



A Maine/Canadian Regional Transmission Organization

Advantages and Disadvantages

Prepared for the Maine Public Utilities Commission

By

Frederick Woodruff
Arthur W. Adelberg
Waine P. Whittier

Energy Advisors, LLC

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1.0 Executive Summary

Over the past several years, the federal government has been pursuing a policy of introducing competition into the market for electricity. Early efforts focused on allowing non-regulated entities to develop and operate power plants, and on requiring regulated utilities to allow those entities and others to use their transmission systems on a non-discriminatory basis. These undertakings brought numerous non-regulated suppliers into the market, and dramatically increased the volume of wholesale power transactions.

More recently, the government has concluded that more sweeping changes are needed to bring about the full benefits of competition. To ensure totally neutral operation of the grid, the government has directed utilities to cede control of their transmission facilities to entities with no financial ties to any participant in the power market. In addition, to facilitate energy trading over large areas, the government has promoted formation of large, regional transmission organizations, as well as standardization of rules for transmitting and trading power within and between regions. In the Northeast, in particular, the government has been encouraging consolidation of the operation of the power market represented by the New England states with that of New York, and possibly the Mid-Atlantic States.

Maine, like other states, has been carefully weighing the benefits and costs of participating in these changes. Unlike many other states, however, Maine borders a Canadian Province – New Brunswick - with an excess of low cost power. This has naturally led policymakers to consider whether Maine electric consumers might fare better if the State were, in effect, to combine its power market with New Brunswick rather than remain part of the consolidating Northeast U.S. market.

This study is an outgrowth of that consideration. In particular, early in 2002 the Maine legislature enacted a Resolve directing the Maine Public Utilities Commission (“MPUC”) to investigate and report back on the tradeoffs in having the state’s utilities form a regional transmission organization with utilities in Canada. The MPUC, in turn, retained Energy Advisors, LLC, a Portland-based consulting firm, in June 2002 to assist in the investigation by preparing this report.

While many factors affect the analysis, chief among them are the following:

- 1) Is New Brunswick likely to continue to have low cost power to export?
- 2) How much transmission capacity is likely to be available for those exports?
- 3) How will the emerging market rules affect the allocation of benefits from those exports between New Brunswick and Maine?
- 4) What are the effects of trade barriers resulting from multiple transmission tariffs between New Brunswick and Maine and how can they be removed?
- 5) Assuming buyers of New Brunswick’s exported power are likely to reap some of the benefits of its low cost, as a practical matter could Maine keep more of the benefits for its residents by exiting the New England Power Pool (“NEPOOL”) (and its successor organizations), and attempting to merge its market with New Brunswick? and

- 6) In any event, assuming that Maine made such an attempt, would New Brunswick be likely to cooperate?

The first issue turns in significant part on whether New Brunswick proceeds with plans to refurbish its Point Lepreau nuclear plant and to convert other plants from coal to Orimulsion, a low cost petroleum slurry product produced in Venezuela. Both of these plans depend on the success of New Brunswick's privatization efforts, which is very uncertain. In addition, the former suffered a major setback with a decision of the New Brunswick Public Utilities Board to recommend against proceeding with the Point Lepreau refurbishment due to the marginality of expected benefits.

Transmission remains an obstacle. Efforts have been ongoing for several years to add cross-border transmission capacity, but they have been stymied by environmental opposition and investor reluctance to commit the necessary funds. Proposed changes in regulation could help overcome these obstacles, chiefly by empowering entities that operate the grid to compel utilities to proceed with the transmission project, but the fate of those proposals, together with their efficacy if adopted, remain uncertain.

Multiple transmission tariffs between New Brunswick and Southern Maine¹ also present an obstacle. Both New Brunswick and Maine Electric Power Company charge for the transmission service they provide to the two regions. Removal of this economic barrier would lead to increased electricity purchases from New Brunswick. However, New Brunswick and Maine Electric Power Company would likely require some form of compensation to offset the loss of revenues. Reaching an agreement on the amount and duration of this compensation would be difficult.

Determining the effect of emerging market rules on the allocation of benefits of low cost New Brunswick power is very complex, and depends in some measure on quantitative analysis that is beyond the scope of this report. However, while it is possible to envision scenarios where there would be some net benefit resulting from combining the wholesale electric markets of Maine and New Brunswick, the benefit is likely to be small relative to existing power costs. In addition, increased reserve requirements in Southern Maine could offset any savings in lower power costs.

In comparison to Southern Maine, benefits in Northern Maine would likely be even smaller. Electric markets in Northern Maine and New Brunswick are already aligned, so there would be fewer opportunities for incremental benefits. Increased power sales by New Brunswick to New England could dilute the benefit Northern Maine currently receives from its relationship with the Province.

¹ Northern Maine and Southern Maine are electrically separate. The primary electrical interconnection between the two regions is through New Brunswick. The Northern Maine electric market is predominately located in Aroostook County and is served mostly by Maine Public Service Company and Eastern Maine Electric Cooperative. The Southern Maine electric market is predominately made up of the service territories of Bangor Hydro Electric Company and Central Maine Power Company.

Maine’s ability to keep more benefits for itself by exiting NEPOOL or its successor organizations has always been doubtful, and has become even more so in light of very recent developments. The Federal Energy Regulatory Commission (“FERC”) has had a clear policy favoring larger electricity trading areas and, in furtherance of that policy, could probably exercise its authority to prevent Maine utilities from leaving NEPOOL. Within the past few months, the FERC proposed a new regulation that would obviate the possible benefit for entities such as the Maine utilities of joining a different trading area by requiring the elimination of “seams”, *i.e.*, inter-area trading barriers. Also, New Brunswick (which is not subject to FERC regulation) recently entered into an agreement with the operator of the New England grid to pursue elimination of those barriers on a voluntary basis.

Finally, it must not be forgotten that any scheme to create an exclusive market with New Brunswick would require New Brunswick’s cooperation. New Brunswick has been more cautious about deregulating its power market, and would require assurances that any consolidation of its market with that of Maine would not jeopardize its continued control of the pace of regulatory change within the Province or its ability to continue to benefit by exporting surplus power to Southern New England.

In sum, Maine is caught up in a rapidly changing marketplace, making it difficult to assess with certainty the overall advantage of attempting to align its energy market with New Brunswick rather than New England. On balance, there does not appear to be strong reason to try to shift from association with NEPOOL/New England to association with New Brunswick/Canada, because (a) it is not clear there would be benefits, and (b) it is not clear that it is possible, in light of legal and regulatory obstacles. The better course is to continue working to improve Northeast markets while at the same time increasing opportunities for trade with New Brunswick and others to the north.

* * * * *

The remainder of this Report consists of five chapters. Chapter 2 consists of an introduction. Chapter 3 describes the status quo with respect to northeastern markets. Chapter 4 sets forth the legal and regulatory issues associated with forming a Maine/New Brunswick pool. Finally, Chapter 5 provides the assessment of advantages and disadvantages. Readers principally interested in the conclusions may wish to skip Chapters 2 through 4, which mainly provide context for Chapter 5.

2.0 Introduction

In 2002, the Maine Legislature enacted a resolution requiring the Maine Public Utilities Commission to study the advantages and disadvantages of Maine's electric utilities, including those in Northern Maine, joining a regional transmission organization that includes portions of Canada.² The resolution noted that the electric industry is in the process of comprehensive restructuring and that important decisions are being made with respect to the structure of the industry. Joining with electric systems and markets in Canada could be an alternative to the restructuring process currently taking place in the Northeast. The purpose of this report is to describe the changes that are taking place in the wholesale electric markets of the Northeast and to provide a qualitative evaluation of the advantages and disadvantages of combining the electric transmission systems and wholesale markets of Maine and portions of Canada.

The electric industry restructuring initiative started in the early 1990s. The Energy Policy Act of 1992 empowered FERC to compel utilities to provide transmission service to third parties and non-utility generators. On April 24, 1996, FERC issued its watershed Order 888. FERC was concerned that discrimination in the provision of transmission services by vertically integrated utilities that provided both transmission and generation services was impeding the development of competitive electricity markets. FERC's goal in issuing Order 888 was for electric utilities to open their transmission systems to competitors. The order required utilities to provide transmission access on a fair and non-discriminatory basis and to separate generation from transmission and distribution functions, and it ordered tight power pools, like NEPOOL, to reform their agreements to ensure an open market with fair and non-discriminatory access to transmission. One of the ways FERC suggested this reformation could be accomplished was through the establishment of an independent system operator ("ISO"). An ISO would administer a non-discriminatory open access transmission tariff and operate the transmission system. According to FERC, an ISO would be independent of market participants and would have no economic interest in any of the market participants.

On December 30, 1996, in response to FERC Order 888, NEPOOL filed a request for FERC approval of a comprehensive restructuring of the NEPOOL Agreement.³ The filing included a new open access transmission tariff, a proposal to form a New England Independent System Operator ("ISO-NE"), and a proposal for a new competitive bid-based wholesale electricity market. ISO-NE started operation and assumed responsibility for operation of the NEPOOL bulk power system on July 1, 1997.⁴ The new bid-based market system started on May 1, 1999.

² Maine State Legislature Resolve, Regarding Participation in Regional Transmission Organization, Resolves, ch.81, 2002.

³ The agreement amending the NEPOOL Agreement was called the Thirty Third Agreement Amending the New England Power Pool Agreement or the Thirty-Third Agreement.

⁴ Prior to July 1, 1997, NEPEX was responsible for operating the NEPOOL bulk power system including both transmission and generation. NEPEX operated under the direction of the electric utilities that comprised NEPOOL.

However, FERC was not satisfied that Order 888 had completely met its goal of creating non-discriminatory competitive wholesale electric markets. Therefore, on December 20, 1999, FERC issued Order 2000 encouraging electric utilities to join together in forming regional transmission organizations (“RTO” or “RTOs”). RTOs would have the sole responsibility for the design and administration of the transmission tariff, the planning and operation of the combined transmission system and maintaining short-term reliability. FERC also outlined a set of minimum characteristics and functions it deemed necessary for RTOs. The minimum characteristics included independence, scope and regional configuration, operational authority, and short-term reliability. The minimum functions included tariff administration and design, congestion management, management of parallel path flow, provision of ancillary services, market monitoring, planning and expansion, and interregional coordination. ISO-NE and NEPOOL embodied most of these functions and characteristics. Consequently ISO-NE and six of the region’s largest electric utilities petitioned FERC proposing a New England RTO and asking FERC to declare that it met the stated requirements of Order 2000.

In an order dated July 12, 2001, FERC found that “the proposed scope and regional configuration (of the proposed New England RTO) would be insufficient to permit the RTO to effectively perform its required functions and support competitive markets” and rejected the New England RTO proposal.⁵ In a related order on the same day, FERC concluded that “it is necessary that the three independent system operators in the Northeastern United States combine to form one Regional Transmission Organization.”^{6,7} The three RTOs were ordered to participate in mediation with the goal of combining the regions represented by the three ISOs into a single RTO. The mediation took place, but to date has not resulted in FERC’s desired outcome.

Subsequently, FERC initiated an investigation into how conformity of market design could enhance market efficiency. On July 13, 2002, FERC issued its Notice of Proposed Rulemaking (“NOPR”) regarding standard market design (“SMD”).⁸ The FERC SMD proposal contains three elements that, if implemented together, could obviate the need for large RTOs. First, FERC has proposed the concept of the Independent Transmission Provider (“ITP”). An ITP would perform many of the functions of an RTO, but on a smaller scale. Individual utilities could become ITPs. Second, FERC proposed a new form of transmission service called Network Access Service. Under Network Access Service, only customers taking power off the system would pay for transmission service, no matter where the transaction originates. And finally, FERC proposed that all wholesale markets be

⁵ FERC Order Granting, in part, and Denying in Part, Petition for Declaratory Order, Docket No. RT01-86-000, July 12, 2001, page 2.

⁶ FERC Order Initiating Mediation, Docket No. RT01-99-000, July 12, 2001, page 1.

⁷ The three ISOs are ISO-NE, the New York ISO (NYISO) and PJM. PJM includes Pennsylvania, New Jersey, Maryland, Delaware, West Virginia and the District of Columbia.

⁸ FERC Notice of Proposed Rulemaking, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Docket No. RM01-12-000.

based on a common market design, thus eliminating barriers to trade resulting from market inconsistencies. Taken together, these elements would achieve most of the benefits that would result from formation of large RTOs. This and other indications from FERC make it unclear whether or not FERC still believes that the three independent system operators in the Northeast should combine into a single RTO. FERC intends to issue a white paper on its proposed SMD in April of 2003. The FERC SMD, and other related orders, are the subjects of significant debate and controversy. The results of which will play out over the coming years, thus leaving a period of uncertainty regarding the structure of wholesale power markets.

Wholesale markets in the United States are continuing to evolve and the outcome will affect Maine's electricity consumers. The cost of electricity and the stability of electricity prices in Maine will ride on decisions about the structure of wholesale electric markets in the region. Eastern Canada is a close neighbor and currently has surplus electricity that could help keep electricity costs in Maine down. Thus, if New Brunswick's current surplus continues, leaving NEPOOL and joining with Canada could enhance Maine's ability to benefit from Canadian electricity. On the other hand, abandoning the NEPOOL market and joining with Canada could be a complex and costly process. This report will examine the advantages and disadvantages of such a plan for Maine consumers and will describe the steps that would have to be executed in order to implement this plan, including the legal and regulatory requirements of exiting the New England market and establishing a very close relationship with Canadian electricity markets.

3.0 Existing and Proposed RTO/Market Structures – Status Quo

In order to provide a basis for evaluating the advantages and disadvantages of a Maine/New Brunswick RTO as compared to the current system, this section will provide an overview of the current situation in New England and New Brunswick with respect to wholesale markets and regional transmission organizations. The current market structures in Southern Maine, Northern Maine, and New Brunswick are at different stages of an evolutionary process. The current status of each market will be described, as will be recent events that could change the future structure of these markets. However, in order to help understand how these various market configurations can impact retail customers, a summary of the major attributes and functions of wholesale electricity and transmission markets is provided first.

3.1 Summary of Major RTO and Market Attributes That Affect Retail Customers

Wholesale electricity markets and the associated transmission organizations are highly complex structures that affect retail electricity price in many different and sometimes incongruous ways. Before proceeding to describe the existing and potential market and RTO structures, the purpose of this section is to identify and explain those attributes of wholesale electricity markets and transmission organizations. They include:

- System Infrastructure (Generation and transmission facilities)
- Wholesale Market Structure (Including transmission tariffs)
- Inter-regional Barriers (Seams)
- Mechanisms for Planning and Expanding Physical Infrastructure
- Market Power
- Governance
- Operational Infrastructure (Control center, personnel, software, etc.)

System Infrastructure

The physical characteristics of the generation and transmission system have the greatest impact on the price of electricity and the reliability of supply. In a competitive marketplace like New England, the market-clearing price of electricity is affected by the fuel price and efficiency of the most expensive generating unit running. Each generator bids the price at which it is willing to supply electricity. In an efficient market, generators will bid a price based on their incremental cost of supply, or the cost of fuel divided by the efficiency of the generator plus any variable operations and maintenance costs. For any given load, the system operator will dispatch the lowest price set of generation to meet that load and the price of the highest bid generator operating will set the market-clearing price. The market-clearing price is the price at which all spot purchases and sales transact. Therefore, wholesale electricity prices are a function of the efficiency of and fuel used by the marginal generation in a region. The marginal generator, and hence the market-clearing price, vary from hour to hour. Changes in load, generator outages and changes in fuel costs affect the market-clearing price in a region. Market-clearing prices increase when load increases, when lower cost generators are out of service and when fuel prices increase.

A region with very efficient resources that use low cost fuels will tend to have low wholesale electricity prices. A region that uses a fuel with relatively stable prices tends to have stable wholesale electricity prices. For example, if coal is on the margin, then prices will follow coal prices. Or, if a region has a significant amount of gas fired generation that is on the margin, then the wholesale price of electricity in the region will tend to follow natural gas prices. This applies to both price level and volatility.

At the bulk power supply level, system reliability is primarily a function of generation mix, load and the reliability criteria. (Of course, the transmission system affects reliability, but to a much lesser degree at the bulk power level that is at issue in this report.) A system comprising a small number of relatively large units is inherently less reliable than a similarly sized system with many small units and a larger system is more reliable than a smaller one. However, most utilities have reliability criteria that compensate for generator size and load uncertainty by requiring an amount of generating capacity in excess of the expected system load. This excess is sometimes referred to as installed reserve. The net result is that for a given reliability criterion, a system comprised of large units requires a greater amount of generating capacity to meet the criterion than a system of the same size comprised of small generating units. Also, systems with greater loads require less excess generating capacity as a percent of load. A corollary to these relationships is that the reliability criteria of a region will affect the price of electricity by virtue of their impact on the total amount of generation in the region, *i.e.*, a reliability criterion that requires higher installed reserves will tend to be more costly than one with lower installed reserve requirements. Most utilities in the Northeast subscribe to the same reliability criterion that requires the system be designed such that the probability of insufficient generation to meet load is one day in ten years. However, the implementation of this criterion and the amount of installed reserve varies from region to region.

The ownership distribution of the generation can also be important. If there are only a few entities that own and control the generating units in a region, there is the possibility that they may exercise market power and unfairly raise prices. To some extent this can be remedied by the market monitoring and mitigation procedures in place in the region.

The regional transmission system is a second infrastructure component that influences wholesale electricity prices. For example, congestion on the transmission system increases the cost of electricity. Transmission congestion occurs when a portion of the transmission system is overloaded. In selecting generators for dispatch, ISO-NE is careful to honor predefined limits on the amount of electricity that can flow over certain transmission lines. If these limits are not observed, transmission lines can become overloaded or the reliability of the system can be jeopardized. The point on the system where a specific limit applies is called a transmission interface. When a transmission interface becomes overused, or “congested,” ISO-NE has to alter what would otherwise be the lowest cost generator dispatch in order to accommodate the transmission limit. In particular, ISO-NE must curtail the operation of low cost generation located on the upstream, or unconstrained side, of the constraint and dispatch more expensive generation located on the downstream, or constrained, side of the transmission constraint. The price

increases resulting from congestion are currently distributed to market participants according to the regional market rules. Transmission congestion can also create or exacerbate market power problems by creating smaller markets.

Transmission links, or ties to adjacent regions, are the last component of infrastructure that can significantly affect regional electricity prices and reliability. Reliability improves in a region if it can call on neighboring regions for assistance during times when it has insufficient generation available to meet customers' demand for electricity. The amount of improvement depends on the characteristics of the adjacent region, the capacity of the ties with that region and the nature of the emergency assistance agreements. Regional reliability criteria take these into account when setting reserve requirements. Therefore, improving the transmission ties with an adjacent region has the effect of lowering cost by lowering reserve requirements. This reduction in cost can be partially or completely offset, depending on the cost of the new transmission and how and to whom the costs are allocated.

Transmission ties also reduce prices by allowing electricity from a low price region to flow to a higher price region. Of course, larger ties mean greater potential for interchange and overall price reductions. However, the structure of the markets in each region and the nature of the interconnection arrangements affect the overall amount of potential cost saving achieved. They also determine who gets the savings.

Wholesale Market Structure - Including Transmission Tariffs

The primary objective of wholesale electric markets is to operate the system to efficiently utilize generating resources while maintaining system reliability. Market systems can be cost-based or competitive. NEPOOL has operated as a competitive or auction based market since May 1, 1999.⁹ In an efficient competitive market with limited market power, generators will tend to bid a price that is equivalent to the incremental cost it will incur if called on to run.¹⁰ Because most sellers receive more than their bid price, they have the opportunity to recover their capital cost and are encouraged to build new generation as the need and price increases.

Regulated, or cost-based, markets dispatch their generators to minimize cost. The units with the lowest fuel cost are dispatched to meet customers' electricity requirements. The regulated generator is paid both its fuel cost and an amount to compensate it for

⁹ NEPOOL, or the New England Power Pool, is a voluntary organization of electric market participants in New England. Prior to the restructuring of the wholesale markets in New England, NEPOOL was primarily controlled by the T&D utilities in the region. They decided on market rules and the transmission tariff for Pool Transmission Facilities. These rules and tariffs were regulated by FERC. NEPOOL also provided for a system operator which was under NEPOOL's control.

¹⁰ If a generator bids a price higher than its incremental cost, it might not be called on to run and would miss an opportunity to earn the difference between the market-clearing price and its incremental cost. If a generator bids a price lower than its incremental cost, there is a chance that it would be called on to run during a period when the market-clearing price is less than its cost and it would lose money on the transaction.

investing the capital to build the generation. New England used to operate as a cost-based system. New Brunswick still does, but is considering restructuring its market.

As mentioned earlier, transmission congestion can increase electric energy prices by preventing the lowest priced generators from operating. Market design can have a profound impact on the “allocation” of these congestion costs. For example, current NEPOOL rules allocate congestion costs across all users of the system in proportion to their use. This system is called uplift. (The uplift mechanism is also used to allocate other costs.) That means that someone located away from the transmission congestion would pay a part of the cost. Locational Marginal Pricing, or LMP, is an alternative market design that will be implemented by ISO-NE in early 2003. Under LMP, congestion costs are charged to electricity purchasers in the region experiencing congestion. Under this system, there is no change in the rules for dispatching generators. The difference between the two market designs lies in the pricing mechanism. Instead of having a single market-clearing price and allocating congestion costs, each region has its own market-clearing price, or LMP, that is based on the highest bid price of the generating units operating in that region. All buyers and sellers receive and pay the LMP corresponding to the region in which they are located. The LMP on the up-stream side of a transmission constraint would be lower than the LMP on the down-stream side. In this manner, customers on the downstream side of a transmission constraint pay the congestion charges. In the example above, Maine would experience lower prices and would not have to pay any congestion related uplift charges. Customers in congested areas in Southern New England would pay the higher price, in effect paying the congestion costs.

LMP market designs often incorporate a system of financial or fixed transmission rights (“FTR” or “FTRs”). FTRs give their owners the right to collect the congestion costs (or revenue, as it is sometimes called) which are paid by customers located downstream from a transmission constraint. FTRs are transmission path-specific and directional. That is, an FTR owner may only collect congestion revenue if and to the extent that the corresponding transmission path experienced congestion. FTRs are tradable. Because FTR revenue is related to congestion costs, they can be used as an effective hedge against uncertainty about the level of congestion and the associated cost. The LMP system NEPOOL is currently implementing incorporates FTRs.

One of the benefits of a system of locational marginal pricing is that regional price differentials resulting from transmission constraints provide economic incentives to build new facilities to relieve the constraints. The alternatives for relieving congestion include additional transmission capacity, generation in the constrained region, and voluntary curtailment by customers in response to economic signals (load response) or other conservation measures.

Another important facet of wholesale markets is the manner in which they ensure that the reliability standards are met. For the bulk generating system, reliability criteria are usually implemented through the two mechanisms of installed and operating reserves. Installed reserves represent additional generating capacity installed and ready to operate.

Installed reserves provide backup for outages of other generators and additional capacity if the load is greater than expected.

Operating reserves are intended to provide energy on relatively short notice. Operating reserves requirements are usually designed to have a specific amount of generating capacity capable of supplying energy within ten minutes and another amount within thirty minutes. Providing operating reserves often increases the cost of operating the system since less expensive generation is kept ready but does not generate. Therefore higher priced generation must be dispatched. In competitive markets, operating reserves may be traded and their value is based on the cost of providing the reserves, including the opportunity cost of not generating.

Wholesale markets must provide for numerous other products and services including automatic generation control, dispatch services, and voltage support. Although these are all necessary to the operation of a wholesale power market, they do not have a significant impact on the analysis of alternative market/RTO designs that follows.

The last significant attribute of wholesale electric markets is the design of the transmission tariff. With the exception of merchant transmission, which is a relatively new concept and has not been implemented to any significant degree, transmission tariffs are designed to recover the full cost of owning and operating the facilities. (In other words, no matter what the tariff design, end use customers will pay the full cost of the transmission system.) The fundamental issue for this analysis is less one of overall cost and cost recovery than the mechanism of cost recovery. Specifically, tariff designs can impose incremental costs on transactions or not. To the extent that they do impose incremental costs, they impede trade and therefore increase overall costs. For example, NEPOOL charges Out-Service for transmitting electricity from NEPOOL to an adjacent region. Any transaction from NEPOOL to an adjacent region pays an incremental transmission cost based on the amount of transmission reserved. However, transactions within NEPOOL are included in Regional Network Service. The charges for Regional Network Service are based on load and not on the size of the transaction. Hence, Regional Network Service does not involve incremental transmission costs.

At one end of the spectrum is a tariff design called “pancaking.” Under this system, a transmission user pays for transmission in each intervening region along the path of the transaction. (Regions can be power pools, individual utility systems and even portions of individual utility systems.) The more regions the transaction crosses, the higher the transaction cost due to additional transmission charges. The net result is that “pancaking” increases incremental transaction costs and inhibits trading between tariff regions. Tariff designs that do not include “pancaking” have lower incremental transaction costs and encourage trading. Increased inter-regional trading reduces overall cost since lower cost resources can replace higher cost generation in other regions.

Inter-Regional Barriers – Seams

Overall, the ability to buy and sell electricity between regions is beneficial.¹¹ Regions with lower cost resources can sell to higher cost regions, thus lowering overall costs. Mutual assistance arrangements can help lower reserve requirements. And, the increased availability of resources reduces the potential for exercise of market power. However, the ability to transact between regions can be impeded by physical, institutional, regulatory and legal barriers.

Transmission links between regions are a fundamental ingredient necessary for inter-regional transactions. The transmission capacity between New England and each of its neighbors (New York, Quebec and New Brunswick) is limited. These barriers can place significant limits on the ability to transact between regions and hence can affect the balance of advantages and disadvantages of various wholesale and transmission market alternatives under consideration in this analysis.

Institutional barriers such as inconsistent market rules and transmission tariffs are also serious impediments to inter-regional trade. These are often referred to as “seams issues.”¹² Market rules, product definitions and operational /scheduling procedures often vary from region to region. For example, regions often have different notice and scheduling requirements for transactions. To the extent these requirements are inconsistent or contradictory, they are nearly as effective a barrier to trade as any physical limitations of the transmission system. The opportunity for economic trade is further thwarted if the two regions are not dispatched as a single entity, which is often the case. Single system dispatch allows the system operators to optimize the entire system on a real-time basis. Lastly, inter-regional transmission charges represent an economic barrier to trade. The extent of the barrier is related to the level of the charge and the price differential between the regions.

One of the issues that frequently arises in discussions about resolving seams issues relating to pancaked transmission tariffs is revenue neutrality. A utility could lose revenue from transmission customers when layers of pancaking are removed, making it necessary for its native load customers to make up the difference. Utilities are reluctant to pursue this course unless some offset can be provided. In theory, the definition of this offset is straightforward. However, in practice it is often complicated, contentious and difficult to resolve.

Legal and regulatory requirements can also be a barrier to inter-regional electricity trade. In particular, this analysis examines the possibility of Maine forming an RTO with New Brunswick and/or other Canadian provinces. There are significant international trade

¹¹ While inter-regional trade is beneficial, the specifics of the arrangements determine how much the individual regions benefit. It may even be possible that one region may suffer from increased trade while the other benefits.

¹² Elimination or minimization of seams between regions has been identified by FERC as one of the more important factors in developing an efficient and competitive wholesale electricity market.

and national security issues that could interfere with the formation of such an organization. Jurisdictional issues between and among the various regulatory bodies involved in approving such an organization could also be an effective barrier.

Mechanisms for Planning and Expansion of Infrastructure

If physical infrastructure, *i.e.*, the generation and transmission system, has significant attributes affecting the economics and reliability of a system, then the mechanisms for planning, approving, implementing and paying for enhancements to that system are also important. In a competitive marketplace, prices provide the signals and incentives to add new generating facilities. Developers will invest capital to build new generation when they think that prices are at a level such that they will recover their investment and operating cost and there is opportunity to make a profit. The generation market in the Northeast has been restructured into a competitive market that seems to be working fairly well. Other areas, like New Brunswick, are still in the process of restructuring their generation markets.

Although there has been some movement toward providing market mechanisms for transmission additions in the northeastern United States, transmission planning and expansion is still primarily a regulated activity. However, the processes are not necessarily the same from region to region and, in fact, are even in a state of flux within regions.

The key questions involved in the issue include:

- How is the need for new transmission defined and who performs the analysis?
- Who decides when and what transmission additions are needed?
- Who approves new transmission and what is the basis for the approval?
- What authority is there to mandate construction?
- What incentives are needed to encourage new transmission?
- Who will own and operate the new transmission?
- Who will pay for the new transmission?
- Does the system provide appropriate opportunities and incentives to relieve congestion through lower cost, non-transmission alternatives, such as demand response?
- How can transmission planning be structured to ensure that it does not intervene with price signals to encourage load response and investment in generation or transmission?¹³

Market Power

Market power is defined as the ability of a market participant to increase market prices above competitive levels. Generally market power is exercised in electric markets by

¹³ Siting and environmental issues associated with transmission additions are also important issues, but are not within the scope of this report.

withholding¹⁴ economic generation from the market and thereby increasing the market-clearing price. Market participants can profit from this behavior if they have other generators that are being dispatched and therefore receive higher payments as a result of higher market-clearing prices. Market participants that own or control a significant portion of the available generating capacity have the greatest potential to profit from the exercise of their market power. Market power is minimized when markets are large and no single participant owns or controls a significant amount of the generation available in the region.

To some degree, market power can be controlled by providing independent market monitoring and effective mitigation measures. For example, economists have devised several methods for detecting when a participant is withholding generation from the market. These and other market monitoring techniques may be employed to detect the exercise of market power. Market power can be mitigated by administratively adjusting bids or in extreme circumstances by the levying of fines.

Governance

Who makes what decisions and the rules for making those decisions are key attributes of a regional electric system. The key attributes that affect the efficiency, economy and reliability of an electric system are listed below. Most of them were previously described in more detail.

- Market Rules
- Reliability Standards
- Transmission Tariffs
- Transmission Planning and Expansion
- Interconnection Standards
- Market Monitoring and Mitigation
- System Operator Budget

FERC has proclaimed that most of the decisions related to the issues listed above should be under the authority of an independent system operator. According to FERC, the independent system operator and its employees should have no ties to any market participant. Of course, the system operator must employ personnel with the requisite expertise to manage a power system. According to FERC, a knowledgeable system operator that is truly independent of the market stakeholders is the best organization to manage a power system. Stakeholders often have widely divergent interests that many times do not lend themselves to a mutually agreeable solution that is in the best interests of participants. In order to provide stakeholder input to the process, FERC has endorsed the concept of stakeholder advisory groups and other forms of non-binding input such as straw votes by stakeholder groups. It should be noted that under the concept of an independent system operator, stakeholders have the additional avenue of requesting alternative dispute resolution or even seeking redress at FERC.

¹⁴ Withholding can be accomplished by taking a generator out of service (physical withholding) or bidding a very high price (economic withholding).

Of course many stakeholders do not agree with FERC's policy and would like to have a greater say in or control over the process for deciding these important issues. And FERC's authority to impose this policy is not complete. In fact, often FERC has had to implement its policy indirectly by threatening to withhold approval of other related matters such as marketer status for participants. This means that the decision-making authority of system operators and stakeholders is in a state of flux and varies from region to region. This fact was emphasized by a recent U.S. Court of Appeals decision (discussed below in Section 4) indicating that FERC had exceeded its authority in several matters related to Independent System Operator formation and responsibility.

Operational Infrastructure

The operational infrastructure of a regional electric system operator consists of the personnel, buildings, computers, software systems and communications equipment associated with the regional control center and any associated satellites or sub-area control centers. The cost of acquiring, modifying, operating and maintaining this infrastructure and the cost of personnel are important factors in examining the advantages and disadvantages of various regional electric system configurations.

3.2 NEPOOL and ISO-NE

Southern Maine's transmission and distribution utilities are currently members of NEPOOL, and their transmission systems are under the control of the Independent System Operator of New England. Although neither NEPOOL nor ISO-NE is officially an RTO, together they embody many of the FERC-defined functions of an RTO. NEPOOL is a voluntary consortium of entities with an interest in the efficient and reliable operation of New England's electric system, excluding Northern Maine, which is electrically separated from the rest of New England. NEPOOL's participants include transmission and distribution utilities, generation owners, marketers and end-users. NEPOOL is established by and functions under the terms of the NEPOOL Agreement.

History

NEPOOL was established in 1971. Originally its membership consisted of the regulated electric utilities in New England. NEPOOL was formed to jointly plan and operate the New England bulk power system to insure reliability and maximize economy. NEPOOL has been very successful in meeting the operational aspects of these objectives. On the other hand, the planning objective has never been fully realized. NEPOOL has performed a valuable advisory role by defining the need for new facilities. However, the individual utilities always retained the authority (subject to required regulatory approvals) to decide what new generation and transmission facilities were to be built, when they would be built, and where they would be built. NEPOOL maintained the authority to review plans for new facilities and had the right to disapprove them if they did not meet reliability criteria. NEPOOL operated under this structure for over 25 years until FERC Order 888

and other restructuring initiatives mandated major changes in transmission tariffs and the market structure in NEPOOL.

In response to FERC's directives, NEPOOL adopted an open access transmission tariff and a new bid-based market structure. Control of the operation of the system was turned over to ISO-NE on July 1, 1997 and on May 1, 1999 the new NEPOOL competitive market system started operation. ISO-NE performed an assessment of the proposed NEPOOL bid-based competitive wholesale market and recommended major changes to the NEPOOL market structure including adopting locational marginal pricing as a means of allocating congestion costs. Consequently, ISO-NE and NEPOOL proposed to adopt a standard market design ("NEPOOL SMD") modeled on the PJM market, which is based on locational marginal pricing. The NEPOOL SMD is expected to become operational early in 2003. In a recent order accepting the NEPOOL SMD, FERC accepted ISO-NE's and NEPOOL's commitment to implement any requirements of the anticipated FERC SMD rulemaking.

Of course, SMD will do little to improve interregional transactions unless adjacent regions adopt the same SMD. To that end, the New York Independent System Operator ("NYISO") and ISO-NE have collaborated to propose the creation of a Northeastern RTO ("NERTO") comprised of New England and New York. The NERTO would be based on the ISO-NE proposed SMD and would eliminate pancaking between the two regions. In addition, ISO-NE and NYISO have proposed a common wholesale electricity market that could extend to Ontario, New Brunswick and Quebec. The objective of the common market would be to incorporate as many elements of the SMD into each area as possible and to establish consistent operating rules. On November 22, 2002, ISO-NE and NYISO withdrew their joint petition for FERC approval of the NERTO proposal. They cited potential for litigation and market participants' desire to focus on SMD as factors motivating their withdrawal.

In summary, NEPOOL and ISO-NE are in a state of flux. At a minimum the SMD in New England will be implemented in March of 2003. Whether or not a larger FERC-envisioned RTO is formed, and how the recently issued FERC SMD NOPR will affect the markets is less certain.

System Infrastructure

In 2001, NEPOOL's peak load was about 25,000 MW. (NEPOOL hit a preliminary all-time peak load of 25,524 on August 14, 2002.) NEPOOL's electricity generating facilities form a relatively diverse portfolio totaling over 27,000 MW. There are over 500 individual generating units in the region and the spectrum of fuels include natural gas, oil, coal, nuclear, hydro, waste and wood. Table 1 shows the breakdown of NEPOOL generation by fuel type.¹⁵ The order that the generation is listed in the table is

¹⁵ NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, April 1, 2002.

representative of their operating costs, with the lowest cost generation at the top of the list and the highest cost at the bottom.¹⁶

Table 1 is useful in understanding the supply characteristics of the NEPOOL market. Hydro, wind, nuclear, pumped storage, waste and coal facilities have very low incremental running costs. Therefore, their bids will be very low. They make up about 11,500 MW of the total NEPOOL capacity. To the extent that these units operate “at the margin”¹⁷, their bids will set the market-clearing price. However, these units hardly ever set the market-clearing price because the NEPOOL loads are above 11,500 MW over 80% of the time.

Table 1

NEPOOL Generation by Fuel Type

	<u>Generating Capacity</u> ¹ MW	<u>Cumulative Capacity</u> MW
Hydro and Wind	1,621	1,621
Nuclear	4,360	5,981
Pumped Storage	1,678	7,659
Waste	460	8,119
Coal	2,987	11,106
Wood	429	11,535
Purch/Sale from outside of the region	1,043	12,578
Combined Cycle-Natural Gas	4,252	16,830
Combined Cycle-Natural Gas/Oil	1,424	18,254
Steam-Oil/Natural Gas	3,998	22,252
Steam-Oil	3,559	25,811
Combustion Turbine	1,518	27,330
Internal Combustion	140	27,470
Total	27,470	

Note 1. As of 2001.

The next group, made up of purchases and combined cycle units, accounts for about 6,700 MW, or 24%, of the total NEPOOL generation. This group comprises mostly relatively new and efficient natural gas fired combined cycle units. Due to their position on the supply curve, they will set the market-clearing price most of the time (roughly 60% of the time assuming that at any given time 15% of the generation in the region is not

¹⁶ The order is only roughly representational since individual generating units have different efficiencies and their fuel costs vary depending on location, purchasing practices, etc.

¹⁷ The highest cost generator operating at any point in time sets the clearing price.

available for service). The next most expensive group, conventional steam driven generators, burn oil and are significantly less efficient than the combined cycle generation. It is at this point that the energy clearing price associated with supply starts to climb very sharply.

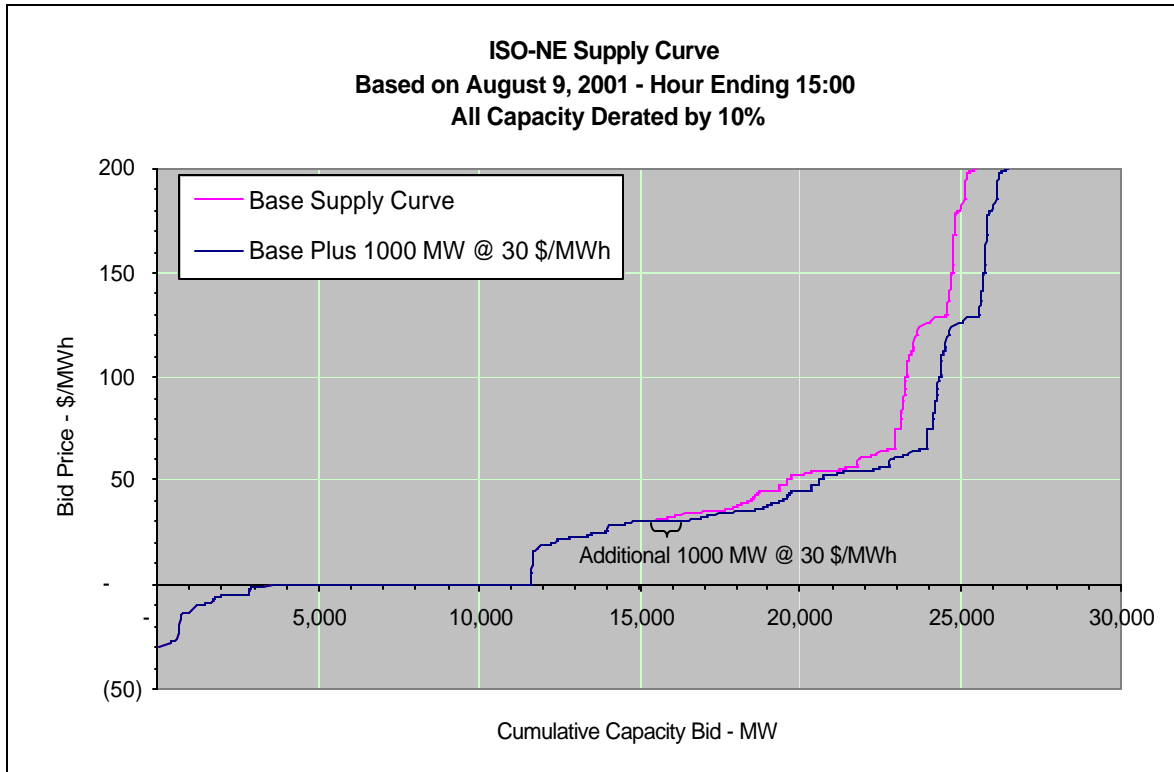


Figure 1

Figure 1 is a typical generation supply curve for NEPOOL.^{18,19} It shows bid prices and the cumulative amount of generating capacity offered up to that bid price. The supply curve demonstrates the NEPOOL generation economics discussed above. There is a substantial amount of zero or negative bid capacity available.²⁰ This is primarily hydro and

¹⁸ Figure 1 was constructed using actual bid data submitted for hour ending 15:00 on August 9, 2001. The amount of generating capacity that was unavailable for service that day was less than the average amount out of service during the year. The capacity amounts in the supply curve were derated by 10% to account for this factor. Further, in the discussion that follows the analysis was simplified by omitting the effect that operating reserves would have on the market-clearing price.

¹⁹ Supply curves are in a constant state of flux. They change as generating units go out-of-service or become available. They also change as fuel prices for individual generators change.

²⁰ Generators bid a negative price to indicate what they are willing to pay in order to run. They are willing to do this to avoid the cost of temporarily shutting down.

other generation that must run for other reasons. However, these units seldom set the market-clearing price because the NEPOOL load is greater than the amount of this low cost generation most of the time. At about 11,500 MW, the supply curve jumps to about \$20/MWh.²¹ From there it gradually climbs until it reaches about 17,500 MW with a corresponding bid price of \$36/MWh. The supply curve then starts to increase at a greater rate until it reaches about 23,000 MW and \$75/MWh. By the time the load reaches 25,000 MW the implied market-clearing price is almost \$200/MWh.

Figure 2 shows the hourly NEPOOL market energy clearing prices that resulted from the actual generator bids and actual NEPOOL loads for 2001. The prices are sorted in descending order.²² The chart also shows the amount of time that the clearing price was at or above a specific amount. For example, the chart shows that 20% of the time the clearing price was \$48/MWh or greater and 80% of the time it was \$25/MWh or greater. Thus, 60% of the time it was between \$25/MWh and \$48/MWh. Also, note that the clearing price was zero or less only about 2% of the time.

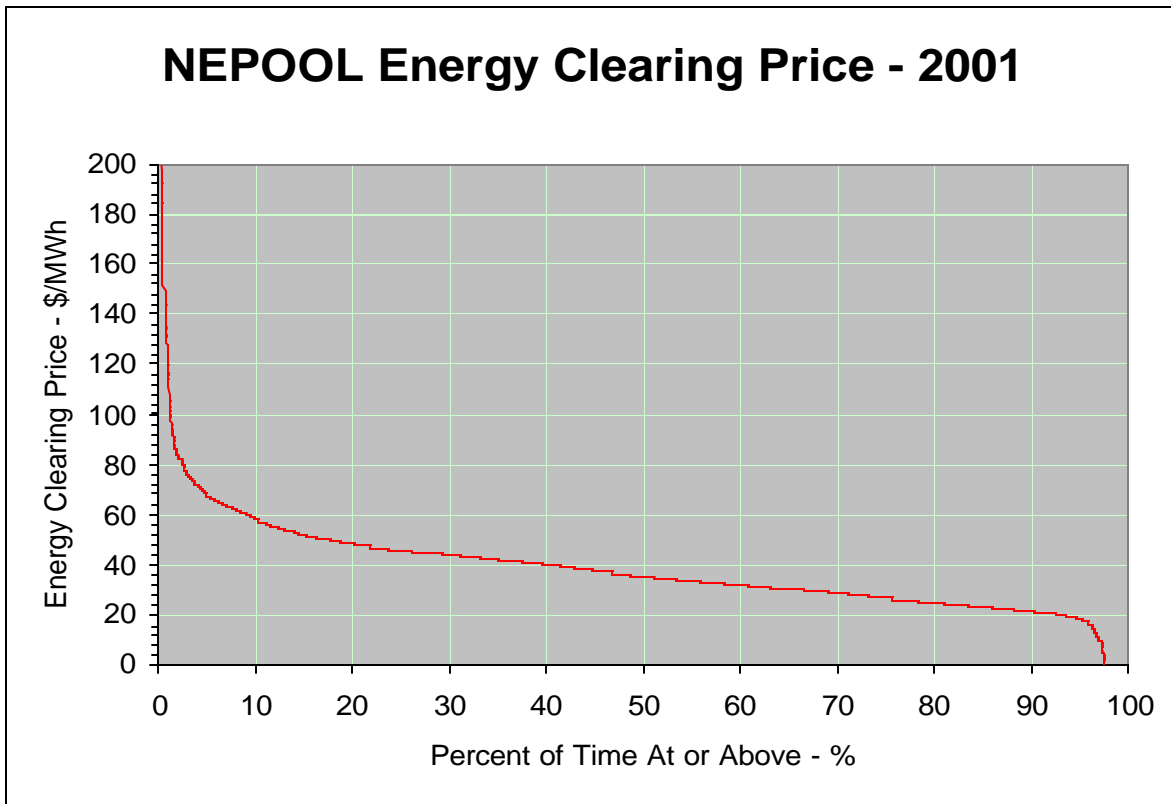


Figure 2

²¹ \$10/MWh is equivalent to 1 cent/kWh.

²² The prices are shown in the range of 0 to \$200/MWh. In 2001, there were thirty hours during which the energy clearing prices exceeded \$200/MWh and there were only seven hours the energy clearing price was less than zero. These data were not shown in order to have a meaningful scale for a remainder of the data.

The availability of additional resources from outside the region can affect prices in the region by shifting the supply curve and reducing market-clearing prices. Figure 1 is useful in demonstrating this phenomenon. Figure 1 shows the impact of the availability of 1000 MW with a bid price of \$30/MWh. Starting from the point on the curve where the bid price is \$30/MWh, the supply curve shifts to the right by 1000 MW. As shown in Table 2, the resulting decrease in market-clearing prices gets larger as the load increases. The net result for this hypothetical example is an average reduction in the market-clearing price of \$2.0/MWh for the year.²³ This would equate to a savings of about \$260 million/year for the entire NEPOOL region.

Table 2

Load - MW	Market-clearing Price - \$/MWh		
	Base Case	Plus 1000 MW	Decrease
<15,000			0.0
17,500	35.6	34.0	1.6
20,000	52.5	45.4	7.1
22,500	64.3	56.0	8.3
25,000	184.8	125.2	59.6

Transmission infrastructure also plays an important role in regional reliability and economics and, therefore, can affect the advantages and disadvantages of the various transmission/market configurations under consideration in this study. This applies to the transmission within NEPOOL and New Brunswick and the transmission tie between the two regions.

Most of the time the NEPOOL transmission system is sufficient to provide uninterrupted service and permit full economic dispatch of the generating units in the region. However, there are occasions when generation is economic but cannot be run due to transmission constraints within NEPOOL. The most recent transmission planning study performed by ISO-NE²⁴ indicates that certain areas within NEPOOL will continue to experience transmission constraints and the associated congestion costs throughout the 2002-2006 planning horizon. (Note that under LMP these costs will be incurred by customers in the congested regions.)

In recent times the transmission lines between Maine and New Hampshire have occasionally been constrained. Electricity flows in the direction from Maine into Southern New England almost all of the time. With all of the new economic generation constructed recently in Maine, the flow across the Maine/New Hampshire lines has increased to the point where there are periods when there is more economic generation available (in excess

²³ In this example, the clearing price is not affected by the additional resource about 54% of the time. Further, the load is at or above 17,500 MW about 8% of the time.

²⁴ 2002 Regional Transmission Expansion Plan (RTEP02), Approved by the ISO-NE Board of Directors on November 7, 2002.

of Maine's needs) than there is transmission capacity. The Maine/New Hampshire transmission interface has the capability of transmitting 1,400 MW from north to south.

However, the incidence of constraints on the Maine/New Hampshire transmission interface is projected to diminish over the next few years. According to the RTEP01, new generation in Southern New England will reduce the economic congestion occurring on the Maine/New Hampshire interface. However, the RTEP01 also points out that "The addition of any significant amount of generation in the Maine sub-areas or increasing the import capacity from New Brunswick would encroach on the forecasted ME/NH margins."

The single transmission line connecting Southern Maine and New Brunswick is capable of transmitting 700 MW from north to south. New Brunswick has economically competitive generation. Therefore, most of the time electricity flows from New Brunswick to New England. The line has very limited capability to transmit electricity from New England to New Brunswick due to operational considerations.²⁵

Wholesale Market Structure – Including Transmission Tariffs

The NEPOOL wholesale market structure has been evolving since 1998. The fundamental market design is now converging on a bid-based energy market with Locational Marginal Prices and Financial Transmission Rights. The rules for setting pool-wide installed reserve, operating reserve, and regulation (AGC) requirements have not changed substantially. However, the market structure for providing and acquiring the corresponding obligations is still changing. The FERC recently approved a new set of market rules for New England based on a standard market design similar to one being used in other pools in the Northeast and similar to standard market design proposed in the recent FERC NOPR.^{26,27}

The current NEPOOL energy market structure is bid-based with a single market-clearing price for the entire region. When congestion occurs, the associated cost is allocated to all load serving entities in proportion to their load. When transmission congestion occurs in Connecticut, for example, those responsible for serving load in Maine pay a portion of the cost. This leads to higher prices for Maine consumers. The new NEPOOL SMD will change this. It calls for a bid-based energy market with LMPs and FTRs. Once implemented, each region in NEPOOL will have its own market-clearing price. When there is no congestion, the market-clearing price in each region will be virtually the same (and the same as it would be under today's rules).²⁸ When there is transmission congestion, these prices will differ. For example, if the Maine to New

²⁵ This limitation results in large part from the need to protect the system from loss of Point Lepreau. If Point Lepreau is shut-down, this south to north limitation is not as severe.

²⁶ ISO-NE filed its Proposed Standard Market Design for New England on July 13, 2002.

²⁷ FERC issued its Notice of Proposed Rulemaking regarding Remediating Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design on July 31, 2002.

²⁸ Electrical losses can cause some differences in LMP's between regions even when there is no congestion.

Hampshire transmission link were congested, prices in Maine would be lower than those in regions south of Maine.

The NEPOOL requirement for Installed Capability, or ICAP, is based on meeting the criterion that the probability of having insufficient generating capability to meet customer requirements is less than one day in ten years. The requirement is called Objective Capability. NEPOOL and ISO-NE determine the Objective Capability requirement based on a probabilistic assessment of the availability of each generator in the region and the expected loads. They also include a consideration of the fact that NEPOOL has joint assistance arrangements with neighboring regions such that if there is a shortage of generation, ISO-NE can call on the neighboring regions to supply electricity, if possible. These calculations result in a total ICAP requirement that is about 18% greater than the expected peak load in the region, implying an installed reserve margin of 18%.

Currently, load serving entities in the region are allocated a share of the total ICAP requirement in proportion to the ratio of their monthly peak load to the sum of the load serving entities peak loads.²⁹ ICAP may be purchased in the bilateral market, but there is no clearing market for the product.^{30,31} Generators may supply ICAP equal to the generating capability of the unit if they meet certain requirements for operation and meet certain criteria. If a participant does not meet its ICAP requirement, it is assessed a monthly Deficiency Charge of \$4.78/kW-month. The current bilateral market price for ICAP in the region is about \$1.00/kW-month. Southern Maine's peak load is about 1,900 MW. At \$1.00/kW-month, the Maine cost for ICAP would be about \$22.8 million per year.

The proposed NEPOOL SMD will not change the fundamental method of determining the Installed Capability requirement. However, the basic ICAP requirement will be converted to a new product called UCAP, or unforced capability, and there will be a bid-based market for the product. The UCAP requirement will equal the ICAP requirement adjusted to account for the fact that generators are not available all of the time. Each load serving entity will be allocated a share of the total UCAP requirement in proportion to the ratio of its annual peak to the sum of all load serving entities' annual peaks. Generators will be able to provide UCAP equal to the generating capability of a unit times its availability rate.³² Load serving entities may self-supply UCAP or purchase it bilaterally or from the ISO-NE-administered auction. In the event that participants do not meet their UCAP requirement, their deficiency will be provided through a UCAP deficiency auction which will have a \$6.15/kW-month cap on the price. The NEPOOL Installed Capability

²⁹ Depending on load shape, the reserve margin for individual load serving entities in NEPOOL can vary several percentage points.

³⁰ The bilateral market involves transactions between two parties outside of the regional spot market.

³¹ There had been a bid-based clearing market for ICAP, but it was abandoned in August, 2000 due to market imperfections and apparent market power in that market.

³² The availability rate is equal to one minus the fraction of the time it is unavailable for service due to a forced outage.

requirements could change again based on the “capacity assurance” approach recently proposed by FERC.

The current NEPOOL operating reserve requirements include a ten-minute and a thirty-minute reserve component. Generating units providing ten-minute operating reserves must be fully available to produce electricity within ten minutes of when they are requested to do so by the ISO. Correspondingly, generation providing thirty-minute operating reserves must be available within thirty minutes. The ten-minute reserve requirement is set equal to the amount required to replace the single largest operating source of supply for the region, otherwise known as the first contingency. The first contingency could be a generator or it could be a tie to an adjacent region. Ten-minute reserves are further broken down into generation that is operating (spinning) and generation that is not operating (non-spinning). The thirty-minute reserve requirement is equal to 50% of the second largest operating source of supply for the region.

The pool operating reserve requirements are allocated to load serving entities in proportion to their electrical load. Participants may meet their operating reserve obligations by self-supply or purchasing them from the ISO-NE administered clearing market. Each operating reserve component is a separate product which has its own bid-based market. Generators submit bids indicating the price at which they are willing to supply operating reserves. The ISO-NE selects the least costly combination of generation to supply the operating reserve requirements based on each generator’s bid prices. The market-clearing price for each product is based on the highest bid prices and opportunity costs for the resources selected to provide the operating reserves. Operating reserves are purchased and sold at the clearing price. The total NEPOOL operating reserve payments were about \$22 million in 2001.

The operating reserve requirements for NEPOOL as a whole would remain the same under the NEPOOL SMD and each participant will have an obligation to pay an operating reserve charge for its pro rata share of the cost based on its load. However, instead of a bid-based clearing market for operating reserves, operating reserves will be provided from the same pool of generators available for supplying energy and the units selected for supplying operating reserve will be paid their lost opportunity cost.

Transmission tariff structure and pricing is an important consideration in understanding the wholesale electricity market and the price of electricity. Within NEPOOL, there are two primary types of transmission service. One is called Regional Network Service (“RNS”) and the other is called Local Network Service (“LNS”). Regional Network Service allows customers to transmit electricity from anywhere to anywhere on the NEPOOL network made up of Pool Transmission Facilities (“PTF”). PTF consist of all of the major transmission facilities in New England that interconnect all of the major substations and the major generating facilities in the region. (PTF can be thought of as the electrical equivalent of the interstate highway system.) Local Network Service is provided throughout the remainder of the New England system by each of the transmission and distribution companies over their respective facilities. Retail customers pay fixed rates for each of these two services. The charges are based on their maximum electrical usage

and are rolled into the rates they are charged by their local transmission and distribution utility. The rate for RNS is currently \$9.02/kW-year for Bangor Hydro and \$18.70/kW-year for Central Maine Power Company. So, as long as the electricity being used comes from generation located on PTF or on the local system of the customer, the cost of transmission is fixed and independent of the location of the source. This is true for most of the electricity consumed in New England.

However, there are two circumstances which can add additional transmission costs. First, any generator in the region that is not located on PTF is charged the local T&D company local transmission service rate if it sends electricity outside the local T&D company's area. Although this is an additional cost, it does not directly impact price consumers pay for electricity.³³ Instead, it cuts into the profits of the local generator and potentially impacts its viability. The second circumstance where additional transmission costs are incurred is when electricity is purchased from outside of NEPOOL. Typically, each intervening system will charge for the use of its transmission system. This is called pancaking.

Inter-Regional Barriers – Seams

The barriers to electricity trade, or seams, between New Brunswick and Maine are significant. For the purposes of this report, seams will be separated into three categories: physical limitations, transmission tariff barriers and wholesale market rules that are inconsistent or otherwise are an impediment to economic transactions.

For both Northern and Southern Maine, the primary barrier to trade with New Brunswick is physical transmission capacity. This is not meant to imply that there are not other significant seams issues. The transmission link between New Brunswick and Southern Maine ("Maine/New Brunswick tie") is the single 345 kV transmission line owned by Maine Electric Power Company ("MEPCo") in Maine and New Brunswick Power Company ("NB Power") in New Brunswick. The line is capable of transmitting 700 MW from north to south and minimal amounts from south to north when Point Lepreau is operating. NB Power often has more than 700 MW of economically competitive electricity that could be sold to customers in Southern New England but for the physical transmission constraint. The physical limitation in the opposite direction comes into play mostly when New Brunswick has a significant amount of generating capability out of service and would like to purchase backup power.

The Maine/New Brunswick tie line presents other barriers by virtue of its transmission tariff. First, anyone wishing to transact between New Brunswick and Maine, or NEPOOL for that matter, must first secure transmission service from both NB Power and MEPCo. The standard rate for firm transmission service is currently \$23.50/kw-year for

³³ However, consumers would pay less for delivery service by virtue of the revenues received from these generators.

out-service from NB Power.³⁴ For service across MEPCo the rate is \$1.05/kw-year for service from the Canadian border to the end of the MEPCo line at Maine Yankee where it interconnects with NEPOOL PTF. This is an example of transmission rate pancaking, a form of seam. These extra charges do not directly impact the cost of electricity in New England. The multiple fees for transmission service cut into the price differential between the two regions and, to the extent that it reduces the differential to zero or below, it is an obstacle to trade.

MEPCo transmission service presents another barrier related to its reservation policy.³⁵ MEPCo permits transmission customers to reserve transmission capacity on a first-come first-served basis. Currently, most of the MEPCo transmission capability has been reserved by two entities for a significant period of time. This leaves virtually all of the access to MEPCo controlled by these two entities. They are required to post any unused capability as available for non-firm service. However, the fact that they control most of the firm access to the MEPCo line means that they can use their access rights to negotiate good deals for the purchase of electricity from New Brunswick. That does not, in and of itself, create a barrier. However, there are times when otherwise economic deals are not consummated because those with reserved capacity cannot reach agreement with New Brunswick or the economic interests of those with the access rights are not served by the deal. The fact that there is a middle man that controls most of the transmission rights acts as an impediment.

For example, assume that the two parties cannot reach agreement for the purchase of electricity from New Brunswick and are not using the transmission capacity. They are required to post the transmission availability as non-firm service on the MEPCo OASIS, but only a few days in advance of the date the transmission would be available. Otherwise economic transactions between the two regions cannot be completed due to the relatively short notice and the short period of time the holder of the rights makes them available. Further, the fact that the service is non-firm means that transactions that include ICAP cannot be implemented.

Mechanisms for Planning and Expansion of Infrastructure

Within NEPOOL the planning and implementation of infrastructure expansions is different for generation than for transmission projects. The need for and the construction of new generation projects are driven by market forces, whereas transmission expansion is implemented through a combination of central planning and market forces.

³⁴ The current NB Power rate for out service is \$36.15/kw-year (CAD). Applying an exchange rate of 0.65 yields a rate of \$23.50/kw-year in U.S dollars. NB Power recently filed a new transmission tariff with their Public Utilities Board. If approved the firm transmission rate for firm point-to-point service would be \$27.04/kw-year (CAD). Applying an assumed exchange rate of .65 yields a rate of \$17.58/kW-year in U.S. dollars.

³⁵ The MEPCo transmission tariff which defines its reservation policy is based on the FERC defined Open Access Transmission Tariff.

The signal for new generation comes primarily from the market prices for energy and ICAP. Developers build new merchant generation when they perceive that prices have risen to the point where they will profit from their investments.

Transmission planning and expansion is accomplished primarily through central planning. There are mechanisms in place in New England that allow consideration of market forces, but they are implemented through the central planning of ISO-NE. Transmission planning starts with a comprehensive analysis of the transmission system for several years into the future. Two types of projects are identified: those that are required to maintain the reliability of the system, and those that improve or enhance the economics of the system, *i.e.*, reduce transmission congestion or losses. The ISO-NE then publishes a report summarizing its findings and listing all of the projects it has identified. Included with the report is information describing whether the project is needed for reliability or economic reasons and the associated value of the project.

The cost of reliability and economic projects that meet the definition of NEPOOL Pool Transmission Facilities³⁶ (“PTF”) are currently “rolled into” the NEPOOL transmission tariff rates, unless one or more participants agree to pay for the project.³⁷ That is, the costs of transmission upgrades are spread over all customers in New England in proportion to their load. FERC has told ISO-NE and NEPOOL that this method of allocating the cost of new transmission must change to a system where those who benefit pay. The NEPOOL tariff indicates that the host utility has an obligation to build a reliability upgrade, however this obligation is subject to the utility’s ability to secure regulatory approvals, financial commitments, and any associated rights of way and subject to the ability of the utility to recover all of its costs. There is no corresponding provision under the NEPOOL tariff or Agreement for economic upgrades and therefore, it is not clear that the host utility has any obligation to undertake an economic upgrade.

Apparently, these same rules could apply to transmission lines between two regions. However, as a practical matter, there are no provisions for joint inter-regional planning and there are no agreements in place that would prescribe how inter-regional transmission would be planned and built. Nor are there agreements with respect to cost recovery of such a line. At this time each one must be negotiated on its own terms and this is not easy.³⁸

³⁶ PTF are transmission facilities rated 69 kV or above that are required to allow energy from significant power sources to move freely on the New England transmission network.

³⁷The distinction between reliability needs and economic needs can be blurred. Reliability projects are generally understood to mean those projects that are required to insure transmission system reliability standards are maintained. Transmission system reliability standards are designed to insure that: 1) system voltages are maintained, 2) transmission lines do not exceed their thermal limits, 3) and that the system stability is maintained. Economic projects are generally considered to be those projects that are needed to relieve transmission congestion. However, reliability projects provide economic benefits by relieving congestion and economic upgrades improve reliability. Therefore, FERC has ruled that it is inappropriate to use the distinction between reliability and economic projects as a basis for allocating costs.

³⁸ Bangor Hydro and NB Power were able to reach agreement on the construction of a second transmission line between New Brunswick and Maine. However, the line has not been approved in Maine or Canada.

Market Power

Although it is impossible to totally avoid market power, the size of the NEPOOL market and the generation ownership/control structure in the region are such that the potential for exercises of market power has largely been limited to periods of tight capacity and periods when transmission congestion occurs. Further, to the extent that market power exists and is exercised, ISO-NE has established a market monitoring function to detect the use of market power to affect prices, and ISO-NE has the authority to mitigate the impact of the use of market power.

NEPOOL has over 27,000 MW of generating capacity. As a result of the divestiture by many of the utilities in recent years, the ownership and control of this generation is distributed among over fifty participants.³⁹ One participant controls about 19% of the generation in the region, and six other participants each control between five and ten percent of the generation. The remaining participant owners each control less than five percent of the total generation in the region. These percentages are not symptomatic of significant market power.

This has been confirmed by two studies in NEPOOL. The first, “An Empirical Assessment of the Competitiveness of the New England Electricity Market” by James Bushnell and Celeste Saravia of the University of California Energy Institute, was completed in February, 2002. This study attempted to discover the exercise of market power by comparing theoretically competitive benchmark prices to actual market-clearing prices for the period May 1999 through September 2001. Bushnell and Saravia did find some differences between the benchmark prices and the actual market-clearing prices. However, on page 2 of the report they concluded that “From the perspective of market efficiency the results to date are encouraging, particularly when compared to California, but need to be considered in context.”

The second study, “Competitive Assessment of the Energy Market in New England” (“Competitive Assessment”) by David B. Patton, et al., was published in May 2002. The researchers examined whether the conduct of market participants during 2001 was consistent with workable competition. They attempted to identify whether or not participants exercised market power by withholding generating resources from the market. They concluded that “This analysis consistently indicates that the New England markets have been workably competitive and produces little evidence of persistent economic or physical withholding.” Competitive Assessment at ii. However, the report did not rule-out the possibility that there may have been discrete instances of physical withholding.

³⁹ For the purposes of this report, control of individual generating units is assumed to exist with the Lead Participant. The Lead Participant usually owns the largest proportion of a unit and controls the generating units bidding strategy.

Governance

Originally NEPOOL was governed by its participants. However, since 1997 when ISO-NE was established, ISO-NE's role and authority have been evolving as a result of changes in the market and FERC's policy as implemented through numerous orders.

ISO-NE now has the responsibility to develop the rules necessary for the efficient and reliable operation of the system. Any changes to existing rules or new rules must be submitted to NEPOOL for approval unless failure to immediately implement a new rule, or change a rule, would have a significant adverse effect on the competitiveness of the market or on system reliability or security.

As described earlier, ISO-NE has the responsibility to determine transmission expansions necessary to maintain system reliability and to identify those that will improve the economic operation of the system. It is required to do so with input from the various stakeholders in NEPOOL. However, subject to regulatory approval, it has sole authority to determine what additions are needed and to require that utilities build transmission facilities it determines are needed to maintain reliability.

The NEPOOL situation is a good example of the governance spectrum and the trade-offs involved. At one end, NEPOOL has comprehensive participant involvement in the governance process. Voting shares are distributed to sectors and then allocated pro rata within sectors. Even the smallest entity that is a Participant has a place at the table and can vote. However, the 2/3 affirmative vote requirements makes it difficult to implement changes when there is a diversity of interest. This is often the case with issues involving the distribution of costs or benefits. On the other end of the spectrum is ISO-NE. It has no economic interest in the system and its major objective is the reliable and efficient operation of the system. And, it can act quickly. Although its decisions are intended to promote the competitiveness of the market, it is possible that particular decisions benefit some and harm others.

Operational Infrastructure

ISO-NE maintains physical facilities in Holyoke, Massachusetts including an office building and a modern control center. ISO-NE employs about 350 people whose primary functions include operations, planning, settlement, market monitoring, and customer service. Support staff includes human resources, finance, accounting, and information technology. The annual operating budget for 2002 is about \$70 million.

The current market system cost about \$53 million to develop. The NEPOOL SMD is expected to cost about \$90 million. (This includes the development costs of CMS/MSS system, a previous design that was the predecessor of SMD.)

Recent Developments

Two recent developments could have important impacts on the structure of transmission and wholesale markets in the Northeast. One of them, FERC's Notice of Proposed Rulemaking on Standard Market Design, was introduced in Section 2.0. The other is the filing by ISO-NE and NYISO on August 23, 2002, of a Joint Petition for Declaratory Order Regarding the Creation of a Northeastern Regional Transmission Organization.

FERC Standard Market Design Notice of Proposed Rule Making

As noted in Section 2.0, FERC issued the SMD NOPR in large part to in response to the failure of its Order 2000 to accomplish market reform through the creation of RTOs. As an alternative to joining RTOs, utilities are given the option of turning control of their transmission systems to ITPs, which are functionally similar to RTOs, but do not meet the geographic scope requirements on an RTO. The NOPR also proposes to eliminate barriers to electricity trade by standardizing the terms of transmission service, eliminating rate pancaking, and adopting measures to more efficiently allocate the cost of transmission constraints.

The proposed changes to the open access tariff include revised transmission planning and expansion mechanisms. The planning process is similar to the one proposed by NERTO.⁴⁰ It involves an assessment of needs and the identification of projects that will maintain the reliability of the transmission system and improve the economic efficiency of the regional markets. If these projects are not implemented voluntarily, the ITP will have the authority to require the affected transmission owner build and operate the facilities. This includes both reliability and economic upgrades. FERC has proposed that the costs of these types of transmission upgrades should be recovered from those who benefit from the upgrades.

The FERC SMD is very similar to the NEPOOL and NERTO SMDs. It calls for a bid-based competitive market with locational marginal pricing and a system of financial transmission rights called CRR's. However, instead of an installed capability or UCAP requirement, the FERC proposes a resource adequacy requirement that would include a forecast of generating capability needs several years into the future. The requirements will be based on the traditional reliability criteria used by utilities. However, the associated obligations will be different than current installed capacity or UCAP requirements. Once the forecast of need is established, it will be allocated to load serving entities in proportion to the load they serve. Those entities will be obligated to demonstrate that they have sufficient generation to meet their respective obligations.

Presumably there will be a bilateral market for the resources to meet these requirements. If a load serving entity does not successfully demonstrate that it meets its resource adequacy requirement, it will be forced to pay a penalty for any energy it

⁴⁰ In paragraph 343 of the NOPR, FERC acknowledges that ISO-NE and NYISO are pursuing a Northeast RTO and consequently FERC proposes that the New York/New England be a consolidated planning area.

purchases as a result of having insufficient resources. And, if there are insufficient resources available to meet regional needs and loads must be curtailed, then, to the extent possible, customers of the deficient load serving entity will be curtailed first. The FERC SMD proposal also includes market monitoring and mitigation functions.

In summary, the FERC proposed SMD and revisions to the open access tariff are intended to eliminate seams between U.S. markets without requiring the formation of large RTOs. It is worthy of note that they encourage the inclusion of Canadian markets in the planning process. Although there are some differences, most of the market design is consistent with the NEPOOL market design. There will be many concerns expressed in response to the NOPR. It may take a while to resolve these issues, but in the mean time FERC has made a clear signal about the direction it intends for wholesale electricity markets.

The NERTO Proposal

(As noted above, ISO-NE and NYISO have withdrawn their petition for FERC approval of NERTO. However, this section is included for further background.)

The NERTO proposal calls for the consolidation of the New England and New York wholesale markets under the control of a single entity called the Northeastern Regional Transmission Organization or NERTO. It also holds out the goal of harmonizing the wholesale markets of the Northeast Power Coordinating Council (“NPCC”) to form what is termed an NPCC Common Market. If approved, NERTO could be fully operational in the 2005 to 2006 time period.

NERTO would be an independent non-profit organization governed by a twelve member board of directors with no market participant affiliations. NERTO would provide for stakeholder and regulatory input through various advisory committees which would have no decision-making authority. NERTO’s responsibilities would include maintaining the reliability of the New England/New York region, maintaining the efficiency and competitiveness of the regional wholesale market and the provision of non-discriminatory transmission access within the region. NERTO would have operational control over transmission facilities in the region and would have the authority to file unilateral changes to the transmission tariff. NERTO would also have expanded transmission planning and expansion responsibility and authority.

NERTO would implement a common set of market rules that are virtually the same as the proposed NEPOOL SMD and NERTO would implement a single consistent region-wide transmission tariff that would eliminate pancaking between New England and New York. The NERTO transmission tariff would have provisions for transmission planning and expansion that would build on the current NEPOOL tariff. NERTO would have the authority to require that transmission utilities build, own and operate any required transmission upgrades not implemented voluntarily. This includes both reliability and economic upgrades. The NERTO proposal is somewhat vague with respect to upgrade cost recovery mechanisms. It simply states:

The costs of Reliability Transmission Upgrades included in the final NSP [NERTO System Plan] will be allocated by the agreement of NERTO participants. If no agreement is reached among the participants, the costs of facilities with a voltage of 345 kV and above that contribute to the parallel carrying capability of the NERTO Transmission System will be rolled into a NERTO-wide rate charged to NERTO load, and costs of facilities with a voltage below 345 kV will be charged to the load in the sub-region (*i.e.*, either New York or New England) in which the facilities are built, in accordance with existing practices in each sub-region.⁴¹

The proposal is even vaguer with respect to economic upgrades. It simply states:

For Market Efficiency Transmission Upgrades, the NERTO Board will consider the foregoing allocation methods and any allocation recommended by the NERTO staff (with input from the PAC).⁴²

The NERTO proposal envisions that the transmission owning entities will enter into transmission operating agreements with the transmission-owning utilities in the Northeast. These agreements are expected to give NERTO the authority to require that the transmission utilities build transmission upgrades when ordered by NERTO. Negotiations on the terms of these agreements have been ongoing over several months, and it is not clear whether all New York and New England utilities will ultimately join in them.

ISO-NE and NYISO plan to consolidate administrative, service and management functions such as accounting, human resources, finance, and public and governmental relations. This is expected to save in the \$10-15 million/year range. They also anticipate further non-price operating savings in the \$15-20 million/year and capital cost savings in the \$10-30 million/year range resulting from implementation of a single region-wide dispatch. These savings will not come without cost. The single dispatch system is anticipated to cost \$85-160 million. They have assumed no additional cost for implementation of SMD, because they both had already committed to spend money to implement SMD. They also expect some additional start-up cost in the range of \$35-60 million.

The NERTO proposal includes a plan to “harmonize” the wholesale markets throughout the Northeast Power Coordinating Council by adopting common market designs and eliminating other seams.⁴³ The process will start with Ontario and New Brunswick. Both provinces have signed letter agreements which establish the intent to start working towards the goals of a seamless Common NPCC Market.

⁴¹ Joint Petition for Declaratory Order Regarding the Creation of a Northeastern Regional Transmission Organization, page 104.

⁴² *Ibid.*

⁴³ NPCC is a voluntary electricity reliability council which includes New York, New England, Ontario, Quebec, New Brunswick, Nova Scotia and Prince Edward Island.

The New Brunswick agreement outlines near, intermediate and long-term objectives leading toward the goal of a seamless NPCC Common Market. The parties have also agreed to establish a Liaison Committee whose function will be to “facilitate communication of information on developments in their respective jurisdictions and to provide a forum for regular discussion in order to advance the objectives of this Agreement.”⁴⁴ It is noteworthy that one of the near-term objectives is expansion of the transmission capability from New Brunswick to Boston. Intermediate-term objective include reserves sharing and joint planning. Lastly, the agreement notes that New Brunswick has not completed its market redesign and industry restructuring process and that it is the Province, not NB Power, who will make the final decision regarding these efforts. Therefore, the agreement sets out several long-term goals that would be worthy of further discussion pending decisions regarding New Brunswick market design and restructuring. These include achievement of common market design and common energy products, region-wide scheduling, unit commitment and dispatch, elimination of barriers to trade and coordination or consolidation of market monitoring.

The NERTO filing also includes an analysis of the potential savings that could result from the combination of New England and New York electricity markets. The study analyzed savings resulting from standardization of markets, elimination of pancaking between New York and New England, implementation of a single dispatch for the region and organizational savings resulting from consolidation of functions. The results of the study are informative and are summarized in Table 3.⁴⁵

Table 3

NERTO Annual Savings – 2005
(Million \$)

	<u>New York</u>	<u>New England</u>	<u>Total</u>
Standardize Markets	77	-16	61
Eliminate Pancaking	166	-24	142
Implement Single Dispatch	34	-27	7
Organizational Benefits	<u>5</u>	<u>5</u>	<u>10</u>
Total Benefits	282	-62	220
Retail Load Savings – cents/kWh	0.16	-0.05	0.07

One of the most informative results is that New York would accrue savings while New England would suffer an increase in cost. This results from the difference in generation mixes between the two regions. Essentially, New England has less expensive generation on the margin than New York and there are both physical and market barriers

⁴⁴ New Brunswick Power – New York ISO – ISO-New England Agreement on Enhancing Coordination of System Operation, Planning, and Market Development

⁴⁵ Economic and Reliability Assessment of a Northeastern RTO, by ISO-NE and NYISO.

that prevent the less expensive New England electricity from reaching the New York market. When the market barriers are eliminated, power flows from New England to New York, lowering prices in New York and raising them in New England. A working group with members from both regions is attempting to develop a mechanism to mitigate the increased cost to New England resulting from elimination of seams between the two regions.

These results also shed some light on which elements of the plan are the most effective in producing savings. Elimination of pancaking and standardization of markets produce savings that are an order of magnitude greater than those produced by a single region wide dispatch or consolidation of certain ISO support and administrative functions. It is noteworthy that this study does not assess the impact of two NERTO features that could also contribute to the benefits accruing from the proposal. First, the NERTO proposal includes provisions that would allow NERTO to require that transmission upgrades be built for economic reasons. This could lead to increased transmission capacity between New York and New England and consequently increased savings. The second feature that could impact power markets in the region is the goal of an NPCC Common Market. Additional benefits could accrue to the extent that this goal is met by lowering market barriers between the eastern Canadian provinces and the Northeast. These savings could accrue without the Canadian provinces becoming full fledged members of NERTO.

To help put this all in perspective, if all of the savings were spread among all of the retail customers in New York and New England, their retail rates would be lower by 0.07 cents/kWh.

Although the proposal has been filed at FERC, there are at least three significant hurdles remaining before it can be implemented. First is the disparity in the allocation of costs and benefits between the two regions described above. The second hurdle is the negotiation of transmission operating agreements between NERTO and the transmission owning utilities. Among the issues that will make these negotiations difficult is the requirement that the transmission utilities not sustain a net increase or decrease in revenue requirements as a result of the elimination of transmission fees for service between New York and New England. Third, relying on a recent court decision, the transmission owning utilities are likely to contest NERTO's position that it has the right to make unilateral filings at the FERC to change transmission rates, without the assent of the utilities.

3.3 Northern Maine ISA

The Northern Maine Independent System Administrator ("NMISA") is a non-profit entity responsible for the administration of the Northern Maine transmission system and wholesale electric power markets in Aroostook and Washington counties. With a peak load of approximately 132 MW and total indigenous generating capacity of about 90 MW, the region relies on electricity imported from New Brunswick to meet total demand. The region is served by four electric utilities: investor owned Maine Public Service Company, consumer owned Eastern Maine Electric Cooperative ("EMEC"), and two municipal utilities, Houlton Water Company ("HW") and Van Buren Light and Power District

("VB"). MPSCo and EMEC also have interconnections to NB Power and are Transmission System Operators ("TSO"). Together with NMISA, they comprise the Northern Maine Area Operator ("NMAO").

NMISA was formed pursuant to the State of Maine mandate that all electricity consumers in the state must be afforded the opportunity to participate in a competitive retail market for electric service. Since the electric system of Northern Maine is not interconnected with any other U.S. electric system, and therefore not under control of ISO-NE, NMISA was formed as an independent entity to administer the Northern Maine transmission system and wholesale market.

The NMISA is operated in accordance with an electric tariff approved by FERC and a set of market rules adopted pursuant to that tariff. The tariff sets forth the organization, governance, funding, responsibilities and authority of NMISA, and the corresponding responsibilities of the Market Participants in Northern Maine. The Market Rules include daily operating procedures for scheduling and dispatch of the system, details on the treatment of ancillary services, outage coordination procedures, and settlement, billing, monitoring, and auditing procedures.

Membership

Membership in NMISA includes entities that are either Market Participants or Users in Northern Maine. Membership in NMISA is mandatory in order to use any of the services of NMISA. Market Participants include generators, Competitive Electricity Providers (CEP), TSOs (only EMEC and MPSCo), and T&D utilities. A User is any other entity that uses the Northern Maine transmission system. Currently, membership includes WPS, Energy Atlantic, Borelax, Wheelabrator-Sherman, MPSCo, EMEC, HW, VB, NB Power, and Emera. FPL Energy has also been a member.

Governance

NMISA is governed by a seven member Board of Directors representing:

- 1) MPSCo
- 2) EMEC
- 3) HW and VB
- 4) Large customers
- 5) Other customers (by Maine Public Advocate designation)
- 6) Generators located in Northern Maine
- 7) CEPs operating in Northern Maine (excludes generators)

NB Power is a non-voting member of NMISA.

The NMISA Board has authority to adopt and change the NMISA tariff, market rules and operating procedures. However, the TSOs retain the exclusive right to amend their transmission tariffs. The NMISA has the authority to create markets for energy, ancillary services, balancing energy, or other products or services, subject to FERC

approval as necessary. The NMISA also has the authority to suspend any part of the Northern Maine Market if necessary for reliable operation of the transmission system. The NMISA may develop transmission system plans and may participate in any regulatory proceeding relating to the Northern Maine transmission system.

The NMISA has market monitoring and auditing responsibility and the authority to impose sanctions for violations of Market Participants' obligations. These sanctions could include formal warnings, administrative sanctions (per event monetary charges), or formula-based sanctions (monetary charges). The NMISA has never imposed a sanction on a market participant.

The NMISA budget requires approval by the NMISA Board and is allocated to retail customers, generators, and CEPs by a formula approach. The current budget includes operating costs equivalent to about 72 cents per MWh for energy delivered to retail customers in the area.

Infrastructure Description

Peak demands for the Northern Maine utilities are approximately: 91 MW for MPSCo, 23 MW for EMEC, 17 MW for HW, 2 MW for VB, and 8 MW for Perth Andover (Canadian load connected at Tinker Station and buying power from WPS), for a total peak demand of about 132 MW. The only indigenous generating resources for serving customer load are within MPSCo's service territory. These include 37 MW of hydro, 18 MW of diesel, 23 MW of oil-fired steam, and 84 MW of biomass, or 162 MW in total. Of this total, the oil-fired steam generation is in deactivated reserve, about 30 MW of biomass (the Borelax-AVEC unit in Fort Fairfield) is exported to NEPOOL, and the hydro is typically derated due to unavailability of water, leaving typical usable capacity of about 90 MW. Another 37 MW of biomass (the Borelax-AEI unit in Ashland) is currently out of service for a generator rewind. Not only is the indigenous generating capacity insufficient to meet Northern Maine's electricity requirements, but much of it is more expensive than generation that is available from NB Power. Traditionally the gap between supply and demand has been filled by NB power. In 2001, total NMISA load was 816,118 MWh. Total generation within the region was 644,318 MWh. Of that amount 507,543 MWh was consumed in the region and 136,775 MWh was exported. Therefore, the amount of energy imported from New Brunswick for NMISA load was 308,575 MWh, or 38% of the total.

The MPSCo interconnections with NB Power include one 138 kV line and four 69 kV lines. Due to voltage and stability limits, transmission transfer capability is limited to 100 MW from MPSCo to NB Power and 90 MW from NB Power to MPSCo.⁴⁶ The EMEC interconnection with NB Power is at 69 kV and has 38 MW of capacity. The MPSCo and EMEC regions are not interconnected with each other. However, neither region has any significant transmission constraints. NB Power is significantly larger than the Northern Maine utilities and therefore controls the electric stability of the region. The interconnections with New Brunswick are essential for adequate operation of the Northern

⁴⁶ From Maine Public Service web site, at http://www.mainepublicservice.com/corporate/transmission/atcmethod_mps.pdf

Maine system. In practice, NB Power controls voltage and frequency, provides balancing power and is the default provider of operating reserves for the region.

Installed and Operating Reserves

The NMISA does not have an installed capability (ICAP) requirement or rules. However, NB Power has indicated that it intends to impose an installed capability requirement of 120% of the region's peak load. The method that the NMISA would use to satisfy such a requirement is uncertain, but would likely be similar to that used under a Maine/New Brunswick RTO.

Operating reserve requirements are set by NB Power. The NMISA's share of the operating reserve is based on its peak load and is currently 2.75% of the total requirement for the Maritime control area.⁴⁷ The total Maritime control area requirement is based on NPCC reliability criteria to cover the first contingency outage (650 MW Point Lepreau nuclear unit) with ten-minute reserve and one half of the second contingency outage (458 MW Belldune coal unit) with thirty-minute reserve. The total NMISA operating reserve requirement is about 18% of its peak load. About 75% of the operating reserve requirement is satisfied by the CEPs supplying load. The remainder is available for bid with NB Power the default supplier.

Wholesale Market Structure

Other than balancing power, the NMISA wholesale market is entirely bilateral and there is no bid-based competitive spot market for energy or other related products such as operating reserves. The bilateral transactions are primarily to supply standard offer service and energy to competitive electricity providers like Energy Atlantic. In fact, HW and VB are essentially wholesale customers buying at the standard offer rate.

Balancing power, or Balancing Energy Requirement, is the difference between a supplier's actual demand and forecast demand for any given hour. The NMISA conducts an hourly auction to supply this energy. Generally Balancing Energy is supplied by NB Power, but may be purchased from other entities. Settlement with each supplier is performed by applying the hourly Balancing Energy Clearing Price (BECP) to the supplier's Balancing Energy Requirement for that hour. The BECP is calculated as the average cost of Balancing Energy for each hour.

The transmission system within the NMISA is unconstrained and therefore does not present a significant impediment to the market and there are no congestion costs within the region.

Since the only external interconnections are with NB Power, NB Power has a significant amount of market power relative to the Northern Maine market. Market Participants and NMISA staff do not think NB Power has abused that market power in

⁴⁷ From NMISA web site, at <http://www.nmisa.com/operations/operatingreserve.asp>

Northern Maine. In fact NMISA states that it has “monitored the market from its inception and has found no evidence of the exercise of market power by NB Power.”⁴⁸ Some evidence supporting that position is that the standard offer rates in Northern Maine, including transmission, while higher than in Southern Maine, are consistent compared to the rest of New England. The standard offer energy rates, excluding delivery charges, are currently 5.689 cents/kWh for MPSCo residential customers and 6.75 cents/kWh for EMEC residential customers.⁴⁹ While somewhat higher than Central Maine Power Company’s rate of 4.95 cents and Bangor Hydro’s rate of 5.0 cents, these rates are comparable to the Massachusetts Electric Company and Fitchburg Gas and Electric Company rates of 5.626 cents for the first six months of 2002 and Boston Edison Company’s rate of 6.376 cents for the first three months of 2002. Additionally, Energy Atlantic, a non-standard offer electricity provider, estimates that it is providing about 20% of the energy within the MPSCo service territory. Presumably, these deliveries are at rates lower than the standard offer.

In 2001, the NMISA balancing energy clearing price ranged from a low of \$24.09/MWh in July to a high of \$43.24/MWh in March. These prices included a pro-rata share of operating reserve costs. Table 4 shows a comparison of NMISA monthly average balancing energy clearing prices to the monthly average clearing prices for ISO New England for the period January 2001 through June 2002. In thirteen out of those eighteen months, the NMISA clearing price was lower and was never more than 15% higher than the ISO-NE clearing price. This table supports the assertion that NB Power is not abusing its market position.

⁴⁸ December 19, 2002 letter from Kenneth Belcher to the Maine Public Utilities Commission.

⁴⁹ From Maine Public Utilities Commission web site, at <http://www.state.me.us/mpuc/Electric%20Supplier/Standard%20Offer%20Rate.htm>.

Table 4

Comparison of Monthly Average Clearing Prices

	<u>NMISA</u> ⁵⁰	<u>ISO-NE</u> ⁵¹
	\$/MWh	\$/MWh
January 2001	29.01	62.57
February	30.79	43.01
March	43.24	50.18
April	34.33	36.27
May	26.55	41.01
June	28.40	35.41
July	24.09	52.24
August	31.98	43.34
September	27.60	33.45
October	27.53	30.95
November	29.28	25.61
December	29.24	27.18
January 2002	27.36	25.49
February	21.80	25.10
March	27.42	30.84
April	30.96	30.07
May	30.84	34.25
June	32.64	28.54

Transmission Market Structure

In addition to the local T&D company charges, retail customers pay the cost of transmission required to deliver the electricity to their local T&D company's system, including any through or out transmission charges by NB Power for electricity delivered from or across their system. These charges are usually paid by the competitive energy supplier, who in turn includes them in its charges to retail customers. These will be billed at standard FERC regulated and individual Transmission Operator tariffs. The NMAO may at times be a transmission customer of NB Power under the Power Services Agreement (PSA) in order to support the Regulation and Frequency Control Service (R&FCS) Schedules. Customers may purchase either network transmission service (for transactions on the local transmission network) or point-to-point transmission service (for transactions between multiple points of receipt and multiple points of delivery). Point-to-point purchases must be sufficient to support the corresponding energy purchase and must be posted on the Open Access Same-time Information System (OASIS). Network transmission service does not have to be posted. The current transmission wheeling rates shown on the MPSCo web site are \$27.49/kW-year for basic transmission and \$1.59/kW-

⁵⁰ From NMISA staff.

⁵¹ From ISO-NE web site, http://www.iso-ne.com/Monthly_Average_CP/.

year for ancillary services. The same rates apply for both network and point-to-point service.

Retail Market Structure

Retail customers have the option of shopping for their energy supplier, or accepting the “Standard Offer” negotiated by the MPUC. As an example, WPS is the Standard Offer supplier for MPSCo’s customers, but many of them (about 20 %) have chosen Energy Atlantic instead. CEPs are generally responsible for all losses on the system to the customers’ meters. For transactions between the MPSCo and EMEC regions, CEPs are not responsible for losses beyond their region’s interface.

3.4 New Brunswick

New Brunswick has a long history of selling electricity to New England. New Brunswick Power Corporation, the Province’s major electric utility, has used revenue from these export sales to keep the rates it charges retail customers low.⁵² NB Power export sales are made possible by a combination of relatively inexpensive generation in excess of provincial needs and international transmission lines connecting New Brunswick to Maine. Continued export sales are a major element of New Brunswick’s energy policy.

New Brunswick Energy Policy

In January of 2001, New Brunswick published its comprehensive energy policy.⁵³ The energy policy white paper describes key elements of the Province’s plans for restructuring its electric sector. Among the Province’s goals was compliance with FERC requirements to permit full access to lucrative export markets. Recognizing that the evolutionary process underway in the U.S. electric markets would have implications for provincial policy, and that there are risks and uncertainties associated with restructuring, the government has determined to “proceed with a deliberate and controlled approach to electricity restructuring which will provide the opportunity for New Brunswick to participate in a competitive market, gather experience, learn from other jurisdictions and set the stage for full retail competition while allowing time for the market to evolve.”⁵⁴ In other words, New Brunswick does not plan to rush into electric industry restructuring.

Although the energy policy does not call for immediate full retail competition, it does target some initial retail access in the Province as early as April, 2003. Large industrial customers with demands of 750 kW or more, taking service directly off the transmission network, and the three existing municipal utilities will be allowed to purchase their electricity from competitive electricity suppliers. Non-utility generation will be

⁵² NB Power is a Crown Corporation, meaning it is owned by the provincial government. Its rates and other activities are regulated by the New Brunswick Public Utilities Board.

⁵³ White Paper, New Brunswick Energy Policy, New Brunswick Department of Natural Resources and Energy, January, 2001, at <http://www.gnb.ca/0085/toc.htm>.

⁵⁴ *Ibid.*, p. v.

permitted in the Province. Unregulated generators will be free to supply those customers for whom retail competition applies. Beyond that initial retail access, the policy anticipates that the Province will revisit the issue of retail competition every two years and will consider further phasing-in of retail competition to the degree societal benefits are expected to accrue.

NB Power will remain the electricity supplier to all of the retail customers who cannot or do not choose to purchase electricity from a competitive provider, and the rates it charges will continue to be regulated by the New Brunswick Public Utilities Board (“PUB”). NB Power will not be required to divest itself of its generation. In order to meet its customers’ electricity needs, it will be allowed to maintain a “heritage” pool of generating facilities consisting of most, if not all, of its current resources. New Brunswick reasons that this will not create a market power problem because most of the generation will remain in the heritage pool serving regulated customers and that the existence of the bilateral marketplace will provide sufficient competition.

In order to avoid unfair competition, NB Power will be required to financially separate, or “functionally unbundle”, its competitive business functions, like generation, from its regulated delivery functions. On May 30, 2002 the provincial government announced its plans for restructuring NB Power. NB Power will remain a Crown Corporation and will be re-formed into a holding company with four subsidiary companies: NB Power Generation, NB Power Nuclear, NB Power Transmission and NB Power Distribution and Customer Service. Each of the companies will be expected to operate on a stand alone basis with its own business objectives. They are expected to be formed and operational by April, 2003.

NB Power Generation and NB Power Nuclear will own NB Power’s current portfolio of generating assets. Those generating assets which will be included in the heritage pool will provide electricity to NB Power Distribution and Customer Service for its retail and standard offer customers. The rates paid for electricity from the heritage pool will be regulated by the PUB. Any unused electricity will be available to the two generating companies to sell in competitive markets, including New England, at unregulated prices. Although NB Power will not be required to divest itself of its generation, it has announced its intent to solicit private sector equity financial participation in two major projects, involving the Point Lepreau nuclear generating station and the Coleson Cove generating station. The intent of these solicitations is to minimize the financial risks associated with NB Power’s current debt load (\$2.5 billion).⁵⁵ The results of these solicitations will not be known until the end of this year or the beginning of next year, but it is unlikely that New Brunswick will accept any proposals that do not provide for reasonably priced electricity for customers taking electricity from the heritage pool. The fates of these projects depend on the results of the equity participation solicitation.

NB Power Transmission will be responsible for the construction, maintenance and operation of NB Power’s transmission system. It will also be responsible for providing

⁵⁵ Long term debt as of March 1, 2002, per New Brunswick Power Corporation 2001-2002 Annual Report.

transmission service for delivery of electricity to NB Power Distribution and Customer Service customers, and to other entities, including unregulated generators, marketers and importers, for transmission within, through or out of the Province. This will be done according to the terms of a new transmission tariff recently filed for approval with the PUB.

A market design committee was instituted to formulate and propose rules and structures for the new market. The committee issued its recommendations on June 18, 2002. The market design committee recommended a bilateral market that does not include a spot market with transparent market-clearing prices. Locational marginal pricing will not be employed and congestion costs will be socialized.

The new bilateral market will be administered by a system operator that is part of NB Power Transmission. The system operator will administer market rules and the transmission tariff, operate the bilateral contract and balancing markets, and perform short and long term transmission planning. The system operator will also provide reports and information on market performance to the PUB. New Brunswick also signaled its interest in improving marketing opportunities with other regions and the possibility of subsequent RTO formation by authorizing the system operator to “continue discussions with neighboring jurisdictions to enhance the overall level of access among these systems” and “present options and recommend decisions with respect to participation in an RTO.”⁵⁶

The market committee has submitted its report and recommendations to the provincial government. The government will now formulate specific rules for the wholesale market, taking into consideration the committee’s recommendations. The intent is that the bilateral market will be operational by April, 2003.

In summary, New Brunswick has embarked on the process of restructuring its electric markets. One of its goals in doing this is to maintain and even expand its export sales into the United States. Although New Brunswick recognizes that its markets must evolve in the same direction as markets in the Northeast, it has adopted a slow and deliberate approach to restructuring. Hence many of the attributes of a competitive marketplace will not be implemented, at least initially. For example, the wholesale market will not include a bid-based spot market with transparent market-clearing prices, locational marginal prices will not be implemented and congestion costs will be socialized. In addition, NB Power will not be required to divest itself of its generation. On the other hand, New Brunswick will allow unregulated generation and will provide non-discriminatory transmission access for all market participants.

System Infrastructure

NB Power currently has a generation mix that is economically competitive with generation in New England, including Maine, much of the time. When this generation is not being used to supply provincial customers, it is available to sell into the New England

⁵⁶ New Brunswick Market Design Committee Final Report, April 2002, page 20.

market. The amount and availability of this competitive electricity is a function of the demands of provincial customers and the amount and type of generation in New Brunswick.

NB Power's electrical demand varies considerably over the course of a year. In the winter its peak is about 3,000 MW. In the summer, its peak load is only about half of that, or about 1,500-1,600 MW. This difference between winter and summer peak load is a result of electric heating load in the Province.

To supply these requirements, NB Power has access to over 4,000 MW of generating capacity, about 2,300 MW of which is less expensive to run than the natural gas-fired combined cycle units that set the market-clearing price in New England most of the time. Table 5 shows the make-up of NB Power's generation portfolio in more detail. Hydro, nuclear, coal and Orimulsion have significantly lower operating costs than natural gas units, and there is over 2,300 MW of these types of capacity available to NB Power.⁵⁷ Whenever NB Power customers are using less than 2,300 MW, NB Power has relatively inexpensive electricity available to sell to New England. NB Power's greatest excess occurs in the summer when New England's loads and market prices are the highest.

Table 5

NB Power Generation by Fuel Type – 2002

	<u>Generating Capacity</u> MW	<u>Cumulative Capacity</u> MW
Hydro	884	884
Nuclear	635	1,519
Coal	515	2,034
Orimulsion	300	2,334
In-Province Purchases	47	2,381
Combined Cycle - Natural gas	263	2,644
Steam - Oil	1,114	3,758
Combustion Turbine	327	4,085
 Total	 4,085	

This fact has not been lost on NB Power. During the past ten years, over 20% of their total sales revenue came from out-of-Province sales, most of which took place in New England. NB Power has estimated that these out-of-Province sales have permitted it to maintain retail rates up to 15% lower than they would have otherwise been. As stated in

⁵⁷ Orimulsion is a liquid fossil fuel made up of 70% bitumen and 30% water. Bitumen is a naturally occurring petroleum hydrocarbon from the Orinoco belt region of Venezuela. Although NB Power's Orimulsion contract is confidential, they have explained that the cost of Orimulsion is similar to that of coal.

New Brunswick's energy policy, it intends to continue to use revenues from sales to New England to keep its retail electricity rates low.

Continuation of New Brunswick's excess of economical electricity and its ability to sell that electricity in New England hinge on the success of three major infrastructure projects: refurbishment of the Point Lepreau nuclear generating facility, conversion of its oil-fired Coleson Cove units to Orimulsion, and the construction of a the second transmission line between New Brunswick and New England. Two of these projects are at risk.

The Point Lepreau nuclear generating facility was built in 1983. It produces about 30% of New Brunswick's electricity. It ran well during the first 10-12 years of its operation. However, in more recent times it has had a number of serious problems that have curtailed its operation. Because of these problems NB Power commissioned a study of its options for Point Lepreau. The study concluded that "Safe reliable plant operation to 2006 is currently predicted, however, beyond this period plant derating to support fuel channel inspection activities will adversely effect generating capability each following year. After 2008 significant incapability is predicted due to the required inspection and maintenance activities. If replacement fuel channels are installed in 2006, safe reliable performance is predicted until at least 2032."⁵⁸ The estimated cost of the refurbishment is \$845 million (CAD).

On September 24, 2002 the New Brunswick Public Utilities Board issued its recommendation regarding the refurbishment to the NB Power Board of Directors. The PUB found that:

there is no significant economic advantage to the proposed refurbishment project. In addition, the Board considers that there are other significant aspects of the refurbishment option for which the economic impact is uncertain. These aspects create additional economic risk which leads the Board to conclude that the refurbishment of Point Lepreau, as outlined in the evidence, is not in the public interest. The Board, therefore, will recommend to the Board of Directors of NB Power that it not proceed with the refurbishment of Point Lepreau.

NB Power has not made a final decision as to whether or not it will proceed with the refurbishment plan. As noted earlier, NB Power has issued a solicitation for equity participation in the project. It is likely that NB Power will wait for the results of the solicitation before making a final decision. In the mean, time it has started exploring the possibility of securing a supply of natural gas to fuel a combined cycle unit that could replace Point Lepreau.

New Brunswick's ability to provide export sales to New England would be seriously jeopardized without Point Lepreau. According to NB Power, the best alternatives to replace Point Lepreau are a 400 MW gas-fired combined cycle unit or a new 450 MW Orimulsion unit. Neither one would replace Point Lepreau's full 650 MW capacity. And if

⁵⁸ Exhibit A-2 of Direct Evidence of Mr. Stuart Groom filed with the New Brunswick Public Utilities Board, January 8, 2002.

a gas-fired combined cycle unit were chosen, it would not be as price competitive. Therefore, loss of Point Lepreau would decrease the amount of competitively priced generation in the Province by 200-650 MW.

Conversion of the Coleson Cove oil-fired units to Orimulsion would add about 1,000 MW to New Brunswick generation that could economically compete with New England's natural gas-fired combined cycle units. The project has PUB approval, but still needs environmental approval. NB Power is optimistic that the environmental permit will be issued shortly. The Coleson Cove project will cost about \$750 million (CAD). As with the Point Lepreau project, NB Power has solicited proposals for equity participation in the project. The results of that solicitation could also affect the viability of the project.

The third project that is important to New Brunswick's ability to export is the proposed second transmission line connecting New Brunswick to New England. The proposed new tie would be a 345 kV transmission line from the Point Lepreau nuclear generating station in New Brunswick to a substation in Orrington, Maine. NB Power would own the portion of the line in New Brunswick and Bangor Hydro would own the portion in Maine. The line would increase the New Brunswick-to-Maine transfer capability from 700 MW to 1,000 MW. It would also increase the capability to transmit electricity from Maine to New Brunswick. NB Power has estimated that the Maine-to-New Brunswick transfer capability would increase from virtually zero to between two and three hundred MW.

NB Power has submitted a revised application for a certificate of public convenience and necessity for this line to the Canadian national Energy Board ("NEB"). Bangor Hydro has secured and maintains all of the permits required in the United States, with the exception of Maine Department of Environmental Protection ("MDEP") and MPUC approvals. MDEP rejected Bangor Hydro's proposed route for the line and Bangor Hydro has not submitted a proposal for a new route. Emera Energy, Inc. acquired Bangor Hydro and has indicated that it is undecided about going forward with the project. Also, if Point Lepreau is permanently shut down, the viability of a second tie is diminished. Consequently, the prospects for the second tie are uncertain at this time.

NB Power also has transmission interconnections with Northern Maine, Quebec, Nova Scotia and Prince Edward Island. NB Power's ties with Northern Maine were described earlier in this report. NB Power's ties permit it to import up to 1,185 MW from Quebec. The ties are also capable of transmitting up to 785 MW in the other direction. Historically, these ties have allowed New Brunswick to purchase significant amounts of electricity from Hydro Quebec. This, in turn, has allowed NB Power to sell more electricity into New England markets. NB Power's transmission links with Nova Scotia allow New Brunswick to export 550 MW and import 350 MW. Finally, the transmission tie with Prince Edward Island is limited to 220 MW. Traditionally, NB Power has not imported electricity from PEI due to the lack of surplus generation in PEI.

Wholesale Market Structure – Including Transmission Tariffs

As noted above, currently New Brunswick does not maintain competitive electricity markets. NB Power is the regulated monopoly supplier of electricity for almost all New Brunswick. NB Power maintains more than enough generation to supply all of its customers. Provincial restrictions have prevented construction of non-utility generation to all but an insignificant degree. Anyone wishing to purchase electricity from New Brunswick or sell electricity to New Brunswick must deal with NB Power.

Also as described earlier, New Brunswick has initiated a deliberate and slow transition to competitive wholesale and retail markets. The first steps, to be implemented in the spring of 2003, will be relatively small and not anywhere as extensive as has occurred in New England. There will be an open bilateral wholesale market, but it will not include a spot market with transparent clearing prices. Non-utility generators will be permitted, but NB Power will maintain the right to be the sole supplier for most retail customers.

As part of its plan to move towards a competitive marketplace, NB Power has filed a new transmission tariff for approval with the New Brunswick PUB. According to NB Power, the new tariff is compatible with the FERC Order 888 Pro Forma Tariff and its rates are designed in accordance with the FERC's Transmission Pricing Policy Statement. The tariff will, for the first time, allow marketers, generators and customers to use its transmission facilities to transmit electricity into the Province from outside and to transmit electricity anywhere within the Province. Formerly, NB Power's transmission tariff provided transmission service only through and out of the Province. The new tariff provides point-to-point transmission service from anywhere in the system to anywhere else on the system for \$27.04/kW-year (CAD), or about \$17.58/kW-year in (USD). (Point-to-point service is what someone would use for through or out service.) This is a drop from the current rate of \$36.15/kW-year (CAD).

The new tariff also provides ancillary services, including operating reserves. NB Power operates as part of the Maritimes control area.⁵⁹ The Maritimes control area follows NPCC guidelines for establishing operating reserve requirements and each utility must carry its share of the required operating reserves. NPCC requires that control areas carry ten-minute reserves equal to the largest source of electricity currently operating (first contingency) and it requires thirty-minute reserves equal to 50% of the second largest source of electricity operating (second contingency). For the purposes of setting operating reserve requirements, the Maritimes control area assumes that the largest first and second contingencies are each 10% of the total annual peak load or 500 MW. Any generators that are larger than 500 MW are responsible for providing the operating reserves associated with the excess. The 500 MW ten-minute and thirty-minute reserve requirements are shared in proportion to load.

The proposed bilateral market will also have an installed capacity requirement. The market design committee has recommended that the system operator be responsible for

⁵⁹ The Maritimes control area includes New Brunswick, Nova Scotia, Prince Edward Island and Northern Maine.

determining the installed capacity requirement for the Province. Each supplier will be responsible for maintaining a proportionate share of the installed capacity requirement based on the ratio of its customers load to the total load. The system operator will be empowered to assess penalties if a supplier fails to meet its installed capacity requirement. Currently NB Power maintains generating capacity equal to 120% of its annual firm peak load. The 120% installed capability is based on the same criterion used by NEPOOL, that there must be enough installed capability to insure that the probability of having insufficient generating capability to meet customer requirements is less than one day in ten years. The market design committee has recommended that New Brunswick maintain this criterion for establishing installed capability requirements.

Transmission Planning and Expansion

Currently, NB Power is responsible for building and maintaining its transmission system to reliably meet the needs of its customers. NB Power is also responsible for determining when and what new transmission facilities are needed to meet those needs. The market design committee has recommended that this policy be changed so that the system operator will be responsible to maintain the reliability and efficiency of the transmission system. The system operator will be empowered to establish criteria for transmission planning and to conduct system studies to determine what new transmission facilities will be needed to meet the criteria. The market design committee specified the system operator's role to include determining the need for transmission expansion with adjacent areas.

The system operator will be required to publish the results of these studies and will be empowered to solicit proposals for meeting the transmission needs it identifies. If necessary to maintain the reliability or efficiency of the system, the committee has recommended that the system operator be empowered to cause new transmission to be built. This means that the system operator can order transmission to be built for economic purposes. The committee did not address how the costs for new transmission would be recovered.

Market Power

As the sole owner of virtually all of the generation in New Brunswick, NB Power could have tremendous market power. NB Power's retail customers are protected against NB Power's exercise of market power by virtue of it being a regulated Crown Corporation. However, it could wield market power in the bilateral wholesale market.

Governance

The NB Power will continue as a Crown Corporation and as such will receive overall direction from the government. The NB Power Transmission and NB Power Distribution and Customer Services companies will continue to be regulated by the PUB. The system operator will be a part of the NB Power Transmission company and as such will

be separated from the NB Power Generating and NB Power Nuclear companies. The system operator will have the authority to monitor and mitigate abuses of market power.

Operational Infrastructure

NB Power operates a sophisticated control center for all of the transmission and distribution facilities in New Brunswick.⁶⁰ Currently the control center employs fifty-five people and has an operations and maintenance budget of about \$3 million a year. When NB Power restructures into four companies, the aspects of the control center having to do with distribution will move to the NB Power Distribution and Customer Service Company. The distribution function at the control center employs about seventeen people and represents about 25% of the total operations and Maintenance budget.

Other Developments - ECTO

In the summer of 2000, several eastern Canadian and Northern Maine companies met to discuss the potential for forming an East Coast Transmission Organization (“ECTO”) that would encompass eastern Canada and Northern Maine, and would be “compatible with the spirit” of FERC RTO requirements as described in FERC’s Order 2000. Of the original group, NB Power, Nova Scotia Power, Maritime Electric Company, MEPCo, MPSCo and NMISA have continued the discussions. The Eastern Maine Electric Cooperative has subsequently joined these discussions. They have adopted a set of objectives, formed working groups, made several informational filings at FERC and hired a consultant.

The primary objective in forming ECTO would be to eliminate pancaking in the region by offering a single region-wide rate for transmission anywhere in the ECTO. It would also provide for through and out service to all adjacent areas. As mentioned previously, elimination of pancaking in a region can shift revenues from one utility to another within that region. Therefore, the parties to the ECTO discussions have agreed that each utility should recover its total revenue requirements. A second objective is to develop market rules that are as compatible as possible with those of New England, New York and PJM. This includes adoption of similar market products services and compatible scheduling procedures and timelines.

Although not an objective per se, a majority of the parties to the ECTO discussions have agreed that “regional cooperation on a second 345 kV transmission line from New Brunswick to Maine is an essential precondition to the formation of ECTO.”^{61,62} This

⁶⁰ The control center also oversees some of the operation of the distribution system.

⁶¹ Third Informational Filing of NB Power Corporation, Nova Scotia Power Incorporated, Maritime Electric company, Maine Electric Power company, Maine Public Service Company, and Eastern Maine Electric Cooperative, FERC Docket No. RT01-000 (Re ECTO).

⁶² The Third Informational filing noted that MEPCo “is continuing to review a second 345 kV transmission line and therefore has not yet reached a conclusion on whether an agreement for the construction of that line should be a precondition to the formation of ECTO.”

requirement is very important to New Brunswick's participation in ECTO. Otherwise, the ECTO would provide little benefit for NB Power.

ECTO would provide benefits to the customers in Northern Maine. Removal of the transmission charge that NB Power imposes for transmission of electricity from New Brunswick to Maine, along with the elimination or reduction of other market seams, would make electricity from New Brunswick more accessible to Northern Maine. Less expensive power from New Brunswick could displace more expensive power from within Northern Maine.⁶³

Progress towards ECTO has been slow. In recent months, the prime mover, NB Power, has concentrated its efforts on revamping its transmission tariff. Although Northern Maine stakeholders would benefit, they are relatively minor players in the negotiations. New Brunswick's participation, on the other hand, is essential to the formation of ECTO, but ECTO would not necessarily get them any closer to their real goal, Southern New England markets.

⁶³ Elimination of the transmission charge would not result in a direct savings. This is because there would likely be some form of offset to make NB Power whole for the lost revenues. Northern Maine customers would likely pay the cost of the offset through some fixed cost mechanism, as opposed to the current transaction specific NB Power transmission charges that increase the incremental costs of a transaction.

4.0 Legal and Regulatory Issues

Because RTOs are a relatively new structure, there is some uncertainty as to the applicable regulatory approval requirements. The agencies most likely having jurisdiction are the U.S. Department of Energy (“DOE”) and the Federal Energy Regulatory Commission. Current DOE and FERC policy favors formation of RTOs, including cross-border entities; however, the FERC has also demonstrated a strong concern that individual RTOs (and the new, broader category of independent transmission operators known as Independent Transmission Providers) eliminate trading barriers with adjacent RTOs—the goal is to promote “seamless” trading of electricity both within and across regions. Accordingly, while the FERC may approve formation of a Maine/NB RTO (or ITP), it will almost certainly condition its approval on assurance that power generated within the RTO will flow freely into Southern New England, without pancaked transmission rates or other trade barriers.

State jurisdiction is less clear, but there do not appear to be any impediments to formation of an RTO in existing approval standards. Canada’s counterpart to the FERC, the National Energy Board, does not currently appear to have jurisdiction over RTO formation, nor do the New Brunswick provincial authorities, although the Province is preparing to adopt relevant regulatory legislation next year. A cross-border RTO would be fully consistent with the North American Free Trade Agreement (“NAFTA”).

Finally, formation of a cross-border RTO does raise the issue of what authority, if any, would settle disputes. Agencies within the U.S. and Canada do not have jurisdiction over cross-border RTO issues, and neither is likely to cede authority to the other. Parties to the RTO may need to resort to a non-governmental process, such as arbitration.

4.1 United States Department of Energy Export License

The requirement of DOE approval arises under Section 202(e) of the Federal Power Act, 16 U.S.C. § 824e(e), which provides, in pertinent part:

no person shall transmit any electric energy from the United States to a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of the Commission. The Commission may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as the Commission may find necessary or appropriate ...⁶⁴

⁶⁴ While the statute refers to action by the “Commission” (which, at the time the statute was enacted, was the Federal Power Commission), the Commission’s responsibilities were transferred to the Department of Energy under the DOE Organization Act, 42 U.S.C. § 7101 *et seq.* See 42 U.S.C. § 7151.

The DOE has issued implementing regulations, codified at 10 C.F.R. Part 205. However, the regulations add little of substance to the statute, other than to interpret the second criterion, relating to “coordination in the public interest of facilities”, to mean “the regional coordination of electric utility planning or operation.” 10 C.F.R. § 205.302(g).⁶⁵

While there are no reported judicial decisions interpreting the statute or regulations, the DOE has published numerous administrative orders in response to export applications.

To begin with, while the reference to the “sufficiency of electric supply within the United States” might suggest that the statute was intended to address transmission of definable amounts of electricity, and not the indeterminate electricity flows following the formation of an RTO, a 1994 Order involving the Western Systems Power Pool (WSPP) indicates that authorization under the statute would be required for formation of a cross-border RTO. Department of Energy, *Electricity Export Authorization*, FE Docket No. EA-98 (September 2, 1994). In that matter, members of the WSPP sought permission for four kinds (but no specific volumes) of short term transactions with BC Hydro: economy energy, unit commitment service, firm system capacity and energy sales, and transmission. Observing that this “type of export arrangement is less structured than authorized by DOE in the past”, DOE nevertheless granted the application, requiring only that the applicants file information reports quarterly, as opposed to annually, and that the authorization would be limited to two years. *Id.* at 4.

While the range of transactions with BC Hydro contemplated by the WSPP members is similar to transactions that would be coordinated through a Maine/New Brunswick RTO, there is potentially a significant difference between the posture of the WSPP application and the form an application by originators of the RTO might take. As noted above, the applicants in the WSPP case were members of the power pool. Specifically, they included all the utilities that contemplated selling and buying capacity and energy with BC Hydro. It is less clear who the applicants to form the Maine/New Brunswick RTO might be. The Maine utilities, for the most part, no longer own generation or participate in the wholesale or retail power markets. It is unknown at this stage whether generators or load serving entities in Maine would even participate in the attempt to organize an RTO. Were the Maine utilities (or the State, for that matter) to file for an export authorization, without participation by generators or load serving entities, DOE might deem the application premature.

The DOE regulations offer little additional guidance on the question of whether an application filed by entities other than those who will sell power across the border would be approved. 10 C.F.R. § 205.300, entitled “Who shall apply”, merely states that “An electric utility or other entity subject to DOE jurisdiction under part II of the Federal Power Act who proposes to transmit any electricity from the United States to a foreign country must submit an application or be a party to an application submitted by another entity.” This

⁶⁵ Under 10 C.F.R. §1021.B.4.2, export authorizations over existing facilities do not require environmental impact statements.

regulation dates from the time of vertically integrated, monopoly utilities; in an unbundled world, it is unclear whether it covers entities (such as a Maine utility) that might transmit on behalf of others upon formation of an RTO. On the other hand, since operation of a cross-border RTO would inevitably entail exports of electricity, DOE authorization would be required for operations to begin.

Assuming the necessary applicants came forward, rulings following passage of the Energy Policy Act of 1992 show that DOE has been mindful of the changes occurring in electric power markets, and would look favorably on applications intended to implement the policies underlying promotion of RTOs. Thus, in 1994, Enron Power Marketing, Inc., then a pioneer in wholesale power marketing, applied to DOE for authority to market power from U.S. utilities to buyers in Mexico. Utilities whose facilities would be needed for the transmission opposed the application, arguing that Enron (which did not own any transmission facilities) had not submitted sufficient information for DOE fully to consider the potential reliability impacts of the exports. DOE brushed aside the utilities' objections, noting that substantial changes in the industry had occurred since the enactment of Section 202(e) of the Federal Power Act in 1935, and of DOE's regulations for export authorizations in 1980:

The US power industry is vastly different than it was in 1935. Integrated regional power pools and multi-regional power exchanges were not envisioned ... Similarly, the emergence of electricity marketers and brokers could not have been anticipated in 1980. Also the passage of the Energy Policy Act of 1992 and the signing of the North America Free Trade Agreement in 1993 were both intended to promote increased competition in energy markets in general and the electric power market in particular. The interpretation and implementation of the statute and regulation ...should be consistent with and account for these changes ...

Department of Energy, *Enron Power Marketing, Inc.*, Docket No. EA-102 (February 6, 1996), pp. 5-6.

Enron was allowed to export power, provided the capacity limits imposed in prior DOE orders with respect to each of the transmission lines used were not exceeded.

In a subsequent order extending Enron's export authorization, DOE said that it would be guided by the same principles of promoting competition and open access that FERC had applied to domestic markets in its landmark Order No. 888:

DOE expects transmitting utilities owning border facilities to provide access across the border in accordance with the principles of comparable access and non-discrimination contained in the FPA andOrder No. 888....The actual rates, terms and conditions of transmission service shall be consistent with the non-discrimination principles of the FPA and the transmitting utility's own Open Access Transmission Tariff on file with the FERC.

Department of Energy, *Enron Power Marketing, Inc.*, Docket No. EA-115-A (September 17, 1998), p. 2.

The *Enron* decisions, coupled with the fact that DOE has never denied an export authorization, leave little if any basis in precedent to conclude that DOE would deny authorization for a Maine/New Brunswick RTO. The only circumstance imaginable that might lead DOE to act otherwise is if FERC signals (or DOE deduces) that it disfavors creation of such an RTO, because of the disruptive effect on creation of a broad Northeast RTO. Given DOE's apparent eagerness to act consistently with FERC policies, DOE might depart from its unbroken string of approvals. The second of its criteria for approval under Section 202(e), "coordination of facilities in the public interest under its jurisdiction," could afford DOE the basis for such a ruling. As noted above, DOE's regulations construe that criterion to mean "the regional coordination of electric utility planning or operation." To the extent FERC's recent pronouncements on the desirable scope of RTOs remain FERC policy, DOE might conclude that a Maine/New Brunswick RTO would indeed impair that coordination. In that case, the RTO would probably fail for lack of FERC approval under Section 203 as well. See discussion of FERC Section 203 authority below.

In sum, DOE has aligned its policies on electric markets and competition with those of the FERC. To the extent a Maine/New Brunswick RTO proposal conflicts with FERC policies, it is likely to face serious obstacles at the DOE as well.

4.2 United States Federal Energy Regulatory Commission (FERC) Approvals

In its landmark Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089, *order on reh'g, Order No. 2000-A*, 65 Fed. Reg. 12,088, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001), the FERC explained the filings that it would require in order to review and approve formation of an RTO. It began by describing the basic elements of the RTO proposal itself:

An RTO proposal includes a basic agreement setting out the rules, practices and procedures under which the RTO will be governed and operated, and requests by the public utility members of the RTO under section 203 of the FPA [Federal Power Act] to transfer control of their jurisdictional facilities from individual public utilities to the RTO.

Id. at 7 n.5.

The Commission then elaborated on the number and types of possible filings as follows:

Most RTO proposals by public utilities are likely to involve one or more filings under FPA sections 203 and 205, but the number and types of filings may vary depending on the type of RTO proposed and the number of public utilities involved in the proposal. Under the Rule, a utility may file a petition for a declaratory order asking, for example, whether a proposed transmission entity would qualify as an RTO or if a new or innovative method for pricing transmission services would be acceptable, to be followed by appropriate filings under sections 203 and 205.

Id.

The next sections elaborate on the issues relating to filings under sections 203 and 205. As will be shown, a court of appeals decision issued subsequent to Order 2000 appears to have invalidated the FERC's holding that utilities must seek approval under section 203

to transfer control of facilities to an RTO. The section 205 filing requirement remains in effect, however, and many of the criteria for approval under that section are spelled out in Order 2000 itself, as well as subsequent FERC orders implementing Order 2000. In addition, we discuss below whether approval for withdrawal from NEPOOL by Maine utilities, an issue not discussed in Order 2000, would also be required.

FERC Section 203 Approval

Section 203 of the Federal Power Act, 16 U.S.C. § 824b provides, in pertinent part:

No public utility shall sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, ..., without first having secured an order of the Commission authorizing it to do so. ... After notice and opportunity for hearing, if the Commission finds that the proposed disposition, consolidation, acquisition, or control will be consistent with the public interest, it shall approve the same.

As noted above, the FERC has interpreted this section to apply to transfers of control of transmission assets associated with formation of RTOs. *Regional Transmission Organizations, Order No. 2000, supra*, FERC Stats. & Regs. ¶ 31,089, p. 154. However, on July 12, 2002, the DC Circuit Court of Appeals rejected that interpretation. *Atlantic City Elec. Co. v. FERC*, 295 F.3rd 1 (DC Cir. 2002). *Atlantic City* involved a challenge by several transmission owning utilities to an order of the FERC requiring them to modify agreements with an independent transmission system operator to forbid them from withdrawing from those agreements without prior FERC approval. In ruling for the utilities, the Court cited three reasons why Section 203 did not apply to withdrawal from an agreement to authorize ISO control of transmission: first, the language of the statute “clearly contemplate[s] a transfer of ownership or proprietary interests”, which the court distinguished from operational control; second, a requirement of FERC approval was inconsistent with the intent of Section 202 of the Federal Power Act to make utility participation in coordination and interconnection agreements purely voluntary; and third, the Court found the FERC’s interpretation to be inconsistent with prior rulings of the agency. The government has chosen not to seek Supreme Court review of this decision.

While this portion of the *Atlantic City* ruling appears to invalidate the FERC’s *Order 2000* holding that Section 203 does apply to transfers of operational control of transmission assets to a third party, the scope of the ruling is clouded by other language in the decision. The Court says that while it “would be anomalous for FERC to have jurisdiction under section 203 to prohibit the utility petitioners from ending their voluntary coordination and interconnection through the PJM ISO,”

This does not mean that FERC is prohibited from reviewing entry to or exit from an ISO. The petitioners are not disputing FERC’s authority to review their agreements at the outset and to decide, based on the evidence in the record, whether the entrance and exit rights specified therein are just and reasonable within the meaning of section 205. Nor do petitioners contest FERC’s authority to review a specific withdrawal under section 205. Rather it is only FERC’s assertion of jurisdiction under section 203 that is at issue.

Thus, while the full implications of this paragraph are not readily apparent, the Court left some room for continued FERC supervision under Section 205 of utility decisions to transfer operating control of transmission assets. (Section 205 standards are addressed below.)

Ordinarily, it is assumed that decisions of a federal court of appeals are binding on an agency such as the FERC, until reversed on further appeal or by action of Congress. However, on July 31, 2002, the agency issued a Notice of Proposed Rulemaking involving transfer of operational control of transmission facilities to a new form of entity, Independent Transmission Providers (“ITPs”), that includes RTOs, without any mention of *Atlantic City. Remediating Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design* Docket No. RM01-12-000 (SMD NOPR). Whether this reflects FERC’s optimism that the *Atlantic City* decision will be invalidated is uncertain; what is likely, however, is that utilities (and perhaps others) will challenge the FERC’s authority to compel the transfer of control of transmission assets to ITPs based on the Court decision.

Assuming that the FERC prevails in maintaining that Section 203 does apply to formation of RTOs, it is useful to examine the criteria the FERC will apply under that Section. The relevant criteria are found in Order 592, a policy statement relating to utility mergers, issued in 1996. *Inquiry Concerning the Commission’s Merger Policy Under the Federal Power Act*, 61 Fed. Reg. 68,595 (1996), FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 62 Fed. Reg. 33, 34, 79 FERC ¶ 61,321 (1997).⁶⁶ The FERC summarized those criteria as follows: applicants under Section 203 generally need to demonstrate that “post-merger market power [will] be within acceptable thresholds or be satisfactorily mitigated, acceptable customer protections [will] be in place, and any adverse effect on regulation [will] be addressed.” *Id.* at 7. The Commission acknowledged, however, that not all Section 203 applications would fit neatly under this three-part test; accordingly, the Commission committed to apply the test flexibly. *See, e.g., id.* at 7-8.

The Order 592 standards are codified at 18 C.F.R. § 33.2, which specifies that applicants must include in their applications, in addition to information describing the applicant and the proposed transaction, “a general explanation of the effect of the transaction on competition, rates and regulation of the applicant by the Commission and state commissions with jurisdiction over any party to the transaction.” § 33.2(g).

As noted above, the FERC issued its policy on RTOs in January 2000. Within a few months, a case involving DTE Energy gave the FERC the opportunity to apply its Order 592 standards to an RTO-related transfer of facilities. *DTE Energy*, 91 FERC ¶ 61,317 (2000). DTE Energy and Detroit Edison sought to transfer transmission facilities

⁶⁶ While purporting to ‘focus’ on mergers, the Commission adopted standards that apply to all applications under Section 203 of the Federal Power Act, including transfers of control of transmission facilities. *See, e.g., DTE Energy Company, Order Authorizing Disposition Of Jurisdictional Facilities*, Docket No. EC00-86-000, (June 29, 2000)(applying merger policy public interest standards to transfer of control of transmission facilities to an ITC in context of establishing an RTO).

and related assets to a new entity, International Transmission Company that would qualify for membership in an RTO. In ruling on DTE Energy's Section 203 application, the FERC applied the standards of Order 592, but did so with explicit recognition of the impact of its RTO policy of Order 2000. Specifically, the FERC ruled that the first part of the three-part Order 592 test, effect on competition, was satisfied because

the creation of [Independent Transmission Company] may facilitate the subsequent transfer of Detroit Edison's transmission facilities to an RTO, an important first step in achieving the goals set forth by the Commission in Order No. 2000. Under these circumstances, we find that the proposed transfer of the Transmission Assets will not have an adverse effect on competition .

While the FERC clearly views RTOs as pro-competitive, it does not follow that all proposed transfers of facilities intended to facilitate formation of RTOs will be looked upon favorably under Section 203. Order 2000 embodies a broad policy of encouraging RTOs, but also defines minimum characteristics which RTOs must meet, as discussed above.

FERC Section 205 Approval

Subsection (a) of Section 205 of the Federal Power Act, 16 U.S.C. § 824d(a), sets forth the basic criteria which all rates, agreements and related practices of utilities must meet:

All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable ...

The FERC's implementing regulations, 18 C.F.R. Part 35, require the filing of comprehensive cost data to demonstrate the justness and reasonableness of rates, and other explanatory information for agreements and other documents reflecting "rules and regulations affecting or pertaining to such rates." While there is a large body of case law interpreting the "justness and reasonableness" standard, most relevant to the present discussion are the FERC's pronouncements on the application of section 205 to RTOs specifically, as found in Order 2000, FERC's Order 2000 regulations, and subsequent implementing decisions.

In describing the requirements that must be met to receive approval, the FERC identified four characteristics and eight functions that the proposed RTO must have. Briefly, the characteristics are:

1. The RTO must be independent of any market participant;
2. The RTO must serve a region of sufficient scope and configuration to support reliable, efficient and nondiscriminatory power markets;
3. The RTO must have operational authority for all facilities under its control;
and
4. The RTO must have exclusive authority for maintaining the short term reliability of the grid.

The eight required functions are:

1. Tariff administration and design;
2. Congestion management
3. Parallel path flow management
4. Supplier of last resort of ancillary services;
5. Transmission tariff administration
6. Market monitoring
7. Grid planning and expansion; and
8. Interregional coordination.

Order 2000 itself devotes over 700 pages to explaining these requirements, and there have been several follow-on orders providing additional FERC guidance. While it is clearly beyond the scope of this Report to repeat or even summarize those discussions, a few of them are especially relevant to the potential viability of a Maine/NB RTO and deserve brief additional comment.

First, the requirement that the proposed RTO be “of sufficient scope” could pose a significant obstacle. While the FERC stated its intent to defer to market participants in the first instance to propose the appropriate scope of RTOs, it noted that a particular proposal “could interfere[] with the formation of a larger, more appropriately configured RTO.” If so, it would not be approved. *Order 2000* at 247-48.

The Commission had occasion to consider the minimum acceptable scope for a New England RTO in *Bangor Hydro Electric Co.*, Docket No. RTO1-86-000, *Order Granting, In Part, And Denying In Part, Petition For Declaratory Order* (July 12, 2001). In finding that an RTO comprising the six New England states was insufficiently large to meet that criterion, the Commission said:

Given that a goal of this [RTO] initiative is to promote competition in electricity markets, regions should be configured so as to recognize trading patterns, and be capable of supporting trade over a large area, and not perpetuate unnecessary barriers between energy buyers and suppliers. There may exist today some infrastructure or institutional barriers unnecessarily inhibiting trade between regions that could be economically reduced. RTO boundaries should not perpetuate these unnecessary and uneconomic boundaries.

Id. at 23. Applying these criteria, the FERC found that existing trading patterns supported a single RTO serving a market including the Mid-Atlantic States⁶⁷ as well as New York and New England. Indeed, the Commission went even further, suggesting that Canadian utilities that are members of the Northeast Power Coordinating Council (including New Brunswick), should participate in the development in the RTO, “to the extent consistent with their status as subjects of a foreign sovereign nation.” *Id.* at 31.

⁶⁷ The mid-Atlantic region consists of Pennsylvania, New Jersey and Maryland, and is referred to as “PJM”.

In short, as of July 2001, the FERC seemed determined to disapprove of an RTO covering less than New England, New York, and the mid-Atlantic region, and evidently hoped to attract adjacent Canadian utilities to participate as well. Against that backdrop, it is difficult to imagine the FERC looking favorably on an RTO consisting of a single New England state and a Canadian province.

More recent developments raise a question as to whether the FERC remains fully committed to its policy against smaller RTOs, however. After the FERC's July 2001 Order rejecting a New England-only RTO, the independent system operators (ISOs) in New England and New York entered into negotiations with the PJM ISO to form an RTO covering all three areas. When those negotiations broke down, the New York and New England ISOs decided to go forward without PJM. However, the New York and New England ISOs also had difficulty reaching agreement with other market participants on the terms of a two-region RTO. Upon learning of this difficulty, in early June of 2002, members of the FERC stated in a public meeting that they were less concerned that a three-region RTO be established than that barriers to electricity trade between the regions be eliminated. The FERC subsequently asked the ISOs to postpone filing a proposal for a two-region RTO pending the agency's issuance of the SMD NOPR. The ISOs made the filing on August 23, 2002.

The SMD NOPR itself also calls into question the continued effectiveness of the geographic scope criterion of Order 2000. While the NOPR does not propose to overrule any part of Order 2000, it can be read as allowing utilities to turn over control of their transmission assets to ITPs instead of RTOs. The scope of an ITP can be as small as the territory of a single transmission owning utility.

In light of these recent developments, it is conceivable that the FERC would not object to the formation of a Maine/New Brunswick RTO. However, the SMD NOPR makes clear that such an entity will be expected to eliminate trade barriers with adjoining transmission regions. This would permit power to flow freely from New Brunswick into Southern New England, removing the economic justification for a Maine/NB RTO.

Finally, the Commission's discussion of the potentially international scope of RTOs in Order 2000 deserves brief mention. As noted above, the Commission sought to encourage development of RTOs of a scope that recognizes electricity "trading patterns." The FERC elaborated that those patterns do not necessarily respect national boundaries:

The Commission recognizes that natural trading boundaries do not necessarily coincide with international boundaries. Indeed, a large part of Canada's transmission grid ...is interconnected with that of the U.S. on a synchronous basis. Accordingly, an appropriate region need not stop at an international boundary...However, this Commission does not have, and is not intending by this rule to seek, jurisdiction over facilities in a foreign country. We will ask our international neighbors to participate in discussion of these issues. Perhaps what could be thought of as a "dotted line" boundary at the international border could be used to indicate that a natural transmission region does not necessarily stop at the international border, while the Commission's jurisdiction does.

Id. at p. 262.⁶⁸ Thus, if presented by Maine utilities with a proposal to form a Maine/New Brunswick RTO, the FERC might have to balance the competing Order 2000 policies of encouraging Canadian utility participation in U.S. RTOs, and preventing formation of RTOs of insufficiently large geographic scope.

FERC Approval to Withdraw from NEPOOL

Central Maine Power Company and Bangor Hydro-Electric Company are currently members of the New England Power Pool. Participation in an RTO with New Brunswick would be incompatible with continued NEPOOL membership, and would therefore require them to withdraw from the pool.

Withdrawal from NEPOOL is permitted under Section 21.2 of the NEPOOL Agreement. Participants may voluntarily withdraw under Section 21.2(a) on six months' notice, and may be terminated from membership under subsection (d) for failure to pay amounts due to the pool or its administrator, or for non-compliance with other pool requirements. In addition, under subsection (e), following termination, "all pending requests for transmission service under the Tariff relating to such Participant's facilities shall be followed to completion under the Participant's own tariff and all existing service over the Participant's facilities shall continue to be provided under the Tariff for a period of three years." Subsection (e) also provides that former participants' transmission facilities remain subject to NEPOOL reliability requirements, or any other reliability requirements as the FERC may direct in acting on the termination.

While requirements to honor pending and existing transmission commitments survive withdrawal from NEPOOL, there is no obligation for withdrawing parties to continue funding the substantial capital costs associated with creation of NEPOOL markets, standard market design, and other aspects of ISO-NE operations. Those costs are being recovered under system usage and load-based tariffs, and Maine utilities would only continue to contribute to them to the extent they used pool facilities.

While the NEPOOL Agreement appears to allow participants to withdraw at their discretion, FERC approval might be required. Technically, the Agreement is a FERC rate schedule, and members are identified in a schedule to the Agreement. As such, withdrawal would constitute an amendment to a rate schedule, which is subject to Section 205 of the Federal Power Act, 16 U.S.C. §824d, which requires that changes to rate schedules be "just and reasonable." Indeed, NEPOOL has had a practice of submitting notices by pool members of withdrawal to the FERC for approval, and the FERC has approved those submittals (albeit without comment).

As noted above, the recent *Atlantic City Electric* decision to the effect that utility participation in coordination and interconnection agreements was intended to be purely voluntary raises a question as to whether decisions to withdraw from a power pool require

⁶⁸ The FERC reaffirmed its support for Canadian participation in its recent *RTO West* Order. Docket No. RT01-0035 *et al.*, *Declaratory Order on Regional Transmission Organization Proposal* (September 18, 2002), p. 19.

regulatory review. On the other hand, also as noted previously, the Court left the issue unsettled by limiting its ruling to the scope of Section 203 of the Federal Power Act, and noting that Section 205 approvals might still be required.

Rate changes under Section 205 are subject to Section 35.1(c) of the Federal Power Act Regulations, 18 C.F.R. § 35.1(c). Section 35.1(c), in turn, specifies that changes in rate schedules “shall be filed as a change in rate in accordance with Sec. 35.13”.

Section 35.13 generally requires parties to justify “a change in rate” with exhaustive cost information. However, subsection 35.13(a)(2)(iii) creates an exception for changes in schedules other than rate increases. Those changes generally require only a description of the proposed change, the reasons for the change, and (where applicable) a comparison of revenue under the schedule with and without the change. While no transmission utility has sought permission to withdraw from the pool under this procedure, it has been invoked in the case of withdrawal by power marketers. *See, e.g.*, FERC Docket No. ER01-1926-000 (June 1, 2001)(permitting withdrawal by Koch Energy Trading Co.).

The FERC might react differently, however, to an attempt by a transmission utility to withdraw from NEPOOL, particularly if the intent was to capture the economic benefits of imported power without sharing them with adjoining regions. While the SMD NOPR may prevent that intent from being carried out, it is clear that FERC generally has jurisdiction to consider “the anticompetitive effects of regulated aspects of interstate utility operations...” *Gulf States Utilities v. FPC*, 411 U.S. 747, 758-59, 36 L.Ed. 2d 635, 644 (1973)(FPC had authority to examine anticompetitive effects of bond issue); *accord FPC v. Conway Corp.*, 426 U.S. 271, 279, 48 L. Ed. 2d 626, 633-34 (1976)(FPC had authority to examine anticompetitive effects of wholesale power price that was otherwise in zone of reasonableness). The rationale of *Gulf States* and *Conway* has been applied to cases dealing specifically with competition-based challenges to power pool and interconnection agreements. *See Central Iowa Power Coop. v. FERC*, 606 F.2d 1156 (DC Cir. 1979)(FERC had jurisdiction to consider competitive effects on pool membership classes); *Municipalities of Groton v FERC*, 587 F.2d 1296 (DC Cir. 1978)(FERC had jurisdiction over pool imposed capacity deficiency charges); *City of Huntington v. FPC*, 498 F.2d 778 (DC Cir. 1974)(FPC had jurisdiction over interconnection agreement which included limitations on municipalities’ right to resell power).

In short, notwithstanding the *Atlantic City* ruling limiting the scope of the FERC’s authority under Section 203, Section 205 is likely to provide the FERC the authority it needs to review a utility’s decision to withdraw from a power pool. There is no reason to believe the FERC would hesitate to use that authority to prevent actions which might lead to creation of new market seams.

Finally, it bears noting that NEPOOL itself may go out of existence, as market participants conform their advisory committee structures to rules emanating from the SMD NOPR. FERC presently envisions compliance with its new standard market rules occurring over the next two years, which could mean the disappearance of NEPOOL by the time any Maine/NB RTO could be established.

4.3 Maine Approvals

PUC Approval Under 35A M.R.S.A. § 3133-A

Section 3133-A of Title 35A M.R.S.A. requires Commission approval of “significant agreements,” which are defined in subsection 2A as

a contract or other agreement enforceable as a contract that binds the utility to a future course of action with respect to supplying, purchasing or exchanging transmission capacity or any renewal, amendment or extension of any contract or agreement that is for a period of longer than 3 years and involves one of the following, whichever is less: (1) More than 5,000 kilowatts of electrical transmission capacity, or 50,000,000 kilowatt hours or more of energy per year, flowing over a transmission line with a capacity greater than 100 kilovolts; (2) More than 10% of the transmission capacity of the utility; or (3) The transmission of an amount equal to more than 1.0% of the total annual kilowatt hour sales in the utility's service territory.

There is a threshold question of whether one or more of the agreements associated with the formation of an RTO would fall within the purview of this definition. While the answer may depend on how the RTO is structured, experience with other RTOs currently under development suggests that, at a minimum, there will need to be an agreement by utilities to transfer operational control of their transmission facilities to the entity designated to operate the RTO. An argument could be made that transferring operational control constitutes “supplying ... transmission capacity” within the meaning of the definition. The counter-argument would be that, given its juxtaposition with the terms “purchasing or exchanging”, “supplying” should be read to mean “selling”, or some other similar form of conveyance under which another party acquires the right to use a definable amount of transmission capacity. This position is supported by the latter part of the definition, which sets precise lower limits on the amount of transmission capacity that must be involved in the transaction.

Because the application of the statute to an RTO-related transfer of control is arguably unclear, and there do not appear to be any earlier decisions interpreting this language, the Commission, as the agency charged with administration of the statute, would be entitled to a measure of deference from a reviewing court in determining whether the statute applies. *Agro v. Public Utils. Comm'n*, 611 A.2d 566, 569 (Me. 1992). However, the DC Circuit's recent decision overturning FERC's ruling that the transfer by utilities of operating control of transmission facilities to an RTO requires approval under Section 203 of the Federal Power Act (see discussion at Section 5.2.B above), while involving different statutory language, is a reminder that that deference is not without limits.

One other issue of statutory coverage relates to the “longer than 3 years” requirement. Again, the issue may turn on the eventual terms of agreements not yet negotiated, but it is plausible that an agreement between utilities and the system operator would have no specific term, *e.g.*, it might continue until a party exercises a right of withdrawal. If so, it is unclear whether the Commission would find that the 3 year threshold was met.

Assuming Section 3133-A does apply in this context, it does not appear that it would constitute a significant hurdle to formation of an RTO. The statute merely specifies that an applicant shall supply such supporting information as the Commission deems necessary by rule, and that “[i]f the commission finds that a need for [the agreement] exists and it is reasonable and consistent with the public interest, the commission shall issue the certificate of public convenience and necessity.” 35A M.R.S.A. § 3133-A(1).

The Commission’s rules require applicants for approval of significant agreements to file 30-year load forecasts and energy resource plans and supporting information. PUC Rules, Ch. 334, §§6-7. However, the rules also authorize waivers of those filing requirements (*id.*, §4.A). Given that Maine utilities no longer have load obligations, it is safe to assume that the information requirements of the rule would be waived.

Prior Commission decisions applying the criteria of Section 3133-A and statutes with similar terms offer little, if any, additional guidance as to the criteria the Commission would apply in reviewing an application for approval of an RTO agreement. Those decisions address power supply contracts, including buy-outs of previous contracts, which generally raise issues of energy resource planning not relevant to an RTO application; and in many cases the Orders simply approve stipulations in summary fashion. *See, e.g., Central Maine Power Co.*, Docket No. 98-711 (December 29, 1998) (approving stipulation regarding buy-out of cogeneration contract); *Bangor Hydro-Electric Co.*, Docket No. 98-699 (October 20, 1998) (approving stipulation for power purchase agreement); *Central Maine Power Co.*, Docket No. 97-248 (June 23, 1997)(approving stipulation regarding buy-out of cogeneration contract).

In the absence of more specific criteria for approval in the statute and rule, the Commission would enjoy broad discretion to determine whether an RTO agreement was needed and in the public interest. While the Commission might take issue with some particulars of a proposed agreement, if the legislature were to conclude as a result of this study that a Maine/New Brunswick RTO was desirable, the Commission would no doubt have latitude to approve its formation.

Other PUC Approvals

Two other statutes deserving consideration are Sections 708 and 1101 of Title 35A M.R.S.A. While these provisions deal with transfers of ownership or control of property, they do not appear to cover the kinds of transactions likely to be involved in formation of a Maine/NB RTO.⁶⁹

Section 708(2)(A) requires PUC approval for any “reorganization”, which is defined in subsection (1) as:

any creation, organization, extension, consolidation, merger, transfer of ownership or control, liquidation, dissolution or termination, direct or indirect, in whole or in part, of an

⁶⁹ There are no Commission rules implementing either of these sections.

affiliated interest as defined in section 707 accomplished by the issue, sale, acquisition, lease, exchange, distribution or transfer of voting securities or property. The commission may decide what other public utility actions constitute a reorganization to which the provisions of this section apply.

Section 707, in turn, defines “affiliated interest” as:

- (1) Any person who owns directly, indirectly or through a chain of successive ownership, 10% or more of the voting securities of a public utility;
- (2) Any person, 10% or more of whose voting securities are owned, directly or indirectly, by an affiliated interest as defined in subparagraph (1);
- (3) Any person, 10% or more of whose voting securities are owned, directly or indirectly, by a public utility;
- (4) Any person, or group of persons acting in concert, which the commission may determine, after investigation and hearing, exercises substantial influence over the policies and actions of a public utility, provided that the person or group of persons beneficially owns more than 3% of the public utility's voting securities; or
- (5) Any public utility of which any person defined in subparagraphs (1) to (4) is an affiliated interest.

Read together, these two sections cover the “creation [or] organization ... of an affiliated interest”, and the “transfer of ownership or control .. of an affiliated interest” (emphasis added); and there must be some element of ownership for an interest to be “affiliated.” Because an RTO is, by FERC definition, an entity with no ownership ties to utilities, and the transfer of control would occur *to* it, neither its creation nor the transfer of control of transmission facilities would be a covered transaction.

Section 708 also includes the catch-all sentence that authorizes the PUC to “decide what other public utility actions constitute a reorganization”. However, the Commission has apparently never invoked that authority, and the use of that language to subject an RTO proposal to Section 708 review would likely run into Constitutional due process problems. *See, e.g., Eastlake v. Forest City Enterprises*, 426 U.S. 668, 675, 49 L.Ed. 2d 132 (1976)(“delegation of power to a regulatory entity must be accompanied by discernible standards, so that the delegatee’s action can be measured for fidelity to the legislative will”); *Interstate Circuit v. Dallas*, 390 U.S. 676, 20 L.Ed.2d 1512 (1960).

Section 1101(1) requires Commission approval before a utility may “[s]ell, lease, assign, mortgage or otherwise dispose of or encumber the whole or part of its property that is necessary or useful in the performance of its duties to the public.” Subsection 4 of Section 1101 exempts from the approval requirement “[t]ransactions involving utility property that do not materially affect the ability of a utility to perform its duties to the public do not require commission authorization under this section.” While there does not appear to be any useful precedent on the subject, it seems unlikely that the Commission would construe this language to apply to the formation of an RTO. The statute is reasonably read as addressing property transactions which have the potential to adversely affect a

utility's ability to satisfy its public service obligations; formation of an RTO would presumably be in furtherance of legislative (and perhaps FERC) policy of benefiting consumers by improving the performance of the wholesale electric market.⁷⁰

4.4 Canadian Approvals - National Energy Board

Canada's counterpart to the Federal Energy Regulatory Commission is known as the National Energy Board (NEB). While there are parallels between the two agencies, the NEB's jurisdiction is narrower than the FERC's.

The NEB's authority derives from the National Energy Board Act, Chapter N-7 of the Consolidated Statutes of Canada. Part I of the Act confers general powers on the Board, much like those accorded the FERC and state public utility commissions, *e.g.*, to hold hearings, issue orders and rules, and determine compliance with its orders and rules. The NEB's substantive authority over electricity issues is found in Chapters III and VI of the Act. Chapter III applies to construction and operation of international transmission lines; Chapter VI addresses exports of electricity. These two sections, in turn, are implemented in Parts II and III, respectively, of the National Energy Board Electricity Regulations, SOR 97/130.

Read together, the statute and regulations generally impose requirements to seek NEB approval for construction and operation of international transmission lines and electricity exports, but say very little about the criteria the NEB will apply in granting approvals. The only indication of what those criteria might be is in the provisions specifying information that must be submitted with applications, and conditions that the NEB may impose on licenses. They suggest that the Board will approve applications for transmission lines and exports that do not adversely affect the environment and do not interfere with the stability of the power grid. In addition, parties seeking to export electricity must have offered to sell the power on equivalent terms to potential buyers within Canada. *See generally National Energy Board Memorandum Of Guidance To Interested Parties Concerning Full Implementation Of The September 1988 Canadian Electricity Policy (Revised 1998)*, NEB File No.185-A000-19, reprinted at http://www.neb.gc.ca/pubs/mogelec_e.htm.

As to whether proponents of an RTO would need approval from the NEB, the wording of the statute and regulations is ambiguous. As noted, they require approval for "construction and operation of an international transmission line." If the word "and" in that phrase were read in the disjunctive, "operation" alone of an international transmission line would require NEB approval; because a Maine/New Brunswick RTO would probably "operate" cross-border transmission lines, it would be NEB jurisdictional. However, the NEB staff does not interpret the statute and regulations in that manner. They interpret "and" in "construction and operation of an international transmission line" conjunctively, meaning

⁷⁰ Because state statutes governing utility regulation differ, utilities in other states may be required to obtain approval for RTO participation from their state regulatory authorities under counterpart provisions. For example, the counterpart to Section 1101 in New York requires utilities to obtain state approval of any contract "for the operation of its works and system." *New York Consolidated Laws, Ch. 48, Art. 4, §70.*

that approval is required only in connection with lines newly proposed to be built.⁷¹ Accordingly, unless it would require construction of a new line, it does not appear that formation of a Maine/New Brunswick RTO would require NEB approval under that language.

Whether NB Power would need an export license is a factual question. NB Power has an existing license, under which it has been exporting energy to Maine and other New England states for many years. If the volume of expected cross-border transfers were to remain within the limits of that license, no new license would be required. If not, the company would have to seek a new license, which would involve offering power to other Canadian buyers on comparable terms. The NEB staff does not anticipate any problems in approving such a license, were it necessary.⁷²

4.5 Canadian Approval – New Brunswick Provincial Approvals

New Brunswick's electric company is a "Crown" utility, meaning that it is owned by the Province. The company has a Board of Directors, of which the Chairman reports to the Minister of Natural Resources and Energy. As such, major policy decisions may be as much political as regulatory.

In fact, the Provincial government has already adopted a policy in favor of participation in a regional RTO. That policy is reflected in a 2001 Energy Policy White Paper, prepared by an Energy Policy Working Group led by the Department of Natural Resources. The White Paper, which has been approved by the Cabinet, reviews changes in electric markets occurring in the United States and other countries, and recommends that New Brunswick gradually move toward restructuring its own electric market to allow introduction of wholesale competition. Noting the importance of its external interconnections to that competition, the Report states:

An important aspect of enhancing these interconnections is New Brunswick's possible involvement in an RTO. If such an RTO were not established, the New Brunswick power market would need to be integrated more closely with the Northeast power market. Therefore, the Province will direct the Crown utility to continue to pursue discussions with neighboring jurisdictions regarding the formation of a regional transmission organization or other mechanisms that enhance the overall level of access among these systems .

Id. at §3.1.3.2.1 (bold type in original). In accordance with this direction, NB Power recently entered into an agreement with ISO-NE and NY-ISO to pursue enhanced coordination and combination of their markets. See discussion in §3.3 above.

While participation in discussions with neighboring utilities regarding the formation of an RTO has been endorsed by the Provincial Government, that is not to say that NB Power would necessarily agree to participate in a Maine/New Brunswick RTO, or that it

⁷¹ Telephone conversation with Robert Mondré, staff of NEB, July 8, 2002.

⁷² See fn. 5.

would participate in any United States-based RTO in the same manner as FERC expects of United States utilities. As to the former issue, New Brunswick's desire to obtain the benefits of regional competition could well lead it to prefer participation in an RTO covering a larger region than just Maine and New Brunswick. See discussion in Section 6 of this Report.

As to the latter issue, there is no indication that New Brunswick would be any more inclined than other provinces to have its utility subject to the jurisdiction of a foreign government agency. To the contrary, in testimony filed before the New Brunswick Board of Public Utilities Commissioners on July 25, 2002, an executive with NB Power took what appears to be the identical position of Manitoba Hydro (see Section 5.2 below), to the effect that FERC has no jurisdiction over NB Power, and its participation in an RTO would have to "respect[] the regulatory sovereignty of Canadian provinces." *Application of NB Power for Approval of Open Access Tariff, Testimony of Doug Bartlet*, p. 16. In other words, NB Power might agree to coordinate closely with a U.S. RTO, but would probably reserve the right to withdraw at any time, and would also probably not accept the FERC as a forum for resolution of disputes.

New Brunswick statutes are in a state of flux insofar as RTO approvals are concerned. Prior to June 2002, the existing Public Utilities Law, Ch. P-27 of the New Brunswick Acts, only required NB Power to obtain regulatory approval for services performed within the province. *Id.*, §§ 36, 38. In June, the Provincial legislature enacted Bill No. 52, which amends the Public Utilities Law by requiring NB Power transmission tariffs to provide open access, and authorizing the Board of Public Utilities Commissioners to review such tariffs. *Public Utilities Law*, §§54, 57. Much like U.S. law, the statute provides that transmission tariffs must be just and reasonable, non-discriminatory, and based on estimates of the company's cost of providing service. *Id.*, §§ 58, 62. Evidently these provisions are not considered adequate to deal with an RTO proposal, however, because the legislature is planning to consider additional amendments for that purpose in the Spring of 2003.⁷³

In sum, New Brunswick has adopted a policy favoring participation by NB Power in an RTO, but is still in the process of establishing the regulatory framework that will govern any application to form or participate in an RTO. It is likely that legislation pertaining to such an application will be in place early in 2003.

4.6 International Approvals - NAFTA

The North American Free Trade Agreement, signed in 1993, was intended to encourage open trade, promote fair competition and otherwise eliminate barriers to cross-border commerce in goods and services between the United States, Canada and Mexico. *NAFTA*, Article 102. Provisions dealing with energy are found in Chapter 6 of the Agreement.

The overall purpose of Chapter 6 is laid out in Article 602(2):

⁷³ Per telephone conversation with Wanda Harrison, General Counsel, NB Power, July 30, 2002.

The parties recognize that it is desirable to strengthen the important role that trade in energy and basic petrochemical goods plays in the free trade area and to enhance this role through sustained and gradual liberalization.

The application of Chapter 6 to electricity is established by Article 602, which defines “energy and basic petrochemical goods” to include goods identified in certain headings of the Harmonized Code, which is a commodity classification system used in international trade. “Electrical energy”, which bears code 2716 under the Code, is within the headings specified in Article 602.

Nothing in Chapter 6 appears to impose any limitations or approval requirements on the formation of a cross-border RTO. Rather, while generally encouraging free trade in electricity, the Chapter specifically preserves the right of the parties to continue requiring export licenses (Article 603.5), and, by incorporating by reference the General Agreements on Tariff and Trade (“GATT”; see Article 603.1), to limit exports in order to avoid domestic shortages. *GATT*, Article XI, § 2(a).

The only other provision potentially affecting electricity trade is Article 606, which directs the parties to

ensure that in the application of any energy regulatory measure, energy regulatory bodies within its territory avoid disruption of contractual relationships to the maximum extent practicable, and provide for orderly and equitable implementation appropriate to such measures.

“Energy regulatory measure” is defined in Article 609 to include measures that “directly affect ...the transmission or distribution, purchase or sale” of electricity. Regulation of RTOs clearly “directly affects” transmission of electricity, and therefore falls within the scope of the requirement to “avoid disruption of contractual relationships to the maximum extent practicable.” Because formation of a Maine/New Brunswick RTO is unlikely to disrupt existing contractual relationships, Article 606 should not create any barriers to that formation.

While Chapter 20 of NAFTA does establish dispute resolution mechanisms, those mechanisms generally exist to address disputes over the interpretation of NAFTA itself (*see, e.g.*, Article 2002.2(c)), and would not be available to address issues internal to the administration of an RTO.

Finally, it should be noted that Congress has enacted legislation which states that no provision of NAFTA “which is inconsistent with any law of the United States shall have effect.” 19 U.S.C. § 3312. Accordingly, whatever other effects NAFTA may have, they do not provide a basis to contest existing statutory requirements affecting formation of RTOs.

4.7 Ongoing Regulatory Oversight of the RTO

The NOPR poses the question of what entity, if any, would resolve disputes among market participants. For a purely domestic RTO, the answer is relatively straightforward:

the RTO may provide for dispute resolution initially through governance procedures and arbitration or mediation, but ultimately the FERC has authority as part of its general statutory jurisdiction over transmission and wholesale power markets. However, for an international entity such as the RTO under consideration, the answer is much more complex.

To begin with, it is clear that the FERC itself would not have jurisdiction under its existing statutory framework. Section 201 of the Federal Power Act, 16 U.S.C. §824, states that the FERC's jurisdiction applies to electricity "transmitted in interstate commerce." Subsection (c) limits "interstate commerce" under this portion of the Federal Power Act to transmission that "takes place within the United States." 16 U.S.C. § 824(c). The FERC acknowledged this limitation in Order No. 2000, at p. 262 ("this Commission does not have, and is not by this rule intending to seek, jurisdiction over the facilities in a foreign country").

Given that several domestic RTOs are actively encouraging participation by Canadian utilities, it is reasonable to inquire whether Congress might amend the Federal Power Act to empower the FERC to oversee cross-border RTOs. Congress itself does have the authority under the Commerce Clause of the United States Constitution to regulate foreign commerce. *United States Constitution, Article I, Section 8, Clause 3*; see *United States v. Guy W. Capps, Inc.*, 204 F.2d 655, 658-59 (4th Cir. 1953), *aff'd*, 348 U.S. 296, 99 L.Ed. 329 (1955). While Congress could in theory delegate its authority over foreign commerce in electricity to the FERC, thereby enabling the agency to exercise the same control over cross-border RTOs as it does over domestic RTOs, to do so would likely amount to an unwelcome intrusion into the sovereign authority of the Canadian government. As the Supreme Court has long recognized, "the jurisdiction of a nation within its own territory is exclusive and absolute and is susceptible to no limitation not imposed by itself." *The Exchange v. McFadden*, 11 U.S. (7 Cranch) 116, 136 (1812). *Accord Cunard SS Co. v. Mellon*, 262 U.S. 100 (1923); *Oetjen v. Central Leather Co.*, 246 U.S. 297 (1918); *Anderson v. Gladden*, 188 F.Supp. 666, 670 (D. Ore. 1960), *aff'd*, 293 F.2d 463 (9th Cir.), *cert. denied*, 368 U.S. 949 (1961); see also *EEOC v. American Arabian Oil Co.*, 499 U.S. 244, 248 (1991)(citing judicial presumption against extra-territorial application of United States laws "to protect against unintended clashes between our laws and those of other nations, which could result in international discord")⁷⁴.

Nor would it be appropriate for the state of Maine to attempt to oversee a cross-border RTO. Under the concept of the "Dormant Commerce Clause", it has been held that even if Congress does not exercise its Commerce Clause authority to regulate foreign commerce in a particular instance, states are barred from stepping into the void and asserting jurisdiction. *Hill v. State of Florida*, 325 U.S. 538, 547 (1945)(Frankfurter, J., dissenting); *Willson v. Black-bird Creek Marsh Co.*, 27 U.S. 245, 252 (1829)(Marshall, J.); see also *National Foreign Trade Council v. Natsios*, 181 F.3d 38, 50 (1st Cir 1999), *aff'd*

⁷⁴ *EEOC v. American Arabian Oil Co.* holds that the presumption will be overcome only when there is a clear indication of Congressional intent to exercise extra-territorial jurisdiction, and that where the exercise is likely to subject individuals or entities to conflicting obligations, Congress will ordinarily include an explicit conflict of laws provision to minimize or avoid the predicament. *Id.* at 256.

sub nom. Crosby v. National Foreign Trade Council, 530 U.S. 363, 147 L.Ed.2d 352 (2000)(states may not burden foreign commerce).

Recent developments illustrate the challenges of dealing with regulatory oversight of cross-border transmission issues, as well as possible pragmatic solutions. The issue has arisen in the context of efforts by two ISOs to form RTOs that include Canadian utility participants. In one, the Midwest Independent System Operator (“MISO”) is seeking to include Manitoba Hydro, the Manitoba provincial counterpart to New Brunswick Power. Manitoba Hydro has agreed to participate in the MISO RTO, but on terms that recognize its distinctly foreign status. Unlike domestic U.S. utilities, that have agreed to turn over control of their transmission facilities to MISO, Manitoba Hydro has entered into an agreement with MISO under which it will tightly coordinate its operations with MISO, but retain ultimate control to honor any Canadian government obligations which conflict with MISO rules or instructions, and to withdraw from the agreement on 60 days’ notice if prejudiced by any change in law.⁷⁵ While Manitoba Hydro has filed a copy of the agreement with the FERC,⁷⁶ neither the filing nor the agreement itself evidences any intent by the company to submit to FERC jurisdiction; rather, they indicate simply that disputes will be subject to arbitration under Canadian law. Recent comments filed by Manitoba Hydro at the United States Department of Energy in an inquiry of North America transmission reliability issues also suggest that the company considers itself beyond the jurisdiction of the FERC: the comments state that oversight of an international reliability organization will need to be addressed either by international agreement or by the organization’s self-regulation.

The situation in RTO West appears to parallel MISO, insofar as RTO West is seeking to include BC Hydro as a participant. While BC Hydro has not filed a coordination agreement comparable to that of Manitoba Hydro, a status report filed at the FERC by RTO West in December 2001 described an approach to coordination very similar to the MISO/Manitoba Hydro arrangement: ISO West and BC Hydro will operate parallel, coordinated RTOs, with separate regulatory oversight exercised on each side of the border. See <http://www.rtowest.org/Doc/dec1.statusreport.pdf>.

A similar respect for Canadian sovereignty on issues of regulatory jurisdiction is reflected in the treatment of cross-border reliability issues in the U.S. Senate-passed version of the Energy Policy Act of 2002.⁷⁷ Section 206 of the bill provides that the FERC will regulate actions of cross-border reliability organizations only with respect to facilities in the United States, and recommends that the United States and Canada negotiate agreements to allow for effective oversight of cross-border issues.

⁷⁵ The text of the Coordination Agreement is reproduced at http://www.midwestiso.org/documents/200201/Coordination_Agreement_Format.pdf.

⁷⁶ The filing is reproduced at <http://rimsweb1.ferc.fed.us/rims.q?rp2~getImagePages~2223946~44~37~getcoPageNo~50address>.

⁷⁷ H.R. 4, 107th Congress, passed Senate April 25, 2002. The legislation is currently in conference committee. The House-passed bill does not address cross-border reliability issues.

5.0 Advantages and Disadvantages of a Maine/New Brunswick RTO

The purpose of this section is to describe and analyze the advantages and disadvantages of a Maine/New Brunswick RTO as compared to the current situation. Although this analysis will primarily be qualitative in nature, several quantitative examples will be given to help put the advantages and disadvantages in perspective. A rigorous quantitative analysis could provide further insights into the relative magnitude of benefits and detriments. However, given the inherent uncertainties, it would not necessarily provide a definitive answer to the question of whether a Maine/Canadian RTO should be formed.

5.1 Executive Summary

A Maine/New Brunswick RTO would affect each of the three regions (Southern Maine, Northern Maine and New Brunswick) differently. Assuming that New Brunswick continues to maintain its excess of economically competitive generation, Southern Maine and New Brunswick would be favored by the RTO. Whether there would be net advantages for Northern Maine is less clear. However, many of the advantages of leaving NEPOOL and joining with New Brunswick could be achieved separately and many of the costs and disadvantages avoided.

New Brunswick currently has excess low cost electricity and the Province has a stated goal of increasing electricity sales in the profitable New England markets. Reducing barriers to electricity trade with New Brunswick would also benefit the New England region, including Southern Maine. However, Southern Maine could not capture all of the benefits. Leaving NEPOOL and joining with New Brunswick would not close the door to electricity flowing from Maine to Southern New England. Southern Maine is a part of the NEPOOL market and would remain so even after formation of a Maine/New Brunswick RTO. As a condition of going forward with the new RTO, FERC would require that seams between the new RTO and NEPOOL be kept to a minimum.

However, many of these potential benefits are at risk as a result of the recent New Brunswick PUB decision to recommend against refurbishing Point Lepreau. Point Lepreau represents a significant portion of New Brunswick's low cost electricity supply. If Point Lepreau is shut down, NB Power's plans to replace it would not fully recover the amount of generation lost, and New Brunswick would have less electricity for export sales.

To the degree that a Maine/New Brunswick RTO increases New England's ability to import electricity from New Brunswick, Southern Maine would benefit because increasing electricity purchases from New Brunswick would lower the market prices in New England. The new RTO's single transmission tariff without pancaking would increase New Brunswick electricity sales to New England by eliminating existing tariff barriers. Further, if the provisions of the transmission tariff give the ISO authority to require utilities to build new transmission (subject to local permitting requirements) the chances that the second New Brunswick/Maine transmission tie would be built would be enhanced, and the associated increased transmission capacity would improve New Brunswick's ability to export to New England.

However, the advantages to Southern Maine of implementing a Maine/New Brunswick standard market design would be mixed. A common market design would increase New Brunswick electricity sales to and lower prices in New England, including Southern Maine. Yet, increased operating reserve requirements would offset much of the gain.

The results would not be as favorable for Northern Maine. Northern Maine's markets are already closely aligned with those of New Brunswick, so there would be fewer incremental benefits resulting from a Maine/New Brunswick RTO. And the increased sales to New England by New Brunswick would probably lead to higher prices for Northern Maine.

New Brunswick would be better off by virtue of increased sales and profits resulting from elimination of tariff barriers and the improved possibility for building the second tie. New Brunswick could also benefit by adopting a region wide standard market design. However, New Brunswick has adopted a go-slow policy with respect to restructuring of its electric markets.

Many of the advantages could be achieved without incurring the full cost associated with the formation of a new RTO. The parties could negotiate agreements eliminating transmission pancaking. The second New Brunswick tie would produce significant benefits for both New England and New Brunswick. The beneficiaries could negotiate a sharing of the costs and benefits that would make the project feasible without the formation of a new RTO. Although New Brunswick is currently not inclined to adopt a competitive market structure based on the standard market design, they have indicated that they are willing to consider it.

5.2 Introduction

The Maine Legislature's Resolve requesting the Commission to study this matter stated:

That the Public Utilities Commission shall 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. In conducting its study,⁷⁸ the commission shall invite the participation of interested parties in Maine and Canada.

The Resolve did not specify the components or structure of the RTO, nor did it specify which regions of Canada to include in the study. Therefore, Energy Advisors has made certain assumptions regarding the structure of the proposed RTO and its key elements. The fundamental assumption is that the RTO will be comprehensive and will include all of the elements currently considered essential for a regional organization to provide an efficient and non-discriminatory wholesale electricity market.

⁷⁸ Maine State Legislature Resolve, Regarding Participation in Regional Transmission Organization, Resolves, ch.81, 2002.

New Brunswick was chosen as the Canadian partner for the proposed RTO. New Brunswick is Maine's nearest Canadian neighbor and is the only province with which Maine has significant electrical interconnections. In addition, New Brunswick has started down the path of restructuring its electric sector. The Province has proposed an open access tariff that would provide non-discriminatory transmission access. New Brunswick has demonstrated interest in joining with transmission utilities in the U.S. by virtue of its participation in ECTO and its agreement to pursue the benefits of NERTO.

The proposed RTO is composed of the following five key elements:

1. Single region-wide independent system operator
2. Virtual single transmission tariff that eliminates pancaking
3. ISO transmission planning and expansion authority
4. Standard market design with locational pricing
5. Single region-wide generator dispatch

Each element will be described in sequence. Before describing the associated advantages and disadvantages of each element, the steps necessary to implement that element will be outlined. In addressing the advantages and disadvantages, Northern and Southern Maine will be discussed separately. Also, although the focus of this study is the impact on Maine consumers, because New Brunswick's cooperation would be necessary to form the RTO, the effect on New Brunswick will also be discussed. Finally, since many of the advantages of the proposed RTO can be accomplished separately without forming a comprehensive RTO, these alternatives will be outlined for each element.

There are three major assumptions underlying the comparative analysis that follows: the definition of the status quo, the nature of the seams between NEPOOL and the proposed RTO, and an assumption related to New Brunswick market power.

As discussed earlier, the status quo is in a state of flux while FERC is continuing to pursue efficient non-discriminatory wholesale electric markets. Although FERC's initiatives are meeting with varying degrees of success, absent Congressional action to the contrary, FERC is likely to continue these pursuits. For the purpose of comparison to the proposed RTO, it is assumed that the current NEPOOL/ISO-NE structure would remain in place, including the implementation of the NEPOOL SMD planned for early next year; and it is also assumed that NERTO and ECTO would not be implemented. (These two entities would provide some of the components of the proposed RTO.) Also, it is assumed that the FERC-proposed consolidation of PJM, NYISO and ISO-NE does not occur. Finally, MEPCo is assumed to remain an independent utility with its own transmission tariff.

The second major assumption is that the NEPOOL and the Maine/New Brunswick RTO would have the same wholesale market design and their transmission tariffs would be modified to eliminate any interregional pancaking. FERC has a stated goal of reducing seams between regions. It is very likely that in approving Maine utilities' withdrawing from NEPOOL and forming a Maine/Canadian RTO, FERC would seek to minimize the

barriers between Maine and NEPOOL. Further, the NEPOOL Agreement requires a withdrawing utility to continue to provide transmission service to the remaining participants for three years. To the extent that withdrawing from NEPOOL would create new seams or exacerbate any existing seams between Maine and NEPOOL, any advantages or disadvantages associated with increased New Brunswick sales to New England cited later in this report would be diminished.

The third major assumption is that NB Power will not be required to divest its generation as a result of market power concerns. New Brunswick does not currently wield significant market power in NEPOOL. Not only does New Brunswick control less generation than the largest owner of generation in NEPOOL, but the current New Brunswick/Maine transmission tie limits NB Power's ability to export into NEPOOL to 700 MW. New Brunswick does have significant market power with respect to the Northern Maine market. However, it is believed that NB Power has not exercised that market power to any significant degree. Finally, NB Power does not currently plan to divest its generation. The uncertainty about the current and future market value of its generation would be a major concern for New Brunswick in considering whether or not it would be willing to sell its generation.

5.3 Single Independent System Operator

The control and day-to-day management of the Maine/New Brunswick RTO would be vested with a single independent operator or ISO. The ISO would be a non-profit corporate entity located either in Maine or New Brunswick and would be subject to the laws of that country. The ISO would be governed by a board of directors with no interest in any market participant. The ISO would have its own employees and its own facilities.⁷⁹ Stakeholders and regulators would have access to the ISO for the purpose of providing input to the ISO decision-making process. Stakeholders and regulators would have no decision-making authority, other than that provided by the normal regulatory processes. An alternative dispute resolution process would be provided for stakeholders to resolve any dispute with the ISO regarding any ISO action or decision. The scope and the authority of the process to impose decisions on the ISO would have to be negotiated. The ISO would be funded through a set of regulated fees or tariffs charged to market participants. Other than the regulatory authority over its fees, the ISO would have full authority over its operating and capital budgets. If the ISO were Canadian, NB PUB would probably regulate the ISO fees.

The ISO would be responsible for administration of the single open access transmission tariff. This would include calculation and reporting of available transmission capacity, responding to requests for transmission service on a non-discriminatory basis, performing system impact studies to assess the impact of new generation or transmission facilities, and performing the billing function associated with the provision of transmission service.

⁷⁹ It might be possible for the ISO to utilize participating transmission company employees. However, there would have to be effective firewalls in place. The utilities would likely charge for these services.

In addition, the ISO would have the authority to unilaterally file for changes to the transmission tariff. However, the ISO would be required to formulate rates such that transmission owning utilities would have the opportunity to recover their full revenue requirements. Market participants, utilities, regulators and stakeholders would have the right to intervene as allowed by regulatory bodies with jurisdictional authority over the transmission tariff.

The ISO would also be responsible for transmission planning and would be granted the authority to approve transmission projects. The ISO would also have the authority to require that certain transmission projects are built.

Finally, the ISO would be responsible for the operation of the wholesale market. This would include managing the generator bidding process, scheduling and dispatching generating units, coordinating generator and transmission maintenance, and performing the settlement function. The ISO would also be responsible for monitoring the market for compliance, mitigating the effects of market power infractions and issuing sanctions for more egregious violations of the market rules. The ISO would also have the authority to adopt and modify market rules, subject to FERC and any New Brunswick approvals.

The details of the transmission tariff, the ISO's transmission planning and expansion responsibilities and authority, and the wholesale market characteristics are discussed later in more detail.

Implementation Requirements

1. As a first step in the process of implementing a Maine/New Brunswick RTO, the parties would have to reach agreement with respect to the attributes and functions of the RTO and the responsibilities and authority of the ISO. This would include agreements between the transmission owning utilities and the ISO over the terms for transferring operating control of transmission facilities to the ISO.
2. The agreements described in Step 1 would have to be documented and regulatory approval secured. As described in Section 4, regulatory approvals would be required from FERC, and possibly the Maine Public Utilities Commission and the New Brunswick Public Utilities Board.
3. The process for selecting and appointing the initial board of directors would have to be defined and executed.
4. The location of the ISO corporation would have to be determined and the company created.
5. The ISO would have to establish a source of funds to provide for start-up costs. The initial funding could require some form of credit support from the parties involved. Maine and New Brunswick and/or their respective utilities might have

to provide back-up credit or funds until the ISO self-funding tariff becomes operational.

6. The ISO would have to design and secure regulatory approval of a self-funding tariff.
7. The ISO would have to hire and train its staff and provide for all of the normal personnel and benefits functions.
8. The ISO would have to decide on a physical location for its staff and provide appropriate office facilities.
9. Interconnection agreements, emergency support and any other agreements necessary for the coordinated operation of the RTO with adjacent regions would have to be negotiated. This would include the terms of Maine's provision of transmission access to existing NEPOOL participants in the State.
10. Assuming NEPOOL still exists, CMP and Bangor Hydro would withdraw from it, a process that would require six months' notice.
11. Finally, the Northern Maine Independent System Administrator would have to be dismantled. Certain functions currently provided by NMISA might be incorporated into the new RTO if doing so were efficient.

Advantages/Disadvantages – Southern Maine

The start-up costs of the new ISO would be significant. Infrastructure including buildings, computer systems and communications links would have to be modified or added. Existing transmission service and interconnection agreements would have to be renegotiated and regulatory approvals would have to be secured, all of which would result in significant legal costs. In addition, Southern Maine customers would probably pay more for ISO services under the new ISO than they currently pay ISO-NE. Although the Maine/New Brunswick RTO would likely cost less to operate than ISO-NE, Southern Maine's share of the costs would be significantly larger.⁸⁰ Table 6 below shows the 2002 operating budgets for ISO-NE, PJM, the California ISO and NYISO.⁸¹ ISO-NE's total operating budget for 2002 is \$64,249,000 or \$0.49/MWh on a load ratio basis

⁸⁰ On a load ratio basis, Southern Maine represents about 9% of NEPOOL and would represent about 43% of the Maine/New Brunswick RTO.

⁸¹ ISO-NE Filing of Revised Tariff Sheets for Recovery of 2002 Administrative Costs; FERC Docket ER02-, November 1, 2001, Testimony of Patricia P. Mark, Exhibit 4, PPM-6, Schedule 1.

Table 6

ISO Operating Budgets

	<u>ISO-NE</u>	<u>PJM</u>	<u>CA ISO</u>	<u>NYISO</u>
Total Operating Cost (Million \$)	\$ 64.249	\$144.000	\$177.465	\$98.300
Annual Load (million MWh)	130.200	335.500	251.300	162.500
Cost per MWh	\$ 0.49	\$ 0.43	\$ 0.71	\$ 0.60

On a load ratio basis, CMP and Bangor Hydro customers' share of the ISO-NE 2002 operating budget is estimated to be about \$5.8 million. If the Maine/New Brunswick RTO could operate for less than \$13 million a year, or \$0.49/MWh, Southern Maine would pay less than it does today for ISO services.⁸² However, reduced economies of scale associated with a smaller ISO make this outcome unlikely. Therefore, Southern Maine would probably pay more than \$5.8 million for the services of a Maine/New Brunswick RTO.

The Maine/New Brunswick RTO would have a smaller group of stakeholders than are currently involved in NEPOOL. There would be fewer companies owning generation and fewer transmission utilities. This would allow Maine consumers a greater say in the stakeholder input process. (However, with an independent ISO the extent of stakeholder involvement would be limited to advisory input.)

However, cross-border differences and parochial interests could arise. Foreign control of local assets could become an issue. Control of hydro resources, in particular, is an area that could lead to disputes, and the construction of transmission lines that primarily benefit the other region could possibly lead to disagreements.

Advantages/Disadvantages – Northern Maine

It is likely that switching from NMISA to a Maine/New Brunswick ISO would decrease Northern Maine's customers' payments for ISO related services. Currently NMISA's operating budget is about \$629,000 per year. NMISA's retail customers pay about \$0.77/MWh for the operation of NMISA. This is significantly higher than the \$0.49/MWh ISO-NE cost, and ISO-NE operates a more complex wholesale spot market. As stated earlier, the new ISO's per MWh costs will likely be higher than the current ISO-NE costs; however it is unlikely that they will be higher than \$0.72/MWh.

Joining with a Maine/New Brunswick RTO would dilute Northern Maine's voice in the stakeholder process since the new RTO would include NB Power and the Southern Maine utilities and at least one generating company that currently does not own generation in Northern Maine.

⁸² NB Power believes that the cost of operating a Maine/New Brunswick RTO may be overstated. The current cost to run the NB control center is \$4 million (CAD). The cost allocation methodology for ISO-NE is not based solely on load and it is possible that the Maine/New Brunswick ISO's self-funding tariff will not be based solely on load.

Northern Maine could also be exposed to inter-regional issues. Although Northern Maine has had a long operating history with New Brunswick, the new ISO structure could create new or accentuate existing parochial interests. Further, while Northern Maine has a history of close operating ties with New Brunswick, it does not have such a history with Southern Maine and New England. Whether or not that new relationship would create disputes remains to be seen.

Advantages/Disadvantages – New Brunswick

The new RTO would probably be more costly than NB Power's current control center operation. NB Power's wholesale market structure and dispatch system do not include many of the components of the standard market design including competitive bidding and a spot market settlement system that would be a part of the new ISO. However, the increased costs would be offset in large part by the fact that Maine would be responsible for a significant portion of the costs of the new RTO. On a load ratio basis, Maine would pay almost half of the new ISO's operating cost.

Under the new structure, New Brunswick retail customers would lose representation. Today the government and the Public Utilities Board look out for the customers' interest. The new Maine/New Brunswick ISO would have the authority to make many of the decisions formerly made by NB Power. Certain ISO decisions would require regulatory approval; however, many would not. New Brunswick would have to rely on the stakeholder input process and the alternative dispute resolution process to resolve non-jurisdictional disputes.

Alternatives

Many of the advantages of a Maine/New Brunswick RTO could be achieved without the formation of a single independent system operator. These will be described in the following sections.

5.4 Virtual Single Transmission Tariff without Rate Pancaking

One of the key elements of a Maine/New Brunswick RTO would be a transmission tariff that does not impose additional charges when electricity is transmitted from one utility to another, *i.e.*, does not cause rate pancaking, and has consistent terms and conditions across the entire RTO. Elimination of rate pancaking would remove one of the barriers to increased trade between New Brunswick and Maine. Jurisdictional regulatory requirements would require at least two transmission tariffs, one for the United States and one for New Brunswick. However, they could be implemented with nearly identical terms and conditions to form a virtual single transmission tariff for the entire RTO.

The virtual single transmission tariff would provide transmission service similar to Network Access Service proposed in the recent FERC Standard Market Design Notice of Proposed Rulemaking. There would be no charges for transmission through or out of a utility's service territory. Point-to-point transmission service would also be eliminated.

Only those entities responsible for serving load would be charged for transmission. The rate for this service would be based on the customers' load and could vary from utility to utility, or it could be the same for the entire RTO.

The rates would have to be designed to allow the utilities the opportunity to recover the revenue requirements associated with their regulated transmission investments. The issue of lost revenues resulting from the elimination of through, out, and internal point-to-point transmission service would also have to be addressed. Revenue sharing agreements would have to be negotiated to avoid significant cost shifting between utilities. Resolving these issues is likely to be very difficult due to the uncertainties involved with projecting transmission revenues.

The transmission planning and expansion aspects of the virtual single transmission tariff will be described in the next section.

Implementation Requirements

1. The terms and conditions of the tariff would have to be agreed upon and the tariff drafted. Although many of the terms could be modeled after existing tariffs, rate design and revenue allocation issues would be difficult to negotiate. Consultants would be employed to analyze the proposals and to draft the final agreed-upon tariff. They could also facilitate the stakeholder input process.
2. Regulatory approval from FERC and the New Brunswick PUB would have to be secured.
3. Market power studies would be needed to confirm that divestiture of New Brunswick's generation should not be required.
4. A new system for posting transmission availability and for receiving and approving requests for transmission service would need to be implemented.
5. Transmission service billing and settlement processes would have to be designed and implemented.

Advantages/Disadvantages – Southern Maine

The virtual single transmission tariff would remove transmission price, reservation and scheduling barriers between New Brunswick and NEPOOL. This would benefit the entire region currently encompassed by NEPOOL, including Southern Maine, by lowering market prices for the entire region. As stated earlier, New Brunswick has surplus electricity that could be sold in the NEPOOL market. Elimination of pancaking would increase the economic incentive for additional sales from New Brunswick to Southern Maine and the remainder of NEPOOL.⁸³ Elimination of reservation and scheduling barriers would also

⁸³ For the purposes of analyzing the advantages and disadvantages of a Maine/New Brunswick RTO, it has been assumed that the new RTO would not create any new barriers between Maine and Southern New

increase the amount of electricity reaching Southern New England from New Brunswick. Additional electricity from New Brunswick would lower the market-clearing prices in Southern New England by replacing more expensive generation that had been setting the market-clearing price.

A recent report prepared by ISO-NE and the NYISO provides some insight into the potential savings resulting from the removal of barriers related to the pancaking of transmission rates.⁸⁴ The report describes an analysis of the economic impact of the proposed Northeastern RTO, and includes an assessment of the savings and costs associated with each of the following NERTO elements: elimination of pancaking between New England and New York, adopting a standard wholesale market design, and implementing single system dispatch.

The study shows a significant savings for New York resulting from the elimination of transmission charges between the two regions. New England, on the other hand would, suffer increased costs. This results from the fact that New England's generation has lower operating costs than the generation in New York. By eliminating a barrier, additional electricity from New England replaces more expensive generation in New York, lowering New York's market-clearing price and raising New England's.

The study indicates that eliminating transmission fees between New England and New York would reduce the average cost of electricity in New York by about \$0.97/MWh in 2005 and about \$0.53/MWh in 2010. If the Maine/New Brunswick virtual single transmission tariff produced similar results and lowered the market-clearing price in New England by \$0.50/MWh, Southern Maine's retail customers' electricity costs could be lowered by \$5.9 million per year. (This comparison using data from the NERTO study is provided only to give perspective to the issue. A detailed quantitative analysis would be required to estimate the actual impact on market-clearing price.)

Advantages/Disadvantages – Northern Maine

The results for Northern Maine are not as clear. Northern Maine prices would be impacted by two countervailing forces. On one hand, all other things being equal, elimination of transmission tariff barriers between Northern Maine and New Brunswick would have the impact of increasing the amount of electricity flowing from New Brunswick into Northern Maine, hence lowering the market price. The associated reduction in market prices would not be as great as for Southern New England because there is no intervening transmission utility with transmission charges between New Brunswick and Northern Maine. (MEPCo intervenes between New Brunswick and Southern Maine).

England. Therefore, subject to possible transmission congestion between Maine and Southern New England, market prices in the two regions will equilibrate. To the extent that any congestion does occur, market prices in Southern Maine will be lower, and Southern Maine will benefit more from the removal of barriers resulting from establishing the new RTO.

⁸⁴ Economic and Reliability Assessment of a Northeastern RTO, August 23, 2002.

On the other hand, New Brunswick would also be selling more electricity to Southern New England as a result of the new tariff. This would leave less electricity for sales to Northern Maine and would tend to raise the market price for electricity in New Brunswick and Northern Maine. Whether or not these two countervailing forces would play out in Northern Maine's favor is uncertain.

Advantages/Disadvantages – New Brunswick

New Brunswick would benefit from the removal of current transmission tariff barriers resulting from adopting the virtual single transmission tariff. New Brunswick's revenues would increase as a result of increased electricity sales to Southern Maine and NEPOOL. During the 2000-2001 fiscal year, New Brunswick's export sales yielded average net profits of about \$20/MWh (USD). Incremental sales would not yield the same level of profits, but they would still be substantial.

Alternatives

Most of the current transmission tariff barriers could be eliminated without forming a Maine/New Brunswick RTO. New Brunswick's charge for out transmission service could be eliminated by agreement with NB Power. Such an agreement between NB Power and NEPOOL would be in both parties' interests. NB Power would want some amount of compensation to make up for the loss of transmission revenues. The amount and form of the compensation would have to be negotiated among the parties and would probably include some consideration of the expected benefits each party would receive. In spite of the possibility of net benefits for all parties, these negotiations could be difficult. As mentioned previously, defining and predicting the lost revenues would be a difficult task at best, and the same would be true of the benefits for each party.

Similar agreements could be negotiated between MPSCo, the NMISA and NB Power. In fact, removal of transmission tariff barriers is one of ECTO's objectives.

Including MEPCo in NEPOOL's open access transmission tariff is an additional alternative that could be implemented even if the Maine/New Brunswick RTO were not implemented. This would eliminate the additional transmission fee that MEPCo charges for transactions between New Brunswick and NEPOOL. It would have the additional benefit of removing some of the scheduling and reservation impediments resulting from MEPCo's existence as a separate transmission entity with its own reservation and scheduling requirements. As with NB Power, MEPCo would likely want some amount of compensation to make up for the loss of transmission revenues.

5.5 Transmission Planning and Expansion

The ISO would be responsible for transmission planning and would have the authority to make decisions regarding transmission system expansion or upgrades. The ISO would perform transmission system adequacy assessments on a regular basis and publish its findings. The adequacy assessment would identify both reliability and economic

transmission needs. Market participants would be allowed to propose projects in response to the ISO needs assessment. The ISO would approve feasible projects that would be self-funded, *i.e.*, projects whose cost would not be included in the transmission tariff rates. The Maine/New Brunswick standard market design would include locational based pricing and financial transmission rights. Presumably these would provide the incentive for market participants to propose self-funded projects. For other proposed projects, the ISO would approve the project if it satisfied transmission needs identified in the adequacy assessment and if its costs were warranted. If sufficient proposals were not forthcoming to meet the projected needs for transmission expansion and upgrades, the ISO would have the authority to require the appropriate electric utilities to build the project, subject to regulatory requirements. These ISO responsibilities for transmission planning and expansion would be defined in the transmission tariff described in Section 5.2.

The cost allocation issue for projects that are not self-funded would have to be addressed in the transmission tariff. The current NEPOOL Agreement and OATT “roll” the cost of any reliability or economic transmission upgrade into the regional tariff rate unless some other mechanism is agreed to by the participants. In other words, the costs of reliability upgrades are included in the region-wide transmission rate and hence are allocated to all participants in proportion to their load. FERC has expressed concern with this methodology because it is inconsistent with its policy that the cost of transmission system upgrades should be allocated to those who benefit from the upgrade to the extent they can be identified or to those who agree to pay.⁸⁵ FERC has accepted the current NEPOOL transmission upgrade cost allocation methodology, but only until it is superseded by the standard market design of the proposed Northeastern RTO.⁸⁶ Recently, in its Standard Market Design Notice of Proposed Rulemaking, FERC stated their “preference is to allow recovery of the costs of expansion through participant funding, *i.e.*, those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for it.”⁸⁷ This is bound to be a contentious issue and its ultimate outcome difficult to predict. For the purposes of comparison, this study will assume that the new RTO will adopt FERC’s principle for allocation of transmission upgrade costs to those who benefit.

Implementation Requirements

The steps necessary for implementing the transmission planning and expansion process are subsumed in the transmission tariff implementation requirements outlined in Section 5.2.

⁸⁵ FERC Order on Rehearing Requests and Compliance Filings, Docket EL00-62-004, Issued June 13, 2001, page 29.

⁸⁶ FERC Order on Compliance Filings and Requests for Clarification, Docket EL00-62-032, Issued February 15, 2002, paragraph 60.

⁸⁷ FERC Notice of Proposed Rulemaking regarding Remediating Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, July 31, 2002, paragraph 197.

Advantages/Disadvantages – Southern Maine

Under the current⁸⁸ rules for allocating the costs of transmission upgrades in NEPOOL, CMP and Bangor Hydro customers would be required to pay a portion of the costs of any reliability or economic transmission upgrade that were not voluntarily paid for by others. In the near term this could be very expensive if ISO-NE and NEPOOL do not conform the transmission tariff to FERC's policy of "he who benefits pays." For example, ISO-NE has identified the need for over \$600 million of transmission upgrades in Southwestern Connecticut. These upgrades would both improve the reliability of that region and reduce the amount of transmission congestion into that region. However, under current NEPOOL rules, CMP and Bangor Hydro customers would be allocated about \$54 million of that cost, based on their load ratio shares. On the other hand, assuming that the virtual single transmission tariff would allocate the cost of transmission upgrades in proportion to the benefits derived from the project, Southern Maine's share would be significantly less.

The transmission planning and expansion provisions of the virtual single transmission tariff would improve the likelihood that the second transmission tie between New Brunswick and Maine is built. The proposed tariff would authorize the ISO to require electric utilities to use good faith efforts to construct transmission projects that the ISO identified as being necessary for reliability or economic reasons. (Local permitting approvals would still have to be secured and could pose an impediment to the project.)

The second tie and any required associated transmission upgrades in Southern New England would significantly increase the transfer capability from New Brunswick to Maine and Southern New England. Assuming that NB Power's plans for refurbishing Point Lepreau and refueling Coleson Cove come to fruition, the second tie would lead to increased sales of electricity by New Brunswick into the New England market. This would lower the market-clearing price and hence lower Southern Maine customers' electricity costs. Of course, the benefit of lower prices would have to be weighed against the cost of constructing the second tie and any associated transmission in Southern Maine.

The example of how additional resources from outside the region could lower the market-clearing price provided in Section 3 is useful in gauging the potential impact of the second tie. In that example, the addition of 1,000 MW at a price of \$30/MWh had the effect of dropping the weighted average annual NEPOOL market-clearing price by \$2.03/MWh. If 300 MW of additional resources were made available, the market-clearing price would drop \$0.72/MWh. Of course New Brunswick's incremental cost is not always at or below \$30/MWh. However, if it is assumed that half of the \$0.72/MWh reduction resulted from the second tie, the annual savings to southern Maine customers would be over \$4 million per year.

⁸⁸ As noted above, the current transmission cost allocation has been accepted by FERC on an interim basis. There is a good likelihood that in the future FERC will require that NEPOOL adopt a cost allocation methodology that is consistent with FERC's policy of "he who benefits pays."

The second tie might also lead to reductions in the installed capability requirements by improving the ability for Maine and New Brunswick to rely on each other's generation for backup. This would depend on how the new RTO implemented its reliability criteria.

Advantages/Disadvantages – Northern Maine

The transmission planning and expansion process of the Maine/New Brunswick RTO would be a mixed blessing for Northern Maine. Both Northern Maine and New Brunswick are currently responsible for paying the costs of upgrades on their own systems. This would not change under the new RTO unless one party clearly benefited by construction on transmission in the other's territory.

Again, the new planning and expansion provisions could enhance the possibility of the second tie. The second tie would allow electricity to flow from south to north. This would provide access to markets in Southern New England for Northern Maine. This would be beneficial during periods of high loads in New Brunswick and other periods when New Brunswick does not have economically competitive resources available.

The second tie could also be disadvantageous for Northern Maine. As New Brunswick increases its sales to Southern New England, New Brunswick will have fewer generating resources available to supply Northern Maine, and the price New Brunswick charges for electricity will likely rise.

Advantages/Disadvantages – New Brunswick

The transmission planning and expansion process of the new RTO would also benefit New Brunswick by improving the chances that the second tie is built. The second tie, and any associated new transmission in Maine, would significantly increase New Brunswick's ability to sell electricity to New England. The second tie would also provide access to resources in New England that could serve as sources of replacement power during the long outage required to refurbish Point Lepreau.

Alternatives

The second transmission tie between New Brunswick and Maine could benefit both regions and could be built independently of a Maine/New Brunswick RTO. The project has already been proposed by NB Power and Bangor Hydro. However, efforts to develop the project have been stalled. In the Spring of 2002, Bangor Hydro withdrew its environmental permit application when the Maine Department of Environmental Protection issued a draft order denying approval due to concerns over the siting of the line. Emera has purchased Bangor Hydro and is evaluating its capital allocation options. At this time Emera has not indicated whether or not it intends to proceed with the project; however NB Power is still pursuing the project. In July of 2002, NB Power submitted an updated application for a certificate of public necessity and convenience from the National Energy Board.

There are several impediments to the development of the second tie. The siting issues would have to be resolved, and Emera would have to be convinced that its investment in the line would earn an acceptable return. Earning a regulated return on its investments in a second tie might not meet Emera's investment requirements. Assuming that New Brunswick continues to have excess generation that is economically competitive in the New England markets, the second tie would provide significant benefits by lowering prices across the region and reducing losses. However, Emera would not be the direct recipient of these benefits. The project would be more appealing to Emera if some of the value associated with these region wide benefits could be provided to the company. Finally, if New Brunswick's excess of economically competitive generation shrinks New Brunswick's incentives to build the line will be greatly diminished.

5.6 Standard Market Design

The Maine/New Brunswick RTO would adopt a standard market design consistent with the standard market design currently being implemented by ISO-NE and NEPOOL. Using the NEPOOL SMD would minimize seams between the new ISO and NEPOOL and could save money. There would be a bid-based energy market which employs locational marginal pricing as a mechanism to deal with transmission congestion. The market would provide for tradable rights to transmission congestion revenue. Those rights would be auctioned and the revenues from the auction allocated to those who pay the cost of congestion and those who pay to use the transmission system. Revenues from the auction of FTRs would also be allocated to those who paid for new transmission.

The ISO would provide for operating reserves when scheduling and dispatching generators. There would not be an operating reserve obligation or market. Instead, operating reserves would be provided as an integral part of the energy market. The ISO would compensate any generator that did not recover its full energy market bid-based cost as a result of providing operating reserves. Further, generators that would have operated, but for being used to provide operating reserves, would be paid their lost opportunity costs.

The installed capability requirement would be based on the current NB Power standard. NB Power currently sets its installed reserve requirement equal to the greatest of 20% of its peak load or the capacity of its largest unit. The installed capability requirement would be implemented as an unforced capability, or UCAP, requirement similar to the one currently being implemented by NEPOOL in its SMD. Participants could self-supply this requirement or rely on an ISO administered auction.

This market design would eliminate market related seams by providing a competitive wholesale market with consistent market products and requirements for the entire Maine, New Brunswick and NEPOOL region. Scheduling and dispatch rules would also be consistent. Further, this market design would be similar to others already implemented in the Northeast and similar to the standard market design proposed by FERC.

Implementation Requirements

1. Market rules would have to be negotiated and drafted. Presumably this would not be difficult if the NEPOOL SMD were used as the template.
2. Regulatory approvals for the market rules would be required.
3. The systems necessary to implement the new market would have to be designed and built or purchased. This would include a generating unit scheduling/dispatch system and a settlement system. These systems would involve hardware, software and communications networks. It could be possible to purchase portions of these systems from ISO-NE since they will have similar designs. Also, the NB Power unit scheduling/dispatch system might be used.
4. The communication network would have to be reconfigured to connect all Maine and New Brunswick generators to the new dispatch system.

Advantages/Disadvantages – Southern Maine

To the extent that SMD increased electricity sales from New Brunswick to Southern New England, market prices in Southern Maine would be lowered. Assuming the second tie with New Brunswick is built, standardization of markets and conforming scheduling protocols would permit more trade between New Brunswick and New England. Assuming their excess of competitive generation continues, New Brunswick would be able to increase its sales of electricity to New England, thus lowering the market prices for the region.

The Economic and Reliability Assessment of a Northeastern RTO cited earlier also provides some perspective on the economic benefit of eliminating seams by standardizing markets. That study estimated that New York's average price of electricity would drop by \$0.45/MWh in 2005 and by \$0.10/MWh in 2010. Again, these results are not directly applicable to the Maine/New Brunswick RTO, but they do provide some insight into the magnitude of the potential benefit for Southern Maine. If the new ISO reduced average prices by \$0.10/MWh, Southern Maine customers would save \$1.2 million a year.

Southern Maine would probably not be significantly advantaged or disadvantaged by virtue of the Maine/New Brunswick RTO installed capability requirements. The NEPOOL and New Brunswick installed reserve requirements would not be very different.

However, Southern Maine would be disadvantaged in the area of operating reserves if it joined with New Brunswick. Although the total operating reserve requirements for the new ISO would be smaller than those of NEPOOL, Maine's share would be significantly larger. The total average NEPOOL ten-minute and thirty-minute operating reserve requirements for 2001 were 1,180 MW and 510 MW, respectively. Of these amounts, Southern Maine's share was about 106 MW and 46 MW, respectively, assuming a load ratio share of 9%. If Maine were to join with New Brunswick, the total operating reserve

requirements would be about half the total NEPOOL requirement: 650 MW for ten-minute operating reserves and 230 MW for thirty-minute operating reserves. However, its load ratio share of these requirements would be between 30% and 43%.⁸⁹ The net result would be for Southern Maine's operating reserve requirements to increase by 75% to 150%. It is difficult to estimate the cost associated with this increase. NEPOOL's total cost of operating reserves was about \$22 million in 2001. Southern Maine's load ratio share of this amount is about \$2 million. However, the mechanism for allocating operation reserve requirements and for allocating their cost will be substantially different under the NEPOOL SMD.

The cost required to implement the new market system would be shared by all parties. ISO-NE has estimated that its new SMD will cost about \$90 million to implement. Since the two markets will be based on the same design, it might be possible to save some money by purchasing the NEPOOL SMD from ISO-NE.

Advantages/Disadvantages – Northern Maine

A common market design based on competitive bidding could increase sales from New Brunswick to Northern Maine. However, Northern Maine's market is currently substantially integrated with New Brunswick's. In fact, Northern Maine is a part of the Maritimes control area. Therefore, the increase in sales would probably not be significant. In addition, increased sales to New England could raise the price New Brunswick charges to Northern Maine.

Northern Maine's installed capability requirement would probably not change. Currently, it does not have such a requirement; it relies on New Brunswick for backup power. However, New Brunswick is considering imposing its own 120% of peak load requirement on Northern Maine. Assuming New Brunswick does, there would be no change in installed capability requirements for Northern Maine resulting from a Maine/New Brunswick RTO.

Northern Maine would have to pay a share of the cost to implement the new market system.

Finally, New Brunswick's market power would be diminished slightly by virtue of a more extensive market without seams. As mentioned earlier, it is felt that New Brunswick has not exercised its market power in Northern Maine to any significant degree.

Advantages/Disadvantages – New Brunswick

New Brunswick would benefit from standardizing its market to conform to that of NEPOOL. Elimination of market related seams between New Brunswick and New England would permit New Brunswick to increase the amount of electricity it sells to New

⁸⁹ Currently, New Brunswick shares its operating reserve requirements with Nova Scotia and Prince Edward Island. If it would continue doing this under a Maine/New Brunswick RTO, Southern Maine's load ratio share would be 30%. If it discontinued this practice, Southern Maine's load ratio share would be about 45%.

England, especially if the second tie is built. As stated earlier, recently New Brunswick's net revenue from such sales was about \$20/MWh (USD) on average. Again, increased sales would increase New Brunswick's marginal costs, but the net revenues resulting from increased sales would be significant.

New Brunswick would also have to pay a share of the cost of implementing SMD.

Alternatives

New Brunswick could implement the NEPOOL standard market design for its wholesale markets without forming a Maine/New Brunswick RTO. However, New Brunswick's immediate plans for reconfiguring its wholesale market do not include a competitive bid-based spot market.

5.7 Single Dispatch

Southern Maine, Northern Maine and New Brunswick could implement a single unit commitment and dispatch for the entire region. This would mean that the dispatch and operation of all the region's generators would be optimized to meet the load of the entire region on a real time basis. This is already being done by New Brunswick and Northern Maine.

Implementation Requirements

1. The NB Power dispatch system would have to be modified to include the entire region. This could require special accommodations to account for the operating limits of the New Brunswick to Maine transmission line.

Advantages/Disadvantages - Southern Maine

A single region wide dispatch would benefit Southern Maine. By optimizing the dispatch of the region's generating units across the region on a real time basis, more economic generation from New Brunswick would be dispatched for New England. This would lower Southern Maine's market-clearing prices. Of course, Southern Maine would have to share in the cost of implementing the system. The Economic and Reliability Assessment of a Northeastern RTO provides some insight in to the magnitude of the associated benefits. According to that study, New York would realize an average drop in market prices of \$0.20/MWh in 2005 and \$0.09/MWh in 2010. Assuming that a single dispatch system for the Maine/New Brunswick RTO would yield a \$0.09/MWh drop in Southern Maine's market-clearing prices would result in a saving of about \$1 million a year.

Advantages/Disadvantages – Northern Maine

Presumably Northern Maine would see very little impact from single dispatch because it is already operating with New Brunswick under a single dispatch system. Northern Maine could be disadvantaged to the extent that New Brunswick's market-clearing prices increase as a result of more electricity flowing to Southern New England.

Advantages/Disadvantages – New Brunswick

New Brunswick would suffer increased costs by implementing a single system dispatch since their generators would run more, thus increasing their fuel costs. This could be offset to some degree by increased sales to Southern New England.