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MAINE PUBLIC UTILITIES COMMISSION
Investigation of Maine Utilities Continued
Participation In ISO-NE

ORDER

REISHUS, Chairman; VAFIADES and CASHMAN, Commissioners

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I. SUMMARY

In this Order, we conclude that Maine's Transmission Owners, Central Maine Power Company (CMP) and Bangor Hydro-Electric Company (BHE), should not exercise the notice of non-renewal provision of the Transmission Owners' Agreement (TOA) on August 1, 2009 and thus should allow the TOA to be extended and therefore, remain in ISO-NE for an additional two year term effective February 1, 2010. We find that although not all of the reform objectives identified in our January 16, 2009 Order have been achieved, remaining in the ISO-NE and continuing to work for additional reforms is the best option for the State's ratepayers at this time.

Of the two remaining options to staying in ISO-NE which were identified in our January 16, 2009 Order and which were examined in this phase of the case, the Maine Contract Option no longer appears viable at this time and the Maine Independent System Administrator (MISA) option would not provide Maine's ratepayers with tangible economic benefits in the foreseeable future; would represent a step backwards in terms of energy market development; and would present significant transaction risks to implement. While the MISA model would allow Maine to exercise greater control over issues such as transmission planning, a significant amount of control over other energy issues would reside outside of the United States and in New Brunswick and be subject to significant influence by New Brunswick Power, a crown corporation of the Province of New Brunswick. Moreover, remaining in ISO-NE for the next two years while reforms are pursued provides the best opportunity for the State to meet its goals of promoting the development of renewable resources in the State as well as maximizing the efficient use of energy and both the potential use of demand resources and smart grid technologies to satisfy energy needs.

Although we have determined that it is in Maine ratepayers' best interests for CMP and BHE to remain in ISO-NE and to close this investigation at this time, our efforts at ISO-NE reform will continue. We intend to encourage efforts of the Maine Transmission Owners, and the other parties to this matter, to assist in pursuing the reform objectives identified by the Commission in this proceeding.

II. BACKGROUND

A. The Commission's Phase I Order

The initial term of the current ISO-NE TOA is scheduled to expire on February 1, 2010. Under the terms of the TOA, the Maine Transmission Owners (METOs), CMP and BHE, must provide notice of non-renewal by August 1, 2009, if they seek to withdraw from ISO-NE after the initial term. Absent such notice, or a new agreement among the New England TOs (NETOs), the TOA renews by its own terms for an additional two-year period. On January 16, 2009, the Commission issued an Order in this proceeding (hereinafter the Phase I Order) in response to the provisions of the stipulation approved by the Commission in *Central Maine Power Company, Request for Approval of Reorganization, Requisition of*

Energy East Corporation by Iberdrola, S.A. Docket No. 2007-355, Order Approving Stipulation (February 7, 2008) and to the Legislature's "Resolve Regarding ISO New England"¹ signed by Governor Baldacci on April 10, 2008 (Resolve II) regarding the METOs continued participation in ISO-NE.

In the Phase I Order, the Commission found, based on the evidence and testimony submitted in this investigation, as well as the information previously collected during its inquiry in response to the Legislature's "Resolve To Direct the Public Utilities Commission To Examine Continued Participation by Transmission and Distribution Utilities In the State in the New England Regional Transmission Organization" (Resolve I)², that the present arrangement with ISO-NE met the Commission's objectives for RTO participation in the areas of energy, market design, market operation and capacity. With regard to the capacity market, the Commission noted its concern with how the capacity levels were established and voiced its support for the position taken by the IECG's witness Dr. Richard Silkman that the New England States, and not the ISO or the FERC, should set the required capacity levels. The Commission found that ISO had done a relatively good job in the area of Demand Response (DR) programs but was concerned by recent actions which indicated a shift away from ISO's past support of DR programs. See Phase I Order at 39-42.

The Commission found, however, that ISO-NE's performance was significantly deficient in the following areas: governance, transmission cost allocation and transmission cost containment. With regard to governance, the Commission concluded, as evidenced by the ISO-NE's governing documents, that the institution lacked a cost focus and that cost considerations apparently did not play a role in ISO-NE's decision making. *Id.* at 46-49. With regard to cost allocation, the Commission found that the socialized cost allocation methodology currently employed by ISO-NE failed to provide appropriate price signals and incentives to prospective users of the transmission system. Second, socialization provided transmission owners with an incentive to overbuild since each transmission owner's customers paid only a load-weighted share of the investment. Finally, socialized cost allocation created a cycle of overbuilding as investors and states sought to obtain the benefits of socialization. *Id.* at 42-45.

In addition, the Commission found that issues of governance and cost allocation contributed to an overall system that inadequately contained costs. Compounding these problems was FERC's Return on Equity (ROE) adder, which FERC has granted on top of FERC's authorized ROE for new transmission investment. This adder not only created a strong, and perhaps irrational, incentive to invest in transmission, but also provided an incentive to invest in transmission over other alternatives which might be more cost effective. Further, FERC did not provide an adequate check on excessive and costly transmission investment. The Commission noted, perhaps because of this insufficient cost oversight, that the costs of projects included in ISO-NE's Regional System Plan (RSP) have been consistently underestimated. *Id.* at 45-46.

¹ Resolves 2007, ch. 193.

² Resolves 2005, ch. 187.

The Commission, therefore, concluded that although the ISO-NE performs a number of functions well, given the overall lack of attention to costs and consumer impacts, the flawed transmission cost allocation methodology, and the lack of adequate transmission cost containment procedures and policies, that the status quo was inadequate. The Commission found that of all the options to the status quo (the Reform Option, the Stand-Alone Maine/ITC Option, the Maine/New Brunswick Common Market Option, the Maine Contract Option, and the Expanded NMISA Option) the Reform Option, discussed in section V below, presented the lowest transaction risk and represented the best alternative to the status quo. The Commission, therefore, instructed the METOs to pursue these reforms as part of their negotiations for the renewal of the TOA.

Since the TOA negotiation process had just begun, however, the Commission could not assess whether the reform objectives identified in the Reform Option would actually be achieved. Of the other options presented in the case, the Commission concluded that two options remained open: (1) the Maine Transmission Owner/ISO-NE Contract Option as the preferred option of the majority of the Commissioners; and (2) the Expanded NMISA Option as presented by Commissioner Cashman in his dissent.³ Neither of these options, however, were sufficiently developed during the case to allow the Commission to determine their costs and benefits. Therefore, before such options could be fully evaluated against either the status quo or the Reform Option, further details on how such models would actually be implemented would need to be developed. In the near term, the Commission determined that the best approach to pursuing ISO-NE reform was to marshal the resources of the Commission Staff and the parties to this proceeding, especially CMP and BHE, to aggressively move these reforms forward. The Commission, therefore, ordered CMP and BHE to actively and aggressively pursue the reforms found to be necessary in the Order and to report back to the Commission at regular intervals. After reviewing the utilities' May 1 reports, the Commission stated that it would provide the parties with an opportunity to submit their views on what actions if any, the METOs should take with regard to providing notice of non-renewal of the TOA and the planning for and developing the alternative models to the status quo reform.

B. Legislative Study Request

In a letter to the Commission dated March 6, 2009, the chairs of the Utilities and Energy Committee (U & E Committee), Senator Barry Hobbins and Rep. Jon Hinck, requested that the Commission develop and provide to the Committee by May 15, 2009, a preliminary design for an alternative to the status quo along the lines identified by Commissioner Cashman in his dissenting opinion. In order to conduct the study, Senator Hobbins and Rep. Hinck urged the Commission to access and use any available funds,

³ In his dissent, Commissioner Cashman found that some variation of the NMISA option as presented in the OPA's brief could be a viable alternative to the status quo. Commissioner Cashman concluded that to be in a position to compare this option against continued membership in ISO-NE, work would need to begin immediately on determining the details of the NMISA option. By doing that, the Commission then would have a viable exit strategy on August 1, 2009 should negotiations on ISO-NE reform fail.

including funds that may remain from the “Iberdrola/Industrial Energy Consumer Group (IECG) ISO Participation Study Fund.”

On March 19, 2009, the IECG and CMP filed a letter with the Commission which set forth their agreement to use the remaining balance of the Iberdrola/IECG ISO Participation Study Fund for a study to assess a Maine-based alternative to continued participation in ISO-NE in order to assist the Commission in responding to the U & E Committee’s request. As set forth in the agreement, Ken Belcher, President of the NMISA, would act as coordinator of the study and the Brattle Group, a consulting firm headquartered in Cambridge, Massachusetts, would serve as the principal economic and technical consultant. Pursuant to the agreement, a scoping session was held with the Commission Staff and the parties in the case to provide input into the conduct of the study.

On March 31, 2009, the Commission informed Senator Hobbins and Rep. Hinck that the Commission Staff had worked with the IECG and CMP to develop a plan for the alternative study. As noted in the work plan, which had been filed by CMP and the IECG, the Brattle Group Study would explore a Maine based alternative structure to ISO-NE participation. The starting point would be a NMISA-NBSO structure scaled up to cover all of Maine, designed in a manner that it would likely conform with NERC⁴ and FERC requirements and address the needs of generators, suppliers and other market participants. The scaled up NMISA-NBSO arrangement would focus on necessary changes to the NMISA arrangement, infrastructure needs, and anticipated costs. The study would also assess how the design addresses key issues related to (a) system administration; (b) transmission service; (c) reliability services; and (d) power markets and congestion management. The study would further identify possible modifications to the scaled up NMISA-NBSO structure if such modifications would be necessary to address one or more of these issues. To the extent time and resources permit, this study would also identify technical feasibility issues, necessary steps and likely timelines, and the economic implications of the alternative structure(s), including the potential costs, opportunities, benefits, risks and detriments for Maine consumers and market participants relative to the status quo. A full assessment of the compliance of the alternative with applicable law and the necessary legal steps to effectuate the alternative would not be part of the study.

On May 13, 2009, CMP and the IECG filed the study conducted by Mr. Belcher and the Brattle Group (together referred to as the Report Authors) entitled an “Assessment of a Maine ISA Structure as a Possible Alternative to ISO-NE Participation” (referred to as the Brattle Group Report).

⁴ North American Electric Reliability Corporation.

C. The 719 Process

On October 17, 2008, the FERC issued Order No. 719.⁵ One of the areas covered by Order No. 719 is the responsiveness of Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). Specifically, Order No. 719 states:

In this section of the Final Rule, the Commission requires RTOs and ISOs to establish a means for customers and other stakeholders to have a form of direct access to the board of directors, and thereby to increase the boards of directors' responsiveness to these entities. (By responsiveness, we mean an RTO or ISO board's willingness, as evidenced in its practices and procedures, to directly receive concerns and recommendations from customers and other stakeholders, and to fully consider and take actions in response to the issues that are raised.) The Commission requires each RTO or ISO to submit a compliance filing demonstrating that it has in place, or will adopt practices and procedures to ensure that its board of directors is responsive to customers.⁶

ISO-NE convened an RTO Responsiveness Working Group in which numerous parties, including the MPUC, the OPA, the Connecticut Department of Public Utilities (CTDPUC), and other entities representing State consumers participated and developed proposals⁷ to improve ISO-NE responsiveness. The RTO Responsiveness Working Group met eight times (including one teleconference). On April 3, the Participants Committee voted on proposals for a mission statement including one developed by the Maine Public Utilities Commission, the Vermont Public Service Board, the Connecticut Department of Public Utility Control and the New Hampshire Public Utility Commission. This proposal received a majority approval (57.38%) but not the supermajority required for passage. NEPOOL participants instead approved a mission statement developed by ISO-NE. On April 26, 2009, ISO-NE made a filing at FERC to comply with the requirements of Order 719.⁸ On May 26, 2009 the Commission and the IECG filed joint comments on the ISO-NE compliance filing. CMP, BHE, and the Public Advocate filed comments supporting the Commission's pleading.

⁵ *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats & Regs. ¶ 31,281 (2008) ("Order No. 719"), *reh'g pending*.

⁶ *Id.* at P. 477.

⁷ These proposals are discussed in section V below.

⁸ This filing was docketed as ER09-1051 at FERC.

III. PROCEDURAL HISTORY

See Appendix A.

IV. LEGAL STANDARDS FOR TERMINATION

A. Authority to Order CMP and BHE to Withdraw from Membership in ISO-NE

The Commission's 2007 Interim Report addressed the issue of the authority to direct CMP and BHE to withdraw from ISO-NE. In that Interim Report, the Commission stated that determinations about RTO membership fall within federal, not state jurisdiction.⁹ The Commission further discussed a FERC order, Opinion No. 472, in which FERC exempted a utility from a Virginia State law restricting the ability of the utility from joining PJM and requiring the utility to obtain Virginia public utility commission approval prior to joining the RTO. FERC relied on a provision of the Federal Power Act that allowed FERC to exempt an electric utility from any State law, rule or regulation which prohibits or prevents the voluntary coordination of electric utilities.¹⁰ The Interim Report also discussed the effect of *Atlantic City Electric Co. v. FERC*¹¹ which stands broadly for the proposition that transmission owner membership in RTOs is voluntary.

The Interim Report thus preliminarily viewed the decision to withdraw from ISO-NE as a matter within the control of the transmission owner, subject to FERC approval of any termination and replacement arrangement. However, it left open the question of whether regulatory tools such as prudence reviews are nevertheless available relating to a utility's decision to terminate or renew RTO membership.¹²

The Interim Report preceded the approval of the stipulation in Docket No. 2007-355 (the Iberdrola Stipulation) in which CMP and the other parties to the proceeding agreed to the Commission undertaking an investigation into whether extension or renewal of the Transmission Owners Agreement was in the public interest. CMP further agreed that it would act in accordance with the Commission's order regarding RTO membership and that it "would not assert or seek federal preemption, such as FERC authority, to frustrate the Commission's action or subsequent order."¹³

⁹ Interim Report at 26.

¹⁰ *Id.* at 27.

¹¹ 295 F 3rd 1 (D.C. Cir 2002).

¹² Interim Report at 28.

¹³ *Central Maine Power Company Request for Approval of Reorganization, Acquisition of Energy East Corporation and Iberdrola, S.A., Order Approving Stipulation*, Docket No. 2007-355 (February 7, 2008) Attached Stipulation at Paragraph 43(b).

CMP's discussion of the issue in its final comments fails to acknowledge its agreement not to seek any preemption of the Commission's decision should it order CMP to file a notice of withdrawal. Instead, CMP asserts that it is in FERC's "exclusive province" to determine whether CMP and BHE can withdraw. IEPM/NextEra point out that other parties are not bound by the Iberdrola Stipulation as is CMP and therefore "the preemption argument will be raised in the appropriate forum."¹⁴ IEPM/NextEra and BHE agree with CMP that any action by the Commission or the Legislature ordering CMP and BHE to withdraw from ISO-NE would be preempted by federal law.

The OPA asserts that *Atlantic City* stands for the proposition that FERC does not have the authority to decide whether CMP and BHE should withdraw or stay in ISO-NE but that FERC does have the authority to determine whether a specific withdrawal or membership proposal was just and reasonable under section 205 of the Federal Power Act. The OPA asserts that by analogy, since continued membership in ISO-NE "has a direct and significant impact on Maine ratepayers, the Commission has the authority to investigate whether the Maine transmission owners should extend their membership in ISO-NE and has the authority to direct their action with respect to that decision."¹⁵

The IECG asserts that the effect of federal jurisdiction over unbundled transmission service, *Atlantic City*, as well as FERC's Opinion No. 472, is that "actions by the Maine Commission to review RTO membership, to make determinations regarding the reasonableness of such memberships, and to implement appropriate remedies would not be prohibited so long as these actions do not interfere with Maine's utilities compliance with their obligations under federal law."¹⁶ The IECG suggests that if the Commission directed CMP and BHE to give notice of withdrawal, such direction would not prevent them from complying with their federal obligations and, therefore, such direction would not be preempted by federal law.

Whether or not the Commission has authority under its current powers to direct withdrawal is not discussed here since the Legislature has expressed a desire to make the ultimate decision if the Commission determines that CMP and BHE should withdraw. Therefore, the Commission need not look to Title 35-A for authority to direct withdrawal since a final decision on any direction to withdraw would be made by the Legislature.

However, the Commission does recognize, as it did in the Interim Report, that in general, there are limitations on the ability of the Legislature or the Commission to *mandate* withdrawal. *Atlantic City* involved the question of whether FERC could force the utilities to surrender their section 205 rights to file for rate design changes such as would be implicated in an RTO arrangement¹⁷ under the Federal Power Act. The federal appeals

¹⁴ IEPM/NextEra May 15 comments at 10.

¹⁵ OPA May 15 filing at 11.

¹⁶ IECG May 16 filing at 16.

¹⁷ In shorthand, *Atlantic City* is generally cited for the proposition that RTO membership is voluntary.

court ruled that FERC could not. In *Maine Public Utilities Commission v FERC*,¹⁸ the federal appeals court confirmed that FERC does have the authority under section 205 of the Federal Power Act to determine whether the terms of the withdrawal are just and reasonable. Of course, CMP has agreed that it will act in accordance with any direction from the Commission or Legislature resulting from this proceeding and would not seek to frustrate the Commission's action or subsequent order. Thus, with regard to the holding of *Atlantic City*, it is not clear that this case would necessarily be helpful to other parties seeking a court challenge to a Commission decision directing withdrawal of CMP from ISO-NE. If a utility voluntarily surrenders its section 205 authority, as it can be argued that CMP has done in the Iberdrola Stipulation, it is not clear that another party can assert those rights.

At the oral argument in this matter, counsel for CMP recognized that even if the Commission did not order withdrawal from the ISO-NE in this proceeding and the provisions of paragraph 43 were no longer applicable, the Commission would have oversight of CMP's continued participation in ISO-NE under the provisions of paragraph 44 of the Iberdrola Stipulation which provides:

CMP, Energy East and IBERDROLA consent to Commission oversight of actions taken by CMP relative to NEPOOL, ISO-NE and related regional transmission organization matters affecting the State of Maine to (1) determine whether CMP's actions are in accord with the public interest and (2) order appropriate remedies if CMP's actions result in a material adverse impact to CMP's customers.

On the other hand, BHE has not voluntarily surrendered any section 205 rights since it was not a signatory to the stipulation or a party in the Iberdrola merger case. Thus, under *Atlantic City*, it appears that a decision to withdraw by BHE would be within BHE's control, rather than the Commission's, the Legislature's or FERC's, and FERC would have the authority to determine whether the withdrawal is just and reasonable. With the exception of the Iberdrola Stipulation, none of the arguments made by the parties have changed the Commission's analysis from that originally set forth in the Commission's Interim Report. The question, which does not need to be addressed in this order is: if the Commission found that it was in the ratepayers' best interest for the Maine Transmission Owners to withdraw from ISO-NE, could the Commission find that BHE acted imprudently in choosing not to exercise that option absent BHE's agreement to paragraph 44 of the Iberdrola Stipulation or a similar type provision.

¹⁸ 454 F. 3rd 278 (D.C. Cir. 2006).

B. The Effect of Providing Notice of Withdrawal

At various points during this proceeding, it has been argued that providing notice of withdrawal under the TOA would bring other transmission owners to the table and force renegotiation of the TOA. The Commission disagrees with these assertions. While under section 10.01(e) of the TOA, the effect of a notice of withdrawal is to require the withdrawing transmission owner to develop a plan to transfer ISO-NE's operating authority to another entity,¹⁹ the TOA does not require remaining transmission owners to take any steps to renegotiate the TOA. Rather the TOA specifically provides that for the remaining transmission owners, the TOA "shall remain in full force and effect" unless within 20 days after the withdrawing transmission owner gives notice any remaining transmission owner can give notice of withdrawal. *Id.* The Commission recognizes that if all of the TOs file such a notice, the effect would be to trigger a renegotiation of the TOA. However, there is no basis upon which to conclude that the remaining transmission owners would exercise this provision. Accordingly, while the notice provision does trigger action, the action that is required to be taken is by the withdrawing transmission owner and these actions, the development of a transition plan and the negotiation of such plan with the ISO and the remaining transmission owners, would require a significant investment of resources.²⁰

Further, as noted in CMP's filing,²¹ the provisions addressing areas of concern to the Commission are, to a large extent, outside of the scope of the TOA. Thus, issues relating to transmission cost allocation and transmission cost containment are addressed in the ISO-NE OATT and issues related to RTO governance are addressed in the Participants Agreement.

C. What Continuing Legal Obligations Would CMP and BHE Have (if any) Upon Leaving ISO-NE and What Obligations Would Remaining Transmission Owners Have (if any) to CMP and BHE?

1. Transmission Upgrade Costs

¹⁹ TOA § 10.01(e). This provision requires the withdrawing transmission owner to commence the development of "a plan under which Operating Authority shall be transferred from the ISO to another entity," and requires the withdrawing transmission owner to try to negotiate an agreement with the remaining transmission owners and ISO on such a plan. If the parties cannot agree on such a plan, any affected Party has the right submit the matter to FERC for resolution. Further, the failure of negotiations cannot hold up termination for more than one year after providing notice of withdrawal, but the FERC's approval of the termination as just and reasonable must be obtained before the termination is effective.

²⁰ CRA estimated that the implementation of the Maine Contract Option would require approximately 16 to 25 months depending on the course of proceedings at FERC and that there would be transition costs of between \$10 to \$15 million.

²¹ CMP May 1 filing at 2.

The Phase I Order discussed the effect of the FERC decision in *Duquesne* on the question of whether CMP and BHE would be required to continue paying for the cost of transmission upgrades built by other transmission owners and whether remaining transmission owners would have any obligation to continue paying for upgrades built by CMP and BHE if they withdrew from the ISO. The Commission concluded that the likely result under *Duquesne* is that CMP and BHE would not be required to pay any load ratio share of regional system costs beyond the year in which the revenue requirement was established and that remaining transmission owners would not have any obligation to continue funding BHE's and CMP's upgrades. Similarly the Phase I Order stated that:

Duquesne does not explicitly address the treatment that would be given to projects already built by withdrawing transmission owners, however, both equitable principles and the actual language in the ISO-NE OATT strongly suggest that the remaining transmission owners would have no obligation to pay the undepreciated portion of transmission investments made by the withdrawing transmission owners. First, it is unlikely that FERC would find it equitable for a transmission owner to be able to recover costs for its own facilities while not contributing to the costs of others. Second, the language of the OATT does not support the view that a transmission owner which is no longer a Participating Transmission Owner (PTO)²² can recover the cost of its transmission investment through the ISO-NE OATT.

Phase I Order at 14. The Commission reasoned that the language in the OATT provided for a PTO to be able to recover its revenue requirement, but a transmission owner that leaves ISO-NE would no longer be a PTO and, therefore, there would be no provision in the OATT for it to recover its revenue requirement.

CMP agrees with the likely outcome posited in the Phase I Order. Based on its analysis of the ISO-NE tariff, the language in the TOA and the *Duquesne* case, CMP states, "should CMP withdraw from ISO-NE's tariff, CMP would, absent a tariff change by FERC, be obligated for transmission costs in the year in which the Pool PTF Rate was established based in part on CMP's revenue requirements, but would not be required to pay any load ratio share of 'Pool PTF Rates' beyond that year." CMP May 8 filing at 13. With regard to whether remaining transmission owners would have an obligation to continue paying for CMP's and BHE's upgrades if these utilities withdrew from ISO-NE CMP states:

Once CMP's (and BHE's) facilities are no longer in the 'Pool PTF Rate' annual revenue requirement calculation, the rest of New England would not have to pay for any share of the transmission facilities in Maine. There is no tariff mechanism to recover those costs from ISO-NE customers, outside Schedules 8 and 9 of the

²² A PTO is a transmission owner that is a signatory to the TOA. Both CMP and BHE are PTOs.

OATT, in which these costs are included in the 'Pool PTF Rate' revenue requirements determined annually.²³

The IECG and the OPA agree with CMP's analysis. BHE, however, contends that CMP and BHE *might* be required to continue paying for the upgrades of transmission projects built by other New England transmission owners even after the Maine utilities withdrew from ISO-NE. BHE posits that because CMP and BHE would not be leaving ISO-NE to join another RTO, "FERC might draw a distinction and be more inclined to impose more burdensome continuing obligations on Bangor Hydro [than it did on Duquesne] for transmission upgrade costs as a disincentive to non-RTO membership. BHE also cites an order in which FERC found that the phrase in "all financial obligations" included all cost allocations made under MISO's Attachment FF, "thereby imposing continuing responsibility for those costs" following a utility's withdrawal from MISO. BHE May 8 filing at 6. IEPM/NextEra agrees with BHE stating; "it is far from clear that FERC would reach the same conclusion in this case that it did in Duquesne." IEPM/NextEra filing at 13. The OPA notes that the Midwest ISO cases cited by BHE were distinguished in *Duquesne* because the transmission owners agreement and the tariff language in Midwest ISO were significantly different than the applicable PJM documents. OPA May 15 filing at 12.

The Commission agrees with the CMP analysis which is consistent with our conclusion in the Phase I Order. The applicable language in the New England TOA and the ISO-NE OATT is much more similar to the PJM documents interpreted in the *Duquesne* case than in the MISO cases cited by BHE. Further, the Commission disagrees that FERC would place more burdensome requirements on CMP and BHE because they would not be joining an RTO. As FERC has stated, membership in RTOs is voluntary.²⁴ Thus, it refused in *Louisville* to impose withdrawal conditions that were more onerous than those required under the governing documents.²⁵ If FERC imposed burdensome conditions not justified by the applicable documents, it would be doing indirectly what it cannot do directly - - that is, forcing the utilities to remain in ISO-NE even if they sought to withdraw.

2. Other Continuing Obligations

CMP states that the load serving entities that serve Maine's retail load "would continue to be allocated their share of Forward Capacity Market (FCM) costs based on their Maine customers' contribution to the prior annual system peak during the applicable FCM obligation period." May 8 report at 13. The applicable period would be the period in which ISO-NE has included Maine's forecast peak load contribution in setting the installed capacity requirement. CMP also outlined other obligations that it would have to

²³ CMP May 8 filing at 14-15.

²⁴ *Duquesne 122 FERC ¶ 61,039 at P.128* (As we recognized in the *LG&E Withdrawal Order*, companies that voluntarily join RTOs should have the ability to withdraw as long as the replacement rates that are established are just and reasonable, the contractual obligations under the RTO arrangement are met, and adverse effects on remaining RTO members as a result of the transmission owner's withdrawal have been considered).

²⁵ *Louisville*, 116 FERC ¶ 61,020 at P. 30.

honor, including existing interconnection agreements. See May 1 Report at 25-29. IEPM/NextEra also stress that CMP and BHE would be required to honor existing contractual arrangements so that its interconnection customers would not have to pay increased transmission rates as a result of these utilities' withdrawal from ISO-NE. IEPM/NextEra specify the agreements that CMP and BHE would have to honor:

In particular, CMP and BHE have obligations to generators located in Maine under existing long-term interconnection agreements. Some of those agreements protect the right of the generator to deliver its output into the New England PTF system. In addition, some Maine generators are parties to settlement agreements that ensure the ability of generators to export their power out of Maine without paying wheeling charges. These obligations will remain with the Utilities and will be enforceable even if CMP and BHE are no longer members of ISO-NE.

IEPM/NextEra May 15 filing at 15. CMP agrees that CMP and BHE will have to continue their existing interconnection agreements with generators and municipal utilities. CMP further states that these interconnection customers will be ensured "firm transmission rights into the ISO-NE energy, forward capacity and ancillary services markets up to the existing 1575 MW transfer capability between Maine and New Hampshire." CMP May 1 filing at 25. Neither the IECG or the Public Advocate comment on other existing obligations.

The Commission agrees with CMP and IEPM/NextEra that CMP and BHE would likely be required to honor existing interconnection agreements. See Interim Report at 22. It is also likely that LSEs will be responsible for capacity purchased on Maine customers' behalf by ISO-NE. However, the Commission does not agree that the Maine utilities are required to grant their interconnection customers firm transmission rights up to the existing transfer limits. The Commission offers no opinion here on the specific continuing obligations CMP and BHE would have under their existing interconnection agreements. Such a determination is not only premature, but would require an examination of the specific interconnection agreements at issue. At this time, it is sufficient to indicate that interconnection agreements are a source of a continuing obligation and that this continuing obligation could limit the degree to which CMP and BHE could charge its existing generator customers to access the ISO-NE markets.

V. REFORM OPTION

A. Governance

1. Reform Objectives Identified in Phase I

In the Phase I Order, the Commission concluded that the first step in governance reform was to modify ISO-NE's governing documents to incorporate language

to require the ISO-NE to consider costs, and the cost impacts of its decisions on consumers, in its decision making process. The Commission also agreed with the positions expressed by the IECG and the OPA that if consumer interests had a greater presence on the ISO Board, the ISO-NE would likely give a higher priority to consumer and cost issues. The Commission determined, therefore, that one of the existing board member slots should be reserved for a candidate that had an extensive background in representing consumers or adjudicating issues relating to retail electric rate regulation.

The Commission also found that consumer representation throughout the transmission planning process needed to be enhanced through the establishment of a regional consumer advocate. The Commission noted that while the vehicle for such a mechanism might be through NESCOE, stakeholders should pursue this reform mechanism as the renegotiation of the TOA goes forward.

2. Reform Actions Taken

As part of the RTO Responsiveness Working Group process, the Maine Commission with the support of the Vermont, Connecticut and New Hampshire Commissions, proposed the following (Joint Commission Proposal) ISO mission statement:

“The ISO shall fulfill its mission at the lowest reasonable cost, consistent with the preceding principles and further with its obligations under the Federal Power Act, to ensure just and reasonable rates ultimately to the benefit of all consumers who pay for electricity services. In evaluating any major ISO initiative that affects market design, system planning or operation of the New England bulk power system, and to improve the functioning of ISO-NE competitive markets for the benefit of consumers, the ISO will provide quantitative and qualitative information on the need for and the impacts, including costs, of the initiative.”

ISO-NE initially expressed opposition to any mission statement that included cost considerations. Eventually, ISO-NE conceded that some cost consideration is appropriate and proposed the following mission statement language:

In fulfilling this mission and consistent with the preceding principles, the ISO shall strive to perform all its functions and services in a cost-effective manner, for the benefit of all those served by the ISO. To assist stakeholders in evaluating any major ISO initiative that affects market design, system planning or operation of the New England bulk power system, the ISO will provide quantitative and qualitative information on the need for and the impacts, including costs, of the initiative.

The Joint Commission Proposal language and the language proposed by ISO-NE differed in two significant ways. First, the ISO-NE language, by stating that "ISO shall strive to perform all its functions and services in a cost-effective manner", appeared only to apply to the way the ISO process works and not to ISO-NE's actual decisions. Second, ISO-NE's cost-effectiveness standard would only require that the benefits of the solution exceed the costs. It would not require that ISO-NE identify alternative solutions and adopt the solution which can be done at the lowest reasonable cost as part of its decision making.

The competing proposals went to the NEPOOL Participants Committee on April 3, 2009. The Joint Commission Proposal was supported by the municipal sector, most of the end user sector, some of the alternative resource sector, and by CMP and BHE. In total, the Joint Commission Proposal received a favorable vote of 57.38%. Since a supermajority of 70% was required for passage, however, the Joint Commission Proposal failed. ISO-NE's language was then considered by the Participant's Committee and passed with a vote of 80.5% in favor.

The primary supporter for the concept of a regional consumer advocate during the RTO Responsiveness Working Group process was the Maine Office of the Public Advocate (OPA) who, in working in cooperation with the Massachusetts Attorney General's office, made a proposal for the establishment of a New England Regional Consumer Advocate (NERCA) to the RTO Responsiveness Workgroup. The ISO-NE, as well as utilities outside of Maine, were resistant to the proposal and support for NERCA seemed to evaporate when the Massachusetts Attorney General pulled his support for the NERCA proposal and instead proposed a consumer liaison. The ISO-NE then proposed a modified consumer liaison proposal which the OPA interpreted to be a "serious attempt to meet consumer expectations."²⁶

During the RTO Responsiveness process, several consumer advocates, including the OPA, and several commissions including the Maine PUC, proposed to have one or two seats on ISO-NE's Board of Directors be designated consumer representative positions. While ISO's Board of Directors recognized the importance of such a perspective on the Board, it opposed a formal requirement of

²⁶ OPA Report of April 1, 2009 to the Utilities and Energy Committee.

designation of a board slot because of the difficulty of recruiting qualified board members who do not have conflicts, and because of a concern that the appointment of a dedicated “consumer representative” position on the board would lead to requests from other sectors for representation of their interests.

Although not addressed in the Commission’s decision as one of the areas to be pursued as part of the Reform Option, the issue of transparency of ISO-NE’s decisions and its decision making process was raised by the Maine stakeholders as part of the RTO Responsiveness Working Group process. The Commission proposed language that would require the ISO to post on its website both the agenda and minutes for its Board and Committee meetings. In addition, the Commission proposed that ISO provide in writing to the Board, and to the appropriate standing or special committees, any position that differs from that of ISO-NE management if the differing position is supported by either: (1) a majority of one NEPOOL sector, or (2) any State regulatory commission. The IECG also proposed, and the MPUC concurred, that all ISO Board meetings be open to the public.

In response, the ISO agreed to post the agendas of both its Board and Committee meetings on its website, to provide for one option of sending written communication directly to the Board through a link or the website, and to bring minority and state positions orally to the Board as determined by the CEO. On April 3rd, the Participants Committee voted to modify the ISO proposal on Board presentations to also include stakeholder positions. The CEO would include an oral summary of significant outcomes in this monthly report to NEPOOL. The ISO accepted this position and presented its proposal, as modified, to FERC in its April 28th 719 filing.

3. Assessment of Reform Efforts

We judge the efforts to reform the ISO-NE governance process as only a partial success and ISO’s approach to reform to be somewhat disappointing. While ISO-NE did agree to a mission statement that included cost considerations, their “cost-effectiveness” language is weaker than the alternative Joint Commission Proposal which would have required ISO to actually identify alternative solutions to a problem being addressed and to choose the one which addressed the problem at the lowest reasonable cost. On the positive side, we note that in ISO-NE’s Order 719 filing with FERC, it affirmatively stated that the “cost-effectiveness” standard would apply to ISO decisions and not only to ISO’s processes.²⁷

During the reform efforts, the ISO-NE opposed the OPA’s efforts to establish a Regional Consumer Advocate and instead offered up a “Consumer Liaison” who will essentially act as an information officer. Whether this

²⁷ ISO-NE Filing In Response to Order 719, (April 28, 2009) at 118.

“Liaison” will actually help New England states and ratepayers more effectively participate in the ISO-NE decision making process is yet to be seen. On a positive note here, it appears that NESCOE, as evidenced from the discussions which have occurred on cost containment reform, See section V (B)(2) infra, has recently taken a much more active role in reform efforts and may be able to fulfill the Commission’s objective of providing greater ratepayer input into the ISO-NE decision making process.

While ISO’s opposition to designated consumer board seats on the grounds that this could eventually lead to a “stakeholder” board is a reasonable response, ISO-NE’s resistance to efforts to make ISO-NE’s decision making process and outcomes more transparent is difficult to comprehend. In particular, the opposition to providing minutes of ISO-NE’s board meetings and the reluctance to provide meaningful feedback that is accessible to all stakeholders of the outcomes when considering minority positions appears to lack any rational basis. ISO-NE’s resistance to open board meetings is also inconsistent with the practice of several other RTOs.

B. Cost Containment

1. Reform Objectives Identified in the Phase I Order

In the Phase I Order, the Commission found that the first step to change ISO-NE’s flawed cost containment procedures was to change the mandate, focus and culture of the ISO by incorporating language in the governing documents of ISO-NE to explicitly include costs as a factor to be considered in decisions about reliability. Second, the Commission found that regional planning procedures needed to be modified and that ISO-NE’s open season approach to soliciting transmission alternatives must ensure that all reasonable alternatives to the transmission project being proposed are credibly presented and fully considered. As part of the planning process, ISO-NE should evaluate the “least-cost” solution in determining whether to include a transmission project in the RSP and there should be a clear definition of how “least cost” solutions are to be calculated. Third, the Commission found that transmission project sponsors should be required to specify the problem addressed by their project, the alternatives to their project, and the respective costs of each. Comparisons between proposed transmission investments and alternatives should be done on a comparable basis, and not by comparing the full cost of the alternative to the TOs load-ratio share of the transmission project. In addition, ISO’s review of projects should be coordinated with State reviews, and state siting entities should be provided with information about the cost consequences of ISO’s decisions even in States where CPCN-type approval is not required. Phase I Order at 53.

With respect to cost estimation and cost overruns, if project costs exceeded cost estimates by a pre-defined level at any stage during planning and construction, the project sponsor should be required to fully document the reasons and provide copies of such documentation to all State commissions. Before granting initial approval for any project, ISO-NE should independently conduct a review of the

reasonableness of the sponsoring TO's cost estimates and escalation figures, as well as assesses the adequacy of the cost control measures to be used. There should be a more robust process, including ISO and the States, to reexamine projects in light of changed circumstances, such as load forecasts, new generation development, or project cost changes that may alter the need for, or the benefits of, the project. *Id.* at 54.

Finally, the States and ISO-NE should press for changes in FERC ratemaking to eliminate financial bonuses for transmission project costs in excess of initial cost estimates and to develop a performance-based ratemaking mechanism with respect to transmission projects that allows projects that meet or keep project costs below estimates to earn a higher ROE than projects that exceed cost estimates. *Id.*

2. Reform Actions Taken

The reform effort in the area of cost containment has been channeled through ISO-NE's Cost Estimating and Control Working Group which was established in October 2008 in response to a variety of transmission related concerns expressed by New England state regulatory commissions²⁸. As part of the process, NECPUC²⁹ representatives put forth a list of the following thirteen issues regarding transmission project cost estimating and cost control for the Cost Estimating and Control Work Group to address:

1. Methods to improve project cost estimates;
2. Standardization of industry best practices;
3. Measures to increase project cost transparency;
4. Improved cost reporting and timely updating;
5. The feasibility of a peer-to-peer cost validation process;
6. The role of regulators in a cost validation process;
7. The overall efficacy of the ISO transmission approval process;
8. Establishing a bright line project approval mechanism;
9. How to balance transmission reliability with costs to customers;
10. Incorporating a productive evaluation of Non-Transmission alternatives;
11. Methods to limit customer exposure to cost overruns;
12. Creating an effective prudence review; and
13. Appropriate circumstances for allowing bonus returns on investment.

For their part, the NETOs proposed to adopt a standardized approach to cost estimating in the region as well as recommended several changes to the ISO's regional planning process. The document, called the "Project Cost Estimating Guidelines" provides common definitions for the various project design and planning stages. It also

²⁸ Commissions had expressed concerns for cost overruns, lack of transparency in how project costs translated into rates, consequences of FERC's incentive rates, and need for improved analysis and consideration of non-transmission alternatives.

²⁹ The New England Conference of Public Utilities Commissioners, Inc.

defines common terms which are used often, but slightly differently, among utilities in the various stages of project development. The NETOs based much of their work on recommendations and standards of the Association for the Advancement of Cost Engineering International (AACEI). AACEI is a professional society for cost estimators, cost engineers, schedulers, project managers, and project control specialists.

The Project Cost Estimating Guidelines also set forth an improved cost reporting and updating process by requiring that members of the ISO Planning Advisory Committee (PAC) receive formal project cost updates in a standardized template, three times per year as a part of each of the regularly scheduled Regional System Plan updates. The NETO proposal also requires project cost updates to be provided at the newly standardized planning milestones contained in the document; concept, proposed, planned, and final design.³⁰

Finally, the NETOs have proposed improvements to project cost reviews through the implementation of a "Cost Review Committee," (CRC) that would provide advisory input on development of project costs to ensure consistency with the Project Cost Estimating Guidelines, serve as a peer to peer exchange forum on project costs among TOs, and include one or more regulatory representatives. The CRC would meet at least twice during formally defined stages of a project's cost development and be empowered with making recommendations on project costs. The CRC would also be empowered to recommend equipment substitutions or changes in project scope that can reduce total project costs.

The ISO has been working with the TOs to improve the ISO transmission planning and cost allocation approval processes by incorporating the various stages defined in the Project Cost Estimating Guidelines into the regional system planning process where regular updates on project costs will be provided in a standardized template. ISO also proposes changes to Planning Procedure Number 4 (PP-4), "Procedure for Pool Supported PTF Cost Review." Planning Procedure 4 provides detailed guidance, regarding the Transmission Cost Allocation (TCA) application process for transmission system projects eligible for regional cost support. ISO will recommend changes to PP-4 that improve the quality and process of cost reporting. Specifically ISO has committed that:

- The recommendations of the Cost Estimating and Controls Working Group will be incorporated into the TCA application process;
- The TCA application form will be revised to align with the cost categories defined in the Project Cost Estimating Guidelines; and
- The Project Cost Estimating Guidelines will be added as an appendix to ISO's PP-4.

³⁰ Transmission projects move through four milestones in the regional review and approval process; concept, proposed, planned, and final design.

On April 1, 2009, CMP initiated a discussion among the TOs to develop an appropriate transmission investment risk/reward approach and presented the Transmission Owners Executive Committee with the following statement:

CMP is willing to support incentives targeted at project cost management if such incentives meet the following criteria:

- Incentives are symmetrical;
- Incentives are adopted by the region as a whole;
- Performance indicators measure factors within a transmission owner's control;
- Performance indicators take into account project scope changes; and
- Performance indicators take into account additional costs and delays imposed by regulatory, permitting and siting authorities.

CMP requested comments and suggestions on these positions from the other New England transmission owners but has received no responses as of the date of this Order. The issue has been put before the Working Group and will be discussed at its next meeting.

Discussion of how evaluation of non-transmission alternatives should be included in the process continues at the Working Group. Some New England states require this evaluation as an element of the transmission siting process while others do not. The Working Group is investigating requirements for each of the States to determine whether there is an approach that can standardize how the analysis is conducted across the region.

3. Assessment of Reform Efforts

Of the areas identified for reform, the efforts in the cost containment area seem to have borne the most fruit. The Project Cost Estimating Guidelines proposed by the TOs address many of the issues highlighted by NECPUC. Standardized terms and defined project stages together with a cost review committee and process improvements at the ISO will result in a much greater degree of project cost transparency and comparability, more frequent and timely reporting of costs, and a new peer to peer review for cost validation that provides a role for regulators. More contentious issues such as how to balance system reliability with the cost consequences to consumers or the need for more effective prudence reviews have not yet been tackled by the group. The Commission anticipates that these are issues on which it will be difficult to develop consensus, and therefore, will ultimately require the involvement of the FERC.

C. Cost Allocation

1. Reform Objectives Identified In the Phase I Order

In the Phase I Order, the Commission identified several “hybrid” alternatives to the current allocation methodology which have been approved by FERC and which utilize a blend of a “beneficiary pays” methodology and a load ratio share methodology. The Commission recognized, however, given the major transmission proposals pending approval before the Commission, that a flash cut change in cost allocation methodologies could result in Maine paying for all of the costs of the new transmission projects under a new methodology as well as its load ratio share of transmission projects built in other New England states under the current socialization methodology³¹. The Commission also recognized that developing an alternative transmission cost allocation scheme that was acceptable to a broad consensus of stakeholders could be difficult. The Commission therefore stated that it would monitor the progress of negotiations over transmission cost allocation reform during the overall TOA negotiation process.

In addition to the alternative cost allocation methodologies for reliability projects identified and discussed in the Phase I Order, previously in its January 15, 2008 Report to the Legislature in response to Resolve I, the Commission had suggested several changes with respect to the economic upgrades, or Market Efficiency Transmission Upgrades (METUs) as they are called under the ISO-NE tariff. The changes included ensuring that new transmission which accesses diverse resource generation in northern New England be dealt with in the ISO-NE tariff as a transmission upgrade eligible for socialized cost recovery. In addition, the Commission recognized that the market effects of expanding transmission in exporting regions needed to be addressed. Specifically, the Commission noted that it was not reasonable to expect consumers in exporting regions to support the development of new generation and transmission to serve other areas in the region if, as a result, prices in the exporting state increase.³²

2. Reform Efforts

The METUs are the most likely designation and cost allocation scheme for transmission needed to access renewable generation in the more rural areas of Maine. As such, METUs hold special importance to the State given the State’s policy goal of developing its wind resources. In 2008, the ISO-NE process for reviewing and approving METUs became bogged down in politics with the consideration of Maine Power Connection (MPC)³³ for METU cost allocation. The dysfunctional nature of the ISO-NE METU process and the related lack of progress with the MPC, made it clear that reforms are needed.

³¹ Phase I Order at 52.

³² Final Report in Response to Resolve I, January 15, 2008 at 34-36.

³³ The Maine Power Connection CPCN was ultimately dismissed without prejudice on the grounds that the underlying rationale for the project had evaporated. *Central Maine Power*

There has been a good deal of progress towards reform of the METU cost allocation and approval process. Perhaps the greatest progress towards economic transmission cost allocation reform was driven by a joint letter from New England's Governors to ISO-NE requesting a study of what transmission would be needed to reach the potential pool of renewable generation in New England and whether there was federal assistance available to support some of this transmission. NESCOE formally presented this request to the NEPOOL Participants Advisory Committee on March 31, 2009, and has continued to take an active role in this process. ISO-NE was receptive to the letter and agreed to perform studies to examine what transmission would be necessary to reach renewable energy sites in New England. Discussions on the study, and the study itself, are progressing, and it is anticipated that ISO-NE will publish its results in the next few weeks. Once the study is released, discussions regarding prioritizing which resources to access and how to pay for that transmission will begin.

Transmission cost allocation reform with respect to reliability upgrades, or Reliability Transmission Upgrades (RTUs) has necessarily progressed slowly in the months since the Phase I Order. In the Phase I Order, the Commission noted that, given the controversy surrounding this issue, and the dissention it would produce, it might be more fruitful to pursue other areas of reform before introducing it in an ISO-NE stakeholder working group. See Phase I Order at 52. CMP and BHE echoed this sentiment in each of their three progress reports.³⁴ The Commission Staff is now in the process of interviewing consultants to help develop a proposal that could form the starting point for discussions in a working group setting as part of a continued reform effort.

3. Assessment of Reform Efforts

Factors beyond the New England region are helping to drive even further progress with respect to METU cost allocation. A significant driver from outside of New England comes from the Obama administration's push for expanded renewable generation and the possibility of access to federal funding. Another driver is the pending federal legislation that is likely to require an increasing level of renewable generation while potentially expanding the federal role in transmission siting.³⁵ There is a concern among many ISO-NE stakeholders that each of these may favor transmission expansion to wind

Company and Maine Public Service Company, Request for Certificate of Public Convenience and Necessity to Build a 345 kV Transmission Line Between Limestone, ME and Detroit, ME (the Maine Power Connection), Docket No. 2008-256, Order of Dismissal at 6 (Feb. 5, 2009).

³⁴ See CMP First Progress Report at p.7 (March 2, 2009); BHE First Progress Report, at pp.6-8 (March 2, 2009); CMP Second Progress Report, at p. 14 (April, 2009); BHE, Second Progress Report, at pp. 10-11 (April, 2009); CMP, Final Progress Report, at pp.11-12 (May, 2009); BHE, Final Progress Report, at p.5 (May 2009).

³⁵ Letter from Maine Governor John Baldacci to ISO-NE CEO Gordon Van Weile (Jan. 22, 2009) attached to CMP First Progress Report, (March 1, 2009).

sites in the Midwest while more cost effective renewable generation located closer to the east coast will not be developed, or will be competitively disadvantaged by an interconnection-wide or federal subsidy for the Midwestern transmission investments.

The potential for federal involvement has begun to bring the New England states together in an effort to ensure that the many renewable resources located in the New England region are not overlooked and that the most cost effective solutions to expanding the nation's renewable energy resources are developed first. Consequently, further progress with respect to reforming cost allocation mechanisms for METUs is likely because accessing renewable energy sites closer to the load centers of the east coast necessitates an answer to the question of who will pay for the transmission which brings such resources to market. The Commission will continue to work at the regional level to ensure that these developments move in directions that are fair to Maine. Though the bulk of the effort has been at the governor level, CMP and BHE have both supported this effort, to the extent they have had the opportunity, and it is anticipated that this support will continue.

Achieving meaningful reforms in allocation of costs for reliability upgrades will be hard fought given that any change to the allocation of costs will shift more of the burden onto some and relieve the burden from others. Given the complexity and controversial nature of this issue, any progress towards eliminating the current approach of entirely socialized costs for RTUs will necessarily be slow. It will take a substantial amount of work from the Commission, with the support of the utilities and other stakeholders, to achieve any meaningful progress on RTU cost allocation reform.

D. Demand Response

1. Reform Objectives Identified

Demand Response (DR) was an area where the Commission found that the ISO-NE's performance through the years has been adequate. Although criticized on a number of fronts for its negative impact on ratepayers, ISO-NE's Forward Capacity Market (FCM) was unique at the time of its adoption because it was designed from the start to allow DR resources to compete on an equal footing with traditional generation resources. The FCM was remarkable in its success at attracting large amounts of DR at prices which have resulted in unexpectedly low capacity costs, primarily because the DR bids effectively reduced capacity prices substantially.

In the Phase I Order, the Commission noted, however, that:

Although ISO-NE has done a relatively good job of integrating DR into the markets, there are indications of movement in a different direction. The IECG and the OPA's briefs comment on the potential for a shift in the ISO-NE's policies, apparently motivated by concerns about reliability. Going forward, it will be important to ensure that

reliability objectives can be met, but in a way that does not diminish, or unnecessarily limit, participation by demand resources.

Phase I Order at 42.

2. Recent Reform Efforts

Last fall, ISO began an effort to reduce or eliminate capacity payments received by customers participating in the Day-Ahead and Real-Time Demand Response Programs. Compared to the New England average, there are a disproportionate number of Maine customers participating in these programs. The New England PUC's, particularly Massachusetts and Maine, have been successful in causing ISO-NE to withdraw this proposal and continue the existing program for at least the next two years. The Markets Committee (MC) has not yet voted, however. Assuming that the proposed changes will, in fact, be delayed, there will be another round of discussions on the future of this program. It appears probable, but by no means certain, that viable alternative Real Time and Day Ahead Demand response programs will ultimately be adopted.

In a similar vein, certain NEPOOL members, particularly generators, have begun to argue for "reconciliation" of DR payments. In this context, "reconciliation" means that a customer receiving a payment to reduce its usage will be billed based on its actual electricity usage, plus the electricity it did not use due to its participation in the DR program. If successful, this would have the effect of increasing customer bills and making demand response less attractive. The Maine PUC, other PUCs and a group of consumer and environmental advocates have raised some questions about the wisdom of the generators' proposal and ISO now proposes to postpone any action on this matter for the foreseeable future. The next hurdle will be to obtain MC approval of the proposal to delay reconciliation. Here, the Commission is cautiously optimistic.

Finally, last fall, the Maine PUC argued at the MC that for DR to work effectively, ISO needed to modify the way capacity charges were charged to customers. More specifically, the Commission's concern was that under the current rules, customers would not be credited with reducing their on-peak usage, even though lower peaks would reduce the need for new resources and result in significant savings for the region. After a fairly thorough vetting, this position now has the support of most or all of the New England PUCs. While ISO-NE's initial reaction was to largely ignore the proposal, it has recently shifted position and has put forward an approach which is very similar, if not identical, to the original Maine proposal. The New England PUCs, through NECPUC, are in the process of developing a consensus document which will be consistent with the Maine position and supportive of ISO's latest approach.

3. Assessment of Reform Activities

While each item listed above represents positive progress, all three issues are still in the discussion stage. This history of the FCM may be instructive here, however. The basic structure of the FCM market was initially set out in papers and testimony by Maine PUC Commissioners and Staff. ISO's initial reaction was strongly negative. However, over time, ISO modified its position to the point where it was strongly supportive of that structure. This suggests that while working within the ISO structure can be time consuming and on occasion frustrating, it can also be successful.

While the Commission hopes that ISO-NE will continue to adopt the constructive attitude it has recently taken on DR reforms, this is by no means a certainty. One key will be to continue to impress on ISO-NE the importance of demand response and conservation and to develop and maintain PUC and stakeholder support for those efforts.

E. Overall Assessment of the Reform Option

As evidenced by the above discussion, all of the reform efforts to date have taken place outside of the TOA negotiation process. Indeed, it appears based on the information provided by the utilities in their reports to the Commission, that the TOA negotiation process has yet to begin.³⁶

Advancing reforms through the ISO-NE working groups has met with incremental success, although it has been a time-consuming and sometimes frustrating process. On the positive side, the work of the Cost Estimation and Containment Working Group may produce several changes and reforms which should provide real benefits to ratepayers. The Commission is also hopeful that the process initiated for METU reform will yield positive results. However, at times ISO-NE management appears to be more focused on maintaining the status quo than on actively engaging in constructive discussions to advance reforms, especially where reforms are advanced by consumer interests. For example, ISO-NE's reluctance to reform its governance, as well as to achieve a better understanding of the cause of ratepayers' frustration with ISO-NE decision making, means that efforts to make headway with reforms will continue to be time consuming, and resource intensive. Nevertheless, the Commission views the reform effort as far from static, and each incremental reform, such as those outlined in the areas of demand response, cost containment and, even governance, provide a platform for the next round of incremental reforms.

Finally, the Commission notes that many of the ISO reforms that were achieved since the Commission's Phase I Order can be attributed to the collaborative efforts of the parties to this proceeding. The continued commitment and efforts of the parties to this proceeding will be crucial in achieving further necessary reforms at ISO-NE.

³⁶ See Report of the MPUC to the U & E Committee, March 10, 2009; Third Progress Report of CMP, May 1, 2009; and Third Progress Report of BHE, May 1, 2009.

VI. MAINE CONTRACT OPTION

The Phase I Order identified the Maine Contract Option as a possible alternative to continuing membership in ISO-NE if changes that result from pursuing the Reform Option do not bear fruit. The Order broadly outlined the components of the Maine Contract Option:

The Maine Transmission Owner ISO-NE Contract Option would include the following features: (1) CMP and BHE would remain within the ISO New England control area (or balancing authority area), in terms of the reliability and operational aspects of our system; (2) Load Serving Entities serving CMP and BHE's customers would continue to participate in the ISO-NE energy and capacity markets; (3) transmission cost rate structure that moves from 100% socialization toward "hybrid/beneficiary pays;" (4) disciplined and cost-conscious decision-making about investments, particularly transmission; and (5) consumer representation in governance. As part of the ISO-NE control area, Maine would remain within a bulk power system in which reliability objectives could be met more effectively and efficiently than by a smaller system. With respect to the markets, as discussed throughout this report, the New England markets are sufficiently liquid, competitive, and flexible, and as such provide advantages to consumers. The remaining features noted above for the Maine Transmission Owner-ISO-NE Contract Option would provide needed changes to incentives and decision-making to ensure that investment and other decisions are made with consideration of consumers and the costs they bear. The TOs would plan and implement their own transmission projects within the parameters of existing state oversight and submit the necessary tariffs to FERC for approval.³⁷

The Phase I Order also directed CMP and BHE to:

1. Indicate what steps would be necessary and what documents would be required to be submitted to FERC to accomplish the Maine Transmission Owner/ISO-NE Contract Option.
2. Indicate whether ISO-NE would consider negotiating an agreement or agreements to accomplish the Maine Transmission Owner/ISO-NE Contract Option.
3. Provide an outline of the steps required and cost estimates for the TOs to assume responsibility for transmission planning, implementation and necessary filings with FERC.

³⁷ Phase I Order at 62-63.

Subsequent to the issuance of the Phase I Order on January 16, 2009, FERC issued a decision rejecting a MISO proposal to provide a new option for MISO membership. The impact of the MISO decision on the Maine Contract Option is discussed below.

A. Impact of MISO Decision on the Maine Contract Option

On February 19, 2009, FERC issued a decision rejecting a proposal made by the Midwest Independent System Operator (MISO) that would have allowed non-member transmission owners to take certain market services that are available to MISO members.³⁸ These new market service customers would be responsible for their own transmission planning, would continue to have a separate OATT, would not be responsible for transmission upgrade costs of projects developed through the MISO planning process but would participate in MISO's energy and ancillary services markets. The market services option was also available to transmission owners which were already members of MISO.

Even though FERC recognized the benefits of the proposal in expanding the reach of the MISO market, it concluded that the proposal could provide an incentive for existing members to terminate and become market services members, or for potential new members to take only market services, thereby avoiding paying transmission upgrade costs (called RECB costs). FERC stated:

The ability for existing signatories to the Transmission Owners Agreement and potential new members to avoid RECB costs while maintaining or gaining full access to Midwest ISO's security constrained economic dispatch by taking Market Service could create a new incentive for current members to withdraw or for non-members to forego joining the Midwest ISO.

Id. at P. 64. FERC also found that the ability to "opt-out" of sharing transmission upgrade costs could dampen the incentive for MISO's transmission owners to invest in new transmission. FERC concluded that the "opt-out" incentive and the investment disincentive could affect MISO's ability to satisfy its Order 2000 obligations. It reasoned that if existing transmission owner members left MISO to become market services customers "such departures could affect Midwest ISO's scope and configuration under Order No. 2000 and its ability to perform regional transmission operations." *Id.* at P. 64.

The scope implications would arise because there could be "holes" within the existing MISO footprint which could reintroduce rate-pancaking and remove MISO's operational control from some areas. *Id.* at P. 65. FERC concluded that the potential benefits from market service did not outweigh "the longer term costs associated with potential adverse impacts to Midwest ISO." *Id.* at P. 74.

³⁸ *Midwest Independent System Operator Transmission Operator*, 126 FERC at 61,139 (2009)(*Midwest ISO or MISO*).

While CMP and IEPM/NextEra assert that the MISO case, in varying degrees, “casts doubt” on the viability of the Maine Contract Option, and BHE states that such an option would face “close scrutiny” from FERC, the Public Advocate states that “the MISO order does not foreclose the possibility that FERC would approve ‘a limited participation agreement’ between the Maine transmission owners and ISO-NE.”³⁹ Similarly, the IECG asserts that the MISO case does not preclude FERC approval of an arrangement with ISO-NE to provide market services to Maine and that “it is quite likely that a market services arrangement could be developed that would be acceptable to FERC.”⁴⁰

The Commission agrees with CMP and IEPM/NextEra that the MISO case casts doubt on the viability of the Maine Contract Option. The Maine Contract Option, like the MISO case, would allow utilities to avoid participation in the RSP process and, importantly, payment of upgrade costs, thereby spreading the costs among a smaller group of consumers. FERC would be expected to have a similar concern to that expressed in the MISO case, that the new tariff arrangement which would need to be available to other existing members so as not to be discriminatory, could result in a smaller and smaller pool of customers as they see their share of costs rising. Of equal significance though, is FERC’s interest in maintaining RTO arrangements, and its reluctance to make it more attractive to leave an RTO than to stay. In short, while FERC reaffirmed that RTO membership is voluntary, FERC has no obligation to approve new services that may make it more attractive than not to leave RTOs, and it has shown, based on the specific facts as presented in the *MISO* case, that it will decline to do so.

The Commission disagrees with the IECG that many of the concerns that were present in the MISO case would not be present if a Maine entity sought to have ISO-NE provide market services (but not regional planning services). While IECG asserts that the arrangement *could be designed* to address FERC’s concerns, such as rate pancaking and the incentive for existing members to withdraw, it does not provide any explanation of how these concerns would be addressed. Accordingly, the Commission agrees with CMP and IEPM/NextEra that *Midwest ISO* casts doubt on the viability of the contract option, especially given that in *Midwest ISO*, MISO strongly advocated for the market services option and still was unable to convince FERC that the option would not ultimately harm the RTO. In contrast, as discussed below, ISO-NE and NEPOOL participants have shown very little interest in developing this option.

B. ISO-NE and NEPOOL Response to the Maine Contract Option

In a Memorandum dated April 14, 2009, CMP and BHE asked ISO-NE for an indication of its willingness to negotiate a contractual arrangement that would accomplish the Maine Contract Option discussed in broad outline in the Phase I Order. ISO-NE responded that “it is not currently in a position to enter into negotiations related to the contract option.” ISO-NE explained that because of the significant resources that would

³⁹ OPA May 15 filing at 6.

⁴⁰ IECG May 15 filing at 8.

have to be devoted to such an undertaking, which resources are already committed to other major ISO undertakings, it could not commit to “the effort that would be required to undertake even the preliminary work” unless “there is broad stakeholder support for this significant change in ISO direction.”⁴¹ A preliminary discussion of whether there was NEPOOL interest in such an undertaking indicated that NEPOOL Participants were not interested in pursuing this option for a variety of reasons including: (1) the unlikelihood of FERC approval based on *Midwest ISO*; (2) a concern that ISO-NE should not redirect any of its resources from its current priorities; and (3) a concern that the option was not outlined in sufficient detail to weigh in on it.

Based on the information in the record, it is clear that there is *not* broad stakeholder support for ISO-NE to enter into negotiations to implement the Maine Contract Option which ISO-NE made clear is a condition precedent for its undertaking the steps necessary to begin such negotiations. Accordingly, the Commission concludes that ISO-NE will not enter into negotiations to implement the Maine Contract Option at this time.

C. Costs Projections for Maine Contract Option

In accordance with the Phase I Order, CMP and BHE outlined the steps necessary to implement the Maine Contract Option and the estimated cost of such implementation. CMP concluded that without completing the steps necessary to develop its own transmission planning process, it could not provide detailed cost estimates, but preliminarily estimated “that the incremental costs of CMP assuming and implementing transmission planning and related function are likely to be in the range of \$400,000 to \$500,000 per year.”⁴²

BHE’s consultant CRA outlined the steps necessary for CMP to assume responsibility for transmission planning as well as the implementation of the Maine Contract Option, including necessary filings at FERC. CRA estimated that the implementation of the Maine Contract Option would require approximately 16 to 25 months depending on the course of proceedings at FERC and that there would be transition costs of between \$10 to \$15 million⁴³ and annual costs of \$2 to \$4 million as well as an exit fee.⁴⁴

⁴¹ Appendix D to CMP’s May 1, 2009 filing.

⁴² CMP May 1 filing at 40.

⁴³ BHE May 1 Report, Attachment D at 6.

⁴⁴ As discussed in the Phase I Order, the Commission does not agree with the BHE’s analysis regarding exit fees and instead concluded that under *Duquesne*, CMP and BHE would likely not be responsible for transmission upgrade costs except for those that are within the annual revenue requirement for the year in which the utilities withdraw from ISO-NE. Conversely, the Commission found it was highly unlikely that remaining transmission owners would be responsible for the remaining costs of any of the upgrades undertaken by CMP and BHE.

VII. THE BRATTLE GROUP REPORT

As requested by the Utilities and Energy Committee, the Brattle Group Study provided a detailed description of an alternative to Maine's continued participation in ISO-NE based on the current arrangement between the Northern Maine Independent System Administration (NMISA) and the New Brunswick System Operator (NBSO).

A. NMISA/NBSO Background

The NMISA is a not-for-profit entity responsible for the administration of the Northern Maine transmission system and electric power markets in portions of Aroostook, Penobscot, and Washington counties, with a winter-peaking load of approximately 140 MW. NMISA was created in response to the enactment of electric retail competition in Maine which took effect on March 1, 2000. It was approved by the FERC as an independent system administrator in Northern Maine and as a Regional Transmission Group (RTG) on November 15, 1999. Unlike the rest of Maine, the transmission systems in Northern Maine are not directly interconnected with ISO-NE or any other U.S. transmission system. Rather, the Northern Maine market area is interconnected with New Brunswick via NB Power's transmission system.

In 2004, the New Brunswick government restructured its electricity market. The restructuring broke up New Brunswick Power Corporation (NB Power), a crown corporation, into a holding company, regulated subsidiaries, (NB Power Distribution and NB Power Transmission Company), and unregulated "gencos". NB Power's gencos own approximately 85% of New Brunswick's generating capacity and control 70% of the transmission capacity between New Brunswick and Maine. The remainder of the transmission capacity between New Brunswick and ISO-NE is currently controlled by Hydro-Quebec.

The New Brunswick electric restructuring act also created the NBSO. The NBSO is an independent, not-for-profit corporation whose primary responsibilities are to ensure the reliability of the electrical system and to operate the electricity market in New Brunswick. The NBSO, has its own independent board of directors and its functions are carried out by employees located at New Brunswick Power Transmission's (NBPT) Energy Control Center in Fredericton, New Brunswick.

The NBSO ensures transmission system reliability, oversees access to and use of the transmission grid, and administers the OATT and Market Rules in New Brunswick. As the Reliability Coordinator for the Maritimes Area, NBSO is the authority responsible for the operation of the bulk power system in New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine. NBSO is the Balancing Authority for New Brunswick, Prince Edward Island, and Northern Maine and is the Transmission Service Provider, the Market Operator, and the Transmission Operator for New Brunswick. NBSO also provides ancillary services, including load following and regulation service, to the system in order to maintain reliability and supply in-province customer load while maintaining scheduled flows on interconnections within established limits.

The interconnection between New Brunswick and the BHE zone of ISO-NE is limited to 1,000 MW of imports from New Brunswick and 550 MW of exports to New Brunswick. Existing transmission constraints within the ISO-NE portion of Maine create three subareas: BHE, which is export-limited in some hours to the south over the 1,200 MW Orrington-South transmission constraint; the central Maine subarea (CME); which is export-limited in some hours to the south over the 1,150 MW Surowiec-South transmission constraint; and the Southern Maine subarea (SME), which is export-limited in some hours into the rest of New England over the 1,575 MW Maine-New Hampshire transmission constraint. CMP has proposed as part of its Maine Power Reliability Project (MPRP) upgrades that would increase the thermal limits of these transmission lines to 1,700 MW, 1650 MW, and 2,450 MW, respectively.⁴⁵

B. MISA Structural Overview

Under the alternative structure proposed in the Brattle Group Report, the NMISA would be scaled up to encompass all of Maine and would be known as the Maine Independent System Administrator (MISA or Maine ISA). MISA would be comprised of two sections: Northern Maine, the area currently served by NMISA, and Rest of Maine, the area in Maine currently served by ISO-NE. MISA's organization and reliability functions would be identical to those of the NMISA and operate under a coordination agreement with the NBSO.⁴⁶

Under the Maine ISA proposal, Northeast Power Coordinating Council (NPCC) reliability standards would continue to apply. The difference would be that the NBSO, rather than ISO-NE, would be the reliability coordinator for the Rest of Maine. Under this arrangement, the following reliability functions would be undertaken jointly by the Maine ISA and the NBSO:

- Perform long-term planning to maintain reliability and system adequacy;
- Determine and enforce operating reserve requirements;
- Monitor and enforce capacity obligations of load-serving entities;
- Coordinate generation and transmission outage planning;
- Administer and dispatch supply of operating reserves;
- Dispatch regulation reserves and frequency control; and
- Monitor system reliability and take corrective action for conditions impacting system reliability, including the dispatch emergency energy transactions.

⁴⁵ Brattle Group Report at 14.

⁴⁶ *Id.* at 19-20.

Similar to the NMISA market design, the market function of the Maine ISA would be based on a bilateral market model under which market participants would submit balanced day-ahead schedules that can be revised up to 30 minutes before delivery. Within the delivery period, the Maine ISA, with the support of the NBSO, would provide imbalance energy service for deviations of actual loads and generation from the market participant's balanced schedules. The imbalance energy service for Northern Maine would continue to be provided by the NBSO under the current arrangement. For the Rest of Maine, the imbalance energy service design would be identical to the balancing market operated by the NBSO within New Brunswick, which includes a market-based least-cost dispatch of the market area's generating resources. The imbalance energy clearing and dispatch functions within the Rest of Maine area of the Maine ISA would be subcontracted to NBSO, which would operate the Rest of Maine area as an imbalance energy and market-dispatch zone that, although integrated with New Brunswick dispatch, would clear at prices different from the New Brunswick Zone. This means that NBSO would conduct its combined redispatch for New Brunswick and the Rest of Maine, respecting the transmission constraint between the two areas and within the Rest of Maine. The resources in both New Brunswick and the Rest of Maine would bid into the NBSO-administered market. Any hourly blocks of energy needed to match supplies to hourly changes in load would need to be:

1. purchased bilaterally from generators in the region;
2. imported from the ISO-NE day-ahead market; or
3. be provided through a Maine ISA energy market if the current NBSO imbalance energy market design can be expanded beyond imbalance service to allow for schedules with net short or net long positions.

The Maine ISA, via the "Maine Area Operator", would continue to operate the existing control center responsible for scheduling and operations in Northern Maine under agreement with MPS and, additionally, operate a second control center responsible for the same functions in the CMP and BHE portion of Maine. This second control center would be based on the current arrangement (under ISO-NE as the reliability coordinator) between CMP and BHE under which CMP operates the Maine Local Control Center (MLCC) for both CMP and BHE. Given the increase in responsibilities for CMP, the current MLCC would need to be upgraded in coordination with NBSO to accommodate greater responsibilities and market functions such as administering an OATT and operating an OASIS for the Rest of Maine. Both CMP and BHE currently have experience with transmission scheduling functions because some generation facilities are located on their local transmission systems. For the Maine ISA, staffing would need to increase from the current three person operation.

In the proposed Maine ISA, as is the case for the existing NMISA, transmission would be provided on the basis of physical reservations where market participants would need to reserve and schedule transmission usage for transactions between Northern Maine and New Brunswick (as is the case today), between Rest of Maine and New Brunswick (as is also the case today), and between Rest of Maine and

ISO-NE (as is currently not necessary within ISO-NE). Within the Rest of Maine area, load serving entities would schedule transactions under network service, which would not require transaction-specific reservations.

The transmission tariffs would be structured along the two Maine zones. The Northern Maine tariff would follow the existing NMISA tariffs and would include separate license plate tariffs for Maine Public Service Company and Eastern Maine Electric Cooperative. The Rest of Maine tariff would be based under a “postage stamp” arrangement under which BHE’s and CMP’s combined transmission revenue requirements would be recovered from through and out charges into Southern New England and (to a much lesser extent) to New Brunswick. In other words, BHE’s and CMP’s combined transmission revenue requirement would be recovered from all transmission service, which would include through and out service in addition to the transmission service to loads within the BHE and CMP footprint.

In the sections below, we assess the costs, benefits and feasibility of the MISA model set forth in the Brattle Group Report.

C. Likely Rate Impacts of MISA Structure

1. Overview

As part of the Brattle Group Report, the authors provided a breakdown of the costs recovered in CMP’s 2008 bundled residential electricity charges which is set forth in the table below:

Table I
Cost Recovered in CMP’s 2009 Bundled Residential Rates⁴⁷

	(cents/kWh) (%of total bill)	
Energy market costs	6.45	43.1%
Capacity costs	0.73	4.9%
Ancillary services costs	0.12	0.8%
ISO-NE administrative charges	0.06	0.4%
Distribution losses and uncollectables	0.72	4.8%
Supplier premium	0.85	5.7%
Total cost of standard offer service	8.92	59.7%
Transmission charges	1.34	9.0%
Distribution costs	4.07	27.2%
Stranded costs, ELP, DSM	0.62	4.1%
Total 2009	14.95	100%

⁴⁷ Brattle Group Report at 16.

This breakdown by cost category provides a useful tool for assessing the costs and benefits of the MISA option.

2. Energy Market Costs

As can be seen from the table above, energy costs represent, by far, the largest portion of the customer bill. Under the MISA model, energy would be traded on a bilateral, or day-1 market design, basis while the neighboring ISO-NE market would continue to operate a day-2 (day-ahead and spot hourly) market. Under the MISA arrangement, Maine sellers would now have to make a transmission reservation to sell into the ISO-NE market. This would create a seam which would discourage generators from selling into ISO-NE and, thus, depress prices in Maine. On the other hand, load-serving entities that need to purchase blocks of energy on the hourly market would now need to import such energy from ISO-NE and into Maine which would have the effect of increasing prices⁴⁸.

An additional barrier between the two markets could occur if the Maine ISA tariff collected a “through and out” charge for transmission service into the ISO-NE market. Such a charge would impose additional costs on suppliers to sell into New England and should translate into a discount off the ISO-NE price in Maine prices. The efficacy of such charges is discussed in section VII(C)(6) *infra*.

While such seams would tend to drive energy prices down, they would also have the impact of discouraging the construction of new generation in the State since generators will locate in those areas where their investments are maximized. In his testimony at the Technical Conference, Mr. Belcher noted that while economic theory states that in the long run energy prices should reach equilibrium, prices in northern Maine are lower than the Rest of Maine and New England nine years after restructuring. However, the price comparisons upon which Mr. Belcher’s statements are based do not provide support for a conclusion that the northern Maine market is inherently lower-priced. First, Mr. Belcher compares retail standard offer service prices, noting that northern Maine’s prices have generally been less than in Rest of Maine. Because the comparisons are based on standard offer prices that were not set contemporaneously, the differences Mr. Belcher notes are largely driven by market timing rather than inherent structural differences between the two markets. Second, Mr. Belcher compares “energy clearing prices” in the two markets, noting lower prices in northern Maine. Again, this comparison is not valid and, is indeed, misleading. The “energy clearing prices” referenced for northern Maine are cost-based, tariff fees for “balancing energy” from NB Power. The fees apply only to small amounts of energy needed to balance minor variations between load and supply that otherwise must match (i.e., through bi-lateral contracts) in accordance with NMISA market rules. As such, they are certainly not comparable to clearing prices in ISO-NE, nor provide a good indication of the level of energy prices more generally in northern Maine.

⁴⁸ See Brattle Group Report at 45.

Therefore, we continue to believe, as stated in our Phase I Order, that all things being equal, energy prices in the long-run will gravitate towards the market price set in the larger market as such prices represent the opportunity cost for energy sales and that there would be little advantage, in terms of long-run energy prices to Maine customers, of moving to a MISA model.

3. Capacity Costs

Capacity obligations under the MISA model are based on projected peak load plus projected operating reserve requirements. This system-wide level of capacity obligation is assigned to load serving entities based on monthly coincident peak shares. Capacity obligations are satisfied through bilateral obligations and cannot be satisfied by energy only contracts.

Capacity charges in the ISO-NE are set in the FCM. The Forward Capacity Market (FCM) resulted from a settlement among a wide range of parties in the region. The settlement, which was approved by FERC, included a transition period during which generators and demand response providers would be paid a fixed capacity price. The transition period ends in May 2010. Two auctions have already taken place under the FCM. Both auctions cleared at the floor price, i.e., the lowest price the auction could produce. Since generators under the MISA model would still have the option to sell into the FCM auction, we would expect that, similar to energy market prices, the ISO-NE market price would greatly influence the capacity price in the Maine ISA market.

As noted in our Phase I Order, the Commission agreed with the IECG's witness's concern over how the ISO-NE sets the region's overall capacity obligation and found that the States should be allowed to set the overall capacity obligation. Under the MISA model, there would be coordination with the NBSO for capacity adequacy issues, although it is unclear how disputes would be resolved in the event MISA and NBSO disagreed on either the amount, or the qualifications, of capacity required.

We cannot determine at this point, based on the record in the case, whether concerns about the purchase of capacity would be addressed by the MISA/NBSO model. However, we note, as previously discussed, that ISO-NE has been a leader in allowing DR to qualify as capacity through the FCM process which has served to benefit Maine ratepayers' interests.

4. Ancillary Services/Reserves

Consistent with NPCC requirements, both the ISO and the NBSO calculate the reserve requirements based on 100% of the single largest contingency plus 50% of the second largest contingency. Maine's share of the ISO-NE reserve requirement is approximately 158 MW, which translates into a charge of approximately \$6 million per year.⁴⁹ The Brattle Study estimates that Maine's reserve share of a combined Maine-

⁴⁹ See Phase I Order at 59 and Schnitzer Testimony at 15 (May 7, 2008).

NBSO system would be approximately 204 MW of which 14 MW would be attributed to Northern Maine and approximately 190 MW would be attributed to the Rest of Maine.⁵⁰ This represents an increase of approximately 20% in terms of reserve quantity. The Brattle Study also noted that the calculations were approximations and further study would be required to calculate actual requirements if the Maine ISO model was pursued.

In the Phase I proceedings, CMP estimated that a Maine stand-alone entity would have to provide 788 MW of reserves at an additional cost of \$23 million based on current ISO-NE prices. CMP's witness, Mr. Schnitzer, then applied what he considered to be the likely price impact of increased reserve prices which increased the cost impact to \$90 million. In the overview to the Brattle Study, the NMISA notes that reserve costs may actually go down under the MISA even though reserve levels are higher as a result of lower reserve prices from the NBSO.⁵¹ The Brattle Group however, did not adopt this finding.

While the price for reserves is uncertain, assuming that the price under the Maine ISA-NBSO arrangement is similar to ISO-NE's pricing, the costs of additional reserves under a MISA model would be approximately \$1.2 million more per year; significantly less than that projected by Mr. Schnitzer in Phase I of the case. We, therefore, find that the costs of reserves should not significantly alter the equation of whether to stay in the ISO-NE or pursue the MISA model.

5. Administrative Charges

In the Commission's Interim Report in response to Resolve I, the Commission noted that the ISO-NE's administrative costs, on a per kWh basis, were the highest of any of the RTOs in the United States.⁵² The Brattle Study estimated that administrative costs under the MISA model would likely be less than under the ISO-NE arrangement. The NMISA estimated that if costs per kW were the same for MISA as they are for MNISA, the rest of Maine's administrative costs would decrease from \$9.5 million to \$3.3 million.⁵³ The authors acknowledge that the costs of scaling up the operations of the NMISA and the NBSO, as well as the allocations for shared services, would need to be studied further to get a firm number.

Given the relatively small portion that such costs represent in overall rates, however, even a 50% reduction in administrative costs would only represent a 0.25% rate reduction. In its comments to the Brattle Report, the IEPM notes that this decrease of 50% in administrative costs would only translate into a reduction of \$0.25 per month for a residential customer with a \$100 monthly bill. We, therefore, agree with the assessment of the Brattle Report authors that administrative cost savings should not be a material factor in deciding whether to leave ISO-NE.

⁵⁰ Brattle Group Report at 26.

⁵¹ Brattle Group Report at 2.

⁵² Interim Report in Response to Resolve I, at 10 (January 16, 2007).

⁵³ Brattle Group Report at 7.

6. Transmission Revenue Requirement and Transmission Rates

As set forth in Table I, transmission charges for residential customers are 1.34¢/kwh which represents 9% of the residential customer's bill. Whether the MISA model will favor Maine customer's in terms of the transmission rates they must pay is dependent on several future events, none of which can be predicted with any degree of certainty.

The first area of uncertainty is what the level of transmission costs in Maine will be. At the present time, CMP's MPRP transmission proposal, with an estimated cost of \$1.4 billion, is still pending before the Commission. Under ISO-NE's current socialized cost allocation scheme, Maine ratepayers would be responsible for 8.2% of the costs of this project, or roughly \$115 million. Under the MISA model, depending on what could be recovered in through and out charges or cost sharing, the cost might be borne entirely by Rest of Maine ratepayers. The amount of the costs which will need to be recovered from ratepayers will be dependent on how much of the project proposed by CMP is approved by the Commission and the actual construction costs incurred after project approval.

The second area of uncertainty is what the level of transmission investment will be by the other New England states in the coming years. Given the NETOs track record on cost containment and cost underestimations, we have no reason to believe current projections of likely investment are an accurate predictor of actual future costs. While progress has been made in the cost estimation area, the new processes identified have not been applied to the proposed projects at this point. In addition, as we stated earlier, much work still needs to be done in the cost containment area should the Maine utilities remain in the ISO-NE.

In the Brattle Group Study, the authors assumed that MPRP as well as the other major transmission project approved by ISO-NE, the New England East-West Solution (NEEWS), went into revenue requirement as proposed in 2012. Under such assumptions, the Maine ISA transmission revenue requirement would be \$158/kW year⁵⁴, while the ISO-NE revenue requirement would be \$86/kW year. The current regional revenue requirement for New England is \$44/kW year. While the above scenario is a possibility, it must be recognized as just that and that there are a number of other possible results which might occur including a lower MPRP investment and a higher ISO-NE investment which would change these numbers.

Based on its projected revenue requirements, the Brattle Group study notes that unless 45% of the Rest of Maine transmission costs are recovered through either a wheeling charge or through a cost sharing arrangement with ISO-NE, Maine ratepayers would be worse off under the MISA model. While a case can be made that imposing through and out charges is equitable and is consistent with a "beneficiary pays" approach, Brattle notes a "Catch 22" type problem with imposing such charges since the higher the wheeling charge the more exports are discouraged which ultimately reduces wheeling

⁵⁴ A rate of \$158/kW year would represent an approximate tripling of CMP's current costs.

revenues.⁵⁵ The ability to obtain wheeling revenue may further be compromised by generators who claim that they have grandfathered rights to the transmission system, either from their previous sale of capacity in the FCM, contractual arrangements, or in NB Power's case, reservations to sell to the ISO-NE border. In addition to these problems, it is likely that high wheeling charges would meet with opposition at FERC by generators who would argue that such charges create "pancaked" transmission rates. In this case, several parties have questioned whether FERC would approve transmission pricing that resulted in pancaked rates. A review of the cases cited shows FERC's obvious preference for seams elimination, but does not preclude the possibility that FERC would approve a replacement arrangement that created seams.

In *Louisville Gas and Electric*, 114 FERC ¶ 61,282 at P. 33 (2006), the FERC reviewed a transmission operating agreement that required a transmission owner seeking to withdraw from the Midwest ISO to hold existing customers "harmless." To meet this obligation applicants agreed that existing transmission contracts would keep the same service and pricing. FERC construed this provision to mean that existing transmission customers will not pay pancaked transmission rates or pancaked ancillary service rates. *Id.* Thus, in this case the requirement to avoid rate pancaking was based on a contractual commitment in the TOA. FERC made clear, however, that this requirement applied to existing transmission arrangements and that the provision does not extend to customers that do not have contracts and also does not extend to future service. *Id.* at P. 49. Further, FERC made clear that the hold harmless provision applied only for the remaining term of the contract for existing service. In addition to the obligation under the hold harmless agreement, the Louisville utility proposed a "rate de-pancaking" provision. Under this proposal, the withdrawing utilities would charge a "non-pancaked" transmission rate for certain transactions but other transactions would be subject to a re-pancaked transmission charge. FERC accepted the proposal to maintain rate de-pancaking as part of Louisville's stand alone OATT because (with certain revisions) it would maintain rate de-pancaking between Louisville's system and the footprint of the remaining Midwest ISO membership, however, the proposal could not be implemented until a reciprocity agreement was negotiated with MISO. FERC stated "[w]e encourage the maintenance of rate de-pancaking and encourage Applicants to pursue their negotiations with the Midwest ISO and its remaining transmission owners. However, we will not require these entities' consent to Applicants' requests." Finally FERC rejected some aspects of the applicants' proposal to re-implement pancaking for certain transactions. *Id.* at PP. 115-116.

In *Duquesne*, which CMP cites for the proposition that "FERC is unlikely to allow the creation of new seams, separations or restrictions on exports," CMP May 1 filing at 25, citing *Duquesne*, 122 FERC ¶ 61, 039 at P. 134, FERC *rejected* generators arguments that third parties were entitled to "hold harmless" treatment holding that:

Moreover, since RTO withdrawal is expressly permitted under the TO Agreement, parties were on notice that withdrawal was a possibility and that, in the event of

⁵⁵ Higher wheeling charges which discourage exports would also have the effect of lowering energy charges.

withdrawal, they might need to enter into other transmission agreements and incur other costs. On the record presented here, then, we cannot find a general obligation to hold parties harmless from all costs occasioned by a withdrawal contemplated under the RTO agreements.

Id. CMP also cites to Order 2000 for the proposition that FERC frowns on pancaked rates. While it is clear that one of the FERC's motivations for Order 2000 was to eliminate seams, the requirements of Order 2000 apply to RTOs. Since MISA would not be an RTO, the requirements of Order 2000 do not apply. Nevertheless, FERC's preference for seams elimination would be expected to bear upon its determination of whether a replacement arrangement that introduces pancaked rates is just and reasonable.

An alternative to through and out charges would be for the MISA to negotiate a cost sharing agreement with ISO-NE. Under such an agreement, ISO-NE could be assessed a portion of BHE's and CMP's combined revenue requirement based on a usage or "beneficiary pays" metric. It is likely, however, that as part of the agreement ISO-NE would be asking Maine to pay for a portion of ISO-NE costs on a reciprocal basis. Any reciprocal agreement may result in the socialized cost methodology that the Phase I Order identified as flawed, but with Maine now negotiating from outside of ISO-NE rather than from the inside. Again, how successful such negotiations would be is another area of uncertainty.

Given the uncertainties discussed above, it appears unlikely that the MISA model, in the short to medium term, would benefit Maine ratepayers in terms of transmission rates. In the long-term, however, unless the unresolved cost containment issues at the ISO are addressed, Dr Silkman's argument that Maine is better off being responsible for 100% of its own costs rather than 8.0% of the "Big Dig," may be true.

D. Market Design and Market Monitoring

As the Brattle Report notes, given the size of the Maine market, a "day-2" market structure similar to that administered by ISO-NE would be cost prohibitive for the MISA to institute; therefore, the MISA model would be based on a "day-1" market only.⁵⁶ Without the market systems and features that a day-2 market would provide, wholesale electricity would have to transact through bilateral contracts; there would be no spot market for energy (real-time or day-ahead); no market-based congestion management; and no central market settlement system within which market participants could manage their supply and load obligations. Supply would tend to be less liquid, and prices would be less-transparent and comparable, i.e., they would be embedded in private bi-lateral contracts. In its Report, the Brattle Group notes that the transmission system is also used less efficiently in a day-1 market citing a study undertaken by the Midwest ISO that found

⁵⁶ A "day-1" market would generally not have the centrally-administered markets, price transparency and market-based congestion management features of a "day-2" market.

transmission capabilities were used 5% to 10% less under its previous day-1 market design compared to its current day-2 market design.⁵⁷

We agree with the Brattle Group's assessment that without the day-2 features, the MISA market would be less efficient and less competitive. In addition, the effectiveness and attractiveness of price-based demand response programs would also be diminished.

E. Reliability Functions

The Brattle Study described the reliability functions that would be performed by NBSO, the expanded MISA, and by CMP and BHE to plan and operate the MISA system reliably. The Brattle Group concluded that from both an operating and capability perspective, the MISA model is viable and could meet all NPCC and NERC requirements.

Given the time allotted for the study, the authors were not able to estimate what the expanded reliability functions of the NBSO and the other MISA stakeholders would cost. At the technical conference, however, Mr. Pfeifenberger, on behalf of the Brattle Group, stated that it was his opinion that these costs would not likely be of a magnitude to change his opinion as to the overall efficacy of the MISA structure as an alternative to continued ISO-NE participation.

We agree with the findings of the Brattle Group here that, from a reliability perspective, the MISA model is viable and should be able to meet all NPCC and NERC reliability criteria.

F. Control Over Decisions Which Affect Maine

The MISA would be governed by a stakeholder board consisting of Maine market participants and the OPA. By definition, Mainers and the State would have a stronger and more direct voice in controlling areas within MISA's jurisdiction, such as transmission planning, transmission cost allocation, and resource additions. However, because NBSO would be the reliability coordinator and the balancing authority, a great deal of authority would rest outside of the State, and of the country. Since MISA would be near equal to New Brunswick in terms of load ratios, it is also possible that Maine would have more influence over market structure and design issues than it does now as partner in ISO-NE, representing only 8% of the load.

It also must be recognized, however, that the largest player in the New Brunswick market is NB Power, which as a crown corporation, can be seen as extension of the New Brunswick government. Therefore, it may be difficult for the NBSO and/or the New Brunswick regulator to take positions adverse to NB Power's position or interest when faced with a dispute. Accordingly, an acceptable dispute resolution mechanism would have

⁵⁷ Brattle Group Report at 45.

to be part of a coordination agreement between the MISA and the NBSO and would require a significant amount of time and resources to negotiate.

G. Impact on Wind Development

The Maine Wind Energy Act provides the Legislature's findings that:

It is in the public interest to explore opportunities for and encourage the development, where appropriate, of wind energy production in the State in a manner that is consistent with all state and federal environmental standards and that achieves reliable, cost-effective, sustainable energy production on those sites in the State that will attract investment and permit the development of viable wind energy projects. The Legislature finds that the development of the wind energy potential in the State needs to be integrated into the existing energy supply and transmission systems in a way that achieves system reliability, total capital cost-effectiveness and optimum short-term and long-term benefits to Maine people.

35-A M.R.S.A. § 3402. In addition, Resolve II further provides that in deciding whether Maine's TOs should provide notice of non-renewal of the TOA, the PUC should consider, among other factors, the State's policy to encourage the development of indigenous renewable power resources.⁵⁸ Thus, through the enactment of the above provisions, the Legislature has requested that the Commission pay particular attention to the impact that any alternative transmission organization would have on wind development in the State. The evidence in the case indicates that the MISA model poses several potential barriers to the development of wind in the State.

First, similar to other generation resources, wind generators under the MISA model may be discouraged from investing in Maine due to the creation of the market seam and the pancaked transmission charge seam described in section VII(C)(6). Second, given the intermittent nature of wind generation, wind generators may find it particularly challenging to operate in a day-1 market which requires the submission of day-ahead balanced schedules. Third, the smaller MISA/NBSO balancing area may make it difficult for wind generators to find space on the transmission system. At the present time, there are 1,300 MW of wind projects in Maine in ISO-NE's interconnection queue. In addition, there are 1500 MW of potential wind generation which have been identified for development by the NBSO.⁵⁹ The combined peak load for Maine and New Brunswick is 5,200 MW. As noted in the Brattle Report, a system may face significant challenges when wind generation exceeds 20% of peak load. Above this threshold, the system may require

⁵⁸ See Resolve II, section 1.

⁵⁹ See Final Report of the MPUC in response to Resolve I, Jan. 15, 2008 at 21.

substantial amounts of additional flexible resources or the development of dynamic scheduling capability with neighboring systems. In addition to dynamic scheduling requirements, the transmission system may also need to be expanded to ensure system reliability.⁶⁰ The amount of wind generation identified for development in the combined MISA/NBSO system greatly exceeds the 20% limit which could pose a barrier to wind generation development in Maine. Issues of which generation is developed is a potential concern which would need to be resolved with the NBSO and the New Brunswick government.

In the Phase I Order, the Commission noted that despite the barriers discussed above, there appeared to be continued interest in wind development in Maine and New Brunswick. Such interest may be related to superior wind resource availability and ease of siting in these jurisdictions. In addition, it should be recognized that ISO-NE has not resolved the transmission cost allocation issues surrounding the connection of new renewable resources, and, therefore, the development of wind within the ISO-NE system is, at the present time, not without barriers. See section V (C), *supra*. Going forward, it will be necessary to resolve these issues as pressure at the federal level to incorporate greater quantities of renewables increases.

In the end, it is not possible to say how all these variables will play out in the investment decisions of wind developers and whether wind developers will invest in Maine in spite of the barriers discussed here. We do find, however, that the potential barriers implicit in the MISA model, will tend to make it more difficult, rather than less difficult, to attract wind generation investment in the State.

H. Transaction Risks/Timeline

The Brattle Report identifies a number of transaction risks of Maine migrating to the MISA model. These include developing suitable agreements with the NBSO and Canadian entities. These agreements would need to address cost sharing, jurisdiction, dispute resolution, and market monitoring. In addition, agreements will have to be worked out with generators, including NB Power who may claim existing or “grandfathered rights” on the transmission system to export power to New England.

In the Commission’s Interim Report in response to Resolve I, the Commission concluded that, while there were many hurdles that would have to be cleared in the formation of a Maine/New Brunswick market or some variant thereof, those hurdles were difficult rather than insurmountable.⁶¹ The authors of the Brattle Study reach a similar conclusion, that the MISA/NBSO model faces barriers but such barriers are likely not insurmountable.

⁶⁰ Such transmission investment would raise additional cost recovery issues discussed in section VII (C)(6), above.

⁶¹ Interim Report in response to Resolve I January 16, 2007 at 34 and Appendix.

We agree with this assessment. In the Commission's Interim Report, it was noted that there were cross-border agreements in the Midwest between the MISO and the province of Manitoba and in the far west, between the Northwest Power Pool, which includes eight northwestern States, and the provinces of Alberta and British Columbia. Certainly, NMISA's existing arrangement with the NBSO provides support for the proposition that the MISA/NBSO arrangement is feasible.⁶²

In addition to the agreements that would need to be reached between the Maine and New Brunswick a number of principle services would need to be costed out, such as: expanding the local control center, establishing market monitoring, and installing compatible communications systems as part of the implementation of a new system. At the technical conference on the Report, Mr. Pfeifenberger testified that he would not expect that these costs were of a magnitude to change his opinion on the feasibility of the MISA model. However, the negotiation of these arrangements would be time and resource intensive.

With regard to the timeframe to implement the project, Mr. Pfeifenberger testified that it would take about three years to implement if things went smoothly.⁶³ Given the scope the tasks which would be required to fully implement the MISA model, we find Mr. Pfeifenberger timeframe to be credible and while it is conceivable that MISA could be implemented in a somewhat shorter timeframe (perhaps two years), it is clear that it would not be possible to have the structure in place within the six-month interval between the time for notice of non-renewal of the TOA on August 1, 2009, and the expiration of the agreement on February 1, 2010.

Finally, it is not clear whether New Brunswick would actually agree to the MISA-NBSO partnership. While there are certain areas where there would clearly be benefits to New Brunswick from the partnership, such as reserve sharing, other areas such as NB Power's current transmission reservation to the ISO-NE market at the Maine border, could be problematic and would need to be resolved. The authors of the Brattle Study acknowledge that while they have discussed operational issues with the NBSO as part of the study, they have not done an assessment of New Brunswick's willingness to enter into the partnership.

VIII. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. While the Iberdrola Stipulation can be viewed as a voluntary waiver by CMP of the rights discussed in *Atlantic City* to join or withdraw from an RTO, BHE has made no such voluntary waiver but has agreed to cooperate with the Commission for the benefit of its customers.

⁶² *Id.* at Appendix.

⁶³ May 19, 2009 Technical Conference Tr. at 94.

2. FERC has the authority under the TOA to approve or disapprove of any withdrawal and to approve a replacement arrangement under a just and reasonable standard.
3. If Title 35-A does not provide explicit authority to direct CMP and BHE to withdraw from ISO-NE, the Legislature could provide the Commission such authority. There are limitations, however, on the jurisdictional authority of the Legislature or the Commission to mandate withdrawal.
4. Providing Notice of Withdrawal under Section 10 of the TOA does not trigger a renegotiation of the TOA but does require the withdrawing TO to begin formulating a transition plan.
5. Most of the areas requiring reform identified in the Phase I Order are outside of the scope of the existing TOA. However there is no prohibition for their inclusion in a newly negotiated TOA.
6. The FERC would likely not impose a hold harmless provision on withdrawing transmission owners with respect to remaining transmission owners or other NEPOOL participants since there is no such provision in the TOA.
7. FERC's preference for seams elimination in the creation of RTOs does not preclude the possibility that FERC would approve a non-RTO replacement arrangement that created seams.
8. CMP and BHE would likely not be obligated to pay upgrade costs of remaining NETOs beyond the revenue requirement for the year in which withdrawal occurred. Remaining NETOs would not likely be responsible for the upgrade costs of withdrawing TOs.
9. CMP and BHE would likely be required to honor existing interconnection agreements but the terms of the interconnection agreements would govern the scope of the continuing obligation. The obligation would likely not extend beyond the term of the interconnection or other agreements.
10. As recognized by counsel for CMP at the June 12, 2009 oral argument on this matter, the Commission shall continue to retain jurisdiction to review the terms of a renegotiated or renewed TOA pursuant to the terms of paragraph 44 of the Iberdrola Stipulation which provides:

“CMP, Energy East and IBERDROLA consent to Commission oversight of actions taken by CMP relative to NEPOOL, ISO-NE and related regional transmission organization matters affecting the State of Maine to (1) determine whether CMP's actions are in accord with the public interest and (2) order appropriate remedies if CMP's actions result in a material adverse impact to CMP's customers.”

11. The present arrangement with ISO-NE is adequate in the areas of operational control and management of the NE power grid, market design and operations, managing installed capacity, and the administration of DR programs subject to the successful completion over time of reforms advanced by the Commission.
12. To date, the Reform Option pursued subsequent to the Commission's Phase I Order, has met with partial success.
13. ISO-NE's response to the efforts of governance reforms demonstrates an apparent lack of understanding of the extent of consumer frustrations over its consideration of cost impacts and the lack of transparency underlying its decisions. However, the concept of providing cost efficient operations/services and providing information regarding the cost impacts of major initiatives is now embedded in the ISO-NE mission statement.
14. To the extent that reforms were achieved, the collaborative efforts of the Maine stakeholders were critical in achieving such successes. Continued cooperation and collaboration among the Maine stakeholders will be necessary in the future if subsequent efforts are to be successful.
15. To enable the development of wind generation in the State, ISO-NE will need to successfully resolve issues of cost recovery and cost containment for transmission projects built to connect renewable resource generation.
16. ISO-NE was not willing to engage in a process to consider options and was not willing to enter into negotiations to implement the Maine Contract Option citing lack of interest in pursuing the option by a broad group of stakeholders.
17. The FERC's decision in *Midwest Independent System Transmission Operator*, 126 FERC ¶ 61,139 (2009) reaffirms the voluntary nature of RTO membership but raises questions regarding whether FERC would approve of contracting for specific services from ISO-NE.
18. The MISA option put forth in the Brattle Group Study represents a feasible alternative to continued membership in the ISO-NE but is not without significant risks.
19. The southern Maine seam between the MISA and ISO-NE markets would discourage the development of generation in the State. The addition of a third seam in northern Maine (in addition to out charges paid to MPS and wheeling charges to NB Power) would place a new toll barrier between northern Maine generators and the ISO-NE market.
20. The day-1 market which would be implemented as part of the MISA model, would provide less price transparency, would likely increase the risk premium in prices, and would represent a step backwards in terms of market development. The day-1 market would also limit the State's ability to develop renewable resources.

21. It is not likely that the MISA model would produce significant savings in energy costs and capacity costs which represent the largest portion of Maine customers' bills.
22. If the MPRP is built as proposed and current projections of transmission investment in the rest of New England are accurate, Maine ratepayers' transmission rates, in the short to medium term, would be lower under the current ISO-NE system.
23. In the longer term, unless cost containment and cost allocation issues are addressed at ISO-NE, Maine's transmission costs could increase to, or exceed, the level projected for MISA in the Brattle Report.
24. While it might be possible to recover a significant portion of Maine's transmission investment from through and out charges, such charges would likely face challenges at FERC and would likely discourage generation investment in the State. An alternative to through and out charges for recovery of transmission investment would be a seams agreement with ISO-NE. The negotiation of such an agreement would likely result in a cost recovery mechanism similar to the one employed in the current system and instead of negotiating cost allocation from inside of ISO-NE, Maine would now have to try and influence such decisions from the outside.
25. The MISA model would likely not have an appreciable effect on the costs of operating reserves in Maine.
26. The MISA model would likely reduce administrative costs significantly. However, due to the relatively small share that such costs are of total customer costs, such savings would only have a small impact (approximately 0.2%) on customer bills.
27. The MISA model would likely increase the State's control over transmission planning, transmission cost allocation (in State) and resource additions. However, as the reliability coordinator and balancing authority, the NBSO would have a considerable amount of decision making authority over transmission issues. In addition, Maine's influence over the decision making process in New Brunswick may be compromised by NB Power's dominant market share and their status as a crown corporation.
28. The MISA model would likely discourage the development of wind generation in the State.
29. Should the MISA model be pursued, issues of developing infrastructure, staffing, cost recovery and dispute resolution will need to be addressed. There is precedent for inter-border agreements, and such issues are likely resolvable. However, reaching agreement would require an extensive commitment of resources. The MISA model will likely face additional transaction risks in the way of likely opposition at FERC and the resolution of grandfathered rights.

30. It would likely take approximately three years to be able to implement the MISA model. This extended time of regulatory uncertainty could discourage generation development during the transition period. While it might be possible to accelerate matters, the MISA model could in no case be implemented at the end of the current TOA.

IX. DECISION AND ORDER

Based on the above findings of fact and legal analysis, as well as those contained in our Phase I Order, we conclude that the Maine Transmission Owners, CMP and BHE, should not exercise their notice of non-renewal on August 1, 2009 and thus should allow the TOA to be extended for two additional years effective February 1, 2010. In reaching this conclusion, we recognize that not all of the reform objectives set forth in the Commission's Phase I Order have been achieved. Nor can we say definitively that ISO-NE's perspective, attitude or approaches towards consumers or the impacts of its decisions on consumers, have been transformed. That being said, we are convinced after the exhaustive process that has led us to today's decision, that staying in ISO-NE and pressing for further reforms remains the State's best option to fulfill its energy objectives at this turning point in the State's, and the nation's, energy future.

At this point in time, there is an energy vision coalescing at every level and branch of government around the need to move away from our over-reliance on fossil fuel for generating electricity, and instead integrate new renewable power resources into the supply mix, as well as maximize the efficient use of energy and minimize consumption, achieve a smarter and more secure grid, support technological innovation, and encourage economic development in the State. Maine, with its vast renewable resource potential combined with the resources of our Canadian neighbors to the north, is uniquely situated geographically to take advantage of that potential resource to benefit the State, the region, and the nation. To achieve this vision of our energy future, Maine needs sophisticated, competitive electricity markets, including ones that offer high functioning ancillary services and the massive planning and operating resources necessary to schedule and balance the flow of new intermittent renewable power and distributed generation, be it small or large-scale solar power, the deployment of electric cars, or the development of commercial wind farms and municipal renewable projects. Maine's consumers cannot afford to pay for even half of the transmission investment that may be needed to address the State's reliability needs, nor can they alone shoulder the burden to expand the transmission system within Maine in a way that will likely be required in the coming decades to support the growth of even modest amounts of new wind, solar, tidal, biofuel, pumped hydro, or other non-fossil based generation in the State.

In order to fulfill our energy objectives, neither Maine nor our sister States in New England can act alone. We in New England cannot ignore the reality that there are federal moves afoot to bring vast quantities of Midwest wind to the east coast through the construction of high voltage transmission that Maine will be required to help pay for. A concerted and cohesive regional response by New England and its neighbors, showing

that, in the alternative, we have the ability to collectively plan, build and pay for wind and other local renewable resources along with the necessary transmission to bring that energy to east coast load centers at a cost that is less than that contemplated by the Midwest plan will be required to thwart efforts at the national level to impose the costs of Midwest wind on New England ratepayers unilaterally.

In the great Yankee tradition, Maine always has been, and should continue to be in the future, as thrifty as possible to achieve our common goals. But we should not do so in a way that is penny wise and pound foolish. The Commission has greatly benefited from the analysis done by the Brattle Group and NMISA at the request of the U & E Committee. What that analysis has demonstrated, however, is that for the foreseeable future, there would be no tangible economic benefit to Maine ratepayers of leaving ISO-NE and creating the MISA model. Local control is an important issue that deserves utmost consideration but it should not be achieved at the cost of denying ourselves the energy vision we collectively share and must see become reality if we care about our State's and our nation's economic and political security and about the significant threats facing our environment.

After an exhaustive adjudicatory process, it is now time to bring this case to a close. As noted above, we conclude that BHE and CMP should not submit a notice of withdrawal at this time but should instead allow the August 1, 2009 notification deadline to pass without action, resulting in an automatic two year renewal of the existing TOA. We reject as premature, however, the suggestion put forth by CMP in its May 27, 2009 filing, that the Commission should, at this time, authorize a new TOA of up to seven years. In holding so, we note that all of the reform efforts which have taken place since the Commission's Phase I Order, have taken place outside the context of a the negotiation of a new TOA, and in fact, formal efforts to negotiate a new TOA have not yet begun. Therefore, the Commission cannot predict, or have anyway of judging, the terms of a new agreement. Instead, we order both CMP and BHE to provide notice to the Commission once formal negotiations of a new TOA commence and, thereafter, to provide monthly updates to the Commission on the status of negotiations and the progress made, as part of such negotiations, in meeting the reform objectives of the Commission.

To the extent that TOA negotiations are commenced, BHE and CMP shall pursue such negotiations in a manner consistent with the objectives set forth in this Order and the Commission's Phase I Order and shall incorporate, if applicable and appropriate, such objectives into the terms of the new TOA. In no case, however, shall BHE and CMP enter into a new TOA that frustrates the provisions of our Orders. Prior to execution, CMP and BHE shall bring any proposed new TOA to the Commission. Any new agreement by CMP, would be subject to Commission review pursuant to paragraph 44 of the Iberdrola Stipulation. While BHE was not a party to the Iberdrola Stipulation, we would expect that BHE would be a participant in such a proceeding and would cooperate in the Commission's review efforts.

Our decision to have the Maine utilities remain in the ISO-NE should not be interpreted as a decision that our efforts at reform have come to a conclusion; they have not. We expect BHE and CMP to remain actively involved in the continued reform efforts at ISO-NE and to continue to pursue those reforms already put forth by the utilities or by the Commission and to advance the reform objectives embodied in both this Order and our

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.
2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21 days** of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.
3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.

APPENDIX A

As discussed in section II, the Commission issued its Phase I Order in this matter on January 16, 2009. On February 3, 2009, BHE filed a Motion for Clarification seeking clarification of whether the January 16th Order was a final order for purposes of appeal. In its Motion, BHE argued that it was unclear as to whether the Order was a final judgment. Given this ambiguity, BHE stated that it must seek appellate review at this time, in order to preserve any legal arguments it may wish to raise in the future concerning continued participation in ISO-NE. Given the important tasks involved in pursuing the Reform Option, BHE stated that it preferred to seek clarification of the finality of the Commission's Order so that BHE could preserve its rights and all legal arguments in the future without pursuing an appeal at this time, which would be time consuming, expensive and distracting for all parties. Therefore, BHE requested that the Commission clarify its Order, by issuing a further order that contained the following statements:

1. That the January 16, 2009 Order was not a final adjudication of the issues presented in this proceeding;
2. That this docket will remain open so that the Commission can receive the reports referenced in the January 16, 2009 Order from the parties on the status of the Reform Option and the development of an alternative to the Reform Option, consider the information presented in those reports, and conduct further proceedings to ultimately determine whether BHE and CMP should continue to participate in ISO-NE or withdraw from ISO-NE; and
3. That failure to appeal the January 16, 2009 Order shall not preclude any party from raising any legal argument on appeal from any further Commission order in this proceeding or subsequent proceedings that could have been raised in an appeal of the January 16, 2009 Order, absent this clarification.

To avoid any confusion, the Commission granted the first two requests for relief contained in BHE's Motion. The Commission, however, denied BHE's third request for relief since it would be inappropriate, and likely beyond the Commission's jurisdiction to provide the warranty of what appeal rights BHE or other parties may have at the Law Court, should the Commission's final order in this case be appealed. See Order of Clarification (March 17, 2009) at 3.

As part of the Commission's Phase I Order, the Commission directed CMP and BHE to pursue the reform objectives set forth in the Order as part of their negotiations of a new TOA. The Commission also directed the Staff to hold a meeting with the parties to establish a process to facilitate the Commission's role in the TOA negotiations and in the ISO-NE process addressing transmission cost containment, transmission cost allocation for economic transmission projects, and governance.

Pursuant to a Procedural Order issued on January 22, 2009 by the Hearing Examiner, a case conference was held on February 4, 2009. At such time, the Commission Staff and the parties discussed a process for moving forward with the Reform Option which would allow the Commission, and the Commission Staff, to participate in the reform discussions. On March 10, 2009, the Commission received a Stipulation filed by counsel for BHE which was subsequently signed by all parties to this matter.⁶⁴ The parties to the Stipulation agreed that, pursuant to the provisions of section 103 of Chapter 110 (the Commission's Rules of Practice and Procedure), Chapter 110, section 760 of the Commission's Rules should be waived to permit limited ex parte communications. Ex parte communications refer to communications between the Commissioners or the Commission Staff, and any party to this matter, any proposed intervenor in this matter and representative, or employees of ISO-NE. The Commission found that the parties agreement to a waiver of the ex parte communication provisions of Chapter 110 of the Commission's Rules would aid the Commission in pursuing the Reform Option at the ISO-NE, was reasonable, and was in the public interest. See Order Approving Stipulation at 3 (April 22, 2009).

The parties in attendance at the February 4, 2009 conference also agreed that it would be beneficial to hold a series of collaborative stakeholder meetings to discuss the reform activities at the ISO-NE as well as positions on reform issues. On February 19, 2009, BHE filed a request for a protective order to restrict the release of confidential reform negotiation information exchanged during such collaborative/settlement discussions. On February 24, 2009, the Hearing Examiner issued Temporary Protective Order No. 4 (ISO-NE Negotiations), which granted BHE's request for protection. Subsequently, seven collaborative/settlement sessions were held, after due notice, at the Commission's offices.

As part of its Phase I Order, the Commission also required BHE and CMP to submit reports on March 1, 2009 and May 1, 2009 on the progress of the negotiations to implement the Reform Option. The Commission noted that as part of the May 1st Report, the utilities should address specific questions related to the Maine Contract Option. See section VI, *infra*. In its March 6, 2009 letter to the Commission, Senator Hobbins and Representative Hinck also asked that BHE and CMP file an additional report with the Commission on April 1, 2009. BHE and CMP submitted progress reports to the Commission on March 1, 2009, April 7, 2009 and May 1, 2009.

A case conference to develop a schedule to allow parties an opportunity to provide input on the options being considered and to conclude the Phase II portion of

⁶⁴ The parties to this matter are: the Office of the Public Advocate, Central Maine Power Company; Bangor Hydro-Electric Company; the Independent Energy Producers of Maine; FPL Energy Maine, Inc.; the Industrial Energy Consumer Group, Eastern Maine Electric Cooperative; Constellation Energy Commodities Group, Inc.; Constellation New Energy, Inc.; the New England Power Generators Association, Inc.; the Electric Power Supply Association; the Northern Maine Independent System Administration; Houlton Water Company; and Kennebunk Light and Power District.

the case was held on April 28, 2009. On April 29, 2009, the Hearing Examiner issued a Procedural Order which set forth the schedule as well as a list of the following eight legal issues to be addressed by the parties:

1. Would a Maine-only system administrator have access to services and resources from other RTOs or ISOs and on what terms?
2. What is the impact of FERC's recent decision in *Midwest Independent System Transmission Operator*, 126 FERC ¶ 61,139 (2009) on the ability to access discrete services from ISO-NE?
3. What would be the effect of one or more parties providing a notice of withdrawal under section 10.01 of the Transmission Operating Agreement ("TOA")? In answering this question, the parties should address whether providing the notice of withdrawal will force a renegotiation of the TOA among the remaining participating transmission owners. In addressing this question, the parties should support their answers with a discussion of the effect of the relevant provisions of the TOA.
4. Would the Commission or the Legislature have authority to order CMP and BHE to withdraw from membership in ISO-NE?
5. What continuing obligations would CMP and BHE have (if any) upon leaving ISO-NE?
6. Would remaining ISO-NE members have any obligation to continue paying for transmission upgrades built by CMP and BHE prior to withdrawing from ISO-NE?
7. Under FERC Order 2000, what would be the scope requirements if an RTO arrangement is developed?
8. What are the standards that would be applied by FERC to transmission pricing mechanisms for the Alternative Structure?

On May 1, 2009, BHE and CMP submitted their third progress reports which included the issues identified to be addressed by the Commission in its Phase I Order, as well as the legal issues 1 through 3 set forth above. On May 8, 2009, BHE and CMP submitted filings which addressed legal issues 4 through 6. On May 15, 2009, the OPA, the IECG and IEPM/NextEra filed responses to the utilities filings on issues 1 through 6.

A case management conference was held via telephone on May 18, 2009. At such time, the parties were provided an opportunity to object or propose additions to the exhibits proposed to be admitted into the record in this matter by the Hearing Examiner in a Procedural Order of May 12, 2009. There were no objections to the Examiner's proposed exhibits. At such time, however, counsel for BHE requested that if the Commission's letter of March 10, 2009 to the Utilities and Energy Committee went into

the record, that BHE be allowed to introduce its response of March 19, 2009. BHE's request was granted without objection. In addition, by agreement of counsel, the transcript of the May 19, 2009 technical conference on the Brattle Group Report was also admitted. The record in the case then consists of the evidence admitted during the phase I hearings, the exhibits set out in the May 12, 2009 Procedural Order (provided as Attachment One to this Appendix), the March 19th letter of Bob Hanf to Chairman Reishus, and the transcript of the Brattle Group Report technical conference.

On May 19, 2009, the technical conference on the Brattle Group Report, which was filed with the Commission on May 13, 2009, was held. On May 27, 2009, the Commission received the Final Comments of the parties which included comments on the Brattle Group Report,⁶⁵ the ISO-NE reform efforts, legal issues 6 through 8 and the recommendations and arguments of the parties. Final Comments were filed by CMP, BHE, the IECG, the OPA, and the IEPM/NextEra. On June 2, 2009, the Hearing Examiners in this matter issued an Examiner's Report which provided the Examiners findings of fact and conclusions of law but did not include recommendations. Parties were provided with an opportunity to provide exceptions to the Examiner's Report at an oral argument held on June 10, 2009. At such time, CMP, BHE, MPS, IEPM/NextEra, the IECG, and the OPA presented their final arguments and exceptions to the Examiner's Report.

⁶⁵ As part of the May 22, 2009 Procedural Order, the Hearing Examiner clarified that the comments on the Brattle Group Report would be in the nature of argument and not further expert testimony.