UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket Nos. ER13-193-000 and**
Participating Transmission Owners	**)**	**ER13-196-000**
Administrative Committee	**)**	

NOTICE OF INTERVENTION AND PROTEST OF THE SOUTHERN NEW ENGLAND STATES

December 10, 2012

TABLE OF CONTENTS

Page No.

I. INTRODUCTION 1

II. DESCRIPTION OF PARTIES 3

A. The Mass DPU 4

B. The Rhode Island PUC 7

C. The CT PURA 7

III. COMMUNICATIONS 8

IV. NOTICE OF INTERVENTION 9

V. THE *MOBILE-SIERRA* DOCTRINE DOES NOT PROTECT THE FILING PARTIES FROM COMPLYING WITH THE ORDER NO. 1000 REQUIREMENT TO ELIMINATE CERTAIN FEDERAL RIGHTS OF FIRST REFUSAL FROM JURISDICTIONAL TARIFFS AND AGREEMENTS. 9

A. The Federal Right of First Refusal in the TOA Is Not Protected by the *Mobile-Sierra* Doctrine. 11

1. The Commission Is Not Required To Presume That the Federal Right of First Refusal in the TOA Is Just and Reasonable. 11

2. The Commission's 2004 Order Granting *Mobile-Sierra* Treatment of Section 3.09 of the TOA Does Not Require a Public Interest Finding Any Different from that which the Commission Has Already Made in Order No. 1000 To Justify Elimination of the Federal Right of First Refusal in the TOA. 14

B. Even if the *Mobile-Sierra* Doctrine Applied in this Case, the Applicable Public-Interest Standard of Review Affords the Commission an Adequate Basis to Require Compliance with Order No. 1000. 17

VI. THE FILING PARTIES' ROFR IS UNJUST AND UNREASONABLE AND SHOULD BE ELIMINATED. 22

A. The Commission Found Federal ROFRs Unjust and Reasonable. 23

1. A ROFR Restricts the Universe of Transmission Developers Offering Potential Solutions for Consideration in the Regional Transmission Planning Process and Creates Opportunities for Undue Discrimination and Preferential Treatment Against Non-Incumbent Transmission Developers. 24

2. A ROFR May Result in the Failure To Consider More Efficient or Cost-Effective Solutions to Regional Needs and, in Turn, the Inclusion of Higher-Cost Solutions in the Regional Transmission Plan. 25

3. It Is Not in the Economic Self-Interest of Incumbent Transmission Providers To Permit New Entrants To Develop Transmission Facilities, Even if Proposals Submitted by New Entrants Would Result in a More Efficient or Cost-Effective Solution to the Region's Needs. 27

4. Elimination of the ROFR in New England Will Increase Potential Competition Among Project Sponsors........ 29

5. Competition Is Already Limited by the Exclusions to the Commission's No-ROFR Requirement. 30

B. Contrary to the Filing Parties' Argument, Retaining the ROFR in the Existing New England Planning Process Does Not Satisfy the "Consistent with or Superior To" Standard Set Forth by the Commission for Changes to the OATT. 32

1. The Filing Parties' Claim That the Existing Transmission Planning Process Has Been Highly Successful Fails To Consider the Cost to Consumers........ 34

2. Contrary To the Filing Parties' Claim, the Existing Process Does Not Ensure That All Potential Solutions Will Be Openly Considered. 36

3. The Filing Parties' Claim That No Other Superior Potential Solutions Have Been Identified in the Existing Planning Process is a Self-Fulfilling Prophecy........ 38

4. The Filing Parties' Claim That Disrupting the Existing Process Would Mean the Loss of Incumbent Transmission Provider Expertise in Reviewing Alternatives and the Incurrence of Additional RTO Costs is Unsubstantiated. 39

5. The Filing Parties' Claim That the Current Process Reduces Costs, the Probability of Disputes, and Resulting Delay, is Misplaced........ 40

6. The Filing Parties' Claim That Competition Occurs under the Current Process is Simply Incorrect. 41

7. The Filing Parties' Claim That Non-Incumbents Will Be Disadvantaged in the Siting Process is Unsupported and, In Any Event, Does Not Justify Precluding Non-Incumbents from Competing. 42

8. The Filing Parties' Claims That Competition Will Not Reduce the Cost of Transmission Are Not Credible and Are Unsupported. 43

C. The Filing Parties' Primary and Contingent Compliance Filings Are Unsupported by the Vast Majority of Stakeholders and Should Be Rejected. 45

D. The Commission Should Reject The Filing Parties' Contingent Compliance Filing. 45

1. The Contingent Compliance Filing Is Not Compliant with Order Nos. 1000 and 1000-A and Should Be Rejected. 45

2. The ROFR Provisions of the Contingent Compliance Filing Are Unjust and Unreasonable. 47

a. The Contingent Compliance Filing retains the barriers to entry that the Commission explicitly ordered eliminated in Order No. 1000. 48

b. Implementation of a five-year ROFR will stifle competition and keep the lion's share of projects for the incumbent transmission providers. 51

3. If the Commission Permits the Retention of a Federal ROFR in the Contingent Compliance Filing, the Commission Should Approve the NEPOOL Alternative Proposal. 52

VII. THE FILING PARTIES' PUBLIC POLICY PROJECT PROPOSAL IS PART OF AN UNJUST AND UNREASONABLE COMPLIANCE FILING THAT IS NOT COMPLIANT WITH ORDER NO. 1000; THE NEPOOL ALTERNATIVE PROPOSAL IS A BALANCED PROPOSAL REFLECTING STAKEHOLDER CONSENSUS ON THE APPROPRIATE MEASURES TO ADDRESS PUBLIC POLICY PROJECTS IN REGIONAL AND LOCAL TRANSMISSION PLANNING AND COST ALLOCATION PROVISIONS. 54

A. The Compliance Filing Including the Filing Parties' Public Policy Project Proposal Should Be Rejected. 54

B. The NEPOOL Alternative Proposal Is a Balanced Mechanism That Will Achieve the States' Public Policy Goals and Meet the Needs of All Stakeholders. 54

C. The Central Role of the States in the Identification and Selection of Public Policy Projects and in the Determination of Costs Is Essential to the Success of the Public Policy Planning Process. 58

D. Reasonable and Effective Cost-Containment Tools Are Essential. 60

1. Documentation of Supporting Costs Is an Important Element of the NEPOOL Alternative Proposal. 64

2. The NEPOOL Alternative Proposal Provides States with Greater Ability to Contain Costs. 65

3. Only the NEPOOL Alternative Proposal Provides States the Ability to Negotiate Final Pricing with Project Sponsors. 66

4. The NEPOOL Alternative Proposal Eliminates Unnecessary Returns on Cancelled Investment. 66

E. The NEPOOL Alternative Proposed Cost Allocation Method for Transmission Projects Driven by Public Policy Requirements Is Consistent with Order No. 1000 and Should Be Approved. 66

1. NEPOOL's Proposal To Allocate Pre-Construction Project Development Costs Is Reasonable and Consistent with the Order No. 1000 Regional Cost Allocation Principles. 67

2. The NEPOOL Alternative Proposal Appropriately Ensures that the Default Load Ratio Share Method of Allocating Public Policy-Driven Transmission Project Costs Is Not the Primary Method of Cost Allocation. 72

3. The NEPOOL Alternative Proposal Appropriately Gives Consumer-Owned Utilities the Right to Opt-out of Cost Responsibility for Upgrades Inapplicable to Them. 74

VIII. CONCLUSION 74

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and Participating Transmission Owners Administrative Committee	)))	**Docket Nos. ER13-193-000 and ER13-196-000**

NOTICE OF INTERVENTION AND PROTEST OF THE SOUTHERN NEW ENGLAND STATES

Pursuant to Rules 211 and 214(a)(2) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. §§ 385.211 and .214(a)(2), and the Commission's Notice of Compliance Filings, issued November 1, 2012, the Department of Public Utilities of the Commonwealth of Massachusetts ("Mass DPU"), the Rhode Island Public Utilities Commission ("Rhode Island PUC") and the Connecticut Public Utilities Regulatory Authority ("CT PURA") (collectively, the "Southern New England States") hereby jointly and severally file their Notices of Intervention and Protest in the above-captioned proceeding, concerning the "Order No. 1000 Compliance Filing of ISO New England Inc. and the Participating Transmission Owners Administrative Committee," filed on October 25, 2012 ("Compliance Filing").[1]

I. INTRODUCTION

The Southern New England States' protest is focused on two overriding issues: (1) the unjustness and unreasonableness of the proposed retention by the Participating Transmission Owners ("PTOs") of the right of first refusal ("ROFR") contained in the Transmission Operating

---

[1] *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49,841 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011) ("Order No. 1000"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), 77 Fed. Reg. 32,183 (May 31, 2012) ("Order No. 1000-A"), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

Agreement ("TOA"); and (2) the need for the Commission to reject the public policy proposal of the PTOs and ISO New England, Inc. ("ISO-NE") (collectively, the "Filing Parties") as part a Compliance Filing that is unjust, unreasonable and non-compliant with Order No. 1000. The Southern New England States urge the Commission instead to accept the alternative proposal submitted in the "Comments of the New England Power Pool Participants Committee," filed in these dockets on November 16, 2012 ("NEPOOL Comments") ("NEPOOL Alternative Proposal"), as part of a broad-reaching compromise among diverse stakeholders. The Filing Parties' proposed retention of the ROFR is inherently anticompetitive, inconsistent with explicit findings and direction in Order No. 1000 supporting the elimination of ROFRs, and, contrary to their arguments, not subject to *Mobile-Sierra* protection. The *Mobile-Sierra* doctrine poses no bar to the elimination of the PTOs' ROFR.

The Filing Parties' Public Policy Project Proposal[2] contains a number of elements that were important to the states, giving the states a major role in the planning and selection process, and the Southern New England States appreciate the Filing Parties' incorporation of these elements. Nonetheless, other elements of the Filing Parties' Public Policy Project Proposal are not just and reasonable and, most importantly, it is part of an integrated compliance filing the Commission should reject as unjust and unreasonable and not compliant with Order No. 1000. The NEPOOL Alternative Proposal for public policy transmission planning, in contrast, is more responsive to the needs of all stakeholders, including the states, and fully compliant with Order No. 1000. The Filing Parties' Proposal, while developed through an extensive stakeholder process, only garnered the support of its proponents – the PTOs. The NEPOOL Alternative

[2] For ease of reference, the Filing Parties' new public policy transmission planning process, described at pages 49-65 of the October 25, 2012 Transmittal Letter, is hereinafter referred to as the "Public Policy Project Proposal." Letter to the Honorable Kimberly D. Bose, Secretary, from Filing Parties, ER13-193-000 and ER13-196-000, October 25, 2012.

Proposal also a product of that stakeholder process, was supported by 83 percent of the stakeholders – all but the 17 percent which comprise the PTOs.

The NEPOOL Alternative Proposal recognizes the paramount role of the states in setting public policy and in selecting (in consultation with other stakeholders) those projects which the states determine are best suited to achieve their public policy goals; includes strict provisions for cost containment of selected projects; and gives the states the ability to determine how the costs of each selected project are allocated among the states supporting that project. The six New England states have long been committed to the advancement of public policy goals, such as the attainment of aggressive goals for the development and integration of renewable resources, and already have in place processes that meet if not exceed the goals of Order No. 1000. The NEPOOL Alternative proposal best ensures consistency with the goals and processes that the New England states already have in place, and the Southern New England States urge the Commission to direct ISO-NE and the PTOs to modify their Public Policy Project Proposal to conform to the alternative submitted by NEPOOL. The Southern New England States emphasize their request that the Commission direct the Filing Parties to implement the NEPOOL proposal in total; if changes are made to the NEPOOL Alternative Proposal that upset its balance, the consensus support for that proposal may well dissolve.

II. DESCRIPTION OF PARTIES

The Southern New England States represent more than 75% of the load in New England and have implemented aggressive renewable portfolio standards accounting for more than 90% of the New England states' current renewable requirements.[3] With these common interests, the Southern New England States have joined to respond to the Compliance Filing.

[3] *See* ISO New England Inc., 2010 Regional System Plan (Oct. 28, 2010) at 27 (Table 3-4) and 129 (Table 8-18), *available at* http://www.iso-ne.com/trans/rsp/index.html.

A. The Mass DPU

The Mass DPU is the agency of the Commonwealth of Massachusetts charged with general regulatory supervision over gas and electric companies in Massachusetts and has jurisdiction to regulate rates and charges for the sale of electric energy and natural gas to consumers.[4] Therefore, the Mass DPU is a "state commission" as defined by 16 U.S.C. § 796(15) and 18 C.F.R. § 1.101(k).

Massachusetts is the largest state by population[5] and electricity demand in New England[6] and its capital city, Boston, is the largest load center in the region.[7] Massachusetts consumes 46% of the region's electricity and comprises 46% of the population.[8] Generating plants located in Massachusetts have an aggregate capacity of over 13,000 megawatts, which represents 41% of New England's capacity.[9]

Massachusetts was an early adopter of a Renewable Energy Portfolio Standard ("RPS") program. In 1997, as part of its electricity industry restructuring, Massachusetts became the first New England state and one of only a handful of states in the nation to enact an RPS statute.[10] The law obligated suppliers to obtain a percentage of electricity from qualifying renewable units for their retail customers, beginning with an obligation of 1% in 2003, which then increased by

---

4 MASS. GEN. LAWS Ch. 164 §§ 76, et seq.

5 *See* U.S. Census Bureau, *State and Country QuickFacts 2011*, available at http://quickfacts.census.gov/qfd/index.html.

6 *See* ISO New England Inc., *2012 Regional System Plan* (Nov. 2012), at 34 (Table 3-3), available at http://www.iso-ne.com/trans/rsp/index.html.

7 *Id.*

8 *See* ISO New England Inc., *Massachusetts 2011-2012 State Profile* (Dec. 2011), at 1, available at http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/ma_12-2011_profile.pdf.

9 *Id.*

10 *See* Barry G. Rabe, University of Michigan, *Race to the Top*: *The Expanding Role of U.S. State Renewable Portfolio Standards* (Jun. 2006), at 4, available at www.pewclimate.org/docUploads/RPSReportFinal.pdf.

one-half percent annually until it reached 4% in 2009.[11] Thereafter, pursuant to An Act Relative to Green Communities ("Green Communities Act" or "GCA") signed by Massachusetts Governor Deval Patrick in 2008, the annual obligation for RPS Class I increases by 1% annually.[12]

The Green Communities Act established aggressive goals for energy conservation and renewable resources. The GCA set goals of meeting at least 25% of the state's electricity needs with demand-side resources by 2020 and reducing total energy consumption by at least 10% by 2017.[13] The GCA required all electric and gas distribution companies and approved municipal aggregators (collectively, "Program Administrators") to develop three-year energy efficiency plans,[14] and required electric distribution companies to obtain up to 3% of their total annual supply from long-term contracts for renewable energy with terms of 10 to 15 years.[15] The GCA also established net metering throughout the state and allowed on-site generators to be credited for excess energy that they provide to the grid.[16]

This year, Governor Patrick signed an Act Relative to Competitively Priced Electricity in the Commonwealth ("2012 Energy Act"), which *inter alia*, increased the overall percentage of electricity supply that electric distribution companies may purchase from renewable generating facilities under long-term contracts from 3% to 7%.[17] The 2012 Energy Act did this by extending the long-term contracting provision to the GCA that requires distribution companies to solicit proposals from renewable energy developers for long-term contracts with terms of 10 to

---

[11] MASS GEN. LAWS Ch. 25A, § 11F.

[12] MASS GEN. LAWS Ch. 169, § 32 (2008).

[13] *Id.* at § 116.

[14] *Id.* at § 11.

[15] *Id.* at § 83.

[16] *Id.* at § 78.

[17] MASS. SESS. LAWS Ch. 209, §§ 1 et. seq. (2012)

20 years for up to 4% of their annual load.[18] The 2012 Energy Act also doubled distribution companies' net metering caps and labeled anaerobic digestion a qualifying technology.[19]

Massachusetts is among ten Northeastern and Mid-Atlantic states participating in the Regional Greenhouse Gas Initiative ("RGGI"), which sets a regional cap on greenhouse gas emissions and auctions emissions allowances.[20] Through this mechanism, RGGI serves to internalize the cost of carbon emissions from fossil-based generation offering into the wholesale market, which raises the price of fossil generation while generating revenues through auction proceeds for energy efficiency and renewable energy programs.

Massachusetts has considerable renewable resource potential. With regard to offshore wind power alone, Massachusetts has "by far the best and most accessible offshore wind resource potential in New England" due in part to the water depths and wind speeds off its coast.[21] Massachusetts' potential for wind generation development ranks high even when compared to other areas in the country with strong wind capacity. In 2009, the U.S. Department of Energy recognized Massachusetts as a hub of wind development, designating the Commonwealth as one of only two "Wind Technology Testing Centers" in the nation and awarding funding for a wind turbine testing facility in Boston.[22]

In short, Massachusetts is a national leader in and committed to developing a cleaner energy future.

---

[18] *Id.* at § 36.

[19] *Id.* at §§ 22-30.

[20] Additional information on RGGI is available at www.rggi.org.

[21] *See* Susan F. Tierney, Ph.D., *Strategic Options for Investment in Transmission in Support of Offshore Wind Development in Massachusetts*, *Summary Report* (Jan. 2010), at 3, available at http://masscec.com/masscec/file/Final%20Technical%20Report.pdf.

[22] *Id.* at 2.

B. The Rhode Island PUC

The Rhode Island PUC serves as a quasi-judicial tribunal charged with the power and authority to supervise, regulate and make orders governing the conduct of public utilities, with specific responsibility of ensuring just and reasonable rates charged by public utilities. RIGL 39-1-1 and RIGL 39-1-3.

Rhode Island accounts for 6% of the New England region's electricity consumption and represents 7% of its total population.[23] Similarly, generation resources located within the state account for 6%, or 1,850 MW, of the region's existing generation capacity.[24] Although it is the smallest state in the Union, Rhode Island has some of the most robust clean energy mandates in the nation, including a Renewable Energy Standard that requires 16 percent of total retail electricity sales to come from renewable sources by 2019.[25] The state is also recognized as a national leader in advancing energy efficiency initiatives[26] and is a participant in the Regional Greenhouse Gas Initiative.

C. The CT PURA

The CT PURA is the state commission charged with regulating electric companies and setting retail electricity rates for all electricity used within Connecticut. The CT PURA, like the Commission, must balance the interests of utilities providing electricity services with ratepayers who must pay a fair price – but no more – for those services. The CT PURA is authorized by the General Statutes of Connecticut (CONN. GEN. STAT.) § 16-6a to participate in proceedings

---

23 *See* ISO New England Inc., *Rhode Island 2011-12 State Profile* (Dec. 2011), at 1, available at http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/ri_12-2011_profile.pdf.

24 *Id*.

25 RIGL §39-26-4.

26 Rhode Island continues to rank among the top ten energy efficiency states as tabulated by the American Council for an Energy-Efficient Economy. Additional information is available at http://aceee.org/sector/state-policy/scorecard.

before federal agencies and courts on matters affecting utility services rendered or to be rendered in Connecticut.

III. COMMUNICATIONS

All communications concerning this filing and future filings in this proceeding should be directed to:

For the Mass DPU:

Thomas E. Bessette
Senior Counsel
Department of Public Utilities
Commonwealth of Massachusetts
One South Station, Second Floor
Boston, Massachusetts 02110
Tel: (617) 305-3629
Fax: (617) 345-9103
E-mail: Thomas.Bessette@state.ma.us

John J. Keene, Jr.
Director, Regional & Federal Affairs
Department of Public Utilities
Commonwealth of Massachusetts
One South Station, Second Floor
Boston, Massachusetts 02110
Tel: (617) 305-3624
Fax: (617) 345-9103
E-mail: John.J.Keene@state.ma.us

John Michael Adragna
Phyllis G. Kimmel
Miller, Balis & O'Neil, P.C.
1015 15th Street, N.W.
Twelfth Floor
Washington, D.C. 20005
Tel: (202) 296-2960
Fax: (202) 296-0166
E-mail: Jadragna@mbolaw.com
E-mail: Pkimmel@mbolaw.com

For the CT PURA:

Clare E. Kindall
Assistant Attorney General,
Department Head,
Energy Attorney General's Office
10 Franklin Square
New Britain, CT 06051
Phone: (860) 827-2683
Fax: (860) 827-2893
E-mail: Clare.Kindall@ct.gov

Robert Luysterborghs, Esq.
Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051
Phone: (860) 827-2742
Fax: (860) 827-2613
E-mail: Robert.luysterborghs@po.state.ct.us

For the Rhode Island PUC:

Nicholas S. Ucci
Principal Policy Analyst
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, Rhode Island 02888
Tel: (401) 780-2106
Fax: (401) 941-1691
E-mail: Nucci@puc.state.ri.us

The Southern New England States request that each of the individuals identified above be placed on the Commission's official service list in this proceeding.

IV. NOTICE OF INTERVENTION

As previously noted, the Mass DPU, the Rhode Island PUC and the CT PURA each is a "state commission" as defined by 16 U.S.C. § 796(15) and 18 C.F.R. § 1.101(k). This notice of intervention has been filed within the period established under Rule 210(b). Accordingly, the Southern New England States may intervene in this proceeding pursuant to Rule 214(a)(2).

V. THE *MOBILE-SIERRA* DOCTRINE DOES NOT PROTECT THE FILING PARTIES FROM COMPLYING WITH THE ORDER NO. 1000 REQUIREMENT TO ELIMINATE CERTAIN FEDERAL RIGHTS OF FIRST REFUSAL FROM JURISDICTIONAL TARIFFS AND AGREEMENTS.

In Order No. 1000 the Commission determined that it has authority under section 206(a) of the Federal Power Act ("FPA")[27] to require the elimination of provisions in Commission-jurisdictional tariffs and agreements that grant federal ROFRs to incumbent transmission providers with respect to the construction of transmission facilities selected in a regional transmission plan for purposes of regional cost allocation, based upon its finding that such provisions are unjust, unreasonable, unduly discriminatory or preferential, and thus unlawful.[28]

---

[27] 16 U.S.C. § 824e(a).

[28] Order No. 1000 at PP 284-86.

National Grid USA—a commenter in the rulemaking and parent of one of the Filing Parties here—objected that section 3.09 of the TOA established a federal ROFR that the Commission can modify only if it finds the provision to be contrary to the public interest under the *Mobile-Sierra* standard.[29] The Commission declined to address these arguments in Order No. 1000, concluding that it would be better to address them, including the applicable standard of review, in the proceeding on the ISO-NE compliance filing.[30] In Order No. 1000-A, the Commission clarified that it will first decide whether the agreement is protected by *Mobile-Sierra* "and, if so, whether the Commission has met the applicable standard of review such that it can require the modification of the particular provisions."[31] If the Commission determines that the agreement is not protected by *Mobile-Sierra* or that the Commission has met the applicable standard of review, then the Commission will determine whether the revisions to the jurisdictional tariff and agreements comply with Order No. 1000.[32]

The Filing Parties have now raised these issues in their Compliance Filing. They argue that section 3.09 of the TOA is protected by *Mobile-Sierra*, and thus the Commission cannot order the Filing Parties to eliminate the federal ROFR in that section of the TOA absent a finding that it is contrary to the public interest. They maintain that such a finding can be made only in extraordinary circumstances not present here.

As shown below, the Filing Parties are wrong on both counts. The *Mobile-Sierra* doctrine does not apply in this case; but even if it did apply, the Commission has an ample basis

---

29 *See* Order No. 1000 at P 283. *See United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956).

30 Order No. 1000 at P 292.

31 Order No. 1000-A at P 389.

32 *Id.*

for making the findings required by the applicable standard of review and then considering whether the Filing Parties have complied with the directives of Order No. 1000.

A. The Federal Right of First Refusal in the TOA Is Not Protected by the *Mobile-Sierra* Doctrine.

1. The Commission Is Not Required To Presume That the Federal Right of First Refusal in the TOA Is Just and Reasonable.

In *Morgan Stanley*, the Supreme Court reaffirmed and clarified the *Mobile-Sierra* doctrine by instructing the Commission that it "must presume that the rate set out in a freely negotiated wholesale-energy contract meets the 'just and reasonable' requirement imposed by law" and may overcome that presumption "only if [it] concludes that the contract seriously harms the public interest."[33] The Filing Parties quote this statement—omitting the modifier "wholesale-energy"—and suggest that *Morgan Stanley* provides the applicable standard of review in this case.[34]

But the Filing Parties also imply that the Commission must presume that the federal ROFR in section 3.09 of the TOA is just and reasonable, and thus *Mobile-Sierra* automatically applies to the TOA by default.[35] That is not the case. As the Filing Parties acknowledge, the *Morgan Stanley* presumption applies to "negotiated bilateral contracts as opposed to unilaterally filed tariffs or other agreements that are not executed by the buyers."[36] But the TOA—and in particular the federal right of first refusal in section 3.09 and its corollary schedule 3.09—is not a "negotiated bilateral contract," much less a "freely negotiated wholesale-energy contract." The TOA was not executed by any "buyers" and is not a contract to sell any jurisdictional wholesale

---

[33] Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1 of Snohomish County, Wash., 554 U.S. 527, 530 (2008).

[34] Transmittal Letter at 19.

[35] *See id.* at 20.

[36] *Id.* at 19. *See Devon Power LLC,* 134 FERC ¶ 61,208, at PP 12–13, *reh'g denied*, 137 FERC ¶ 61,073, at P 21 (2011).

energy or transmission service. The TOA does not contain any rates, much less freely negotiated rates.

Moreover, the TOA has an indefinite—*i.e.*, perpetual—term, and no provisions governing a periodic renegotiation, reopening, or resetting of its provisions—as one would expect in a wholesale energy contract. There is no indication in any of the case law that the *Mobile-Sierra* presumption of lawfulness for negotiated "contract rates" should be extended to jurisdictional agreements of indefinite duration not containing any rates.

In particular, the federal right of first refusal in section 3.09 and schedule 3.09 is far from a negotiated wholesale energy rate to which any presumption of lawfulness should attach. Rather, section 3.09 and schedule 3.09 "set[] forth the rights and obligations of the Participating Transmission Owners and the ISO-NE RTO with respect to system planning and expansion" and "delineate the Transmission Owners' obligation to build in response to the regional needs as may be determined by the ISO-NE RTO."[37] These provisions are essentially an agreement among the ISO and the incumbent transmission providers restraining competition among themselves—and by non-signatory third parties—in the planning and expansion of the New England regional transmission grid.

Agreements among actual or potential competitors to divide markets or allocate customers are unlawful under section 1 of the Sherman Act, 15 U.S.C. § 1 ("Every contract, combination in the form of trust or otherwise, or conspiracy, in restraint of trade or commerce among the several States, or with foreign nations, is declared to be illegal."). Indeed, they are normally *per se* unlawful because they have the same anticompetitive effect as horizontal price

[37] *ISO New England, Inc.*, *et al.*, 109 FERC ¶ 61,147, at P 77 n.50 (2004).

fixing.[38] The Commission must consider the anticompetitive consequences of jurisdictional agreements when acting under section 206 of the FPA.[39]

That is indeed how the Commission viewed the matter in Order No. 1000. The Commission asserted authority under section 206(a) of the FPA to modify a federal right of first refusal in a jurisdictional tariff or agreement because it was "a 'rule, regulation, practice, or contract' affecting the rates for jurisdictional transmission service,"[40] and because it "create[d] opportunities for undue discrimination and preferential treatment against non-incumbent transmission developers" and for "anticompetitive practices."[41] In these respects, the federal right of first refusal in the New England TOA is no different from any other provision in a transmission provider's OATT.

The default presumption of lawfulness that *Morgan Stanley* applied to "freely negotiated wholesale-energy contracts" was based on the Court's conclusion that "[i]n wholesale markets, the party charging the rate and the party charged [are] often sophisticated businesses enjoying presumptively equal bargaining power, who could be expected to negotiate a 'just and reasonable' rate as between the two of them."[42] While the transmission owners and the ISO may have been sophisticated businesses with fairly equal bargaining power, there is no basis for applying a presumption of lawfulness to their agreement to give incumbent transmission owners

38 *See Palmer v. BRG of Georgia, Inc.*, 498 U.S. 46, 50 (1990) (per curiam) (market-allocation "agreements are anticompetitive regardless of whether the parties split a market within which they both do business or whether they merely reserve one market for one and another for the other"). *See also United States v. Topco Associates*, 405 U.S. 596-97 (1972); *United States v. Sealy, Inc.*, 388 U.S. 350 (1967); *Timken Roller Bearing Co. v. United States*, 341 U.S. 593 (1951).

39 See Gulf States Utilities Co. v. FPC, 411 U.S. 747 (1973).

40 Order No. 1000 at P 285 (quoting section 206(a)).

41 *Id.* at P 286. *See also id.* at PP 256, 257 (federal right of first refusal can discourage new entry and create a barrier to entry).

42 554 U.S. at 545 (quoting *Verizon Communications, Inc. v. FCC*, 535 U.S. 467, 479 (2002)) (alterations original).

a federal right of first refusal, where: (1) there were no buyers or non-incumbent transmission developers with which to negotiate the terms of that right; and (2) the incumbent PTOs had a complete community of interest in retaining for themselves the monopoly in the construction and ownership of transmission.

Accordingly, there is no basis for a claim that the TOA's federal right of first refusal is protected by a *Mobile-Sierra* default presumption that it is just and reasonable. Accordingly, Mobile-Sierra protection does not apply by default to the federal right of first refusal in the TOA so as to require the Commission to satisfy a heightened public-interest standard of review before it may order changes to that arrangement. As shown next, the Commission also has not imposed that standard on itself by order.

2. The Commission's 2004 Order Granting *Mobile-Sierra* Treatment of Section 3.09 of the TOA Does Not Require a Public Interest Finding Any Different from that which the Commission Has Already Made in Order No. 1000 To Justify Elimination of the Federal Right of First Refusal in the TOA.

The Filing Parties' main argument for why *Mobile-Sierra* protects their federal right of first refusal rests on the Commission's 2004 order accepting language in the TOA stating that, absent the agreement of the parties to the TOA, the standard of review for changes to section 3.09 of the TOA proposed by a party, nonparty, or the Commission acting *sua sponte* is "'the 'public interest' standard of review under the Mobile-Sierra Doctrine ….'"[43]

But the Commission's order accepted this language in the TOA with the explicit understanding that section 3.09 was subject to the provisions of the ISO England OATT as they may be modified from time to time, and thus would not adversely affect the public interest: "We will grant Mobile-Sierra treatment, as requested by the Filing Parties. Section 3.09 provides

[43] Transmittal Letter at 18 (quoting section 11.04(c) of the TOA).

direction to the Transmission Owners and ISO-NE to follow planning procedures contained in the ISO-NE OATT. As such, this provision will have no adverse impact on third parties or the New England market."[44] Thus, by its terms, the Commission's grant of *Mobile-Sierra* treatment to section 3.09 protects the section from certain collateral attacks to the provision itself, but it does *not* insulate this section of the TOA—including its federal right of first refusal—from conforming to the governing provisions of the ISO-NE OATT as they may exist from time to time (and understanding that the OATT will be changed from time to time).

The Filing Parties acquiesced in the 2004 order's limited *Mobile-Sierra* protection. In so doing, the Filing Parties assumed the risk that the planning procedures in the ISO-NE OATT might be modified in ways that required modification of their federal right of first refusal.[45] In any event, the Commission clearly had power to take this action. In instances not involving "contract rates" where *Mobile-Sierra* applies by default, the Commission has broad discretion to apply *Mobile-Sierra* treatment or not, depending on the particular circumstances.[46]

Moreover, even if the TOA were a contract rate, the Supreme Court has recently reaffirmed the long-established principle that the *Mobile-Sierra* doctrine affords substantial flexibility to contracting parties to specify the conditions under which their contract rates can be changed.[47] In this instance, the *Mobile-Sierra* clause in the TOA, when applied to section 3.09, is analogous to a "*Memphis* clause" that allows a contract rate to change in response to a tariff

---

44 *ISO New England, Inc.*, *et al.*, 109 FERC ¶ 61,147, at P 78.

45 *See Texaco Inc. v. FERC,* 148 F.3d 1091, 1098 (D.C. Cir. 1998) (parties "always contract in the shadow of the regulatory state, and they cannot presume that their contracts are immune to its inherent risks").

46 *See, e.g., Devon Power LLC*, 134 FERC ¶ 61,208, at PP 23-24.

47 *See NRG Power Mktg. v. Me. Pub. Utils. Comm'n*, 130 S. Ct. 693, 699 n.3 (2010) (citing *United Gas Pipe Line Co. v. Memphis Light, Gas & Water Div*., 358 U.S. 103, 110–113 (1958); *Papago Tribal Util. Auth. v. FERC,* 723 F.2d 950, 953 (D.C. Cir. 1983); *Louisiana Power & Light Co. v. FERC,* 587 F.2d 671, 675–76 (5th Cir. 1979)).

rate in effect from time to time.[48] The *Mobile-Sierra* protection of section 3.09 of the TOA is limited, and it specifically does not protect that section from being modified to conform to the governing requirements of the ISO-NE OATT's planning procedures.

Thus, the Filing Parties have things backwards: section 3.09 of the TOA does not override the provisions of the OATT; instead, the OATT provisions override section 3.09 of the TOA.

A central element of Order No. 1000 is to open up regional transmission planning processes to participation by non-incumbent transmission providers. To this end, Order No. 1000 requires all public utilities, including RTOs, to eliminate provisions in their tariffs or agreements that establish a federal ROFR for a provider with respect to transmission facilities selected in a regional plan for purposes of cost allocation. The *Mobile-Sierra* treatment accorded to section 3.09 by the Commission's 2004 order expressly makes that section of the TOA subject to future changes to the ISO England OATT's planning procedures. Thus, the federal right of first refusal in section 3.09 of the TOA is not protected by the *Mobile-Sierra* doctrine in this case.

Because the *Mobile-Sierra* doctrine does not protect the federal right of first refusal in section 3.09 in this case, the Commission need make no "public interest" finding in this compliance proceeding beyond that already made in Order No. 1000. The only remaining issue is whether the Filing Parties have complied with the requirement to eliminate that right from their jurisdictional tariffs and agreements.

---

[48] *See Memphis*, 358 U.S. at 110–113.

B. Even if the *Mobile-Sierra* Doctrine Applied in this Case, the Applicable Public-Interest Standard of Review Affords the Commission an Adequate Basis to Require Compliance with Order No. 1000.

Even if the *Mobile-Sierra* doctrine did protect the TOA's federal right of first refusal for incumbent transmission owners, the public interest standard of review is a flexible standard and affords the Commission broad discretion to identify the relevant public interests and order modifications to the TOA to protect those interests. Indeed, the FPA obliges the Commission to protect those interests, and nothing in the *Mobile-Sierra* doctrine relieves the Commission of that obligation.

Both the *Mobile* and *Sierra* cases recognize the supremacy of the Commission's regulatory authority over contracts. As the Court stated in *Mobile*, "contracts remain fully subject to the paramount power of the Commission to modify them when necessary in the public interest."[49] Similarly, *Sierra* stated that the Commission "has undoubted power under § 206(a) to prescribe a change in contract rates whenever it determines such rates to be unlawful."[50]

In accordance with that understanding, in the *Permian Basin Area Rate Cases*, the Court upheld the FPC's abrogation of wholesale gas contract prices that exceeded the just-and-reasonable cost-based area maximum rates.[51] The Court observed that section 5(a) of the Natural Gas Act ("NGA")[52] "provides without qualification or exception" the authority to determine a just-and-reasonable contract rate.[53] Citing *Mobile*, the Court noted that the NGA "is premised upon a continuing system of private contracting," but citing *Sierra*, it also noted that "the Commission has plenary authority to limit or to proscribe contractual arrangements that

---

49 *Mobile*, 350 U.S. at 344.

50 *Sierra*, 350 U.S. at 353.

51 390 U.S. 747, 783–84 (1968).

52 15 U.S.C. § 717d.

53 *Permian Basin*, 390 U.S. at 783-84.

contravene the relevant public interests."[54] The Court thus upheld the FPC's abrogation of wholesale gas sale contracts to enforce the statutory just-and-reasonable standard.

Moreover, the Supreme Court clarified in *Morgan Stanley* that the *Mobile-Sierra* "public interest" standard is not separate from the statutory just-and-reasonable standard but is simply the application of the statutory standard in the context of contract rates.[55] As such, the *Mobile-Sierra* public-interest standard is flexible and permits the Commission to look to "the totality of the circumstances" (not just the factors originally identified in the *Sierra* opinion) to identify the public interests relevant in a particular case.[56] Nothing in the Filing Parties' submission is to the contrary. The Filing Parties recite[57] the Supreme Court's statement in *Permian Basin*,[58] later quoted by the Court in *NRG*,[59] that the NGA allows the abrogation of private contracts "only in circumstances of unequivocal public necessity." But the Court made that statement in *Permian Basin* in the context of upholding the FPC's refusal to *increase* the area maximum rate to account for the fact that some gas contracts contained prices below the otherwise applicable area maximum rate.[60] Thus, the Court's holding protected consumers from paying higher area maximum rates and does not represent a limitation on the Commission's power to protect the public interest. Moreover, the Court's holding was a straightforward application of the holding in *Sierra* that under section 206 of the FPA the Commission cannot abrogate contract rates

---

54 *Id.* at 784.

55 554 U.S. at 535; 128 S. Ct. at 2740.

56 554 U.S. at 549, 128 S.Ct. at 2747–48 & n.4. *See also Northeast Utils. Serv. Co. v. FERC*, 55 F.3d 686, 690, 691, 692 (1st Cir. 1995) (*Mobile-Sierra* allows Commission to decide "what circumstances give rise to the public interest," does not limit the Commission to the three factors identified in *Sierra*, and does not mean the public-interest standard is "practically insurmountable in all circumstances"); *Devon Power LLC*, 134 FERC ¶ 61,208, at P 25.

57 Transmittal Letter at 19, 20.

58 *Permian Basin*, 390 U.S. at 822.

59 *NRG*, 130 S. Ct. at 699.

60 *See Permian Basin*, 390 U.S. at 820-22.

because they are too low unless it identifies unequivocal public-interest reasons for doing so,[61] a holding that the *Permian Basin* Court specifically cited.[62] The circumstances and the relevant public interests in this case are far different, however, and neither *Permian Basin* nor *Sierra* implies the Commission is disabled from protecting those interests. At issue here is not a rate negotiated at arms' length, but rather an agreement among competitors to exclude competition going forward in the development, construction and ownership of transmission in New England.

The Filing Parties also cite[63] the Supreme Court's statement in *Arkansas Louisiana Gas Co. v. Hall* ("*Arkla*"), quoting *Permian Basin*, that the Commission "lacks affirmative authority, absent extraordinary circumstances, to 'abrogate existing contractual arrangements.'"[64] But far from diminishing the importance or the scope of the Commission's regulatory authority, *Arkla* held that the *Mobile-Sierra* doctrine's respect for private contracts "does not affect the supremacy of the Act itself," and that the Commission's opportunity to review the reasonableness of rate contracts was so important "in the federal scheme for regulating the sale of natural gas" that the seller could not be permitted to charge an unfiled contract rate.[65] If anything, *Arkla* suggests that the Commission has broad authority in this case to ensure just and reasonable rates for jurisdictional transmission services.

The Commission's rationale in Order Nos. 1000 and 1000-A provides a basis for the Commission to make the required public-interest findings in this case, if such findings are required. In Order No. 1000 and 1000-A, the Commission identified two public-interest reasons under section 206 of the FPA for eliminating federal ROFR for incumbent transmission

---

61 *See Sierra*, 350 U.S. at 355.

62 *See Permian Basin*, 390 U.S. at 821.

63 *Transmittal* Letter at 19.

64 *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 582 (1981) (quoting *Permian Basin*, 390 U.S. at 820).

65 *Arkla*, 453 U.S. at 582.

providers in jurisdictional tariffs and agreements. First, a federal right of first refusal is a "practice" that affects rates for jurisdictional transmission services, has an adverse effect on competition, and can lead to unjust and unreasonable rates for such services.[66] Second, "on an alternative and independent basis,"[67] the Commission determined that eliminating federal ROFRs was necessary to remedy undue discrimination and preference against non-incumbent transmission providers.[68]

Each of the rationales in the Commission's orders provides a basis for the Commission to determine in this case—if the *Mobile-Sierra* doctrine requires—that the federal right of first refusal in the New England TOA is contrary to the public interest and thus should be eliminated. In both *Permian Basin* and *Northeast Utilities*, the courts upheld the abrogation of *Mobile-Sierra* contracts in order to ensure just and reasonable rates.[69] Moreover, the *Mobile-Sierra* public-interest standard empowers the Commission to protect non-parties to a *Mobile-Sierra* contract. As the Court held in *NRG*, "the *Mobile-Sierra* doctrine does not overlook third-party interests; it is framed with a view to their protection. The doctrine directs the Commission to reject a contract that 'seriously harms the consuming public.'"[70] In this case, neither consumers nor non-incumbent transmission developers are parties to the TOA, and thus the *Mobile-Sierra* doctrine recognizes the Commission's power to abrogate the TOA if necessary to protect them.

Accordingly, the Commission's determinations in Order Nos. 1000 and 1000-A that a federal right of first refusal can harm consumers who are forced to pay unjust and unreasonable

---

66 *See* Order No. 1000 at PP 253-57, 268, 284, 285; Order No. 1000-A at PP 357–358.

67 Order No. 1000-A at P 361.

68 *See* Order No. 1000 at P 286; Order No. 1000-A at P 361-63.

69 *See Permian Basin*, 390 U.S. at 783–84; *Northeast Utils.*, 55 F.3d at 692–93.

70 *NRG*, 130 S. Ct. at 700 (quoting *Morgan Stanley*). *See also Arizona Corp. Comm'n v. FERC*, 397 F.3d 952, 954 (D.C. Cir. 2005) (abrogating settlement agreement to prevent imposition of an excessive burden on third parties); *Northeast Utils.*, 55 F.3d at 691–692(upholding abrogation of contracts because of burden on third parties); *Devon Power*, 134 FERC ¶ 61,208, at P 25 (same).

rates for transmission service, and can harm non-incumbent transmission providers who are placed at a competitive disadvantage against the incumbents, provide a basis for the Commission to find in this case that the federal right of first refusal in the New England TOA is unlawful and should be eliminated.

The D.C. Circuit's 1998 decision in *Texaco Inc. v. FERC* supports this approach (albeit in the context of a contract rate to which the *Mobile-Sierra* default presumption applied). That case upheld Commission orders requiring a gas pipeline company to reform its jurisdictional transportation contracts to comply with a Commission rulemaking proscribing the rate design used in the contracts. The contracts expressly prohibited the pipeline from changing its rate design by filing new rates under section 4 of the NGA.[71] The court of appeals held that under *Mobile-Sierra*, the contract also necessarily prohibited the Commission from changing the rate design under section 5 of the NGA, except as required by the public interest.[72] The court further held that "the 'public interest' that permits FERC to modify private contracts is different from and more exacting than the 'public interest' that FERC seeks to serve when it promulgates its rules."[73] Thus, "more is required to justify regulatory intervention in a private contract than a simple reference to the policies served by a particular rule."[74] But, the court found that the Commission had not relied on generalized public-interest goals when it ordered the pipeline to change its contract rate design. Instead, the Commission had determined that retention of the contract rate design would "distort gas market pricing to the detriment of the integrated national

[71] 15 U.S.C. § 717c.

[72] 148 F.3d at 1095-96.

[73] *Id.* at 1097.

[74] *Id.*

gas sales market" and "would be particularly anti-competitive" because it would harm the pipeline's "main competitor."[75]

If the *Mobile-Sierra* doctrine applies in this case, the Commission can take the same basic approach. As demonstrated below, the Commission has the basis for finding in this case that the rationales in Order Nos. 1000 and 1000-A supporting the elimination of federal ROFR apply to the New England TOA, and that nothing in the Filing Parties' response demonstrates that New England is different from other regions of the country so as to require a different result or to justify retention of the ROFR.

VI. THE FILING PARTIES' ROFR IS UNJUST AND UNREASONABLE AND SHOULD BE ELIMINATED.

In Order No. 1000, the Commission explicitly directed public utility transmission providers to remove any provisions providing for a federal ROFR from their OATTs and Commission-jurisdictional tariffs and agreements.[76] Leaving no doubt as to its directive, the Commission in Order No. 1000-A (P 415) stated:

> We affirm the decision in Order No. 1000 to require the elimination of a federal right of first refusal from Commission-jurisdictional tariffs and agreements for transmission facilities selected in a regional transmission plan for purposes of cost allocation.

But for the limited exceptions discussed in section VI.A.5 below, this obligation is absolute: no federal ROFR is permissible for transmission facilities selected in a regional transmission plan for cost allocation purposes, regardless of the ROFR's duration.

> Allowing incumbent transmission providers to maintain a federal right of first refusal, **even with a limited 90-day election period** as proposed by Xcel, would discourage transmission developers from proposing transmission projects that may be a more efficient or cost-effective solution to meet regional transmission

[75] *Id.* (internal quotations omitted).

[76] Order No. 1000 at PP 7, 313.

> needs, resulting in rates for jurisdictional transmission services that are unjust and unreasonable or unduly discriminatory or preferential. [77]

The Filing Parties, while acknowledging the Order No. 1000 mandate to eliminate the ROFR: (1) argue the *Mobile*-Sierra doctrine insulates them from compliance with Order No. 1000's required deletion of ROFRs; and (2) seek waiver of that requirement claiming that an Order No. 1000-compliant process that eliminates the ROFR altogether "would be substantially inferior" to the current ROFR for reliability projects that exists today.[78] The flaws in the *Mobile-Sierra* argument have been demonstrated in the preceding section. As demonstrated below, the Filing Parties have submitted no evidence to support their claim that the current process is consistent with or superior to the no-ROFR process required by Order No. 1000 and its progeny; the Southern New England States submit that no such evidence exists. The Filing Parties have submitted no evidence that demonstrates that, unlike public utility transmission owners in every other part of the country subject to Order No. 1000, New England transmission owners should be permitted to retain the ROFR. The Commission should reject the Filing Parties' request to retain a five-year ROFR as unjust and unreasonable and contrary to Commission rules and precedent.

A. The Commission Found Federal ROFRs Unjust and Reasonable.

The Commission made numerous findings and provided detailed explanations in Order Nos. 1000 and 1000-A concerning the unjustness and unreasonableness of permitting incumbent transmission providers to retain ROFRs for reliability projects selected in a regional plan for regional cost allocation. The Filing Parties have provided no evidence or valid explanations why those findings are not as applicable to the New England PTOs as any other incumbent transmission owner throughout the country.

77 Order No. 1000-A (at P 428, emphasis supplied).

78 *See e.g.*, Transmittal Letter at 3.

1. A ROFR Restricts the Universe of Transmission Developers Offering Potential Solutions for Consideration in the Regional Transmission Planning Process and Creates Opportunities for Undue Discrimination and Preferential Treatment Against Non-Incumbent Transmission Developers.

The Filing Parties propose to retain the existing ROFR for reliability upgrades, regardless of whether the upgrades are local in nature or are to be included in the regional plan for regional cost allocation purposes. The Commission found in Order No. 1000 that allowing a federal ROFR for transmission facilities selected in a regional transmission plan for cost allocation purposes "create[s] a barrier to entry that discourages nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level."[79] In affirming Order No. 1000, the Commission explained that:

> Allowing entities, such as non-public utility transmission developers, the opportunity to potentially propose a transmission project as a nonincumbent transmission developer furthers the Commission's goal in Order No. 1000 of ensuring that all transmission developers have a comparable opportunity to incumbent transmission developers/providers to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation.[80]

Comparability is the fundamental tenet of the Commission's open-access transmission policy. The federal ROFR sought to be retained by the Filing Parties violates comparability by providing incumbent transmission owners an undue preference in proposing, implementing and owning transmission solutions for regional reliability concerns. This preference unduly discriminates against non-incumbent transmission developers, and discourages if not effectively prevents their proposal of regional solutions to reliability needs identified by ISO-NE. There is no justification for continuing this barrier to the entry for entities able and willing to submit competing proposals for regional reliability projects.

---

79 Order No. 1000 at P 257.

80 Order No. 1000-A at P 417.

2. A ROFR May Result in the Failure To Consider More Efficient or Cost-Effective Solutions to Regional Needs and, in Turn, the Inclusion of Higher-Cost Solutions in the Regional Transmission Plan.

The economic inefficiency and anticompetitive effect of the PTOs' ROFR is apparent. As the Commission concluded:

> Failure to [eliminate a federal ROFR] would leave in place practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective solutions to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers.[81]

In Order No. 890, the Commission "sought to ensure that the more efficient or cost-effective solutions are in the regional transmission plan"[82] by requiring comparable evaluation of all potential transmission solutions.

The retention of a federal ROFR for regional reliability projects would discourage if not effectively preclude the participation of new transmission developers in the process of finding transmission solutions to regional reliability needs, limit the alternatives presented to ISO-NE and its stakeholders, and thus impede the identification and evaluation of the most efficient and cost-effective solutions to regional transmission needs. For example, ISO-NE is currently considering proposals to address a reliability need in the Greater Boston area. The initial study group comprised ISO-NE and three incumbent transmission owners. In 2010, New Hampshire Transmission, LLC ("NHT" or "New Hampshire Transmission") joined the group as a transmission owner by virtue of its ownership of a single transmission asset – a substation at the Seabrook Nuclear Project – which was identified as requiring an upgrade of certain line termination equipment as part of the proposed project. The other incumbent transmission owners

[81] Order No. 1000 at P 253; *see also* PP 7, 284-86; Order No. 1000-A at P 428.

[82] Order No. 1000 at P 255.

proposed a series of upgrades and additions to the high voltage AC system around and north of Boston that would cost almost $800 million. New Hampshire Transmission subsequently proposed as an alternative an HVDC submarine cable to connect the New Hampshire seacoast and the Greater Boston area, which they claim would dramatically reduce the number and extent of additions and modifications to the high voltage AC systems, reduce environmental impacts and provide addition benefits to the grid. But for New Hampshire Transmission's ownership of a single substation giving it the ability to participate in the planning process, this option would not now be before ISO-NE for consideration.

If the ROFR is retained, the only way such alternatives will see the light of day is if they are proposed by incumbent transmission owners or by a non-incumbent transmission owner that wishes to dedicate the time and resources to develop such an alternative on the unlikely chance that the incumbents will not exercise their ROFR rights. As the Commission found in Order No. 1000-A (at P 358, internal footnotes omitted):

> The ability of an incumbent transmission provider to discourage or preclude participation of new transmission developers through discriminatory rules in a regional transmission planning process, and in particular, the inclusion of a federal right of first refusal, can have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs. This in turn can directly increase the costs of new transmission development that is recovered from jurisdictional customers through rates.

The transmission projects selected in the regional transmission planning process for purposes of regional cost allocation directly affect jurisdictional transmission rates as the costs of those facilities are included in transmission rates paid by transmission customers (and ultimately borne by consumers). The exclusion of more efficient or cost-effective solutions from the regional transmission planning process by retention of the federal ROFR in New England will almost inevitably result in increased costs to ratepayers in Massachusetts and throughout New England.

3. It Is Not in the Economic Self-Interest of Incumbent Transmission Providers To Permit New Entrants To Develop Transmission Facilities, Even if Proposals Submitted by New Entrants Would Result in a More Efficient or Cost-Effective Solution to the Region's Needs.

The economic self-interest of incumbent transmission providers rests in excluding the development of transmission facilities that they do not own, *i.e.*, maintaining a monopoly over the ownership of transmission facilities on their respective transmission systems. The factual basis for this conclusion is apparent. The profits of transmission owners come from owning transmission facilities; the more they own, typically the greater their profits. The federal ROFR provides incumbent transmission owners the means by which to discourage if not totally exclude competition in the development and ownership of transmission facilities on their transmission systems.[83]

The Commission determined that federal ROFRs exacerbate the obvious disincentive to the development of transmission solutions by non-incumbents,[84] concluding "that an incumbent transmission provider's ability to use a right of first refusal to act in its own economic self-interest may discourage new entrants from proposing new transmission projects in the regional transmission planning process."[85]

---

[83] The self-interested desire of a transmission provider to seek to exclude competition in any form is not new to the Commission. For example, the Commission recognized in Order Nos. 888 and 890 that "it is not in the economic self-interest of public utility transmission providers to expand the grid to permit access to competing sources of supply." Order No. 1000 at P 254 (citing Order No. 888, FERC Stats. & Regs. at 31,682; Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524).

[84] Order No. 1000 at P 257.

[85] *Id.* at P 256.

The Filing Parties maintain that non-incumbent developers have sufficient opportunity to participate in the development of reliability projects under the existing process with a ROFR because incumbent transmission owners may voluntarily bid out projects for construction by other entities.[86] The contracting out of the construction of a project, however, does nothing to mitigate the continued monopoly by the incumbent transmission provider over the ownership of the transmission facilities. Moreover, if a non-incumbent transmission developer cannot develop and own a transmission project, why would that developer devote time and resources to develop a proposal to resolve regional reliability concerns? As the Commission correctly recognized:

> [T]here is a disincentive for a non-incumbent transmission developer to commit its resources to a potential transmission project when it runs the risk of an incumbent transmission provider exercising its federal right of first refusal once the benefits of the transmission project are demonstrated.[87]

It is noteworthy that the Federal Trade Commission, the federal agency tasked with the promotion of consumer protection and elimination of anti-competitive business practices, supported the Commission's conclusion that a federal ROFR can create a barrier to entry that discourages non-incumbent transmission developers from proposing alternative solutions for consideration at the regional level.[88]

The Commission is appropriately concerned about the stultifying effect that barriers to new entry created by a federal ROFR may have on innovation. The solutions to many of the problems and needs of the twenty-first century transmission grid that the Commission seeks to foster will be found through innovation and new technology. High market concentration, such as is perpetuated by the ROFR, is most often:

---

86 Transmittal Letter at 26.

87 Order No. 1000 at P 257.

88 *See id*.; Order No. 1000-A at P 76.

apt to retard progress by restricting the number of independent sources of initiative and by dampening firms' incentive to gain market share position through accelerated R&D. Likewise, given the important role that technically audacious newcomers play in making radical innovations, it seems important that barriers to new entry be kept at modest levels.[[89]]

The federal ROFR is not a modest or natural barrier to entry. There is no question that the ROFR discourages if not precludes the active participation in the development of solutions to reliability and economic problems on the New England regional transmission grid. The innovation that the Commission seeks is being frustrated by this unnecessary and anticompetitive barrier to entry.

The Commission should reject the Filing Parties' arguments that retention of a federal ROFR for regional reliability projects will not harm New England consumers.

4. Elimination of the ROFR in New England Will Increase Potential Competition Among Project Sponsors.

Retention of the existing ROFR will likely result in very few, if any, new transmission projects being developed, constructed and/or owned by non-incumbent transmission developers in New England. A recent analysis performed by New Hampshire Transmission of the Greater Boston planning study demonstrates that if a five-year planning horizon is employed in New England and the ROFR retained, none of the approximately 48 projects in the current Regional System Plan for the greater Boston area would be open for solicitation of competitive bids.[90] In contrast, if the Commission eliminated the ROFR, the potential would exist for solicitation of

---

[89] F. M. Scherer & David Ross, Industrial Market Structure and Economic Performance, p. 660, Houghton Mifflin Company (3d ed., 1990). See Philip J. Weiser, Innovation, Entrepreneurship, and the Information Age, 9 J. ON TELECOMM. & HIGH TECH. L. 1, 7-8 (2011) ("as Scherer and Ross put it, "[t]echnological progress thrives best in an environment that nurtures a diversity of sizes and, perhaps, especially, that keeps barriers to entry by technologically innovative newcomers low.").

[90] Memo (at 3 & n. 2) from Matt Valle, President, New Hampshire Transmission, LLC, to Calvin Bowie, Chairman, Participants Committee (Sept. 26, 2012), at 116, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2012/oct32012/npc_20121003_composite.pdf; NHT's analysis, available at http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2012/aug1314152012/index-p2.html.

competitive proposals for all qualifying new transmission projects in New England. This is likewise evidenced by NHT's analysis of the Greater Boston planning study.

The underlying premise of Order No. 1000 is that increased competition will result in more innovative solutions and ultimately lower cost solutions to regional transmission system needs. Anticompetitive provisions, such as the ROFR, stifle innovation as well as competition, and impede new entry that into the market for regional transmission solutions.

5. Competition Is Already Limited by the Exclusions to the Commission's No-ROFR Requirement.

The Filing Parties' proposal seems to ignore that the Commission has carved out significant exclusions to its requirement that incumbent transmission providers eliminate federal ROFRs of any duration for reliability projects selected in a regional plan for regional cost allocation: (1) new transmission facilities that are located solely within an incumbent transmission provider's retail distribution service territory or footprint that are not selected in a regional transmission plan for purposes of regional costs allocation;[91] (2) upgrades to an incumbent transmission provider's own transmission facilities;[92] and (3) transmission facilities associated with an incumbent transmission provider's use and control of its existing rights-of-way under state law.[93] In Order No. 1000-A, the Commission affirmed these rulings, clarified that the requirement to eliminate a federal ROFR does not apply in the following situations:

> [T]he Commission [is not] eliminating the right of an owner of a transmission facility to improve its own existing transmission facility by allowing a third-party

[91] In Order No. 1000-A, the Commission clarified that if the regional cost allocation method results in 100% of a transmission facility's cost being allocated to a public utility transmission provider in whose retail distribution service territory or footprint the facility is to be located, the requirement to eliminate the ROFR does not apply. Order No. 1000-A at P 423.

[92] *See* Order No. 1000-A a P 426 (clarifying what is meant by "upgrade").

[93] The Commission explained that "[t]he retention, modification, or transfer of rights-of-way remain subject to relevant law or regulation granting the rights-of-way." Order No. 1000 at P 319.

> transmission developer to, for example, propose to replace the towers or conductors of a transmission line owned by another entity.[94]
> ….
> Furthermore, the Commission reiterates that the non-incumbent transmission developer reforms were not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way under state law.[95]
> ….
>
> Moreover, we note again that Order No. 1000 continues to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located within its retail distribution service territory or footprint and that are not selected in a regional transmission plan for purposes of cost allocation.[96]

The retention of these exclusions reflects Commission recognition that each incumbent transmission provider has obligations with respect to service reliability within its own retail service territory and under state law and requires some degree of discretion as to how to meet those obligations. These exceptions to the elimination of the ROFR already foreclose competition for a substantial number of proposed transmission projects.

NHT's study examined ISO-NE's Regional System Plan using a three-year planning horizon, and found that 161 Reliability Upgrade projects totaling $2.38 billion were approved for construction over the next three years. Of those 161 projects, $1.5 billion are upgrades to existing projects, local transmission projects, or greenfield projects to be constructed on existing rights-of-way.[97] The costs of these projects represent 64% of the total costs of the Reliability Upgrade projects in the three-year horizon. Under the Order No. 1000 ROFR exclusions, none of these projects would have been available to competing proposals. Restricting the analysis to

---

94 Order No. 1000-A at P 426.

95 Order No. 1000-A at P 427.

96 *Id.* at P 428.

97 Order No. 1000 - Competitive Analysis – v3, at Slide 4, prepared by New Hampshire Transmission, LLC (August 2, 2012), available at http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2012/aug1314152012/index-p2.html (posted under Transmission Committee Materials on Aug. 27, 2012).

data from just the last 18 months reveals that more than 90% of the projects in the Regional System Plans were for upgrades to existing facilities or local projects that would not have been open to competition.[98]

B. Contrary to the Filing Parties' Argument, Retaining the ROFR in the Existing New England Planning Process Does Not Satisfy the "Consistent with or Superior To" Standard Set Forth by the Commission for Changes to the OATT.

The Filing Parties contend that applying the same principles that govern deviations from the Commission's *pro forma* OATT under Order Nos. 888 and 890, the existing ISO-NE process – *i.e.*, with the ROFR -- is superior to the proposed dueling submission process set out in Order No. 1000.[99] The Commission has long held that deviations to the Order No. 888 *pro forma* tariff must be demonstrated to be consistent with or superior to the *pro forma* tariff.[100] The Commission upheld this approach in implementing Order No. 890.[101] Subsequently, with Order No. 1000, the Commission adopted regulatory language providing that any public utility that seeks a deviation from the *pro forma* tariff contained in Order No. 888, as revised in Order No. 890 and Order No. 1000, must demonstrate that the deviation is consistent with the principles of Order No. 888, Order No. 890, and Order No. 1000.[102] Additionally, the Commission adopted

---

98 *Id.*

99 Transmittal Letter at 3-4.

100 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at p. 31,770 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part and remanded in part*, *sub nom Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

101 *See, e.g.*, *Duke Energy Carolinas, LLC*, 126 FERC ¶ 61,226, at PP 22-24 (2009) (finding proposed tariff revisions to be consistent with or superior to the *pro forma* OATT) (citing *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009)).

102 18 C.F.R. § 35.28(c)(1)(vi).

regulatory language providing that if an RTO believes its existing open access tariff is consistent with or superior to the revisions to the then-current pro forma tariff, it can attempt to so demonstrate under FPA section 206.[103]

In addition to seeking, in essence, a waiver of the Order No. 1000 mandate to eliminate the federal ROFR in order to continue the ROFR for transmission projects needed to satisfy both local and regional reliability concerns, the Filing Parties argue in their Contingent Compliance Filing that, if the Commission rejects their request to retain the ROFR for regional reliability projects, they nevertheless should be allowed to retain the ROFR for regional reliability projects needed within a five-year planning horizon. In other words, the Filing Parties' alternative to elimination of the ROFR is the continuation of the ROFR for regional reliability projects for a rolling five-year period.

Retaining the ROFR for regional reliability projects for a five-year period is neither consistent with nor superior to, but rather is demonstrably inferior to, the Order No. 1000 required elimination of that anticompetitive device. The Southern New England States oppose the retention of the ROFR for a five-year period for regional reliability projects and address the substantive deficiencies in the Filing Parties' Contingent Compliance Filing in section VI.D, below.

The current transmission planning process in New England is described in Attachment K to Part II of the ISO-NE OATT. ISO-NE conducts the transmission planning process in four stages (Attachment K, Section 4): (1) a Needs Assessment Study where reliability needs in New England are identified over a 10-year planning horizon; (2) Solutions Studies, which include the development of alternative solutions that may mitigate the identified needs; (3) Critical Load

[103] 18 C.F.R.§ 35.28 (c)(4)(ii).

Level/Year-of-Need Analysis; and (4) Preferred Solution(s), where, as the name suggests, preferred solutions to identified needs are selected and approved by the ISO-NE. The preferred solution is then included in the Regional System Plan and assigned for construction by the incumbent transmission provider in whose service territory the facilities are to be located. The Filing Parties propose to retain this format, contending that "the existing New England reliability and market efficiency planning process…are consistent with, or superior to, the process described by the Commission in Order No. 1000…."[104] In support of their contention, the Filing Parties make a number of unsubstantiated claims. Contrary to their claims, the existing transmission planning process in New England is both inferior to and inconsistent with the Order No. 1000 no-ROFR process.

1. The Filing Parties' Claim That the Existing Transmission Planning Process Has Been Highly Successful Fails To Consider the Cost to Consumers.

The Filing Parties claim that the existing transmission planning process in New England has been "highly successful, resulting in the construction of a large number of new ISO-NE-approved transmission projects…."[105] There is no question that the existing process has been successful in terms of getting new transmission built, but it has only done so at an extraordinary cost to consumers. Between 2002 and 2011, more than $4.7 billion in new pool transmission facilities were added, with another $5.7 billion in new pool investments planned to go into service between 2012 and 2020.[106] One study estimates transmission system expenditures in New England in the last ten years are 5-6 times their level in 2000 and were up approximately 17

[104] Transmittal Letter at 22.

[105] *Id*. at 22-23.

[106] *Id* . at 10.

times in 2008 from 2000 levels.[107] The fact that transmission has been built in New England under the existing transmission process does not answer two critical questions implicit in Order No. 1000: at what cost?; and could the cost have been less?

The current transmission planning process in New England is resulting in significant rate increases for New England consumers – in 2012, the Regional Network Service ("RNS") rate in New England was $75.25/kW year, and was projected to rise to $115/kW in 2016, an increase of more than 50% over the four-year period, with an average 10% increase annually.[108] Not only have transmission expenditures been rising substantially in New England, but "New England expenditures on transmission are growing at a radically steeper rate than those of the rest of the country," and this trend is expected to continue.[109] Though there may be reasonable explanations for some of this difference, is simply not credible to claim that the existence of competition unfettered by the barriers imposed by the ROFR could not have produced, and will not produce going forward, material savings in regional reliability transmission investment costs.

The magnitude of these increases is attributable in part to significant cost overruns in many transmission projects in recent years.[110] In recent years, over two-thirds of transmission projects with in-service estimated costs in excess of $10 million had in-service costs that

---

[107] Environment Northeast, *Escalating New England Transmission Costs and the Need for Policy Reforms* (June 2011), at 8, available at http://www.env-ne.org/public/resources/pdf/ENE_EscalatingNETransmissionCostsandNeedforPolicyReforms_20110630_Final.pdf. The Southern New England States note that while they believe this report's summary of transmission costs is reasonable and accurate, they do not endorse any other findings or the conclusions set forth in the report.

[108] Affidavit of Rose Ann Pelletier (appended as Attachment A), at P 9; RNS Rates – Five Year Forecast, prepared by PTO AC-Rates Working Group (Aug. 13-15, 2012), at Slide 7, available at http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2012/aug1314152012/index-p2.html (posted under Transmission Committee Materials on Aug. 7, 2012).

[109] Affidavit of Rose Ann Pelletier, at P 6, citing *Escalating New England Transmission* at 9.

[110] Affidavit of Rose Ann Pelletier at P 7; *see also New England Conference of Public Utilities Commissioners, Inc. v. Bangor Hydro-Electric Co. et al*, Docket No. EL08-69-000, "Complaint of the New England Conference of Public Utilities Commissioners, Inc. Seeking Limitation on Amount of Transmission Costs to Which Incentive ROE Adder Applies" (June 12, 2008), Attachment A (discussing cost overruns as much as over 400% in the relevant timeframe).

exceeded the planned estimate costs.[111] The Southern New England States are not here disputing the prudence of prior cost overruns, but note that the mere existence of such substantial cost overruns and their resulting impact on consumers are of major concern to them. And the existence of these cost overruns demonstrates that the current ISO-NE transmission planning process clearly lacks effective cost control mechanisms.[112] There simply is no evidence supporting the Filing Parties' unsubstantiated claims that the current process results in a process superior to the regimen contemplated by Order No. 1000 that would use competition to develop a more efficient and cost-effective transmission system to meet the needs of the region.

2. Contrary To the Filing Parties' Claim, the Existing Process Does Not Ensure That All Potential Solutions Will Be Openly Considered.

The Filing Parties argue that the cornerstone of the existing New England transmission planning process is open collaboration,[113] claiming that:

> The benefits of this open collaboration will be lost if the Commission forces ISO-NE to replace the existing process with a process in which parties must submit their own individual proposed solutions and then compete for inclusion in the RSP Project List.[[114]]

This self-interested observation is transparently not true. Allowing competitors to submit proposals in an open and competitive process will not destroy the collaborative and open regional transmission planning process in ISO-NE. Order No. 1000 mandates the extension to the regional transmission planning process of seven of the nine transmission planning principles

111 Affidavit of Rose Ann Pelletier at P 9.

112 The cost impact on consumers of these significant cost overruns is exacerbated by the significant rate incentives awarded for regional transmission projects under the Commission's transmission rate incentives rule in Order No. 679 (*see e.g., Northeast Utilities Service Company and National Grid USA*, 125 FERC ¶ 61,183 (2008), and stale rates of return on equity that were authorized over ten years ago when capital costs were significantly higher – *see, e.g., Martha Coakley, Massachusetts Attorney General, et al. v. Bangor Hydro-Electric Co. et al.*, 139 FERC ¶ 61,090 (2012) (setting for hearing and settlement proceedings the complaint filed by the Massachusetts Attorney General and other parties challenging the existing returns on equity authorized for public utility transmission providers in New England).

113 Transmittal Letter at 23-24.

114 *Id*. at 24.

adopted in Order No. 890, including the requirements for an open and collaborative planning process.[115] Order No. 1000 contemplates that all stakeholders, not just incumbent transmission owners, should have a role in the regional transmission planning process. All stakeholders, including incumbent transmission owners, will be able to review and analyze proposals submitted by non-incumbent developers, and the changes the Filing Parties submitted to accommodate non-incumbent proposals allows ISO-NE to obtain input from incumbent transmission owners on those proposals.[116]

In contrast, the existing New England transmission planning process frustrates effective collaboration by effectively excluding competing non-incumbent transmission owners from the transmission solution development process and the possibility of transmission ownership. Under the existing New England transmission planning process there is no incentive for non-incumbent transmission providers to submit transmission solutions for reliability needs. Non-incumbent transmission developers cannot construct and own proposed reliability projects without the incumbent transmission owner's agreement – an unlikely outcome given the financial incentive to keep competitors out of the process. Even if a non-incumbent transmission provider proposed an alternative reliability solution, the existing ROFR would not allow the non-incumbent to build the reliability project if it were to be included in the Regional System Plan,[117] thus discouraging non-incumbents from submitting proposal for regional reliability projects. The current New

[115] Order No. 1000 at P 151.

[116] Attachment K, Section 4.2(e) (allowing the Planning Advisory Committee to provide feedback to the ISO on the results of solutions studies related to Market Efficiency and Reliability transmission upgrades); *See also* Attachment K, Section 2.2 (providing for the Committee's input on Needs Assessments, as well as the development of the Regional System Plan and assumptions used in developing the plan) and Section 2.3 (allowing any entity, including incumbent transmission owners, to be members of the Planning Advisory Committee).

[117] Transmission Owners' Agreement, Section 3.09 and Schedule 3.09(a)(1.1)(b); *see also* proposed Contingent Compliance Filing Attachment K, Section 4.1(h) continuing in place a ROFR for reliability transmission projects needed in service within a five-year planning horizon.

England transmission planning process is exclusionary, not inclusionary, and discourages, not fosters, collaboration; it is demonstrably inferior to the regional transmission planning process contemplated by Order No. 1000.

3. The Filing Parties' Claim That No Other Superior Potential Solutions Have Been Identified in the Existing Planning Process is a Self-Fulfilling Prophecy.

The Filing Parties claim that "[n]o party has ever come forward with a reliability project that should have been constructed in New England that was superior to one that was selected…."[118] This is, of course, a Catch-22. Under the existing process, even if a non-incumbent developer committed the time and resources to develop a superior proposed solution, an incumbent transmission owner would be selected to construct and own the project. As previously discussed, a transmission planning process that includes a ROFR, such as the existing New England transmission planning process, discourages non-incumbent transmission developers from committing resources to the development of potential transmission or other innovative solutions. Under the current ROFR, an incumbent transmission provider need not exercise its ROFR until after the benefits of the transmission project have been demonstrated, thus minimizing its own development costs and eliminating any prospect for the non-incumbent to benefit from its proposal. Non-incumbent transmission providers have no reason to propose solutions knowing that ultimately the construction and ownership of the project will go to the incumbent transmission providers.

[118] Transmittal Letter at 24 (internal footnotes omitted).

4. The Filing Parties' Claim That Disrupting the Existing Process Would Mean the Loss of Incumbent Transmission Provider Expertise in Reviewing Alternatives and the Incurrence of Additional RTO Costs is Unsubstantiated.

The Filing Parties claim that "[i]f the ROFR is eliminated from the planning process, the [incumbent transmission providers] will not be able to share their expertise with ISO-NE in the same manner that has produced exemplary results under the current process…"[119] and that "[t]he dueling submission approach would represent a huge step backward from the existing process…."[120] Preliminarily, it bears noting that what the PTOs call a "huge step backward" is the introduction of competition into the regional transmission planning process, the specific goal of the Commission-ordered elimination of the ROFR.

Moreover, there is nothing in the Order No. 1000 required transmission planning process that would prevent ISO-NE from obtaining the input of incumbent transmission providers in evaluating alternative proposals; indeed, prudent utility practice would suggest that the PTOs would have an obligation to participate in the planning of any facility to be connected to and integrated into their own transmission facilities. Nor is there any reason why incumbent transmission providers could not be compensated on a cost basis, as necessary, for any analyses actually conducted.

The fallacy of the Filing Parties' claim can be found in the process they proposed for compliance with the public policy mandates in Order No. 1000.[121] In their primary proposal, the Filing Parties submitted "a project-based process that…is open to competition from non-incumbent pre-qualified developers…."[122] Notably, the Filing Parties make no claim that the

---

[119] Transmittal Letter at 24. *See also*, PTO Testimony at 27-28.

[120] Transmittal Letter at 25.

[121] Order No. 1000 at P 203.

[122] Transmittal Letter at 49.

lack of a ROFR in the public policy project planning process would mean the loss of incumbent transmission provider expertise in reviewing alternatives and the incurrence of additional RTO costs. The Filing Parties' claim that eliminating the ROFR will eliminate opportunities to take advantage of their expertise is obviously self-serving and should be rejected.

5. The Filing Parties' Claim That the Current Process Reduces Costs, the Probability of Disputes, and Resulting Delay, is Misplaced.

The Filing Parties' claim that elimination of the ROFR, which "will require ISO-NE to make decisions among dueling submissions," is inferior to the existing New England process, which is "open and transparent,"[123] makes no sense. Order No. 1000 ordered the adoption of an open and transparent regional transmission planning process.[124] The Filing Parties do not explain how a process which places all potential transmission owners on an equal footing and which encourages the submission and consideration of all competing proposals for reliability projects could be less transparent or less open that the current process, which does none of those things.

The Filing Parties are really arguing that, if they are not required to compete, the regional transmission planning process will cost less. It is theoretically possible that this claim could be correct in the near-term, but any savings in transmission planning process costs would come at the cost of the loss of the beneficial effects of competition. It is beyond question that monopolies stifle innovation and have no incentive to control costs.[125] The dramatically escalating RNS rate

[123] Transmittal Letter at 25.

[124] Order No. 1000 at P 151.

[125] *United States v. Aluminum Co. of America*, 148 F.2d 416, 427 (2d Cir.1945), noting that the Sherman Act is founded on the belief that:

> possession of unchallenged economic power deadens initiative, discourages thrift and depresses energy; that immunity from competition is a narcotic, and rivalry is a stimulant, to industrial progress; that the spur of constant stress is necessary to counteract an inevitable disposition to let well enough alone.

See also Nat'l Soc. of Prof. Engrs. v. U.S., 435 U.S. 679, 695 (1978).

can be considered testament to these precepts. There is no assurance in the current regional transmission planning process with the ROFR that the best and lowest reasonable cost project will be selected, because the best project may never be submitted for consideration.

Moreover, the current ROFR process is not insulated from inefficiency, particularly the potential for litigation. The Commission is well aware of the cost allocation litigation that has occurred under existing, pre-Order No. 1000 transmission planning processes,[126] as well as the disputes under the Midwest Independent Transmission System Operator, Inc. ROFR among incumbent transmission owners.[127]

6. The Filing Parties' Claim That Competition Occurs under the Current Process is Simply Incorrect.

The Filing Parties claim that the existing New England transmission planning process incorporates competition because:[128]

> when one or more [incumbent transmission providers] are selected to build a reliability project under the current process, they generally hold a competitive solicitation for the construction and procurement of work for the projects.

The fact that there may be some competition in *construction* of facilities and asset procurement obviously does not mean that there is competition in the submission of proposals or for *ownership* of regional reliability transmission projects; there is not. As discussed in section VI.D.2.b, retention of a ROFR for the existing projects included in the Greater Boston Analysis study would result in no new transmission projects being open for competitive solicitation since all those projects either fall within one of the three categories of projects excluded from the

---

126 *Illinois Commerce Comm'n, et al., v. FERC,* Nos. 11-3421, *et al.* (7th Cir., filed October 27, 2011) (appeal of Midwest Independent Transmission System Operator, Inc. allocation of the cost of Multi-Value Projects across the region); *see also Illinois Commerce Comm'n, et al. v. FERC,* 576 F. 3d 470 (7th Cir. 2009) *(appeal of PJM regional cost allocation method).*

127 *Xcel Energy Services, Inc. et al. v. American Transmission Company, LLC*, 140 FERC ¶ 61,058 (2012) (ruling on a dispute between two incumbent transmission owners in the Midwest ISO as to ownership and construction obligations under the existing ROFR).

128 Transmittal Letter at 26.

required eliminate of the ROFR or are reliability projects for which the PTOs exercise the ROFR. Moreover, the Filing Parties have not demonstrated that any regional reliability projects in the Regional System Plan to date have been subject to development, construction and ownership by non-incumbent transmission developers.

7. The Filing Parties' Claim That Non-Incumbents Will Be Disadvantaged in the Siting Process is Unsupported and, In Any Event, Does Not Justify Precluding Non-Incumbents from Competing.

The Filing Parties claim that allowing non-incumbents to compete for regional reliability transmission projects will result in additional costs, wasted effort, and lost time because non-incumbents do not have the incumbents' longstanding relationships with State regulators and local officials responsible for permitting projects.[129] The Filing Parties also argue that, with limited land opportunities and projects routed through highly populated areas, they often have to use political capital to get projects approved.[130] The Filing Parties do not, however, provide any evidence or analyses of the experience that non-incumbents have had to date in getting projects sited and constructed. As such, their comments are entirely speculative.[131] As the Commission is well aware, there have been many non-incumbent and merchant projects throughout the Nation in recent years that have received state siting authority.[132]

---

[129] Transmittal Letter at 26. *See also* PTO Testimony at 30-31.

[130] Transmittal Letter at 26.

[131] Indeed, in many circumstances, the regulators that possess siting authority are the same that support the introduction of competition into the regional transmission planning process.

[132] *See, e.g., Trans-Allegheny Interstate Line Co.*, Pub. Serv. Comm'n of West Virginia Case No. 07-0508-E-CN, order granting certificate (August 1, 2008), *orders on reh'g* (February 13, 2009 and September 7, 2011); and *PATH West Virginia Transmission Co., LLC, et al.*, Pub. Serv. Comm'n of West Virginia Case No. 09-0770-E-CN, order granting certificate (May 15, 2009), *order dismissing case* (March 1, 2011) (at PATH's request due to PJM's cancellation of the project); *see also Trans-Allegheny Interstate Line Co.*, Pennsylvania Pub. Util. Comm'n Case Nos. 110172, *et al.*, Orders (December 12, 2008 and November 19, 2010) (approving certificate application and settlement revising the certificate application).

The supposed problems of non-incumbents developing transmission projects in highly populated areas of New England is equally speculative and over-stated. There clearly are heavily populated areas of New England and there are also extensive areas of New England that are less densely populated and which may be prime areas for transmission development, not to mention the possibility of development of underwater transmission projects.

Finally, to the extent these claims have any merit, incumbent transmission providers have nothing to fear because they will have an advantage in any competitive process. Let the competitive process work and the Filing Parties' supposed advantages will either be proven or not. The Commission should not rely on self-serving speculation to preclude competition, which is what the PTOs seek.

8. The Filing Parties' Claims That Competition Will Not Reduce the Cost of Transmission Are Not Credible and Are Unsupported.

The Filing Parties claim that competition in the transmission planning process will not reduce the costs of transmission development in New England for six reasons: (1) incumbent transmission providers subject their projects to competitive solicitation for procurement and construction services; (2) the current process identifies the combination of ideas "that will eliminate reliability and market efficiency issues in the most cost-effective manner;" (3) incumbent transmission providers' projects will be regulated, cost-of-service facilities; (4) there is no reason to believe non-incumbent transmission providers can finance projects at a lower cost than incumbent transmission providers; (5) project development costs are subject to regional cost recovery and a submission-based cost would increase costs; and (6) ISO-NE would have to hire additional staff to study multiple project submissions.[133]

[133] Transmittal Letter at 27.

These claims, generally unsupported by analysis or rationale, provide no basis for retaining the ROFR. The Filing Parties claim the existing process minimizes costs because incumbent transmission providers subject their projects to competitive solicitation for procurement and construction services; however, there is nothing that would prevent a non-incumbent transmission provider from competitive solicitation for these services. Similarly, the argument that the current process identifies the best combination of ideas and eliminates reliability and market efficiency issues in the most cost-effective manner is a conclusion, not a fact, premised on the assumption that the absence of competition is the most efficient and cost-effective means of transmission development. That assumption is directly contrary to the findings of Order No. 1000 upon which Commission's order to eliminate the federal ROFR rests.

The filing Parties ignore that a non-incumbent transmission developer may have financing advantages unavailable to the incumbents and thus be able to obtain lower cost financing for the project, or take advantage of economies of scale unavailable to smaller incumbent transmission owners. A large non-incumbent transmission developer may be able to leverage its credit and attain savings because of the scale by which it can procure materials and labor, and may be more willing to accept different risk-sharing arrangements for the financing of transmission facilities. The planning process should not foreclose the potential for achieving these types of cost efficiencies by retaining the ROFR for regional reliability transmission projects.

As discussed in the preceding section, if incumbent transmission owners believe they can propose solutions to regional transmission needs at lower costs than non-incumbents, they should have an advantage in the transmission planning process and should not object to opening up the process to competition.

C. The Filing Parties' Primary and Contingent Compliance Filings Are Unsupported by the Vast Majority of Stakeholders and Should Be Rejected.

At the September 25, 2012 ISO-NE transmission committee meeting, only 17 percent of the stakeholders voted in favor of the ISO and Majority PTO's proposal.[134] The 17 percent of stakeholders that supported the proposal were all members of one sector – the transmission owner sector. In other words, the *only* stakeholders to vote in favor of the PTO proposal were the incumbent PTOs themselves, who stand to profit from keeping competitors out.

The Commission emphasized in Order Nos. 1000 and 1000-A the importance of the stakeholder process,[135] yet the Filing Parties submitted a Primary Compliance Filing, as well as a Contingent Compliance Filing, that was supported by only one-sixth of the stakeholders – the PTOs – and that was not supported by a single stakeholder that was not a PTO. In contrast, the overwhelming majority of ISO-NE stakeholders – the 83 percent of stakeholders which are not PTOs – voted in support of an alternative proposal, the proposal offered by NHT.

D. The Commission Should Reject The Filing Parties' Contingent Compliance Filing.

1. The Contingent Compliance Filing Is Not Compliant with Order Nos. 1000 and 1000-A and Should Be Rejected.

The Contingent Compliance Filing does not comply with Order Nos. 1000 and 1000-A and therefore should be rejected.

---

134 Memo. (at 3 and fns. 7-9) From Eric Runge, NEPOOL Counsel, to NEPOOL Participants Committee (Sept. 26, 2012), at 238, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2012/oct32012/npc_20121003_composite.pdf.

135 Order No. 1000 at P 466; Order No. 1000-A at P 518 (stakeholders must have meaningful opportunity to provide input into the development of interregional transmission coordination procedures prior to submission to Commission).

Order No. 1000-A permitted any transmission provider to argue in its compliance filing that the ROFR was protected by the *Mobile-Sierra* doctrine, but explicitly required that:[136]

> any such compliance filing must include the revisions to any Commission-jurisdictional tariffs and agreements necessary to comply with Order No. 1000 as well as the *Mobile-Sierra* provision arguments. . . . if the Commission determines that the agreement is not protected by a *Mobile-Sierra* provision or that the Commission has met the applicable standard of review, then the Commission will decide whether the revisions to the Commission-jurisdictional tariffs and agreements comply with Order No. 1000 and, if such tariffs and agreements are accepted, would become effective consistent with the approved effective date.

The Filing Parties' Contingent Compliance Filing does not comply with this requirement. Order Nos. 1000 and 1000-A categorically reject and require the elimination of the ROFR (except for the three limited circumstances discussed above). The Contingent Compliance Filing retains a ROFR for incumbent public utility transmission owners to construct and own transmission projects arguably needed to resolve reliability violations within five years of the date that the need for the project is determined.[137] In essence, the Filing Parties propose that if the Commission rejects their request to retain the ROFR for all reliability projects, the Commission should accept their Contingent Compliance Filing, which provides for the retention of a ROFR for reliability projects needed within a five-year window. This proposal is in violation of Order Nos. 1000 and 1000-A and compels the rejection of the Contingent Compliance Filing.[138]

The core Contingent Compliance Filing revisions are in Sections 4.1 and new Section 4.3 to Attachment K. Section 4.1(h) "provide[s] that where the forecast year of need is five years or less from the completion of a Needs Assessment…ISO-NE would continue to utilize the existing

---

[136] Order No. 1000-A at P 389.

[137] The Mass DPU notes that the date by which a reliability project is needed can be a subject of dispute.

[138] *See, e.g.*, *Entergy Louisiana, Inc.*, *et al.*, 94 FERC ¶ 61,330 at pp. 62,232-33 (2001) (rejecting compliance filing because the "proposal violated the unambiguous requirements of Order No. 888-A . . ."); *see also Cleco Utility Group, Inc.*, 100 FERC ¶ 61,323 at P 9 (2002).

Solution Studies process."[139] In other words, under the Contingent Compliance Filing, projects identified as being within five years of the completion of a Needs Assessment will be developed in the same manner they are today. This contingent proposal, like the primary proposal, violates the Order No. 1000 requirement to eliminate the ROFR; therefore, the Southern New England States urge the Commission to also reject the retention of a five-year ROFR in the Contingent Compliance Filing.

2. The ROFR Provisions of the Contingent Compliance Filing Are Unjust and Unreasonable.

In rejecting the retention of federal ROFRs, the Commission explained that leaving federal ROFRs in place can undermine the identification and evaluation of solutions to regional transmission needs, which could result in unjust and unreasonable rates for Commission-jurisdictional facilities and in undue discrimination by public utility transmission providers.[140] The Commission affirmed its decision in Order No. 1000-A with respect to reliability projects,[141] explicitly requiring the elimination of a federal ROFR *for reliability projects* as well as other types of projects.

The Filing Parties submitted no evidence to support their claim that the ROFR given to incumbents within the five-year window is necessary or reasonable. Nor do they attempt to distinguish projects for which retaining a ROFR would be appropriate based on location, size, or type of facility, factors which could affect both how long and complex the comparative evaluation may be and how long the project would take to develop once selected. Instead, they claim, without support, that there would be insufficient time to develop and analyze competing

---

[139] Transmittal Letter at 66-67. This is true unless the solution to the needs assessment will likely be a Market Efficiency Transmission Upgrade.

[140] Order No. 1000 at PP 7, 284.

[141] Order No. 1000-A at PP 415, 428.

proposals for projects needed in service within this five-year window. In other words, the Contingent Compliance Filing contains at its core the very ROFR the Commission ordered eliminated. For the reasons discussed below, the Commission should reject the Filing Parties' claims and direct them to remove the ROFR for reliability projects within the five-year window from the Contingent Compliance Filing tariff language.

a. The Contingent Compliance Filing retains the barriers to entry that the Commission explicitly ordered eliminated in Order No. 1000.

The Commission recognized in Order No. 1000 that an incumbent transmission provider could use a ROFR to "discourage new entrants from proposing new transmission projects in the regional transmission planning process"[142] and that removal of the federal ROFR would remove a barrier to participation by all potential transmission providers.[143]

The Filing Parties fail to submit any evidence to support their proposition that "employment of the five-year reliability window is consistent with or superior to the principles and compliance approach set forth in Order No. 1000 regarding the right of first refusal,"[144] or that such a ROFR will not perpetuate precisely the same barrier to entry by new potential transmission providers that the Commission ordered removed in Order No. 1000. The Filing Parties claim:

> The five-year threshold was selected to permit submission of dueling projects in appropriate circumstances, while recognizing the reality of near- to mid-term reliability needs. Factors that came into play were the time needed to design, site and construct transmission projects, with major projects requiring more than five years and more minor 115 kV projects requiring around five years to complete.[[145]]

---

[142] Order No. 1000 at P 256.

[143] *Id.* at P 265.

[144] Transmittal Letter at 67 (internal footnotes omitted).

[145] *Id.* at 65.

In support of this contention, however, the Filing Parties submitted generalized testimony that predictably offered their opinions that a five-year ROFR is essential. For example, Stephen J. Rourke, Vice President of System Planning with ISO-NE, testified that entertaining competing proposals would require ISO-NE to add 12-24 months to conduct the solicitation and two phases of review, and speculated that there would be potentially additional delay associated with possible litigation arising from the award decisions.[146] Not surprisingly, the PTOs, the only supporters of the Contingent Compliance Filing, concur in ISO-NE's opinion.[147]

The Filing Parties fail to explore in any way what modifications could be made to the process to accommodate competing proposals during the five-year period. The Filing Parties ignore the Commission's explicit findings as to the unjustness, unreasonableness and anticompetitive impact of the ROFR, and, instead, cobble together reasons why the ROFR is nevertheless supposedly needed in New England. In fact, competing proposals can be accommodated without unnecessarily prolonging the selection and award process.

For example, PJM has proposed in its Order No. 1000 compliance filing in Docket No. ER13-198 (Transmittal Letter at 54-57) to allow non-incumbent developers to submit proposals for reliability projects needed within a five-year window. PJM's proposal is that: (1) Long-lead projects (those needed in-service more than 5 years from now) are subject to competing proposals from non-incumbent developers; (2) Short-term projects (needed in service in years 4 and 5) to resolve reliability criteria violations are subject to a 30-day window for competing proposal from all developers, incumbent and non-incumbent alike; and (3) Immediate Need

[146] Rourke Testimony at 19.

[147] PTO Testimony at 38-39 and 42.

Reliability projects (those needed in service in 3 years or less)[148] to resolve a reliability criteria violations are open to competing proposals from incumbent and non-incumbent developers if PJM determines that there is sufficient time to hold a shortened proposal window considering the project's overall timeframe.

Likewise, the Southwest Power Pool, Inc. ("SPP") and the Midwest Independent Transmission System Operator, Inc. ("MISO") submitted Order No. 1000 contingent compliance filings in the event the Commission rejects their *Mobile-Sierra* arguments against elimination of their respective ROFRs.[149] Neither MISO nor the SPP contingent compliance filings appears to contemplate a carve-out of five years (or some other period of time) in which the ROFR would be retained for reliability projects. MISO's proposal is to assign those categories of projects that are excluded from the ROFR requirements by Order No. 1000 to transmission owners under the existing process outlined in the MISO TOA. Projects that are covered by the Order No. 1000 mandate to eliminate ROFRs "will be classified as Open Transmission Projects, for which MISO will issue Transmission Proposal Requests, in response to which both non-incumbent transmission developers and incumbent Transmission Owners may submit New Transmission

---

[148] PJM proposes to define Immediate Need Reliability Project as: "A reliability-based transmission enhancement or expansion: (i) with an in-service date of three years or less from the year the Office of the Interconnection identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in section 1.5.3 of this Schedule 6; or (ii) for which the Office of the Interconnection determines that an expedited designation is required to address existing and projected limitations on the Transmission System due to immediacy of the reliability need in light of the projected time to complete the enhancement or expansion. In determining whether an expedited designation is required, the Office of the Interconnection shall consider factors such as, but not limited to, the time necessary: (i) to obtain regulatory approvals, (ii) to acquire long lead equipment; (iii) to meet construction schedules, (iv) to complete engineering plans, and (v) for other time-based factors impacting the feasibility of achieving the required in-service date." *See* PJM Operating Agreement at section 1.15A; *see also,* PJM Tariff at section 1.14A.001, *proposed*.

[149] *See Southwest Power Pool, Inc.*, Docket No. ER13-366-000, (filed Nov. 13, 2012); *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER13-187 (filed Oct. 25, 2012). SPP and MISO's Order No. 1000 compliance filings are extensive. The Mass DPU has not undertaken to fully evaluate either proposal and, therefore, expresses no opinion as to whether the SPP or MISO Order No. 1000 compliance filings are compliant with Order No. 1000.

Proposals…."[150] Pursuant to SPP's conditional proposal, in addition to the exceptions delineated in Order No. 1000, incumbent transmission owners will retain the right to construct "local transmission facilities," which will be defined as local transmission facilities as established in its Highway/Byway cost allocation methodology proceedings.[151]

83 percent of the ISO NE Participants – all participants except the PTOs – supported an alternative proposal submitted by NHT that, while not perfect from the Southern New England States' perspective, includes only a three-year ROFR which dramatically reduces the adverse effect of the ROFR on competition and is much more preferable than the Filing Parties proposal. *See* section VII, below.

In short, contrary to the Filing Parties' contention, and as demonstrated by the PJM compliance filing, a five-year ROFR is not necessary for near- or mid-term reliability projects.

b. Implementation of a five-year ROFR will stifle competition and keep the lion's share of projects for the incumbent transmission providers.

The Commission found that allowing incumbent transmission owners a federal ROFR, even of a very limited duration, "would discourage transmission developers from proposing transmission projects that may be a more efficient or cost-effective solution to meet regional transmission needs…."[152] This concern is not merely academic. Materials presented by NHT during the ISO-NE Order No. 1000 stakeholder meetings indicate that providing incumbents with a ROFR for reliability projects needed within a five-year window in the Greater Boston

---

150 MISO Transmittal Letter at 40.

151 SPP Transmittal Letter at 52-53.

152 Order No. 1000-A at P 428. *See also Nat'l Soc'y of Prof'l Eng'rs v. United States*, 435 U.S. 679, 695 (1978) ("The assumption that competition is the best method of allocating resources in a free market recognizes that all elements of a bargain – quality, service, safety, and durability – and not just the immediate costs, are favorably affected by the free opportunity to select among alternative offers.").

Study "would not have yielded any competitively bid projects" for that time period.[153] Retention of a five-year ROFR for reliability projects, therefore, would result in consideration of only transmission proposals of incumbent transmission owners to meet regional reliability needs, precisely the result the Commission sought to preclude in Order Nos. 1000 and 1000-A.[154]

3. If the Commission Permits the Retention of a Federal ROFR in the Contingent Compliance Filing, the Commission Should Approve the NEPOOL Alternative Proposal.

In September 2012, NHT submitted a proposal through the ISO-NE stakeholder process that, *inter alia*, offered a less restrictive ROFR to encourage competition – a reliability horizon of three years instead of five years (the "NHT Amendment"). In support of the NHT Amendment, NHT noted:

> Instead of developing a package of reforms that espouse the spirit of Order 1000 and takes into account various stakeholder concerns, NHT views the Majority PTO/ISO-NE proposal as substantially erecting barriers to competition in an attempt to maintain the status quo with regard to transmission needed for reliability, and also with regard to the construction of public policy transmission projects.[[155]]

The NHT Amendment is incorporated in the NEPOOL Proposal filed with the Commission in response to the Filing Parties' proposal on November 16, 2012.

The Southern New England States support strict adherence to the Order No. 1000's ordered elimination of the federal ROFR, but if the Commission were to consider its retention for shorter-term reliability projects, the Southern New England States submit that the NEPOOL

153 *See* Order No. 1000 - Competitive Analysis – v3, at Slide 5, prepared by New Hampshire Transmission, LLC (August 2, 2012), available at http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2012/aug1314152012/index-p2.html (posted under Transmission Committee Materials on Aug. 27, 2012).

154 Order No. 1000-A at P 428.

155 Memo. (at 2-3) From Matt Valle, President, New Hampshire Transmission, LLC, to Calvin Bowie, Chairman, Participants Committee (Sept. 26, 2012), at 115-116, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2012/oct32012/npc_20121003_composite.pdf.

Alternative Proposal, as part of the comprehensive package of changes that includes the NHT amendment, is a reasonable proposal that balances the competing concerns of maintaining reliability in the short term while still allowing competition for some reliability projects from non-incumbent developers. The NHT presentation to the ISO-NE stakeholders indicated that restricting a ROFR for reliability projects to a three-year window would have allowed competing proposals for all fourteen of the reliability projects not subject to Order No. 1000 exceptions for continued use of ROFRs, *i.e.* for local reliability projects, upgrades to existing facilities, or projects built on incumbent held rights-of-way.[156]

The Southern New England States emphasize that if the Commission finds the need for a limited ROFR for short-term reliability projects, the Commission should accept the NHT-proposed three-year ROFR as part of the total package proposed by NHT. The Southern New England States' willingness to support the NHT ROFR proposal is only as that proposal fits in with the overall package of measures that comprise the NHT proposal. The Southern New England States' one caveat is that the Commission should condition acceptance of the NHT proposal on a review, *e.g.*, after three years, to determine the effect of the three-year ROFR on competition.

The Commission should reject the proposal in the Contingent Compliance Filing to retain a ROFR for reliability projects needed within a five-year window as contrary to Order No. 1000 and as demonstrably inferior to the widely supported compromise proposal proposed by NHT and supported by the vast majority of stakeholders.

[156] *See* Order No. 1000 - Competitive Analysis – v3, at Slide 5, prepared by New Hampshire Transmission, LLC (August 2, 2012), available at http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2012/aug1314152012/index-p2.html (posted under Transmission Committee Materials on Aug. 27, 2012).

VII. THE FILING PARTIES' PUBLIC POLICY PROJECT PROPOSAL IS PART OF AN UNJUST AND UNREASONABLE COMPLIANCE FILING THAT IS NOT COMPLIANT WITH ORDER NO. 1000; THE NEPOOL ALTERNATIVE PROPOSAL IS A BALANCED PROPOSAL REFLECTING STAKEHOLDER CONSENSUS ON THE APPROPRIATE MEASURES TO ADDRESS PUBLIC POLICY PROJECTS IN REGIONAL AND LOCAL TRANSMISSION PLANNING AND COST ALLOCATION PROVISIONS.

A. The Compliance Filing Including the Filing Parties' Public Policy Project Proposal Should Be Rejected.

The Filing Parties' Public Policy Project Proposal has elements that the Southern New England States could support, but there are essential elements of the proposal discussed below that are either inadequately addressed or not addressed at all. The overriding failing of the proposal, however, is that it is part of a compliance filing package which, as demonstrated above, is unjust, unreasonable and non-compliant with Order No. 1000. The NEPOOL Alternative Proposal, by contrast, better addresses the concerns and needs of the states and all stakeholders.

B. The NEPOOL Alternative Proposal Is a Balanced Mechanism That Will Achieve the States' Public Policy Goals and Meet the Needs of All Stakeholders.

The Southern New England States urge the Commission to direct the Filing Parties to modify their Public Policy Project Proposal to conform to the NEPOOL Alternative Proposal proffered by NEPOOL in its Comments. The NEPOOL Alternative Proposal is a compromise package that more appropriately balances the interests of the states, ratepayers, project developers and other stakeholders. This compromise is grounded in the achievements to date and the steps already taken by the six New England states to promote and facilitate the development of projects that will assist the states in meeting current and emerging public policy objectives, including, for example, the development of additional renewable and energy efficiency resources and smart grid technologies.

The New England states supported Order No. 1000's requirement that transmission providers explicitly include consideration of state public policy requirements in the local and regional transmission planning processes.[157] The fundamental principle of the NEPOOL Alternative Proposal is that the regional transmission planning process for public policy projects be driven by the public policy goals and decisions of the six New England states. Any significant changes to the proposal or this bedrock principle may compromise the support of the Southern New England States, as well as the support of other New England states. From this starting point, the Southern New England States view the process of planning for transmission needs driven by public policy requirements through the prism of what they are already doing. For example, as previously noted, Massachusetts is aggressively implementing a number of public policy objectives, and has been actively pursuing Renewable Portfolio Standards initiatives since at least 2003.[158] At the same time, the New England regional transmission grid has undergone unprecedented expansion with the addition of billions of dollars of new transmission facilities, albeit at considerably higher rates to consumers.[159] While the incumbent public utility transmission owners in New England would appear to take full credit for this accomplishment,[160] the New England states, while seeking to control the costs of transmission expansion, have played an active role in that process and in identifying the potential for transmission infrastructure improvements and additions to facilitate attainment of the states' public policy objectives.

---

[157] *See* Order No. 1000 at PP 203-204.

[158] The Massachusetts Renewable Energy Portfolio Standard is a statutory obligation that obligates both regulated distribution utilities and competitive suppliers to obtain a percentage of electricity from qualifying renewable resources for their retail customers. MASS GEN. LAWS c. 25A, § 11F.

[159] Transmittal Letter at 2.

[160] *See, e.g.*, Prepared Direct Testimony of David Boguslawski and Carol Sedewitz at 3, ISO NE, Inc., et al., Docket No. ER13-193-000; *see also* Transmittal Letter at 3, and 5, n.22.

For example, the six New England states, through the New England States Committee on Electricity ("NESCOE"), have been actively investigating since September 2011 the prospect of obtaining analyses of Non-Transmission Alternatives ("NTAs") from the public utility transmission providers subject to their jurisdiction prior to the initiation of state transmission siting proceedings.[161] In 2009, the New England Governors adopted a Renewable Energy Blueprint that identified 10,000 MWs of combined on-shore and off-shore wind and other non-carbon resources and provided for a cross-border plan for the region to pursue development of those resources that will best meet state public policy initiatives in the region.[162] The Blueprint specifically noted that "New England has considerable recent experience successfully siting significant transmission facilities, including in some of the most densely populated areas in the region."[163] The New England states also requested in 2010 that ISO-NE conduct the "Economic Study – New England Power System, 2030," analyzing and forecasting reliability, cost and policy compliance outcomes expected for New England's power system over a 20-year period under assumptions that reflect status quo market and reliability constructs.[164] NESCOE also embarked upon an initiative to evaluate the benefits of investing in smart grid technologies to attain resource adequacy, system expansion and public policy goals.[165]

---

161 ISO New England States Committee on Electricity, *Non-Transmission Alternative Analysis: New England's Regional Framework* (Nov. 11, 2012), available at http://www.nescoe.com/uploads/NARUC_NTA_Framework.pdf.

162 New England Governors, *New England Governors' Renewable Energy Blueprint* (Sep. 15, 2009), available at http://www.nescoe.com/uploads/September_Blueprint_9.14.09_for_release.pdf.

163 *Id*. at 1.

164 ISO New England, *Economic Study: New England Power System, 2030*, available at http://www.nescoe.com/Economic_Study__2030.html.

165 Allison Smith, New England States Committee on Electricity, *New England States Smart Meter Status Report* (Nov. 1, 2012), available at http://www.nescoe.com/uploads/NECA_Smart_Grid_A.Smith_Final.pdf. Additionally, Massachusetts has opened a Notice of Inquiry in Docket No. 12-76 on Grid Modernization, to explore additional smart grid opportunities.

The six New England states have been and are continuing to work together to address policy goals and regional needs. The NEPOOL Alternative Proposal can assist the states by providing an alternative means through which public policy objectives can be achieved. The Southern New England States worked diligently with the other New England states, as well as other stakeholders in ISO-NE, to develop a public policy transmission planning and cost allocation process that would enhance the states' efforts already underway to achieve their public policy goals. Certain elements of the NEPOOL alternative public policy proposal are essential for the Southern New England States' support. For example, it is critical that the projects identified and selected be those that the states support as best suited to achieve the public policy goals selected by the states. The NEPOOL Alternative Proposal, by ensuring the central role of the states in the identification of policy requirements, potential transmission projects, and the best method for allocating the costs of those projects, ensures that any public policy-driven transmission projects in New England will be those that the states agree provide sufficient benefits to consumers as to merit the cost of development.

The success of Order No. 1000's public policy initiative will, in substantial part, depend upon how well it meets the policy goals of the states. Any modifications or steps which minimize the role of the states in the identification of public policies, potential transmission projects and cost allocation methods may well result in a mechanism that the states will avoid in favor of alternative processes already available to the states to achieve their public policy objectives. The NEPOOL Alternative Proposal is a better mechanism with which the states can work.

The following demonstrates that the NEPOOL Alternative Proposal is just and reasonable, meets the goals of Order No. 1000, and will enable the states to meet their policy goals.

C. The Central Role of the States in the Identification and Selection of Public Policy Projects and in the Determination of Costs Is Essential to the Success of the Public Policy Planning Process.

The Filing Parties' Public Policy Project Proposal offers the states a major role in regional transmission planning, but it comes at the price of an anticompetitive ROFR and the other objectionable aspects of the Compliance Filing. The NEPOOL Alternative Proposal appropriately places the states at the center of the process for identifying which public policy requirements are driving transmission needs, which transmission projects, if any, should be selected for inclusion in the Regional System Plan, and how the costs of such projects should be allocated among the states.[166] The reasons why the states should occupy such a central role are obvious. Public policy projects are not driven solely by engineering or economic analyses, but rather reflect the goals, aspirations, and concerns of the policy makers in the region, *i.e.*, the New England states. The public policies selected by the states drive the need for these projects, and it should be the public policy makers – the states – that drive the process and decision-making. For example, a state may determine that its citizens' electricity needs are best served with sustainable, renewable, or clean energy technologies, *e.g.*, wind, solar, biomass or hydrokinetic resources. In reviewing the relative merits of these state-determined public policies, state legislatures and regulatory authorities must factor in the relative costs and benefits of the policies, along with often hard-to-quantify societal benefits. Attainment of a public policy objective may result in construction of resources and facilities that are more costly than other

[166] NEPOOL Proposed Attachment K, Section 4A.1.

types of facilities built to address reliability or economic needs, but the state may determine that the benefits to its citizens from attainment of the public policy goal, such as reductions in greenhouse gases, outweigh those costs. In each instance, however, the decision is uniquely the state's to make.

The highly integrated nature of the New England regional transmission grid means that the attainment of one state's public policy goals will likely require the cooperation and participation of other states. The buy-in of each affected state is critical to the success of multi-state projects. If one state does not see its interests advanced by a particular project, it must have the ability not to participate and/or withdraw from the process at critical stages in the developmental process as development costs escalate. Similarly, the states participating in such a multi-state project must have the ability to decide how the costs of such projects should be allocated. The allocation of costs is an essential component of compromise on such projects. In short, the consensus of the states in public policy identification, project selection, and project cost allocation stages of the process, is critical to ensure that such projects move forward to construction. The Southern New England States and the other New England states, as reflected in NEPOOL's alternative, must consider, and would welcome, the input of other stakeholders in the ISO-NE local and regional transmission planning processes (NEPOOL Proposed Attachment K, Section 4A.1 and 4A.2), but at the end of the day, the states that adopt these policies should be the ones to decide which public policies should drive transmission needs, which projects should be evaluated and selected, and how costs should be allocated. Each state ultimately must decide whether a particular public policy or a particular project driven by public policy requirements advances the state's interests in a manner that justifies the associated costs for its consumers.

Ensuring the states this critical role, with stakeholder input, as proposed in the NEPOOL alternative proposal, provides the best means of assuring state support for any public policy projects ultimately selected. Providing the states a central role in the local and regional transmission planning and cost allocation process for public policy-driven transmission projects is also likely to reduce the potential for litigation about policy and project selection, as well as allocation of the associated costs.[167]

The NEPOOL Alternative Proposal also provides critical details omitted from the Filing Parties Public Policy Project Proposal. For example, Section 4A.5(e) of the NEPOOL alternative proposal addresses the information project developers must include in Stage 1 proposals at the request of NESCOE. States will consider and decide which proposed projects will best advance state public policies, and the states should have the opportunity to specify the information they need to determine what project proponents should include in proposals.

D. Reasonable and Effective Cost-Containment Tools Are Essential.

New England has benefitted from significant new investment in regional transmission infrastructure; however, that investment has come at a high cost to consumers. Over the past ten years, over $4.7 billion in new transmission expansions and upgrades have been constructed in New England,[168] resulting in nearly a 500 percent increase in the Regional Network Service ("RNS") rate for New England consumers over that same time period, to the current $75.25/kW-year rate level.[169] Proposed projects currently approved in the Regional System Plan that are in

[167] *See, e.g., Illinois Commerce Comm'n, et al., v. FERC*, Nos. 11-3421, *et al.* (7th Cir., filed October 27, 2011) (challenging the Midwest Independent System Operator, Inc.'s proposed approach for allocating the costs of Multi-Value Projects, including public policy-driven projects, across MISO's footprint); and *Illinois Commerce Comm'n, et al. v. FERC*, 576 F. 3d 470 (7th Cir. 2009) (appealing PJM's allocation of the costs associated with new transmission facilities rated at 500 kV and above across the entire PJM footprint).

[168] Transmittal Letter at 2; Affidavit of Rose Ann Pelletier at P 5 (noting that in 2011, transmission expenditures were up 5-6 times the 2000 level).

[169] Affidavit of Rose Ann Pelletier at P 9 (*see* Figure 5).

different stages of development total $5.7 billion in additional transmission infrastructure investments,[170] and are estimated to increase the RNS rates for New England consumers by nearly another $40/kW by 2016.[171]

Moreover, many of these completed projects, as well as the projects currently under construction, have experienced significant cost overruns. Between 2004 and 2008, there were a number of cost overruns, ranging from 30 to 408 percent.[172] As the Commission recently recognized in its Policy Statement on transmission rate incentives in Docket No. RM11-26-000, transmission project cost overruns are not unusual within the industry.[173] It is not unreasonable to assume that the trend toward significant cost overruns for transmission expansion will continue. Moreover, transmission incentives approved by this Commission under Order No. 679[174] have exacerbated the impact of these project costs for New England consumers.[175] It is thus imperative that the significant cost of new transmission investment be mitigated for future projects, including public policy-driven projects, to the maximum extent practicable. Consumers cannot be expected to fund seemingly unlimited new transmission investment without reasonable assurances that the costs of transmission projects are being kept to a minimum.

Managing and containing the cost of developing new transmission projects is even more imperative in the post-Order No. 1000 era where competing developer proposals are an intended result. While competition among proposals may well bring cost-efficiencies in the development

---

170 Transmittal Letter at 2.

171 Affidavit of Rose Ann Pelletier at PP 7-8.

172 *Id*. at P 7.

173 *Promoting Transmission Investment Through Pricing Reforms*, 141 FERC ¶ 61,129, PP 28-29 (November 15, 2012) (“Policy Statement”).

174 *Promoting Transmission Investment Through Pricing Reforms*, Order No. 679, 71 FR 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) (“Order No. 679”), *order on reh’g*, Order No. 679-A, 72 FR 1152 (January 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2007), *order on reh’g*, Order No. 679-B, 119 FERC ¶ 61,062 (2007).

175 *See e.g., Northeast Utilities Service Company and National Grid USA*, 125 FERC ¶ 61,183 (2008).

of needed upgrades to the transmission grid, those cost-efficiencies could be whittled down substantially if steps are not taken to control development and construction costs. The potential for the depletion of cost-benefit savings for consumers due to the financing of multiple competing public policy proposals became a significant concern in ISO-NE's Order No. 1000 stakeholder process.[176] Unless effective cost containment features are included in the transmission planning process, New England ratepayers might well be placed at the unacceptable risk of paying the pre-construction costs associated with projects that may never come to fruition or of having perceived cost savings eroded by post-award cost overruns.

Unlike transmission projects needed to solve reliability concerns, purely public policy-driven transmission projects do not have to be constructed to meet reliability needs. Accordingly, it is even more essential that the "real" costs of these projects be known at the time of decision-making, *i.e.*, that the cost projections are well prepared and realistic, and that there are effective means to ensure that cost overruns are kept to an absolute minimum after the award of a project. The states have a number of tools with which to meet their public policy objectives, and new investment in transmission infrastructure is just one option. If the price of the transmission option for achieving public policy objectives exceeds the perceived benefits to be attained or the cost of other options, or if there are not adequate assurances that project costs will not escalate unreasonably, the states are likely to pursue other means to attain their objectives. Foregoing potential public policy-driven transmission projects may well deter consideration of multi-value projects that could meet reliability, economic and public policy goals in a more efficient or cost-effective manner.

---

[176] S*ee, e.g.*, NESCOE Order No. 1000 Public Policy Framework, Development Cost Recovery & Allocation – Illustration (June 5, 2012), at Slides 2-3, available at http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2012/jun212012/a4_nescoe_presentation_cost_recovery_order_1000.ppt.

For these reasons, the Southern New England States support the cost control measures included in the NEPOOL alternative proposal for public policy projects. First and foremost, only public policies, Stage One Proposals and Stage Two Solution Proposals selected by the states, can be pursued for further exploration and project development.[177] Only Stage One Proposals specifically requested by the states are eligible for cost recovery under the Tariff; if the states do not request proposals, developers will bear the costs of such proposals.[178] If the states elect not to pursue such proposals, ISO-NE can only proceed with further planning for these public policies with the approval of this Commission.[179] Once the actual costs of a study reach 90% of the estimated costs, the developer is required to provide ISO-NE, NESCOE and the supporting states a revised estimate of the cost to complete the work, at which time the supporting states have the ability to advise the developer to stop work.[180]

These cost containment features of NEPOOL's proposed Attachment K are consistent with this Commission's efforts to ensure that new investment in transmission is undertaken in a cost-effective manner. Order No. 1000 seeks to facilitate more efficient and cost-effective solutions to regional transmission needs, including needs driven by public policy requirements, an objective similar to that of the Commission's recent Policy Statement regarding implementation of Order No. 679 transmission rate incentives.[181] There, the Commission stated that before awarding enhanced return on equity ("ROE") incentives, applicants would first be required to pursue incentives that would reduce financial risk, and thus the overall cost, of new

[177] NEPOOL Proposed Attachment K, Sections 4A.4, 4A.5 and 4A.6.

[178] *Id*. at Section 4A.6.

[179] *Id.* at Section 4A.4.

[180] *Id*. at Section 4A.6.

[181] Policy Statement at P 11.

transmission investment.[182] The Commission further required that if ROE incentives are pursued, applicants commit to limiting the application of the incentive ROE to the cost estimate in place at the time the project is approved by the public utility transmission provider.[183] While the Commission recognized "the challenges of determining the appropriate cost estimate for a project," particularly where an applicant seeks incentives at a relatively early stage in the project development process, it nevertheless required applicants to demonstrate efforts to control development costs, including how incentives will be applied to costs beyond initial estimates.[184]

The Commission's concern about the cost of transmission infrastructure in the context of Order No. 679 transmission rate incentive proceedings is equally applicable in the context of the Order No. 1000 regional transmission planning process. Both orders are targeted at encouraging new investment in a more efficient and cost-effective transmission grid.

1. Documentation of Supporting Costs Is an Important Element of the NEPOOL Alternative Proposal.

Section 4A.4. of the NEPOOL alternative proposal requires the PTOs to provide NESCOE with documentation supporting transmission-owner incurred costs associated with work in support of ISO-NE's studies being conducted at the request of the states. The Southern New England States have a strong interest in ensuring that only prudently incurred costs are passed on to ratepayers in furtherance of any project intended to meet state public policies. This provision will enable the Southern New England States and other New England states to satisfy themselves as to the prudency of transmission costs without having to resort to filing a FPA section 206 complaint with the Commission in connection with transmission projects built at one or more states' direction to satisfy state public policies.

---

[182] *Id.*

[183] *Id.* at P 28.

[184] *Id.* at P 29.

2. The NEPOOL Alternative Proposal Provides States with Greater Ability to Contain Costs.

Section 4A.6 of the NEPOOL alternative proposal, which the Southern New England States believe should be adopted in place of Section 4A.5(f) of the Filing Parties' Public Policy Project Proposal, requires project developers, when actual costs of a study reach ninety percent of the estimated costs, to provide ISO, NESCOE and the supporting states a revised estimate of the cost to complete the work. If any one or more of the supporting states does not accept the revised estimate, NESCOE shall notify the ISO either that (i) the states do not accept the revised estimate, and the ISO shall promptly advise the developer to stop work or (ii) shall notify the ISO that the remaining states continue to support the revised estimate and shall provide a revised cost allocation mechanism. By contrast, the Filing Parties' Public Policy Project Proposal allows a project developer to exceed its cost estimate by 25% before it must notify the states of the cost over-run or request to revise the estimate. The Southern New England States emphasize that the states' ability to control costs is critical to whether projects will be selected for a public policy transmission study. States will select which projects will be studied based on criteria, including costs, in a competitive proposal process. Therefore, accurate cost estimates are paramount to the integrity of the competitive process. If a project exceeds its estimate, states should have the ability to direct that the project be cancelled. This is especially important given that transmission studied for public policy goals, which may not be needed for reliability, will not necessarily result in construction of a project. States should have the opportunity to step in and prevent the incurrence of additional costs beyond the original estimate where the state has decided to no longer pursue a project.

3. Only the NEPOOL Alternative Proposal Provides States the Ability to Negotiate Final Pricing with Project Sponsors.

Section 4A.9(a) of the NEPOOL alternative proposal provides states that elect to support a project in furtherance of state public policy objectives the opportunity to negotiate final pricing with the project sponsor. States will only proceed with a public policy project to the extent one or more states conclude that a certain project is the most cost-effective way to achieve policy goals. Since states will ultimately decide whether to support a project, at what price and level of risk its ratepayers will bear, and the allocation of costs among participating states, states should have the ability to enter final negotiations with the project proponent that prevails in a competitive process.

4. The NEPOOL Alternative Proposal Eliminates Unnecessary Returns on Cancelled Investment.

Section 4A.9(d) of the NEPOOL alternative proposal eliminates language contained in the Filing Parties' proposal that provides for discontinued projects to receive a reasonable return on investment at the Commission approved ROE. One or more states that elect to pursue a public policy project to advance state policy objectives will ultimately negotiate a final cost agreement with the selected developer that prevails in a competitive process as described in Section 4A.9(a). Interested developers will participate in the public policy transmission study process on a voluntary basis according to the terms defined in the tariff and agreed to by the states and not pursuant to a guaranteed a rate of return.

E. The NEPOOL Alternative Proposed Cost Allocation Method for Transmission Projects Driven by Public Policy Requirements Is Consistent with Order No. 1000 and Should Be Approved.

The NEPOOL alternative public policy proposed method for allocating the costs associated with public policy-driven transmission projects properly allocates costs to those whom the states perceive to be the primary beneficiaries of their public policy objectives and is thus consistent with the Order No. 1000 cost allocation principles. The NEPOOL alternative proposal's cost allocation method recognizes that the beneficiaries of the work undertaken at the different stages of a public policy-driven transmission projects may differ, because the pool of states willing to continue pursuit of projects at each iterative stage of the process may differ. As discussed below, by considering the potential for differences in the pool of states supporting continued project development at different stages of the process, the NEPOOL proposal reflects compliance with Cost Allocation Principle No. 1 (allocation of costs roughly commensurate with benefits received – Order No. 1000 at P 622), Cost Allocation Principle No. 2 (no involuntary allocation of costs to those who do not benefit – Order No. 1000 at P 637); Cost Allocation Principle No. 4 (allocation of costs within the ISO-NE region – Order No. 1000 at P 657); Cost Allocation Principle No. 5 (transparency – Order No. 1000 at P 668); and Cost Allocation Principle No. 6 (different methods for different types of projects and different stages of project development – Order No. 1000 at P 685).[185] The Southern New England States note that the New England states are committed to each of these principles. For example, to ensure transparency, the Southern New England States envision a regulatory proceeding in which stakeholders would be invited to participate and in which issues would be openly vetted.

1. NEPOOL's Proposal To Allocate Pre-Construction Project Development Costs Is Reasonable and Consistent with the Order No. 1000 Regional Cost Allocation Principles.

The NEPOOL alternative proposal includes a process by which every three years the states will identify public policy requirements that may drive the need for additional transmission infrastructure to attain the objectives in the state policies, subject to input from other

[185] There is no benefit-to-cost threshold proposed for public policy-driven projects; hence there is no need to comply with Cost Allocation Principle No. 3, Order No. 1000 at P 646.

stakeholders in the RTO.[186] ISO-NE would then conduct an initial Public Policy Transmission Study at NESCOE's request to develop a rough estimate of the costs and benefits of conceptual projects that could meet the transmission needs driven by public policy requirements.[187] If NESCOE and/or stakeholders agree that it is worth pursuing a follow-on study, ISO-NE will conduct a second, more detailed study analyzing the engineering work needed and potential options for system upgrades needed to accommodate the identified state or federal public policies.[188]

Section 4A.4 of the NEPOOL alternative proposal provides that the costs of these Public Policy Transmission Studies be allocated across the region as part of the RTO's operating expenses. The Southern New England States support this proposal as consistent with Cost Allocation Principles 1 and 2. The initial effort to identify the public policy requirements that may be driving a need for transmission investment is a benefit to all stakeholders and consumers in the New England region. This initial evaluation will allow stakeholders to explore a broad realm of public policies across the six-state region that might be better attained through regional transmission solutions. Every stakeholder has an opportunity to comment on, and potentially add to, the list of public policies identified by the states. It is only reasonable to require all stakeholders to thus fund these initial public policy identification efforts.

---

[186] NEPOOL Proposed Attachment K, Section 4A.1. The process also provides a process for other stakeholders, or ISO-NE itself, to identify federal policies that may be driving the need for additional transmission infrastructure to attain the objectives in the federal policies. Attachment K, Section 4A.1.1. The Mass DPU limits its comments to a discussion of the transmission planning process related to transmission projects driven by state public policy requirements.

[187] NEPOOL Proposed Attachment K, Section 4A.3.

[188] *Id.*

Once the results of the Phase One and Phase Two Public Policy Transmission Studies are posted, Section 4A.4[189] provides that NESCOE may transmit to ISO-NE, on behalf of one or more states, a request to pursue certain options that those states are interested in exploring further through the solicitation of Stage One Proposals, *i.e.*, proposals to develop, build and operate one or more projects based on the options identified by NESCOE for further exploration. Qualified Transmission Project Sponsors that are requested by NESCOE or by one or more states to submit a Stage One Proposal would be entitled to recover the costs of developing those proposals from the Regional Network Loads of the states directly requesting those Stage One Proposals;[190] otherwise, Section 4A.6 provides that the cost of Stage One Proposals are to be funded by the developers submitting the proposals.

Placing project developers at risk for the costs of their proposals (unless such proposals are specifically requested by one or more states) ensures that developers will submit only serious proposals designed to achieve the public policy requirements identified in the studies. Moreover, allowing developers to recover Stage One Proposal costs from regional network load in the states requesting such studies ensures that those entities which the states perceive as receiving benefits from the public policy projects will bear the costs of those efforts.

Upon review of Stage One Proposals for technical feasibility and ability to satisfy the NESCOE-identified public-policy driven needs, ISO-NE will post a list of Stage One Proposals that meet the criteria, and upon agreement by NESCOE acting on behalf of one or more states, ISO-NE will solicit from prospective developers a written estimate of the anticipated cost of

---

[189] Section 1.2.2 of the ISO-NE Tariff defines a Stage One Proposal as "a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor," and defines a Stage Two Solution as a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor."

[190] The NEPOOL alternative proposal deleted "governors," which the Mass DPU believes to be appropriate, given that NESCOE managers are appointed by governors.

preparing Stage Two Solution Proposals.[191] NESCOE will then identify projects that they are interested in exploring as Stage Two Solution Proposals.[192] The costs of developing Stage Two Solution Proposals will be funded by the pool of states requesting pursuit of Stage Two Solution Proposals.[193]

The Southern New England States support the proposal to allocate the costs associated with Stage Two Solution Proposals to the states willing to "opt-in" for the development of those studies. Consistent with Order No. 1000 Cost Allocation Principles 1 and 2, the proposal for funding the cost of Stage Two Solution Proposals ensures that no costs are involuntarily allocated to a state that does not opt-in to funding such studies.[194]

Finally, NESCOE will transmit a letter to ISO-NE identifying any Stage Two Solution Proposals that one or more states are willing to pursue to the project development stage.[195] ISO-NE will include in the Regional System Plan any project proposals identified by the respective states for inclusion in the Plan. The NEPOOL alternative proposal would allocate the costs of constructing, operating and maintaining any public Policy Transmission Upgrades included in the Regional System Plan in the manner voluntarily agreed upon by the states that opt-into the development of such projects.[196] In the event the states electing to opt-in to the development of a Public Policy Transmission Upgrade do not specify a cost allocation method, costs would be

---

191 NEPOOL Proposed Attachment K, Section 4A.5(c)-(f).

192 *Id*. at Section 4A.5(g).

193 *Id.*

194 There have been concerns raised over one or more states not opting in and then enjoying the benefits of the Public Policy Projects without bearing a fair share of the costs. These concerns are not hypothetical and were understood by the states when they formulated the voluntary opt-in cost allocation process, yet the states nevertheless chose the voluntary process. Any such concerns are, in the Mass DPU's view, overstated. As demonstrated previously, the states are currently engaged in widespread cooperation on Public Policy Projects. The Mass DPU urges the Commission not to let a concern over a potential problem cloud or distort the good proposal set forth in the NEPOOL Comments.

195 NEPOOL Proposed Attachment K, Section 4A.7.

196 *Id*. at Section 4A.9(a).

allocated on a Network Load ratio share basis to the states opting to fund development of the project.[197]

The Southern New England States strongly support the proposal to allow the states willing to support and finance the Public Policy Transmission Upgrade to decide among themselves how best to allocate the costs associated with these projects. This approach is consistent with Order No. 1000's Cost Allocation Principle No. 1, ensuring that those states which perceive their consumers as benefiting from the public policy-driven transmission project will bear the costs of achieving those policies through that transmission project. State buy-in also ensures that costs are not involuntarily allocated to those states and consumers who will receive no benefits from these projects, as required by Cost Allocation Principle No. 2. The best method to ensure that project costs are aligned with the benefits of the proposed project is one in which the states supporting a project voluntarily agree how the costs should be borne.

The states are best positioned to determine whether consumers subject to their jurisdiction will receive the benefits anticipated to be provided by the public policy transmission projects. The Southern New England States support, as a last resort only, the default cost allocation method proposed by the NEPOOL alternative proposal in the event the states opting in to the development of the public policy transmission project cannot reach agreement among themselves on a method for allocating project costs. The default method would allocate project costs on a load-ratio share basis of those states supporting the project. This default method would be appropriate only if the states cannot otherwise reach agreement on an alternative method because it would reflect the belief of those states opting in to a project that it will provide benefits to their states sufficient to justify construction of the project.

---

[197] NEPOOL Proposed Attachment K, Section 4A.9(a).

2. The NEPOOL Alternative Proposal Appropriately Ensures that the Default Load Ratio Share Method of Allocating Public Policy-Driven Transmission Project Costs Is Not the Primary Method of Cost Allocation.

The Southern New England States consider it essential that the states have the opportunity to decide among themselves how the costs of any selected transmission projects driven by public policy requirements are to be allocated among the participating states before the default method is employed. In New England, a load-ratio share cost allocation method should not be the primary method for allocating public policy-driven transmission project costs. The states must first be allowed to adopt a cost allocation method reflecting their perception of how the benefits of the project are spread across their regions. It is the states' public policies that are driving the need for the transmission projects, and it is only reasonable to allow them to have the first say as to who should pay for those costs.

Section 4A.9(c) of the NEPOOL alternative proposal provides that project costs will be allocated according to the method agreed to by the states. In contrast, the Filing Parties propose to allocate costs to a state that chooses to participate in a public policy project later in the process than other participating states according to RNS rates. One or more states that conclude a proposed project is the preferred means to advance their state public policies will come to terms on the allocation of costs associated with such project or the project will not move ahead as the means to satisfy state public policies. In this framework, there is no reason to allocate costs associated with public policy project costs to RNS.

The Filing Parties' proposal to socialize the costs of public policy-driven transmission projects across the ISO-NE footprint, or even across the states opting in to those projects, without first providing the states opting into a project an opportunity to decide for themselves how the project benefits their jurisdictions would not comport with the cost allocation principles of Order No. 1000. Adopting a method of allocating the costs of such a project across the entire ISO-NE region would force states who do not perceive any benefits from another state's public policy initiatives to subsidize those policies.

Adopting the proposed default cost allocation method as the primary method for allocating the cost of transmission projects driven by public policy requirements would not reflect the unique nature of those projects. A load-ratio share cost allocation method may be appropriate in the context of a reliability project that will provide region-wide benefits of strengthening the transmission grid and ensuring reliability for all consumers in the ISO-NE footprint. However, treating a public policy-driven transmission project as a reliability project would ignore the fundamentally different purpose of a public policy-driven transmission project. Public policy transmission projects will reflect the unique needs of the state or states adopting the public policy initiatives and requirements driving those projects. The Commission should refrain from decoupling the allocation of the costs of such projects from the purpose for which those projects are being constructed. Not only would such a policy be unreasonable under the Commission's traditional cost allocation principles of allocating cost to those who cause the costs to be incurred or who benefit from the incurrence of the costs, it would also violate the cost allocation principles of Order No. 1000, especially those that require no allocation of costs to those not willing to pay (Cost Allocation Principle No. 2) and no allocation of costs to those not benefitting from the projects (Cost Allocation Principle No. 1).

The Commission should, therefore, limit the use of the load-ratio share default cost allocation method to default status among those states that have opted into a project but have not agreed on a method of allocation.

3. The NEPOOL Alternative Proposal Appropriately Gives Consumer-Owned Utilities the Right to Opt-out of Cost Responsibility for Upgrades Inapplicable to Them.

As explained in the NEPOOL Comments, the NEPOOL alternative proposal includes recommendations from consumer-owned utilities that would allow them to opt out of cost responsibility for each public policy transmission upgraded that is intended to address a Public Policy Requirement that is not applicable to them.[198] These recommendations are incorporated in Section 4A.9 of NEPOOL Proposed Attachment K. The Southern New England States believe this provision is important to retain because in Massachusetts, as well as in some other New England states, consumer-owned utilities are not subject to certain public policy requirements – *e.g.*, renewable portfolio standard obligations – that are applicable to load-serving entities in public utility franchise areas. Providing consumer-owned utilities the ability to opt out of cost responsibility for such projects ensures that this aspect of the tariff is consistent with Order No. 1000's cost allocation principles, namely: Cost Allocation Principle No. 1, that costs be allocated in a way that is roughly commensurate with benefits, and Cost Allocation Principle No. 2, that there be no involuntary allocation of costs to non-beneficiaries. The Filing Parties' failure to include such a provision is another reason why the Southern New England States believe it is not fully compliant with Order No. 1000.

VIII. CONCLUSION

For the reasons stated above, the Southern New England States request that the Commission: (1) reject the retention of the ROFR in the Filing Parties' Primary and Contingent Compliance Filings; (2) if the Commission determines that a ROFR of some duration is needed in the case of short-term reliability projects, that it reject the Filing Parties' Contingent

[198] NEPOOL Comments at 10-11.

Compliance Filing and adopt the NEPOOL alternative proposal addressed above; (3) reject the Public Policy Project Proposal presented by the Filing Parties and instead, direct the Filing Parties to conform their proposal to that presented by NEPOOL as a broad compromise among diverse stakeholders; and (4) take such other actions as the Commission deems necessary and appropriate in light of the foregoing protest.

Respectfully submitted,

/s/ Thomas E. Bessette
Thomas E. Bessette
Senior Counsel
Department of Public Utilities
Commonwealth of Massachusetts
One South Station, Second Floor
Boston, Massachusetts 02110
Tel: (617) 305-3624
Fax: (617) 345-9103
E-mail: Thomas.Bessette@state.ma.us

/s/ John Michael Adragna
John Michael Adragna
Randolph Lee Elliott
Phyllis G. Kimmel
Miller, Balis & O'Neil, P.C.
1015 15th Street, N.W.
Twelfth Floor
Washington, D.C. 20005
Tel: (202) 296-2960
Fax: (202) 296-0166
Email: Jadragna@mbolaw.com
Email: pkimmel@mbolaw.com

/s/ Nicholas S. Ucci
Nicholas S. Ucci
Principal Policy Analyst
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, Rhode Island 02888
Tel. (401) 780-2106
Fax. (401) 941-1691
Email: nucci@puc.state.ri.us

/s/ Robert Luysterborghs, Esq.
Robert Luysterborghs, Esq.
Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051
Phone: (860) 827-2742
Fax: (860) 827-2613
E-mail: Robert.luysterborghs@po.state.ct.us

/s/ Clare E. Kindall
Clare E. Kindall
Assistant Attorney General,
Department Head,
Energy Attorney General's Office
10 Franklin Square
New Britain, CT 06051
Phone: (860) 827-2683
Fax: (860) 827-2893
E-mail: Clare.Kindall@ct.gov

ATTACHMENT A

Affidavit of Rose Ann Pelletier

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket Nos. ER13-193-000 and**
Participating Transmission Owners	**)**	**ER13-196-000**
Administrative Committee	**)**	

AFFIDAVIT AND VERIFICATION OF ROSE ANN PELLETIER

STATE OF MASSACHUSETTS §
§
COUNTY OF SUFFOLK §

BEFORE ME, THE UNDERSIGNED AUTHORITY, A Notary Public in and for Suffolk County, Massachusetts, on this date personally came and appeared Rose Ann Pelletier who, after being duly sworn, did depose and state that:

1. My name is Rose Ann Pelletier. My business address is the Massachusetts Department of Public Utilities, One South Station, Boston, MA.

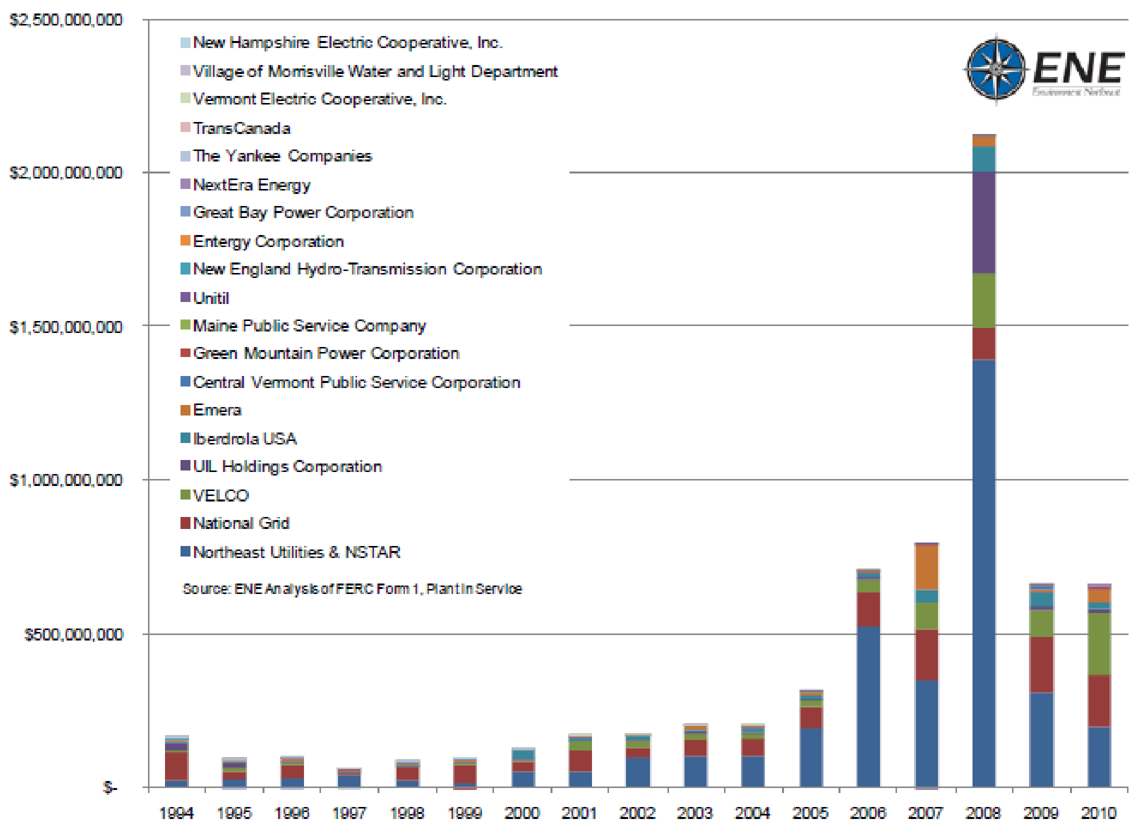
2. I received a B.A. degree in economics from Providence College and an M.A. in economics from Boston College. I was previously employed by NSTAR (formerly Boston Edison Company), from 1980-2003 in various roles including Fuel Rate and Unit Performance Administrator, Special Assistant to the Executive Vice President for Operations, Manager of the Power Contract Division and Director of the Transmission and Power Contract Administration Department. In 2004, I joined the Massachusetts Department of Public Utilities where I currently work as an Economist in the Division of Regional and Federal Affairs.

3. I have been asked to describe the history and projected future of transmission costs in New England.

4. An evaluation of New England transmission costs and rates, both historical and projected, requires the compilation of significant data from multiple sources. Environment Northeast (ENE)[1] undertook such an effort and summarized its findings in a report published in June 2011.[2] I believe the report accurately and effectively demonstrates the fact that New England transmission costs have escalated dramatically since 2000 and will continue to do so in the near future.

5. In 2011 (the time of the ENE report) transmission expenditures in real dollars were up by 5 to 6 times their 2000 level; in 2008 they were up by about 17 times (Figure 1).

Figure 1

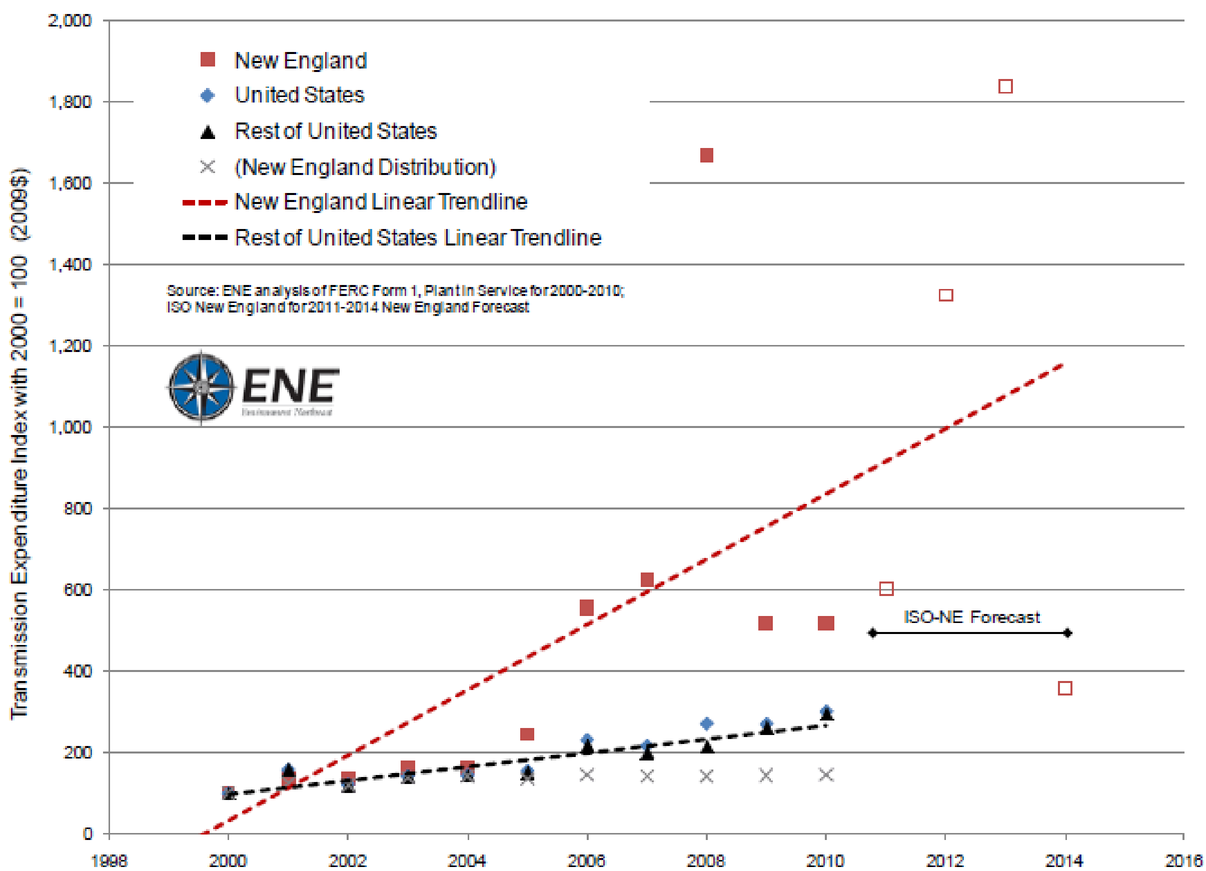


Source: Environment Northeast (ENE), *Escalating New England Transmission Costs and the Need for Policy Reforms* 9 (June 2011). ("*Escalating New England Transmission*"), *available at* http://www.env-ne.org/resources/detail/escalating-new-england-transmission-costs-and-the-need-for-policy-reforms.

[1] http://www.env-ne.org.
[2] http://www.env-ne.org/public/resources/pdf/ENE_EscalatingNETransmissionCostsandNeedforPolicyReforms_20110630_Final.pdf.

6. In addition to the sheer magnitude of the New England transmission expenditures illustrated above, according to the ENE Report, "New England expenditures on transmission are growing at a radically steeper rate than those of the rest of the country."[3] Figure 2 compares New England expenditures to the rest of the country using an index with expenditures in 2000 equal to 100.[4]

Figure 2



Source: Escalating New England Transmission 10.

7. On June 12, 2008, the New England Conference of Public Utility Commissioners ("NECPUC") filed a complaint with the Commission seeking to limit the amount of transmission

[3] Escalating New England Transmission at p. 9.
[4] I have not had the opportunity to review the data underlying the ENE analysis as it relates to other parts of the country and do not purport to testify as to its accuracy.

costs to which the incentive ROE adder applies. That complaint contained data on the comparison of estimated versus actual costs on a variety of projects with development beginning between 2004 and 2008 (Figure 3 is a chart that contains the same data as that provided in Exhibit A to the NECPUC complaint, but in a different format). The data shows a range of cost overruns, from 30 to 408 percent. (See Attachment RP-1, pp. 9-11).

Figure 3

Project	Estimated Cost	Actual Cost	% Change
Northeast Utilities Southwest Connecticut Reliability Project	690,000,000 (date not clear)	1,047,000,000 (date not clear)	51.74
NSTAR 345 kV Reliability Project	217,000,000 (date not clear)	283,144,600 (date not clear)	30.48
Northeast Utilities White Lake - Saco Valley	5,600,000 (October 2004)	28,412,000 (April 2008)	407.36
United Illuminating New Trumbull	1,800,000(October 2004)	8,930,000(April 2008)	396.11
Central Maine Power Convert Maguire Road to a Switching Substation	3,300,000(October 2004)	7,500,000(April 2008)	127.27
NSTAR Boston Area 115 kV Enhancements (Framingham)	1,800,000(October 2004)	3,100,000(April 2008)	72.22
Central Maine Power Reconductoring Louden - Maguire Road	1,200,000 (April 2006)	3,000,000 (April 2008)	150
Vermont Electric Power Middlesex Substation	2,000,000 (April 2006)	4,857,000(April 2008)	127.27
National Grid Extension of L-190 line to W. Kingston)	6,400,000 (April 2006)	13,400,000 (April 2008)	109.38
Vermont Electric Power Lamoille County Upgrade Project	1,500,000 (April 2006)	3,000,000 (April 2008)	100
National Grid Reconductoring L-190 line b/w Kent CO. and Davisville	1,722,000 (April 2006)	3,000,000 (April 2008)	74.22
Northeast Utilities Norwalk Glenbrook Cable Project	5,000,000 (July 2006)	8,390,000 (April 2008)	67.8
National Grid Reconductoring Kenyon - Wood River 115 kV 1870 line	1,622,000 (April 2006)	2,600,000 (April 2008)	60.3
Northeast Utilities-Monadnock Area	35,900,000 (April 2006)	54,358,000 (April 2008)	51.42
NSTAR Boston Area 115 kV Enhancements (East Cambridge)	1,200,000 (April 2006)	2,500,000 (October 2007)	108.33

Source: Chart compiled from data contained in Complaint of the New England Conference of Public Utilities Commissioners, Inc. Seeking Limitation on Amount of Transmission Costs to Which Incentive ROE Adder Applies, at Exhibit A, *New England Conference of Public Utility Commissioners, Inc. v. Bangor Hydro-Electric Co., et al.*, Docket No. EL08-69-000 (June 12, 2008). ("Complaint").

8. ISO-New England releases updates to the Transmission Project List three times a year. It is a compilation of data provided by the transmission owners. Figure 4, below, reflects all projects with in-service estimated costs in excess of $10 million (see Column 6), beginning with Project ID 960 through Project ID 1487. Project IDs are assigned consecutive numbers. Project ID 960 was first reported in the July 2007 Transmission Project List and Project ID 1487 was first reported in the October 2012 Transmission Project List. The difference between in-service and planned estimate costs as well as the resulting percentage change in costs is shown in columns 8 and 9, respectively. As noted in Figure 4, nine (or 69%) had in-service costs that exceeded the planned estimate costs, one (or 8%) was identical, and three (or 23%) had in-service costs that were less than the planned estimate costs.

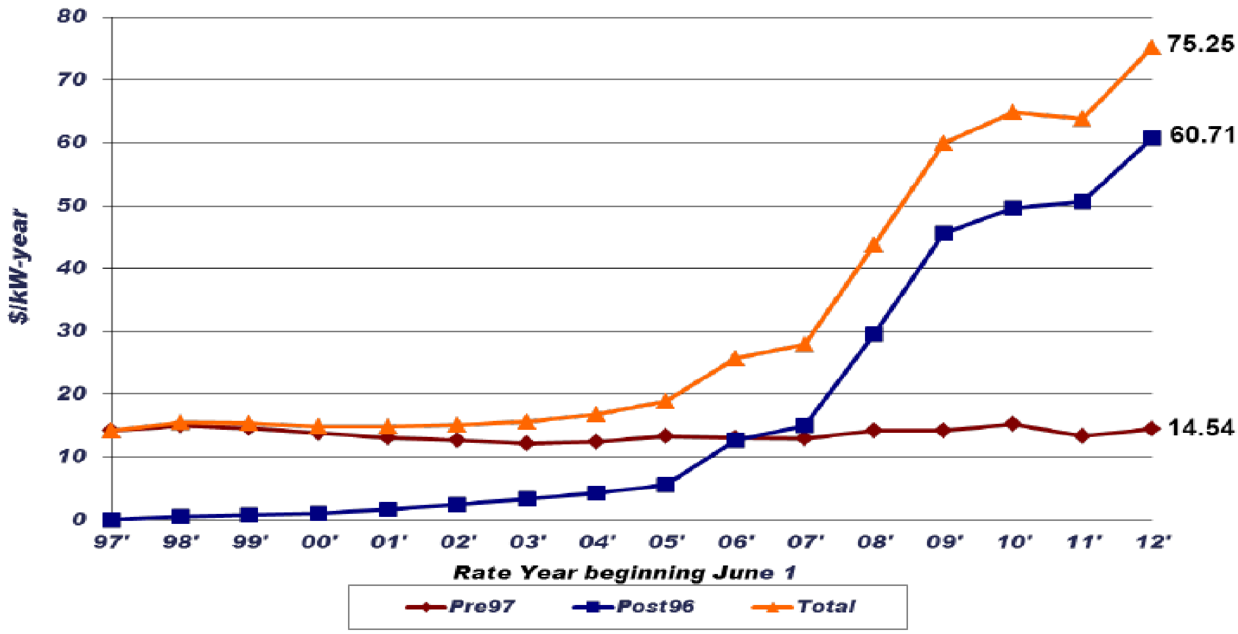
Figure 4

Sampling of Transmission Projects with Greater Than $10M In Service Estimate Costs

								%	69%	8%	23%
								Count	9	1	3
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	In service post 2008		
Project	Project ID	If available earliest planned estimate		Report Date yyyymm	In service estimate	Report Date yyyymm	Difference Col 6 - Col 3	% Change Col 8 / Col 3	In service estimate > Planned estimate	In service estimate = Planned estimateCost	In service estimate < Planned estimate
Grand Avenue 115 kV Switching Station Rebuild.	976	$48,000,000	Planned	200904	$63,400,000	201206	$15,400,000	32.08%	1		
Separate and reconductor the 1311 and 1412 (West Springfield - Agawam) 115 kV double circuit.	1000	$22,000,000	Planned	200807	$27,500,000	201111	$5,500,000	25.00%	1		
Installation of a new 345/115kV substation called Vernon including a new 345/115kV autotransformer	1032	$64,600,000	Planned	200810	$51,000,000	201104	-$13,600,000	-21.05%			1
Expansion of Coolidge 345kV substation	1035	$18,000,000	Planned	200810	$19,000,000	201104	$1,000,000	5.56%	1		
Sherwood Substation - add a 115/13.8 kV substation with two transformers and a 115 kV circuit breaker.	1056	$9,751,000	Planned	200904	$10,969,000	201203	$1,218,000	12.49%	1		
Install (1) 345kV 160 MVAR shunt reactor at Mystic Station	1064	$8,000,000	Planned	200810	$10,400,000	200907	$2,400,000	30.00%	1		
Upgrade and expand the 345 kV West Farnum Substation Equipment	1095	$73,800,000	Planned	200810	$55,200,000	201210	-$18,600,000	-25.20%			1
345/115 kV line interconnections at Berry Street	1098	$23,000,000	Planned	200810	$22,000,000	201203	-$1,000,000	-4.35%			1
Union Avenue 115/26.4 kV Substation	1111	$8,700,000	Planned	200904	$13,500,000	201203	$4,800,000	55.17%	1		
L 64 Rebuild	1116	$37,126,000	Under Construction	201004	$37,626,000	201203	$500,000	1.35%	1		
New 115 kV line between Wyman Hydro and Rice Rips Tap, parallel to exiting Section 83. Install a 115 kV circuit breaker at Wyman Hydro termination	1129	$19,500,000	Planned	200904	$32,800,000	201206	$13,300,000	68.21%	1		
Bear Swamp - Pratts Jumction 230kV Line Refurbishment Project (E205E)	1152	$43,596,000	Planned	200910	$43,596,000	201010	$0	0.00%		1	
345 kV Ludlow - Northfield (portion of 354) Line Structure replacements	1216	$17,000,000	Under Construction	201104	$25,100,000	201206	$8,100,000	47.65%	1		

9. Transmission spending in the region is leading to significant increases in the transmission component of electricity rates. Regional network service ("RNS") rates have risen steeply since 2007, when the RNS rate was approximately $28/kW-year, to today when the RNS rate is approximately $75.25/kW-year. (Figure 5). This trend is projected to continue, with the RNS rate expected to be approximately $115/kW-year in 2016. (Figure 6). This amounts to a 400% increase in under 10 years.

Figure 5



Source: PTO AC – Rates Working Group Presentation: *RNS Rate Effective June 1, 2012*, Slide 27 (Presented at NEPOOL, Reliability Committee/Transmission Committee Summer Meeting August 13-15, 2012, Revised August 9, 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2012/aug1314152012/index.html.

Figure 6

	2013	2014	2015	2016
Estimated Additions In-Service and CWIP ($M)	1,172	1,184	1,330	1,246
Forecasted Revenue Requirement ($M)	197	182	212	212
Estimated RNS Rate Impact ($/kW-Yr)	10	9	10	11
Estimated RNS Rate Forecast ($/kW-Yr)	85	94	104	115
Estimated RNS Rate Forecast ($/kWh) *Assumes a 60% Load Factor*	0.016	0.018	0.020	0.022

Source: PTO AC – Rates Working Group Presentation: *RNS Rates – Five Year Forecast*, Slide 6 (Presented at NEPOOL, Reliability Committee/Transmission Committee Summer Meeting August 13-15, 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2012/aug1314152012/index.html.

10. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and Participating Transmission Owners Administrative Committee	)))	**Docket Nos. ER13-193-000 and ER13-196-000**

VERIFICATION

State of Massachusetts	)
City of Boston,	)
County of Suffolk	)

I, the undersigned, being duly sworn, depose and say that the foregoing is the Affidavit of the undersigned, and that such Affidavit (and the exhibits sponsored by me) to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said Affidavit as if given by me in formal hearing, under oath.

Rose Ann Pelletier
Massachusetts Department of Public Utilities

Subscribed and sworn to before me
this 7th day of December, 2012

Notary Public

My Commission expires: 9/5/2019

Attachments to Rose Ann Pelletier Affidavit

Attachment RP-1	Complaint of New England Conference of Public Utility Commissioners (NECPUC) in Docket No. EL08-69 (with Exhibit A attached)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New England Conference of Public Utilities Commissioners, Inc.,	)	
	)	
Complainants,	)	
	)	
v.	)	**Docket No. _________**
	)	
Bangor Hydro-Electric Company	)	
Central Maine Power Company	)	
National Grid, USA	)	
NSTAR Electric & Gas Corporation	)	
Northeast Utilities Service Company	)	
The United Illuminating Company	)	
Vermont Electric Power Company,	)	
	)	
Respondents.	)	

COMPLAINT OF THE NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC. SEEKING LIMITATION ON AMOUNT OF TRANSMISSION COSTS TO WHICH INCENTIVE ROE ADDER APPLIES

Pursuant to Commission Rule 206, 18 C.F.R. § 385.206, and Sections 206 and 306 of the Federal Power Act, 16 U.S.C. § 824e and § 825e, the New England Conference of Public Utilities Commissioners, Inc. ("NECPUC") files this complaint against Bangor Hydro-Electric Company, Central Maine Power Company, National Grid, USA, NSTAR Electric & Gas Corporation, Northeast Utilities Service Company ("NU"), The United Illuminating Company, and Vermont Electric Power Company (collectively "NETOs").[1] Under *Bangor-Hydro Electric Co., et al*., 117 FERC ¶ 61,129 (2006)("Opinion No. 489"), as modified on rehearing, the NETOs are allowed to receive a 100 basis point return on equity adder ("ROE adder") for "*all*

[1] The New England state commissions voted five in favor, none against, and one—the Connecticut Department of Public Utility Control ("CT DPUC")—abstained. Each state retains the right to intervene in its individual capacity and to express specific concerns in a responsive pleading in this proceeding.

DB02/773844.0098/8027605.1

transmission projects identified by ISO New England in its regional planning process," Opinion No. 489 at P 121 (emphasis in original), provided that the facilities have been placed into service by the end of 2008. *Bangor-Hydro Electric Co., et al*., 122 FERC ¶ 61,265 (2008) at P 51 (Rehearing Order). But changed circumstances, in particular, substantial post-Opinion No. 489 increases in the estimated costs of many projects qualifying for the ROE adder, have rendered unqualified application of the ROE adder to *all* costs associated with the projects approved by ISO New England unjust and unreasonable under § 206 of the Federal Power Act (FPA) – even as to the narrower group of projects still qualifying for the adder following the Rehearing Order. In many cases the actual or current estimated costs of these projects have doubled or tripled from the levels assumed when the adder was approved even though the scope of these projects did not change in any substantive way. Where the Commission finds that a rate for jurisdictional service is no longer just and reasonable, it *must* establish the just and reasonable rate to be applied thereafter. *Id*.

As discussed *infra*, the Commission's decision to grant an ROE adder was predicated, by the Commission's account, on record evidence of the estimated costs and benefits of the projects qualifying for the adder. Opinion No. 489, 117 FERC ¶ 61,129 at P 106. This complaint, therefore, seeks to limit application of the ROE adder for each qualified NETO project to no more than the estimated cost for that project presented at the hearing.[2] To that end, NECPUC requests that the Commission initiate complaint proceedings and establish the earliest possible refund effective date for all rates that include ROE amounts in excess of the proposed limit.

---

2 NECPUC and other parties sought rehearing of Opinion No. 489 challenging the reasonableness of the ROE adder. Except as to the scope of projects qualifying for the adder, the Commission has denied rehearing. Those parties, including NECPUC and some of its members, have sought judicial review of the opinion. *Connecticut Dept. of Public Utility Control, et al. v. FERC*, No. 08-1199 (D. C. Cir. March 23, 2008). This complaint accepts Opinion No. 489 (as modified in the Rehearing Order) as a given, but should not be interpreted as a retreat from NECPUC's position that the ROE adder is unjustified and unreasonable.

Allowing an ROE adder to apply without limit to project costs no matter how much they exceed the project's earlier- estimated costs is not required to spur project construction and provides no discernible benefits to customers. At best, it irrationally rewards transmission owners when capital costs increase for reasons outside their control. At worst, indiscriminate application of the ROE adder reduces the incentive to contain project costs and may even create a perverse incentive to delay project deployment if doing so results in increased project costs, and thus the overall dollar return that can be realized from a project. While the Commission may not have anticipated such consequences when Opinion No. 489 issued, more recent orders have evidenced a heightened concern about granting unlimited preauthorization of incentive adders for future projects. *See, e.g., Baltimore Gas & Electric Co.*, 120 FERC ¶61,084 at PP 46-55 (2007).

EXECUTIVE SUMMARY

This Complaint is filed against the backdrop of dramatically increasing transmission costs and unprecedented cost overruns in projects proposed by the NETOs. While due only partially to cost overruns, NECPUC notes that effective June 1, 2008, the regional network service (RNS) rate increased by over 49%. That increase is over and above other increases that occurred between 2004 and 2007. This translates, for example, into close to a 6.5% increase in the distribution component of Central Maine Power Company's residential rates. In this context, NECPUC and the New England state commissions are committed to ensuring that only reasonable costs are passed on to ratepayers. This complaint is one step toward accomplishing that objective. NECPUC and the New England state commissions are engaging ISO-NE and stakeholders to scrutinize the transmission project review and cost allocation process to identify means to improve cost estimates and cost management. It is NECPUC's hope that this process will result in tariff and/or process changes that will bring costs under control.

Commission approval of a 100 basis point ROE adder for "*all* transmission projects identified by ISO New England in its regional planning process," Opinion No. 489 at P 121, was predicated on its conclusion that "the evidence reviewed below demonstrates a sufficient link between the cost of the ROE incentive and the benefits to be derived from it." *Id*. at P 106. That evidence included project cost estimates for 272 projects of $3 billion, *id*. at n. 91; a "*total* " pre-tax cost of the incentives of $148.2 million, *id*. at n. 100; "*annual* benefits" of "at least $76 million, *id*.; and the less quantifiable benefit of "timely, successful completion of the projects" qualifying for the incentive. *Id*. at P 111 (emphasis added).

Cost estimates for a number of the projects at issue in Opinion No. 489 (comprising a substantial portion of the total $3 billion estimated project costs) have increased dramatically since that time. Even accepting, *arguendo*, the reasonableness of including an ROE adder as a spur to building needed transmission, unqualified application of that adder to all project costs, no matter how high they go, is no longer just and reasonable – particularly given representations by various NETOs during project reviews that they have no control over the substantial project cost increases they have experienced. An objective of the ROE adder is "successful completion of the projects." Order No. 489 at P 111. It is at best questionable whether a project can be considered to have been completed successfully where its costs have risen substantially above the estimates on which the incentive adder request was predicated. On the contrary, the cost overruns may wipe out the assumed benefits, removing the basis for granting the adder in the first place. At a minimum, these projects should no longer qualify for the full application of the ROE adder.

DB02/773844.0098/8027605.1

Given the swings that may occur between initial estimates and final costs, the Commission has recognized the danger in preauthorizing rate incentives for planned projects based on "estimation of future expenditures." *Baltimore Gas & Electric Co*., 122 FERC ¶ 61,034 at P 11 (2008). While NECPUC has sought judicial review of Opinion No. 489 (and recognizes that the ROE adders allowed by the rehearing order are currently in effect subject to refund if the appeal is successful), for purposes of this complaint NECPUC does not contest the application of the ROE adder to the originally-projected costs of the qualifying projects. But the public interest is not served by applying the adder to project costs that substantially exceed the 2004 regional transmission expansion plan ("RTEP 04") estimates. Indeed, applying the adder to the entire costs of a project, no matter how much they exceed estimated costs, would have the perverse effect of reducing incentives to contain costs or ensure timely deployment. And even where the cost increases are truly beyond the NETOs' control, there is no reason they should *benefit* from an adder applied to such cost increases.

I. COMMUNICATIONS

All correspondence and communications to NECPUC should be addressed to the following individuals, whose names should be entered on the official service list:

Harvey L. Reiter
Dennis Lane
Stinson Morrison Hecker LLP
1150 18th St. NW Suite 800
Washington, DC 20036
Telephone: 202.785.9100
Facsimile: 202.785.9163
Email: hreiter@stinson.com
dlane@stinson.com

William Nugent
Executive Director
New England Conference of
Public Utilities Commissioners, Inc.
500 U.S. Route One, Suite 21C
Yarmouth, MA 04096
Telephone: (207) 846-5440
Email: Bill.Nugent@verizon.net

II. ALTERNATIVE RESOLUTION PROCEDURES

In accordance with Rule 206(b)(9), NECPUC states that it has not used an informal or alterative dispute resolution process before filing this complaint with the Commission. This complaint raises legal and policy issues related to application of the ROE adder that can only be resolved by the Commission, and are not susceptible to informal resolution between the parties (as might be the case where the parties disputed a certain amount of money owed or how a contract should be interpreted). In addition, as the ROE adder was only recently applied to the NETOs, this complaint presents a matter of first impression as to the extent and scope of the adder's implementation in the context of concrete facts, and thus should be resolved by the Commission to provide future guidance on these matters.

For the same reasons, NECPUC does not believe that FERC's ADR procedures would assist in resolving these matters. As demonstrated below, the material facts are not in dispute, making this a matter that can and should be resolved by the Commission in the first instance.

III. BACKGROUND

One question addressed by Opinion No. 489 was "whether the incentive [*i.e.*, the ROE adder] is needed to encourage investment in new transmission." Opinion No. 489 at P 104. The Commission looked to two factors to answer this question: "whether (i) the proposed incentive falls within the zone of reasonable returns; and (ii) there is some link or nexus between the incentives being requested and the investments being made, *i.e.*, to demonstrate that the incentives are rationally related to the investments being proposed." *Id.* at P 105 (footnote omitted). The Commission ruled that "*all* transmission projects identified by ISO New England in its regional planning process" qualified for the adder. Opinion No. 489 at P 121 (emphasis in original). More specifically, it found that "[t]he 2004 Regional Transmission Expansion Plan

(RTEP-04) approved by ISO New England has identified specific projects necessary to satisfy the needs of the region," *Id.* at P 108, and concluded that the ROE adder "will assist ISO New England in bringing these projects on line in a timely fashion." *Id.* at P 109. The Rehearing Order limits the adder to projects that come on line in 2008,[3] but with that qualifier still makes eligible all transmission projects identified in RTEP-04. This complaint addresses the continued reasonableness of the unqualified application of the adder to the full amount of actual or currently estimated, and substantially higher, costs for some of those projects.

Of significance here, under Opinion No. 489, the ROE adder appears to apply automatically to all costs of projects "identified" by the ISO in RTEP-04 (assuming they go into service this year) without qualifying eligibility for the adder based on the level of approval received in the RTEP process. This is significant because, under ISO New England's RTEP process, a proposed project goes through several planning stages, and is subject to differing levels of approval, from "Concept Project" to "TCA-Approved Project."[4] One factor considered during these stages is the estimated costs of a project. As a project moves up the approval chain

---

[3] Rehearing Order, 122 FERC ¶ 61,265 (2008) at P 51.

[4] The information in this paragraph is obtained from the ISO New England web site. *See, e.g*. http://www.iso-ne.com/trans/rsp/2007/jul07_update_final_redacted_073107.pdf. ("RSP Update") The two status levels of note are defined therein as follows:

> "Proposed: A significant degree of analysis is available to show potential need for the project, but 1.3.9 approval has not been received yet. ISO New England has been provided with a copy of the analysis associated with the project."
>
> "Planned: The project has received 1.3.9 approval (if required), but may or may not have received T[ransmission] C[ost] A[llocation] approval."

"TCA Approval" means "when the project PTF costs were reviewed and approved. This approval indicates that it has been agreed whether, and by how much, the scope of the project and associated costs exceed regional needs."

"1.3.9 Approval" means "when the projected received approval pursuant to Section 1.3.9 of the ISO-New England Tariff. This approval indicates that the project will have no adverse impact on the stability, reliability or operating characteristics of the system."

in the RSP process,[5] its estimated costs are subject to increasingly smaller "accuracy tolerances," as ISO New England explains:

The pool supported project cost estimate presented here should be the best available. It is understood that the estimate accuracy may vary dependent on the maturity of the project. Accuracy tolerances for these estimates are targeted as follows:

- Concept Project (-50%, + 200%),
- Proposed Project that has been reviewed and approved to proceed by IS-NE (-25%, +50%),
- 1.3.9 Approval Project (+/- 25%), and
- TCA-Approved Project (+/- 10%)

RSP Update at p. 33. Thus, it can be reasonably inferred that project approval -- even at the earliest stage of approval -- does not constitute a blank check to build a project at any price, but is based on an expectation that the estimated costs approximate what the final costs of building the project will be. What NECPUC has seen, however, is that actual or current estimated costs for the projects expected on line this year have, in many instances, greatly exceeded not only the estimates for Concept and Proposed Projects, but even the estimates for 1.3.9 and TCA Approved Projects.

IV. COMPLAINT

The Commission has the authority to modify already-approved rates that have become unjust and unreasonable as a result of circumstances that have changed significantly since the rates were approved. *Central Kansas Power Co.*, 5 FERC ¶61,291, at p. 61,621 (1978). As discussed below, significantly changed circumstances since approval of the ROE adder in Opinion No. 489 render the unrestricted application of the ROE adder to any and all costs for all RTEP-04 projects unjust and unreasonable and warrant its modification.

[5] The RTEP process is now referred to as the RSP (Regional System Plan).

Commission approval of a 100 basis point ROE adder for "*all* transmission projects identified by ISO New England in its regional planning process," Opinion No. 489 at P 121, was predicated on its conclusion that "the evidence . . . demonstrates a sufficient link between the cost of the ROE incentive and the benefits to be derived from it." *Id*. at P 106. That evidence included: project cost estimates for 272 projects of $3 billion, *id*. at n. 91; a "*total*" pre-tax cost of the incentives of $148.2 million, *id*. at n. 100; "*annual* benefits" of "at least $76 million, *id*.; and, the less quantifiable benefit of "timely, successful completion of the projects" qualifying for the incentive. *Id*. at P 111.

But project cost estimates on many of the RTEP-04 projects now in service or expected to be in service in 2008, have increased dramatically. Exhibit A.[6] The names of a number of the projects included in the RTEP-04 list have changed since first proposed, in some cases because they are now identified as several separate projects. This has made it difficult to match 2004 cost estimates with actual costs of those 2004-identified projects now in service or current estimated costs for those 2004-identified projects expected to be in service by the end of 2008. Nonetheless, the dramatic upward trend in costs for many of these projects is obvious.

For example, the 2004 estimated costs of the NSTAR 345 kV Transmission Reliability Project rose approximately $57 million, from $217 million in RTEP-04 to $283 million in RSP-07, or roughly a 30% increase. Exhibit A hereto.

Even confining the cost estimate comparisons to the 15 month period between July 2006 and October 2007, the cost increases for several projects have been striking. The cost of Central Maine's Project ID 154 (reconductor the Louden-Maguire Road 115 kV line 250 –in service

---

[6] Exhibit A is a compilation of data from several ISO New England transmission project reports. It identifies the transmission projects included in the RTEP-04 report that are in service or expected to go into service by the end of this year, and compares the RTEP-04 or RSP July 2006 estimated costs of those projects with actual or current estimated costs contained in 2007 and 2008 ISO New England reports.

December 2008) rose from $1.2 million to $3 million. National Grid's extension of the L-190 line to W.Kingston (Project ID 170 -- in service September 2007) increased from an estimated cost in 2006 of $5.54 million to $13.4 million. Project ID 149 – a Central Maine project expected in service by December – went from an expected cost of $3.3 million to $7.5 million in that same time span. NSTAR's Project ID 305, the addition of a 115 kV capacitor bank at Sudbury – was projected to cost $1.2 million in RTEP 2005 but went into service at double that cost. National Grid's Project ID 171 –projected last summer to be in service in February 2008 – also was expected to more than double in cost from July 2006 estimates, increasing from $1.48 million to $3 million. Velco Project ID 320 shows a similar pattern. Projected to cost $2 million in July 2006, the 2007 cost figure jumped to $4 million (in service date December 2006). Estimated costs for Velco Project ID 322 – the Lamoille County upgrade project – increased from $1.5 million to $3 million. Seven other projects with actual or projected in service dates before 2009 – project IDs 313 (United Illuminating), 242 (Northeast Utilities), 168 (National Grid) and 187 (Northeast Utilities), involved increases of more than 50% over that same 15 month period.[7]

There have been further marked increases in cost estimates for several projects even since last July. Northeast Utilities Project ID 187 alone – the installation of two new 115 kV cables from Norwalk to Glenbrook – went from $120 million to $183.2 million between July 2006 and October 2007. Incredibly, the price tag for that project – a mere 8.7 miles of cable – has jumped as of April 2008 to a staggering $234.2 million. There has also been a similar increase in the costs of several Velco projects. The estimated costs of Project ID 320 have climbed from $4 million in July 2007 to $4.86 million in April 2008. Taking into account this latest cost increase,

---

[7] Two other projects were originally expected to go into service by 2008, but are now expected to be completed in 2009 and 2010, followed a similar pattern. The estimated cost of National Grid Project ID 674 (replacement of Comerford 230kV breakers, previous expected in service date of March 2008) went from $604,000 to $11,396,000. The cost of Velco's Burlington 115 kV loop – Project ID 321 (previously expected to be in service December 2008) – went from $10,000,000 to $30,000,000.

the estimated costs of Project ID 320 have now more than doubled since 2006 (from $2 million in July 2006 to $4.86 million currently). The estimated cost of Velco Project ID 138 (part of the Northwest Vermont Reliability Project) escalated from $56.2 million in October 2007 to $70.2 million in April 2008. Similarly, the estimated costs of Velco Project ID 139 (also part of the Northwest Vermont Reliability Project) almost doubled from $11 million last October to $20 million in April 2008. Finally, cost estimates for Velco Project ID 187 moved from $30 million to $50 million over that same 7 month period.

In sum, those projects with pre-2009 in-service dates whose estimated costs rose more than 50% since issuance of Opinion No. 489 (as shown on Exhibit A) now are projected to cost many millions more than when they were approved. Application of the adder to these substantial rate base additions above 2004 estimates will also materially increase transmission rates to New England consumers.

Not even included in the projects described above is NU's Middletown-to-Norwalk transmission project, a major transmission project in Southwest Connecticut that NU is constructing jointly with United Illuminating. This project was included in RTEP-04 and has a current price tag of approximately $1.4 billion -- about twice as much as its estimated cost only a few years ago. The project is not listed above because its expected in service date is not until early 2009. On May 16, 2008, however, NU filed a request in Docket No. ER08-966-000 that the Commission waive the December 31, 2008 in service date requirement for adder eligibility and grant NU the adder on its share of this project. Needless to say, if the adder is applied to the cost increases on this project alone it will have a significant impact on ratepayers.[8]

[8] The projects covered by this complaint are those identified in RTEP 04 and now either in service or expected in service by year's end. The precise change between the estimated costs of these projects in 2004 and their actual costs (for those projects now in service) and their current estimated costs (for those expected to go into service in 2008) has been difficult to calculate. But even comparing 2006 cost estimates (in lieu of 2004 estimates where 2004

Although project costs cannot be estimated with complete precision, the dramatic increase in estimated costs for the projects identified in this complaint represents a significant change in the core circumstances that led to the finding of "a sufficient link between *the cost of the ROE incentive* and the benefits to be derived from it." *Id*. at P 106. (emphasis added) The "cost of the ROE incentive" is now decidedly larger for those projects than what was expected at the time of Opinion No. 489. The Commission recently recognized the danger in preauthorizing rate incentives for planned projects based on "estimation of future expenditures," rejecting such preauthorization without any restriction on a project's ultimate cost as contrary to Commission policy. *Baltimore Gas & Electric Co*., 122 FERC ¶ 61,034 at P 11. *Baltimore Gas & Electric* dealt with a situation where the utility sought advance authorization to apply the ROE adder to projects that had yet to be approved by the RTO, while here, the NETOs had in many cases already achieved some level of ISO NE approval for the RTEP-04 projects. That distinction, however, does not diminish the core concern expressed in *Baltimore Gas & Electric*, that future conditions might differ from those extant at the time the incentive rate treatment is approved, and thus require further consideration of whether application of the adder remains justified.

Without an adjustment to the adder, the changed conditions can lead to unreasonable rates. The Baltimore Gas & Electric case followed the issuance of, and applied Order No. 679. As the Commission noted its order on rehearing in *Baltimore Gas & Electric*, "like decommissioning costs or CWIP, any error in estimates could result in intergenerational inequities because current customers could pay more or less than their fair share of transmission

---

estimates could not be traced to projects because of changes in project names and descriptions) to actual costs or most current cost estimates, the cost increase has been around $160 million. Assuming a 50-50 debt/equity ratio and project amortization periods of 30 years, the price tag for the adder would increase about $12 million. By the same calculation, if the Commission were to allow the 100-basis-point incentive adder to apply to the apparent $700 million overrun on the Norwalk-to-Middletown transmission project, the cost to ratepayers would be $52.5 million more, a total of $64.5 million.

rate incentive costs." *Id.* at n. 4. Even though Order No. 679 did not literally apply to Opinion No. 489, the Order cautioned that a declaratory order pre-approving an incentive rate did not constitute automatic approval of its implementation in a Section 205 filing. Affected parties could establish that the circumstances since the original grant had changed. Order No. 679, FERC Stats. & Regs, ¶ 31,222 at P 78 (2006). The assurance that incentives, once granted, will remain in place for a fixed term has been similarly qualified to account for possible future changed circumstances. "[T]o ensure that ratepayers are also adequately protected," the Commission "will require any applicant seeking such a fixed term for its plan to explain how ratepayers can be assured that such a plan is delivering the benefits that formed the basis for the Commission's initial approval of it." *Id*. at P 36.

While NECPUC recognizes that the application of the ROE adder to the originally-projected costs of the qualifying projects is in effect, subject to judicial review and refund, it here focuses on the project costs that exceed the project cost estimates upon which Order 489 and the Rehearing Order are based. The public interest is not served by applying the adder to project costs that exceed those estimates as originally submitted to, and approved by, ISO New England. Indeed, applying the adder to the entire cost of projects no matter how much their costs exceed RTEP-04 estimated costs would have the perverse effect of reducing incentives to contain costs or promote timely deployment. Allowing the passthrough of the ROE adder to the full project cost in a formula rate does not assure ratepayers that the incentive plan "is delivering the benefits that formed the basis for the Commission's initial approval of it," Order No. 679 at P 36, particularly given how substantially project costs have changed since the time of FERC approval with no commensurate increase in benefit.

Even accepting valid reasons for the dramatic increases in the estimated costs of some of the listed projects, such as rising costs of labor and materials, applying an incentive adder to a rate base increased by rises in uncontrollable costs serves no public purpose. Moreover, the fact, even if true, that some project cost increases have been beyond the NETOs' ability to control, leaves unanswered why many other RTEP-04 projects, presumably facing the same conditions, maintained or lowered their estimated costs through the RSP-07 report. This difference may suggest that stronger cost control measures can and do have a large effect on the final costs of at least some projects. Giving NETOs unfettered authority to apply the ROE adder to the full ultimate cost of an approved project – without limit – counters whatever other incentives the NETOs may have to undertake such cost controls in completing their projects. Worse, it rewards them for their failure to do so.

V. REQUEST FOR RELIEF

Limiting the ROE adder to no more than a materially unchanged project's original estimated cost (which itself includes a contingency factor under RTEP practice) at the time the adder was approved in Opinion No. 489 comports closely with the rationale for relying on the ISO New England planning process to determine a project's eligibility for the adder. Rather than agency review of the reasonableness of project costs, Opinion No. 489 looked to the RTEP process as an appropriate surrogate for assuring a reliable energy supply with adequate transmission at the lowest reasonable cost is available. *See* Opinion No. 489 at PP 107-08 (placing reliance on the ISO New England's "independent analysis and the process by which it was conducted" to identify "regulated transmission solutions in the event a market solution is not forthcoming in response to ISO New England's identified needs"). That requires the RSP process to include a cost-benefit analysis for identifying the most efficient means of providing needed reliability and expansion in the context of regional planning where competing alternatives serving the same purpose are available, including, for example, demand response programs. To the extent the ROE adder "is needed to encourage investment in new transmission," Opinion No. 489 at P 104, the adder is only needed for the cost estimates provided by the transmission owners. These should represent the full amount of the investment that a NETO is willing to make in the project, and thus the full amount to which the ROE added should apply to encourage that investment. Limiting recovery for the ROE adder to the RTEP-04 cost estimate appropriately matches the incentive with the investment decision being made. If this cost estimate proves to be too low, then the NETO bears the risk that it will not recover ROE adder amounts for any costs in excess of its original estimate.

It bears emphasis that the relief requested would disallow the ROE adder *only* for any amounts in excess of the cost estimates at the time Opinion No. 489 issued. Even in the case where project costs are in excess of that level (as is the case for the projects identified in Exhibit A), NECPUC proposes that the affected NETO still earn the allowed base return on equity for the full amounts of its investment (assuming, of course, that the costs were prudently incurred), including all amounts exceeding the RTEP-04 estimate, and still earn the ROE adder on all amounts below the RTEP-04 estimates. In other words, the relief requested would deny recovery only for the ROE adder as applied to that portion of a project's costs that are more than the investment estimate originally proposed by the NETO in RTEP-04, an estimate that itself incorporated a substantial contingency factor to account for estimation errors and incidental scope adjustments.

NECPUC further proposes, as discussed more fully in Section VII, *infra*, that if the project is completed at below its estimated cost, the NETO would be allowed a *higher* incentive return (i.e., in excess of 100 basis points) calibrated so that the total incentive return dollars would equal the incentive related income had the project been completed at its estimated cost. This will provide a symmetrical incentive to complete projects at or below their estimated costs.

Finally, NECPUC emphasizes that the relief in this case is, by statute, prospective. NECPUC requests the Commission to establish the date of this complaint as the refund effective date. NETOs will only owe refunds from the date of this complaint for adders applied to project cost overruns.

VI. THE COMMISSION HAS THE CLEAR AUTHORITY TO MODIFY THE INCENTIVE ADDER AS URGED IN THIS COMPLAINT

NECPUC's complaint has been brought under Section 206 of the Federal Power Act. Under that provision, where the Commission finds that an existing rate, term or condition of service is unjust, unreasonable or unduly discriminatory, it has both the power and the *obligation* thereafter to establish the just and reasonable rate to be applied. *New York State Elec. & Gas Corp. v. FERC*, 638 F.2d 388, 394 (2nd Cir. 1980); *Papago Tribal Authority v. FERC*, 610 F.2d 914, 923 (D.C. Cir. 1979). Thus, when Commission finds a rate unreasonable or unduly discriminatory it "*must* prescribe the remedy for that condition." *American Smelting and Refining Co. v. FPC*, 494 F.2d 925, 940 (D.C. Cir. 1974) (emphasis added). And, in fashioning a remedy, the Commission has considerable latitude:

> Section 309 of the FPA, 16 U.S.C. § 825h (2000), authorizes the Commission to prescribe such orders as it may find necessary or appropriate to carry out the provisions of the FPA and authorizes the Commission to use regulatory means not spelled out in detail in the FPA. The Commission's discretion is at its zenith when fashioning policies and remedies in order to effectuate the FPA's objectives.

El Paso Electric Company, 105 FERC ¶61,131 at P 48 (2003), (citing *Niagara Mohawk Power Corporation v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967)). See also, *Columbia Gas Transmission Corp. v. FERC,* 750 F.2d 105,109 (D.C. Cir. 1984); *Conn. Valley Elec. Co. v. FERC* , 208 F.3d 1037, 1044 (D.C. Cir. 2000); *Towns of Concord, Wellesley, and Norwood v. FERC,* 955 F.2d 67, 76 (D.C. Cir. 1992).

In this case, the remedy NECPUC urges –limiting the adder to the estimate of the project cost contained in the RTEP-04 projections relied upon by the Commission in this proceeding – will ensure that the rates charged are just and reasonable, as the Commission is required to do. The limitation needed to accomplish this objective is well within the Commission's discretion. Just as it was within the Commission's discretion to approve or reject the adder, it is within the Commission's authority to condition the availability of the adder. "The power to approve implies the power to disapprove and the power to disapprove necessarily includes the lesser power to condition an approval." *Southern Pac. Co. et al. v. Olympian Dredging Co*., 260 U.S. 205 (1922). Nor is the remedy urged novel. Consider the Commission's 1978 incentive rate of return order concerning pipeline projects related to the Alaska Natural Gas Transportation System:

> In an effort to discourage cost overruns, the Commission adopted the concept of an Incentive Rate of Return (IROR), a one-time adjustment to rate base that would have the same effect as varying the allowed rate of return over the operating life of the pipeline. The adjustment would either increase or decrease the rate base attributable to equity financing, depending on whether or not the project was completed within budget and on schedule. A one-time adjustment, increasing the equity component of Northern Border's rate base in the project, was made shortly after Northern Border commenced operating to reflect the fact that the project was completed under budget and on schedule."

Northern Border Pipeline Company, 52 FERC ¶61,102 at 61,492-93 (1990) (citing Order No. 17, *Incentive Rate of Return for Alaska Natural Gas Transportation System*, 5 FERC ¶ 61,199 (1978)).

VII. TO ENSURE THAT LIMITING THE ADDER DOES NOT DISTORT DECISIONMAKING, NECPUC SUPPORTS A SYMMETRICAL ADJUSTMENT WHERE PROJECT COSTS ARE BELOW RTEP 04 ESTIMATES.

NECPUC is mindful of likely Commission concerns that adoption of the adder adjustment neither (1) defeat investor expectations nor (2) create incentives for the transmission owners to inflate their initial cost projections. On the first point, there is no serious reason to believe that limiting the adder as urged herein would defeat any realistic or reasonable investor expectations. Having made a good faith representation to the NEPOOL Planning Advisory Committee (PAC) that they could build a project at a certain estimated cost, including a contingency factor, and having asked for the adder based on that estimate, NETO transmission owners and their shareholders could not have had a reasonable expectation that they would earn the incentive adder on cost overruns. Commission approval of the adder, moreover, was predicated on an estimate of benefits tied to the estimated project costs. Opinion No. 489, *supra* at P 106. As to the second point, the record in this case indicates that there are already safeguards in place that constrain the ability of transmission owners to inflate their cost estimates. Under the existing planning process the transmission providers are already required to demonstrate that the project is economical compared to other alternatives, including demand side solutions. *See, e.g.,* Opinion No. 489 at PP 107-08. This process therefore serves as a check against overstating transmission project cost estimates.

While the relief NECPUC urges would neither defeat legitimate shareholder expectations nor create incentives to inflate investment estimates, NECPUC is concerned that the proper incentive exist to encourage cost efficiency. To that end, NECPUC would propose, not only that the NETOs cannot earn the adder on cost overruns, but that they receive the full benefit of the adder if their projects are constructed at or below the original approved cost estimate. In *Incentive Rate of Return for Alaska Natural Gas Transportation System*, *supra*, the Commission contemplated that if the pipeline project came in under budget, it would be allowed to capitalize – and thereby earn a return on – the savings. NECPUC does not recommend that the Commission engage in such rate base adjustments here. But the same result can be achieved by allowing the NETO to earn a somewhat higher adder when its project is completed at less than budgeted cost. The adder adjustment would produce the same level of return dollars as if the project had come in at budget.[9]

VIII. THERE IS NO NEED FOR AN EVIDENTIARY HEARING.

The basic facts at issue in this complaint are not in dispute. The identity and original estimated costs of the projects included in RTEP-04 are matters of record in the Docket No. ER04-157 proceeding. And, while the names of the projects may have changed since they were first proposed,[10] the actual costs of those RTEP-04 projects that have since gone into service are also matters properly subject to judicial notice. Finally, as to those RTEP-04 projects not yet in

---

9 A simple numerical example illustrates how this would work. Assume that the expected cost of a project was $100 million dollars. If the project is completed at that cost the transmission owner would earn an incentive adder of $1 million. Now assume that the project is completed for $75 million. In that case, without an adjustment, the transmission owner's incentive adder would be worth $750,000. The adjustment proposed here would increase the adder from 100 basis points to 133 basis points so that the transmission owner would still have the ability to earn $1 million in adder-related revenues.

10 In some instances the originally identified projects have been divided into several separate projects, but facilities contemplated are the same and it is therefore possible to trace the projects and the change in their actual or estimated costs from the original estimates relied upon by the Commission when it issued Opinion No. 489.

service, but expected to go on line by the end of this calendar year, there is a public record – again amenable to judicial notice – of formal filings with ISO New England, showing the most recent cost estimates for their completion.

These facts also support a conclusion – a conclusion at the heart of this complaint - that is not subject to material dispute: the current actual costs or most recent estimated costs of many of the facilities identified in the RTEP-04 process and either in service or expected to go into service by the end of this year, are substantially higher than the cost estimates relied upon by the Commission when it approved the ROE adder.

Finally, the Commission need not hold an evidentiary hearing to explore the reasons for the cost escalation. There are only three explanations for the cost escalation – (1) that the transmission owners intentionally understated those costs, (2) that the transmission owners misestimated the project costs, or (3) that the cost increases were the result of circumstances beyond their control. Regardless of which explanation applies, NECPUC's complaint should be resolved in its favor.

If, for example, the project costs were intentionally understated (and NECPUC is not suggesting that this happened in any project), such an underestimate would have unfairly biased the transmission planning decision in favor of the project and against other possible alternatives made artificially to look uneconomic. The transmission owners should not be rewarded with an incentive adder in such circumstances.

An honest misestimate of the project's costs would not justify the adder either. By its terms, the project estimate represented the transmission owner's reasonable expectation about the costs of completing the project and, under New England's practice, the estimate also included a substantial contingency factor. It is not only fair, but *logical* to assume that if there was a nexus between the adder and the transmission owner's decision to proceed with the project, it was based on the transmission owner's project cost estimates. In other words, the transmission owner was prepared to proceed with the project at its projected cost. There is no rational reason to reward the transmission owner for mistakenly underestimating the project's actual cost – the transmission owner will still earn the full base rate of return on the higher, actual project cost (assuming the cost was prudently incurred) and will also earn the incentive adder based on the capital costs it expected to incur. But if the transmission owner earns an incentive adder on the cost overrun it will be rewarded not only for undertaking the project, but for coming in over budget. An adder in this circumstance sends exactly the wrong message – not merely reducing the transmission owner's incentive to contain project costs but rewarding it for poor performance. The limitation urged here on the availability of the adder self-evidently does not impinge on reasonable shareholder expectations about the availability of the adder. Having made a good faith representation to the PAC that they could build a project at a certain estimated cost, including a contingency factor, and having asked for the adder based on that estimate, the transmission owner and its shareholders did not have a reasonable expectation that they would earn the incentive adder on cost overruns.

The same conclusion applies where the transmission owner misses its projected cost due to factors beyond its control – increases in regional labor costs, escalations in the cost of critical materials whose prices are determined in world market materials, etc. Allowing the adder to apply to cost increases attributed to these factors irrationally rewards the transmission owner for doing nothing. And worse, it reduces the incentive of the transmission owner to ascertain whether a cost is truly beyond its ability to control.

IX. CONCLUSION

For the reasons stated, NECPUC urges the Commission to grant the requested relief described herein, effective as of the date of this complaint.

Respectfully submitted,

NEW ENGLAND CONFERENCE
OF PUBLIC UTILITIES COMMISSIONERS,
INC.

/s/ Harvey L. Reiter

Harvey L. Reiter
Dennis Lane
STINSON MORRISON HECKER LLP
1150 18th Street, NW, Suite 800
Washington, DC 20036
(202) 785-9100 (phone)
(202) 785-9163 (fax)

Dated: June 12, 2008

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document, via electronic mail or first class mail, upon the Respondents in this proceeding.

Dated at Washington, D.C., this 12th day of June, 2008.

/s/ Harvey L. Reiter
Harvey L. Reiter

EXHIBIT A

Comparison RTEP-04 and RTEP-07 Listings for SW Conn Reliability Project

Project ID	Equipment Owner	Projected Year of In-Service	Major Project	Project Description	Status	Estimated Costs	
02-74017a	Northeast Utilities-CT/UI	2007	Southwest Connecticut Reliability Project	Build new 345 kV line from Scovill Rock to Chestnut Jct.	Proposed	$690,000,000	
222 [3]	Northeast Utilities-CT	2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Install new 345-kV line from Scovill Rock to Chestnut Jct.	Under Construction	$1,047,000,000	51.74%

Comparison RTEP-04 and RTEP-07 Listings for NSTAR 345 kV Transmission Reliability

Project ID	Equipment Owner	Projected Year of In-Service	Major Project	Project Description	Status	Estimated Costs	
02-71034a	NSTAR	2006	NSTAR 345 kV Transmission Reliability Project	Add (1) new 345 kV UG Cables from Stoughton to Mattapan Sq.to K Street and install new autotransformer at K. St.	Proposed	$217,000,000	
116	NSTAR	Oct-08	NSTAR 345 kV Transmission Reliability Project	Add 2nd 345 kV UG Cables from Stoughton to Mattapan Sq.to K Street and install another new autotransformer at K. St.	Under Construction	$283,144,600	30.48%

EXHIBIT A

OCT '04 NEPOOL PROJECTS

Temporary ID	Equipment Owner	Projected Year of In-Service	Major Project	Project Description	October '04 Estimated Costs
02-63009	Northeast Utilities-NH / Central Maine Power	**2006**		White Lake - Saco Valley (Y138) Line Closing - Add PAR on Y138 at Saco Valley, retension lines, upgrade Beebe terminal, and add capacitors	$5,600,000
02-74031	United Illuminating Company	2006		New Trumbull Junction 115/13.8 kV Substation	$1,800,000
02-61009	Central Maine Power	2008		Convert Maguire Road to a switching substation by replacing switches with breakers	$3,300,000
02-71034d	NSTAR	2005	Boston Area 115 kV Enhancements	DCT separation of Framingham to Speen St. 433-507 circuit	$1,800,000

EXHIBIT A

APRIL '08 ISO NE PROJECTS

Project	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	I.3.9 Approval	TCA Approval	Oct-07 Estimated Costs	Apr-08 Estimated Costs	% Change Est. Costs 04-08
267	Northeast Utilities	Central Maine Power Company	12/2008		White Lake - Saco Valley (Y138) Line Closing - Add PAR on Y138 at Saco Valley, retension lines, upgrade Beebe terminal, and add capacitor banks at White Lake and Beebe.	01/01/2006	No	$28,565,000	**$28,412,000**	407.36%
313	United Illuminating Company	Northeast Utilities	**06/2008**	UI LSP - Trumbull Substation	New Trumbull 115/13.8 kV Substation and 115 kV switching station.	**3/13/2008**	No	$5,500,000	**$8,930,000**	396.11%
149	Central Maine Power Company		12/2008	Maguire Road Project	Convert Maguire Road to a switching substation by replacing switches with breakers.	03/01/2007	No	$7,500,000	$7,500,000	127.27%
302	NSTAR Electric Company		**05/2008**	Boston Area 115 kV Enhancements	DCT separation of Framingham to Speen St. 433-507 circuit.	01/18/2005	01/2	$3,100,000	$3,100,000	72.22%

EXHIBIT A

JULY '06 ISO NE						
Project ID	**Primary Equipment Owner**	**Other Equipment Owner(s)**	**Major Project**	**Project**	**April 06 Estimated Costs**	**July 06 Estimated Costs**
313	United Illuminating Company			New Trumbull 115/13.8 kV Substation	$2,000,000	$3,000,000
154	Central Maine Power Company	Northeast Utilities	Maine / NH Short Term Enhancements	Reconductor Louden - Maguire Road 115 kV Line 250	$1,200,000	$1,200,000
320	Vermont Electric Power Co			Middlesex Substation relocation and breaker addition	$2,000,000	$2,000,000
149	Central Maine Power Company			Convert Maguire Road to a switching substation by replacing switches with breakers	$3,300,000	$3,300,000
170	National Grid, USA		Southwest Rhode Island Reliability Enhancements	Extend L-190 line to W. Kingston.	$6,400,000	$5,541,000
322	Vermont Electric Power Co			Lamoille County Upgrade Project	$1,500,000	$1,500,000
171	National Grid, USA		Southwest Rhode Island Reliability Enhancements	Reconductoring L-190 between Kent Co. and Davisville.	$1,722,000	$1,458,000
243	Northeast Utilities-CT		Norwalk-Glenbrook Cable Project	Expand and upgrade to BPS and remove SPS at Glenbrook 115 kV substation.	TBD	$5,000,000
168	National Grid, USA		Southwest Rhode Island Reliability Enhancements	Reconductor Kenyon - Wood River 115 kV 1870 line.	$1,622,000	$1,597,000
176	Northeast Utilities-NH		Monadnock Area Reliability	Monadnock Area Reliability	$35,900,000	$35,900,000

OCTOBER 05 ISO-NE PROJECTS

305	NSTAR		Boston Area 115 kV Enhancements	Add 115 kV 54 MVAR capacitor bank at East Cambridge.	$1,200,000	$1,200,000

EXHIBIT A

OCT '07 ISO NE

Project ID	Primary Equipment Owner	Project	July 2007 Estimated Costs	October 2007 Estimated Costs
313	United Illuminating Company	New Trumbull 115/13.8 kV Substation and 115 kV switching station.	$5,500,000	$5,500,000
154	Central Maine Power Company	Rebuild Louden - Maguire Road 115 kV Line S163.	$3,000,000	$3,000,000
320	Vermont Electric Power Co	Middlesex Substation breaker addition	$4,000,000	$4,000,000
149	Central Maine Power Company	Convert Maguire Road to a switching substation by replacing switches with breakers.	$7,500,000	$7,500,000
170	National Grid, USA	Extend L-190 line to W. Kingston.	$13,400,000	$13,400,000
322	Vermont Electric Power Co	Lamoille County Upgrade Project	$3,000,000	$3,000,000
171	National Grid, USA	Reconductoring L-190 between Kent Co. and Davisville.	$3,000,000	$3,000,000
243	Northeast Utilities-CT	Expand and upgrade to BPS and remove SPS at Glenbrook 115 kV substation.	$8,350,000	$8,350,000
168	National Grid, USA	Reconductor Kenyon - Wood River 115 kV 1870 line.	$2,600,000	$2,600,000
176	Northeast Utilities-NH	Install new Fitzwilliam 345/115-kV substation and 345-kV breakers.	Portion of $54,358,000 (above)	$54,358,000

APRIL '08 ISO NE

Project ID	Primary Equipment Owner	Projected In-Service Month/Year	Project	Oct-07 Estimated Costs	Apr-08 Estimated Costs	% CHANGE Estimated Costs '06 TO '08
313	United Illuminating Company	**06/2008**	New Trumbull 115/13.8 kV Substation and 115 kV switching station.	$5,500,000	**$8,930,000**	346.50%
154	Central Maine Power Company	12/2008	Rebuild Louden - Maguire Road 115 kV Line S163.	$3,000,000	$3,000,000	150.00%
320	Vermont Electric Power Company	**06/2008**	Middlesex Substation 115 kV breaker addition.	$4,000,000	**$4,857,000**	142.85%
149	Central Maine Power Company	12/2008	Convert Maguire Road to a switching substation by replacing switches with breakers.	$7,500,000	$7,500,000	127.27%
170	National Grid, USA	06/2008	Extend L-190 line to W. Kingston.	$13,400,000	$13,400,000	109.38%
322	Vermont Electric Power Company	12/2008	Installation of new Duxbury Substation that involves looping in and out of the Middlesex - Essex 115	$3,000,000	Part of Lamoille County Project	100.00%
171	National Grid, USA	12/2008	Reconductoring L-190 between Kent Co. and Davisville.	$3,000,000	$3,000,000	74.22%
243	Northeast Utilities	09/2008	Expand and upgrade to BPS and remove SPS at Glenbrook 115 kV substation.	$8,350,000	**$8,390,000**	67.80%
168	National Grid, USA	11/2008	Reconductor Kenyon - Wood River 115 kV 1870 line.	$2,600,000	$2,600,000	60.30%
176	Northeast Utilities	12/2008	New Fitzwilliam 345/115kV substation along with 345 kV breakers.	$54,358,000	$54,358,000	51.42%

305	NSTAR	Add 115 kV 54 MVAR capacitor bank at East Cambridge.	$2,500,000	$2,500,000	108.33%

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 10th day of December, 2012.

By: *<u>/s/ Phyllis G. Kimmel</u>*

Phyllis G. Kimmel
Miller, Balis & O'Neil, P.C.
1015 Fifteenth Street, NW
Twelfth Floor
Washington, DC 20005
202-296-2960
202-296-0166 (fax)