retroactively Redrawing Zonal Boundaries Could Undermine Predictability And Raise Prices In The Future

First, the Commission agreed with ISO New England that trying to shift reliability charges for that past period would be "unworkable." Compliance Order at P 50, JA 824. The Commission concluded, as had ISO New England, that tinkering with selected past charges,[11] based on temporary cost conditions, would

[11] Here, the charges would indeed be selected, in that the Municipals sought, not to bifurcate the reliability region in fact (and for all purposes), but only to reallocate the Canal uplift charges to benefit themselves. *See* 2010 Rehearing Order at P 67, JA 877. *See also id.* at P 45 & n.63 (noting that Municipals did not

risk increasing costs to all customers in the future, because such reallocation would create unpredictability that would lead market participants to add risk premiums to contracts. Compliance Order at PP 50-51, JA 824-25. Though the Municipals dispute the potential for future risk premiums because their reallocation claim focuses on past charges (Br. 49-50), the Commission explained that, even when considering retroactive refunds, its concerns about predictability and contracting behavior are necessarily forward-looking. 2010 Rehearing Order at P 46, JA 870. In addition, the Commission saw a particular risk of undermining predictability where the claim for refunds was not based on "costs that were incurred or charges allocated in error or on the basis of some misconduct or mistake or otherwise in an unjust and unreasonable manner." *Id.*, JA 871. Here, "the tariff performed correctly," but the challenged costs were caused by increases in fuel prices. *Id.*[12]

Notwithstanding the Municipals' skepticism about such effects on the market (*see* Br. 49-50), this policy judgment is manifestly the Commission's to

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provide an analysis of the overall transmission rate and disavowed any challenge to the reasonableness of the zonal boundaries other than the effect on the allocation of the Canal out-of-merit costs), JA 870.

[12] The Commission further explained that "neither the cost of running the Canal Units nor [ISO New England]'s decision to utilize the Canal Units is at issue at this stage of the proceeding," concerning reallocation based on changes to the regional boundaries. *Id.* The Complaint Orders already had denied the Municipals' claims regarding alternative contingency arrangements and reclassification.

make; indeed, the courts have long deferred to the Commission's expertise when addressing practical complexities of the electricity market. *See, e.g., Blumenthal v. FERC*, 552 F.3d 875, 884-85 (D.C. Cir. 2009) (noting "'presumption of validity'" afforded to "'each exercise of the Commission's expertise,'" especially in light of electricity market's "'intensely practical difficulties' demanding a solution from FERC," and latitude necessarily given to FERC "to balance the competing considerations and decide on the best resolution") (quoting *Permian Basin*, 390 U.S. at 767, 790); *Elec. Consumers*, 407 F.3d at 1238-39 (deferring to Commission's policy judgment in formulating regional rate design).

2. Regional Allocation Of Reliability Costs Provides Price Stability

Furthermore, the Commission explained that using a regional structure to allocate reliability costs "appropriately spreads costs among customers within a region and prevents price fluctuations due to . . . temporary conditions" (such as increased fuel costs for generation). Compliance Order at P 51, JA 824; *see also id.* at P 50 (citing ISO New England's "identification of several past system conditions, which did not result in regional boundary changes or cost reallocations"[13]), JA 824; 2010 Rehearing Order at P 68 (same), JA 877. Over the

[13] For example, ISO New England pointed to a number of transmission upgrades since the establishment of the Southeastern Massachusetts Reliability Region — in addition to the upgrades designed to reduce or eliminate reliance on

long term, system conditions and costs change — the Municipals shared the increased fuel costs for the Canal Units, but at other times higher costs in their own areas may be spread to Cape Cod: "while different costs may be located in one part of a zone in a given instance, other costs are likely to be incurred in other areas over time." 2010 Rehearing Order at P 66, JA 876. For those reasons, the Commission agreed with ISO New England that smaller zones, in which costs would be more concentrated and therefore more prone to sharp fluctuations, may not provide the price stability over time that is fundamental to long-term contracting — which, in turn, facilitates standard offer service. Compliance Order at P 51, JA 824; *see also* 2010 Rehearing Order at P 66, JA 876. *See generally ExxonMobil Gas Mktg. Co. v. FERC*, 297 F.3d 1071, 1085 (D.C. Cir. 2002) (Commission has "wide discretion to determine where to draw administrative lines"; courts are "generally unwilling to review line-drawing performed by the Commission . . . [unless] lines drawn are patently unreasonable, having no relationship to the underlying regulatory problem") (internal quotation marks and citations omitted).

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the Canal Units in contingencies (*see supra* p. 12) — that affected that zone. ISO Compliance Report at 29, JA 634. ISO New England further explained that "[v]ery local reliability needs that may emerge from time to time because of transmission or transmission outages, or due to construction, may be better suited to a broader sharing of costs." *Id.* at 30, JA 635.

Fostering such stability over time is key to the difference between regionalizing some costs, such as reliability operations and planning, and concentrating other costs in smaller areas. For example, the Commission permits market designs that use locational marginal pricing and financial transmission rights "to address short-term congestion and related costs on the system, whereas the regional structure is intended to provide a stable platform for allocating long-term reliability costs." Compliance Order at P 53, JA 825; *cf. Blumenthal*, 552 F.3d at 883, 885 (in rejecting a challenge to ISO New England's adoption of locational marginal pricing, Court emphasized the signaling function of price fluctuations to encourage development of supplies in constrained areas), *cited in* 2010 Rehearing Order at P 46 n.67, JA 871. Indeed, the Commission has repeatedly upheld zonal allocation of reliability costs, including out-of-merit uplift charges, to reliability regions. *See New England Power Pool*, 100 FERC ¶ 61,287 at P 61 (2002); *ISO New England Inc.*, 91 FERC ¶ 61,311, at 62,067 (2000); *see also* 2010 Rehearing Order at P 46 n.67 (citing earlier New England orders), JA 871. For that reason, the Commission concluded that ISO New England's use of a smaller area in lower Southeastern Massachusetts for the distinct purposes of addressing capacity pricing and congestion does not support Municipals' request to split the larger reliability region in order to reallocate uplift charges. Compliance Order at P 53, JA 825.

3. Regional Allocation Of Reliability Costs Is Reasonable Because All Users Benefit From Reliable Network Operations

That distinction in the purposes of regionalizing some costs (such as reliability operations) and localizing others (such as capacity) underlies the Commission's application of cost causation principles in this case. From the first order, the Commission heeded the principle that "[c]osts should be allocated to customers in a manner than reflects the costs of providing service to them; . . . cost causation principles compare the costs assessed to the benefits drawn or the burdens imposed." Complaint Order at P 27, JA 499. But this Court has "never required a ratemaking agency to allocate costs with exacting precision." *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1369 (D.C. Cir. 2004) (citing *Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002)); *accord Pub. Serv. Comm'n of Wis. v. FERC*, 545 F.3d 1058, 1067 (D.C. Cir. 2008). Of course, the benefits must be real — not "insubstantial, limited or purely speculative" (Complaint Order at P 27 & n.12 (citing FERC precedents), JA 499) — but "costs can be allocated on a zonal basis even if not all entities within that zone receive the same level of benefits." *Id.* at P 27 & n.13, JA 499.

Indeed, a key tenet of the Commission's cost allocation methodology is that all users of an integrated power grid benefit from the operation of and improvements to that network, in different ways and to different degrees:

> The principal reason behind adoption of this methodology is that an integrated system is designed to achieve maximum efficiency and reliability at a minimum cost on a systemwide basis. Implicit in this theory is the assumption that all customers . . . receive the benefits that are inherent in such an integrated system.

Cal. Dep't of Water Res. v. FERC, 489 F.3d 1029, 1038 (9th Cir. 2007) (FERC precedent "strongly favors" rolled-in allocation), *quoted in* 2010 Rehearing Order at P 44 n.60, JA 869-70.

This Court has consistently upheld the Commission's broad view of benefits. For example, system enhancements, such as network upgrades on an integrated transmission grid, are presumed to benefit the entire system, and thus are rolled into network costs. *W. Mass. Elec. Co. v. FERC*, 165 F.3d 922, 927 (D.C. Cir. 1999) (affirming FERC's approval of socialization of grid upgrades associated with interconnections). (In the instant case, the Commission noted that the Settlement provided that costs of the reliability transmission upgrades on Cape Cod were eligible to be allocated to the entire ISO New England footprint. *See* 2010 Rehearing Order at P 48 n.68, JA 871.)

Similarly, this Court has affirmed the rolled-in allocation of the administrative costs of operating a regional network. *Midwest ISO Transmission Owners*, 373 F.3d at 1368-71. In that case, the Commission had approved a cost adder in the ISO's tariff that was designed to cover administrative costs. Transmission owners argued that certain kinds of loads would benefit little from those costs and should not be charged the adder. *Id.* at 1369-70. The Court, however, concluded that the adder recovered "the administrative costs of *having* an ISO," which benefits users "even if they are not in some sense *using* the ISO." *Id.* at 1371. The Commission found that conclusion particularly relevant to the instant case, in that the Court "affirmed [the Commission's] finding that all transmission customers benefitted from the independent system operator's operational and planning responsibilities, as well as from increased grid reliability of the transmission system, and affirmed cost allocations on that basis." 2010 Rehearing Order at P 41 (citing 373 F.3d at 1369), JA 868; *cf.* 373 F.3d at 1369-70 (noting that "all transmission customers . . . benefit from the enhanced reliability and security [the ISO] brings to the transmission grid").

Furthermore, this Court recognized that cost sharing could be just and reasonable notwithstanding the varying degrees of benefits to particular customers. 373 F.3d at 1368 ("[A]ll approved rates reflect *to some degree* the costs actually caused by the customer who must pay them.") (internal quotation marks and citation omitted) (emphasis added); *accord Pub. Serv. Comm'n of Wis.*, 545 F.3d at 1067 (upholding application of principle to system-wide cost allocation of transmission upgrades).

The Seventh Circuit's decision in *Illinois Commerce Commission v. FERC*, 576 F.3d 470 (7th Cir. 2009), is not to the contrary, as the Municipals contend

(Br. 47). That case turned, not on a divergence from this Circuit's precedents concerning "some degree" of relation between costs and benefits, but on that court's doubt as to the benefits. That court concluded that, although midwestern utilities in a multistate network derive "*some* benefit" from construction of large transmission lines to relieve import constraints in another portion of that network, the Commission had not explained why such benefits were not "trivial." 576 F.3d at 476-77. *But see id.* at 480 (Cudahy, J., dissenting) ("Since there is a *presumption* that enhanced reliability benefits all of the system's members, [petitioner] can be required to bear a proportional share of an improvement's costs even where it is not possible to determine precisely how much it benefits.") (citing, among other cases, *Midwest ISO Transmission Owners*).

Here, the Commission has explained the zone-wide benefits of reliability operations and planning. The Commission appropriately concluded that "local reliability planning and operations . . . serve, over time, to benefit all customers in the region with stable pricing and reliable service." Compliance Order at P 54, JA 825. The Commission "do[es] not find these critical reliability benefits to be trivial." 2010 Rehearing Order at P 42, JA 868. Because, by contrast, *Illinois Commerce Commission* "did not concern costs associated with generation facilities needed to reliably meet the demands of the local zone," the Commission reasonably concluded that the Seventh Circuit's decision was not cause to "revisit [the Commission's] long-standing precedent for pricing zonal facilities operated by a utility to serve its customer load." *Id.* at P 42, JA 869; *see also id.* at P 40 (contrasting "local reliability planning and operations" with "large scale transmission upgrades"), JA 867; Compliance Order at P 54 (same), JA 825. Thus, "the Municipals were appropriately allocated a share of the Canal Unit costs, which were incurred to provide for long-term reliability and meet the requirements of the [applicable electrical] reliability standards. . . . [The Municipals] benefit from service from the Canal Units, consistent with those criteria." 2010 Rehearing Order at P 41, JA 867-68; *see also id.* at P 73 (operating Canal Units to meet reliability standards in the interim "was a pragmatic practice until new facilities could be constructed to ensure reliable electric service in [Southeastern Massachusetts]"), JA 878; *id.* at P 38 (same), JA 867.

B. The Commission Appropriately Considered The Stakeholder Process As A Supplement To Its Own Deliberation

The Municipals argue that the Commission "unreasonably deferred" to the stakeholder process. Br. 52. The Commission, having extensive experience with entities, such as power pools and regional transmission organizations, that routinely conduct stakeholder proceedings (involving system operators, transmission owners, power suppliers, load-serving entities, and end users), values such processes "as an independent forum to consider the issues" that come before the Commission. 2009 Rehearing Order at P 55, JA 602. *See, e.g., Pub. Serv.*

Comm'n of Wis., 545 F.3d at 1062-63 (Commission often gives weight to proposals resulting from stakeholder processes). Nevertheless, the Commission views stakeholder input as "supplement[ing]" — not displacing — its own deliberations. 2009 Rehearing Order at P 55, JA 602; *see also* 545 F.3d at 1064 (Commission "make[s] its own, independent assessment" of policy). The Commission's extensive discussion, in both the Compliance Order and the 2010 Rehearing Order, of the reasons to deny a retroactive, temporary change to the Southeastern Massachusetts region — including the Commission's clarification of its forward-looking concerns about the market effects of retroactive reallocation and its explanation of the policy rationale and precedential support for zonal allocation of reliability costs (*supra*) — belies any suggestion that the Commission rubber-stamped the stakeholders' decision.

Nor was the Commission's decision to seek input from New England stakeholders improper or prejudicial. The Settlement itself contemplated just such a process: the Municipals specifically reserved the right to seek a change before the New England Power Pool Participants Committee during the moratorium period. Sett. § 7.2, JA 225, *quoted at supra* p. 11. "Since the . . . Settlement itself anticipated Municipals' use of the [stakeholder] process to pursue [their] claims," the Commission determined that other Settlement provisions limiting the other parties' positions in that process "[did] not compromise the stakeholder process,

[but] . . . merely suggest[ed] that those parties" — having bargained for the moratorium — "would be unlikely to support the disputed changes in the stakeholder process." 2009 Rehearing Order at P 53, JA 602. In any event, such a settlement moratorium was not "particular to this proceeding" and did not warrant a departure from the Commission's longstanding "practice of relying on stakeholder input when appropriate." *Id.* at P 54, JA 602. *See Jepsen v. FERC*, No. 10-1104, slip op. at 2 (D.C. Cir. Apr. 26, 2011) (unpublished) (affirming Commission's approval of ISO New England's expenditures, based in part on support from ISO's stakeholders and independent Board of Directors).

More important, the Commission made clear, in advance of the stakeholder process, that it construed the Settlement to allow full participation in that stakeholder process. 2009 Rehearing Order at P 54 ("[T]he Settlement does not prohibit a party from providing a reasoned analysis of the benefits and costs of a proposed rate structure, nor does it prohibit others from considering the issues and providing input."), JA 602; *see also id.* at P 51 (Commission "does not generally interpret a rate moratorium to prevent any person from considering, or discussing or even taking a position outside a Commission proceeding" on prospective rate changes), JA 601. Indeed, while provisions of the Settlement barred the parties from supporting reclassification or reallocation of the Canal Unit charges before the Commission or in any other forum, nothing in the Settlement limited any party's position on changing the boundaries of the reliability region. *See* 2009 Rehearing Order at P 52 (citing Sett. § 9.2, JA 228), JA 601. In particular, the Commission noted that, while Section 7.1(c) provided that the other parties could either oppose or remain silent as to the Municipals' claim regarding alternative arrangements, there was no corresponding constraint (in Section 7.2 or elsewhere) on any party's position if the Municipals sought a change in regional boundaries. *Id.* n.55, JA 601; *see also* Sett. § 7, JA 224-25, *quoted supra* at p. 11.

C. The Commission Properly Denied The Municipals' Request To Reallocate Charges Without Altering The Reliability Region

Having lost their challenge to the actual boundaries of the Southeastern Massachusetts Reliability Region, the Municipals urged the Commission to reallocate the Canal out-of-merit costs as though the region had been bifurcated for the locked-in period. Again, however, as with their reclassification argument, the Municipals' claim for reallocation went beyond the scope of the issues they had reserved in the Settlement, and the Commission appropriately adhered to the language of that agreement. *Cf. supra* Part II.B (finding reclassification claim precluded by Settlement). Section 7.2 permitted the Municipals "to seek a change (in [the New England Power Pool Participants Committee] or before the Commission) in the [ISO New England] definition of the [Southeastern Massachusetts] reliability region . . . ." Sett. § 7.2, JA 225, *quoted at supra* pp. 11-12; 2010 Rehearing Order at P 20, JA 859. The Municipals sought such a change;

accordingly, the Commission reviewed "whether the Commission should direct a change in the definition of the . . . region that would cause a change in the allocation of Canal Unit charges, in the [Complaint Order]." 2010 Rehearing Order at P 20, JA 859-60.

The Commission found, preliminarily, that the existing regional boundary, originally selected based on engineering considerations, may no longer result in the just and reasonable allocation of costs and directed the stakeholder process to address whether region should be divided, and if so, how. Complaint Order at P 29, JA 500. The Commission directed ISO New England to submit a compliance filing one year later "to address whether a change in the . . . definition of the . . . reliability region was needed." 2010 Rehearing Order at P 20, JA 859-60. Following the conclusion of the stakeholder process — in which neither the Municipals nor any other party advocated changing the boundaries going forward — the Commission considered the merits of altering those boundaries retroactively and concluded that the existing boundaries were satisfactory. That process was all that the Municipals reserved under the Settlement.

Furthermore, once the Municipals' effort to redefine the regional boundaries failed, the Settlement foreclosed any other claim for reallocation. Turning again to the language of the Settlement, the Commission properly concluded that "neither Section 7.1 nor Section 7.2 contains language to permit reallocation of Canal

LSCPR costs because the [Southeastern Massachusetts Reliability Region] 'should have been changed,'" absent an *actual* change in the definition of that region. 2010 Rehearing Order at P 21, JA 860. *See also* Compliance Order at P 48 (Settlement moratorium "time-bars certain proposals . . . that are beyond the issue of how [Southeastern Massachusetts]'s boundary could be reconfigured"), JA 824; 2010 Rehearing Order at P 39 (same), JA 867; Compliance Order at P 52 ("the . . . Settlement bars the Municipals from seeking reallocation of the Canal Unit LSCPR charges through the stakeholder process other than through a change in the [Southeastern Massachusetts] boundary"), JA 825; *see also* 2010 Rehearing Order at P 70 (same), JA 877.

In sum, the Commission reasonably construed the Settlement as having "barred reallocation except: (1) based on the argument . . . [for] a switching arrangement . . . and (2) through a change in the . . . definition of the [Southeastern Massachusetts] reliability region." 2010 Rehearing Order at P 34, JA 865. Having failed to obtain additional rate relief — beyond the $3.77 million in Settlement reimbursements for Canal out-of-merit reliability operation (*see supra* p. 8) — under either of those defined exceptions, the Municipals cannot claim further, extra-Settlement relief. *See Transcont'l Gas Pipe Line*, 922 F.2d at 869 (Court "affords a high degree of deference to the Commission's interpretation of a settlement agreement").

CONCLUSION

For the reasons stated, the petitions for review should be denied and the challenged FERC Orders should be affirmed in all respects.

Respectfully submitted,

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April 29, 2011
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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 Respondents contains 11,276 words, not including the tables of contents and authorities, the glossary, the certificates of counsel, and the addendum.

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June 30, 2011

ADDENDUM

Statutes and Other Materials

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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) of this section 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 reports, information, and documents required under sections 77g, 78*l*, 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.)

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 provided 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.

(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.)

AMENDMENTS

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).

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 anticompetitive 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) of this section, 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) of this section 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

[1] See References in Text note below.

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.)

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, as amended, 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).

Effective Date of 1988 Amendment

Section 4 of Pub. L. 100–473 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

Section 3 of Pub. L. 100–473 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 costs to be paid by other electric utility companies of such registered holding company. For purposes of this section, 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 [15 U.S.C. 79 et seq.]."

Study

Section 5 of Pub. L. 100–473 directed that, no earlier than three years and no later than four years after Oct. 6, 1988, Federal Energy Regulatory Commission perform a study of effect of amendments to this section, analyzing (1) impact, if any, of such amendments on cost of capital paid by public utilities, (2) any change in average time taken to resolve proceedings under this section, and (3) such other matters as Commission may deem appropriate in public interest, with study to be sent to Committee on Energy and Natural Resources of Senate and Committee on Energy and Commerce of House of Representatives.

§ 824f. Ordering furnishing of adequate service

Whenever the Commission, upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing, shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation: *Provided*, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel the public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.

(June 10, 1920, ch. 285, pt. II, §207, as added Aug. 26, 1935, ch. 687, title II, §213, 49 Stat. 853.)

§ 824g. Ascertainment of cost of property and depreciation

(a) Investigation of property costs

The Commission may investigate and ascertain the actual legitimate cost of the property of every public utility, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation, and the fair value of such property.

(b) Request for inventory and cost statements

Every public utility upon request shall file with the Commission on inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.

(June 10, 1920, ch. 285, pt. II, §208, as added Aug. 26, 1935, ch. 687, title II, §213, 49 Stat. 853.)

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.

§ 825*l*. 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 application 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) of this section, 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) of this section 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.)

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''.

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 contract" as used herein is a contract between an LSE and a person who is not a Party to this Settlement.

3.8 Subject to Section 9.3, the final responsibility among the Parties for 2006 SEMA NCPC Charges for LSCPR shall be in accordance with Sections 3.1 through 3.7 of this Settlement Agreement, and no Party shall have the right to seek any other recovery or allocation of 2006 SEMA NCPC Charges for LSCPR. This Section 3.8 does not affect the distribution of litigation proceeds as established pursuant to Section 10.7.

Section 4 – Allocation of Post 2006 NCPC Charges for LSCPR:

4.1 Subject to Sections 4.2(a), 5.1, 5.2, 5.4 and 7, during the Moratorium Period, all NCPC Charges for LSCPR for all reliability regions and for both the Day-Ahead and Real-Time Markets, including the SEMA NCPC Charges for LSCPR, shall be allocated (i) on the same basis that NCPC Charges for LSCPR are allocated pursuant to the allocation mechanisms in Section III of the ISO-NE Tariff in effect on the date of this Settlement, and (ii) on the basis of those provisions as amended pursuant to Section 5 of this Settlement, if and as of the date those amended provisions become effective. Subject to the exceptions in the preceding sentence, no Party shall seek or support a different allocation mechanism prior to the end of the Moratorium Period, or seek or support reclassification of ISO-NE's designation of Canal as an LSCPR for service during the Moratorium Period.

4.2 (a) Section 4.1 shall not prevent the submission or support of proposed Market Rule amendments, in addition to those contemplated by Section 5, affecting NCPC Charges for LSCPR that (1) do not increase the allocation of NCPC Charges for then meet promptly with the appropriate NEPOOL stakeholder committee and with state representatives to discuss the above issues, including any appropriate potential remedial actions.

(b) The two Reporting Criteria, both of which must be satisfied in a month to trigger the obligations in the prior paragraph, are as follows:

(i) The total Real-Time NCPC Charges for LSCPR in a Reliability Region (expressed in $/MWh) for the month exceed 4% of the Load Weighted Real-Time LMP in that Reliability Region (also expressed in $/MWh) for the month; and

(ii) The total Real-Time NCPC Charges for LSCPR in a Reliability Region (in $/MWh) for the month, expressed as a percent of the Load Weighted Real-Time LMP (also in $/MWh) in the Reliability Region for the month, exceed 150% of the average total Real-Time NCPC Charges for LSCPR in that Reliability Region (in $/MWh) for the immediate prior twelve months (again expressed as a percent of the Load Weighted Real-Time LMP (also expressed in $/MWh)).

6.3 Increases in Other Charges: Within 60 days of approval of this Settlement, ISO-NE shall inform the ISO-NE stakeholders of a process for reporting significant out-of-merit charges other than Real-Time NCPC Charges for LSCPR. Under such process, the incurrence of such charges will trigger reasonable and appropriate reporting obligations comparable to the obligations imposed on ISO-NE in Section 6.2(a) above.

Section 7 – Municipals Reserved Litigation Rights:

7.1 (a) Nothing in this Settlement is intended to prevent one or more of the Municipals, as of January 2, 2008, from seeking relief from SEMA NCPC Charges for LSCPR through litigation against ISO-NE or the Transmission Owners over whether consistent with Applicable Criteria as defined in Section 6.1(b) such charges could be or should be reduced through implementation of an SPS or Post-First Contingency Switching arrangement. However, any financial relief from such excess charges shall be limited to the difference between the SEMA NCPC Charges for LSCPR imposed on the Municipals and the charges that would have been imposed if an SPS or Post-First Contingency Switching arrangement had been implemented. Such relief shall be prospective from the date of filing of a proceeding seeking such relief (which date shall not be prior to January 2, 2008), except that the Municipals are entitled to seek relief for the three-month period prior to the date of initiating such proceeding.

(b) This Section 7.1 does not create any rights that would not exist in the absence of the Settlement.

(c) Each Party retains all rights to respond in opposition or to remain silent, as it sees fit, to any such actions taken or proceedings initiated by one or more Municipals under this Section 7.1.

7.2 The Parties, other than the Municipals, agree not to seek a change (in NEPOOL or before the Commission) in the ISO-NE definition of the SEMA Reliability Region to become effective prior to June 1, 2010; provided that the Municipals may seek such a change to become effective no earlier than January 1, 2008.

<u>Section 8 – Further Adjustments</u>:

(a) The LSEs, including but not limited to those that are suppliers of National Grid and/or NSTAR under Basic Service Contracts, will not seek any reimbursements or payments, in addition to those provided in this Settlement, from National Grid or NSTAR of any kind with respect to Canal Out-of-Merit Charges, including but not limited to

SEMA NCPC Charges for LSCPR, for the period January 2006 through May 2010 in any forum; provided that this sentence shall not be construed as reducing or modifying any obligations that NSTAR or National Grid otherwise have for passthrough of Canal Out-of-Merit Charges under Basic Service Contracts with the LSEs.

(b) NSTAR and National Grid will not seek any payments from the Municipals or LSEs with respect to 2006 SEMA NCPC Charges for LSCPR of any kind in any forum in addition to the payments provided for by this Settlement; provided that this sentence shall not be construed as reducing or modifying any obligations that the Municipals and LSEs otherwise have under bilateral contracts with NSTAR and National Grid.

(c) No Party shall propose, or argue, either to the Commission or within the ISO-NE or NEPOOL process, or vote within either process, for Market Rule amendments that would provide for a different mechanism for allocation of NCPC Charges for LSCPR, or shall seek or support reclassification of ISO-NE's designation of Canal as a LSCPR during the Moratorium Period other than as provided in Sections 4, 5, or 7 of this Settlement. Except for amendments authorized by Section 4.2(a), the Parties shall oppose any Market Rule amendments that would provide for a different mechanism for allocation of NCPC Charges for LSCPR than provided in Section 4.1 and Sections 5.1 and 5.2 or re-classification of ISO-NE's designation of Canal as a LSCPR during the Moratorium Period proposed by persons who are not Parties to the Settlement.

(d) Except (i) as limited by Section 7.1 as to the Municipals, (ii) as to the Transmission Owners' satisfaction of their obligations to the LSEs and Municipals under reflected in initial settlement invoices expired prior to the date of execution of the Settlement Agreement; and (v) any RBAs for 2006 SEMA NCPC Charges for LSCPR that might be submitted based on resettlement invoices would be limited to the amount of any change between the initial settlement invoice and the resettlement invoice.

9.2 It is the intent of the Parties that this Settlement Agreement resolve all issues relating to the classification of Canal as LSCPR during its operation Out-of-Merit and to the allocation of NCPC Charges for LSCPR during the period from January 1, 2006 through May 31, 2010. The Parties further intend that any Non-Participating LSE that does not submit a timely RBA for 2006 SEMA NCPC Charges for LSCPR or does not participate in Settlement negotiations in the Proceeding is: (a) ineligible to participate in the $20.5 million reimbursements to LSEs set forth in Section 3 of this Settlement; and (b) should be precluded from disputing SEMA NCPC Charges for LSCPR through May 31, 2010. Subject to the exceptions in the last sentence of this Section 9.2, all Parties agree to support those positions before the Commission and in any other forum in which the issue may arise, and shall oppose any attempt by the Commission or any non-Party to change the allocation of NCPC Charges for LSCPR as provided for in this Settlement during such period. This provision does not limit the rights established by Sections 4.2, 5.4 and 7 of this Settlement.

9.3 In the event that, despite Section 9.2 above, the Commission ultimately finds that one or more Non-Participating LSEs is entitled to share in the $20.5 million reimbursement to be provided under this Settlement, the following shall occur:

III.6 Local Second Contingency Protection Resources

III.6.1 Definition.

"Local Second Contingency Protection Resources" are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

III.6.2 Day-Ahead and Real-Time Energy Market.

When establishing operating schedules, the ISO will select and identify Local Second Contingency Protection Resources on a not unduly discriminatory basis in accordance with the procedures defined in the ISO New England Manuals. Appendix A will determine which, if any, Supply Offers will be adjusted. The ISO will also record, in an auditable log, the reason the Resource was selected.

III.6.2.1 Special Constraint Resources.

When establishing operating schedules, at the request of a Transmission Owner or distribution company in order to maintain area reliability, the ISO will commit and dispatch generating Resources to provide relief for constraints not reflected in the ISO's systems for operating the New England Transmission System or the ISO's operating procedures in accordance with the procedures defined in the ISO New England Manuals. The ISO will also record, in an auditable log, the designation of such generating Resource as a Special Constraint Resource and the name of the requesting Transmission Owner or distribution company. Any NCPC Charge associated with the Real-Time operation of the Special Constraint Resource is charged in accordance with the provisions of Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

III.6.3 [Reserved.]

III.6.4 Local Second Contingency Protection Resource NCPC Charges.

III.6.4.1 [Reserved.]

III.6.4.2 [Reserved.]

III.6.4.3 Calculation of Local Second Contingency Protection Resource NCPC Payments.

Day-Ahead and Real-Time NCPC Credits for Local Second Contingency Protection Resources are determined in accordance with the provisions of paragraphs (a), (b), (c) and (e) in Section III.3.2.3, as applied to Pool-Scheduled Resources, but such credits shall not be included in NCPC Charges pursuant to Section III.3.2.3 and shall instead be allocated and charged in accordance with Section III.6.4.4. The Day-Ahead and Real-Time NCPC Credits for Local Second Contingency Protection Resources are subject to market power review and mitigation.

III.6.4.4 Calculation of Local Second Contingency Protection Resource NCPC Charges.

(a) The Day-Ahead NCPC Credits calculated in accordance with Section III.6.4.3 for Local Second Contingency Protection Resources are aggregated into an NCPC Charge and charged pro rata to each Market Participant in proportion to the sum of its Day-Ahead Load Obligations in MWhs for that Operating Day for Locations within the affected Reliability Region.

(b) The Real-Time NCPC Credits calculated in accordance with Section III.6.4.3 for Local Second Contingency Protection Resources are aggregated into an NCPC Charge and charged to each Market Participant in proportion to the sum of its Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resource (pumps only) operation that is above its Minimum Consumption Limit) in MWhs during the Operating Day within the affected Reliability Region. For hours for which a Local Second Contingency Protection Resource NCPC Charge is calculated and an Emergency energy sale is being made by the ISO, the amount (MWh) of Emergency energy sales will be included in the above calculation, with a proportional share attributable to the Emergency energy sale being added to the purchasing Control Area’s cost for Emergency energy.

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CERTIFICATE OF SERVICE

In accordance with Fed. R. App. P. 25(d) and the Court's Administrative Order Regarding Electronic Case Filing, I hereby certify that I have, this 30th day of June 2011, served the foregoing upon the counsel listed in the Service Preference Report via email through the Court's CM/ECF system, as indicated below:

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