MAINE PUBLIC UTILITIES COMMISION

INTERIM REPORT

Pursuant to "A 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"

Presented to the Utilities and Energy Committee

January 16, 2007

I. OVERVIEW

On April 13, 2006, Governor John E. Baldacci signed a "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")."[1] The Resolve directs the Maine Public Utilities Commission (the "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;
>
> (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.

The Resolve requires the Commission to submit an interim report on the status of the inquiry and any preliminary findings and recommendations to the Legislature's Joint Standing Committee on Utilities and Energy by January 1, 2007.[2] The Resolve also directs the Commission to file a final report with the Legislature by January 1, 2008.[3]

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[1] Resolves 2005, ch. 187

[2] At the request of the Commission, the Chairs of the Utilities and Energy Committee agreed to extend the deadline to file this interim report to January 16, 2007.

[3] The Legislature's interest in examining Maine's relationship with the New England power grid and market is neither novel nor infrequent. For example, Resolve 2001, ch. 81, required the Commission to conduct a study to determine the advantages and disadvantages of the State's transmission and distribution utilities joining a regional transmission organization that includes northern Maine and portions of Canada. Prior to that time, the Commission was required to periodically investigate Maine's utilities' continued involvement in the New England Power Pool pursuant to the provisions of 35-A M.R.S.A. § 3143-A (Repealed).

On June 29, 2006, the Commission issued a Notice of Inquiry ("NOI") initiating the proceeding mandated by the Resolve. The NOI set forth a number of issues that the Commission would address during the course of the study period and requested stakeholders to comment and respond to a series of questions and issues identified in the NOI. [4] The Commission received extensive comments from a range of parties.[5]

On October 30, 2006, the Commission circulated two discussion documents entitled, "What If Maine Were An Electricity Island" and "Legal Implications of Withdrawal of Central Maine Power Company and Bangor Hydro-Electric Company from the New England Regional Transmission Organization." On November 17, 2006, the Commission issued a third discussion piece entitled, "The Canadian Option. Prospects for a Market Comprising Maine, New Brunswick, Nova Scotia and Prince Edward Island."[6] Stakeholders commented on these papers and were provided an opportunity to participate in technical conferences held at the Commission on July 21, 2006, September 13, 2006, and December 14, 2006.

Finally, as part of the Commission's inquiry,[7] the Commissioners, staff members and the Commission's consultants have met with stakeholders individually and Canadian governmental officials, including members of the energy ministries and public utility boards in New Brunswick and Nova Scotia, as well as

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[4] Maine Public Utilities Commission, Inquiry into Transmission and Distribution Utilities Continued Participation in the New England Regional Transmission Organization, Docket No. 2006-364, Notice of Inquiry (June 29, 2006). The NOI and all comments from stakeholders can be accessed from the Commission's virtual case file on its webpage www.maine.gov/mpuc and reference to Docket No. 2006-364.

[5] Comments have been received from Bangor Hydro-Electric Company ("BHE"); Calpine Corporation and Westbrook Energy Center ("Calpine"); Central Maine Power Company ("CMP"); Constellation Energy Group (Constellation); Eastern Maine Electric Cooperative ("EMEC"); FPL Energy Maine, Inc. ("FPL"); Industrial Energy Consumer Group ("IECG"); Independent Energy Producers of Maine ("IEPM"); ISO New England, Inc. ("ISO-NE"); Maine Public Service Company ("MPS"); New Brunswick System Operator ("NBSO"); New England Power Pool ("NEPOOL"); New England Power Generators Association ("NEPGA"); Northern Maine Independent System Administrator ("NMISA"); Van Buren Light & Power District ("Van Buren"); and WPS Energy Services, Inc. ("WPS").

[6] As part of ISO-NE's response to the "Maine As An Island" draft, ISO-NE also provided its own analysis of the issues entitled, "Report on the Issues," which is available in the virtual case file.

[7] The Commission's rules regarding Inquiries do not prohibit *ex parte* communications as do the Commission's rules with regard to adjudicatory proceedings.

officials from the NBSO, New Brunswick Power Company ("NB Power"), and Nova Scotia Power Incorporated ("NSPI").

Our preliminary findings are as follows:

A. Significant inequities exist in the current ISO New England, Inc. ("ISO-NE")[8] transmission cost allocation system and the pricing of generation services. Therefore, during Phase II of this Inquiry, the Commission will weigh the benefits and costs of three distinct options, which are discussed more fully below.

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").

C. There are reasonable alternatives to continued participation in ISO-NE. These include the formation of one or more Maine independent transmission companies, and the development of a common Maine/Canadian Maritimes market. Practical alternatives will be developed further during the remainder of this Inquiry.

The Commission intends to continue this Inquiry and aggressively pursue alternatives to the ISO-NE *status quo.* We shall provide a final report consistent with the Resolve that will include concrete plans for alternatives, as appropriate. Therefore, in the coming year the Commission intends to:

A. Continue to engage New Brunswick and other Maritime provinces, as appropriate, in high-level negotiations to expand electricity trade between Maine and New Brunswick, and to develop a plan for a common market.

B. Explore the creation of one, or more, independent transmission companies (ITCs) in Maine.

C. Engage the New England Conference of Public Utilities Commissioners (NECPUC), or the New England State Committee on Energy, as applicable, to form a transmission cost allocation regime that creates incentives for the development of the diverse generation needed to power New England.

These three activities are not, necessarily, mutually exclusive, and should not occur in isolation. Indeed, in all three activities the Commission will strive to

[8] ISO-NE is the RTO for New England.

achieve one goal: to create the proper incentives to expand New England's energy infrastructure, while lowering the subsidies Maine consumers pay to the consumers of other states.

II. COSTS ASSOCIATED WITH *STATUS QUO* ARRANGEMENT WITH ISO-NE

The Resolve requires the Commission to "determine the costs and benefits of directing (CMP and BHE) to withdraw from the New England RTO." In this interim report we attempt to quantify the major cost items associated with the current RTO arrangement, as well as identify and quantify those cost items that we consider to be inequitable under the status quo arrangement. This analysis will be part of a benchmark cost/benefit analysis against which any alternative structure will be measured.

A key question for any cost/benefit analysis is the scope of the period analyzed to identify costs and benefits. While understanding that the past is important, it does not appear to us that a retroactive analysis of costs is as meaningful as an estimate of future costs. In addition, estimating costs in the too distant future is perilous. Therefore, we have chosen a five year period, commencing in 2007, to estimate the costs and benefits of ISO-NE and alternative arrangements. Five years seems appropriate to us because it is the period in which the ISO's transmission expansion plan is the most amenable to estimates, and the period in which capacity costs have been established the most clearly in the recent FERC approved forward capacity market settlement.[9]

While it is not possible to reach any definitive cost/benefit conclusions at this time, certain conclusions regarding the current cost allocation scheme are obvious. First, the RTO's current transmission cost allocation methodology is inequitable and results in a transfer of payments from Maine consumers to consumers in southern New England. This inequity is likely to grow substantially over the coming years as significant transmission investments are made in Connecticut and Massachusetts in order to address increased demand in those areas. Second, ISO-NE's administrative costs which have grown by 8.0% since 2003, and are expected to grow by 3.5% during the coming years, appear to be somewhat high when compared to the costs of its RTO peer group. It may be possible for Maine consumers to recognize administrative savings here under alternative arrangements. Finally, while it is not likely that energy costs will vary substantially under an alternative arrangement, the investments needed to bring Maine generation to the broader New England market would be inappropriately recovered from Maine consumers under the existing ISO-NE arrangement.

[9] *See* Devon Power, LLC, 115 FERC ¶ 61,340 (June 16, 2006)("Settlement Order").

A. Socialized Costs Associated with Operation of ISO-NE

1. Transmission Costs

Many of the costs of the transmission system are “socialized” by the RTO. Under the current cost allocation methodology, Maine pays into a transmission fund based on the average cost of all New England transmission but receives revenue from the fund based on the cost of the transmission located within Maine. As a result, if there is proportionately more transmission investment outside of Maine, or in Maine to benefit customers to our south,[10] Maine’s net cost will increase because the New England-wide costs would be growing faster than the costs necessary to serve Maine customers.

The ISO estimates that the net cost of socialized transmission will increase in the future. There are major new transmission projects elsewhere in New England that are either under construction or being designed that could cost more than $4.4 billion in the aggregate.[11] The larger projects which are well enough defined to have cost estimates are the Southwest Connecticut reliability project ($1.659 billion), the NSTAR 345 kV project ($226 million) and the Northwest Vermont Project ($210 million). These large projects total about $2.1 billion. There are also a number of smaller projects and, of greater concern, some very large, but as yet vaguely defined, projects. For example, ISO-NE recently presented plans for the Southern New England Transmission Reinforcement (SNETR) project with a preliminary cost estimate of $1.1 billion.[12] If recent history is a guide, there is a significant chance that the actual SNETR cost could be significantly higher.

It is possible then, that the total cost of all new transmission projects in the rest of New England could be higher than $4.4 billion. For each billion dollars in new transmission investment outside of Maine that is socialized, Maine’s share of the annual carrying costs on that investment is about $17 million per year.[13] Thus, if the future investment is $4.4 billion, Maine would be charged about $75 million per year for new transmission investment throughout New England. Even though some suggest that these projects are a benefit to Maine because Maine is connected to the rest of the New England system, the benefits

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[10] We recognize that since Maine has historically been a net exporter of energy, one could argue that much of the existing transmission in Maine is for the benefit of those to our south.

[11] See ISO-NE "2006 Regional System Plan," and ISO-NE "October '06 Project Listing." Both are available at http://www.iso-ne.com/trans/rsp.index.html.

[12] Information taken from ISO-NE "Southern New England Transmission Reinforcement (SNETR)" briefing, December 15, 2006.

[13] This number is based on Maine being allocated an 8.5% share of the investment based on load ratio and a 20% annual carrying charge including the return of and the return on investment.

accruing to Maine ratepayers from transmission projects in southern New England are minimal, at best.

The effect of the RTO cost allocation methodology on Maine is clearly shown by reviewing CMP's costs over the last two years. For the year beginning June 1, 2005 CMP paid $31.7 million into the transmission fund based on the total New England cost and received $28.5 million back from the fund to cover the costs of CMP transmission. CMP's net cost was the difference between the payments and the receipts, or $3.2 million. The figures changed significantly for the most recent period beginning June 1, 2006. New transmission in other states caused CMP's payment into the pool to rise by $10.6 million to $42.3 million. On the other hand, because CMP did not have as much new investment itself, its receipts from the pool increased by only $2.5 million to $31.0 million. In other words, CMP's net cost of socialized transmission rose from $3.2 million last year to $11.3 million this year. For BHE, the cost of socialized transmission this year was $1.3 million.

The cost increases associated with the socialization of out-of-state transmission upgrades must be balanced against the benefit of having costs of new Maine transmission projects socialized and covered by the rest of the region. CMP estimates that over the next five years, it will need transmission investments of about $229 million. BHE estimates its transmission investments over the same period at approximately $165 million.[14]

As set forth in the table below, even balancing the benefits of socializing transmission costs, Maine is substantially prejudiced by the RTO's transmission cost allocation methodology. Indeed, if all of the new transmission investments for New England were allocated by location rather than by ratio, as occurs under the *status quo* arrangement, Maine's investment share would decrease by approximately $200 million, or approximately $40 million on an annual cost basis.[15]

[14] A substantial portion of this new investment in Maine is likely to benefit the region as a whole rather than Maine specifically.
[15] This calculation is based on an annual carrying cost of 20%.

Table I

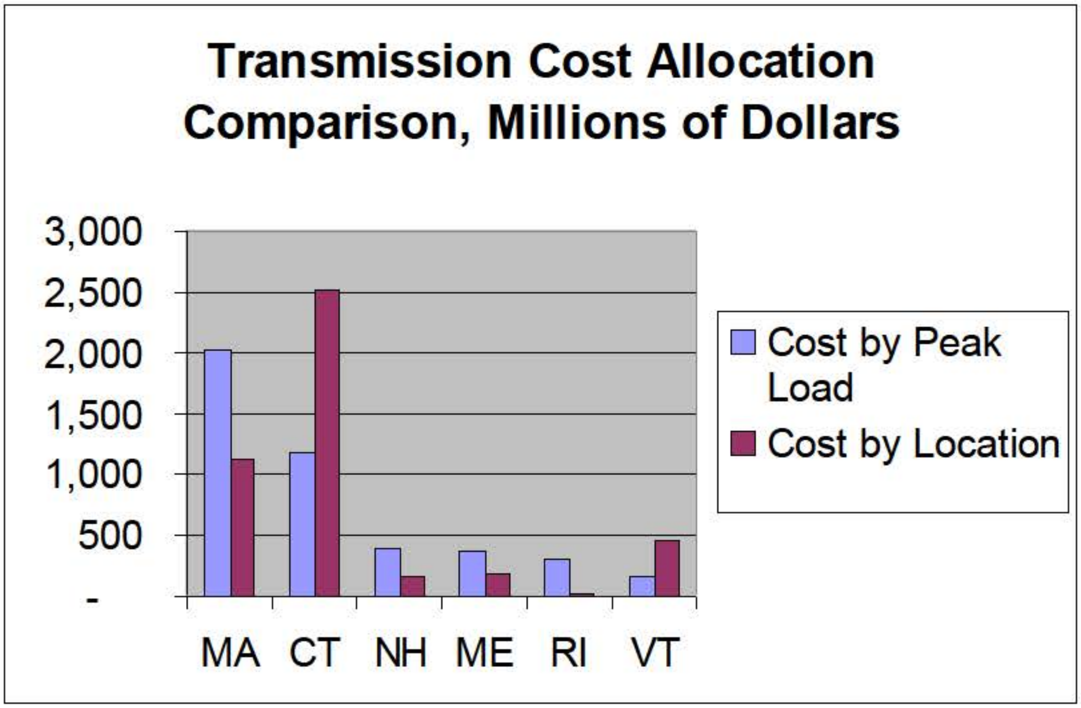
NEW TRANSMISSION INVESTMENT COST ALLOCATION COMPARISON[16]

State	Cost by Peak Load	Cost by Location	% of Peak
MA	**2,031**	**1,122**	**45.7%**
CT	**1,178**	**2,513**	**26.5%**
NH	**384**	**162**	**8.7%**
ME	**377**	**178**	**8.5%**
RI	**301**	**17**	**6.8%**
VT	**170**	**448**	**3.8%**
Total	**4,440**	**4,440**	**100%**

The incremental impact on Maine transmission rates represented by this table is in addition to the current $12.6 million annual subsidy Maine's utilities pay to other states for current transmission investment. Figure I below illustrates the same information in graphic form.

[16] Costs except for SNETR are from the July 2006 ISO-NE project list. SNETR costs are estimated at $1.1 billion. Rhode Island SNETR costs are allocated to Connecticut and a portion of the Massachusetts SNETR costs are allocated 50/50 to Massachusetts and Connecticut under the cost by location column based on a "beneficiaries pays-cost causation" analysis.

Figure I



In addition to the projects being proposed by CMP and BHE, ISO-NE and private parties are contemplating new transmission construction in Maine to serve the rest of New England. Total investment in Maine for projects to benefit the region could exceed $1 billion.[17] While Maine might see some benefit from this expanded import and export capability, most of the benefit is likely to go to other regions in the form of lower prices, creating corresponding price increases in Maine.[18]

2. <u>Administrative Costs</u>

RTO administrative costs are primarily composed of three items: salaries and benefits (40%) depreciation and amortization (30%), and outside consultants and lawyers (20%). The RTO administrative costs are borne solely by customers. In 2005, Maine paid about $7.85 million as its share of RTO Administrative Costs and this figure is likely to rise over time.

[17] Possible projects include the Orrington-South project, the so-called "Green Line" and the Aroostook County connection between Edmunston, New Brunswick and BHE's service territory.

[18] The impact of transmission investment on energy costs is discussed more fully below in section B.

Table II

Maine's Share of ISO-NE Administrative Costs

2003 actual	2004 actual	2005 actual
$7.25 million	$8.12 million	$7.85 million

According to its 2007 budget, the RTO expects the growth in administrative costs to continue to increase at a rate of about 3.5% per year. Almost all of these Administrative Costs are recovered through RTO tariff charges which are ultimately paid by electricity consumers. For the purposes of this analysis, we will assume the ISO-NE projected annual growth rate increase of 3.5% over the five-year period from 2007-2011.[19]

3. System Operating Costs

a. VAR Uplift Charges

In layman's terms, VAR uplift costs are incurred because there are some regions in New England, notably the greater Boston area, where the local transmission system is relatively weak.[20] On frequent occasions, it has not been possible to operate the system without extra voltage support from VARs. In general terms, these additional VAR costs are caused by some generating units being forced to run uneconomically to produce VARs instead of electric energy. These uneconomic costs are treated as "uplift" costs[21] and allocated to all of the RTO territory, including Maine. If Maine were not part of the RTO, it could avoid most, if not all, of the VAR uplift costs.

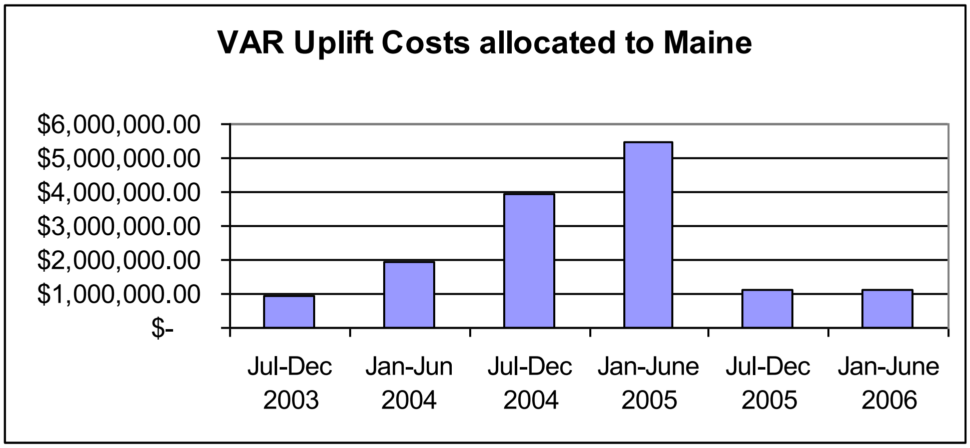
[19] It is worth noting that ISO-NE administrative costs, on a per kWh basis, are roughly twice as great as PJM's and MISO's and slightly greater than the costs of the NYISO, CAISO and IESO. This makes ISO-NE the most expensive RTO in the country on a per kWh basis. *See*, ISO-NE 2007 Operating and Capital Budget Presentation at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/budgfin_comm/budgfin/mtrls/2006/aug282006/2007_oper_cap_budgets_rev.pdf.

[20] VAR uplift charges are incurred under the NEPOOL Open Access Transmission Tariff (OATT) Schedule 2: Reactive Supply and Voltage Control from Generation Sources Service. The charges are allocated to all transmission customers based on a pro-rata share of the total monthly network load.

[21] In general, uplift costs are any costs incurred by the system where the cost recovery occurs through allocating charges to market participants, as opposed to being recovered through the price of electricity or the ancillary services. There are a number of other forms of uplift, but they are allocated to the region that causes them. As a result, Maine would not see a significant savings from avoiding these other forms of uplift.

ISO-NE estimated Maine's monthly share of VAR uplift costs for the period March 2003 through June 2006. These charges are highly variable. In the period between March 2003 and June 2006, charges to Maine ranged from a low of $13,015 per month to a high of $1,679,763 per month. For 2004 and 2005, VAR uplift charges assigned to Maine were about $6 million annually. For the first half of 2006, the charges had dropped to $1.1 million.

Figure II[22]



The future cost of VAR uplift is difficult to predict. On one hand, the costs have declined, probably because of some investments in the transmission system in greater Boston. On the other hand, the circumstances that created the voltage control problems in the Boston area may well arise again, especially in other urban areas with aging infrastructure. It is also possible that the RTO and the FERC will decide to allocate other non-Maine costs to Maine in other forms of uplift. Therefore, for the purposes of our five year estimate, we will take the average annual VAR uplift charges since 2003 and apply it to the 2007-2011 time period.

b. Operating Reserves

For an electric system to operate reliably, the system requires operating reserves; unused capacity that can be quickly dispatched in case there is a sudden, unexpected loss of resources. Typically, the system operator will need to carry operating reserves equal to the largest single contingency (loss of supply) plus one-half of the second largest contingency. The total amount of reserves varies depending on the size of the largest two sources on-line at any given time. For example, when the DC transmission line to Hydro Quebec is fully loaded at about 1,800 MW and the Seabrook nuclear unit is operating at capacity (about 1,200 MW), the operating reserve requirement for New England is 2,400 MW. Other times, when the HQ line is not heavily loaded,

[22] Source: ISO-NE Response 2.4, Docket No. 2006-364.

the first and second contingencies may be two nuclear units and the operating reserve requirement would be about 1,800 MW. In either event, Maine is roughly 8.5% of regional monthly peak load, requiring us to carry the costs of 153 to 204 MW of operating reserves.

ISO-NE has estimated that over the past three years Maine's operating reserve costs have averaged approximately $5 million. Since operating reserves requirements would not go away under an alternative arrangement, the cost of this service would need to be incorporated into a cost/benefit analysis which compared the status quo to an alternative arrangement.[23]

c. Regulation Costs

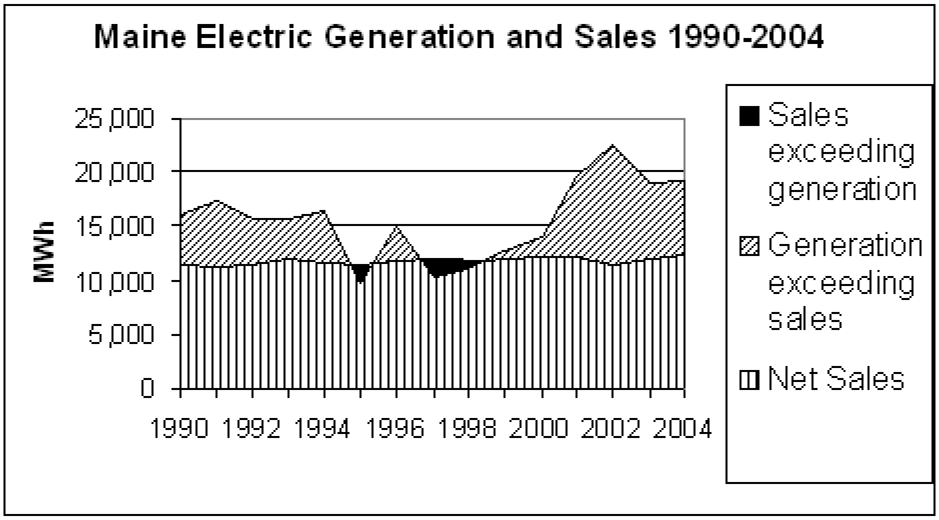
Regulation is the ability of some generators to respond quickly to requests for small increases and decreases in output in order to maintain the balance between generation and usage. Requests for changes in output can occur as frequently as every four seconds. In 2005, the total RTO cost for regulation was $70 million[24] so that Maine's share was in the range of $6 million. Similar to the costs of operating reserves, the costs would have to be compared to the costs for similar services in a cost-benefit analysis of an identified alternative.[25]

B. The Regional Market for Electricity and Its Impact on Maine

Maine is part of a regional electricity market, largely regulated by the RTO's administration of the energy market and related services markets. As part of the New England regional electricity markets, we are directly affected by the supply and demand for electricity in the region. In most recent years, Maine has generated significantly more electricity than it has consumed. Figure III shows the total generation in Maine from 1990 through 2004, as well as the total usage in the State.

[23] For example, if Maine were to become a stand-alone Transmission Organization, Maine would need to carry significantly greater operating reserves. NMISA, in its comments, suggested that Maine would need to carry operating reserves of 761 MW, assuming the largest contingencies are the Calpine Westbrook plant and Maine Independent Station, suggesting that Maine would need to carry 4 to 5 times more operating reserves operating as a stand alone Transmission Organization as opposed to as part of the RTO.
[24] ISO-NE, 2005 Annual Report, page 79.
[25] ISO-NE has asserted that a stand-alone Maine RTO might have regulation costs of three times the current cost, which suggests an increase of roughly $14 million compared to current costs. ISO-NE has not provided any basis for this assertion and we are unable to confirm it at this time.

Figure III[26]



As the Figure indicates, between 1990 and 1994, in-state generation exceeded consumption by about 4,000 to 5,000 GWH per year. Stated a bit differently, generation in Maine produced about 30% to 50% more electricity than Maine customers consumed.[27] In 1995, Maine Yankee experienced major operating problems and by 1997 it was permanently inoperable. As a result, during the mid to late 1990's, Maine generation and consumption were roughly in balance. By 2000, however, large amounts of new generation began coming on line and, as a result, Maine is again producing substantially more electricity than it consumes. In the years 2001 through 2004, Maine generated at least 50% more electricity than it consumed[28] with the surplus being exported outside the state.

The New England transmission system is also constrained, effectively "bottling-in" a modest amount of otherwise competitive generation in Maine during certain hours. During these constrained hours, a sub-market forms in Maine characterized by lower prices and increased reliability.[29]

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[26] The underlying data is available at: http://www.eia.doe.gov/cneaf/electricity/st_profiles/maine.html

[27] Note that a portion of the Maine generation was lost in transmitting and distributing the generation to customers. As a result, a portion of the surplus generation was not available for sales to other regions.

[28] These figures are based on an historical data set produced by the US DOE Energy Information Administration (EIA) and data for 2005 is not yet available from the EIA. We expect the 2005 data to be generally consistent with the 2001-2004 period.

[29] The system constraint that creates the generation bottleneck also prevents Maine from sinking into temporary capacity deficiencies as often as southern New England.

The submarket in Maine creates an energy market that is approximately $30 million less expensive each year than the New England hub. However, the value of this "benefit" is eroding rapidly. As Maine's demand for electricity increases each year the submarket benefit is decreasing. Though increased generation is being planned in Maine, which could increase the benefits of the submarket, it would be imprudent for the purposes of this study, for the reasons discussed below, to focus on these energy market attributes as entitlements for Maine ratepayers.

First, generation is locating in Maine to serve regional load, not simply the load of Maine consumers. If Maine were to consider alternatives to ISO-NE, such as creating a Maine "electricity island,"[30] it is likely that much of the investment in generation currently planned for Maine would be chilled. Second, Maine has policies promoting renewable generation,[31] which generation would be greatly discouraged by a regulatory regime that sought to artificially capture generation and lower prices. Finally, as discussed previously, parties are considering several significant transmission projects that would expand the current transmission system in order to remove the constraint and increase the system's capability to export power outside of Maine.

For the foregoing reasons, we have assumed that there is no net cost of energy for Maine associated with the current ISO-NE arrangement. We note, though, that under the *status quo* arrangement, costs for the investments needed to increase Maine's capability to serve load in southern New England would not only result in increased energy costs in Maine, but would also be socialized and, thus, recovered in part from Maine ratepayers. An essential question as part of our analysis going forward will be whether there are alternatives to the *status quo* arrangement which might more equitably allocate such costs to the cost causer or investment beneficiary and, as a result, more accurately price, from an economic perspective, both transmission and generation service.

C. <u>Capacity Costs</u>

Capacity costs are the costs associated with paying generators in New England to agree to be available during periods when the reliability of the system is threatened. Until December 2006, capacity costs have generally been a relatively small portion of the costs paid by electricity customers in Maine and New England. Recently, the FERC approved a settlement which has significantly increased the capacity costs. The settlement sets fixed capacity prices during a "transition period," from December 2006 through May 2010 at levels ranging from

[30] *See,* Discussion document entitled, "What if Maine Were an Electricity Island," which can be accessed from the Commission's Virtual Case File.
[31] *See,* P.L. 2005, ch. 677 "An Act to Enhance Maine's Energy Independence and Security."

$3.05 to $4.10 per kilowatt-month[32]. Beginning in June 2010, capacity costs will be determined by a “Forward Capacity Market" ("FCM"), under which capacity prices will be determined through a complex auction mechanism.

Predicting Maine’s capacity costs under the status quo is relatively easy during the interim period. On the other hand it is very difficult to predict capacity costs after the interim period either for the status quo or under an alternative arrangement.[33] In general, we would expect Maine capacity costs to be lower under an alternative arrangement because the alternative arrangement would be better able to differentiate between the costs of new construction in Maine, as opposed to other states in New England. If the FCM auction is not held or fails for some reason, the cost of capacity beginning in June 2010 will be $4.70, according to the settlement.[34] This would appear to be a reasonable estimate of the lowest capacity cost Maine customers would face in 2010 and 2011, and we have used it in estimating the capacity costs under the FCM market for those years.[35]

The Commission opposed the capacity settlement generally and was particularly critical of the interim payments as being unreasonably high for Maine. In particular, the Commission offered evidence that the capacity costs for Maine during the interim period should be $2.00 per kw-month,[36] rather than the $3.05 to $4.10 figure preferred by the generators, ISO-NE, and those in southern New England. A $2.00 per kw-month charge would result in reducing capacity payments by approximately $335 million through the end of 2011.

D. *Status Quo* Cost Summary

The Table below provides a summary of the current cost subsidies from Maine, or transfer of payments from Maine consumers to consumers of other states, under the existing ISO-NE arrangement projected over a five year period.

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[32] See March 6, 2006 Settlement Agreement in FERC Docket No. ER03-563-030, Section VIII, subsection B.

[33] There are several difficulties here. There is no experience either with the FCM market nor are there similar markets which might produce different results. It is not possible to know what bidding strategies generators will employ in bidding into the FCM. And, perhaps most importantly, the results for Maine could be much higher if new transmission between Maine and southern New England is constructed.

[34] See March 6, 2006 Settlement Agreement in FERC Docket No. ER03-563-030, Section VIII, subsection I.

[35] By using $4.70, our capacity cost estimate is conservative. Indeed, our estimate could increase to $660 million, rather than $335 million, if the higher end of the range was used for the purposes of this study.

[36] Affidavit of Thomas D. Austin, FERC Docket No. ER03-563-030, March 27, 2006.

These costs may be significantly reduced or eliminated under an alternative arrangement.

Table III

FIVE YEAR PROJECTION FOR TRANSMISSION, VAR AND CAPACITY COSTS UNDER THE *STATUS QUO*

Cost Category	Projected Five Year Impact
Current Investment	$63,000,000
New Investment	$200,000,000
VAR Type Costs	$18,000,000
Capacity Costs	$335,000,000
Total	**$616,000,000**

Other costs, such as reserve, regulation and administrative costs would be incurred in any alternative arrangement. The table below shows the cost projections for reserve, regulation and administrative costs under the status quo.

Table IV

FIVE YEAR PROJECTION FOR RESERVE, REGULATION AND ADMINISTRATIVE COSTS UNDER THE *STATUS QUO*

Cost Category	Approximate Five Year Cost
Reserve Requirements	$25,000,000
Regulation Costs	$30,000,000
Administrative Costs	$45,000,000

One of the tasks for the next stage of this Inquiry is to develop projections for these cost categories under an alternative arrangement.

III. LEGAL ISSUES CONCERNING THE WITHDRAWAL CMP AND BHE FROM THE RTO

There 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. RTO withdrawal is not a novel strategy to reduce costs. FERC case law and the contract terms which govern withdrawal and RTO membership termination provide a straight forward path for CMP and BHE to withdraw from ISO-NE at the end of the initial term of the TOA. Although circumstances under which termination or withdrawal prior to the end of the TOA are more narrowly circumscribed, under certain circumstances, early withdrawal is also possible.

Under any scenario, federal law is clear that states have limited control over a utility's decision to participate in an RTO. It is the utilities, BHE and CMP, which have the ultimate legal authority, subject to FERC approval, of the applicable terms and conditions, to participate in an RTO, withdraw from an RTO, or to join an alternative RTO arrangement. Nevertheless, CMP and BHE's interest in lowering rates to increase sales may well converge with a result that reduces electricity costs for consumers. Therefore, to the extent that withdrawal from ISO-NE accomplishes this objective, utilities may well have an interest in pursuing such action.[37]

A. Legal Structure of Regional Organizations

ISO-NE is the entity that serves as the RTO for New England.[38] 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 and ancillary services. ISO-NE is a public utility within the meaning of the Federal Power Act and is thus regulated by FERC.

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[37] Indeed, the failure to do so might be considered imprudent.

[38] In contrast to the rest of Maine, which is part of the ISO-NE region, Northern Maine is electrically part of the Canadian Maritimes region, which also includes the electric loads and generation of New Brunswick, Nova Scotia and Prince Edward Island. Load and generation in Northern Maine are connected to the rest of Maine and New England only by transmission through New Brunswick. The region includes the service areas of Maine Public Service Company (MPS) and three consumer-owned utilities: Houlton Water Company, Van Buren Light and Power District, and Eastern Maine Electric Cooperative. The New Brunswick System Operator ("NBSO") serves as the system operator for the Maritimes region as a whole, while the Northern Maine Independent System Administrator ("NMISA") administers the bulk power and transmission systems for the Northern Maine region.

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,[39] 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.[40] The TOA also governs a transmission owner's rights to withdraw from the RTO. 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. Withdrawal from the RTO

The TOA and relevant FERC precedent provide a clear path for CMP and BHE to withdraw from the RTO. RTO withdrawal at the end of the term of the

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[39] 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.

[40] 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.

TOA is straightforward. Withdrawal prior to the end of the term of the TOA is also possible under certain circumstances. In either case, the state has a limited ability to compel the utilities to withdraw from ISO-NE.

1. Withdrawal At The End Of The Initial Term

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 Operations 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 automatic renewal of the agreement for an additional two-year term.[41]

In order to withdraw after the five-year initial term, 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.[42] 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. First, 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."[43] However, a withdrawing Transmission Owner may be subject to an exit fee for "financial obligations incurred and payments applicable to the time period prior to the Termination Date."[44]

FERC has the authority under the TOA to determine that the withdrawal is just and reasonable.[45] However, FERC cannot require transmission owners to relinquish certain legal rights that utilities have under section 205 of the Federal Power Act.[46] Recently, FERC issued decisions balancing these two competing principles in a line of cases involving two utilities' withdrawal from the Midwest ISO ("MISO").

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41 TOA § 10.01(a).
42 TOA § 10.01(c).
43 *Id*.
44 TOA §10.01(g)(i).
45 TOA § 10.01(f).
46 *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").

In *Louisville Gas and Electric Company*,[47] 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 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."[48] 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 by the Resolve. 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

[47] 114 FERC ¶ 61, 282 (2006) ("Louisville"); Order on rehearing, E.On U.S. LLC, 116 FERC ¶61,020 (2006) ("Rehearing Order")
[48] *Louisville*, 114 FERC ¶ 61,282 at P.13.

Order 888, but not *Order 2000*.[49] 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. Ultimately, FERC's approval of the Kentucky utilities' withdrawal from MISO is instructive and underscores the "voluntary" nature of RTOs. Further, the *Louisville* orders provide a clear path for Maine's utilities to follow.

The TOA leaves the parties room to argue that a withdrawing transmission owner may have to pay some sort of exit fee even if the transmission owner is not withdrawing before the end of the term of the agreement. This is so because a transmission owner that gives notice that it is not agreeing to additional terms beyond the five-year initial term is described as giving a "notice of withdrawal." Moreover, a decision not to sign on for additional terms is described as a "withdrawal" in section 10.01. The section providing for "continuing obligations" states that "each withdrawing or terminating Party" shall have certain continuing obligations following withdrawal from the agreement. Reading these provisions together, it is possible to argue that any withdrawal, even if the withdrawal is in essence a decision not to extend the term of the TOA beyond the initial five year term, may be subject to an exit fee. However, as discussed below, it is not at all clear that exit fees of any significant magnitude will be applicable to CMP and BHE.

The TOA describes the continuing financial obligation as follows:

[49] *Order 2000* established minimum requirements for RTOs while acknowledging that RTO formation is voluntary. *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd, Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001). Among the *Order 2000* requirements the MISO asserted would not be met by the stand alone arrangement proposed by the Louisville utilities, were the requirements that an RTO (1) be "of sufficient scope and configuration to permit the [RT0] to maintain reliability, effectively perform its required functions and support efficient and non-discriminatory power markets"; (2) the have a market-based congestion management plan; and (3) have a regional planning process; (3) have an objective market monitoring function.

> 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.[50]

Thus, under the TOA, any exit fee would have to be based on a determination that the withdrawing transmission owner had incurred a financial obligation prior to the termination date and the amount of that financial obligation. Other portions of the TOA suggest that financial obligations may arise from a withdrawing transmission owner's interconnection agreement,[51] or any other specific obligation set forth in the TOA. The agreement makes clear, however, that the withdrawing transmission owner is not obligated for the reallocation of revenues that may result from a transmission owner's decision to terminate its participation in the RTO.[52]

Reading these provisions together with provisions of the ISO-NE OATT, the withdrawing transmission owner would likely be expected to honor its interconnection agreements, pay bills issued by the ISO prior to the termination date, pay amounts due under the formula rate OATT for the year beginning July 1, 2009 through June 30, 2010, and perform any additional obligations it incurred prior to February 1, 2010.[53] Included in the amounts due under the formula rate would be that year's charge for regionalized transmission upgrade costs.

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. Support for this conclusion is found in Schedule 12 and Attachment F of the ISO-NE OATT. These provisions indicate that transmission costs approved by ISO-NE for regional cost support are recoverable costs but that the costs may

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[50] TOA § 10.01(g).

[51] TOA § 2.05.

[52] See TOA § 3.07(a)(i) ("Nothing in this Agreement shall restrict any rights:. . . (B) of any [transmission owner] to terminate its participation n this Agreement pursuant to Article X of this Agreement, notwithstanding any effect its termination from the ISO may have on the distribution of transmission revenues among other [transmission owners].").

[53] One additional obligation that could be incurred prior to February 1, 2010, is an obligation to build new transmission facilities identified in the ISO's regional system plan. However, this obligation to build is subject to government regulations and approvals "including requirements to obtain any necessary federal, state of local siting construction and operating permits, the availability of required financing; [and] the ability to acquire necessary rights-of-way." TOA Schedule 3.09 §1.1(a).

be recovered only in accordance with Attachment F which "sets forth details with respect to the determination each year of the Transmission Revenue Requirement for each [transmission owner]."[54] Thus, CMP and BHE incur financial obligations to pay their share of the transmission revenue requirement for each transmission owner only when that transmission revenue requirement is annually determined.[55]

2. Early Withdrawal under the TOA

The TOA provides for early termination or withdrawal from the RTO under the following circumstances:

- An ISO event of default;
- A FERC change in policy, stating that the federal government no longer encourages the participation of transmission owners in RTOs and allowing withdrawal, or preventing Transmission Owners under the agreement from recovering the costs of existing transmission facilities on a cost of service basis;
- FERC orders changing the relative rights and responsibilities of the transmission owners and the ISO under the agreement, so as to materially adversely affect the interests of one or more transmission owners;[56]
- ***The withdrawing transmission owner has received FERC approval to form an Independent Transmission Company ("ITC"); or***
- The withdrawing transmission owner has obtained authorization from FERC to join another RTO or similar organization, in connection with a merger with or acquisition by another entity other than one of the other New England transmission owners.[57]

Of the circumstances giving rise to the potential for early withdrawal, the formation of an ITC[58] is the most pragmatic for CMP and BHE, if early withdrawal is desirable. FERC's approval is required to form an ITC[59] and for early withdrawal. In most respects, if early termination is permissible and acceptable to FERC, the obligations on the withdrawing utilities are the same as they would be under withdrawal at the termination of the TOA. As discussed

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[54] Attachment F to ISO New England OATT.
[55] In *Louisville*, the parties had actually contracted to pay part of MISO's deferred capital costs. Here, there is no such specific commitment.

[56] The right to withdraw under this provision extends only to the transmission owners affected by the FERC order.
[57] TOA § 10.01(b)(i-vi) (emphasis added).
[58] An ITC is a for-profit transmission company that meets the independence criteria of Order 2000. An ITC may operate within an RTO, as contemplated in the TOA, or instead of an RTO.
[59] *See*, ISO-NE OATT, Attachment M.

above, a transmission organization replacing an RTO, like an ITC, should also meet all of the requirements of a replacement organization outlined in *Louisville*, including the filing of an Order 888 compliant tariff. Finally, the same legal analysis applies to exit fees under an early withdrawal as a withdrawal after the initial term.

Early withdrawal, through an ITC or some other legal means, has one potential advantage over withdrawal in 2010 at the end of the initial term of the TOA. The earlier CMP and BHE withdraw from ISO-NE, the greater the reduction will be in Maine ratepayers' contribution to projects built to relieve congestion or solve reliability problems in other states.[60]

3. 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*.[61] On rehearing, FERC further explained its holding:

> 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.[62]

Assuming, for the sake of this analysis, that the new arrangement will be something less than a new RTO, like an ITC consisting only of BHE and CMP, the new OATT must be consistent with or superior to the Pro Forma OATT established under *Order 888*. *Order 888* "required that wholesale transmission function be unbundled from the sale of power and required utilities to

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[60] Conversely, there will be a reduction in other states' ratepayers' contribution to projects built in Maine, but as the cost analysis in Table I above shows, Maine's share of New England projects under a socialization scheme is far greater than the total cost of Maine projects.
[61] *Louisville*, 114 FERC ¶ 61,282 at 930.
[62] Rehearing Order, 116 FERC ¶ 61,020 at P. 12.

provide open access to their transmission lines in a non-discriminatory fashion."[63] The rule also establishes an OASIS requirement and protocols for the operation of the OASIS system.

In the *Louisville* orders, FERC was very careful not to let its concern with seams[64] 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, or to elevate seams reduction above all other market goals articulated by FERC in prior orders. On rehearing, FERC reiterated this position, stating:

> We disagree that the Withdrawal Order is inconsistent with either the spirit or the letter of EPAct 2005[65] as it relates to regional coordination issues. When Congress adopted EPAct 2005, it did not revise the principle of Order No. 2000 that participation in an RTO is voluntary, nor did it amend a public utility's section 205 filing rights. Our findings in the Withdrawal Order were necessarily built upon this foundation. Since Applicants, subject to conditions, satisfied the withdrawal requirements of the TO Agreement, Applicants are entitled to propose rates, terms and conditions applicable to their stand-alone operation. The Midwest ISO's argument that Applicants' facilities could be operated in a more reliable, efficient manner in an RTO (and thus promote the regional coordination goals of EPAct

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[63] *Atlantic City Electric Co. v. FERC,* 295 F. 3rd 3, 5 (D.C. Cir 2002) *citing, Promoting Wholesale Competition Through Open Access Non-discriminating Transmission Services by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. P 31,026, 61 *Fed. Reg. 21,540 (1996), clarified, 76 FERC P 61,009 and 76 FERC P 61,347 (1996), on reh'g, Order No. 888-A, FERC Stats. & Regs. P 31,048, 62 Fed. Reg. 12,274, clarified, 79 FERC P 61,182 (1997), on reh'g, Order No. 888-C, 82 FERC P 61,046 (1998), aff'd in part and remanded in part sub nom. TAPSG, 225 F.3d 667, aff'd sub nom. New York v. FERC 535 U.S. 1, 152 L. Ed. 2d 47, 122 S. Ct. 1012.*

[64] 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.

[65] MISO had argued that allowing the Louisville utilities to withdraw from MISO was inconsistent with provisions of the Energy Policy Act of 2005 ("EPAct 2005) that concern reliability and transmission access. MISO cited provisions that (1) required the formation of joint federal/state regional boards to study the issue of security constrained dispatch and (2) the development of enforceable electric reliability standards militates against approval of the Louisville utilities withdrawal request because the withdrawal would undermine these policies by weakening an existing RTO. As discussed above, FERC rejected these arguments.

> 2005) simply overlooks Applicants' contractual rights under the TO Agreement, which we are not at liberty to ignore. [66]

Thus, a decision by CMP and BHE to withdraw from ISO-NE and to form an ITC, should not be rejected by FERC simply because the RTO does not comply with *Order 2000*.

C. Federal Preemption of Interstate Transmission

1. The Federal Power Act

Under the Federal Power Act ("FPA"), FERC has exclusive jurisdiction over "transmission of electric energy in interstate commerce."[67] The Supreme Court has held that "transmissions on the interconnected national grids constitute transmissions in interstate commerce."*New York v. FERC*.[68]

The significance of FERC's exclusive authority is that, ultimately, any determinations concerning RTO membership (and any other matters concerning the operation of transmission systems) by Maine utilities will be governed by federal, and not state, authorities. The relationship of FERC's authority over transmission in interstate commerce under the Federal Power Act to its jurisdiction over RTO and ITC arrangements can best be understood in the context of the FERC orders influencing the development of independent system operators and later RTOs.

2. *Order 888* and *Order 2000*

FERC's *Order 888*[69] "mandated that the wholesale transmission of electric energy be unbundled from the sale of power." *Detroit Edison Company v. F.E.R.C.*, *334 F. 3rd 48 130 (D.C. Cir. 2003)*. In *Order 2000*, FERC established the primary characteristics and functions of regional transmission organizations ("RTOs").[70] However, *Order 2000* did not require or mandate participation of utilities in RTOs.[71]

In *Atlantic City Electric Co. v. FERC*, 295 F.3rd 1 (D.C. Cir. 2002), the D.C. Circuit Court limited the means through which FERC could approve or disapprove a utility's decision to withdraw from an RTO, but left open FERC's authority to review entry or exit from an RTO to determine if the terms are just and reasonable under the FPA. The D.C. Circuit Court of Appeals recently rejected an appeal by the New England transmission owners, finding that FERC had not exceeded its authority in conditioning its approval of the New England RTO upon an amendment to the TOA which would require FERC approval of a

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[66] Rehearing Order, 116 FERC ¶ 61,020 at P. 30.
[67] *See*, 16 U.S.C. § 824(b).
[68] 535 U.S. 1 (2002) citing, *FPC* v. *Florida Power & Light Co.,* 404 U. S. 453, 466-467 (1972); n. 5.
[69] *Order 888*, 61 Fed. Reg. 21,580.
[70]*Order 2000*, 18 C.F.R § 35.34(j), (k) and (l).
[71]*Order 2000,* FERC Stats. & Regs. ¶ 31,089 at 31,033-34.,

withdrawal from the RTO under a just and reasonable standard. *See*, *Maine Public Utilities Commission v. FERC*, 454 F.3rd 278 (D.C. Cir. 2006) (affirming FERC's authority to require the TOA to be amended to provide for FERC review of a transmission owners' withdrawal request on a just and reasonable standard).

Thus, the FPA grants FERC the authority to determine whether any rate change or new rate filed, including RTO or ITC agreements, by a transmission owner to provide transmission service is just and reasonable.[72] However, as seen in *Atlantic City,* FERC's authority over a utility's decision to join or remain a member of an RTO is limited.

3. Federal Preemption of States to Prevent RTO Membership or Require Withdrawal from an RTO

While the *Atlantic City* and *Louisville* cases address the voluntary nature of RTO membership, another FERC case, resulting in Opinion No. 472, addressed the situation where a utility (AEP) sought to join an RTO but was potentially prevented from doing so by a Virginia statute that required the approval of the Virginia public utility commission before the utility could join PJM. FERC invoked section 205(a) of the Federal Power Act to preempt the state approval requirement. Section 205(a) states, in relevant part:

> The Commission may, on its own motion, and shall, on application of any person or governmental entity, after public notice and notice to the Governor of the affected State and after affording an opportunity for public hearing, exempt electric utilities, in whole or in part, from any provision of State law, or from any State rule or regulation, which prohibits or prevents the voluntary coordination of electric utilities, including any agreement for central dispatch, if the Commission determines that such voluntary coordination is designed to obtain economical utilitization of facilities and resources in any area.[73]

FERC found that the Virginia law did prevent the utility from joining PJM because the statute prohibited a utility from joining before a specific date and required the state commission's approval. Further, FERC found that Virginia's actions were not "designed to protect public health, safety, or welfare, or the environment, or intended to conserve energy or mitigate the effects of emergencies from fuel shortages." Instead, FERC, finding that Virginia was acting

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[72] *Pennsylvania Electric Co. v. F.E.R.C.*, 11 F.3rd 210 (D.C. Cir. 1993).
[73] 16 USC § 824a-1(a).This provision does not allow FERC to grant an exemption if it finds that the state law provision at issue is either required by Federal law or "designed to protect public health, safety, or welfare, or the environment or conserve energy or is designed to mitigate the effects of emergencies resulting from fuel shortages." *Id.*

to protect the state's economic interest, overrode the provisions of the Virginia statute to allow AEP to join PJM.

Opinion No. 472 might be applicable if CMP and/or BHE sought to extend their membership beyond the initial 5 year term of the ISO-NE RTO agreements and the Commission directed them not to do so or if the Commission directed CMP and BHE to withdraw from ISO-NE. Less clear, however, is the applicability of Opinion No. 472 to situations where the Commission does not directly order the utilities to participate (or not participate) in an RTO but nevertheless uses other regulatory tools (such as prudency review) to achieve the same result. At this initial stage of our analysis, it is enough to recognize the possible limits of the state's authority to require CMP and BHE's withdrawal from ISO-NE.

D. Conclusion

This legal analysis provides a starting point for the further discussion of legal and policy issues involved in conducting the inquiry directed by the Legislature. At this point in the analysis, several conclusions can be reached. First, the TOA does not allow any party to prevent a transmission owner from withdrawing from the RTO after the initial term, and early termination is allowable under certain circumstances. Second, FERC will recognize the voluntary nature of RTOs and will not disapprove a withdrawal request because the alternative arrangement does not meet the requirements for RTOs under *Order 2000*. Finally, it is not clear that exit fees of any significant magnitude will be applicable to CMP and BHE upon a withdrawal from the RTO either before or after the initial term, although CMP and BHE may have continuing obligations relating to interconnection agreements. In any event, it appears unlikely that the "continuing obligation" provision of the TOA will impose an impediment to a possible withdrawal by CMP and BHE from the RTO.

IV. ALTERNATIVES

As set forth above, the status quo arrangement with ISO-NE is inequitable to Maine's ratepayers and must be corrected. As there are no insurmountable obstacles to withdrawal from ISO-NE, it is appropriate to investigate further alternatives to the *status quo*. The Commission has identified the following three viable alternatives to the *status quo* arrangement:

1. developing a market with one or more of the Canadian Maritime provinces;

2. withdrawal by Maine's utilities from ISO-NE without creating a new inter-jurisdictional market structure through the creation of one or more independent transmission companies ("ITC"); and

3. working within the current ISO-NE framework to address and correct the identified inequities.

The Commission believes that the Legislature's motivation in directing us to conduct this Inquiry is to create a market which is fair and equitable to Maine consumers, provides the correct price signals to consumers and suppliers, and fosters the development of cost-effective and environmentally sustainable generation in Maine. Alternatives appear to exist that could accomplish these goals more effectively than does ISO-NE *status quo.* The Commission does not believe that the three alternatives discussed below are, necessarily mutually exclusive.

A. The Possibility of Combining Maine's Electricity Market With Those in the Maritime Provinces to Create a Common Market (the "ME/CAN" Proposal)

This is not the first time that Maine has explored the balance between its electric market relationships with the rest of New England and its relationships with its Canadian neighbors. The Commission has, in fact, within the past several years undertaken studies of the advantages and disadvantages of strengthening ties (both in terms of market structure and physical interconnections) with Quebec and New Brunswick. The Commission's recent approval of a major additional transmission line linking Maine to New Brunswick is an example of the continuing attempts to optimize those ties. Based on our preliminary assessment, it appears that such a combination at the very least warrants further exploration and that there do not appear to be factors that would rule out the possibility that a Maine/Maritimes market would provide reliable electricity service at an economically efficient price to Maine consumers.[74]

Our preliminary assessment of the relevant factors for the viability of a ME/CAN market suggests that, while there is a significant degree of uncertainty concerning relative load growth and supply in the ME/CAN area, the areas involved appear to be complementary in that there is a reasonable degree of supply and load growth homogeneity, and combining into one market will bring improvements in supply and peak load diversity. Further, the interconnections between Maine and the Maritime provinces, and in particular with New Brunswick, will likely increase transfer capability to allow the areas within ME/CAN to work effectively together. Finally, the increasing interest in the Canadian Atlantic provinces in expanding their electricity production, and in bringing that production

[74] For a more extensive preliminary assessment a Maine/Maritimes market ("ME/CAN"), see "The Canadian Option. Prospects for a Market Comprising Maine, New Brunswick, Nova Scotia and Prince Edward island," released for comment November 17, 2006. A revised version of this document will be posted on the Commission's website.

to and through Maine, provides strong impetus for those provinces to develop closer physical and institutional ties with Maine with respect to electricity.

1. Electricity usage appears likely to grow at between 0.5% and 2.0% across Maine and the Maritime provinces, with slightly faster growth projected in the Maritimes, though there is significant variation in estimates.

The load growth projections for Maine and the Maritimes, taken together, suggests that load will likely increase at a modest rate over the foreseeable future, and that growth rates throughout the ME/CAN region are roughly comparable. Because infrastructure costs are, to a significant extent, driven by increases in load, this suggests that no one participant in the ME/CAN region would be likely to impose a greatly disproportionate cost burden on the other participants under any cost recovery system, since the differences between socializing all such costs over the entire system and assigning responsibility on a more granular basis would likely be small. If it proved to be the case that the Maritimes growth substantially exceeded the growth in Maine, the costs imposed on the overall ME/CAN system by the Maritimes area would be greater than the costs imposed by Maine, and a cost recovery approach that failed to recognize this difference could lead to a cost shift toward Maine. On balance, however, the likely differences are small, uncertain in size and even in direction, suggesting a reasonable degree of homogeneity in economic (and thus electricity infrastructure cost) growth.

The data also suggest that the total peak load of the ME/CAN system is likely to be less than the sum of the peak loads identified by each of the constituent utilities. As CMP observes, in five of the past six years, CMP has experienced a summer peak, reflecting an increase in air conditioning load. The ISO-NE projections suggest the same. Since electricity usage in the Maritime provinces peaks in the winter, the ME/CAN system as a whole would likely experience at least a reduction in peak load relative to supply when compared to Maine or the Maritimes, standing alone.

Table V

Current Peak Load and Projected Growth Rates

	N. Maine	CMP	BHE	NB[75]	Maritimes[76]
2006 peak MW	142	1680	294	3207	5599
Growth rate	1.0–2.0 %	0.6%	0.0%	1.6%	0.79%

[75] NBSO estimate

[76] 2006-2009 estimates from NPCC (2005); includes NB, NS and PEI

2. The Installed Capacity in the ME/CAN area appears to be sufficient to meet the load projections over at least the next several years, and the fuel mix is likely to remain diverse.

While the estimates provided by the various utilities and system operators of generation capacity over the next ten years show little change, there are a number of factors that could result in significant changes. In Maine, for example, there are proposals that could add as much as 500 MW of wind generation which, while contributing proportionately less than other resources to the capacity required for reliability, could nevertheless provide significant amounts of energy and displace some consumption of fossil fuels. Moreover, as discussed below, the Atlantic provinces have shown an interest in substantial expansion of their generation capabilities.

The overall fuel mix for ME/CAN and its constituent parts is reflected in the following table:

Table VI

2006 Fuel Mix for ME/CAN

	Nuclear	Hydro	Gas	Oil	Renew.	Coal	Total
N. ME	0	37	0	40	70	0	166
S. ME	0	549	1534	864	277	75	3301
NB	582	895	353	1907	39	515	4290
NS	0	360	150 [77]	462	60[78]	1261	2293
PEI	0	0	0	88	40	65	193
Total	582	1841	2037	3361	486	1916	10243
%	5.7%	18.0%	19.9%	32.8%	4.7%	18.7%	99.8%[79]

Other factors that may impact the future fuel mix of the ME/CAN area include the possible wind projects in Maine noted above and additional renewable development in Nova Scotia. PEI is planning for an additional 30 MW of new wind power by the end of 2006, with a projected future total of up to 200 MW. New Brunswick is also seeking to add 200 MW of wind, with installation by 2009. Significantly, the geographic dispersion of the various proposed wind projects in the ME/CAN area could contribute in a positive way to the overall capacity factor of wind within the system.

[77] About 13% of Nova Scotia's generating capacity (about 300 MW) can burn either gas or oil; for the purposes of this table, this unit is counted as 50% oil and 50% gas.
[78] Estimated: 40 MW of wind and 20 MW of tidal generation.
[79] Numbers do not add to 100% due to rounding.

Finally, the province of Newfoundland and Labrador has indicated that it plans to develop very substantial additional hydro and wind resources, including as much as 4500 MW of hydro in the Lower Churchill Falls project and 1500 to 1800 MW of wind. While the extent to which this power would be available to the other Maritime provinces or to Maine is as yet undetermined, the projects carry the possibility of reducing ME/CAN dependence on fossil resources further.

These data suggest that a ME/CAN market would have a relatively high degree of diversity in fuel mix, thus providing a hedge against volatility in the prices of any particular fuel. Hydro, nuclear, wind, coal, and other fossil fuels are relatively (and in most cases almost completely) independent of one another in terms of production cost. With the level of diversity that a ME/CAN market would likely reflect, it appears that during most hours it would be possible to produce all the energy needed to meet load even if one fuel source were entirely removed. While the loss of an entire category of resource would likely raise important reliability and market power issues, the ability of the remaining resources to continue to support the load is likely to minimize the impact of a spike in the cost of any one fuel source on the wholesale price available to the system.[80]

3. <u>The level of reserves for which Maine consumers in ME/CAN would be responsible would be lower than those required of Maine as a stand alone entity.</u>

As noted by NB Power, NPCC reliability criteria require 10-minute reserve for the first contingency (650 MW based on the loss of Point Lepreau) and 30-minute reserve for ½ the second contingency (460 MW based on Belledune); this requires a reserve of 880 MW. The reserves required for Maine

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[80] While generation ownership in Maine is relatively fragmented, ownership in the Maritime provinces is concentrated, with New Brunswick Power owning virtually all the generation in New Brunswick (over 4000 MW) and Nova Scotia Power all the generation in that province (over 2000 MW). Such concentrations rule out, unless and until the generation in those provinces is divided into sufficiently small ownership shares, the implementation of a fully competitive, bid-based clearing price market such as exists in New England. This characteristic alone does not, however, suggest that ME/CAN could not operate as an integrated market. There are many areas in the country where vertically integrated utilities operate within markets. Moreover, the restructuring of the markets in the Maritimes provinces, and in particular New Brunswick, is still evolving, so any conclusions about the opportunities for the exercise of market power are necessarily preliminary. It does mean, however, that to the extent one of the purposes of organizing a market is to bring competitive forces to bear on generation, those forces are likely to be blunted by the fact that, as a practical matter, the prices available within the market will be to a significant degree governed by regulation.

standing alone have been estimated at a total of about 760 MW.[81] Assuming sufficient interchange capability (which should exist once the second tie line between Maine and New Brunswick becomes operational), the reserves required for the combined system would be about 908 (as the second contingency becomes the Calpine Westbrook plant at 516 MW), resulting in a modest increase over those required for Maine alone – but at a lower cost than for Maine alone, because there would be more customers over whom to spread the cost. For similar reasons, there would likely be a lower cost of satisfying that NPCC requirement in ME/CAN than in New Brunswick alone, due both to the presence of more available resources and the fact that the cost of supplying the reserves for ME/CAN could be spread over all the ME/CAN participants.

4. Transmission capability in ME/CAN appears adequate to ensure that few constraints would be experienced within the system once the new tie line is in operation

Closely related to the question of adequate supply for a new configuration is the question of the extent to which the electricity generated by that supply can move freely within the area, and the extent to which congestion is likely to emerge.

The transfer capability relative to New Brunswick (as reported by NB Power) is set forth in the table below:

Table VII

Neighboring System	Transfer Capability to NB	Transfer Capability from NB
Quebec	1185	735
New England (incl. Southern Maine	100	700
Nova Scotia	350	300
Prince Edward Island	124	222
Northern Maine	90	100
Eastern Maine	15	15

NB Power observes that, with the addition of the planned 345 KV line between Maine and New Brunswick at the end of 2007, the transfer capability from New Brunswick to Maine (i.e. the current NE system) would increase to 1000 MW, and the capability from Maine to New Brunswick would (in a preliminary view) increase to 400 MW.

With the addition of the planned 345 KV line spanning Maine and New Brunswick, it appears that, as a practical matter, there will be little or no congestion between Maine and New Brunswick, or within Maine or New

[81] *See,* section II(A)(3)(b).

Brunswick, within a ME/CAN system. NB Power reported that it does expect, barring additional infrastructure development, periodic congestion in the interface between Nova Scotia and New Brunswick and between New Brunswick and New England.

5. Plans for increasing generation in the Atlantic provinces may provide a basis for closer structural ties between Maine and the Maritimes provinces

As observed earlier, the governments of both New Brunswick and Newfoundland and Labrador have publicly announced an interest in developing significant new generation resources. For example, the government of Newfoundland and Labrador is currently considering major additions to its electricity capacity in the form of as much as an additional 4500 MW of hydro (the Lower Churchill Falls project, with a projected in-service date of 2015) and 1500-1800 MW of wind and also is actively considering creating a new path out of Newfoundland and Labrador for its electricity (i.e., a path that does not go through Quebec), a path that would almost certainly run through, or at least to, Nova Scotia and/or New Brunswick. The government of New Brunswick has also indicated an interest in developing its energy infrastructure, including the additional development of renewable resources and increase electricity production fueled, in part, by the new liquefied natural gas facility being developed in the province.

The value of these initiatives in the Atlantic provinces is unlikely to be realized fully if the energy produced cannot find major markets. Because Maine is located directly in the path between the new generation and the major population centers of New England, the provinces are likely to have a keen interest in establishing a relationship with Maine that will facilitate such trades.

It thus may be that this is an especially propitious time to explore how the relationship between Maine and the Maritime provinces can be enhanced to achieve benefits for all involved. Separating Maine from New England and establishing a market organization with the Maritime provinces is only one of the alternatives to be considered: others include a reduction in “seams” between Maine and New Brunswick, and developing bilateral agreements designed to increase Maine’s access to lower cost generation while encouraging additional infrastructure to move power through Maine to southern New England.

B. The Formation of a Maine ITC

As discussed in sections II and III, *infra.*, Maine may be able to reduce the amount of upgrade costs paid for projects in other regions if CMP and BHE withdraw before 2010 to form an ITC. The formation of an ITC also increases Maine’s ability to determine its own future while removing disincentives for investment in generation and transmission resources in Maine and will thus allow Maine to help meet the energy needs of the New England states.

In the coming months, the Commission will explore with CMP and BHE the possible formation of a Maine ITC. The exact form and structure of such an organization is beyond the scope of this report, but the following fundamental characteristics would be part of any proposal.

First, as its name suggests, an ITC would be an entity that owns only transmission assets. It thus would not own either generation or distribution assets. Second, the ITC, unlike ISO-NE, would be a for-profit entity. Third, its entire focus would likely be on the identification of transmission needs and construction of needed transmission projects, together with the operation of the transmission system.

FERC has indicated support for the creation of Independent Transmission Companies (also called "Transcos"). In Order 2000, FERC stated that it would consider a Transco as an RTO as long as the RTO meets the minimum characteristics and functions required by *Order 2000.*[82] In 2001, FERC approved the establishment of a for-profit transmission company that operates under an RTO umbrella.[83]

Recently, in Order 679, "Promoting Transmission Investment through Pricing Reform," FERC found that utilities that form a Transco[84] are eligible for an incentive return on equity ("ROE")[85] as well as other incentives. In finding that Transcos should be eligible for the higher ROE, FERC praised the "proven and encouraging track record of Transco investment in transmission infrastructure."[86]

Finally, FERC's approval of ISO-NE as the RTO for New England includes approval of a framework through which any of the New England Transmission Owners may form an ITC, approved by FERC, and negotiate an ITC agreement with ISO-NE to determine the division of functions and obligations between the two entities.[87]

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[82] Order 2000, 65 Fed. Reg. 809.

[83] *See*, *International Transmission Company,* 97 FERC ¶ 61,928 (2001).

[84] The rule defines a Transco as "a stand-alone transmission company that has been approved by the Commission and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility." 18.C.F.R. § 35.35(b)(1)

[85] This means that the ITC is eligible for an ROE at the upper end of the zone of reasonableness for its transmission investments.

[86] Order 679 "Promoting Transmission Investment Through pricing Reform," 116 FERC ¶ 61,057, P. 222 (2006).

[87] The framework for the process for transitioning to an ITC and the agreement between the Transmission Owner and ISO are set forth in Attachment M to the ISO-NE OATT.

The cost recovery mechanisms for a Maine ITC will be considered in the next stage of our inquiry. One possible approach would be for the Maine ITC to recover the costs of new transmission investment through reservations or through other contractual arrangements. The extent to which such arrangements may create seams, and whether there are ways to reduce concerns about seams creation, will also be considered.

C. Working within the Existing Framework to Change the Current Inequitable Transmission Cost Allocation Methodology

On Monday January 8, 2007, the New England Conference of Public Utilities ("NECPUC") unanimously agreed to a resolution that committed the NECPUC staff energy policy group to study the pros and cons of transmission cost allocation alternatives that, among other things would, (1) provide incentives for siting transmission in resource states, and (2) identify beneficiaries of proposed transmission upgrades. The NECPUC energy policy staff will prepare a report analyzing these issues by June 1, 2007 for consideration by NECPUC at the summer NECPUC meeting.

This initiative is the first step, on a New England-wide basis, in fixing the inequities in the current cost allocation scheme and in providing the right incentives for siting generation and transmission resources in Maine. As part of the NECPUC study, the Commission staff will be exploring “beneficiary pays” transmission cost allocation methodologies that have been approved in other control areas. The Commission is committed to allocating the resources necessary to work with the other state commissions, market participants, ISO-NE and FERC staff to develop a transmission cost allocation alternative that has the potential, not only to reduce the transmission costs that would otherwise be imposed on Maine ratepayers, with little benefit in return, but also to provide incentives to encourage the development of new generation and transmission resources that can help meet the region’s energy needs.

V. INTERIM REPORT CONCLUSIONS AND ISSUES FOR FURTHER DEVELOPMENT IN THE FINAL REPORT

The current transmission cost allocation and pricing mechanisms under the current ISO-NE structure are inequitable and need to be remedied. Without ruling out any particular recommendation concerning how Maine's electricity market should align with its neighbors, there are some areas which, based on the analysis done in preparing the Interim Report, appear more promising to address these issues and where, in the view of the Commission, the Final Report is most likely to focus. There are also structures which, based on our preliminary assessment, are less promising and as to which the Commission does not, absent further direction from the Legislature, intend to examine further.

The structures that appear to have promise, or at least warrant significant further inquiry, include:

1. Developing a market with one or more of the Maritime provinces (New Brunswick, Nova Scotia, and Prince Edward Island) as an alternative to the current association with the New England market (i.e. ME/CAN). While many issues would need to be resolved before any such combination could be implemented, including a careful assessment of the costs and benefits, there appear to be no insurmountable legal or political obstacles to such a combination, and the relative sizes and existing electricity infrastructures are sufficiently complementary to warrant closer examination. As a variation on this approach, the prospects should be examined for developing bilateral or multi-lateral agreements between Maine and one or more of the Maritime provinces to facilitate electricity trade and achieve complementary objectives (e.g. finding a "home" for increased production, hedging against fossil fuel price increases or volatility) within the current market structure. The particular issues that will be explored in greater depth with respect to this area include:

a. Would such an organization, and the transactions undertaken within it, be subject to NAFTA, and if so in what way?

b. What Canadian, provincial, Maine and U.S. approvals would be required? Would a DOE export license be required? What would a new entity be required to show to satisfy the FERC open access rules?

c. How would conflicts between, and among, market participants be resolved? How could enforcement authority be established? Do the mechanisms in place between MISO and Manitoba (or any similar arrangements) provide a useful guide?

d. By what process should any new structure be developed? Should any new organization be entirely voluntary? What are the implications of the non-participation of some entities within the area encompassed by any new structure?

e. What implications are there for possible changes in U.S. federal regulation concerning the requirements of open access and/or the implications of trading with RTOs? In particular, is it likely that FERC policy on the removal of inter-system seams would impact significantly the economics of developing a separate structure?

f. What estimates can be developed concerning the likely costs of transmission, energy and the administration of any new structure, both in relative and absolute terms, and what degree of confidence should the Legislature have in any such estimates? Are there implications in forming such a structure for changing the existing or expected investment and operational patterns in Maine for generation?

2. Withdrawal of Maine's utilities from the New England ISO without creating a new inter-jurisdictional market structure. The form this might take, suggested by the recent filing of the "Green Line" proposal by the New England Independent Transmission Company, could be a statewide independent transmission company (ITC) that would own the transmission assets of all of Maine's utilities. Such an entity would develop its own transmission tariff, while market and reliability functions might be performed by a new entity, or be purchased under contract from the NMISA, New Brunswick or the New England ISO. In assessing this opportunity, the Commission's analysis will include:

a. Would an ITC structure permit more rapid withdrawal from the New England ISO (i.e. prior to 2010), and if so the extent to which burdens currently incurred as a result of membership would be avoided?

b. What are the cost implications, for energy as well as transmission, of this approach? This would include an assessment of the cost of contracting for, or performing, reliability and dispatch functions now performed by ISO-NE.

c. If the ITC approach does not defer, or even accelerates, the ability of additional energy to flow out of Maine (or through Maine from the Maritimes), what are the implications for Maine's energy costs, and are any incremental increases offset by other savings (e.g. in avoiding New England capacity or transmission allocations)?

3. Working within the current ISO-NE institutional framework to correct the transmission and generation and pricing inequities so that such prices more closely follow costs. This work will include working with the other New England commissions in NECPUC and with the New England Governor's Conference.

The structures that do not appear sufficiently promising to pursue as recommendations are:

a. Isolating Maine completely from other electricity markets (creating an "island"). Our analysis and the comments persuade us that such isolation would be unlikely to be permitted by federal authorities – the ability to trade with relative freedom across state boundaries is an imperative of federal law under the Energy Policy Act. Moreover, while there might be advantages with respect to transmission costs of such isolation (because Maine would not need to share in the costs incurred outside of Maine), standing alone Maine would likely suffer decreasing energy reserve margins, risk a lower degree of reliability, and lose the market and diversity benefits of a larger system. Indeed, a decision to isolate Maine, even if allowed, would likely risk a reduction in investment in supply, so that Maine's current surplus could prove transitory.

b. Seeking to combine with Canadian provinces other than New Brunswick, Nova Scotia and Prince Edward Island. In particular, while preserving and enhancing trading opportunities with the provinces of Quebec and/or Newfoundland & Labrador is an important objective under any configuration, combining Maine into a more closely knit market with either or both is likely to be impractical. Quebec in particular, due to its size alone, would likely dominate any such market, and, beyond that, has a very different regulatory approach to both markets and the use of transmission. Moreover, neither province has significant direct electrical links to Maine.

c. Aligning Maine with other states in northern New England to form a new multi-state RTO. Although Maine shares some common issues with New Hampshire and Vermont (all are small relative to the rest of New England, all have similar climates), and adding states to a new market would not raise the difficult international contract and jurisdiction issues raised in joining with Canadian provinces, there are significant hurdles to joining the "northern tier," as an RTO. These include the absence of east-west transmission, differing market and ownership structures, and the significant differences in regulatory approach. These factors suggest that such an alignment might make better sense as an adjunct to, rather than a substitute for, ME/CAN, and for that reason the Final Report will focus on the opportunities with the Maritime provinces.