STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2008-156

January 16, 2009

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. INTRODUCTION

This case involves an investigation of whether Central Maine Power Company (CMP) and Bangor Hydro-Electric Company (BHE) should continue to participate in ISO New England (ISO-NE) which serves as the Regional Transmission Organization (RTO) for New England. ISO-NE is regulated by the Federal Energy Regulatory Commission (FERC), has an independent board of directors and is not accountable to any state authority in New England. Its rights and obligations to operate the region's transmission grid are governed by the Transmission Operators Agreement (TOA), a voluntary contract between the ISO and Maine's transmission owners: CMP and BHE. While an in-depth procedural history follows, a brief review of the steps leading to this case are in order.

In April 2006, Governor Baldacci signed a resolve directing the Commission to determine the legal options for Maine's utilities to withdraw from the ISO-NE, to determine the costs and benefits of doing so, and to examine other reasonable options to replace the services provided by the ISO. The resolve directed the Commission to submit an Interim Report to the Legislature in January 2007, and a Final Report in January 2008.

The Interim Report, issued on January 1, 2007, identified inequities, particularly in the transmission cost allocation system, found no insurmountable legal obstacles to CMP and BHE's withdrawal from ISO (although subject to FERC approval), and found that there were at least three reasonable alternatives to the status quo, including forming an independent Maine transmission company, developing a common Maine/Maritimes market, and working within the ISO to correct certain flaws in its structure and operations.

The Final Report, issued on January 2, 2008, identified the specific benefits to Maine of remaining in a regional market operated by the ISO. These included: providing the platform for retail competition and for regional energy planning, running a sophisticated dispatch and market system to optimize generation efficiency, and creating a framework that supports a liquid and transparent energy market with many buyers and sellers. Also, the report found that the benefits of economies of scale are significant and that access by Maine to ISO's vast engineering, economic and regulatory professionals would be difficult to replicate in a smaller system.

The report also identified deficiencies in the status quo, including rising and volatile energy prices, an overdependence on natural gas fired generation, less control over decisions (in that these decisions are made by federal regulators), less influence of consumer interests in regional decision making, and concern that Maine may be paying more than its "fair share" of regional costs.

The Final Report also focused on whether the status quo arrangement effectively advanced the development and integration of renewable resources across New England and the Maritimes. The entire region has recognized the importance of renewable resources and in the past year has been working toward solutions that promote renewables and integrate them into the New England and Maritime regions. Thus, the concerns identified in the Final Report about over-reliance on fossil fuels are being addressed by multiple entities, including many within Maine, within the existing framework. Trying to address directly the broader questions of energy price and supply diversity are important considerations, but are not addressed in this proceeding, except to the extent of considering the implication of various alternatives on seams and whether such seams would hinder renewable development. But the other defects in the status quo, primarily related to the reasonableness and fairness regarding cost allocation and what role the state and in particular consumers' interests can play in shaping the activities and decisions within the ISO's domain are directly implicated by the previous reports to the Legislature and are appropriately the focus of this proceeding and this Order.

In addition to the two reports to the Legislature in 2007 and 2008, the following other events of note transpired in the past two years that are relevant to this case.

- The stipulation the Commission approved on February 7, 2008, related to CMP's merger with Iberdrola in 2007, which included a provision giving (in effect) the Commission authority over CMP's renewal or continuation in the TOA and initiating a proceeding to examine the issue. *See Central Maine Power Company, Request for Approval of Reorganization Acquisition of Energy East Corporation and Iberdrola, S.A.,* Docket No. 2007-355, Order Approving Stipulation (February 7, 2008).

- In April 2008, Governor Baldacci signed a second resolve directing the Commission to submit a report to the Legislature by January 15, 2009, on the results of the proceeding, and to include a determination of whether it is in the interests of Maine ratepayers for Maine's T&D utilities to provide notice of non-renewal in ISO-NE, and if so found, to direct the utilities to file a plan to form an alternative structure to manage and dispatch the utilities' transmission assets. This Order is in response to the second Resolve.

- At the request of Maine Senator Collins and Connecticut Senator Lieberman last year, the GAO conducted an analysis about whether the RTOs are focused sufficiently on costs and benefits. The GAO's final report, issued in September 2008, made many observations, but one of note is that in the Midwest and New England, stakeholders, not just those in Maine, are concerned that the RTOs do not place adequate emphasis on assessing the implication on consumer prices of their decisions, such as whether there are lower-cost options available to achieve the grid reliability they seek; and

- CMP's filing last year for the Maine Power Reliability Project (MPRP), a massive transmission reliability project, the cost of which, if the project is approved by the PUC, would be funded regionally under the existing ISO-NE regime, and the filing, as well, of the smaller Maine Power Connection (MPC) project, jointly proposed by CMP and MPS along with a request for MPS to join the ISO-NE. The MPC proposal also envisions regional ISO-NE cost support for the project.

The Commission understands that the issues addressed herein are difficult ones; however, the Commission also recognizes their significance to the long term future of the people of Maine. While this Order specifically considers the findings and recommendations in the Examiners' Report, the Order can also be viewed as part of a continuum in the process that began in 2006, and is not the final end point. The Order makes certain findings, but much work remains as the Commission strives to achieve the best outcome for Maine ratepayers.

II. SUMMARY

In its Final Report to the Legislature in response to "Resolve, To Direct the Public Utilities Commission to Examine Continued Participation by Transmission and Distribution Utilities in this State in the New England Regional Transmission Organization" (Resolve I), the Commission concluded that the current arrangement with the Independent System Operator- New England (ISO-NE) deficient and that one of the following options was potentially superior: ISO-NE Market Reform; a stand-alone Maine/ITC; or the formation of a Maine/New Brunswick transmission organization.

Based on the evidence and testimony submitted in this investigation, as well as the information previously collected during its inquiry conducted in response to Resolve I, the Commission concludes that the present arrangement with ISO-NE is, significantly deficient in the areas of transmission cost containment, transmission cost allocation and ISO-NE governance. Of the options presented, the ISO-NE Reform option appears to be the best alternative to the status quo. Therefore, we direct CMP and BHE (collectively, the Maine TOs) to pursue the reform objectives set forth in this Order as part of their negotiation of a new TOA. The Commission further requires CMP and BHE to submit reports every 60 days starting March 1, 2009, following the issuance of this Order describing CMP and BHE's progress in pursuit of these reforms. The Commission will establish a process for evaluation of the progress toward achieving the reforms, and will issue an order in July providing further direction to CMP and BHE as a result of the evaluation.[1]

[1] Commissioner Cashman dissents with regards to the timing of pursuing an alternative to ISO-NE participation should reform efforts fail. Commissioner Cashman's dissent is attached hereto.

III. BACKGROUND

A. Overview of Current RTO Arrangement

ISO-NE is the entity that serves as the Regional Transmission Organization (RTO) for New England. It operates the New England transmission system including transmission facilities owned by CMP and BHE. It also administers New England's wholesale electric markets including markets for energy, capacity and ancillary services. ISO-NE is a public utility within the meaning of the Federal Power Act and is thus regulated by FERC. It is a non-profit entity with an independent board of ten directors. ISO-NE is not accountable to any state government or regulatory authority within New England.

ISO-NE derives its authority ultimately from agreements with New England's transmission owners,[2] including CMP and BHE, and these agreements are approved by FERC. ISO-NE's rights and obligations with respect to operating the New England transmission owner's transmission facilities are governed by the TOA.[3] The TOA also governs a transmission owner's rights to withdraw from the RTO. The current TOA became effective on February 1, 2005. The initial term ends on February 1, 2010.

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[2] The New England transmission owners include: Bangor Hydro-Electric Company; Town of Braintree Electric Light Department; Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company; Central Maine Power Company; Central Vermont Public Service Corporation; Connecticut Municipal Electric Energy Cooperative; The City of Holyoke Gas and Electric Department; Florida Power & Light Company; Green Mountain Power Corporation; Massachusetts Municipal Wholesale Electric Company; New England Power Company; New Hampshire Electric Cooperative, Inc.; Northeast Utilities Service Company as agent for: The Connecticut Light and Power Company, Western Massachusetts Electric Company, Holyoke Power and Electric Company; Holyoke Water Power Company; and Public Service Company of New Hampshire; Norwood Municipal Light Department; Town of Reading Municipal Light Department; Taunton Municipal Lighting Plant; The United Illuminating Company; UniTil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Electric Cooperative, Inc; Vermont Electric Power Company, Inc.; Vermont Public Power Supply Authority, and Vermont Transco LLC.

[3] The TOA, among other things, defines: the extent and purpose of the ISO's operating authority; the transmission owners' authority to establish and revise revenue requirements for transmission facilities; the transmission owners' authority to establish and revise rates to recover those revenue requirements; the ISO's authority to establish and revise market rules; the ISO's authority to establish and revise rates to recover ISO administrative and capital costs; the process for and allocation of authority for transmission planning; the term of the agreement and the process for termination, early or at the end of the term; and, the ramifications for default by either the transmission owners or the ISO.

Other sources of authority for RTO operation and administration of the wholesale electric markets include the ISO New England Open Access Transmission Tariff (OATT) and market rules. Prior to ISO-NE's role as the RTO for New England, it served a similar role as the independent system operator for New England beginning in 1997. It served in this capacity until the RTO operational date of February 1, 2005.

B. Commission Reports in Response to Resolve

On April 13, 2006, Governor John E. Baldacci signed Resolve I[4]. Resolve I directed the Maine Public Utilities Commission (Commission) to undertake an inquiry in order to:

> (1) determine the legal options for directing Maine Transmission and Distribution Companies that are currently part of the New England Regional Transmission Organization (RTO) to withdraw from the RTO;
>
> (2) determine the costs and benefits of directing these utilities to withdraw from the New England RTO; and
>
> (3) examine the other reasonable options for providing the services currently provided by the New England RTO, including any options involving Canadian governments, agencies or other authorities as well as options involving other state governments or agencies within the United States.

Resolve I required the Commission to submit two reports the Legislature: an Interim Report in January 2007 and a Final Report in January 2008.

On January 16, 2007, the Commission submitted its Interim Report on the status of the inquiry which set forth the following preliminary findings:

> A. Significant inequities exist in the Regional Transmission Organization's transmission cost allocation system and the pricing of generation services.
>
> B. There are no insurmountable legal, economic or technical barriers to Central Maine Power Company (CMP) and Bangor Hydro-Electric (BHE) withdrawing from the ISO-NE regime. However, the State of Maine is limited in its ability to direct such a withdrawal over the objections of the utilities, and any such withdrawal would be subject to approval by the Federal Energy Regulatory Commission (FERC).

[4] Resolves 2005, ch. 187.

C. There are reasonable alternatives to continued participation in the RTO. These include the formation of one or more Maine independent transmission companies, the development of a common Maine/Canadian Maritimes market, and working within the current ISO-NE framework to address and correct the identification inequities.

C. The Commission's Final Report

In the Final Report to the Legislature in response to Resolve I, issued on January 15, 2008, the Commission concluded that the current New England RTO and regional market provided certain benefits to Maine consumers which included: a platform for retail competition; a regional approach to energy resource planning; sophisticated dispatch protocols and market systems that optimize generation efficiency; and a liquid market with many buyers and sellers. In addition, the economies of scale provided by the size of the region allow it, through ISO-NE, to have access to a vast array of engineering, and economic and regulatory professionals which can be deployed in a manner that would be difficult to replicate in smaller systems.

However, the Commission found that are a number of serious defects in the status quo arrangement, including:

- Electricity supply prices are rising, particularly in the Northeast: Since 1990 prices nationwide have increased by 35%, compared to 55% in Maine and New England – over two-thirds of the run-up has occurred since Maine restructured its electric supply industry;

- Electricity supply prices are volatile, aggravating price pressures: Due to New England's heavy dependence on natural gas, electricity prices expose consumers to the volatility of international fossil fuel markets – costing Maine consumers a substantial premium each year;

- Energy security is at risk: New England's dependence on natural gas poses a substantial risk to electrical reliability because of the region's remoteness from sources of natural gas, and weak natural gas transportation system;

- Maine consumers are paying more than their fair share of regional costs: Regional rules inequitably allocate costs among the region's consumers, driving the consumers of a smaller state like Maine to shoulder the costs of larger states;

- Decisions about Maine's electricity industry have moved to Washington: Through electric restructuring, wholesale power markets set electricity prices – elevating the influence of federal regulators over those of state institutions; and

- Consumers are left-out of the increasingly influential regional and federal decision-making process: Regional institutions do not have institutional mechanisms to ensure responsiveness to state goals.

These defects led the Commission to continue to conclude that the status quo arrangement was undesirable and that each of the three options identified earlier in the Commission's Interim Report (ISO Market Reform, Development of a Maine ITC, and Development of Maine/New Brunswick Market) were potentially superior to the status quo.

D. The Energy East/Iberdrola Stipulation and Resolve II

On August 1, 2007, CMP and Maine Natural Gas Company (MNG) filed a petition for the approval of the acquisition of Energy East, CMP and MNG's parent corporation, by Iberdrola S.A. (Iberdrola), a corporation organized under the laws of the kingdom of Spain. On January 10, 2008, the Commission received a stipulation entered between the parties in the case which recommended approval of the proposed merger subject to the conditions set forth in the stipulation. The stipulation set out 59 separate conditions for approval, including CMP's continued participation in ISO-NE.

With regard to the ISO-NE participation condition, paragraph 43 of the stipulation provides that within 60 and not more than 90 days following receipt of Commission approval of the stipulation, CMP will initiate and the Commission will conduct a proceeding to determine, subject to any applicable legislative approval or review as may be necessary, if extension or renewal of the Transmission Owners Agreement is in the public interest. Pending the initiation and resolution of this proceeding, and any legislative approval or review to the extent necessary which may occur in 2008 or 2009, Iberdrola, Energy East and CMP agree to take no action with regard to CMP's position in any RTO, including whether to extend, consent to, amend, or renew or otherwise modify the terms of the ISO-NE Transmission Owners Agreement without explicit Commission approval. The stipulation further provides that upon issuance of a Commission order, and subject to any applicable legislative approval or review, as may be necessary, CMP will act in accordance with that order and that CMP will not assert or seek federal preemption, such as FERC authority, to frustrate the Commission's action or subsequent order. Specifically, CMP, Iberdrola and its affiliates agree that (1) they will not appeal the Commission order on the basis that the Commission lacks the jurisdiction to issue its order or that the Commission lacks the authority to issue or enforce its order, including but not limited to, that the Commission is preempted by federal law from issuing or enforcing its order, and (2) pending the resolution of any such appeal, they will not seek to stay the effect of any such order and will take all steps required to effectuate the same, until and unless such order is overturned or modified by a court or body of competent jurisdiction.

On February 7, 2008, the Commission issued an Order which found that the proposed merger, subject to the conditions set forth in the stipulation, was consistent with the interests of CMP's and MNG's ratepayers and thus approved the merger pursuant to the provisions of 35-A M.R.S.A. §708. *Central Maine Power*

Company, Request for Approval of Reorganization Acquisition of Energy East Corporation and Iberdrola, S.A., Docket No. 2007-355, Order Approving Stipulation (February 7, 2008). On September 16, 2008, the Commission received a letter from counsel for CMP informing the Commission that Iberdrola's proposed acquisition of Energy East had closed, and that Iberdrola was now the parent company of CMP and MNG.

On April 10, 2008, the Governor signed a "Resolve Regarding ISO New England" (Resolve II)[5] which required the Commission to submit a report to the Utilities and Energy Committee by January 15, 2009 regarding the Commission's proceeding pursuant to paragraph 43 of the Energy East/Iberdrola Stipulation. Resolve II stated that the report must include the Commission's findings in that proceeding including its determination of whether it is in the interests of Maine ratepayers for Maine's transmission and distribution utilities to provide timely notice of nonrenewal of membership in ISO-New England. In addition, Resolve II also requires that if it is in the interests of Maine consumers to provide timely notice of nonrenewal, considering the state's policy to encourage the development and discovery of renewable power resources, the Commission shall no earlier than March 31, 2009, order the Maine's three investor-owned utilities to file a plan to form an alternative structure to hold, manage, dispatch and expand the transmission assets of the investor owned utilities.

E. <u>The GAO Report</u>

In a May 21, 2007 letter, Maine Senator Susan M. Collins and Connecticut Senator Joseph I. Lieberman asked the Government Accountability Office (GAO), for an investigation by GAO into whether ISOs and RTOs are sufficiently focused on the costs and benefits of their actions. The Senators asked the GAO to "begin an investigation into ISO and RTO costs, structure, processes, and operations." GAO Letter at 2. Explaining the need for the investigation, Senators Collins and Lieberman questioned whether RTOs and ISOs were "living up to their full potential with respect to improving and reducing costs" and whether they had, "adequate incentives to minimize costs." *Id*. at 1. The Senators asked that the GAO report on several questions relating to whether RTOs and ISOs have: (1) mission statements that include obligations to control administrative and operational costs, and the cost impacts of its market-design decisions, in order to keep costs low for consumers; (2) incentives to ensure that costs to consumers are as low as reasonably possible; and (3) mechanisms to identify, assess, track, and monitor the cost impacts of its decisions at the retail consumer level. The Senators also asked the GAO to identify for each RTO/ISO:

> (a) what process is in place to ensure that an evaluation of the costs and benefits of the market design proposals is conducted prior to their submission to the FERC for approval; and,

[5] Resolves 2007, ch. 193.

> (b) what role do market participants and other stakeholders (*e.g.,* state commissions) play in the development, consideration and submission for approval to FERC and approval of (i) new market design proposals; and (ii) the RTO/ISO annual operating budget?

The GAO report, issued in September 2008, indicates that the GAO was asked to review: 1) RTO expenses and key investments in property, plant, and equipment from 2002 to 2006, [using] the most current data available; (2) how RTOs and FERC review RTO expenses and decisions that may affect electricity prices; and (3) the extent to which there is consensus about RTO benefits. [6]

While the GAO's perceived mission was more limited in scope than the areas that the Senators asked them to investigate, the report nevertheless contains some interesting data and observations especially regarding ISO-NE's and FERC's view on cost containment concerns. In addition, the report found that FERC's oversight of RTO expenses should be more rigorous. Of relevance to this case, the GAO report made the following observations:

- Stakeholders representing consumers expressed concern that RTOs did not place adequate emphasis on how decisions may affect consumer prices.[7]

- Decisions RTOs make when carrying out by implementing rules and transmission pricing outlined in their tariffs and performing reliability planning by considering factors such as weather conditions and equipment outages that could affect electricity supply and demand—as well as operating wholesale markets for electricity and other services can influence the wholesale price of electricity and ultimately the price consumers pay.[8]

- In 2006 (the most recent year for which complete figures were available) ISO-NE had the second lowest RTO expenses of the six RTOs but the highest expense per MWH. The fact that it had the highest per MWH rate was due, according to the GAO to the fact that it transmitted less electricity.

- In MISO and ISO-NE, many consumer advocates and state commissioners were concerned that RTOs do not place adequate emphasis on assessing the implications on consumer electricity prices of decisions, such as whether to build new transmission lines, when to create markets for services in lieu of charging cost-based rates, and reliability decisions. In addition, some stakeholders

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[6] GAO Report highlights. The Report can be found at the following link: http://www.gao.gov/new.items/d08987.pdf

[7] *Id.* at 6.

[8] *Id.* at 14-15.

believed that RTOs overemphasize ensuring reliability without full consideration as to whether lower-cost options are available.

- Officials from ISO New England responded to these concerns by acknowledging that there can be "trade-offs" between reliability and costs, but maintained that the FCM market and transmission planning efforts "are effective in keeping payments for reliability as low as possible."[9]

- ISO-NE and other RTO officials explained that "fulfilling their mission of ensuring reliability and efficient markets will minimize consumer prices in the long run." *Id.*

- Many consumer representatives expressed concern that RTOs do not conduct enough cost benefit analyses of how decisions may affect electricity prices.

- FERC relies heavily on stakeholders to raise concerns about RTO expenses, but in the case of protests by the Massachusetts and Connecticut Attorneys Generals contesting the reasonableness of ISO-NE executive salaries, FERC found that the proposed salary expenses were just and reasonable after reviewing the record: however, FERC did not perform any independent analysis of ISO New England salaries, review the surveys or benchmarks ISO New England cited, or conduct comparisons of salaries across RTOs.

- Consumers believe that it is difficult for consumers to contest the reasonableness of RTO expenses because of the burden of proof, the expense associated with filing a complaint and the fact that the data needed to show that expenses are not just and reasonable are typically proprietary.

- FERC has not developed a comprehensive set of publicly available standardized measures to track RTO performance. "In the absence of measures for evaluating the success of the decision to encourage the creation of RTOs, FERC may be missing opportunities to facilitate improvements in RTO operations and markets."[10]

The report recommended better oversight over RTO budgets and further recommended that the FERC Chairman take the following two actions:

- work with RTOs, stakeholders, and other experts to develop standardized measures that track the performance of RTO operations and markets and

- report the performance results to Congress and the public annually, while also providing interpretation of (1) what the measures and

[9] *Id.* at 35.

[10] *Id.* at 59.

reported performance communicate about the benefits of RTOs and, where appropriate, (2) changes that need to be made to address any performance concerns.

IV. PROCEDURAL HISTORY

On April 8, 2008, the Commission issued a Notice of Investigation to initiate this proceeding as contemplated in the Docket No. 2007-355 stipulation. As part of its Notice, the Commission determined that since the issues to be addressed in this matter would be of statewide interest, and would affect ratepayers in the service territories of Bangor Hydro-Electric Company and Maine Public Service Company (MPS) as well as those in CMP's service territory, all three utilities were considered in the scope of the investigation and made parties to the proceeding at the outset. The Notice of Investigation provided other interested persons wishing to participate as parties in this matter an opportunity to intervene.

Petitions to intervene were filed by the following entities and were granted without objection: the Office of the Public Advocate (OPA); Independent Energy Producers of Maine (IEPM); FPL Energy Maine, Inc. (FPL); Electric Power Supply Association (EPSA); the Industrial Energy Consumers Group (IECG); Eastern Maine Electric Cooperative (EMEC); New England Power Generators Association (NEPGA); Constellation Energy Commodities Group, Inc, and Constellation New Energy, Inc. (Constellation); Energy Matters to Maine; the Northern Maine Independent System Administrator (NMISA); Houlton Water Company (HWC), and Kennebunk Light and Power District.

CMP submitted its initial filing on May 7, 2008, consisting of a report entitled "Examination of Maine's Continued Participation in ISO-NE" by Michael Schnitzer. Following CMP's initial filing, a case conference was held on May 13, 2008, at which time the issues and objectives of RTO participation to be addressed in the parties filing were discussed. At the case conference, MPS and HWC requested that the issues involving northern Maine and its possible participation in ISO-NE should be segregated from this case and addressed in the case expected to be filed by MPS for approval of its proposed MPC project. On May 27, 2008, the Hearing Examiner issued a Procedural Order which set forth a list of objectives of ISO-NE and/or ISO-NE alternative participation and requested that the parties address a series of questions including how each of the alternatives to the status quo identified by the Commission could be configured to best achieve the listed objectives. The Examiner also concluded that while this case and the MPC case should not be consolidated as suggested by some, the matters in the two cases were interrelated and the issues raised in one case could not be excluded from the other. Therefore, the Examiner agreed with the proposal of CMP that the relevant evidence in one case may be incorporated into the record in the other case.

On June 13, 2007, Mr. Schnitzer filed an updated report on behalf of CMP, Tim Brown filed testimony on behalf of MPS and Robert Stoddard filed testimony on behalf of BHE. A technical conference on the utilities' cases was held on June 20, 2008. Both Mr. Schnitzer and Mr. Stoddard filed rebuttal testimony on September 26, 2008.

On August 19, 2008, Richard Silkman, Ph.D. filed testimony on behalf of the IECG, Gordon Weil, PhD., filed testimony on behalf of EMEC, HWC and the IECG, Roy Shanker, Ph.D., filed testimony on behalf of FPL, Constellation, IEPM, EPSA and NEPGA (the Consortium of Energy Generators and Suppliers) and Ken Belcher filed comments on behalf of NMISA. On August 21, 2008 Richard Barringer, Ph.D. filed testimony on behalf of the IECG. A technical conference on the Intervenors' cases was held on September 3, 2008. Surrebuttal testimony was filed by Dr. Weil, Dr. Silkman, Dr. Barringer and Dr. Shanker on October 14, 2008.

In its case management memo filed on October 16, 2008, the IECG objected to the testimony filed by Dr. Shanker as such testimony responded to the direct testimonies of the IECG's witnesses, and therefore, should have been filed as rebuttal. The IECG moved to strike the testimony, or in the alternative, requested the opportunity to present oral surrebuttal testimony by Dr. Weil and Dr. Silkman at the hearing in response to the Shanker Rebuttal. Argument was heard on this matter at the case management conference held on October 20, 2008. At such time, the Examiner denied the IECG's motion to strike the Shanker testimony but agreed with the IECG's argument that such testimony should have been filed at the rebuttal stage and therefore granted the IECG's request that Dr. Silkman and Dr. Weil be allowed to present oral surrebuttal to the Shanker testimony at the hearing.

Hearings in this matter were held on October 21, 22 and 23, 2008. At the conclusion of the hearings, the IECG, HWC and EMEC filed a motion to extend the hearings to allow the moving parties to present testimony regarding whether Aroostook Wind Energy (AWE) could pay for the transmission lines to deliver the output from its proposed project. The motion to extend the hearings was denied by the Hearing Examiner on October 30, 2008 on the grounds that request to provide additional testimony was untimely and also not critical to the resolution of this case.

CMP, BHE, MPS, Constellation, the IEPM and FPL, HWC, the IECG, and the OPA submitted briefs on November 13, 2008, and on November 20, 2008 the Commission heard oral arguments from the parties in this matter.

On December 12, 2008, the IECG filed a Motion to Reopen the Record, to Admit New Evidence, and Strike Inaccurate Statements from the Record. On January 2, 2009, the Hearing Examiners denied the motion on the grounds that the proffered evidence was cumulative and not necessary for the adjudication of the case and that the IECG failed to demonstrate that there was any basis to strike the expert testimony identified by the IECG.

V. POSITIONS OF THE PARTIES

A. CMP's Position

CMP asserts that the costs and the risks associated with Maine's withdrawal from ISO-NE, either in whole or in part, outweigh any potential benefits. CMP states that "many of ISO-NE's services are quite valuable, and performing them outside the ISO will be costly, complex and risky."[11] CMP advocates for a decision that: (1) requires the Maine TOs to seek reforms through renegotiation of the TOA, (2) provides guidance for other parties in the case to simultaneously work towards similar reforms at ISO-NE through other means (i.e. the New England Conference of Public Utilities Commissioners (NECPUC), the New England States Committee on Electricity (NESCOE), and stakeholder forums), and (3) requires the Maine TOs to report to the Commission on the progress of their efforts in the TOA renegotiation process.[12]

In the event that reforms are not achieved, however, CMP asserts that remaining a member of ISO-NE is in the best interest of Maine consumers. CMP relies on several examples to support its contention that leaving ISO-NE will be costlier to Maine than remaining. For example, recreating the administrative functions that ISO-NE currently performs, CMP argues, would be costlier due to economies of scale that would be lost in a smaller system.[13]

The cost of meeting NPCC mandated generation reserve requirements is another example used by CMP to demonstrate the benefits of ISO-NE. Currently reserves are shared with all members of ISO-NE. In a stand-alone system, CMP argues that Maine would likely have to provide its own reserves sufficient to cover 100% of the largest contingency and 50% of the second largest. Without reserve sharing from ISO-NE, CMP argues that Maine would be subject to a requirement of 788 MW rather than the current of 158 MW, or nearly five times Maine's current obligation. In a system where Maine and New Brunswick shared reserves, the costs would likely be double those incurred within the ISO-NE. CMP further argues that that reserve costs could be even greater, given the mix of generation resources in Maine that would be most capable of providing them.[14]

CMP observes that leaving ISO-NE would result in Maine depending on "the smallest wholesale market in the country"[15] to meet its needs. It contends that this

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[11] CMP Brief at 6.

[12] *Id.* at 1-2.

[13] *Id.* at 1-2.

[14] *Id.* at 8-10.

[15] *Id.* at 7.

would lead to greater uncertainty among generators, and less market liquidity, resulting in higher energy prices. CMP argues that to attract sufficient energy supply, prices would have to be high enough to tempt generators into selling their products into Maine.[16]

With respect to capacity, CMP cites the decision of FERC in *Duquesne Light Co*., 122 FERC ¶61,039 (*Duquesne I*) to demonstrate that Maine would also be unlikely to achieve savings in the alternatives to ISO-NE.[17] CMP argues that the Duquesne decision would require capacity resources that have existing commitments in ISO-NE to honor those commitments post-withdrawal. To achieve this, CMP argues, the generators would be given firm transmission rights for the duration of their commitments. Furthermore, based on FERC's general policy against the creation of seams, CMP asserts that it is unlikely that generators in Maine could be precluded from selling into the ISO-NE capacity and energy markets. Accordingly, CMP argues prices in Maine would tend to track these markets.

CMP sees several problems with the "hybrid" alternatives to ISO-NE proposed by the IECG's experts, Drs. Richard Silkman and Gordon Weil. CMP contends that these alternatives are unrealistic because they are based on the flawed assumption that ISO-NE services (or markets) can be unbundled so that Maine can pick and choose the ISO-NE functions that it wants.[18] CMP argues that ISO-NE has no legal obligation to provide "a la carte" services to a non RTO member. FERC Order 888's requirement of "open access" and "nondiscrimination" is not a source for such an obligation because Order 888 refers only to the provision of electricity transmission, not to an RTO's authority as the system operator and reliability coordinator.[19] Further, CMP contends that this purported obligation does not derive from the Federal Power Act or ISO-NE governing documents. CMP also argues that FERC would likely not approve of removing transmission planning from the basket of services that ISO-NE provides, because transmission planning is a key component to an RTO's reliability function.

Finally, CMP argues that the "essential facilities" doctrine does not support the contention that ISO-NE would be obligated to contract for services on an "a la carte" basis. CMP points to a recent Supreme Court decision's refusal to recognize the doctrine at all, especially when there is a regulatory body that can compel access to the facility in question if necessary. In this case, ISO-NE is regulated by FERC.[20]

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[16] *Id.* at 7-8.

[17] CMP Brief at 10-11.

[18] *Id.* at 19.

[19] *Id.* at 20.

[20] *Id.* at 23 (citing *Trinko v. Verizon,* 540 U.S. 398 (2004)).

CMP also argues that it is not reasonable to expect ISO-NE to provide selected services to Maine at a cost-based rate. CMP cites to other RTOs that charge non-cost based rates for emergency services and for operating reserves.[21] CMP also points out that FERC has allowed market-based rates for the provision of ancillary services and indicated in its decisions that it would support non-cost-based rates for RTO services provided to non-members.

CMP argues that an additional risk under any of alternatives to ISO-NE is that such alternatives may hinder the realization of Maine's ambitious wind generation policy goals.[22] Regulatory uncertainty and the market issues discussed above provide some of the reasoning behind CMP's position, as well as uncertainty about how the alternatives would affect access to the ISO-NE renewable energy credit (REC) market. CMP notes that REC trading could become more difficult and expensive under the proposed alternatives to ISO-NE, particularly for intermittent resources like wind. Finally, CMP notes that substantial transmission investment will be necessary for the wind resources to be developed, and without cost socialization, transmission costs could discourage generators from locating their facilities in Maine.

CMP does concur that there are problems with the status quo, however. For example, CMP notes that transmission socialization is problematic with respect to Market Efficiency Transmission Upgrades (METUs).[23] CMP points to general agreement among the parties that a "beneficiary pays" cost allocation would be a better approach than full socialization, and asserts that the best place to achieve such reforms is the ongoing working group efforts to address problems under Attachments K and N to ISO-NE's OATT.[24]

With respect to the issues raised by the IECG regarding demand-side programs, CMP contends that these issues can be addressed from within ISO-NE, especially given that better demand resource programs should also benefit other stakeholders in ISO-NE.[25] CMP also notes that Maine can pursue demand resources on its own, e.g., with RGGI proceeds, with or without changes at ISO-NE.[26]

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[21] *Id.* at 24.

[22] CMP Brief at 35-39.

[23] *Id.* at 43.

[24] *Id.* at 49-50.

[25] Schnitzer Surr. Test. at 6.

[26] *Id.* at 30.

CMP recognizes that it has a large role in achieving reforms in the areas identified by the Commission and the other parties through its TOA negotiations. At the same time, CMP contends that to achieve some of the desired reforms, work outside of the TOA negotiations must be performed by other parties. CMP proposes that the Commission and other parties should attempt to generate support for their reforms on governance and transmission costs from other states and stakeholders in ISO-NE. CMP posits that improvements to the transmission planning process at ISO-NE should be pursued by the Commission in conjunction with the other small New England states. CMP also argues that NESCOE is well positioned to achieve transmission planning and transmission cost containment reforms. CMP also asserts that many of the concerns such as capacity requirements and FERC's regulation of RTOs are more properly resolved at FERC.[27]

CMP believes that working on one of the non-ISO-NE or hybrid alternatives, while negotiating for ISO-NE reform, is not in Maine's interest.[28] CMP asserts that an alternate would neither be perceived as a credible threat nor provide much leverage in the TOA negotiations. CMP points out that Maine's strength lies in its rich wind resources, and the state's position between desirable energy supplies in the Maritimes and load centers in the rest of New England.[29]

CMP argues further that continuing to work on alternatives to ISO-NE creates regulatory uncertainty that may be harmful to Maine's efforts to develop wind resources.[30] Developers will be hampered by not knowing whether (1) there will be a Day 2 market, (2) they will need to spend money to acquire firm transmission to reach the New England market, (3) their resources will qualify for RECs from other New England states, and (4) there will be sufficient transmission in Maine for their resources to tie into.

B. <u>BHE Position</u>

BHE's general position with respect to this case is similar to that of CMP's. BHE does not believe that any of the alternatives presented in the Commission's Final Report to the legislature or developed through the course of this proceeding are in the interests of Maine consumers, and therefore the best option is to seek reforms from within ISO-NE. BHE maintains that, unlike CMP, it does not bear the burden of proof in this case. It supports this contention with the fact that BHE was not a signatory to the

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[27] CMP Brief at 4-5.

[28] *Id.* at 45.

[29] *Id.* at 44.

[30] CMP Brief at 46-47.

stipulation in Docket No. 2007-355, and was permitted by the Commission to withdraw from the case prior to the stipulation's execution.

BHE maintains that "continued participation in ISO-NE is the strongest alternative across a majority of the metrics."[31] BHE argues that even the problems and costs associated with the status quo transmission cost allocation are not sufficient to warrant withdrawal.[32] BHE notes that none of the parties, even those most opposed to membership under the status quo, support full withdrawal.

BHE maintains that there would be no significant energy or capacity savings to Maine consumers under any of the non-ISO-NE or hybrid alternatives because FERC is not likely to allow seams between ISO-NE and any new market.[33] Without seams, generators will sell into the higher price market. Thus, in any new Maine market, prices would be at least as high as those that generators could command in ISO-NE.

BHE argues that remaining in ISO-NE is the best way for Maine to achieve its renewable energy goals.[34] BHE also maintains that, even though under the alternatives, renewable resources in Maine could export power out of Maine, there would be inherent inefficiencies in exporting power across RTO boundaries. Mr. Stoddard, BHE's expert, estimated that these inefficiencies add approximately $5/MWh to any exports.[35] BHE contends that these costs would make exports less competitive and thereby would render Maine a less desirable place to site renewable power.

Similar to CMP, BHE asserts that remaining in ISO-NE: (1) will advance the development of wind resources, (2) results in lower costs for reserve requirements, and (3) results in a reliable system.[36]

BHE further notes that Maine consumers, through the State's membership in NEPOOL and then ISO-NE, have made substantial investments in both organizations and the regional grid to achieve this reliability. BHE argues that Maine consumers

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[31] BHE Brief at 8.

[32] *Id.* (citing Shanker Dir. Test. at 24).

[33] *Id.* at 18.

[34] *Id.* at 10-11.

[35] BHE Brief at 10-11 (citing Stoddard Dir. Test at 32).

[36] BHE notes, for example, that ISO-NE avoided problems during the 2003 blackout that brought the rest of the northeastern electricity grid down for an extended time period.

should not have to pay again for the same investments under a new system.[37] BHE also points out that the two main proponents of alternatives, the IECG's experts, Drs. Weil and Silkman each recognize these benefits because they both recommend retaining many of ISO-NE's reliability functions through post-withdrawal contracting.

Like CMP, BHE suggests that Maine has a short-term need for transmission investment and that this is a reason to remain in ISO-NE. BHE asserts that, despite its flaws, the existing transmission cost allocation mechanisms favor Maine. BHE witnesses contend that "fewer transmission dollars leave Maine than are recovered by Maine from the rest of New England."[38] Looking forward at currently planned transmission projects ($1.4 billion in Maine, and $6 billion for the rest of ISO-NE) BHE asserts that this benefit is likely to grow.

BHE argues that the recent FERC decision in *Duquesne* cuts both ways with respect to Maine leaving ISO-NE.[39] On the one hand, FERC is unlikely to require Maine to pay for its share for regional transmission cost allocation beyond the year of its withdrawal. On the other hand, the Northeast Reliability Interconnect (NRI) line was approved and constructed with the current cost allocation scheme in mind. Based on BHE's reading of *Duquesne*, the rest of ISO-NE would likewise not be subject to payment for its current share of Maine transmission projects beyond the year of Maine's departure from ISO-NE. That could require that the entire $140 million cost of the NRI be borne by Maine consumers rather than the 8.5% that Maine currently pays. Finally, BHE notes that there is likely to be costly litigation in the event of Maine's departure from ISO-NE over the proper interpretation of the *Duquesne* and other decisions.

BHE claims that ISO-NE has never provided a la carte services to transmission owners. The governing documents contemplate that the ISO-NE services are offered as a package. BHE recognizes that there are examples of RTO's providing select service on a contract basis to non-members, but distinguishes those from the ISO-NE situation, based on the fact that they involve vertically integrated utilities that have control over generation dispatch, whereas the utilities in Maine have divested their generation assets.

BHE argues further that even if the barriers to the provision of a la carte services by RTOs were overcome, it is quite possible that those services would come at a premium. That is because under the TOA the ISO's provision of services is discretionary.[40] BHE points out that the ultimate price ISO-NE could command from

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[37] *Id.*

[38] *Id.* at 14 (citing Jones-Haehnel Dir. Test. at 9).

[39] BHE Brief at 15-17.

[40] *Id.* at 23.

Maine is likely to be influenced both by the cost to the ISO of providing the services, and on Maine's avoided costs.[41] In essence, the ISO would be able to charge a premium over its actual costs, assuming that the costs to Maine of otherwise procuring or self supplying the services would be higher. As support for this proposition, BHE cites to examples of extra-territorial transactions with RTOs where the premium above cost is clear, such as the emergency energy supply agreements between NYISO and PJM in which prices are set at 150% of the locational marginal price.

BHE notes that each of the hybrid options put forth by the IECG strip certain functions from the ISO while leaving the reliability coordination in ISO's hands. BHE notes that ISO-NE, as reliability coordinator, has mandatory reliability obligations under federal law, and that without functions such as transmission planning that would be stripped away under Dr. Silkman or Dr. Weil's hybrid alternatives, ISO-NE might not be able to meet these obligations.[42]

BHE is opposed to any alternative that would require immediate notice of withdrawal under the TOA and instead advocates for a decision that requires the notice of withdrawal to be prepared but not immediately issued. BHE proposes that until the August 1, 2009 notice deadline, the parties continue to gather information regarding the likelihood of achieving reforms at ISO-NE, thus allowing the Commission to make the most informed decision with respect to whether the Maine TOs should issue their notices or not.

BHE argues that requiring it and CMP to develop alternatives while they pursue the negotiation of reforms at ISO-NE, as suggested by both Dr. Weil and Dr. Silkman, is not in Maine's best interest. BHE notes that even Dr. Weil characterized the NMISA option as a second best alternative that was merely "acceptable."[43]

C. Position of the IECG

The IECG presented testimony from three experts. Each expert testified to problems with the ISO-NE, and each expert provided advice on how Maine should resolve those problems. Though the views of the IECG witnesses were not entirely consistent, a common theme that the IECG reiterated in its post-hearing brief was that the purpose of this proceeding is to lower energy costs for Maine consumers by altering or concluding its relationship with ISO-NE. Throughout the proceeding, the IECG emphasized that maintaining the status-quo with ISO-NE was unacceptable. The major areas of concern for the IECG are: (1) ISO-NE's transmission cost allocation methodology; (2) its lack of sensitivity to the cost implications of its actions and policy decisions puts on consumers; and (3) its unresponsiveness to Maine's interests.

[41] *Id.* at 24.

[42] *Id.* at 31.

[43] *Id.*

The stipulation in Docket No. 2007-355 gives CMP the burden of proof in this case.[44] The IECG also asserts that BHE and MPS share this burden through the language of Resolve II, and the Notice of Investigation. The IECG further asserts that the parties to the stipulation all agreed that certain ISO-NE policies were highly detrimental to Maine consumers.[45] This, says the IECG, created "a presumption, that continued participation in ISO-New England is not in the interest of Maine consumers." The IECG asserts that this language indicates that all the utilities bear the burden of disproving this presumption.

The IECG does recognize that ISO-NE performs some functions well. Those functions are: "management and operation of energy and related markets, reliability coordination, the dispatch of generation, management of the transmission system and control area services.[46] However, the IECG maintains that ISO-NE "overreaches" in setting determination of capacity requirements and that its development of a methodology to secure adequate amounts of capacity resulted in Maine consumers having to pay a $350 million transition payment. Specifically, the IECG claims that the auction's "floor" price will keep capacity prices artificially high. Further, the IECG claims that these prices are unfair to Maine because Maine has more than enough generation in-state to meet the State's needs. Because of this, the IECG claims that Maine's capacity payments represent a subsidy to southern New England states which do not have sufficient generation for their own needs.

Dr. Silkman also commented on ISO-NE's reluctance to initiate demand response programs that often serve to reduce the need for future generation and also reduce the cost of meeting capacity requirements.[47] Dr. Silkman commented that ISO-NE's demand response programs often fall short of what proponents seek because ISO-NE is preoccupied with reliability and administering its energy markets and does not devote as much time to demand response.

The IECG also takes the position that ISO-NE's current transmission cost allocation methodology provides incentives to overbuild transmission.[48] The IECG argues that, "because the customers of each transmission owner with approved projects only pay their load-weighted share of the transmission investment, they have little

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[44] IECG Brief at 5 (citing to Paragraph 43(a) of the stipulation, "[t]he utility shall bear the burden of proof in the proceeding").

[45] *Id.* (citing to Paragraph 41 of the stipulation).

[46] IECG Brief at 10.

[47] *Id.* at 14.

[48] Silkman Dir. Test. at 19.

incentive to hold the costs down and much incentive to allow costs to rise."[49] The IECG contends that because ISO-NE does not evaluate whether the transmission projects presented to it by their sponsors are cost effective, and does not have any cost sensitivities in its mission statement, the incentive to overbuild is subject to very few limitations.

Dr. Weil, claims that under the ISO-NE's market design, consumers subsidize generation.[50] Dr. Weil claims that ISO-NE is using transmission charges to provide additional subsidy by utilizing Attachments N and K of its tariff to socialize the costs of transmission that is intended to bring new generation onto the grid. Dr. Weil then predicts that, "Maine seems certain to subsidize a system from which it cannot reasonably expect to receive commensurate benefits. Maine customers will bear an unwarranted burden."[51]

The IECG's third expert, Dr. Barringer, argues that Maine's ability to make important decisions regarding its energy policies were restricted under ISO-NE. His point was that these decisions were being made more and more on a regionalized basis, or by private entities, often with little regard to the effect their decisions have on Maine consumers. Dr. Barringer's conclusion was that if Maine put itself in the position to again make more of these decisions that it would likely produce superior results for its citizens.[52]

The IECG also complains of the amount of costly litigation that this Commission, the state's utilities, and other Maine groups have had to undertake because of many of ISO-NE's decisions.[53] Dr. Silkman pointed to the expense of the LICAP litigation. The IECG, in its brief also notes CMP's protest of the transmission cost allocation mechanisms created at ISO-NE, as well as BHE's protest of retroactive ICAP deficiency charges.[54]

The IECG has proposed two alternative hybrid models through its witnesses Drs. Silkman and Weil. The IECG argues that hybrid RTO structures can and do work. In support of this, it references the varied structures for RTOs that currently

[49] IECG Brief at 15.

[50] Weil Dir. Test. at 9.

[51] *Id.* at 13-15.

[52] IECG Brief at 19-20.

[53] *Id.* at 25.

[54] IECG Brief at 27.

exist in different areas of the country, and FERC regulations and policy requirements which allow such variation.

The IECG contends that, as long as certain minimum characteristics and functions are met by an RTO, and it enjoys support from its member state(s) and stakeholders, FERC would likely approve it. The IECG notes that a utility in the southern part of the U.S., Aquila-Missouri, contracts with the Southwest Power Pool for reserve sharing, something proposed by Dr. Silkman in his concept of a hybrid alternative to ISO-NE.

The IECG points also to the NMISA as another example of an RTO structure that is very different than ISO-NE. NMISA provides only limited services with respect to its service area. It is the independent transmission administer, while MPS acts as the system operator, and NBSO is the reliability coordinator and balancing authority. IECG contends that the examples provided by Dr. Silkman "proves that a wide variety of organizational structures and relationships exist to ensure that all of the necessary functions involved in operating a transmission grid and wholesale market system are performed and, importantly, that Maine does not have to participate completely in the ISO-NE structure in order to receive or purchase all of these functions."[55]

The IECG does not advocate that this Commission recommend withdrawal from ISO-NE before seeking changes to its structure as a member. Rather, the IECG recommends a decision in this proceeding that delays a final decision to allow time for a better exploration of its alternatives. It blames the utilities for necessitating this to some extent, because, in the IECG's view, they failed to fully explore the options as laid out in the Commission's Final Report to the legislature, and as required in the stipulation in Docket No. 2007-355.

The IECG would like the Commission to require the parties to further explore working with NMISA to develop further the "Maine-Only" option. It advocates a decision that requires the utilities to file their notices of withdrawal on August 1, 2009, so that the automatic two-year renewal clause of the TOA does not become effective. It also argues that the Commission "should set forth the changes it desires in specific detail along with the reasons for particular changes,"[56] and that these requirements should be backed with a decision to leave ISO-NE if the reforms are not accomplished.

The IECG provides a list of recommendations for the Commission. First, the IECG wants ISO-NE to relinquish capability responsibilities to the states. Second, the IECG contends that there must be substantial reform of ISO-NE's governance structure. The IECG argues for a hybrid board with both independent members and the addition of a similar number of stakeholder representatives. Additionally, the IECG

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[55] *Id.* at 34.

[56] *Id.* at 66.

wants cost responsibility to be included in ISO-NE's governing documents and also seeks that the NEPOOL Participants Committee be granted, FPA §205 filing rights for major tariff provisions because, according to the IECG, §206 rights alone are not sufficiently protective of consumer interests in its view.

Third, the IECG wants to see a major reformation of the ISO-NE cost-allocation system. It proposes a system that places utility sponsors of transmission lines substantially at risk for these costs so that they will be incented to build only the transmission that is absolutely necessary to meet their responsibilities.

Fourth and finally, the IECG argues that reform of the demand response market at ISO-NE be modified to ensure that those consumers that interrupt their loads are paid for both the capacity value and the energy value of their reductions. The IECG contends that the ISO-NE has regressed from its support in the growth of such programs.

D. OPA Position

The OPA's position is that in many respects Maine's consumers are not well served by ISO-NE. At the same time, the OPA recognizes the benefits that currently flow from membership and the risks to Maine consumers that come with leaving. Accordingly, the OPA advocates a Commission decision that requires BHE and CMP to renegotiate terms for a new TOA with ISO-NE that are in Maine consumers' best interests. The OPA supports allowing the automatic two-year extension to occur, which it contends should allow time for the Commission to determine whether the utilities' negotiations were successful enough to warrant continued participation.

The OPA advocates a resolution to this proceeding that enables the Commission to shepherd BHE and CMP through its negotiations to ensure that Maine's ratepayers are best served by the outcome. On the other hand, the OPA recognizes that the negotiations could work against Maine's consumers, and therefore, does not support CMP's contention that Maine's utilities should remain in ISO-NE regardless of the outcome of their renegotiations. The OPA argues that the Commission should ensure that there is a viable exit strategy because it recognizes that adequately addressing Maine's interests with respect to transmission cost allocation, among other needed reforms, will be challenging and potentially unsuccessful. [57] At the same time, this challenge is why the OPA supports allowing the automatic two-year TOA renewal which will, in the OPA's view, allow sufficient time to work through the issues fully.

In the event that the negotiations do not result in an outcome that is acceptable to the Commission because it goes against the interests of Maine's consumers, the OPA argues that the Commission should order the utilities to apply for membership with NMISA. In order to carry out this objective, the OPA recommends that

[57] OPA Brief at 4.

the Commission keep this docket open until at least 18 months before August 2012, the next opportunity for the utilities to provide their notice of withdrawal under the current TOA with its renewal term.

At that time, the Commission would determine whether the new TOA is acceptable or whether the utilities should file applications with NMISA. This strategy is informed by Dr. Silkman's testimony where he stated that "…[w]ithout a viable exit strategy, CMP and BHE will be captive to the majority, at best, and to the will of the largest utilities in New England, at worst."[58] This is an untenable position from both Dr. Silkman and the OPA's perspective.

The OPA argues that the overall cost of transmission projects is too high. It claims that reasons for this include cost socialization, that ISO-NE is focused on developing transmission rather than on the ultimate cost of projects on consumers, and that the rate incentives provided by FERC encourage high transmission costs. To control these costs the OPA suggests a list of measures for the Commission to require CMP and BHE to negotiate for. These are:

- Requiring that the ISO approve reliability projects on a "least cost" basis for both PTF and non PTF facilities.

- Requiring the ISO-NE and the TOs to clearly define how the "least cost" solutions are to be calculated.

- Amending the existing Regional System Plan methodology and components to require more extensive consideration of non-transmission alternatives to transmission including generation and demand response and a consideration of their cost.

- Identifying a method to more reliably identify where new generation will be built so that generation alternatives may be more reliably considered as alternatives to transmission.

- Providing consequences for projects that exceed cost estimates under certain circumstances. Require documentation and justification of cost overruns on projects beyond a threshold amount and require notice to state commissions of the cost overruns.

- Requiring meaningful coordination between ISO-NE committee review and state review in the transmission planning process.

- Providing a process for reexamination and reconfiguration of a project under certain circumstances. Circumstances which might lead to such a

[58] Silkman Surr. Test. at 10-11.

reexamination could include significant cost overruns, significant changes to load forecasts, or other significant events.

- Changing the “no adverse impact” standard for ISO-NE approval of reliability upgrades to one that requires a showing that the need is met at the least cost.

- Including the cost of non-transmission alternatives in any transmission cost allocation methodology that is adopted.[59]

The OPA further requests that the Commission require CMP and BHE to work toward achieving greater state and stakeholder authority over the regional transmission planning process. The OPA recognizes that the PAC already has some input in this process, but it wants this role to be enforceable rather than simply advisory. Similarly, the OPA argues that NESCOE, once it becomes fully operational, should have 205 filing rights for the most important regional issues.

The OPA argues that there should also be an office of a regional consumer advocate, because state based organizations do not have the time or expertise to fully participate in the ISO-NE stakeholder process. The OPA argues further that most states lack the resources to hire consultants and staff with the requisite skills, and that travel to and from the stakeholder meetings is also expensive. The OPA proposes a regional consumer advocate supported by funding from all of the states to participate more meaningfully on behalf of consumers in the transmission planning process.

E. MPS’s Position

MPS’s position in this proceeding is very limited. In its brief, it focused on a single issue, whether the MPC transmission project could be achieved without the benefit of regional cost socialization. MPS asserts that the MPC is not likely to be built unless: (1) at least a portion of the costs of the project are socialized and (2) the 800 MW Aroostook Wind Energy (AWE) project goes forward[60]

In support of its position, MPS’s Vice-President of Engineering and Operations testified that:

> Our development of the Maine Power Connection Project (“MPC”) has been premised on Maine’s remaining in ISO New England such that the Project would be eligible for regional “cost socialization.” (Also MPS has requested membership in ISO-New England, subject to certain specific

[59] *Id.* at 19-20.

[60] MPS Brief at 2.

> conditions.) Were Maine to depart from ISO-New England, it would appear that we would loose the cost socialization vehicle that we have been counting on and working hard to secure. Further, we have no backup plan for the MPC Project in the event that the State of Maine decides to pursue the "Stand Alone" of "NB" options. [61]

MPS contends that its customer base is too small to support even a smaller connection to the rest of Maine without some socialization of the costs.[62]

MPS notes that it has not stated that 100% socialization is necessary for it to build the line, and it anticipates some investment in the line by AWE. MPS argues leaving ISO-NE closes the door on regional cost sharing that, in its view, is necessary to build transmission to facilitate wind generation in Maine and to integrate northern Maine into the New England markets. MPS also claims that if CMP and BHE leave ISO-NE, the state's effort to expand its resource mix to make Maine less dependent on natural gas for generation would not be advanced.

F. Constellation (Constellation Energy Commodities Group and Constellation New Energy) Position

Constellation asserts that the benefits of staying in ISO-NE greatly outweigh the costs of exiting. It is opposed to the hybrid models proposed by the IECG's experts and argues that these models are "problematic at best."[63] Constellation is not convinced that IECG's proposed hybrid models are even feasible or in Maine consumers' interest. Constellation argues that holding onto the possibility of these options would not give CMP or BHE leverage in negotiations for ISO-NE reforms. Constellation, therefore, supports a Commission determination that CMP and BHE should stay in ISO-NE and seek changes to the TOA.

In support of its position that the benefits of staying in ISO-NE outweigh the cost of leaving, Constellation relies on the testimony of CMP, BHE, and the Consortium of Energy Generators' experts who agree that Maine consumers are better off within ISO-NE.[64] Constellation contends that the three experts provided by the IECG failed to effectively dispute these claims. Specifically, Constellation points to Dr. Weil's testimony that he could show no guarantied savings in his hybrid model.[65]

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[61] Brown Dir. Test. at 2.

[62] MPS Brief at 3.

[63] Constellation Brief at 12.

[64] *Id.* at 3.

[65] *Id.*

Constellation further argues that the Commission should not order CMP and BHE to provide their notice of withdrawal. Constellation relies on Dr. Shanker's testimony that it would very likely cost Maine more to leave ISO-NE than it would to stay, and that Maine would very likely be foregoing the significant short-term benefit of cost socialization for its planned transmission projects. Constellation further references Dr. Shanker's contention that the rest of New England would have to invest $18 billion in New England for Maine to go from being a net beneficiary of ISO-NE's cost socialization to breaking even. Finally, Constellation notes that the two-year automatic extension period in the TOA allows time for CMP and BHE to try to negotiate reforms. Constellation suggests that, at the end of that period, the Commission will be able to make a determination with respect to staying in or leaving ISO-NE.

G. HWC Position

Similar to MPS, HWC takes a very limited position in this case. That position is that the Commission should ensure through its decision that northern Maine ratepayers "…suffer no harm and may[be] even benefit…"[66] from its decision in this case. HWC argues that NMISA has been operating the northern Maine system efficiently for years to the benefit of the northern Maine ratepayers. HWC argues that this contrasts with the status-quo at ISO-NE that does not appear to offer the possibility of long-term or continuing benefit to Maine.[67] Consequently, HWC favors a Commission determination that adopts a solution to the problems with ISO-NE and meets, what it says, is the Commission's obligation to not negatively impact the COUs in northern Maine. Whatever choice the Commission makes it should do what it can to ensure that NMISA is not dissolved and that its ratepayers are not forced into ISO-NE. Accordingly, HWC provides support for both Dr. Weil and Dr. Silkman's hybrid proposals, because if Maine leaves ISO-NE, it is unlikely that northern Maine would be forced to join ISO-NE.

H. FPL and IEPM Positions

FPLE and IEPM assert that the costs of withdrawing from ISO-NE outweigh any benefits that might come from it. They assert that the only reasonable alternative to the status quo is to seek reform of ISO-NE, but that the status quo is better than any of the other alternatives if reform fails. FPLE and IEPM believe that the facts presented in this case weigh in favor of a decision whereby CMP and BHE would extend the TOA using its automatic extension clause for at least the initial two years, work with the Commission and the parties to come up with a list of agreed-upon reforms needed at ISO-NE, and commence the negotiation process to amend or revise the TOA.

[66] HWC Brief at 4.

[67] *Id.* at 5

FPLE and IEPM contend that three alternatives to ISO-NE were presented to the Commission in this proceeding. First, the market reform option is supported by FPLE and IEPM. The other two options were the hybrid withdrawal models proposed by Drs. Weil and Silkman. FPLE and IEPM note that the Maine/New Brunswick option presented in our Final Report to the Legislature was not supported by any party in this proceeding and appears to be untenable at this time.

FPLE and IEMP support the ISO-NE reform option because this is the most likely to preserve the substantial benefits that being a part of ISO-NE brings to most of Maine. They note that even Dr. Silkman, a proponent of partial departure, recognized the "powerful synergies" provided by ISO-NE's regional markets.[68] They also cite Dr. Silkman's acknowledgment that ISO-NE does a "good job" with reliability coordination, administration of the energy markets, managing the transmission system, and reserve sharing.[69] FPLE and IEPM also point to Dr. Weil's agreement that transmission and operations planning are benefits of CMP and BHE's membership in ISO-NE.[70]

FPLE and IEPM take issue with the conclusions reached by the Commission in its Final Report that energy and capacity prices would unlikely differ from the status quo if Maine withdrew from the ISO-NE. Instead, they assert, Maine would bear material increases in costs under any withdrawal option. [71]

FPLE and IEPM also contend that Maine's goal of developing 2000 MW of wind generation in the state by 2015 and 3000 MW of wind by 2020 would lead to increased operating reserve requirements for the state if CMP and BHE withdrew from ISO-NE.[72] They also argue that leaving would create uncertainty about whether renewable resources would qualify for renewable energy credits in the more lucrative ISO-NE markets. Another source of uncertainty, according to FPLE and IEPM is the possibility of the operational problems that could result from Maine managing these intermittent resources on its own.[73]

FPLE and IEPM acknowledge that there are legitimate concerns regarding potential overbuilding of transmission in New England, that transmission cost allocation

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[68] Brief of FPLE and IEPM at 7.

[69] *Id.* at 7.

[70] *Id.*

[71] *Id.* at 8-9.

[72] *Id.*

[73] *Id.* at 24.

under ISO-NE may make Maine disproportionately responsible for transmission investments in the New England grid, and ISO-NE's lack of effective least-cost analysis with respect to transmission proposals. FPLE and IEPM support requiring CMP and BHE negotiating for a beneficiary pays approach to transmission cost allocation and to make cost sensitivity a part of ISO-NE's governing documents and tariff.

FPLE and IEPM take issue with some of the parties' contentions that without the threat of withdrawal, Maine has no leverage to negotiate the reforms it needs from ISO-NE. They assert that, instead this threat is not credible given the short-term benefits that ISO-NE's cost allocation will bring to Maine over the next five years and that threatening withdrawal may actually put Maine in a worse position.

FPLE and IEPM request that the Commission order CMP and BHE to remain in ISO-NE, and leave it to those utilities' discretion whether or not to extend the existing TOA for its automatic renewal term. They support a collaborative effort to set out the specific reforms that will be sought at ISO-NE but if the negotiations are unsuccessful, FPLE and IEPM argue that Maine should nevertheless remain in ISO-NE.

VI. LEGAL STANDARDS GOVERNING WITHDRAWAL OF CMP AND BHE FROM THE RTO

As discussed previously, the Commission concluded that in the Interim Report that, "[t]here are no insurmountable obstacles to CMP and BHE withdrawing from the RTO after the initial term of the Transmission Operating Agreement ("TOA") which ends in February 2010."[74] As discussed below, this conclusion has been confirmed by recent decisions issued by FERC. Further, all parties appear to agree that withdrawal from the RTO is possible, however, as discussed herein, there are widely varying opinions among the parties about whether withdrawal is practical or beneficial to Maine ratepayers.

A. Withdrawal from the RTO

FERC precedent makes clear that the RTO governing documents will dictate the terms for RTO withdrawal. In this case, the relevant document is the TOA between the Transmission Owners (including CMP and BHE) and ISO-NE. FERC precedent also provides some guidance on how FERC will interpret various provisions in the TOA.

Section 10 of the TOA governs the terms of withdrawal from and termination of the RTO. The initial term of the TOA is five years from February 1, 2005, the operational date of the RTO. Thus, the initial term expires on February 1, 2010. After the initial term, any of the Transmission Owners may withdraw, subject to certain requirements, by providing at least 180 days notice to the other parties, prior to the

[74] Interim Report at 17.

automatic renewal of the agreement for an additional two-year term.[75] If notice of withdrawal is not given, the initial term is automatically extended for two-year additional terms.

If a transmission owner gives the required notice, the withdrawing transmission owners must develop a plan under which authority to operate the transmission owners' facilities will be transferred from the ISO to another entity.[76] The plan requires the agreement of the ISO and affected New England transmission owners on the technical, operational and market issues associated with the transfer of operating authority, but two provisions ensure that these other parties do not have the ability to prevent a transmission owner's withdrawal. If the parties cannot agree on the transition plan, any party may submit the matter to FERC for resolution. More importantly, the TOA states that a Transmission Owner withdrawing after the initial term "shall not be required to remain a Party to this Agreement for longer than one year after providing notice of withdrawal."[77]

FERC has the authority under the TOA to determine that the withdrawal is just and reasonable.[78] However, FERC cannot require transmission owners to relinquish certain legal rights that utilities have under section 205 of the Federal Power Act.[79] Within the past few years, FERC issued decisions balancing these two competing principles in cases involving two utilities' withdrawal from the Midwest ISO ("MISO") and the withdrawal of Duquesne Light Company from PJM Interconnection, L.L.C. (PJM). Both of these examples of utility withdrawal from RTOs provide guidance on the principles that would be applied to any withdrawal by CMP and BHE from ISO-NE and the development of replacement structures and arrangements. However, as is clear from the parties' testimony and argument, there are numerous questions, especially about replacement arrangements, that cannot be answered with any certainty at this time.

In *Louisville Gas and Electric Company*,[80] FERC granted the proposal of two Kentucky utilities to withdraw from the MISO. Prior to the withdrawal request, the Kentucky Public Service Commission ("Kentucky PSC") had examined the cost impact

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[75] TOA § 10.01(a).

[76] TOA § 10.01(c).

[77] *Id*.

[78] TOA § 10.01(f).

[79] *See, Atlantic City Electric Company v. FERC*, 295 F.3rd 1 ("Atlantic City") (D.C. Cir. 2002) ("Section 205 of the Federal Power Act gives a utility the right to file rates and terms for services rendered with its assets").

[80] 114 FERC ¶ 61, 282 (2006) ("Louisville"); Order on rehearing, E.ON U.S. LLC, 116 FERC ¶61,020 (2006) ("Rehearing Order")

of MISO's implementation of a congestion management system. The Kentucky PSC had determined that the utilities stand-alone operation under a Commission-approved OATT "would be less expensive than their continued participation in the Midwest ISO or any other RTO option that they had studied."[81] Thus, the utilities did not propose joining an alternative RTO, but instead proposed to act as a stand-alone transmission system under a Commission-approved OATT. The utilities proposed to delegate certain tariff administration duties to the Southwest Power Pool, Inc., which would act as an Independent Transmission Organization, while the Tennessee Valley Authority would serve as their Reliability Coordinator.

FERC found that the following legal standards applied to the proposal by the transmission owners to withdraw from the MISO:

1. The proposal must satisfy the terms of the Transmission Operating Agreement;

2. The proposal must address independence and rate pancaking concerns at issue in FERC's earlier approval of the merger of the two utilities;

3. The replacement OATT must be consistent with or superior to the Pro Forma OATT (Order 888); and

4. The withdrawal and new arrangement must be just and reasonable and not be unduly discriminatory.

In granting the utilities' request to withdraw, FERC made several determinations relevant to the analysis required here. First, FERC interpreted the hold harmless and exit fee provision language in the MISO TOA. Second, FERC determined that where the utilities did not seek to form a new RTO, the replacement arrangements were required to be consistent with *Order 888*, but not *Order 2000*. Third, FERC determined that the utilities' withdrawal request was not required to be supported by a cost/benefit analysis. Fourth, the just and reasonableness of a petition to withdraw would be judged primarily with regard to whether the withdrawal is consistent with the relevant transmission agreement and the Pro Forma OATT. However, FERC stated that it would examine alleged cost avoidance issues in a separate generic proceeding. Finally, FERC rejected the argument that the Midwest ISO had the authority to veto the utilities' withdrawal request. [82] Ultimately, FERC's approval of the Kentucky utilities' withdrawal from MISO is instructive and underscores the "voluntary" nature of RTOs.

In the Duquesne cases, FERC permitted Duquesne to withdraw from PJM and join the Midwest ISO, subject to certain conditions. In so deciding, FERC relied on many of the principles expressed in the LG&E case:

> First, we find that Duquesne's movement from one Commission-approved RTO to another is not barred by Order No. 2000. As we recognized in *LG&E*¸ companies that voluntarily join RTOs should have the ability to

[81] *Louisville*, 114 FERC ¶ 61,282 at P.13.

> withdraw from an RTO as long as the replacement rates that are established are just and reasonable. 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.

Duquesne I, P. 128 (citations omitted). Further, FERC found that where the relevant agreements did not require a withdrawing transmission owner to hold third parties harmless, there was no discernable "general obligation to hold parties harmless from all costs occasioned by a withdrawal contemplated under the RTO agreements." *Id*. P. 134. FERC further found that "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 withdrawal, they might need to enter into other transmission agreements and incur other costs." *Id.*

B. Continuing Obligations Related to Transmission Upgrade Costs

Under the TOA, a withdrawing Transmission Owner has a continuing obligation of:

> All financial obligations incurred and payments applicable to the time period prior to the Termination Date shall be honored by the terminating owner withdrawing Party and each other Party in accordance with the terms of this Agreement, and each Party shall remain liable for all obligations arising hereunder prior to the Termination Date.[83]

FERC's recent decision in *Duquesne Light Company,* 124 FERC ¶ 61,219 (2008) (*Duquesne II)* provides guidance on how this provision would be interpreted with regard to existing and planned transmission upgrades. In *Duquesne II*, FERC found, based on applicable tariff language that transmission project costs that had been allocated to the "Duquesne zone" would continue to apply to the Duquesne zone *only through the calendar year ending 2008,* the year of Duquesne's withdrawal from PJM. The interplay of the tariff and contract language interpreted by FERC is similar to language in the TOA and the ISO-NE OATT. For example, the applicable contract language in *Duquesne II* stated that a withdrawing transmission owner "shall remain liable for any and all obligations under this Agreement that such Party incurred, that were incurred on behalf of such Party, or that arose hereunder prior to the date upon which such Party's withdrawal, transfer, or assignment became effective."[84] In order to determine the extent of Duquesne's continuing obligation, FERC looked to schedule 12 of the

[83] TOA § 10.01(g).

[84] *Id., n*. 10.

PJM tariff. The PJM tariff sets the participating transmission owners obligation to pay transmission upgrade costs "based on the annual load that a load serving entity serves within each PJM zone."[85]

Similarly, under the ISO-NE tariff, a transmission owner's responsibility for upgrade costs is determined based on its "monthly network load." As noted by CMP:

> "the ISO-NE tariff is substantially similar to the PJM tariff in its treatment of Regional Network Services (RNS) costs (through which the transmission cost allocations are recovered). Essentially each PTO pays monthly for RNS costs on a per kW basis based on 'Monthly Network Load,' with the shared costs of regional facilities a component of this rate. [86]

Thus, CMP suggests that if Maine withdraws from ISO-NE's tariff, 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. The Commission agrees with this application of FERC precedent to the relevant ISO-NE documents—the TOA and the ISO-NE OATT. This view was expressed in the Interim Report,[87] and the *Duquesne II* decision confirms that this is the way that FERC would likely interpret the governing documents.

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)[88] can recover the cost of its transmission investment through the ISO-NE OATT. For example, the OATT sets forth the process through which PTOs can recover the costs of their investments

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[85] *Id.* P 164.

[86] CMP Brief at 14, citing ISO OATT Sched. 9.

[87] See Interim Report at 22 (stating that, based upon the language of schedule 12 and Attachment F of the ISO-NE OATT "CMP and BHE should not be obligated to pay transmission upgrade costs for projects (built by other utilities) that would be recovered in the formula rate for years subsequent to CMP's and BHE's withdrawal."

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

through their revenue requirements. Specifically, the Attachment F implementation rule states:

> This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each *PTO*. Such Transmission Revenue Requirements shall reflect the *PTO's* costs for Pool Transmission Facilities ("PTF") and the Highgate Transmission Facilities ("HTF"), including costs attributable to those *PTOs* deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each *PTO* will reflect the *PTO's* costs with respect to Pool Supported Pool Transmission Facilities (PTF) and the HTF.

Attachment F to ISO-NE OATT (emphasis added). A transmission owner which has withdrawn from the TOA is no longer a PTO and, thus, there is no provision in Attachment F through which it can collect the costs of its transmission investment. Accordingly, because a withdrawing utility would be expected to be responsible for the undepreciated costs of its upgrades when it withdraws, the Commission rejects the suggestion that CMP and BHE should simply wait two or five years to withdraw from ISO-NE and expect that they can continue to receive payments for projects already built once they withdraw from ISO-NE.[89]

C. Legal Requirements for Replacement Organizations

FERC's openness to a potential withdrawal from ISO-NE by CMP and BHE will be driven, in large part, by the characteristics of the transmission organization that replaces it. In *Louisville*, FERC's principal interest was that the utilities' replacement transmission arrangements were consistent with or superior to the Commission's Pro Forma OATT.

In *Louisville,* FERC rejected MISO's arguments that the utilities' replacement arrangements be required to meet the standards applicable to an RTO under *Order 2000*. FERC held that because the Kentucky utilities were not seeking to establish or operate as an RTO, *Order 2000* requirements were not applicable. Rather, FERC would consider whether the replacement OATT was consistent with or superior to the Pro Forma OATT established under *Order 888*.[90] On rehearing, FERC further explained its holding by stating:

[89] See Shanker Test., October 22, at Tr. 136-137 (suggesting that there is a "no lose window" of opportunity if the TOA is extended until 2010 or 2014 to get the benefit of socializing the MPRP, while only paying the annual costs of the projects in other states that have already been built).

[90] *Louisville*, 114 FERC ¶ 61,282 at P. 30.

> The RTO Filing Requirements Policy Statement does [not] say that an entity seeking to re-establish its stand-alone operating status must meet, with respect to its own system, the RTO formation requirements established in Order No. 2000. That would essentially have made continued RTO membership mandatory, which is clearly not the case. The Commission did not require that a departing RTO member, in effect, re-establish itself as an RTO.[91]

VII. DECISION

A. Objectives of Participation in RTO Organization

As discussed in section IV, *infra.,* as a means of the providing guidance to the parties in developing their presentations to the Commission, the Hearing Examiner, by way of Procedural Order dated May 27, 2008, set forth the following list of objectives, or metrics, to be utilized in assessing both the status quo arrangement as well as alternatives to the status quo:

- Reliable, secure and safe supply and delivery service, consistent with applicable criteria and standards
- Low electricity costs for Maine consumers
    - Short term
    - Long term
- Efficient and equitable transmission investment and cost allocation
    - Transmission investment should be desirable from the perspective of the host state
    - Transmission costs should be allocated consistent with benefits
    - System should encourage/allow for the efficient development of transmission and generation resources to meet regional demand, including resources to ensure fuel diversity and state RPS and RGGI objectives
    - System should not encourage/allow over-investment
- Efficient and equitable allocation of market supply costs
- Efficient dispatch of generation to reduce costs and emissions
- Encouragement of renewable and low carbon resources
- Encouragement of cost-effective conservation and demand response, including to obviate or delay transmission investment
- Access for Maine to a liquid and robust wholesale market
    - Access to resources outside of Maine
- Value to Maine from its position in terms of providing access to resources needed by other ISO-NE states
- Effective participation and greater control by Maine with respect to decisions that directly affect Maine, including in regional, national and international decision-making and planning

[91] Rehearing Order, 116 FERC ¶ 61,020 at P. 12.

- Greater priority to cost impacts on consumers in decision making and planning
- Minimization of administrative costs, and transaction costs and risks, including litigation costs and risks
- Stability and predictability of market structures and rules
- Financial strength of utilities
- Benefits for the Maine economy

While the Examiner recognized that this list may not be exhaustive and that other criteria may be identified during the proceeding, the Commission believes this list of objectives/metrics provides a useful tool for our analysis here.

B. Assessment of the Status Quo

1. Overview

Like most institutions, ISO-NE performs some of its required functions better than others. While a review of procedural case history and positions of the parties correctly gives the impression that this case has been vigorously litigated, a closer look at the positions of the parties indicate that there is actually fairly broad agreement about what functions the ISO performs well and those it performs poorly. The parties generally agree as well, on where there is clear room for improvement. For example, there seems to be fairly broad agreement that the ISO adequately performs the following functions: management and operation of energy and related markets, reliability, coordination and dispatch of generation, and management of transmission system and control area services. The sections below discuss areas where ISO-NE meets the objectives listed above, as well as areas where ISO-NE, in its current form, is inadequate.

2. Areas Where Status Quo Meets Objectives

a) Energy

The ISO-NE energy market is comprised of two components: the day-ahead market and the real-time market. Bidding in the day-ahead market occurs on the day before the energy is to be provided, and the results are financially but not physically binding. In comparison, in the real-time energy market, differences between the day-ahead scheduled supply and demand amounts and the actual real-time amounts are balanced. Participants either pay, or are paid, the real-time locational marginal price for the amount of supply or load that deviates from their day-ahead committed schedules.

The day-ahead market has several beneficial features. Prices in the day-ahead market tend to be less volatile than in the real time market because the day-ahead market is less exposed to real-time events such as the loss of a large generator or an unexpected change in load. The day-ahead market is also less susceptible to manipulation and, thereby, provides some protection against the exercise of market power. Finally, the existence of both a day-ahead and real-time market provides flexibility to suit the various needs of market participants. For example, some types of renewable resources, e.g., wind and hydro, may not be able to precisely forecast their generation due, for example, to uncertainty about weather conditions in the hour of delivery. The day-ahead market provides a risk management tool to deal with this uncertainty. On the other hand, the real-time market provides a market in which much of the forecast risk can be avoided in the first instance.

The ISO-NE energy markets are also locational, which thus far has benefitted Maine load. Energy market prices are comprised of three components: energy, loss, and congestion. The New England region is subdivided in load zones, across which prices vary due to differences in the congestion and loss component. Prices in the Maine zone have historically been lower than in the rest of New England due to transmission system congestion and marginal losses. Maine's relative advantage in this respect derives from there being excess generation located in the state coupled with limits on transmission capacity to the south and our relative distance from load centers in the region.

Although, as noted above, most parties support the existing energy market, IECG and HWC witness, Dr. Weil, does not. Dr. Weil suggests, instead, that the structure of the market ought to be established by market participants, perhaps leading to a market in which more transactions occur on a bilateral basis. Dr. Weil also criticizes the uniform clearing price (UCP)[92] aspect of the ISO-NE energy market, suggesting instead that a "pay as bid" auction would be preferable.

As noted by other expert witnesses, the differences between these two market structures, i.e. UCP vs. pay-as-bid, would tend to affect generators' bidding strategies. With a pay-as bid approach, according to witnesses Schnitzer, Stoddard, and Shanker, bidders would tend to base their bids on the expected clearing price, rather than their own costs. This would likely be less efficient, and possibly lead to higher energy prices than with a UCP market.

The Commission agrees with the position expressed by most of the parties that the ISO-NE administered energy markets appear to meet the objectives outlined above. In addition, the existence of these markets does not appear to limit other types of transactions. Bilateral arrangements for energy regularly occur in the region and there appears to be a fairly liquid and robust forward market. The existence of the ISO-administered markets and the associated settlement functions allow for broad participation in the wholesale and retail markets region-wide and,

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[92] In a UCP system, all resources that are selected to run are paid the price of the marginal unit bid (the most expensive generator needed to clear the load demand for the relevant period). In comparison, under a pay-as-bid approach, resources that are selected to run are paid their bid but this bid price does not set the price for any other resource.

thereby, enable a greater degree of competitive activity. We also agree with the positions expressed by most parties that regardless of the transmission organization configuration, energy prices will gravitate towards the price set in the dominant/major market and, thus, there is no significant benefit of withdrawing from ISO-NE in terms of energy prices.

b) Capacity

The parties disagree on whether the ISO-NE market for capacity (the Forward Capacity Market, or FCM) is a reasonable resource adequacy approach. In particular, Dr. Silkman has proposed withdrawing from the capacity market,[93] while Mr. Schnitzer and Dr. Shanker, as well as Mr. Stoddard, recommend staying in.

The 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 is followed by an auction process to acquire and set prices for capacity in the region.[94] Only two auctions have occurred to date. Both auctions cleared at the floor price, i.e., the lowest price the auction could produce.[95]

As noted above, IECG witness Dr. Silkman does not support the FCM.[96] Dr. Silkman's primary concerns about the ISO-administered FCM appear to relate more to the level[97] and types of resources Maine ought to acquire to meet its reliability needs, rather than to concerns about the design of the FCM, *per se*. As an alternative, Dr. Silkman suggests that Maine establish its own rules governing capacity adequacy, including the amounts and types of capacity needed to meet applicable reliability rules and criteria, as well as the process by which providers of the capacity would be compensated.

[93] Silkman Dir. Test. at 50.

[94] The Commission participated actively in the negotiations and FERC proceedings. The Commission strongly opposed the settlement on the grounds that the transition payments were too high, although the Commission did not object to the basic design of the post-transition FCM market.

[95] The FCM market rules establish a process for setting a minimum and maximum price for the first three years of the FCM.

[96] Silkman Dir. Test. at 47.

[97] The amount of capacity that is required to be purchased is set by ISO-NE and approved by FERC. This amount is called the installed capacity requirement.

The Commission shares Dr. Silkman's concerns about how the installed capacity requirement is set and it is one of the intervenors in a court challenge of FERC's assertion of authority over the appropriate level of installed capacity. In section VII(C)(4) below, we discuss Dr. Silkman's proposed alternative arrangement.

c) <u>Demand Response</u>

There have been some positive aspects regarding treatment of demand resources within ISO-NE markets. For example, the FCM is designed to ensure that demand resources can receive capacity payments for the capacity benefits it provides. Initial results indicate that the FCM appears to be successful in this regard, and thus provides particular value to consumers in Maine. In the first auction, 273 MW of Maine demand resources cleared (out of a total of 2,554 MW overall).[98] In addition, FCM payments for Maine demand resources provide additional support to achieve demand response-related benefits such as reduced consumption of fossil fuels, greater flexibility with regard to maintaining a reliable system, and reduced need for transmission investments.

With respect to the energy market, there is a demand response program for price responsive load through which qualified entities that reduce load are entitled to receive energy market prices when called upon by ISO-NE. As with the FCM, a relatively large number of Maine customers participate in this program, including industrial customers.

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.

3. <u>Areas Where Status Quo is Not Acceptable</u>

a) <u>Transmission Cost Allocation</u>

The Commission has long been concerned with the inefficiencies and inequities of the current transmission cost allocation scheme. In 2003, it united with a coalition of generators, load response providers, the Rhode Island Public Utilities Commission and CMP to propose that the socialization methodology be

[98] See ISO-NE, *Regional System Plan (Public Version)*, Table 5-8 at 49, available at http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf (last visited Dec. 10, 2008).

replaced with a beneficiary pays methodology.[99] In fact, there is general agreement among the economic experts in this case and more generally in the Region that socialized cost allocation is not the most efficient methodology. For example, Dr. Silkman stated, "the current ISO-NE transmission cost allocation is so poorly designed as to actually earn the over-used epithet "fatally flawed."[100] Mr. Stoddard described the current transmission cost allocation methodology as the area in ISO-NE where "the greatest weakness lies."[101] Similarly, Dr. Shanker stated that he shared some of the criticisms expressed of the socialization methodology. Mr. Schnitzer also appeared to share the view that socialized transmission cost socialization was not the optimum cost allocation methodology.

The Commission finds that there are several significant disadvantages of the socialized cost allocation methodology currently employed by ISO-NE. First, socializing the costs of transmission upgrades does not provide appropriate price signals and incentives to prospective users of the transmission system. For example, a buyer may be considering two alternative resources. The first may have relatively high generation costs but is located close to the load being served and requires little or no additional investment in transmission. The second alternative has lower generation costs but is located remotely from load and requires significant transmission expenditures. The economically rational choice is to pick the alternative with the lower combined generation and transmission costs. However, if transmission costs are socialized, then the rational buyer would always chose the lower cost remote generation alternative since the additional transmission costs are not internalized into the price paid by the buyer. Over time, this would lead to too much investment in transmission plant and greater total system costs.

Further, socialization of transmission costs can provide transmission owners uneconomic incentives to overbuild. Dr. Silkman poses the problem as follows:

> Each transmission owner in ISO-NE must submit its transmission projects for approval by ISO-NE to be included in the Regional Network Service (RNS) tariff. From each owner's perspective, the more expensive the project the more it earns through its return on equity, and since this return on equity has been set to encourage transmission investment, the incentive is magnified.[102]

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[99] Beneficiary pays methodologies are discussed in section VII(C)(1), *infra.*

[100] Silkman Dir. Test. at 29.

[101] Tr. at 171.

[102] Silkman Dir. Test. at 29.

When this investment incentive is combined with the fact that, under socialized cost allocation methodology, customers of each transmission owner pay only a load-weighted share of the transmission investment, the result is likely to be excessive transmission costs with all customers in New England, including Maine customers, paying too much for transmission.

Finally, a socialized transmission cost allocation methodology can result in overbuilding as a means of obtaining the "benefits" of socialization. For example, the testimony of Jeff Jones and Gradon Haehnel of BHE introduces the concept of an "RTO Benefit Factor."[103] The RTO Benefit Factor is positive when a New England transmission owner pays less through the regional rate for other projects than it receives in payment for its PTF investment.[104] Because BHE's customers' load, and thus their load ratio share of all PTF investment is very small (1.2%) of the total load in the ISO-NE RTO, and because BHE has recently invested in a relatively large transmission project—the Northeast Regional Interconnect (NRI) — BHE ratepayers received a positive RTO Benefit Factor in 2007. CMP, on the other hand, currently receives a negative RTO benefit factor because it represents 7% of the load, but approximately 4.3% of the regional system's total revenue requirement. These witnesses conclude that "the disparity between RNS charges paid to ISO-NE and RNS payments received from ISO-NE is much smaller for Maine as a whole than for Bangor Hydro."[105] However, they note that the RTO Benefit Factor for the state is still positive at 1.06.

The problem with this approach is that it encourages the promotion of transmission projects by transmission owners to ensure that they have a positive "RTO Benefit Factor." Thus, a utility that currently has a negative RTO Benefit Factor would have the incentive to develop projects to increase their benefit factor. However, every time a project is built by one transmission owner, it affects the benefit factor of another. As a result, there is a never-ending incentive for each transmission owner to build more to increase its benefit factor. When combined with incentive ROEs granted by FERC, consumers in Maine and the rest of New England face a greater risk of paying spiraling rates for new transmission as each transmission owner seeks to ensure it has a positive RTO benefit factor.

Moreover, whether Maine ratepayers are incurring reasonable costs for transmission should not be measured in a relative sense, such as by an "RTO Benefit Factor," but in an absolute sense. In other words, the question is whether the costs are reflective of a transmission system that provides the required level of reliability and an efficient bulk power system and not whether Maine has invested more on a load-ratio basis than other New England states.

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[103] Jones-Haehnel Dir. Test. at 9.

[104] *Id.*

[105] BHE Brief at 16.

b) Transmission Cost Containment Mechanisms

The system as currently designed and implemented provides inadequate incentives for cost containment and may encourage excessive expenditures on transmission. First, the current cost allocation scheme inappropriately incents investments in transmission that may not represent the most efficient solution. Second, the FERC's Return on Equity (ROE) adder provides for an additional bonus return on top of FERC's authorized ROE for new transmission investment. This bonus not only creates a strong, and perhaps irrational incentive to invest in transmission, but also provides an incentive to invest in transmission over other alternatives which might be more cost effective. Third, as discussed in the next section, the focus of the ISO is on reliability and not costs. Thus, the TOs' compelling profit incentive combined with ISO-NE's focus on reliability (but not cost-containment) results in a focus on transmission investment over other possible approaches such as demand response or locating generation closer to load. Further, as discussed below, FERC does not provide an adequate check on excessive and costly transmission investment.

Under the current ISO-NE transmission planning/approval process, transmission system plans in New England are primarily developed in a joint effort between the transmission owning utility and the ISO. The plans are reviewed at multiple stages in their development by stakeholders in the Planning Advisory Committee (PAC) and the Reliability Committee (RC). The projects are listed in their various stages of development (concept, proposed, and planned) in the Regional System Plan (RSP). Once a project reaches "planned" status, it is eligible for cost recovery under the current formula Regional Network Service (RNS) rate. Rate recovery for transmission costs is the responsibility of the FERC. Under the current regime, transmission costs included in the RSP are assumed to be prudent unless found otherwise by the FERC after a formal complaint under section 206 of the Federal Power Act. In such a filing, the burden of proof is on the complainant.

In New England, state public utility commissions are generally involved in siting proceedings which review the location of proposed lines but which do not examine the cost and benefits. In Maine, the Commission is charged with issuing a Certificate of Public Convenience and Necessity (CPCN) for new transmission lines greater than 100 kV. Under the CPCN standards, to approve a transmission line the Commission must find that there is a public need for the line by determining that ratepayers will benefit by the proposed line taking into account economics, safety and reliability. However, there are millions of dollars being spent on transmission projects such as substation upgrades and transmission line reconductoring that do not require any state approval. Thus, in many cases, multi-million dollar investments can go through the entire process without being reviewed to determine that costs are "reasonable," "minimized" or produce "just and reasonable" rates. In addition, to the extent state review does occur and the project will contrast to the reliability of the New England grid, it does so through the lens of "socialization" and by a state that will be responsible for only a portion of the total cost.

Perhaps because there is insufficient oversight over the justness and reasonableness of the costs of the projects, the Regional System Plan developed by ISO-NE has consistently relied on underestimated costs for proposed transmission projects. For example, an examination of Regional System Plan updates from 2005 through October 2008 shows changes in cost estimates of major 345 kV projects[106] from their initial estimates to either their present status or their in-service costs. Without exception, every project on the list exceeded its initial estimates. For the six projects listed beginning in October of 2004, the cumulative cost increases were $4.1 billion over initial project estimates of $1.5 billion.[107]

The problems associated with transmission project cost escalations and overruns appear to be a function of the status quo planning, approval and ratemaking regime. Under the current process, when actual costs exceed projected costs, actual costs are included in rates and are only reviewed by FERC if a complaint is made. Even then, the actual costs would be allowed unless the complainant demonstrates that the costs were imprudently incurred. Thus, there is no disincentive for utilities to underestimate costs in the planning process and then to incorporate the higher actual costs into rates when the project is completed. Again, lack of incentive for cost control is exacerbated by the socialization of costs methodology since a large portion of the costs will not be borne by the state determining whether to site the transmission.

c) Governance

In its 2007 Annual Report, ISO-NE described itself as "the independent not-for-profit corporation responsible for providing day-to-day reliable operation of New England's bulk power generation and transmission system, overseeing and ensuring the fair administration of the region's wholesale electricity markets, and managing comprehensive regional bulk power system planning."[108]

ISO-NE's objectives are set out in the ISO-NE Open Access Transmission Tariff (OATT) as follows:

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[106] Northwest Vermont Reliability Project (VELCO), Southwest CT Phase I SWCT and Phase II SWCT (NU), 345 kV Reliability Project (NSTAR) Northeast Reliability Interconnect Project (BHE), Southern New England Transmission Reliability Project (this project was split into several currently listed in the RSP; for more information, *see* RSP Transmission on Projects, April 2007, update at n.3 at 5), Reinforcement Project, Merimack Valley/Northern Shore Reliability Project, and Vermont Southern Loop (Coolidge Connector).

[107] Regional System Plan, Transmission Project Updates October 2005 – October 2008.

[108] "About ISO New England" 2007 Annual Report.

The Objectives of the ISO as the RTO for the New England Control Area are (through means including, but not limited to, planning, central dispatching, coordinated maintenance of electric supply and demand-side resources and transmission facilities, obtaining emergency power for Market Participants from other Control Areas, system restoration (where required), the development of market rules, the provision of an open access regional transmission tariff and the provision of a means for effective coordination with other control areas and utilities situated in the United Stated and Canada):

(a) to assure the bulk power supply of the New England Control Area conforms to proper standards of reliability;

(b) to create and sustain open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services (including Operating Reserves) that are (i) economically efficient and balanced between buyers and sellers, and (ii) provide an opportunity for a participant to receive compensation through the market for a service it provides in a manner consistent with proper standards of reliability and the long-term sustainability of competitive markets;

(c) to provide market rules that (i) promote a market based on voluntary participation, (ii) allow market participants to manage the risks involved in offering and purchasing services, and (iii) compensate at fair value (considering both benefits and risks) any required service, subject to FERC's jurisdiction and review;

(d) to allow informed participation and encourage ongoing market improvements;

(e) to provide transparency with respect to the operation of and the pricing in markets and purchase programs;

(f) to provide access to competitive markets within the New England Control Area and to neighboring regions; and

(g) to provide for an equitable allocation of costs, benefits and responsibilities among market participants.[109]

The ISO-NE objectives do not include ensuring that costs are reasonable or the need to choose the most cost effective alternative. Thus, cost containment is not part of the ISO-NE review process.

The GAO report also illustrates the lack of ISO-NE focus on cost containment. While the GAO report discussed above did not view its mission as weighing in on the different opinions catalogued in the report, the report nevertheless provides value in setting forth consumer concerns about whether RTOs sufficiently focus on cost impacts and cost containment in making reliability determinations. More important, however, ISO-NE's response is illuminating because it appears to reveal ISO-NE's belief that consumer's concerns about cost impacts of reliability measures are misplaced. These views suggests the need for the changes to ISO-NE's charter outlined in section VII(C)(1)(e) that would require ISO-NE to consider cost impacts of its reliability initiatives as well as lower cost alternatives to specific proposed reliability measures.

Chairman Kelliher's response to the GAO report is also illuminating. Chairman Kelliher responds in relevant part:

> As to reviewing RTO budget and the reasonableness of RTO costs, the report correctly notes that RTOs provide extensive opportunities for stakeholder input on RTO costs, and that RTOs consider such input when making decisions on expenditures. This open, transparent process allows consumer input in ways not matched by other public utilities. More importantly, the report explains that RTO costs for administration and overhead are a small fraction of consumers' total cost of electricity. For example, the report notes that these costs were less than one percent of a typical New England consumers' electricity costs. *This fact is significant in evaluating how the Commission can best use its limited resources to ensure that consumers are protected from excessive costs."*[110]

This statement appears to indicate a view that FERC's obligation to consider rate impacts on consumers does not extend to smaller rate impacts. Such a view is not consistent with FERC's obligation under the Federal Power Act. Further, it provides the wrong message — that FERC will not provide oversight over the reasonableness of RTOs budgets. Thus, although the GAO report's scope is quite limited, its documentation of consumer concerns, and more importantly, ISO-NE's and FERC's

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[109] ISO-NE Open Access Transmission Tariff (OATT) I.1.3.

[110] GAO Report, Appendix IX at 1-2.

response to those concerns indicate a need for the governance reforms outlined in section VII(C)(1)(e).

d) Conclusions on the Status Quo

The lack of consumer or cost focus by the ISO coupled with the flawed transmission cost allocation and cost containment mechanisms discussed above are detrimental to Maine ratepayers and have resulted in substantial costs to Maine consumers. Perhaps most significant, and most tangible, is with respect to transmission, where cost increases have been significant and are projected to continue.[111]

In 1999, the ISO-NE's first year of existence total investment in the regional transmission grid (Pool Transmission Facilities or PTF) was approximately $1.8 billion dollars.[112] By 2007, PTF investment had grown to $3.8 billion and for 2008 is projected to increase to $5 billion. By 2013, PTF investment is projected to be $8.6 billion. Looking at these numbers in terms of Maine's load ratio share of approximately 8%, Maine ratepayers' responsibility for PTF investment has grown from approximately $144 million in 1999 to $400 million in 2008.[113]

Although ISO-NE performs a number of functions well, given the serious flaws in the TCA methodology, lack of transmission cost containment and overall lack of attention to cost and consumer impacts, we conclude that the status quo is unacceptable and in need of significant reforms.

[111] In the Interim Report to the Legislature, the Commission noted the transition period capacity payment mechanisms supported by ISO-NE and approved by FERC would impose at least $335 million in excess costs on Maine ratepayers. As noted previously, the transition payments are essentially sunk and should not affect the actions taken after the expiration of the TOA. Nonetheless, the process that resulted in the settlement and its effect on Maine ratepayers illustrate the lack of consideration of costs and impacts on consumers that is inherent in the status quo.

[112] RTO-NE RNS Rate Presentation, July 22, 2008

[113] *See Id.* (8% times 1999 PTF, and 8% times 2013 projected PTF).

C. Alternatives to Status Quo

1) Reform

a) Market Reform Overview

The Commission noted in its Final Report that under the Market Reform Option, key changes to the status quo would be necessary. In the near-term, such changes would include: (1) new transmission needed to access diverse resource generation in northern New England would be recognized as a reliability transmission upgrade; (2) market impacts that currently discourage development in resource states would be addressed; and (3) the New England States Committee on Electricity (NESCOE) would provide more robust public sector engagement with the RTO. In the longer-term: (1) transmission cost allocation would move toward a "beneficiary pays" model; and (2) RTO governance and accountability would be addressed to ensure least cost solutions and state policy goals of importance to the region are pursued.

Because the Market Reform Option would build upon existing structures and agreements, the Commission concluded it had the lowest transaction risk of the three options. Market Reform would also preserve retail competition in Maine, which is not certain with the other options, and would result in processes and decisions that could be synchronized with the region's policy and environmental goals. In the sections below, the key elements of the Reform option are discussed.

b) Transmission Cost Allocation Reform

Most of the experts in this case who found complete reliance on socialization to be a flawed transmission cost allocation alternative suggested an approach that incorporated elements of a "beneficiary pays" methodology. The following provides a brief summary of the various beneficiary pays cost allocation methodologies that have been approved by FERC.

Both Midwest ISO (MISO) and Southwest Power Pool (SPP) have FERC-approved hybrid cost allocation methodologies. Hybrid means that a portion of the costs are allocated to the entire pool proportionally to load ratio share while the rest are allocated to specific beneficiaries identified by a methodology determined in advance.

For MISO, FERC approved a 20/80 hybrid methodology for reliability projects. This means that 20% of the costs of reliability projects over $5 million and 345 kV or higher voltage are socialized and the remaining 80% is paid for by beneficiaries identified by a load flow study methodology. The 20/80 split was arrived at through a stakeholder group and the MISO staff. The group based the split on load flow analyses. Upgrades that are below the voltage threshold and the dollar threshold are allocated locally based on a specified type of load flow analysis. FERC also approved a transition methodology that involved a list of projects that were far enough along in the planning process to receive the earlier cost allocation treatment (in which the load of the utility owner/builder of the project paid for the cost of the project).[114]

MISO also developed a method for allocating the costs of market efficiency upgrades that differs substantially from that used in ISO-NE. *Midwest Independent System Operator*, 118 FERC ¶ 61, 209 at 217 (Mar. 15, 2007). In MISO, these transmission projects are called Regionally Beneficial Projects (RBPs). Like reliability upgrades, RBPs must have an in-service cost of more than $5 million and involve facilities with voltages of 345 kV or higher. Further, the RBP must meet a benefits test in which the present value of the production cost benefit and the Locational Marginal Pricing (LMP) energy cost benefit, in the aggregate for all generation and load nodes, must be greater than zero. Qualified project costs are allocated 20% across MISO on a load ratio share basis, and 80% to sub-regional beneficiaries. [115]

SPP, like MISO, uses a hybrid method for transmission cost allocation decisionmaking. In SPP, one third of the costs of reliability upgrades are regionalized, while two thirds are assigned to the more direct beneficiaries. Like MISO, SPP determines beneficiaries through load flow studies, though the studies differ from MISO's technique. For reliability upgrades, there is a $100,000 and 345 kV threshold.[116]

On October 16, 2008, FERC approved SPP's proposed cost allocation for economic projects. The SPP methodology requires the consideration of a portfolio of projects that must be determined to be beneficial and balanced. FERC outlined the beneficial and balanced test as follows:

> A portfolio is "cost beneficial" when the sum of the net present value of the benefits of the upgrades equals or exceeds the net present value of the costs of the upgrades over the same ten-year period and assuming that all the upgrades are available at the same time during the ten-year period. A portfolio is "balanced," when for each zone the sum of the net present value of the benefits equals or exceeds the net present value of the costs over the same ten-year time frame. In short, a portfolio is "balanced" when the upgrades are determined to be "cost beneficial" for each SPP zone simultaneously.[117]

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[114] *See, Midwest Independent System Operator, Inc.,* 117 FERC ¶ 61,241 (2006).

[115] *Midwest Independent System Operator,* 114 FERC ¶ 61, 106 at 28 (Feb. 3, 2006).

[116] *Southwest Power Pool, Inc.*, 111 FERC ¶ 61, 118 at 9 (2005). *See also,* SPP FERC Electric Tariff Att. § III (5th Revised Vol. #1 (Mar. 28, 2008)).

[117] *Southwest Power Pool*, *Inc*.,125 FERC ¶ 61,054 (2008).

Further, there is a mechanism to ensure that all zones benefit even if they do not have projects qualifying for economic upgrades. Under this mechanism,

> when a proposed economic upgrade portfolio is not balanced, SPP may include economic upgrades below the 345 kV level to increase the benefits to deficient zones. If the inclusion of such upgrades for lower voltage facilities still does not achieve balance, SPP may transfer part of the zonal revenue requirement for existing or planned facilities (e.g., SPP-planned base plan reliability upgrades and transmission owner-planned facilities) from a deficient zone to the region-wide revenue requirements for reliability upgrades. These transfers in revenue requirements (i.e., "Reallocated Revenue Requirement") will be implemented in increments and are limited to the minimum amount needed to obtain a balanced portfolio.[118] *Id.* P. 8.

SPP described the methodology as a way to ensure that all zones benefit from the balanced portfolio and that no zone will be disadvantaged because it is allocated costs for economic upgrades but receives little or no benefit. *Id.*

Although it is too early to know how this portfolio approach will work, it provides an innovative method of seeking to move efficiency upgrades forward in a manner that "ensure[s] that all zones benefit from the balanced portfolio and that no zone will be disadvantaged because it is allocated costs for economic upgrades but receives little or no benefit." While there may be hybrid/beneficiary pays approaches other than the examples set forth above, the MISO and SPP methodologies provide a good starting point for stakeholders to consider in developing possible changes to ISO-NE's existing cost allocation methodology.

Finally, there is the question of whether Maine customers interests would best be served by a near term reform of transmission cost allocation. Several witnesses, most notably Mr. Schnitzer, point out that there are two major transmission proposals currently before this commission: CMP's Maine MPRP (Docket 2008-255) and the joint MPS and CMP, MPC proposal (Docket 2008-256) with a combined price estimate in the range of $2 billion. Both cases are pending before the Commission and, therefore, the Commission does not address here the merits of those proposals. However, the Commission does recognize Mr. Schnitzer's larger point which is that a flash cut change in cost allocation could, as a worst case, result in Maine paying for most or all of the costs of new transmission projects in Maine coupled with continuing responsibility for transmission projects built in other New England states under the socialization methodology.

While it is clear from FERC's decisions that there are several viable alternatives to ISO-NE's existing transmission cost allocation methodology and

[118] *Id.* at 8.

that it is possible to develop a transition mechanism that is fair to all New England customers, the Commission is also aware that there is no guarantee that an acceptable transmission cost allocation scheme can attract the needed level of consensus. The Commission will continue to examine the progress of negotiations over transmission cost allocation reform (and other reforms described herein) through the process described in section VII(E).

c) <u>Transmission Cost Containment Reform</u>

In addition to transmission cost allocation reform, changes to contain transmission costs overall must be achieved as part of ISO-NE reform and renegotiation of the TOA. A first step in this regard is 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, regional planning procedures must be modified. ISO-NE's open season approach to soliciting transmission alternatives must ensure that all reasonable alternatives to the transmission project are credibly presented and fully considered. Further, 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 the "least cost" solutions are to be calculated. Transmission project sponsors should be required to specify the problem addressed by the project, the alternatives to the project, and the respective costs of each. Comparisons between proposed transmission investments and alternatives should be done on a comparable basis; not, for example, by comparing the full cost of the alternative to the TO's load-ratio share of the transmission project. The ISO's role should be to ensure that the analysis of alternatives, including non-transmission alternatives presented by the TOs is credible and that viable alternatives have a reasonable opportunity to compete with a 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 their decisions even in states where CPCN-type approval is not required. The RSP should also provide more specificity about where new generation is needed and whether there are possible generation alternatives under consideration that may provide a lower cost alternative to transmission. Planning documents should report the position of the state or states and why the ISO accepted or rejected the state input. The Regional System Plan should identify where renewable energy development is most likely to occur and consider that information in plan development. The criteria for Pool Transmission Facilities (PTF) designation (which definition must be met in order to qualify for regional cost sharing) should recognize not only the goal of reliability, but begin to consider the broader goals of fuel diversity, price stability and environmental impact.

With respect to cost estimation and cost overruns, if a project exceeds 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 within 30 days. Before granting initial approval for any project, ISO-NE must independently conduct a review of the reasonableness of the sponsoring TO's cost estimates and escalation figures, as well as assess the adequacy of the cost control measures to be used. There should be a more robust process, including the ISO and 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. 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 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.

d) Capacity Adequacy Reform

Dr. Silkman suggests that Maine establish its own rules governing capacity adequacy, including the amounts and types of capacity needed to meet applicable reliability rules and criteria, as well as the process by which capacity suppliers would be compensated. The Commission agrees with Dr. Silkman in certain respects. First, as argued in the pending court appeal challenging FERC's jurisdiction to set resource adequacy levels, states, not the ISO or FERC, should set the level of capacity needed for reliability. Of course, states would also be subject to all applicable NERC and NPCC standards, criteria and penalties. Second, states should determine what types of resources qualify as capacity. As noted by Dr. Silkman, this would allow states to better balance reliability with other objectives, such as demand response.

However, the Commission does have concerns about the feasibility of withdrawal by Maine from the capacity market while continuing to participate in the energy market. The design of the FCM, the capacity and energy markets are linked in important respects. First, to the extent the FCM attracts additional capacity, it increases supply in the energy markets thereby tending to lower energy prices. Second, generators that sell into the FCM accept certain obligations that tend to reduce prices in the energy market. These include obligations to bid into the energy market and, under the Peak Energy Rent approach, to forego any revenues beyond the operating costs of a relatively inefficient fossil fired generator. Thus, because the FCM serves to reduce costs in the ISO energy market, it seems problematic for Maine to continue to be part of the latter but not the former. While it might be possible to develop a capacity market which would have similar effects on the energy market, it is not clear that such an approach would result in savings to consumers. Most, if not all, experts agreed that the price of capacity in the FCM would influence the price of capacity in any separate Maine market. This would occur because Maine generators would have the option to sell into ISO-NE and thus could price its capacity at the ISO-NE market price. Therefore, withdrawing from the FCM and establishing a different capacity mechanism is not likely to result in savings to consumers.

Maine should continue to participate in the FCM, and, the states should continue to pursue setting the amount of capacity needed by LSEs. The capacity amount would be set in accordance with applicable NERC and NPCC standards and criteria. States would define, in accordance with NERC and NPCC, what types of capacity LSEs must provide in order to meet their obligations. Maine capacity and loads would remain in the FCM, e.g. Maine generators and demand resources could bid into the FCA and Maine load would be assessed capacity costs at prices determined through the FCM. The Commission has signaled its interest in working through NESCOE to set the installed capacity level for the region. Even if the courts rule against the states on this issue, the ISO should join the states in improving the process for development of the installed capacity requirement to allow states to have a greater role in determining the installed capacity requirement and the resources that qualify to meet capacity requirements.

e) Governance Reform

The first step is governance reform is to modify ISO-NE's governing documents to incorporate language which reflects the importance in the decision-making process requirement for ISO-NE to consider the impact on costs and consumers of its decisions.

The Commission agrees with positions expressed by the IECG and the OPA that if consumer interests had a greater presence on the board, the ISO-NE would likely give a higher priority to consumer and cost issues. The Commission determines that one of the existing board member slots be reserved for a candidate that has extensive background in representing consumers or adjudicating issues relating to retail electric rate regulation. Bringing a consumer focus to the ISO board is an important element of the Market Reform.

The Commission finds that the consumer representation throughout the transmission planning needs to be enhanced through the establishment of a regional consumer advocate. The vehicle for such a mechanism may be through NESCOE, however, stakeholders should pursue this reform mechanism as the renegotiation of the TOA goes forward. One of the main functions of this position would be to review transmission projects, above a certain threshold amount. The Commission notes that the regional consumer advocate is not a substitute for having a consumer presence on the ISO-NE board, as discussed above.

f) Conclusions on the Reform Option

As discussed in the Final Report, and as agreed to by all parties to this proceeding, the Reform Option presents the lowest transaction risk of all of the options. There is also widespread agreement that the reforms set forth above are needed and will provide significant benefits to Maine consumers. The Commission finds that the Reform Option represents the best alternative to the status quo and therefore, instructs the Maine TOs to pursue these reforms as part of the negotiations for the renewal of the TOA. During the negotiation process, the TOs should be guided by the objectives set forth in section VII(A) *infra.*

The Commission concludes that in order to ensure that these objectives are pursued actively and within the short time frame set by the Commission, the Commission staff, as well as the parties should, through a collaborative approach, be provided an opportunity to appropriately participate and provide input into the reform process. In addition, since there is no guarantee that such reforms will be adequately addressed, it is necessary to assess the other alternatives to the status quo and to determine what path should be taken should the Reform Option fail.

2. <u>The Maine Stand-Alone Option: A Maine ITC and State-Wide Load Serving Entity</u>

As described in the Final Report, under the Maine ITC Option, Maine transmission and distribution utilities would form an Independent Transmission Company (ITC) that would develop, maintain, and manage access to Maine's transmission system. In terms of supply for Maine consumers, a state-regulated load serving entity would be required, except, perhaps, for large industrial consumers. Supply sources would be "rate-based" or "cost-of service" rather than market-driven, and utilities may be permitted to construct, own and operate power plants. The Maine ITC Option would allow Maine to have more control over the rules and structures that affect consumer costs, as well as over the types of electricity infrastructure sited here. With an ITC that would plan and operate transmission on a coordinated state-wide basis, this option would allow for cohesiveness and focus in terms of transmission development to meet Maine's goals and, potentially, the regional environmental objectives of the Regional Greenhouse Gas Initiative (RGGI). While rate-based generation could reduce price volatility, in terms of risks, the Maine ITC Option: (1) would be expensive and, perhaps, risky to start up; (2) could chill in-state investment of independent power production by disrupting the *status quo* and creating seams; (3) would inhibit retail competition; and (4) could expose consumers to stranded costs.

The Commission concluded in the Final Report that an ITC alone would not be sufficient to maintain a safe and reliable electricity system in Maine and that a load serving entity was likely to also be required to serve the majority of Maine consumers' generation needs, such as a public power authority or an investor-owned franchised utility in the fashion of Maine's pre-restructuring electric utilities. Consequently, this alternative could effectively end Maine's experience with retail competition, at least for small business and residential customers. By ending retail competition, Maine consumers could benefit from rate-based utility generation ownership, but would be exposed to the risks of building new power plants that are now shouldered by private firms.

The evidence presented in this proceeding indicates that a Maine stand alone ITC is the least promising alternative of those considered. Maine's consumers, economy and energy policies appear to be better served by continued association with and access to a larger power system and market. If anything, the current state of the international financial markets combined with the substantial investments required to pursue this strategy have further distanced this concept from consideration.

3. Maine/New Brunswick Common Market

Under the Maine/New Brunswick Option, Maine would join with New Brunswick and, possibly, other Maritime Canadian provinces. The framework for this option includes the following elements:

1. The New Brunswick System Operator (NBSO) would perform joint dispatch of the bulk power system for the region;

2. Transmission systems would be jointly planned;

3. There would be a common energy market relying on a hub located in New Brunswick; and

4. A state-regulated entity would supply Maine consumers.[119]

For this option to be viable for Maine and New Brunswick, key reforms to the existing systems in New Brunswick would have to be undertaken. To attract the private investment needed for development of new renewable capacity, market rules must ensure transparency, fairness, consistency and continuity. A common market for Maine and New Brunswick would need to allow for: (1) system-wide security constrained economic dispatch; (2) system-wide open access transmission; (3) an independent system operator free of control of any single government or market participant; and (4) enhanced access to the New England market. The vast majority of New Brunswick resources are currently concentrated in the hands of New Brunswick Power, which creates a potential market power problem. Due to the smaller size of the Maritimes control area relative to New England's, this option could suffer from reduced liquidity. Finally, the Commission noted that this option may have large transaction costs similar to the Maine ITC Option and would require the cooperation of the transmission and distribution utilities.

While the Commission devoted considerable resources to develop this option as part of its preparation of the Interim and Final Reports, it appears that little progress has been made since the reports were issued to remove the obstacles that stand in the way of this option. None of the parties to this proceeding have suggested pursuing this option further. The Commission, therefore, concludes this option does not hold sufficient prospects for success to warrant further development.

[119] As with the Maine ITC Option, the need for this load serving entity could be limited to loads that could not access a liquid, functioning competitive market.

4. The Hybrid Options

a) The Silkman Model

In his testimony, Dr. Silkman recommends that CMP and BHE be directed to immediately provide notice of non-renewal of the TOA, take steps to join NMISA, and "simultaneously engage in negotiations with ISO-NE to develop a contract under which ISO-NE will provide those services identified as beneficially provided by ISO-NE." [120] Dr. Silkman's contract, or "a la carte," approach, envisions that CMP and BHE would negotiate contracts with ISO-NE for a menu of services – largely those related to "reliability coordination, management and operation of the energy and related markets (except capacity), management and operation of the transmission system and reserve sharing."[121] Maine utilities would retain responsibility for "system planning, resource adequacy and the design and operation of any capacity market, and administration of transmission tariffs."[122]

b) The Weil Model

Dr. Weil recommends that CMP and BHE remain in ISO-NE for many of the functions Dr. Silkman seeks to leave behind, such as transmission planning and resource adequacy. While Maine participants would be allowed to participate in ISO-NE markets if they chose, the Maine markets would be administered by "an enlarged NMISA or similar entity," which would operate only an ancillary services market.[123] This structure, Weil contends, would present less complexity and provide greater opportunities for "open market" and lower-priced bilateral deals than the ISO-NE market.[124]

c) Expanding NMISA to include BHE and CMP

While the Weil proposal had CMP and BHE remaining in ISO-NE for some functions and joining NMISA for some functions, very little evidence was presented on expanding NMISA to include CMP and BHE if they withdrew from ISO-NE. Testimony from Mr. Ken Belcher indicates that this approach would be possible but that it was not possible to determine how much time would be required both to determine what would be necessary to effect this arrangement and to actually

[120] Silkman Dir. Test. at 48.

[121] Included within these classifications are particular responsibilities that Mr. Schnitzer has identified as being especially costly to perform outside ISO-NE, namely ancillary services and operating reserves. Silkman Dir. Test. at 50.

[122] *Id.* At 51.

[123] Weil Surr. Test. at 9.

[124] *Id.* at 10; *see also* Weil Direct at 13; Oct. 22 Tr. at 243:25- 244:3, 230:14-18.

accomplish the desired result. Accordingly, the majority of the Commission determines this is not a viable option at this time; but does not foreclose this option from further consideration.

d) Opposition to the Hybrid Models

The TOs and the generators have all suggested that if reform fails, Maine should accept the status quo. These parties agreed that there is no real alternative, or no alternative that would be superior to, the status quo.

First, as discussed by Mr. Schnitzer and supported by the other parties, if Maine were to adopt any option other than reform or the status quo, Maine would pay considerably more for transmission investments. The parties point to the current planned transmission projects in Maine, the MPRP and MPC, as support for this position. As currently proposed, the projected investments for these two projects is approximately $2 billion. The parties compare this Maine investment with the proposed investment for the region of $7 billion, and argue that Maine is better off under a system that socializes these investments. They argue that even if the investment for the two Maine projects were reduced to $1 to $1.5 billion, the rest of the region would have to spend an additional $10.8 to $16 billion dollars (beyond the $7 billion already proposed) before Maine would be worse off. The Commission agrees that, based on current projections from the Maine TOs and ISO-NE, the current cost allocation scheme favors Maine load.

BHE argues that under the recent *Duquesne* order, if Maine were to leave ISO-NE, Maine ratepayers would be responsible for the full costs of the recent $140 million investment in the NRI transmission line. This argument, however, points up the fragility of basing decisions on new transmission and continued participation in the ISO-NE, assuming socialized cost treatment since such treatment might well evaporate if at some point the state discontinues membership in the ISO.

These parties assert that the costs of providing ancillary services, in particular, operating reserves, would be higher under any alternative to the status quo.[125] Currently the ISO maintains operating reserves equal to 100% of the largest contingency and 50% of the second largest contingency, or approximately 1,856 MW for the region. Maine's share of this amount is approximately 158 MW. On a stand-alone basis, the parties suggest that Maine would have to provide 788 MW, or five times the amount of reserves required as part of the ISO. The parties estimate that the increase in reserves would cost Maine ratepayers $23 million per year. The TOs and generators argue that reserve costs would increase significantly as a result of the type of unit which would be needed to provide reserves in a Maine stand-alone system.

[125] Operating reserves allow the system operator to respond to emergencies or unexpected events, such as large generators tripping off line and/or unexpectedly high customer demand.

The IECG argues that operating reserve costs are unlikely to increase because Maine could obtain operating reserves through reserve sharing arrangements with neighboring regions, including ISO-NE. Other parties do not agree that ISO-NE would be obligated to provide services provided to an entity outside of the RTO and if it did provide such services whether they would have to be cost-based. The IECG maintains that ISO-NE, as a public utility, would be obligated to enter into non-discriminatory arrangements and that just and reasonable rates would be cost-based rates. CMP, BHE and Constellation**,** maintain that ISO-NE has no duty to serve entities outside of the ISO-NE footprint.

Neither an examination of the record nor of relevant precedent answers the question of the extent of ISO-NE's obligation to provide services to utilities outside of its RTO if the Commission ultimately determines that some kind of hybrid approach is preferable to continued membership in ISO-NE. The parties did not agree on whether ISO would have to charge "cost-based" rates in order for such charges to be just and reasonable. Speculating on the amount of, and reason for, an above cost charge at this time will not serve any useful purpose. However, FERC precedent does indicate that FERC would likely not find appropriate above-cost charge for services as a means of holding remaining participants harmless for having more costs allocated to them because of a utility's RTO withdrawal, especially, where as here, there are no "hold harmless" provisions in the relevant documents.

Even if a new arrangement did not promote regional coordination as well as the existing arrangement, FERC will not be "at liberty" to disapprove the new arrangement, as long as it meets the requirements of Order 890.[126] For example, in the *Louisville* orders, FERC was very careful not to let its concern with

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[126] See, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, III FERC Stats.& Regs., Regs. Preambles ¶ 31,131 (2007) ("Order No. 890"). Order 890 institutes several reforms to FERC's landmark order No.888, *Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh'g denied*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002). Order 888 set forth the requirement for open access, non-discriminatory transmission services. Under Orders No. 888, public utilities were required to file *pro forma* open access transmission tariffs and to take transmission services for their own wholesale sales and purchases of electric energy on the same terms that it offered to others. In Order 890, FERC retained the core requirements of Order 888 and added additional reforms intended to increase transparency in rules applicable to transmission planning and strengthen the *pro forma* OATT to ensure that it achieves its original purpose of remedying undue discrimination.

seams[127] reduction interfere with the utilities' contractual right to withdraw from MISO. Thus, even though MISO argued that the replacement arrangements would not promote regional coordination as well as the existing arrangements, FERC did not require the utilities to remain in an RTO, and reiterated that participation was voluntary subject to the withdrawal requirements in the TOA. Thus, a decision by CMP and BHE to withdraw from ISO-NE and to form some sort of hybrid organization should not be rejected by FERC simply because the organization does not meet the with *Order 2000* requirements for RTOs.

The question of whether Maine would be permitted to participate on an "a la carte" basis with the ISO or NBSO is not so much a question of whether, as it is a question of "at what cost." Clearly, there are scale advantages to Maine as well as to the rest of New England to retain Maine load and resources. If a contract for "a la carte" services is priced so that there is a benefit to the remaining members of ISO-NE, there would be good reason for ISO-NE to agree to provide such services. Therefore, it is likely ISO-NE will provide control area service to Maine on a voluntary basis as provided for under section 6.06 of the TOA. It is less clear as to whether the services would be provided at cost. The Commission concludes that price of ancillary services does not present an insurmountable barrier to a hybrid option should the reform option be unsuccessful.

The parties supporting the status quo also argue that any option other than continued membership will chill investment in new wind generation in the state. BHE's expert, Mr. Stoddard, estimated that the seam created by leaving ISO-NE would add approximately $5/MWh to a generator's costs. In addition, since wind generation is intermittent, it requires flexible resources to balance its intermittent output. A smaller system, such as a Maine-only system, or even a combined Maine/New Brunswick system, could not reliably balance as much wind as is slated for development without the additional balancing capabilities from southern New England. The parties also argue that without a large pool to allocate transmission costs it will not be possible to build the transmission needed to transport wind generation to the New England market. MPS argues that continued participation in ISO-NE is needed to pay for transmission to connect northern Maine and its wind resources to the New England grid. The parties supporting the status quo point to the fact that several New England states require that renewable resources outside of ISO-NE obtain transmission rights into ISO-NE to be eligible for that state's renewable energy credits (RECs).

The projection as to what impact leaving ISO-NE will have on prospective wind development appears to be the area which is subject to conjecture. While we agree with Mr. Stoddard that the erection of a new entity to administer transmission is likely to create a seam, it is difficult to assess how significant this barrier would actually be and what effect it would have on wind development.

[127] The term "seams" generally refers to market rule and operation differences between control areas or RTOS which limit electricity trading or interfere with reliable management or operation of the electricity grid.

The Commission noted that at the time of the Final Report there was approximately 10,000 MW of non-CO_2 emitting generation resources, including 3,800 MW of wind, being considered for development in Atlantic Canada for import into ISO-NE. Based on this prospective development, it does not appear that moving power, including wind, across transmission areas poses an insurmountable barrier. Second, the Commission notes that under a hybrid approach, such as that outlined by Dr. Silkman, wind generation located in Maine would still be able to sell into the ISO-NE market and would be balanced as part of a larger system by either the ISO-NE or NBSO. Finally, we note that socialization of transmission investment to interconnect remotely located wind generation is not a given under the status quo. Although the ISO-NE adopted a cost recovery mechanism to accomplish this (the Market Efficiency Transmission Upgrade (METU) mechanism), the METU process appears to be controversial within ISO-NE, *see Central Maine Power Company and Maine Public Service Company,* Request for Certificate of Public Convenience and Necessity, Docket No. 2008-256, Order Denying Motion to Dismiss (No. 24, 2008).

e) <u>Conclusions on the Hybrid Options</u>

The Commission finds that CMP and BHE remaining in the ISO-NE control area and energy and reserve markets, including the capacity market, and assuming their own transmission planning and decision-making functions is the most reasonable of the alternative models. The Commission considers the regional markets to be beneficial to Maine consumers. The Commission agrees that the ISO's administration of system scheduling, dispatch, reliability coordination, and the Open Access Transmission are satisfactory. However, the Commission disagrees strongly that ISO's transmission planning process is satisfactory.

The Commission determines that Maine and the other New England states ought to determine the Installed Capacity obligation as well as the types of resources that qualify as capacity. As also noted in section VII(C)(1)(d), achieving this result with respect to capacity requires compliance with NPCC criteria and processes and continuing ISO's role as reliability coordinator for the region.

The Commission is unable to make conclusions about the costs and benefits of possible alternatives to ISO-NE because they have not been sufficiently developed. We do leave two possible options open. The majority of the Commission supports full development and consideration of the Maine Transmission Owner-ISO-NE Contract Option as the preferred 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;"[128] (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.
If negotiations for the ISO-NE contract option fail, the Commission may consider an expanded NMISA model. Such a model was not investigated in any depth in this proceeding. *See* the Minority Opinion of Commissioner Cashman attached.

D. Findings of Fact and Conclusions of Law

Based on the above analysis then, the Commission makes the following findings of fact and conclusions of law:

- The current ISO-NE/NERTO provision of energy markets and ancillary services is adequate. While the Commission strongly disagreed with the ISO-NE's transition capacity market mechanism, the Commission believes that the forward capacity auction mechanism which will be in place at the time of renewal of the TOA is reasonable, although the state should have a greater role in defining capacity requirements applicable to Maine load.

- The status quo is inadequate in the areas of transmission cost containment, transmission cost allocation, and ISO-NE governance.

- The Commission concludes that the status quo arrangement with ISO-NE is inadequate when compared to the options available.

- Of the options which have been presented, reform of the ISO-NE poses the least transaction risk and the opportunity for maximum consumer benefits and should be considered the first best alternative to the status quo.

- Before renewal of the TOA occurs, however, the problems of transmission cost containment, transmission cost allocation and governance must be addressed.

[128] The details of such a mechanism would need to be developed; however, there would need to be a mechanism for identifying beneficiaries and cost causers outside of the Maine region and a mechanism for payment by these beneficiaries/cost causers of some or all of the costs of the upgrade through (1) a contract reservation mode or (2) through and out charges.

- Reform should focus on the following objectives:

    - reliability (including recognizing new transmission to access diverse resources as reliability upgrades),

    - lower electric costs - greater priority costs to consumers,

    - efficient and least cost transmission system which allows for regional fuel diversity and meets state RPS and RGGI goals,

    - transmission cost allocation consistent with benefits realized,

    - robust markets with equitable allocation of market supply costs and which encourage conservation and demand response,

    - meaningful input on issues that impact Maine,

    - supports financial strength of utilities, and

    - minimize administrative costs and transaction risks

- Since the TOA negotiation process has just begun, the Commission cannot assess whether the reform objectives identified in this Order will actually be achieved.

- Of the other options presented and considered, two options remain 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. These options are not yet sufficiently developed to determine the costs and benefits of either approach.

- Before these options can be fully evaluated against either the status quo or the Reform Option, further details on how such models would actually be implemented need to be developed.

- In the near term, the best approach to pursuing ISO-NE reform is to marshal the resources of the Commission staff, and parties to this proceeding, especially, CMP and BHE, to focus primarily on aggressively moving these reforms forward.

E. Process Going Forward

As discussed previously, the negotiation process of the current TOA is in its very early stages with the deadline for renewal being August 1, 2009. The Commission is aware, as noted in CMP's exceptions to the Examiner's Report,[129] that many of the needed reforms set forth in section VII(C)(1) are already being discussed at the ISO. The test, however, is not whether these matters are discussed, but whether the reform measures which we have identified are actually implemented.

The Commission has been presented with a number of options regarding the renewal deadline, from not exercising non-renewal at all, to allowing the automatic two-year renewal to kick-in in order to allow further time to negotiate the needed changes, to exercising non-renewal immediately. The Commission believes that the most practical course of action at this time is to have BHE and CMP actively and aggressively pursue the reform options found to be necessary here and then to report to the Commission on the progress of such negotiations at sixty day intervals beginning on March 1, 2009 and. After receiving the May 1 report, the Commission will consider whether reporting should occur on a more frequent basis and issue a schedule to receive the parties' views on what actions, if any, the utilities should take with regard to providing notice of non-renewal of the TOA and planning for and developing the alternative models to the status quo reform option. The Commission does not require the development of an alternative structure during these early stages of TOA negotiation because doing so would divert the parties' and the Commission's resources from aggressively pursuing the ISO-NE reforms. While the Commission does not require the development of an alternative on a parallel track to the pursuit of the reform option, it does require CMP and BHE to provide the following information by May 1:

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.

Based on the reports required by this Order, after providing an opportunity for further comment and prior to August 1, 2009, the Commission will determine the status of the various reforms and alternatives presented. Finally, we direct the Staff to hold a meeting of the parties to establish a collaborative process to facilitate the MPUC staff role in the TOA negotiations and ISO-NE processes addressing transmission cost

[129] CMP Exceptions at 3.

containment, transmission cost allocation for economic transmission projects and governance.

VIII. CONCLUSION

Despite disagreement about the timing and process for exploring alternatives, the Commissioners are unanimous in their determination that the status quo relationship with ISO-NE is inadequate. The Commission expects CMP and Bangor Hydro to move forward and negotiate meaningful reform to benefit Maine consumers with the assistance of the Commission. The Commission will continue to participate actively within the ISO-NE stakeholder process to achieve necessary reforms. We, the three Commissioners of the PUC, are committed to working constructively within the process but if we are shut out of the process and progress is impossible, we are committed to implementing a workable alternative to the current regional system.

It is so ORDERED.

Dated at Augusta, Maine, this 16th day of January, 2008.

BY ORDER OF THE COMMISSION

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Karen Geraghty
Administrative Director

COMMISSIONERS VOTING FOR: Reishus
Vafiades
Cashman (Concurring in part and Dissenting in part) See Attached Minority Opinion.

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.

Minority Opinion Regarding Alternative Structure of Commissioner Cashman

The Commission's Order in this docket represents broad agreement amongst the Commission on most issues. Most importantly, we agree that the best course of action for Maine is to have the transmission owners and the Commission work collaboratively on negotiating a series of improvements to the current operation of the ISO-NE. I have a different opinion than my colleagues on how we should proceed to position ourselves should those negotiations fail.

Throughout the past 25 years, Maine has gone through the process of deregulating its energy market, forcing divestiture of our utilities generation assets and becoming more and more subject to the control of the regional system operator. In the process, we have been able to join a robust and liquid energy market and become part of a more reliable system. The down side has been that we have lost control of our energy system and its future, energy costs have escalated and decisions that dramatically affect Maine ratepayers are no longer made in Maine. I, along with my fellow Commissioners, very much want the negotiations now underway to produce an arrangement that serves Maine consumers better and gives us more control of our fate. However, should these negotiations fail; we need to have made every possible effort to be ready to act in our ratepayers' best interest.

Currently, ISO-NE is significantly deficient in several areas. The prospect for negotiated reforms is very uncertain, and there is no guarantee that a new TOA won't leave Maine in an even worse position than we currently are in. I strongly feel that we should begin immediately to assess our options should negotiations fail and be prepared before August 1 to have a viable exit strategy.

The Order correctly points out that an option to continued participation in ISO needs to be more fully developed; however, it gives little guidance on how it should be developed and puts off the process for developing a model to some later date. To be in a position to compare our best option against the continued membership in ISO-NE, work needs to begin immediately to determine the details of that option. If we are to design an exit strategy, I feel it needs to provide as much independence as possible. The objectives in designing a new system should be twofold: 1) to provide as much control over the future of our energy system as possible; and 2) to focus on potential savings for Maine ratepayers.

The NMISA is a FERC approved regional transmission group and belongs to the Maritimes Balancing Authority. The New Brunswick System Operator (NBSO) performs the duties of the Reliability Coordinator for the region. The NMISA operates under a Tariff and Market Rules, along with a Coordination Agreement with the NBSO and administers the northern Maine bilateral energy market. It does not have operational control of the transmission grid, but it does review and enforce its rules as to how MPS and EMEC handle these functions. It operates under the direction of a stakeholder

Board of Directors, which includes the Maine Public Advocate as an alternate representative.

The NMISA operation in northern Maine has proven itself to be cost conscious and to have an ability to contract for a la carte services from the NBSO. The NMISA director, Mr. Ken Belcher, stated in his testimony that “a modified version of the northern Maine Model could be cost effectively expanded to all of Maine”.[130]

A NMISA option could work in a number of ways. As suggested in the OPA filing, NMISA could be expanded to include all of Maine, or we could basically establish two MISAs, the exiting northern Maine system and a second MISA for southern Maine that contracts with ISO-NE instead of NBSO for services we need. As Mr. Belcher stated, the form of the new entity would be up to the market participants.

I believe it would be in Maine’s best interest to instruct CMP and BHE to work in good faith with NMISA to design a system that uses in-state resources as much as possible in providing the necessary components of a reliable, cost-effective electric system. To the extent the resources available to us in state are inadequate; contracting with either ISO-NE or NBSO for those services we are unable to satisfactorily provide should be explored.

There are funds available to pursue this course of action through the fund created jointly by IECG and Iberdrola. Moreover, NMISA, the IECG and the OPA have all expressed an interest and willingness to investigate the design of a model that could work for Maine ratepayers. I do not feel that pursuing this study will significantly detract from the negotiation efforts. In the words of our President-elect “leaders are expected to be able to deal with two things at once.”

I would have the ultimate system design presented to the Commission no later than June 15, 2009. Interim reports on the progress of both the ISO negotiations and the design of a new Maine system would be given to the Commission and the OPA on March 31, 2009 and May 15, 2009.

In July, the Commission would hold a proceeding to review the progress of negotiation with ISO-NE and the alternative system design to determine which course is in Maine’s best interest. Prior to August 1, the commission would issue an order to either have CMP and BHE continue to negotiate reforms to the existing arrangement or provide notice of withdrawal and begin transitioning to the new system

[130] Belcher Dir. at 2-3