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RELIABILITY ASSESSMENT
POWER MARKET COST/BENEFIT ASSESSMENT
OF
MAINE POWER CONNECTION

Prepared for

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Report to the Northern Maine Independent System Operator Concerning the Maine Power Connection 11/12/08

EXECUTIVE SUMMARY

Northeast Energy Solutions, LLC (NES) was retained by the Northern Maine Independent System Administrator (NMISA) to conduct a reliability assessment and wholesale power market economic assessment (pursuant to NMISA Market Rules 8 and 9) associated with Maine Public Service Company's (MPS or Maine Public) request to interconnect a large wind generation project (Aroostook Wind Energy or AWE) to the Northern Maine Transmission System (NMTS) and the New England Independent System Operator's (ISO-NE or ISO) bulk transmission system. The new interconnection is called the Maine Power Connection (MPC). A key assumption related to this new interconnection is the completion of major new transmission facilities principally to the Central Maine Power (CMP) existing transmission system, the so-called Maine Power Reliability Project (MPRP).

The following table provides summary information concerning these related projects:

Project	**Purpose**	**Estimated Capital Cost**	
		Excluding AFUDC	Including AFUDC
AWE	Power generation of 800 MW and 2,300,000 MWh per year.	N/A	$1.6 Billion
MPC	Interconnect AWE to NMTS and ISO-NE. NMTS becomes part of ISO-NE.	$625 Million	$725 Million
MPRP	Upgrade Southern Maine Transmission System. Stated purpose is to meet National Electric Reliability Council (NERC) reliability standards.	$1.55 Billion	$1.80 Billion

The NMISA is a non-profit entity responsible for the independent administration of the NMTS and electric power markets in Aroostook and Washington counties, with a load of approximately 130 MW. The NMISA administers the wholesale power supply market in northern Maine and the transmission systems of the investor-owned and cooperatively-owned utilities in northern Maine, and its members also include all municipally-owned utilities, generators, suppliers of energy, and large retail customers operating in the control area. The NMISA control area includes two regions, North (comprising the transmission system of MPS) and South (comprising the transmission system of Eastern Maine Electric Cooperative or EMEC), each of which are interconnected only with New Brunswick Power.

Although the interconnection request is driven by AWE's development of 800 MW of wind generation in Aroostook County, the MPC transmission interconnection would result in MPS, and possibly EMEC, becoming participants of ISO-NE. AWE desires to deliver the wind capacity, energy, and renewable attributes to New England load principally south of Maine, which obviously requires delivery into ISO-NE. In order to reach the load south of Maine, the completion of the MPRP is also necessary.

The following are NES' key findings from its assessment of reliability and power market economics on the NMTS and its customers related to the MPC:

1. The MPC is likely to provide some incremental reliability benefits, assuming the existing ties to NB Power are maintained and it is properly designed and operated. However, reliability improvement must be considered in terms of whether the incremental improvement is worth the incremental cost. As indicated recently by the Maine Public Utilities Commission (MPUC), other very modest proposals by Maine Public were determined to be not needed to meet the reliability requirements of the NMTS. Therefore, unless conditions in the NMTS have changed substantially, the reliability improvements associated with the MPC are also likely not needed, or economic.

2. While one would expect that having a new, large capacity tie to New England would improve the reliability of the NMTS, the following are concerns that may need to be addressed in order to avoid potential adverse impacts:
    (a) The existing ties to NB Power and/or sufficient northern Maine generation must continue to be available in order to back-up the loss of the Mullen substation tap to the MPC. NB Power must also continue to support the ties to the extent of the loss of supply from the Mullen tap.
    (b) The planned use of a transfer trip of the Mullen tap and the large generation runback schemes required under various contingencies must be acceptable in relation to using the existing NB ties as a back-up supply to the NMTS and in terms of the overall stability performance of the system.
    (c) The planned use of inductive reactors and a static var compensator at Houlton and Limestone to control high voltage associated with the MPC must be acceptable.

(d) It must be acceptable from a system reliability and economic perspective to reduce the dispatch of existing generation in order to accommodate the dispatch of AWE. Because of the significant variability of the AWE output with changes in wind speed, the transmission studies undertaken to date should be supplemented with a detailed evaluation of the need to provide for supplemental Automatic Generation Control (AGC) and operating reserve capability related to the variable nature of the AWE wind generation.

3. If MPS and EMEC become ISO-NE participants, as contemplated by the MPC, NES projects there will be a significant transmission cost shift for northern Maine consumers (i.e., a cost increase for NMTS customers). The reason for the cost shift is that ISO-NE transmission costs are socialized across all customer load and NMTS customer transmission costs are expected to be much lower than average ISO-NE transmission costs.

   NES estimates the cost shift to northern Maine consumers to be between $229 million [ISO-NE 2007 Regional Transmission Expansion Plan (RTEP)/Regional System Plan (RSP) plus Maine transmission buildout (MPRP and MPC)] and $931 million [ISO-NE 2007 RTEP/RSP, Maine buildout, plus rest of New England transmission buildout proportional to Maine] over a 20 year period. The annual average transmission cost shift is between $11.5 million and $46.6 million per year over the 20 years. For the reasons discussed in the body of the report NES believes the cost shift will likely be in the upper end of the cost shift range, and this range does not include potential additional ISO-NE transmission investment associated with regional interconnection projects. The cost shift could be greater than the above estimated range if ISO-NE approves additional transmission interconnection projects to neighboring regions (Canada and NY). These projects were analyzed by ISO-NE with a cost estimate of $11.3 billion. If built, these projects would create an additional transmission cost shift to northern Maine of $241 million over 20 years or $12.1 million per year.

4. If MPS and EMEC become part of ISO-NE, then wholesale power supply costs for NMISA load serving participants will also likely increase compared to the status quo. This is because the cost of wholesale and retail power in the NMTS has reflected both the lower net value of power produced in that area, as well as the fact that the area generation supply is principally lower cost renewable hydro and biomass whereas the supply in ISO-NE is principally driven by high cost oil and natural gas-fired generation. Assuming this dynamic continues NES projects wholesale power supply costs will increase for NMISA participants by $432 million over a 20 year period, or an average of $21.6 million per year. However, should the existing area generation supply of energy and capacity be reduced such that a significant portion of the supply be sourced from the Maritimes, the historical price advantage would likely erode. The historical price advantage may be eliminated or possibly reversed if conditions change such that a significant portion of supply is sourced from ISO-NE.

5. Given the significant cost shift and risks to NMISA participants associated with joining ISO-NE, a strategy should be considered to insulate NMISA participants from this cost and risk but also allow the AWE project to proceed. One approach would be for AWE to directly connect to ISO-NE as a generation lead but not initially interconnect with the NMTS. This could be done in phases, starting with Bridgewater, and will be more likely to result at the most economical outcome for customers in Maine. Under this approach NMTS customers will avoid the expected initial transmission and power supply cost shift, but preserve a relatively low cost option to directly interconnect with ISO-NE in the future if and when it becomes economically desirable. Even if the AWE project does not proceed, in the future the NMTS could still interconnect to ISO-NE directly with a smaller and low cost interconnection as has been studied in the past, and such interconnection cost would likely qualify for socialization in ISO-NE.

1.0 Objective

This report was prepared by Northeast Energy Solutions, LLC (NES) at the request of the Northern Maine Independent System Administrator (NMISA or ISA) to support the evaluation of the reliability impacts and the impacts on the wholesale electric markets of the proposed Maine Power Connection (MPC). In addition to providing an interconnection for Aroostook Wind Energy (AWE) to deliver its output to ISO-NE, the MPC also provides a new interconnection to the Northern Maine Transmission System (NMTS) at the Mullen substation in Houlton.

As part of this evaluation, the report entitled "Maine Power Connection Study-Part B-Aroostook Wind Energy", Final Report-Draft dated April 2008 (MPC Report) which documents thermal, voltage and fault current studies related to the impact of significant proposed transmission additions referred to as the Maine Power Connection (MPC) was reviewed to assess preliminarily the reliability impact. In addition, the report entitled "Maine Power Connection Study Transient Stability Analysis Part B-Aroostook Wind Energy-Status Reports, dated May 28 and June 25, 2008, (TS Report) was reviewed. Finally, since the premise underlying the MPC is that both AWE and Maine Public Service Company, and possibly Eastern Maine Electric Cooperative, would become part of ISO-NE, a detailed analysis was undertaken of T&D and wholesale electricity market costs of such ISO-NE participation compared with the status quo.

2.0 Scope of Evaluation

In accordance with NMISA Market Rule 8, the NMISA is required to conduct an assessment to determine whether a proposed connection of a new facility, such as the MPC, may (1) have an adverse impact on reliability of the NMTS; (2) create additional congestion by causing the NMTS to operate at or close to normal operating limits; or (3) provide reliability benefits to the NMTS. Further, in cases where the proposed

connection is to become part of the NMTS, the ISA may perform a cost-benefit study of the proposed connection.

In addition, under Market Rule 9, the ISA shall coordinate system planning and development responsibilities to ensure the adequacy and reliability of the NMTS and efficient operation of the northern Maine market.

The scope of this evaluation was intended to be at a high-level in order to identify significant issues and questions that should be highlighted for the NMISA as part of its responsibility to review the reliability and economic impacts related to the MPC under its Market Rules 8 and 9. This preliminary evaluation of the reliability impact is not a detailed review of the scores of power system simulations described in the MPC Report, although many of the cases were reviewed for reasonableness. Further evaluation will be needed once all the required studies (which are currently reported in draft form or are still in process) are completed. In addition, since Maine Public has also requested the ISO-NE to include the costs of the MPC in their regional tariff, the studies will also be reviewed in detail by the ISO-NE, as well as various committees of NEPOOL and the Participating Transmission Owners (PTOs) of New England.

This evaluation also includes an independent analysis of the potential impact of the MPC on the northern Maine wholesale electricity markets and T&D costs. The evaluation includes an analysis of this impact on both the Northern Region (MPS, Houlton Water Company, Van Buren Power and Light and a small portion of Eastern Maine Electric Cooperative all located in Aroostook County) and the Southern Region (the balance of Eastern Maine Electric Cooperative located in Washington County, electrically isolated from the Northern Region by New Brunswick Power) of the NMISA control area.

3.0 Reliability Impact of the Maine Power Connection (MPC)

3.1 Overview Issues From Review of the MPC Report

1. The purpose of the MPC study-Part B, as indicated in its Executive Summary (page i), "is to analyze the proposed interconnection of the 800 MW Aroostook Wind Energy (AWE) generation project under ISO-NE Minimum Interconnection Standards (MIS) Procedure No. 5-6", which is intended to assure that the project "poses no significant adverse impact on the reliability, stability and operating characteristics of the interconnected bulk power transmission system". Under this Standard, the reliability impact is evaluated to determine the minimum required upgrades to satisfy the New England reliability standards for the bulk power supply system as a whole as well as on a sub-regional basis while not diminishing the transfer capacity across any transmission line/relevant interface during reasonably stressed conditions. In addition (and potentially particularly relevant in this case), the addition of a proposed resource shall not create a significant adverse effect on the ISO's ability to reliably operate the system. If a project satisfies the standards under MIS, it can interconnect with the ISO-NE system and operate at its full capacity,

assuming other generation which otherwise would be dispatched is reduced in output. Meeting these standards, however, does not mean that the project generation capacity will be fully deliverable throughout the ISO-NE system. If it cannot, its value to New England will be less than otherwise. It also does not mean that the project will provide any improvement to the reliability of the systems' of New England or northern Maine, or maintain/improve the efficiency of the northern Maine electricity market.

2. It is also important to note that the MPC Report relates only to studies of thermal loading, voltage levels and fault currents and still appears to be incomplete. While these studies are important to determine steady state facility loading, voltage levels and required fault current capacities relative to ratings, they must be supplemented by stability studies, which will determine the impact during transient (short-term) periods following contingencies. At the time of this review, a complete set of final studies was not available as is required to determine the full reliability impact of the MPC as well as what additional facilities are required beyond those identified in the draft studies in order to meet the MIS. For example, the TS Reports determined that a static var compensator may be necessary to adequately control voltage and also discovered that the thermal studies had been undertaken with an incorrect modeling of the wind generators (should have been modeled in Q-control, not V-control) and indicated that operation in Q-control will need to be verified in the thermal models.

   It also should be noted that because of the variability of wind generation together with the substantial amount of capacity being proposed, it is very possible that the operation of AWE may create new challenges for the ISO related to reliable system operations. Experience with large wind installations recently in Texas and the Bonneville Power Administration where a reduction in wind speed was not forecast created extreme operating problems is evidence of this risk. This is an evaluation that needs to be undertaken by ISO-NE as part of its review of these studies and MPS' request.

3. Related to the stated purpose of the study, it seems quite clear that the principal reason for the interconnection is to allow AWE to deliver its output to New England. Even with an interconnection to northern Maine at Houlton, it is likely that most of the AWE generation will be physically delivered to New England with a relatively small portion delivered to northern Maine. Accordingly, although it also evaluates the impact on northern Maine reliability, the MPC study is primarily focused on reliability issues associated with the interconnection of AWE to ISO-NE.

3.2 Reliability Assessment

1. One of the key components of the MPC is that Maine Public will connect to the MPC via a substation/transformer at Mullen Substation in Houlton and operate in parallel with the system of New Brunswick Power (i.e., the existing MPS interconnections with NB Power will remain in operation). According to the MPC report, this was

identified as an option in a Central Maine Power Company (CMP) Feasibility Study requested by the developer and Maine Public. However, it does not appear to be necessary to make this connection in order to interconnect AWE with ISO-NE absent the need to meet reliability requirements or improve the markets of northern Maine.

If the AWE project proceeds with an interconnection to ISO-NE, one of the options which should be considered is to defer any transmission connection to the NMTS until such time as the connection is needed for reliability or market efficiency reasons in NMISA's territory.

2. With respect to the reliability of the NMTS, in late 2005 the Maine Public Utilities Commission (MPUC) rejected Maine Public's proposal to increase the capacity of its ties to New Brunswick Power (NB Power) to meet reliability requirements (Docket No. 2004-538). The MPUC concluded the proposal is not necessary. The conditions under which that decision was made do not seem to have changed significantly. In that decision, the MPUC found that, under its largest single contingency (loss of Beechwood-Flo's Inn) Maine Public would have about 110 MW available from its other ties, 12.4 MW from Tinker Hydro and 51 MW from Boralex biomass plants, for a total of about 173 MW of capacity to meet a peak load exposure of 141 MW. Thus, no increase in the capacity of the ties to NB Power was deemed necessary. A key assumption at that time, that the high cost of natural gas would support the economic viability of biomass, seems to continue to be reasonable today. In addition, the MPC study assumes that additional generation will be available in the NMTS, including Evergreen Wind (42 MW), Boralex Ashland (38 MW) and Loring (69 MW) and that future upgrades to the NB ties (50 MW) will occur, further reducing the need for reliability upgrades such as the MPC.

   A key assumption in the MPC study is that many so-called "qualifying modifications/upgrades" will be undertaken by CMP, Bangor Hydro-Electric Company (BHE) and Maine Public. For example, with respect to Maine Public, substantial upgrades to various 69 and 138 KV lines and substations are assumed, including upgrades to its ties to NB Power. Many of these upgrades were not included in the recently published NMISA 2008 Seven-Year Outlook. Moreover, as indicated above, such upgrades may not be required to maintain the reliability of the NMTS, since the existing ties together with available internal generation is assumed (based upon the recent MPUC determination) to be more than adequate. If these additions or similar modifications/additions on the systems of CMP and BHE are required as part of the interconnection of AWE, the costs should be assigned to that interconnection project and not to the applicable T&D system.

3. Nonetheless, with the proposed connection/parallel operating mode, the northern Maine system is impacted by the operation of AWE as well as the transmission facilities associated with AWE and the rest of the New England/NB interconnected system. Some of the impacts are noted below.

4. Having this new high capacity tie to New England should enhance the reliability of the NMTS, assuming it is designed and operated to avoid adverse impacts associated with its operation which may occur during contingencies and assuming that the existing ties to NB Power can continue to be utilized for back-up support as they are today. These existing ties have historically been subject to long standing interconnection and coordination agreements, based upon the reality that the NMTS was solely connected to NB Power. If the new connection at Mullen Substation occurs, it will be important to continue to maintain the existing ties as back-up; otherwise, the loss of the Mullen tap could subject the NMTS to inability to meet load.

5. With the connection at Mullen Substation, power flows will be into Mullen under various system conditions, and be as much as 100 MW + at some times, reducing the flows from the ties to NB. However, this mode of connection to the MPC does introduce reliability risks related to operating northern Maine interconnected to both NB Power and ISO-NE. For example, in the event the Mullen to Chester 345 KV line is lost, it will be necessary to transfer trip the connection to the Mullen 69 KV system; otherwise the 800 MW from AWE will overload the underlying 69/138 KV system of Maine Public and/or NB, possibly resulting in system collapse. It will be important to evaluate the impact of this contingency on the transient stability of the system, including the northern Maine system, prior to making a judgment on whether the transfer trip scheme is acceptable.

6. Similarly, there are other conditions where loss of various transmission elements, principally in Maine, requires significant generation runback, up to 1200 MW, either at AWE, or in New Brunswick. While the rejection of generation is routinely incorporated in power system operations, it does introduce an opportunity for equipment failure, and significant unintended consequences.

7. Another consequence of connecting AWE to northern Maine is the need to install and operate substantial quantities of inductive reactors to reduce voltage when AWE is generating at low outputs. For example, the thermal/voltage studies indicated that 120 Mvar reactors have to be installed at Mullen and Limestone substations. Subsequently, the preliminary transient stability study suggests that a static var compensator (SVC), at least +200/-120 Mvar, would be required at Houlton. This is necessary to control both high and low voltages related to various operating conditions associated to AWE. Both the reactors and SVC introduce higher capital and O&M costs, complexity for operations and potential operating risks.

8. The generation dispatch data in the various MPC study cases illustrates vividly the limited capability of the interconnection facilities proposed. As indicated, in a large portion of the cases in order to allow AWE generation to operate, several other large regional generating facilities had to be reduced in output. Generation is backed off in the NMTS (hydro and biomass), NB Power (hydro and Coleson Cove) and Maine (Maine Independence Station, Great Lakes Hydro, Bucksport, Jay, and Westbrook). This means that the AWE interconnection is not being designed so that AWE will be

fully integrated and deliverable to New England; thus its value to New England will be diminished.

9. Although such re-dispatch allows the thermal and voltage limits to be satisfied for the purpose of the MIS, it is questionable whether this would be acceptable in real-world system operations. For example, the units that have to be re-dispatched are also units that have the capability to deliver spinning reserve, regulation of voltage and power flows and improve the stability of the system during transient stability events. The same capabilities are not available or are less effective from wind generation which normally operates in a non-synchronous mode. If so, it may be necessary to operate some non-AWE generation in less than optimum mode (e.g., postured at minimum load to provide reserves in the event of a contingency).

   And, as discussed section 3.3 below, a lack of transmission capability to allow AWE to operate at full output without re-dispatching existing Maine generation will reduce the economic benefits associated with AWE; rather than displacing high cost natural gas or oil-fired generation in Massachusetts and Connecticut, AWE may displace low cost biomass, hydro, or natural gas-fueled generation in Maine, and possibly cause Maine fossil fuel generation to operate out of economic merit to ensure reliability of the system. In this circumstance the benefits, if any, for Maine and in particular load south of Maine will be reduced. In this case, it is unlikely that the costs of the MPC would be included in the regional transmission rate.

3.3 Comments on the Economics of the MPC

1. The ISO-NE has separately described the studies required to accommodate the request of Maine Public Service Company to interconnect to the ISO-NE system concerning consent to being designated an Additional Participating Transmission Owner as well as the inclusion in regional rates of the costs of the interconnection. In his 3/14/08 letter to Maine Public, Gordon van Welie described the studies to date (including the ISO-NE studies), as incomplete; that no production cost savings studies (required to support the interconnection as a "market efficiency upgrade") have been completed or finalized; and that the preliminary studies have assumed that the AWE wind resources are fully deliverable throughout the New England transmission system. Based upon this letter, it seems quite possible that the ISO-NE will determine that additional transmission facilities (for example, the Green Line, the Northeast Energy Link, or other projects south of Maine) will be needed to allow the AWE generation to reach southern New England to provide substantial economic benefits in ISO-NE, and ultimately be considered for inclusion of the project transmission costs in regional rates.

2. As indicated by the 3/14/08 Gordon van Welie letter, the MPC Project will be evaluated under Attachment N of the ISO-NE OATT. In accordance with Attachment N, transmission system upgrades such as the MPC shall be classified as Reliability or Market Efficiency Upgrades during the Regional System Plan (RSP) process. To be

classified as a Reliability Upgrade, the upgrades must be necessary to ensure the continued reliability of the New England Transmission System. Since the purpose of the MPC is to provide transmission facilities principally to allow AWE to deliver its output to ISO-NE, it is unlikely that this upgrade would be classified as a Reliability Upgrade. To be classified as a Market Efficiency Upgrade, the net present value of the net reduction in total cost to supply the system load, as determined by ISO-NE, must exceed the net present value of the carrying cost of the identified transmission upgrade(s).

It is unclear how the determinations set forth in Attachment N relative to Market Efficiency Upgrades are to be made when the proposed upgrade is needed to interconnect a new generator like AWE. NES believes that the original intent of Attachment N with respect to Market Efficiency upgrades was to identify existing inefficiencies (losses, congestion) which could be eliminated with transmission upgrades (and which would not otherwise be relieved by market responses). The MPC request appears to be the first time that an upgrade primarily associated with a generator interconnection has been proposed to be treated as a Market Efficiency Upgrade.

It appears that other parties also question the appropriateness of the application of Attachment N in this case; a 6/11/2008 letter from Paul Hibbard, Chairman of the Massachusetts Department of Public Utilities, to the ISO-NE stated "there remain significant reservations with respect to ISO's interpretation of related tariff language, the economic and policy rationales for the analytic method proposed for associated studies, and the framing and processing of Attachment N study requests for the MPC" and further, "it is simply premature and inappropriate to process any request under Attachment N prior to resolution at the regional level of the underlying policy and tariff issues associated with such reviews, agreement on analytic modeling approached, and clear delineation of the practical outcomes that flow from such studies…". Similar concerns have been expressed recently by representatives of Connecticut. On October 15, 2008, a proposal concerning the cost sharing for the MPC was discussed that would only provide regional funding for a 138 KV interconnection to the NMTS, with the incremental cost of interconnecting the AWE project to be treated either as generator leads or as a cost responsibility of those who purchase the AWE output.

In any regional system plan, in order to arrive at an appropriate economic conclusion with respect to a proposed project, NES believes all costs should be included in the economic evaluation. These include capital costs (both transmission and generation, when applicable), fuel costs, variable O&M (including annual property taxes), project financing related costs (letter of credit,…), incremental system reliability costs (increased Automatic Generation Control requirement, Reliability Must Run/Net Commitment Period Compensation required to maintain system reliability,…), and other relevant costs items. Therefore, if application of Attachment N is used for MPC/AWE it would seem to be necessary to include the cost of installing and operating the AWE project as part of the determination of the net reduction in total

cost to supply the system load. Otherwise, virtually any generation interconnection could satisfy, to one degree or another, the net present value test of Attachment N. The inclusion of the cost of installing and operating the generation project would also be consistent with the recent ISO-NE 2007 Scenario Analysis where various scenarios related to future supply/demand options (including wind) were evaluated. In the Scenario Analysis, ISO-NE determined that the reduction in the regional clearing price related to wind generation was likely to be substantially less than the cost of adding wind generation to the system.

Another recent study (Avoided Energy Supply Costs in New England: 2007 Final report, dated 8/10/2007) completed by Synapse Energy Economics, Inc. related to the economics of demand-side management alternatives postulated a demand reduction induced price effect (DRIPE) which would only reduce the clearing price for a short period, after which generators would adjust their investments and operations and the price would return to approximately the pre-demand-side price level. It would seem that a similar effect would occur when a new generator is added to the system. If one used the Synapse estimate of the induced price effect of adding demand reduction of approximately $32/MWh applied to AWE generation of 2.3 GWh/year, the four year savings is about $294 million. Similarly, the recent study (6/30/2008) undertaken by La Capra prepared for MPS and CMP and filed with the Maine PUC, indicated an average reduction in the New England LMP over the 1st four years of operation of $0.70/MWh or about $392 million (assuming New England annual load of 140 GWh/year).

In addition, as noted previously in reviewing the reliability impacts of AWE, because wind generation is subject to a high degree of variability, other generation will need to be available and operate to maintain the area load/generation balance within schedule. This generation will need to have automatic generation control (AGC) and Ten Minute Operating Reserve (TMOR) capability, and related incremental costs which needs to be accounted for when the determination of the economics of AWE/MPC is undertaken.

3. Although a detailed economic evaluation has not been completed or finalized by ISO-NE, a preliminary draft of a partial economic evaluation was presented to ISO-NE's Economic Studies Working Group (ESWG) on 5/22/08. Section 4 below describes the preliminary draft in more detail. A simple calculation of the cost of the MPC, based upon the most recent estimate of capital cost of $725 million (including AFUDC), would determine the annual carrying cost of the MPC to be about $131 million (assumes ISO-NE's 2008/09 carrying cost rate of 18.05%). Using an average annual output of AWE of 2.3 billion kwh (33% capacity factor), the per unit cost of the transmission upgrades in relation to AWE's output is $57/MWh. And, using a New England annual energy requirement of about 140 GWh, the reduction in average cost to serve the system load would need to be about $0.93/MWh over the 40+ years of life of the transmission investment to cover only the transmission revenue requirement.

4. On 5/22/08, a preliminary analysis of potential economics of the MPC was presented to the ESWG. This study was intended to be in accordance with Attachment N and indicated production cost savings in the range of $696 million (net present value, 2006$) (slide 45). This savings did not include any of the transmission costs of the MPC or the cost of installing and operating AWE. The estimated cost of transmission is $625 million. This estimate excludes allowance of funds used during construction (AFUDC). If one includes AFUDC (estimated at 16% of cost) the installed cost is about $725 million. Also, if one includes the NPV of annual O&M and property taxes (estimated at 15% of installed cost) then the total cost of the MPC is approximately $834 million, which is greater than ISO-NE's preliminary savings estimate of $696 million. In addition, if one assumes the installed cost of AWE is $2,000 per kw (2006$), then for 800 MW the installed AWE cost would be $1.6 billion. This results in a total AWE installed cost of about $2.4 billion, which is more than 3 times the net present value production cost benefit of $696 million calculated in the preliminary ISO-NE analysis.

   In addition, if the ISO-NE determines that additional transmission facilities will be required in order to achieve the full benefits of AWE (for example, full integration and deliverability), additional costs would need to be included in the economic analysis.

   Based upon the preliminary analysis and above evaluation approach, it appears the MPC/AWE does not qualify as a market efficiency upgrade for inclusion in ISO-NE's Regional Network Service (RNS).

   However, if it is determined that the benefits in terms of lower production costs of a project like AWE are sufficient to classify the MPC as a Market Efficiency Upgrade, it would seem necessary that the developer would need to also provide adequate financial assurance, such as a letter of credit, to assure that AWE's 800 MW of capacity is installed and operates to provide the expected energy production. This is important because the only reason any benefit is projected to be received by load is the actual operation of AWE in the amount assumed over at least 10 years, and on that basis load is paying the cost of the transmission.

5. In several places within the MPC Part B Report (see, for example, page (i)), it is indicated that AWE will build the transmission required to transmit and distribute the wind capacity. If that is the case, then it would <u>not</u> be necessary for the costs to be recovered in the ISO-NE regional tariff, as has been requested by Maine Public. It may well be feasible for AWE to build and pay for its own transmission generation lead to ISO-NE. Other wind projects in Maine, which also require substantial transmission (generation lead) investment, are proceeding without the need to socialize these costs. For example, the Stetson Mountain Project involves a 38 mile line for 60 MW (0.63 miles per MW). This compares to 285 miles for 800 MW (0.36 miles per MW) for AWE.

Also, in terms of seeking to minimize the total costs to serve load, it would seem that ISO-NE would need to consider whether or not the potential benefit from a project like AWE could be achieved by alternative projects where less transmission costs would need to be socialized. For example, if the level of subsidy needed in this case were offered to other wind projects located closer to loads, it may be possible to get more benefit for customers. It may be more economic for New England load for AWE to construct a smaller project, for example the 300 MW component at Bridgewater, and directly interconnect in Haynesville for a substantially lower transmission cost relative to production cost savings.

6. As another measure of comparison for inclusion in ISO-NE's RNS, the most recent major new interconnection completed in New England was the Northeast Reliability Interconnect (NRI), completed late 2007. This project was originally planned to cost about $90 million and provided about 300 MW of additional capacity for New England. At about $300/kw installed cost, its cost/benefit (which included a significant reliability benefit) was determined to be slightly positive and was approved by ISO-NE. This compares to AWE, which will deliver an average of about 264 MW at a cost on the order of $725 million (including AFUDC) or about $2700/kw. Given the magnitude of difference in cost compared to the NRI, one must wonder how this project could be approved by the ISO-NE for inclusion in regional rates.

7. As noted in the MPC Report, in order for the MPC to be considered in the form presented, it is necessary that major improvements be made to the systems of CMP (the Maine Power Reliability Project-MPRP), BHE, and Maine Public. The scope of the effort and investment required by these prerequisite improvements is massive, involving hundreds of miles of transmission lines, many major substation additions/expansions, numerous line rebuilds and other changes. The magnitude of these investments could be in the range of $2 billion or more, substantially exceeding the entire existing Maine investment in transmission facilities of about $400 million (including about $140 million recently related to the NRI) by a factor of 5. It seems likely that such major investments in Maine will not occur unless these projects are also approved by ISO-NE for inclusion in regional rates. These costs, together with even greater upgrade costs expected in the rest of New England, including additional facilities to deliver the AWE output to southern New England, will need to be considered when weighing the costs versus benefits of the MPC either in the context of New England, Maine, or northern Maine.

8. As discussed previously in this report and in Section 3.2.2 of the MPC Report, the MPC study assumed that additional facilities are required in the systems of Maine Public, BHE and CMP beyond the facilities initially assumed to be part of MPC-these are referred to as "qualifying facilities". In some cases the report indicates that these changes had already been incorporated in the plans by the applicable utility, while in others they had not. Regardless, it is important to determine which additions are truly being driven by the MPC and which are driven by needs absent MPC. This will be

particularly true if some or all of the cost of the MPC is deemed allocable to AWE as part of a generator lead.

4.0 Wholesale Markets Impacts of the MPC

1. As described in detail in Appendix A to this report, NES has separately evaluated the effect of the MPC on the northern Maine power markets, both in terms of the impact on transmission costs and wholesale power supply costs. As noted previously, Maine Public Service has requested the ISO-NE to include the costs of the MPC in the regional transmission service tariff and to compensate the customers of the NMISA for any costs which might be incurred by joining the ISO-NE system. The analysis detailed here is intended to provide an estimate of the magnitude of the required level of compensation.

   The transmission costs are related to the costs of transmission which Maine Public and other NMISA T&D utilities will need to recover from customers if northern Maine joins ISO-NE; under the ISO-NE transmission cost recovery mechanism all Pool Transmission Facilities (PTF) are socialized and recovered from all ISO-NE network load serving entities (T&Ds). To the extent that average ISO-NE transmission costs exceed what the costs would be for a T&D utility in northern Maine on a stand-alone basis, a cost shift penalty would be incurred from joining ISO-NE.

   There will also be a cost shift related to the costs of power supply for northern Maine if Maine Public and other participants in the NMISA join ISO-NE. This cost shift occurs because (1) of the existence of costs which are incurred by power suppliers in moving capacity and energy from NMISA to ISO-NE, (2) the cost of ancillary products are higher in ISO-NE compared to NMISA, (3) there are wholesale load serving costs in ISO-NE that are not applicable in NMISA, and (4) the administrative funding costs of ISO-NE/NEPOOL are greater than NMISA.

   The cost shift of transmission and wholesale power supply is more fully described in Sections 2 through 6 below and in Appendix A.

2. As shown in Appendix A, unless a special adjustment is made to the normal treatment of PTF cost recovery, the transmission costs of load in the northern Maine market will increase significantly if Maine Public and other northern Maine T&D utilities join ISO-NE. This is because the current expected transmission costs of ISO-NE will increase dramatically under the approved 2007 regional transmission expansion plan (RTEP2007) and other proposed future transmission additions in New England. For example, the recent increase in the regional network service rate, effective 6/1/08, from $27.91/kw/yr to $44.11/kw/yr (approximately a 58% increase) is an indication of the magnitude of transmission additions already completed. Transmission additions and related dramatic cost impacts will further increase the RNS rate if several currently proposed projects are undertaken. These projects include the

MPRP, MPC, Green Line, Northeast Energy Link, New England East-West Solutions Intrastate Project (MA, CT, RI), Monadnock Area Reliability Project, Northwest Vermont Reliability Project, Vermont Southern Loop Project, New Hampshire's 10 Year Plan, and many others internal to ISO-NE transmission. There has also been some discussion and study performed in 2007 regarding significant transmission investment to increase the transmission delivery capacity between Quebec and NY with southern New England. These costs far exceed the expected transmission costs of Maine Public and Eastern Maine Electric Cooperative (EMEC) on a stand-alone basis.

The following table summarizes the transmission costs assuming already approved ISO-NE RTEP 2007 projects and Maine Only transmission buildout (MPRP, MPC) projects are included in RNS:

TABLE 1
PROJECTED TRANSMISSION COSTS
CASE 1: Maine Only Buildout
(2007 RTEP, MPC, MPRP)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Stand Alone	Join ISO-NE	12 CP Load	Cost Increase	Stand Alone	Join ISO-NE	12 CP Load	Cost Increase	NMISA Cost Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2011	34.37	104.05	119.9	8,356	32.22	88.73	13.6	770	9,126
2012	35.75	107.94	121.1	8,743	32.41	91.78	13.8	817	9,559
2013	35.72	112.43	122.3	9,383	32.61	96.03	13.9	881	10,264
2014	36.42	114.79	123.5	9,683	32.81	98.14	14.0	917	10,600
2015	36.47	116.89	124.2	9,985	33.02	100.03	14.1	945	10,930
2016	36.87	118.49	124.8	10,186	33.23	101.43	14.2	967	11,152
2017	37.10	119.44	125.4	10,326	33.45	102.16	14.2	979	11,305
2018	37.43	121.07	126.0	10,542	33.67	103.56	14.3	1,001	11,542
2019	37.72	121.51	126.7	10,613	33.89	103.78	14.4	1,005	11,619
2020	38.04	121.97	127.3	10,684	34.11	103.99	14.5	1,010	11,694
2021	38.36	122.43	127.9	10,756	34.34	104.22	14.5	1,015	11,771
2022	38.69	122.91	128.6	10,829	34.57	104.44	14.6	1,020	11,849
2023	39.02	123.41	129.2	10,903	34.80	104.68	14.7	1,026	11,929
2024	39.37	123.91	129.9	10,979	35.03	104.92	14.8	1,031	12,010
2025	39.72	124.43	130.5	11,056	35.27	105.17	14.8	1,036	12,092
2026	40.09	124.97	131.2	11,133	35.51	105.42	14.9	1,042	12,175
2027	40.46	125.52	131.8	11,213	35.75	105.68	15.0	1,047	12,260
2028	40.84	126.09	132.5	11,293	35.99	105.94	15.0	1,053	12,346
2029	41.23	126.56	133.1	11,360	36.24	106.11	15.1	1,057	12,417
2030	41.63	127.15	133.8	11,443	36.49	106.38	15.2	1,062	12,505
Total (2011-15)				46,150				4,329	50,479
Total (2011-20)				98,500				9,291	107,791
Total (2011-25)				153,023				14,420	167,442
Total (2011-30)				209,465				19,680	229,145
Annual Avg				10,473				984	11,457

As indicated, the total transmission cost shift from joining ISO-NE under these assumptions is estimated at $229 million over 20 years or approximately $11.5 million per year.

As previously noted, there is a substantial amount of planned and proposed new transmission additions in the rest of New England. With the socialization of the transmission costs in New England, basically each utility (or State) will pay their

percentage of the ISO-NE coincident peak load for the transmission projects undertaken by the utility (or State). Without evaluating in detail the future behavior of all other utilities (or States), one may conclude this is a good outcome for Maine customers. Maine's percentage of ISO-NE coincident peak load is about 8.2 percent, therefore Maine will only pay for 8.2 percent of all its RNS qualified transmission costs in Maine and the rest of New England will pay the remaining 91.8 percent. However, to make a more realistic assessment one must evaluate the likely motivations of all the other utilities (or States) in ISO-NE, as well as the magnitude of potential projects in the other States. The following table shows the estimated coincident peak percentage of each ISO-NE State:

New England
12 Coincident Peak Load
2007 (Estimated)

	MW	%
Vermont	882	4.1%
Rhode Island	1,404	6.5%
Maine	1,760	8.2%
New Hampshire	1,950	9.1%
Connecticut	5,575	25.9%
Massachusetts	9,914	46.1%
Total	21,486	100.0%

Note: Maine Does Not Include MPS and EMEC.

As shown by the table, each State (or Utility in the State) only pays a portion (46.1% or less) of the cost of transmission in their State and therefore will have the motivation to overbuild the transmission system in their State (or Utility Service Territory). In Vermont's case, they only pay 4.1% of the cost of RNS qualified projects in their state. The rest of New England pays the remaining 95.9%. In Massachusetts' case, they only pay 46.1% of the cost of RNS qualified projects in their state. The rest of New England pays the remaining 53.9%. In addition, each utility will pay the ISO-NE RNS rate (regional average cost) and if that utility has actual costs less than the RNS rate they will pay the costs (i.e. subsidize) of the other utilities' transmission projects. The utilities with lower transmission costs will be even more incented to build out their transmission system (to at least the regional average or RNS rate). Therefore, given this transmission cost payment method one could reasonably assume each utility (or State) will build out its transmission system on at least the same proportional basis as the Maine Buildout Case summarized in Table 1 [i.e. Maine Buildout Cost divided by Maine's Percentage of Peak Load]. As evidence of the likelihood of substantial more buildout throughout New England, from the time RSP07 was approved (fall 2007) through February 2008 an additional $2.6 billion of transmission was approved.

Assuming each New England State builds out its transmission system in proportion to the proposed Maine Buildout (and their projects are included in RNS), the following table summarizes the transmission cost impact to NMISA participants:

TABLE 2
PROJECTED TRANSMISSION COSTS
CASE 2: New England Buildout
(Case 1, plus equivalent pro-rata buildout for Each NE State and Green Line)

	Annual Cost (North Region)				Annual RNS Cost (South Region)				Total
	Stand Alone	Join ISO-NE	12 CP Load	Cost Increase	Stand Alone	Join ISO-NE	12 CP Load	Cost Increase	NMISA Cost Increase
Year	$/kwyr	$/kwyr	MW	$K	$/kwyr	$/kwyr	MW	$K	$K
2011	34.37	286.02	119.9	30,175	32.22	270.70	13.6	3,248	33,423
2012	35.75	315.74	121.1	33,910	32.41	299.59	13.8	3,675	37,585
2013	35.72	333.73	122.3	36,452	32.61	317.32	13.9	3,956	40,408
2014	36.42	351.96	123.5	38,983	32.81	335.31	14.0	4,245	43,228
2015	36.47	370.04	124.2	41,416	33.02	353.18	14.1	4,515	45,931
2016	36.87	372.84	124.8	41,923	33.23	355.77	14.2	4,571	46,495
2017	37.10	375.03	125.4	42,378	33.45	357.75	14.2	4,619	46,998
2018	37.43	376.67	126.0	42,755	33.67	359.16	14.3	4,660	47,415
2019	37.72	377.12	126.7	42,989	33.89	359.38	14.4	4,683	47,672
2020	38.04	377.58	127.3	43,222	34.11	359.61	14.5	4,706	47,929
2021	38.36	378.06	127.9	43,459	34.34	359.84	14.5	4,730	48,189
2022	38.69	378.55	128.6	43,696	34.57	360.08	14.6	4,754	48,450
2023	39.02	379.05	129.2	43,936	34.80	360.32	14.7	4,778	48,714
2024	39.37	379.56	129.9	44,178	35.03	360.57	14.8	4,802	48,980
2025	39.72	380.09	130.5	44,422	35.27	360.83	14.8	4,826	49,248
2026	40.09	380.64	131.2	44,668	35.51	361.09	14.9	4,851	49,518
2027	40.46	381.20	131.8	44,916	35.75	361.35	15.0	4,875	49,791
2028	40.84	381.77	132.5	45,166	35.99	361.63	15.0	4,900	50,066
2029	41.23	382.25	133.1	45,403	36.24	361.91	15.1	4,925	50,328
2030	41.63	382.85	133.8	45,657	36.49	362.20	15.2	4,950	50,608
Total (2011-15)				180,936				19,639	200,576
Total (2011-20)				394,205				42,879	437,084
Total (2011-25)				613,897				66,768	680,665
Total (2011-30)				839,706				91,269	930,975
Annual Avg				41,985				4,563	46,549

As shown, the total transmission cost shift from joining ISO-NE under these assumptions is estimated at $931 million over 20 years or approximately $46.6 million per year.

Also, in a purported effort to import more energy from external regions there is a potential for even additional transmission investment with a very significant cost. For example, Emera/BHE has proposed a $2 billion transmission project from Orrington ME to Boston MA, referred to as the Northeast Energy Link. To put this in perspective ISO-NE's total gross transmission investment in 2007 was only about $3.3 billion. Furthermore, according to ISO-NE's 2007 scenario analysis report, to accommodate more energy from Canada about $8.9 billion of transmission investment may be necessary, and to accommodate additional energy from NY about $2.4 billion of transmission investment may be required. Assuming these transmission investments occurs (in addition to the Maine and New England transmission buildout assumptions above), NMISA load would pay an additional $241 million over 20 years or $12 million per year in transmission cost shift from joining ISO-NE.

3. In addition, Appendix A provides a detailed estimate of the cost shift that could occur in wholesale power supply costs should Maine Public and other NMISA participants join ISO-NE. This cost difference has been evident since restructuring in Maine was implemented, for example, in standard offer rates being generally higher in southern Maine (BHE and CMP) compared to northern Maine. During the past 4 years the average cost for standard offer service has been approximately $16/MWh less in northern Maine (MPS) than in southern Maine (BHE).

4. NES' analysis estimates the difference in wholesale costs for northern Maine customers for the status quo versus joining ISO-NE. This analysis calculates the wholesale cost for joining ISO-NE by projecting the future costs of energy and capacity in the ISO-NE market and adding the costs of various load serving/ancillary products and administration. NES then estimated the wholesale load serving cost in northern Maine of the status quo by estimating the amount and cost of northern Maine generation and Maritime generation that would be serving the load. NES estimated the value which would be received by generators located in NMISA's territory from delivering their output to the ISO-NE market and the marginal cost of the existing biomass facilities in northern Maine, It is assumed that the generators would seek to maximize their revenues by setting their price in northern Maine at the greater of (1) their opportunity price in ISO-NE adjusted for the costs incurred to deliver energy from northern Maine to ISO-NE (netback costs) or (2) their marginal cost plus a margin. A generator is expected to operate if it is economic compared to supply from the New Brunswick marketplace. To the extent that adequate generation does not exist or operate in northern Maine, it is assumed that power supply will be available from the surplus New Brunswick marketplace (which would otherwise be sold to ISO-NE) at an energy price equal to the Salisbury node. NES did not include in this analysis any new projects currently under development in northern Maine, such as the 69 MW Loring project or the 50 MW First Wind project in Oakfield.

   With respect to capacity, given logistical transmission and seams issues NES assumed NMISA/NB generation receives 50% of the ISO-NE capacity value. If NMISA/NB generation receives 0% or 100% of the ISO-NE capacity value, then the power supply cost shift will be $11.6 million per year (over the 20 year period) higher or lower, as applicable, than the cost increase shown in Table 3 below. Furthermore, a recent change in tie benefit calculation methodology in ISO-NE has increased the tie benefit with New Brunswick (for June 2011-May 2012) from 360 MW to 716 MW. With a 1,000 MW capacity rating, this leaves only 284 MW of capacity that can be sold into ISO-NE. Given New Brunswick Power Generation Company and Hydro Quebec have all but 28 MW of the firm capacity from New Brunswick into ISO-NE, the ability of northern Maine generators to sell capacity into ISO-NE is severely limited. Therefore, NES believes it is more likely NMISA generation receives significantly less than 50% of the ISO-NE capacity value.

   Note the analysis assumes the MPRP and other New England transmission projects increase ME/NH interface capacity so the benefits of AWE are realized by the load

south of Maine, and as such (1) losses in Maine are reduced, (2) congestion in Maine is reduced, and (3) the projected capacity price in Maine is equal to the region wide cost of new capacity. It is assumed the reduction of losses and congestion results in Maine's LMP basis to the MA HUB increasing from about 93% to 98% (approximate regional basis to Hub). Also, NES did not estimate or incorporate any potential reduction in ISO-NE's energy clearing price associated with AWE's participation in the energy market. Such an estimate is not necessary to calculate the cost shift given the energy cost to NMISA participants under the status quo is highly correlated with ISO-NE's energy clearing price, therefore any reduction in ISO-NE's energy clearing price associated with AWE (or other projects) will also result in a reduction in energy price for NMISA participants regardless of whether or not northern Maine joins ISO-NE.

The following table summarizes and compares the estimated wholesale power supply (market) costs for northern Maine under both the status quo and joining ISO-NE options:

TABLE 3
PROJECTED WHOLESALE POWER SUPPLY COSTS

	Annual Cost (North Region)				Annual Cost (South Region)				Total
	Stand Alone	Join ISO-NE		Cost Increase	Stand Alone	Join ISO-NE		Cost Increase	NMISA Cost Increase
Year	$/MWh	$/MWh	Load MWh	$K	$/MWh	$/MWh	Load MWh	$K	$K
2011	72.23	88.35	763,436	12,305	73.25	90.68	86,715	1,512	13,817
2012	74.16	92.28	771,069	13,970	74.99	94.71	87,583	1,727	15,697
2013	77.61	96.73	778,781	14,887	79.52	99.27	88,458	1,747	16,635
2014	78.38	97.75	786,568	15,240	80.21	100.33	89,343	1,797	17,037
2015	80.02	99.92	794,434	15,803	81.99	102.54	90,236	1,854	17,657
2016	81.54	101.94	802,378	16,370	83.63	104.62	91,139	1,913	18,282
2017	83.09	103.99	810,402	16,942	85.29	106.72	92,050	1,973	18,915
2018	84.75	106.21	818,506	17,563	87.09	108.99	92,971	2,036	19,599
2019	86.36	108.34	826,691	18,170	88.79	111.17	93,900	2,101	20,271
2020	88.12	110.67	834,958	18,834	90.69	113.57	94,839	2,170	21,004
2021	89.92	113.07	843,307	19,519	92.63	116.02	95,788	2,240	21,760
2022	91.77	115.51	851,741	20,226	94.61	118.53	96,746	2,314	22,540
2023	93.68	118.02	860,258	20,936	96.63	121.09	97,713	2,390	23,326
2024	95.71	120.58	868,861	21,602	98.70	123.72	98,690	2,469	24,071
2025	97.79	123.19	877,549	22,291	100.81	126.40	99,677	2,551	24,842
2026	99.92	125.87	886,325	23,005	102.96	129.15	100,674	2,636	25,641
2027	102.09	128.61	895,188	23,744	105.16	131.95	101,681	2,724	26,468
2028	104.30	131.41	904,140	24,509	107.41	134.82	102,697	2,816	27,325
2029	106.57	134.28	913,181	25,301	110.17	137.76	103,724	2,862	28,164
2030	108.88	137.21	922,313	26,122	112.52	140.77	104,762	2,960	29,082
Total (2011-15)				72,206				8,637	80,843
Total (2011-20)				160,085				18,830	178,915
Total (2011-25)				264,658				30,795	295,453
Total (2011-30)				387,340				44,793	432,132
Annual Avg				19,367				2,240	21,607

As indicated, the total wholesale power costs to NMISA load from joining ISO-NE is estimated at $432 million over 20 years or about $21.6 million per year.

In order to reduce the power supply cost shift impact, NMISA's Northern Region could become a separate load zone. The transmission additions between the Northern

Region and southern Maine are likely to be designed to ensure congestion does not exist between these areas. Therefore, the zonal LMP price difference between the Northern Region and southern Maine will be the impact of marginal losses. In this circumstance, NES estimates that the LMP in the Northern Region would reflect a reduction for marginal losses of about 3% compared to southern Maine, which would be approximately $2.54/MWh or $2.1 million per year from 2011 through 2030. Thus, the annual average cost shift would be about $17.3 million for the Northern Region and $19.5 million for all of NMISA over 20 years.

5. It is important to emphasize, under the status quo even though NMISA's wholesale power supply cost is less than ISO-NE's power supply cost, NMISA's cost is driven by and highly correlated with ISO-NE's power supply cost. Therefore, market efficiency and/or cost reductions in ISO-NE also provide a lower power supply cost for NMISA customers in today's marketplace. For example, if AWE directly interconnects with ISO-NE as its own generation lead (i.e., not interconnected with NMTS) and its output results in a lower energy clearing price in ISO-NE, then this impact will be reflected in the price paid by NMISA customers without incurring the risks and costs associated with joining ISO-NE.

6. Participants in ISO-NE incur the costs of ISO-NE for administering the power supply markets and bulk transmission system, as well as the cost of being NEPOOL participants. Participants of NMISA incur the costs of the ISA for administering the markets and bulk transmission system in northern Maine. Participants include T&D companies, competitive energy providers (CEP), generators, and end users. The following is a summary of administrative costs for ISO-NE/NEPOOL and NMISA:

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Cost/Benefit Assessment
Comparison of NMISA and ISO-NE/NEPOOL Funding Costs

November 12, 2008

ISO-NE		2008 Revenue Requirement ($K)	Collection Method
ISO-NE Tariff Schedule 1	Scheduling Service (for RNS)	26,800	Monthly Network Load.
ISO-NE Tariff Schedule 2	Energy Administration Service	52,100	Energy Account Participants (TU and Volumetric Charges).
ISO-NE Tariff Schedule 3	Reliablity Administration Service	46,300	Fixed $/MW of Non-Coincident Peak Load (NCPL).
ISO-NE Tariff Schedule 5	NESCOE (assumes year 3 fully operational budget amount)	2,500	Monthly Network Load.
NEPOOL Participant Expenses			
Participant Expenses (2008 Budget, excl. annual membership fees)		4,324	Annual membership fee plus participant expenses (based on sector/size).
Generation Information System Expenses		1,200	GIS Billable Load
Load Response		1,000	Network Load
Credit Insurance Premium		375	
Total ISO-NE/NEPOOL Participant Revenue Requirement ($K)		134,599	
Wholesale Load (GWh) (2008 CELT Report)		135,000	
ISO-NE Funding Cost ($/MWh)		**1.00**	Assumes Load Ultimately Pays ISO-NE/NEPOOL Funding Costs.
NMISA		2008	
NMISA Tariff Schedule 1	ISA Budget Assessment	634	Proportional Share of T&D Load, CEP Load, and Energy Exports.
Wholesale Load (GWh) (2008 NMISA 7 Year Outlook Report)		825	
NMISA Funding Cost ($/MWh)		**0.77**	Assumes Load Ultimately Pays NMISA Funding Costs.
ISO-NE Increase from NMISA ($/MWh)		**0.23**	
NMISA vs ISO-NE		**-23%**	
NMISA vs ISO-NE ($)		**(189)**	

NMISA's administrative costs have historically and consistently been less than ISO-NE. As indicated above, NMISA's cost is 23% less than ISO-NE/NEPOOL's administrative costs. Northern Maine participants would have paid about $189K more in 2008 administrative funding costs if they were ISO-NE participants.

The administrative cost impact from joining ISO-NE is reflected in the transmission and wholesale power supply market cost benefit assessments.

7. While the analysis presented above is believed to reasonably represent the existing and foreseeable power market in northern Maine, it is possible, that this market may change in the future such that a direct connection to the rest of Maine or ISO-NE would be a lower cost option. If the AWE interconnection does not proceed, then an alternative transmission connection, such as the long studied connection from Houlton to Haynesville, could be undertaken. NES believes that such a connection would qualify as PTF under the so-called "Bucksport Rule", which allows a Transmission Owner's principal interconnection to qualify as PTF as long as its system contains at least 25 MW of generation.

5.0 Conclusions

As required by NMISA market rules 8 and 9, and as described in Section 2 (Scope of Evaluation) of this report, NES addresses the following questions/issues:

1. Would the MPC have an adverse impact on the reliability of the NMTS?

While one would expect that having a new, large capacity tie to New England would improve the reliability of the NMTS, the following are concerns that may need to be addressed in order to avoid a potential adverse impact:

(a) Will the existing ties to NB Power continue to be available at their existing capacity to back-up the loss of the Mullen substation tap to the MPC? If so, will there be an incremental cost from NB Power?

(b) Is the use of a transfer trip of the Mullen tap acceptable in relation to using the existing NB ties as back-up and in terms of the stability performance of the system? Similarly, will the large generation runback schemes required under various contingencies be acceptable? These issues should be fully evaluated as part of the pending stability studies.

(c) Is it acceptable to utilize a substantial block of inductive reactors at Limestone and a large static var compensator at Houlton to control high voltage associated with the MPC during low outputs from AWE?

(d) Is it acceptable from a system reliability (particularly stability) and economic perspective to reduce the dispatch of generation as assumed in this study in order to accommodate the dispatch of AWE?

(e) It will be important to review the final thermal, stability and fault studies required by ISO-NE as part of the MIS. As noted above, with the operation of AWE, the requirements for transfer-trip and generation runbacks, the need to control high voltage and the required redispatch of other generation, the analysis of transient stability may uncover the need for additional facilities not yet identified to maintain acceptable reliability and system operations.

(f) It is also important that the studies, the recommended facilities and any necessary changes to system operating procedures be reviewed by ISO-NE and the PTO's of New England to determine the acceptability. Such review may further identify concerns of the rest of New England regarding the reliability impact of the MPC, including the need to supplement the transmission studies undertaken to date with a detailed evaluation of the

need to provide for supplemental AGC and TMOR capability related to the AWE wind generation operation.

2. Would the MPC create additional congestion by causing the NMTS to operate at or close to normal operating limits?

   (a) In most cases, assuming the ties to NB Power are maintained, it would seem likely that power would flow from NB Power to New England, in which case, most of the output of AWE will also be delivered to New England and not to the NMTS. Generation in the NMTS would generally be unconstrained and, in fact, substantial amounts more than exists today could likely be delivered to New England via Mullen. However, as discussed in this report, the addition of the AWE generation may create congestion in southern Maine unless additional investments in transmission to allow full integration to New England are made.

   (b) In cases when power is delivered to NB Power, this study indicates that constraints may exist in the NMTS, since generation had to be redispatched in order to maintain equal pre- and post tie flows (see cases d2i1 and d4i1 of the MPC Report). This congestion is directly attributable to the MPC and AWE.

3. Would the MPC provide reliability benefits to the NMTS?

   (a) Adding the additional interconnection capacity is likely to provide some incremental reliability benefits, assuming the existing ties to NB Power are maintained and it is properly designed to prevent any new power system characteristics or contingencies which are unmitigated by the design. This new interconnect would provide a new tie to a large synchronous system, which in the normal course would be highly reliable and improve the reliability of the NMTS.

   (b) However, reliability improvement must be considered in terms of whether the incremental improvement is worth the incremental cost. As indicated recently by the MPUC, other very modest proposals by Maine Public were determined to be not needed. Therefore, unless conditions in the NMTS have changed substantially, the reliability improvements associated with the MPC are also likely not needed, or economic.

4. Will the MPC improve the efficiency of the Northern Maine Market?

   (a) As indicated in Section 4 of this report, all else equal, the economic impact of the MPC under the assumption that northern Maine becomes part of ISO-NE would be significantly adverse. The combination of increased transmission costs and wholesale power supply costs could be between $40.49/MWh and $77.59/MWh ($33.1 million to $68.2 million

per year), possibly more (with inclusion of external interconnection projects and the potential for additional internal projects), to the overall status quo cost to northern Maine customers.

(b) There could be offsetting impacts to mitigate some or all of the negative economics to customers. ISO-NE may be willing to offer a share of the savings to New England from the availability of AWE and other future supplies made possible by the MPC. Further, AWE and other generation located in northern Maine may be willing to offer a share of their incremental profits from being able to reach ISO-NE markets, made possible by the MPC.

Finally, it is possible that the energy clearing price in ISO-NE will decrease due to improving power market competition, such as may occur with the addition of non-gas fueled generation. At a high level one may assume any associated decrease in the clearing price will provide incremental benefit to NMISA participants if they join ISO-NE. However, as discussed in Sections 4.4 and 4.5 of in the report, NMISA participants do not need to be participants in ISO-NE to receive the benefits of decreasing energy prices in ISO-NE. NMISA's energy cost is highly correlated with ISO-NE's energy clearing price, and as such energy clearing price reductions in ISO-NE result in energy price reductions in NMISA.

(c) As noted above, AWE and other northern Maine generation will have greater incentives to generate power for delivery to ISO-NE than just to northern Maine and may earn increased profits compared to the status quo.

(d) It also should be noted that any decision to join the ISO-NE market will carry with it future obligations related to investments made in the region where related costs are recovered or socialized through the participants. Even if these identified cost shifts are mitigated by ISO-NE, AWE or others, there is a significant risk that actual costs will be higher, and it will be difficult to withdraw and avoid such higher costs should they occur.

(e) The order of magnitude of cost shift risk to northern Maine customers from both transmission and power supply is very significant. Also, as stated earlier in the report other wind projects have been successfully developed (commercial or in construction) with comparable transmission generation lead costs to AWE. Furthermore, the cost of the installed wind generation and transmission lead has been estimated to be around 8 to 10 cents per kwh. This estimate is consistent with wind generation request for proposal awards by utilities in Canada (Quebec and Maritimes). The forward value of energy, capacity, and subsidies (renewable energy credit, production tax credit, 5 year accelerated depreciation…) appears to support AWE's project proceeding and paying for its own generation lead.

Given the risks to NMISA participants associated with joining ISO-NE and the economics of AWE's project, a logical approach would be for AWE to directly connect to ISO-NE as a generation lead and not interconnect with the NMTS. Under this approach northern Maine customers (NMISA North and South Regions) will (1) avoid the current/projected power supply cost shift, (2) avoid the current/projected transmission cost shift, (3) avoid the risk of substantial transmission and administrative cost increases in ISO-NE (as discussed in this report), (4) likely continue to have lower costs than southern Maine in the foreseeable future, and (5) realize the benefits of lower energy prices in ISO-NE when lower cost resources are developed. In addition, this approach would provide significant flexibility for Maine's regulators and policy makers. If market conditions change in the future such that it becomes economic to interconnect without incurring significant cost risks to northern Maine customers, then the NMTS could interconnect to ISO-NE via an interconnection with AWE's generation lead.

In the event that AWE does not proceed with an interconnection with ISO-NE, the NMTS still maintains an option to interconnect with a much more modest transmission project, which very likely could qualify for inclusion in the regional ISO-NE transmission tariff.

APPENDIX A

COST BENEFIT ASSESSMENT

NES conducted a cost benefit assessment of the transmission interconnection request from the NMTS to ISO-NE. NES assumed NMISA's participants become part of ISO-NE. The assessment was conducted on both the transmission cost impact and the wholesale power supply cost impact on NMISA's Northern and Southern Regions.

TRANSMISSION COST BENEFIT ASSESSMENT

The transmission assessment involved developing 20 year transmission cost projections for (1) MPS under status quo (Stand Alone), (2) ISO-NE, (3) MPS joining ISO-NE, (4) EMEC under status quo (Stand Alone), and (5) EMEC joining ISO-NE. NES determined the cost or benefits for NMISA's North Region by comparing the transmission cost projections for MPS Stand Alone to MPS joining ISO-NE. For NMISA's South Region, NES compared the transmission costs of EMEC Stand Alone to EMEC joining ISO-NE. The following discusses the approach and major assumptions for the transmission cost projections for scenarios 1 through 5 above.

MPS Stand Alone (Status Quo)

NES performed a high level 20 year annual transmission cost projection for Maine Public Service Company on a stand alone basis. MPS currently has about $20.5 million of gross transmission investment, and NES assumed $9 million of increased gross transmission investment from 2008 through 2013 with transmission investment growing at 3% per year (0.5% above assumed annual depreciation, which is equal to projected load growth) thereafter. NES also assumed an annual carrying cost of 17.63% of gross transmission investment. The annual carrying cost includes cost of capital, OM&G, property taxes, and other applicable costs. In addition, NES developed projections of additional transmission related costs (scheduling and dispatch, reactive voltage, customer and regulatory charges, and cancelled plant) based on MPS' current transmission tariff. NES assumed inflationary increases of 3% per year to these costs. Attachment 1 shows the MPS Stand Alone transmission cost projection in detail.

ISO-NE Regional Network Service (RNS) and OATT Schedule 1

NES also performed 20 year projections of ISO-NE's RNS and OATT Schedule 1 costs under (1) a Maine Only Transmission Buildout Case (RTEP 2007, MPC, MPRP) and (2) a New England Transmission Buildout Case (Maine Only Case, Rest of New England builds out at a cost proportional to Maine's buildout, Green Line). NES also reviewed the impact of an External Interconnection Transmission Buildout (additional Canadian and New York transmission interconnection investments). These projections are necessary to estimate MPS' and other NMISA T&D's future transmission costs in the event they join ISO-NE.

Becoming a part of ISO-NE would allow MPS and other NMISA T&Ds to roll the PTF eligible portion of their transmission system into ISO-NE's Regional Network Service, which may help MPS socialize the cost associated with the Maine Power Connection project. However, MPS would be obligated to pay its share of ISO-NE's RNS costs. In 2007 ISO-NE had about $3.3 billion of gross transmission investment with significant additions planned over the next several years. In this assessment, the Maine Only Buildout Case assumed future gross transmission additions that are specified in ISO-NE RTEP 2007 plus MPC related transmission investments proposed in Maine (MPC, Maine Power Reliability Program) which are assumed to be required to allow AWE's energy and capacity production to reach the energy marketplace south of Maine. With respect to the New England Buildout Case, NES assumed Maine Only Buildout Case transmission additions plus the Green Line and other New England transmission investments equal to the same proportional investment made in Maine. Lastly, NES reviewed the impact of External Interconnection Buildout between ISO-NE and Canada/New York. These assumptions and estimated costs are consistent with ISO-NE's 2007 scenario analysis report. Additionally, in the outer years NES assumed ISO-NE's gross transmission investment increases 3% per year (1.1% above assumed annual depreciation, which is equal to projected load growth). NES also assumed an annual carrying cost of 18.05% of gross transmission investment (ISO-NE's actual 2008/09 rate). As with MPS' Stand Alone assessment, the annual carrying cost includes cost of capital, OM&G, property taxes, and other applicable costs. For other RNS assumptions, NES utilized ISO-NE's 2007 RTEP report, 2008 CELT report, and ISO-NE's current tariff Schedule 1 for RNS. NES prepared a 20 year projection of ISO-NE's RNS rate for all three cases. Attachments 2 and 3 shows ISO-NE's RNS and OATT Schedule 1 projection detail for each of the Maine Only Buildout and New England Buildout Cases respectively.

MPS Joins ISO-NE (NMISA's North Region)

NES performed 20 year annual transmission cost projections (Maine Only Buildout and New England Buildout Cases, as well as an External Interconnection Buildout Case) for Maine Public Service (NMISA's North Region) under the scenario that MPS becomes a Transmission Owner participant in ISO-NE. Consistent with MPS' July 1, 2008 filing with the MPUC, NES assumed 76.9% of MPS' transmission assets could be rolled into ISO-NE RNS, and incorporated that amount of RNS payments (or credits) with ISO-NE. In addition, NES estimated future ISO-NE OATT and NEPOOL costs (Maine Only Buildout, New England Buildout, and External Interconnection Buildout Cases). NES' annual projections were based on ISO-NE's current OATT and NEPOOL expenses, with annual inflationary increases of 3% per year (consistent with the MPS stand alone projection). Attachments 4 and 5 shows MPS' annual transmission cost projection detail if MPS joins ISO-NE under the Maine Only and New England Buildout Cases respectively.

EMEC Stand Alone and EMEC Joins ISO-NE (NMISA's South Region)

If MPS joins ISO-NE, NES assumed EMEC would also join ISO-NE. Please note it is unclear at this point whether EMEC could actually obtain the appropriate transmission rights and/or be able to receive roll-in treatment from ISO-NE. NES performed 20 year annual transmission cost projections for EMEC Stand Alone, as well as EMEC Joins

ISO-NE (Maine Only Buildout Case, New England Buildout Case, and External Interconnection Buildout Case).

For this cost/benefit assessment, NES assumed EMEC's transmission costs include the New Brunswick Transmission Tariff and EMEC's transmission system, and 100% of the costs could be rolled-in to RNS. For NES' projection of transmission costs, we assumed EMEC and New Brunswick's current transmission tariff rates would increase of 0.5% per year. Under the EMEC joins ISO-NE scenario, NES assumed ISO-NE's out service charge is waived. The other ISO-NE costs are consistent with the MPS joins ISO-NE scenarios (Maine Only Buildout, New England Buildout, and External Interconnection Buildout). Attachment 6 shows the transmission cost projection details for EMEC Stand Alone and EMEC joins ISO-NE under the Maine Only and New England Buildout Cases, respectfully.

TRANSMISSION COST/BENEFIT ASSESSMENT RESULTS

NMISA North Region

To determine the transmission cost or benefit to NMISA's North Region, NES compared the total annual transmission cost of the MPS Stand Alone scenario with MPS joining ISO-NE. Based on NES' assessment, MPS joining ISO-NE would significantly increase the cost of transmission to customers in NMISA's North Region.

Maine Only Buildout Case: Assuming 2011 ISO-NE participation, the cost of transmission would increase by (a) $8.4 million in the first year, (b) $46.2 million over the first 5 years, (c) $98.5 million over the first 10 years, and (d) $209.5 million over a 20 year period (or an average of $10.5 million per year). The summary results are shown in Table 1 of the main body of this report.

New England Buildout Case: Assuming 2011 ISO-NE participation, the cost of transmission would increase by (a) $30.2 million in the first year, (b) $180.9 million over the first 5 years, (c) $394.2 million over the first 10 years, and (d) $839.7 million over a 20 year period (or an average of $42.0 million per year). The summary results are shown in Table 2 of the main body of this report.

External Interconnection Buildout – Incremental Cost Impact: Assuming 2011 ISO-NE participation, the incremental cost of transmission would be (a) $0 million in the first year, (b) $43.4 million over the first 5 years, (c) $99.7 million over the first 10 years, and (d) $216.8 million over a 20 year period (or an average of $10.8 million per year).

NMISA South Region

To determine the transmission cost or benefit to NMISA's South Region, NES compared the total annual transmission cost of the EMEC Stand Alone scenario with EMEC joining ISO-NE. Based on NES' assessment, EMEC joining ISO-NE would significantly increase the cost of transmission to customers in NMISA's South Region.

Maine Only Buildout Case: Assuming 2011 ISO-NE participation, the cost of transmission would increase by (a) $0.8 million in the first year, (b) $4.3 million over the first 5 years, (c) $9.3 million over the first 10 years, and (d) $19.7 million over a 20 year period (or an average of $1.0 million per year). The summary results are shown in Table 1 of the main body of this report.

New England Buildout Case: Assuming 2011 ISO-NE participation, the cost of transmission would increase by (a) $3.3 million in the first year, (b) $19.6 million over the first 5 years, (c) $42.9 million over the first 10 years, and (d) $91.3 million over a 20 year period (or an average of $4.6 million per year). The summary results are shown in Table 2 of the main body of this report.

External Interconnection Buildout – Incremental Cost Impact: Assuming 2011 ISO-NE participation, the incremental cost of transmission would be (a) $0.0 million in the first year, (b) $4.9 million over the first 5 years, (c) $11.3 million over the first 10 years, and (d) $24.6 million over a 20 year period (or an average of $1.2 million per year).

Total NMISA

Based on this assessment, MPS/EMEC joining ISO-NE would significantly increase the cost of transmission to customers in NMISA.

Maine Only Buildout Case: Assuming 2011 ISO-NE participation, the cost of transmission would increase by (a) $9.1 million in the first year, (b) $50.5 million over the first 5 years, (c) $107.8 million over the first 10 years, and (d) $229.2 million over a 20 year period (or an average of $11.5 million per year). The summary results are shown in Table 1 of the main body of this report and Attachment 13.

New England Buildout Case: Assuming 2011 ISO-NE participation, the cost of transmission would increase by (a) $33.4 million in the first year, (b) $200.6 million over the first 5 years, (c) $437.1 million over the first 10 years, and (d) $931.0 million over a 20 year period (or an average of $46.6 million per year). The summary results are shown in Table 2 of the main body of this report and Attachment 14.

External Interconnection Buildout – Incremental Cost Impact: Assuming 2011 ISO-NE participation, the incremental cost of transmission would be (a) $0.0 million in the first year, (b) $48.3 million over the first 5 years, (c) $111.0 million over the first 10 years, and (d) $241.4 million over a 20 year period (or an average of $12.1 million per year). Attachment 15 shows the summary results for External Interconnection Buildout (in addition to Maine and Rest of New England Buildout).

ADDITIONAL ISSUES TO CONSIDER

There are various cost risks for NMISA participants from MPS/EMEC joining ISO-NE which have not been incorporated into the Cost Benefit Assessment. These risks include (1) future RNS transmission additions in ISO-NE that are not addressed in this report, (2)

potential Reliability Must Run contracts, and (3) ISO-NE tariff costs and NEPOOL expenses. Some of these risks could be substantial. For example, additional ISO-NE transmission investment of $1 billion with a carrying cost of 18.05% would result in an annual revenue requirement of about $180 million or $7.23/kwyr. For NMISA participants, the additional cost would be about $1.1 million per year.

It also should be noted that any decision to join the ISO-NE market will carry with it future obligations related to investments made in the region where related costs are recovered/socialized through the participants. Even if there are attempts to mitigate these identified cost shifts by ISO-NE, AWE or others, there is a significant risk that actual costs will be higher, and it will be difficult to withdraw and avoid such higher costs should they occur.

In addition, NES did not incorporate the transmission cost impact on rest of Maine (BHE & CMP) into this report. In general, the rest of Maine will have to pay its share of any MPS or EMEC transmission additions, including the cost of the MPC, that are rolled into RNS. The cost of MPC to the rest of Maine would be about $10.7 million per year. With the MPRP the resulting cost to the rest of Maine is about $37.3 million per year. Add to that the Green Line (in the event the Green Line is constructed to get AWE generation south of Maine) and the annual cost to the rest of Maine becomes about $60.3 million.

WHOLESALE POWER SUPPLY MARKET COST BENEFIT

The wholesale power supply market assessment involved developing 20 year power supply cost projections for (1) MPS under status quo (Stand Alone), (2) ISO-NE, (3) MPS joining ISO-NE, (4) EMEC under status quo (Stand Alone), and (5) EMEC joining ISO-NE. To determine the cost or benefits for NMISA's North Region NES compared the wholesale power supply cost projections for MPS Stand Alone to MPS joining ISO-NE. For NMISA's South Region NES compared the wholesale power supply costs from EMEC Stand Alone to EMEC joining ISO-NE. The following discusses the approach and major assumptions for the wholesale power supply cost projections for scenarios 1 through 5 above.

MPS Stand Alone (Status Quo)

NES performed a 20 year annual power supply cost projection for NMISA's Northern Region under the status quo. A primary assumption is ISO-NE's external node with New Brunswick (Salisbury, formerly referred to as Keswick) sets the market energy price for the regional Maritime marketplace. NES developed its forecast of ISO-NE's energy price at MA Hub by utilizing the NYMEX MA Hub forwards through 2013 (as of November 11, 2008), and for 2014 and beyond by multiplying the 2013 implied heat rate (MA Hub DA LMP divided by NYMEX Henry Hub natural gas) by the forward NYMEX Henry Hub natural gas prices (as of November 11, 2008)(refer to Attachment 7). NES then assumed the historical basis (adjusted for NRI loss benefits) from MA Hub to Salisbury to project the forward Salisbury market prices (refer to Attachment 8). NES

also assumed the value of energy to a must run generator (hydro, wind…) located in the NMISA's territory is equal to the Salisbury node minus all costs for the generator to move its energy from NMISA through New Brunswick into ISO-NE. NES also developed a marginal cost forecast for each of the existing biomass plants in northern Maine (Fort Fairfield, Ashland, Sherman). Ashland is assumed to be exported from Northern Maine into ISO-NE in order to capture the Renewable Energy Credit (REC) value from Connecticut. With the exception of Ashland, generation located in northern Maine was assumed to be sold, if economic compared to New Brunswick energy at the Salisbury price, in northern Maine (to serve the load in northern Maine) at a price equal to the greater of (1) what they would have received by exporting to ISO-NE through New Brunswick (excluding any Massachusetts or Connecticut Renewable Energy Credit value) or (2) $3/MWh greater than their marginal cost. Any remaining energy requirements are assumed to be supplied from the surplus Maritime marketplace at the Salisbury energy price. Note that First Wind has historically exported Mars Hill's energy from northern Maine through New Brunswick in order to receive the value of MA or CT Renewable Energy Credits (RECs). With Maine's recently implemented new renewable requirement, it is assumed no longer necessary for First Wind to export the energy in order to receive the project's REC value. Attachment 9 details the NMISA Northern Region load and generation resource assumptions. NES also assumed the current NB tariff rate for NMISA load serving operating reserves (escalated by 3% per year), NMISA capacity value equals 50% of ISO-NE's capacity cost, and a load following cost adder of 3% of the usage weighted cost at the Salisbury energy price. Attachment 10 details the Status Quo wholesale power supply cost projection for NMISA's North Region.

MPS Joins ISO-NE

NES performed a 20 year annual wholesale power supply cost projection for NMISA's Northern Region if MPS becomes a Transmission Owner participant in ISO-NE. Under this scenario the load in NMISA's Northern Region would pay the Maine load zone price for energy, ISO-NE load serving costs (regulation, forward reserve market, capacity, NCPC/Uplift, GIS, ISO Sch 2, ISO Sch 3,…), and NEPOOL expenses. Historically, Maine Zone energy clearing prices have been at substantial discount to Mass Hub. Given AWE is intended to serve load south of Maine, NES assumes long term (2013 and beyond) Maine Zone energy prices will equal about 98% of the Hub, which is approximately the regional loss and non-congested price. Starting with 2008, NES projected ISO-NE's wholesale load serving costs by using (1) actual Maine 2007 load serving costs as specified in ISO-NE's 2007 Wholesale Cost Report (WCR), (2) 2008 ISO-NE Tariff revenue requirements, and/or (3) historical billing. For future years, NES incorporated known changes and/or a 3% annual inflationary cost increase. In addition, NES included a load following cost adder of 3% of the usage weighted cost at the ME Zone energy price. With respect to capacity, NES assumed the transition rate for the Forward Capacity Market transition period, $4.50/kwmo in 2011, and then a long-term new capacity rate of ISO-NE's 2005 estimate of $7.50/kwmo escalated at 3% per year. Attachment 11 details the Join ISO-NE wholesale power supply cost projection for NMISA's North Region.

EMEC Stand Alone and EMEC Joins ISO-NE (NMISA's South Region)

NES performed a 20 year annual wholesale load serving cost projection for NMISA's South Region under both EMEC Stand Alone (Status Quo) and EMEC joins ISO-NE.

Under the Status Quo, NES' assumptions and approach are consistent with the MPS Stand Alone scenario. In addition, there is currently not enough energy or capacity in EMEC's service territory (NMISA South) to serve its entire load. NES assumed the energy imported into EMEC is sourced from the energy surplus Maritime market at a price equal to the Salisbury node. NES also assumed the cost of capacity is equal to 50% of ISO-NE's capacity cost.

Under the Join ISO-NE scenario, NES assumed EMEC would have a virtual tie with ISO-NE through New Brunswick, and ISO-NE would waive any energy out service charges associated with serving EMEC South load. As with the North Region, NES assumed EMEC would pay the Maine Zone energy price and over the long term (2013 and beyond) ME Zone energy prices would equal about 98% of the Hub. NES' assumptions surrounding the other wholesale load serving costs are consistent with the MPS joins ISO-NE scenario. Attachment 12 details both the Status Quo and Join ISO-NE wholesale power supply cost projection for NMISA's South Region.

WHOLESALE POWER SUPPLY COST/BENEFIT RESULTS

NMISA North Region

To determine the wholesale power supply market cost or benefit to NMISA's North Region, NES compared the total annual wholesale market costs of the MPS Stand Alone scenario with MPS joining ISO-NE. Based on this assessment, MPS joining ISO-NE would significantly increase the cost of wholesale power supply to customers in NMISA's North Region. Assuming 2011 ISO-NE participation, the cost of power supply would increase by (a) $12.3 million in the first year, (b) $72.2 million over the first 5 years, (c) $160.1 million over the first 10 years, and (d) $387.3 million over a 20 year period (or an average of $19.4 million per year). The summary results are shown in Table 3 of the main body of this report and in Attachment 11.

NMISA South Region

To determine the wholesale power supply market cost or benefit to NMISA's South Region, NES compared the total annual wholesale market costs of the EMEC Stand Alone scenario with EMEC joining ISO-NE. Based on this assessment, MPS/EMEC joining ISO-NE would significantly increase the cost of wholesale power supply to customers in NMISA's South Region. Assuming 2011 ISO-NE participation, the cost of power supply would increase by (a) $1.5 million in the first year, (b) $8.6 million over the first 5 years, (c) $18.8 million over the first 10 years, and (d) $44.8 million over a 20 year period (or an average of $2.2 million per year). The summary results are shown in Table 4 of the main body of this report and in Attachment 12.

Total NMISA

Based on this assessment, MPS/EMEC joining ISO-NE would significantly increase the cost of wholesale power supply to customers in NMISA. Assuming 2011 ISO-NE participation, the cost of power supply would increase by (a) $13.8 million in the first year, (b) $80.8 million over the first 5 years, (c) $178.9 million over the first 10 years, and (d) $432.1 million over a 20 year period (or an average of $21.6 million per year). The summary results are shown in Table 3 of the main body of this report and Attachments 13 and 14.

ADDITIONAL ISSUES TO CONSIDER

As with Transmission, there are potential wholesale power cost risks associated with northern Maine joining ISO-NE that NES has not incorporated into this assessment. These risks include (1) increased price volatility and risk premium, (2) ISO-NE capacity costs, (3) increase in ISO-NE fees compared to NMISA, (4) AGC costs, and (5) increase in Maine and/or regional Reliability Must Run NCPC (Uplift) costs to maintain system reliability, including the potential uplift due to substantial increases in wind generation in the northeast. For example, in their recent wind RFP Hydro-Quebec assessed a balancing cost of $5/MWh to the wind generation. It is unclear whether HQ's balancing cost is driven by increased AGC requirements and/or Uplift. In any case Hydro-Quebec's generation portfolio makeup appears better equipped than ISO-NE's generation portfolio to balance the wind variance. Therefore, one would expect the balancing cost in ISO-NE to be higher than Hydro-Quebec. As another example of the potential impact of wind generation variability, earlier in 2008 the unexpected loss of wind production amid changing weather was blamed, in part, for curtailment of electric service to industrial customers and real-time power prices hitting ERCOT's market cap of $2,250/MWh. If the balancing cost (AGC and uplift from unit posturing for reliability purposes) for AWE is $10/MWh, then the annual cost is approximately $23 million.

In addition, NES did not incorporate the power supply cost or benefits impact on the rest of Maine (BHE, CMP …) into this report. Additional costs could be incurred by the rest of Maine due to impacts of northern Maine wind projects on the Maine Market System. As discussed in the previous paragraph, higher costs could be incurred from AGC, operating reserves, and reliability (posturing or uplift) requirements. These additional costs will increase Maine's load serving costs. With respect to potential benefits, AWE may reduce the regional energy clearing price but the exact magnitude is difficult to determine. It may or may not offset some of the costs to northern and southern Maine.

ISO-NE is best equipped to estimate AWE's impact on the markets, and ISO-NE will be reviewing AWE's impact on the market system as a part of their review. However, in the recently completed scenario analysis, ISO-NE determined that the reduction in the regional clearing price related to wind generation was likely to be substantially less than the cost of adding wind generation to the system.

Another recent study completed by Synapse Energy Economics, Inc. (see report entitled "Avoided Energy Supply Costs in New England: 2007 Final Report, dated 8/10/07) related to the economics of demand-side management alternatives postulated a demand reduction induced price effect (DRIPE) which would only reduce the clearing price for a short period (4 years), after which generators would adjust their investments and operations and the price would return to approximately the pre-demand-side price level. This method estimates the impact on energy and capacity clearing prices associated with demand reduction; but should also be applicable to new generation such as wind.

For example, the Synapse study estimates that a reduction of average demand of 1 MW in Maine will reduce the energy clearing price in Maine by $32/MWh of energy saved for 4 years. If one applied this to new supply like AWE, using a 33% capacity factor, average supply of 2,300,000 MWh, the savings related to the reduction in clearing price over the four year period would be a total of $294 million [($32/MWh x 2,300,000 MWh/yr x 4 years], then $0 thereafter. If useful capacity is 160 MW, the capacity savings (using the Synapse estimate of $22/kw/yr levelized over 15 years is about $30 million (NPV). Therefore, total savings associated with AWE would be $324 million.

ATTACHMENT 1

MPS Annual Transmission Cost Projection
Status Quo

ATTACHMENT 1

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Maine Public Service Company Annual Transmission Cost Projection - Status Quo
November 12, 2008

Year		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Investments		**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**
MPS 2007 Gross Plant		**20,515**																							
MPS Planned Gross Plant Additions *			346	900	1,600	3,400	2,200	450	450																
Growth in Gross Plant										149	150	151	152	152	153	154	155	155	156	157	158	159	159	160	161
* Planned additions from MPUC Chapter 330 Report (April 30, 2008).																									
MPS 2007 Gross Plant	2007	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515	20,515
MPS Gross Plant Additions	2008		346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346
	2009			900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
	2010				1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
	2011					3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
	2012						2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
	2013							450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
	2014								450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
	2015									149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
	2016										150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	2017											151	151	151	151	151	151	151	151	151	151	151	151	151	151
	2018												152	152	152	152	152	152	152	152	152	152	152	152	152
	2019													152	152	152	152	152	152	152	152	152	152	152	152
	2020														153	153	153	153	153	153	153	153	153	153	153
	2021															154	154	154	154	154	154	154	154	154	154
	2022																155	155	155	155	155	155	155	155	155
	2023																	155	155	155	155	155	155	155	155
	2024																		156	156	156	156	156	156	156
	2025																			157	157	157	157	157	157
	2026																				158	158	158	158	158
	2027																					159	159	159	159
	2028																						159	159	159
	2029																							160	160
	2030																								161
Gross Plant Total		20,515	20,860	21,760	23,360	26,760	28,960	29,410	29,860	30,010	30,160	30,310	30,462	30,614	30,767	30,921	31,076	31,231	31,387	31,544	31,702	31,860	32,020	32,180	32,341
Carrying Charge Rate (including OM&G, Property Taxes,...)**		17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%
** MPC CPCN Filing (July 1, 2008)																									
Transmission Investment Carry Cost ($K)		3,617	3,678	3,836	4,118	4,718	5,106	5,185	5,264	5,291	5,317	5,344	5,370	5,397	5,424	5,451	5,479	5,506	5,534	5,561	5,589	5,617	5,645	5,673	5,702
OTHER TRANSMISSION EXPENSES ($/kwyr)																									
Scheduling Sys/Control and Dispatch	Sch. 3 (08/09 Tariff), 3%/yr	1.84	1.87	1.92	1.98	2.04	2.10	2.16	2.23	2.30	2.36	2.44	2.51	2.58	2.66	2.74	2.82	2.91	3.00	3.09	3.18	3.27	3.37	3.47	3.58
Reactive Supply and Voltage Control	Sch. 4 (08/09 Tariff), 3%/yr	0.81	0.80	0.83	0.85	0.88	0.91	0.93	0.96	0.99	1.02	1.05	1.08	1.11	1.15	1.18	1.22	1.25	1.29	1.33	1.37	1.41	1.45	1.50	1.54
Customer Chg. (Sch. 1a)	MPS 08/09 Tariff, 3%/yr	2.08	2.14	2.21	2.27	2.34	2.41	2.48	2.56	2.63	2.71	2.79	2.88	2.96	3.05	3.14	3.24	3.34	3.44	3.54	3.64	3.75	3.87	3.98	4.10
Regulatory Chg. (Sch. 1b)	MPS 08/09 Tariff, 3%/yr	0.79	0.89	0.92	0.94	0.97	1.00	1.03	1.06	1.09	1.13	1.16	1.20	1.23	1.27	1.31	1.35	1.39	1.43	1.47	1.52	1.56	1.61	1.66	1.71
Canc. Plant (Sch. 5)	MPS 08/09 Tariff	2.32	2.29	2.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Transmssion Expenses ($/kwyr)		7.84	7.99	8.03	6.05	6.23	6.42	6.61	6.81	7.01	7.22	7.44	7.66	7.89	8.13	8.37	8.62	8.88	9.15	9.42	9.71	10.00	10.30	10.61	10.93
Other Transmssion Expenses ($/K)		873	894	944	718	747	777	809	841	871	901	933	966	1,000	1,035	1,071	1,109	1,148	1,188	1,230	1,273	1,318	1,364	1,412	1,462
Annual Revenue Requirement (excl. Wheeling) ($K)		4,489	4,572	4,781	4,837	5,465	5,883	5,994	6,106	6,161	6,218	6,277	6,336	6,397	6,459	6,523	6,588	6,654	6,722	6,791	6,862	6,935	7,009	7,086	7,164
Annual Revenue Requirement (excl. Wheeling) ($/kwyr)		40.31	40.87	40.67	40.74	45.58	48.58	49.00	49.42	49.62	49.83	50.05	50.27	50.50	50.74	50.99	51.24	51.50	51.76	52.04	52.32	52.61	52.91	53.22	53.54
Energy for Export from Northern Maine (MWh) (Ashland starting 2008)		126,146	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296	259,296
Previous Year Export Transmission Revenue ($K)		47	1,111	1,717	1,415	1,583	1,800	1,878	1,869	1,904	1,898	1,913	1,917	1,927	1,934	1,943	1,952	1,961	1,970	1,979	1,988	1,998	2,008	2,018	2,028
Through or Out Transmission Rate (Hourly, $/MWh)		8.81	6.62	5.46	6.10	6.94	7.24	7.21	7.34	7.32	7.38	7.39	7.43	7.46	7.49	7.53	7.56	7.60	7.63	7.67	7.71	7.74	7.78	7.82	7.86
Transmission Revenue from Exports ($K)		1,111	1,717	1,415	1,583	1,800	1,878	1,869	1,904	1,898	1,913	1,917	1,927	1,934	1,943	1,952	1,961	1,970	1,979	1,988	1,998	2,008	2,018	2,028	2,039
Total Annual RR (after Wheeling Revenue Credit ($K))		4,442	3,460	3,063	3,421	3,882	4,083	4,115	4,237	4,257	4,321	4,364	4,419	4,470	4,525	4,580	4,636	4,693	4,752	4,812	4,874	4,937	5,002	5,068	5,135
Total Annual RR (after Wheeling Revenue Credit ($/kwyr))		39.89	30.93	26.06	28.82	32.38	33.71	33.64	34.29	34.29	34.63	34.80	35.06	35.29	35.55	35.80	36.06	36.32	36.60	36.87	37.16	37.45	37.75	38.06	38.38
NMISA Expenses (Entire NMISA)	NMISA 2008 Budget, 3% Esc.	217	217	224	231	238	246	254	262	271	279	289	298	307	317	328	338	349	360	372	384	396	409	422	436
MPS Stand Alone- Annual Cost ($K)		4,658	3,677	3,287	3,652	4,121	4,329	4,369	4,499	4,528	4,600	4,653	4,717	4,778	4,842	4,907	4,974	5,042	5,113	5,184	5,258	5,333	5,410	5,490	5,571
MPS Load MW	NMISA 2008 7 Year Outlook	111.4	111.9	117.5	118.7	119.9	121.1	122.3	123.5	124.2	124.8	125.4	126.0	126.7	127.3	127.9	128.6	129.2	129.9	130.5	131.2	131.8	132.5	133.1	133.8
Growth Factor: (2015-2030)	0.50%																								
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MPS Stand Alone- Annual Transmission Cost ($/kwyr)		41.83	32.87	27.96	30.76	34.37	35.75	35.72	36.42	36.47	36.87	37.10	37.43	37.72	38.04	38.36	38.69	39.02	39.37	39.72	40.09	40.46	40.84	41.23	41.63

ATTACHMENT 2

ISO-NE Annual Transmission Cost Projection
Maine Only Buildout Case

ATTACHMENT 2

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
ISO-NE Annual Transmission Cost Projection - Maine Only Buildout Case
November 12, 2008

Year		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Investments		**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**
ISO-NE Gross Plant (June 2007 RNS Rate)		3,321,952																							
ISO-NE Planned Gross Plant Additions (07 RSP)			2,031,611	975,000	1,691,000	431,000	300,000	454,000	50,000	10,000	100,000	10,000	160,000												
New Gross Plant Additions (1.1% per year)									125,768	129,460	132,749	135,309	136,907	140,173	141,715	143,274	144,850	146,443	148,054	149,683	151,329	152,994	154,677	156,378	158,099
Proposed Maine Power Connection (MPC, $650 Million plus AFUDC)					362,500	362,500																			
Proposed Maine Power Reliabiity Plan (MPRP, $1.55 Billion plus AFUDC)						1,160,000	159,500	159,500	159,500	159,500															
Proposed Reliability Upgrades in Other States (Assumes MPRP Cost Per State)																									
Proposed Green Line (Estimate based on NJ to NY Cable and Miles)																									
Proposed Emera/BHE Connection to Boston																									
Potential HQ and NY Connections (2007 ISO-NE Scenario Analysis)																									
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)						2,281	12	12																	
MPS (PTF Qualified Portion, 76.9%)						20,579	1,692	346	346																
ISO-NE 2007 Gross Plant	2007	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952
ISO-NE Gross Plant Additions	2008		2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611
	2009			975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000
	2010				2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500
	2011					1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360	1,976,360
	2012						461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203	461,203
	2013							613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858	613,858
	2014								335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614	335,614
	2015									298,960	298,960	298,960	298,960	298,960	298,960	298,960	298,960	298,960	298,960	298,960	298,960	298,960	298,960	298,960	298,960
	2016										232,749	232,749	232,749	232,749	232,749	232,749	232,749	232,749	232,749	232,749	232,749	232,749	232,749	232,749	232,749
	2017											145,309	145,309	145,309	145,309	145,309	145,309	145,309	145,309	145,309	145,309	145,309	145,309	145,309	145,309
	2018												296,907	296,907	296,907	296,907	296,907	296,907	296,907	296,907	296,907	296,907	296,907	296,907	296,907
	2019													140,173	140,173	140,173	140,173	140,173	140,173	140,173	140,173	140,173	140,173	140,173	140,173
	2020														141,715	141,715	141,715	141,715	141,715	141,715	141,715	141,715	141,715	141,715	141,715
	2021															143,274	143,274	143,274	143,274	143,274	143,274	143,274	143,274	143,274	143,274
	2022																144,850	144,850	144,850	144,850	144,850	144,850	144,850	144,850	144,850
	2023																	146,443	146,443	146,443	146,443	146,443	146,443	146,443	146,443
	2024																		148,054	148,054	148,054	148,054	148,054	148,054	148,054
	2025																			149,683	149,683	149,683	149,683	149,683	149,683
	2026																				151,329	151,329	151,329	151,329	151,329
	2027																					152,994	152,994	152,994	152,994
	2028																						154,677	154,677	154,677
	2029																							156,378	156,378
	2030																								158,099
Gross Plant Additions Total		3,321,952	5,353,563	6,328,563	8,382,063	10,358,423	10,819,626	11,433,484	11,769,098	12,068,058	12,300,807	12,446,116	12,743,023	12,883,196	13,024,912	13,168,186	13,313,036	13,459,479	13,607,533	13,757,216	13,908,545	14,061,539	14,216,216	14,372,595	14,530,693
Carrying Charge Rate (inc.OM&G, Taxes,…) (2007/08 RNS Rate)		18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%
Transmission Investment Carrying Cost ($K)		599,612	966,318	1,142,306	1,512,962	1,869,695	1,952,943	2,063,744	2,124,322	2,178,285	2,220,296	2,246,524	2,300,116	2,325,417	2,350,997	2,376,857	2,403,003	2,429,436	2,456,160	2,483,178	2,510,492	2,538,108	2,566,027	2,594,253	2,622,790
ISO-NE Load MW (12 CP) (2007 CELT)		21,486	21,907	22,256	22,475	22,822	23,024	23,208	23,375	23,528	23,675	23,819	24,080	24,344	24,611	24,881	25,154	25,430	25,709	25,991	26,276	26,564	26,855	27,150	27,447
Growth Factor (2017-2030)	1.10%																								

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ISO-NE RNS Transmission Rate $/kwyr	27.91	44.11	51.33	67.32	81.93	84.82	88.92	90.88	92.58	93.78	94.32	95.52	95.52	95.53	95.53	95.53	95.54	95.54	95.54	95.54	95.55	95.55	95.55	95.56
OATT Schedule 1 (Act.07/08 Tariff Rate, 3% Esc.)	1.32	1.27	1.25	1.29	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33
Total ISO-NE Transmission Rate $/kwyr	29.23	45.38	52.58	68.61	83.25	86.19	90.33	92.33	94.08	95.32	95.90	97.15	97.20	97.26	97.31	97.37	97.43	97.49	97.55	97.61	97.68	97.75	97.81	97.89

ATTACHMENT 3

ISO-NE Annual Transmission Cost Projection
New England Buildout Case

ATTACHMENT 3

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
ISO-NE Annual Transmission Cost Projection - New England Buildout Case
November 12, 2008

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Investments	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**	**ISO-NE $K**
ISO-NE Gross Plant (June 2007 RNS Rate)	3,321,952																							
ISO-NE Planned Gross Plant Additions (07 RSP)		2,031,611	975,000	1,691,000	431,000	300,000	454,000	50,000	10,000	100,000	10,000	160,000												
New Gross Plant Additions (1.1% per year)								438,760	467,309	495,728	502,281	507,916	515,263	520,931	526,661	532,455	538,312	544,233	550,220	556,272	562,391	568,577	574,832	581,155
Proposed Maine Power Connection (MPC, $650 Million plus AFUDC)				362,500	362,500																			
Proposed Maine Power Reliabiity Plan (MPRP, $1.55 Billion plus AFUDC)					1,160,000	159,500	159,500	159,500	159,500															
Proposed Reliability Upgrades in Other States (Assumes Pro-rata Buildout vs ME)					23,006,960	1,946,743	1,946,743	1,946,743	1,946,743															
Proposed Green Line (Estimate based on NJ to NY Cable and Miles)						1,553,353																		
Proposed Emera/BHE Connection to Boston																								
Potential HQ and NY Connections (2007 ISO-NE Scenario Analysis)																								
EMEC (PTF Qualified Portion, including New Brunswick transmission, 100%)					2,281	12	12																	
MPS (PTF Qualified Portion, 76.9%)					20,579	1,692	346	346																
ISO-NE 2007 Gross Plant	2007	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952	3,321,952
ISO-NE Gross Plant Additions	2008		2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611	2,031,611
	2009			975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000	975,000
	2010				2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500	2,053,500
	2011					24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320	24,983,320
	2012						3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300	3,961,300
	2013							2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601	2,560,601
	2014								2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349	2,595,349
	2015									2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552	2,583,552
	2016										595,728	595,728	595,728	595,728	595,728	595,728	595,728	595,728	595,728	595,728	595,728	595,728	595,728	595,728	595,728
	2017											512,281	512,281	512,281	512,281	512,281	512,281	512,281	512,281	512,281	512,281	512,281	512,281	512,281	512,281
	2018												667,916	667,916	667,916	667,916	667,916	667,916	667,916	667,916	667,916	667,916	667,916	667,916	667,916
	2019													515,263	515,263	515,263	515,263	515,263	515,263	515,263	515,263	515,263	515,263	515,263	515,263
	2020														520,931	520,931	520,931	520,931	520,931	520,931	520,931	520,931	520,931	520,931	520,931
	2021															526,661	526,661	526,661	526,661	526,661	526,661	526,661	526,661	526,661	526,661
	2022																532,455	532,455	532,455	532,455	532,455	532,455	532,455	532,455	532,455
	2023																	538,312	538,312	538,312	538,312	538,312	538,312	538,312	538,312
	2024																		544,233	544,233	544,233	544,233	544,233	544,233	544,233
	2025																			550,220	550,220	550,220	550,220	550,220	550,220
	2026																				556,272	556,272	556,272	556,272	556,272
	2027																					562,391	562,391	562,391	562,391
	2028																						568,577	568,577	568,577
	2029																							574,832	574,832
	2030																								581,155
Gross Plant Additions Total		3,321,952	5,353,563	6,328,563	8,382,063	33,365,383	37,326,683	39,887,283	42,482,632	45,066,184	45,661,912	46,174,193	46,842,109	47,357,373	47,878,304	48,404,965	48,937,420	49,475,731	50,019,964	50,570,184	51,126,456	51,688,847	52,257,424	52,832,256	53,413,411
Carrying Charge Rate (inc.OM&G, Taxes,…) (2007/08 RNS Rate)		18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%	18.05%
Transmission Investment Carrying Cost ($K)		599,612	966,318	1,142,306	1,512,962	6,022,452	6,737,466	7,199,655	7,668,115	8,134,446	8,241,975	8,334,442	8,455,001	8,548,006	8,642,034	8,737,096	8,833,204	8,930,369	9,028,604	9,127,918	9,228,325	9,329,837	9,432,465	9,536,222	9,641,121
ISO-NE Load MW (12 CP) (2007 CELT)		21,486	21,907	22,256	22,475	22,822	23,024	23,208	23,375	23,528	23,675	23,819	24,080	24,344	24,611	24,881	25,154	25,430	25,709	25,991	26,276	26,564	26,855	27,150	27,447
Growth Factor (2017-2030) 1.10%																									
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ISO-NE RNS Transmission Rate $/kwyr	27.91	44.11	51.33	67.32	263.89	292.63	310.22	328.04	345.73	348.13	349.91	351.12	351.13	351.14	351.15	351.17	351.18	351.19	351.20	351.21	351.22	351.24	351.25	351.26
OATT Schedule 1 (Act.07/08 Tariff Rate, 3% Esc.)	1.32	1.27	1.25	1.29	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33
Total ISO-NE Transmission Rate $/kwyr	29.23	45.38	52.58	68.61	265.22	294.00	311.63	329.49	347.22	349.67	351.49	352.75	352.81	352.87	352.94	353.00	353.07	353.14	353.21	353.28	353.36	353.43	353.51	353.59

ATTACHMENT 4

MPS Annual Transmission Cost Projection
- Joins ISO-NE (Maine Only Buildout Case)

ATTACHMENT 4

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment (North Region)
Maine Public Service Company Annual Transmission Cost Projection - Joins ISO-NE (Maine Only Buildout Case)
November 12, 2008

Year		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Investments		**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**	**MPS $K**
MPS Gross Plant Total		21,760	23,360	26,760	28,960	29,410	29,860	30,010	30,160	30,310	30,462	30,614	30,767	30,921	31,076	31,231	31,387	31,544	31,702	31,860	32,020	32,180	32,341
CCRate (inc. OM&G, P Taxes,…) (MPC July 1, 2008 Filing)		17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%
Transmission Investment Carrying Cost ($K)		3,836	4,118	4,718	5,106	5,185	5,264	5,291	5,317	5,344	5,370	5,397	5,424	5,451	5,479	5,506	5,534	5,561	5,589	5,617	5,645	5,673	5,702
Assumed Local Transmission Service Percentage		23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%
Local Transmission Investment Carrying Cost ($K)		886	951	1,090	1,179	1,198	1,216	1,222	1,228	1,234	1,241	1,247	1,253	1,259	1,266	1,272	1,278	1,285	1,291	1,298	1,304	1,311	1,317
Other Local Transmission Costs (Sch.. R. Supply,...) ($K)		944	718	747	777	809	841	871	901	933	966	1,000	1,035	1,071	1,109	1,148	1,188	1,230	1,273	1,318	1,364	1,412	1,462
Total Local Transmission Costs ($K)		1,831	1,670	1,837	1,957	2,006	2,057	2,093	2,130	2,167	2,206	2,247	2,288	2,331	2,375	2,420	2,467	2,515	2,564	2,616	2,668	2,723	2,779
Assumed Percentage That Qualifies for PTF (MPC July Filing, Exhibit L pg 7 of 7)		76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%
MPS' PTF Annual Revenue Requirement ($K)		2,950	3,167	3,628	3,926	3,987	4,048	4,069	4,089	4,109	4,130	4,151	4,171	4,192	4,213	4,234	4,255	4,277	4,298	4,319	4,341	4,363	4,385
Year		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MPS PTF Transmission Rate $/kwyr		25.10	26.68	30.26	32.42	32.60	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77
MPS Load MW		117.5	118.7	119.9	121.1	122.3	123.5	124.2	124.8	125.4	126.0	126.7	127.3	127.9	128.6	129.2	129.9	130.5	131.2	131.8	132.5	133.1	133.8
Growth Factor: (2015-2030)	0.50%																						
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		52.58	68.61	83.25	86.19	90.33	92.33	94.08	95.32	95.90	97.15	97.20	97.26	97.31	97.37	97.43	97.49	97.55	97.61	97.68	97.75	97.81	97.89
MPS RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		3,230	4,978	6,355	6,512	7,062	7,358	7,612	7,806	7,917	8,114	8,162	8,209	8,257	8,306	8,355	8,405	8,455	8,505	8,556	8,608	8,660	8,713
OTHER ISO/NEPOOL EXPENSES ($K)																							
NEPOOL Expenses	2008 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	32	33	34	35	36	37	38	39	41	42	43	44	46	47	48	50	51	53	55	56	58	60
ISO Tariff Schedule 1 (System Control & Disp.)	2008 ISO Tariff, 3% Esc.	13	13	13	14	14	15	15	15	16	16	17	17	18	18	19	20	20	21	21	22	23	23
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2007 Tariff Rate, 3% Esc.	36	37	39	40	41	42	43	45	46	47	49	50	52	53	55	57	58	60	62	64	66	68
ISO Tariff Schedule 5 (NESCOE)	2008 ISO Tariff, 09/10 Bud., 3% Esc.	10	14	14	15	15	15	16	16	17	17	18	18	19	20	20	21	21	22	23	23	24	25
OATT Schedule 2 - VAR	Actual 2007, 3% Esc.	376	388	399	411	424	436	449	463	477	491	506	521	537	553	569	586	604	622	641	660	680	700
OATT Schedule 16 - Black Start	Actual 2007, 3% Esc.	60	62	64	66	68	70	72	74	76	78	81	83	86	88	91	94	96	99	102	105	108	112
OATT Schedule 19 - Special Const Resources	Assumed $0. Risk of future costs.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Response Programs	Actual 2007, 3% Esc.	81	83	85	88	91	93	96	99	102	105	108	111	115	118	122	125	129	133	137	141	145	150
Demand Response Program	Actual 2007, 3% Esc.	8	8	9	9	9	9	10	10	10	11	11	11	12	12	12	13	13	14	14	14	15	15
Total Other Expenses ($K)		616	638	657	677	697	718	740	762	785	808	832	857	883	910	937	965	994	1,024	1,054	1,086	1,104	1,137
MPS Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)																							
MPS Annual Transmission Expenses ($K)																							
Local Transmission Expenses ($K)		1,831	1,670	1,837	1,957	2,006	2,057	2,093	2,130	2,167	2,206	2,247	2,288	2,331	2,375	2,420	2,467	2,515	2,564	2,616	2,668	2,723	2,779
PTF Transmission Expenses ($K)		6,180	8,145	9,983	10,438	11,049	11,407	11,680	11,894	12,027	12,244	12,312	12,381	12,449	12,519	12,589	12,660	12,731	12,803	12,876	12,949	13,023	13,098
Other Applicable ISO-NE/NEPOOL Expenses ($K)		616	638	657	677	697	718	740	762	785	808	832	857	883	910	937	965	994	1,024	1,054	1,086	1,104	1,137
Total Transmsission Costs ($K)		**8,627**	**10,453**	**12,477**	**13,072**	**13,753**	**14,182**	**14,513**	**14,786**	**14,979**	**15,259**	**15,391**	**15,526**	**15,663**	**15,803**	**15,946**	**16,091**	**16,240**	**16,391**	**16,546**	**16,704**	**16,850**	**17,014**
Total Transmission Costs ($/kwyr)		**73.39**	**88.04**	**104.05**	**107.94**	**112.43**	**114.79**	**116.89**	**118.49**	**119.44**	**121.07**	**121.51**	**121.97**	**122.43**	**122.91**	**123.41**	**123.91**	**124.43**	**124.97**	**125.52**	**126.09**	**126.56**	**127.15**
MPS Annual Transmission Costs (Stand Alone) ($K)		**3,287**	**3,652**	**4,121**	**4,329**	**4,369**	**4,499**	**4,528**	**4,600**	**4,653**	**4,717**	**4,778**	**4,842**	**4,907**	**4,974**	**5,042**	**5,113**	**5,184**	**5,258**	**5,333**	**5,410**	**5,490**	**5,571**
Annual MPS Transmission Cost/(Benefit) to Join ISO-NE ($K)		**5,340**	**6,801**	**8,356**	**8,743**	**9,383**	**9,683**	**9,985**	**10,186**	**10,326**	**10,542**	**10,613**	**10,684**	**10,756**	**10,829**	**10,903**	**10,979**	**11,056**	**11,133**	**11,213**	**11,293**	**11,360**	**11,443**

ATTACHMENT 5

MPS Annual Transmission Cost Projection
- Joins ISO-NE (New England Buildout Case)

ATTACHMENT 5

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment (North Region)
Maine Public Service Company Annual Transmission Cost Projection - Joins ISO-NE (New England Buildout Case)
November 12, 2008

Year		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Investments		MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K	MPS $K
MPS Gross Plant Total		21,760	23,360	26,760	28,960	29,410	29,860	30,010	30,160	30,310	30,462	30,614	30,767	30,921	31,076	31,231	31,387	31,544	31,702	31,860	32,020	32,180	32,341
CCRate (inc. OM&G, P Taxes,…) (MPC July 1, 2008 Filing)		17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%	17.63%
Transmission Investment Carrying Cost ($K)		3,836	4,118	4,718	5,106	5,185	5,264	5,291	5,317	5,344	5,370	5,397	5,424	5,451	5,479	5,506	5,534	5,561	5,589	5,617	5,645	5,673	5,702
Assumed Local Transmission Service Percentage		23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%	23.1%
Local Transmission Investment Carrying Cost ($K)		886	951	1,090	1,179	1,198	1,216	1,222	1,228	1,234	1,241	1,247	1,253	1,259	1,266	1,272	1,278	1,285	1,291	1,298	1,304	1,311	1,317
Other Local Transmission Costs (Sch.. R. Supply,…) ($K)		944	718	747	777	809	841	871	901	933	966	1,000	1,035	1,071	1,109	1,148	1,188	1,230	1,273	1,318	1,364	1,412	1,462
Total Local Transmission Costs ($K)		1,831	1,670	1,837	1,957	2,006	2,057	2,093	2,130	2,167	2,206	2,247	2,288	2,331	2,375	2,420	2,467	2,515	2,564	2,616	2,668	2,723	2,779
Assumed Percentage That Qualifies for PTF (MPC July Filing, Exhibit L pg 7 of 7)		76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%	76.9%
MPS' PTF Annual Revenue Requirement		2,950	3,167	3,628	3,926	3,987	4,048	4,069	4,089	4,109	4,130	4,151	4,171	4,192	4,213	4,234	4,255	4,277	4,298	4,319	4,341	4,363	4,385
Year		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MPS PTF Transmission Rate $/kwyr		25.10	26.68	30.26	32.42	32.60	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77
MPS Load MW		117.5	118.7	119.9	121.1	122.3	123.5	124.2	124.8	125.4	126.0	126.7	127.3	127.9	128.6	129.2	129.9	130.5	131.2	131.8	132.5	133.1	133.8
Growth Factor: (2015-2030)	0.50%																						
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		52.58	68.61	265.22	294.00	311.63	329.49	347.22	349.67	351.49	352.75	352.81	352.87	352.94	353.00	353.07	353.14	353.21	353.28	353.36	353.43	353.51	353.59
MPS RNS/OATT Schedule 1 Cost Shift Payment to ISO-NE		3,230	4,978	28,174	31,680	34,131	36,658	39,043	39,543	39,970	40,328	40,538	40,748	40,960	41,173	41,388	41,604	41,821	42,039	42,259	42,481	42,703	42,927
OTHER ISO/NEPOOL EXPENSES ($K)																							
NEPOOL Expenses	2008 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	32	33	34	35	36	37	38	39	41	42	43	44	46	47	48	50	51	53	55	56	58	60
ISO Tariff Schedule 1 (System Control & Disp.)	2008 ISO Tariff, 3% Esc.	13	13	13	14	14	15	15	15	16	16	17	17	18	18	19	20	20	21	21	22	23	23
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2007, 3% Esc.	36	37	39	40	41	42	43	45	46	47	49	50	52	53	55	57	58	60	62	64	66	68
ISO Tariff Schedule 5 (NESCOE)	2008 ISO Tariff, 09/10 Bud., 3% Esc.	10	14	14	15	15	15	16	16	17	17	18	18	19	20	20	21	21	22	23	23	24	25
OATT Schedule 2 - VAR	Actual 2007, 3% Esc.	376	388	399	411	424	436	449	463	477	491	506	521	537	553	569	586	604	622	641	660	680	700
OATT Schedule 16 - Black Start	Actual 2007, 3% Esc.	60	62	64	66	68	70	72	74	76	78	81	83	86	88	91	94	96	99	102	105	108	112
OATT Schedule 19 - Special Const Resources	Assumed $0. Risk of future costs.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Response Programs	Actual 2007, 3% Esc.	81	83	85	88	91	93	96	99	102	105	108	111	115	118	122	125	129	133	137	141	145	150
Demand Response Program	Actual 2007, 3% Esc.	8	8	9	9	9	9	10	10	10	11	11	11	12	12	12	13	13	14	14	14	15	15
Total Other Expenses ($K)		616	638	657	677	697	718	740	762	785	808	832	857	883	910	937	965	994	1,024	1,054	1,086	1,104	1,137
MPS Transmission and NEPOOL Membership Related Annual Expenses (Joining ISO-NE)																							
MPS Annual Transmission Expenses ($K)																							
Local Transmission Expenses ($K)		1,831	1,670	1,837	1,957	2,006	2,057	2,093	2,130	2,167	2,206	2,247	2,288	2,331	2,375	2,420	2,467	2,515	2,564	2,616	2,668	2,723	2,779
PTF Transmission Expenses ($K)		6,180	8,145	31,802	35,606	38,118	40,707	43,112	43,632	44,079	44,458	44,688	44,919	45,152	45,386	45,622	45,859	46,097	46,337	46,579	46,822	47,066	47,312
Other Applicable ISO-NE/NEPOOL Expenses ($K)		616	638	657	677	697	718	740	762	785	808	832	857	883	910	937	965	994	1,024	1,054	1,086	1,104	1,137
Total Transmsission Costs ($K)		**8,627**	**10,453**	**34,296**	**38,239**	**40,821**	**43,482**	**45,944**	**46,524**	**47,031**	**47,473**	**47,767**	**48,065**	**48,366**	**48,671**	**48,979**	**49,291**	**49,606**	**49,925**	**50,249**	**50,576**	**50,893**	**51,228**
Total Transmission Costs ($/kwyr)		**73.39**	**88.04**	**286.02**	**315.74**	**333.73**	**351.96**	**370.04**	**372.84**	**375.03**	**376.67**	**377.12**	**377.58**	**378.06**	**378.55**	**379.05**	**379.56**	**380.09**	**380.64**	**381.20**	**381.77**	**382.25**	**382.85**
MPS Annual Transmission Costs (Stand Alone) ($K)		**3,287**	**3,652**	**4,121**	**4,329**	**4,369**	**4,499**	**4,528**	**4,600**	**4,653**	**4,717**	**4,778**	**4,842**	**4,907**	**4,974**	**5,042**	**5,113**	**5,184**	**5,258**	**5,333**	**5,410**	**5,490**	**5,571**
Annual MPS Transmission Cost/(Benefit) to Join ISO-NE ($K)		**5,340**	**6,801**	**30,175**	**33,910**	**36,452**	**38,983**	**41,416**	**41,923**	**42,378**	**42,755**	**42,989**	**43,222**	**43,459**	**43,696**	**43,936**	**44,178**	**44,422**	**44,668**	**44,916**	**45,166**	**45,403**	**45,657**

ATTACHMENT 6

EMEC Status Quo and Joins ISO-NE
Annual Transmission Cost Projections
(Maine Only and New England Buildout Cases)

ATTACHMENT 6

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Transmission Cost/Benefit Assessment
Eastern Maine Electric Cooperative (EMEC) Status Quo and Joins ISO-NE Annual Transmission Cost Projections (Maine Only and New England Buildout Cases)
November 12, 2008

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
TRANSMISSION COSTS																							
Status Quo																							
EMEC Transmission																							
EMEC System ($/kwyr) (2008 Tariff Rate, 0.5% annual escalation)		5.64	5.67	5.70	5.73	5.76	5.79	5.82	5.84	5.87	5.90	5.93	5.96	5.99	6.02	6.05	6.08	6.11	6.14	6.17	6.21	6.24	6.27
NB System ($/kwyr) (2008 Firm Pt-to-Pt Tariff Rate, 0.5% annual esc., 83% Exch. Rate)		24.29	24.41	24.53	24.65	24.78	24.90	25.03	25.15	25.28	25.40	25.53	25.66	25.79	25.91	26.04	26.17	26.30	26.44	26.57	26.70	26.83	26.97
Total EMEC Transmission Cost ($/kwyr)		29.93	30.08	30.23	30.38	30.53	30.69	30.84	30.99	31.15	31.31	31.46	31.62	31.78	31.94	32.10	32.26	32.42	32.58	32.74	32.91	33.07	33.24
EMEC South NMISA Fee - T&D ($K)		25	26	27	28	29	30	31	32	33	34	35	36	37	38	40	41	42	44	45	46	48	49
Total EMEC South Transmission Cost ($K)		425	432	439	446	453	460	466	471	476	482	488	493	499	505	511	517	523	529	535	542	548	555
Total EMEC South Transmission Cost ($/kwyr)		31.83	32.03	32.22	32.41	32.61	32.81	33.02	33.23	33.45	33.67	33.89	34.11	34.34	34.57	34.80	35.03	35.27	35.51	35.75	35.99	36.24	36.49
ME BUILDOUT CASE																							
EMEC Joins ISO-NE (Assume NB & EMEC Transmission Tariff included for RNS Settlement, ISO-NE Outservice Waived)																							
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		52.58	68.61	83.25	86.19	90.33	92.33	94.08	95.32	95.90	97.15	97.20	97.26	97.31	97.37	97.43	97.49	97.55	97.61	97.68	97.75	97.81	97.89
EMEC Projected 12 CP (MW)		13.35	13.49	13.62	13.76	13.89	14.03	14.10	14.17	14.24	14.32	14.39	14.46	14.53	14.60	14.68	14.75	14.82	14.90	14.97	15.05	15.12	15.20
EMEC RNS Cost ($K)		702	925	1,134	1,186	1,255	1,296	1,327	1,351	1,366	1,391	1,398	1,406	1,414	1,422	1,430	1,438	1,446	1,454	1,463	1,471	1,479	1,488
OTHER APPLICABLE ISO/NEPOOL EXPENSES ($K)																							
NEPOOL Expenses	2008 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	4	4	4	4	4	4	4	4	5	5	5	5	5	5	6	6	6	6	6	6	7	7
ISO Tariff Schedule 1 (System Control & Disp.)	2008 ISO Tariff, 3% Esc.	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2007 Tariff Rate, 3% Esc.	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6	6	7	7	7	7	7	8
ISO Tariff Schedule 5 (NESCOE)	2008 ISO Tariff, 09/10 Bud., 3% Esc.	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3
OATT Schedule 2 - VAR	Actual 2007, 3% Esc.	43	44	45	47	48	50	51	53	54	56	57	59	61	63	65	67	69	71	73	75	77	80
OATT Schedule 16 - Black Start	Actual 2007, 3% Esc.	7	7	7	7	8	8	8	8	9	9	9	9	10	10	10	11	11	11	12	12	12	13
OATT Schedule 19 - Special Const Resources	Assumed $0. Past/Potential future costs.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Response Programs	Actual 2007, 3% Esc.	9	9	10	10	10	11	11	11	12	12	12	13	13	13	14	14	15	15	16	16	17	17
Demand Response Program	Actual 2007, 3% Esc.	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2
Total Other Expenses ($K)		70	72	75	77	79	82	84	87	89	92	95	97	100	103	106	110	113	116	120	123	125	129
Total EMEC (South Region) Transmission Costs (Join ISO-NE) ($K)		**772**	**998**	**1,209**	**1,263**	**1,334**	**1,377**	**1,411**	**1,438**	**1,455**	**1,483**	**1,493**	**1,504**	**1,514**	**1,525**	**1,536**	**1,548**	**1,559**	**1,571**	**1,582**	**1,594**	**1,605**	**1,617**
Total EMEC (South Region) Transmission Costs ($/kwyr)		57.82	73.98	88.73	91.78	96.03	98.14	100.03	101.43	102.16	103.56	103.78	103.99	104.22	104.44	104.68	104.92	105.17	105.42	105.68	105.94	106.11	106.38
NMISA South Region Transmission Cost/(Benefit) to Join ISO-NE ($K)		**347**	**566**	**770**	**817**	**881**	**917**	**945**	**967**	**979**	**1,001**	**1,005**	**1,010**	**1,015**	**1,020**	**1,026**	**1,031**	**1,036**	**1,042**	**1,047**	**1,053**	**1,057**	**1,062**
NEW ENGLAND BUILDOUT CASE																							
EMEC Joins ISO-NE (Assume NB & EMEC Transmission Tariff included for RNS Settlement, ISO-NE Outservice Waived)																							
ISO-NE RNS Rate (incl. OATT Sch 1) $/kwyr		52.58	68.61	265.22	294.00	311.63	329.49	347.22	349.67	351.49	352.75	352.81	352.87	352.94	353.00	353.07	353.14	353.21	353.28	353.36	353.43	353.51	353.59
EMEC Projected 12 CP (MW)		13.35	13.49	13.62	13.76	13.89	14.03	14.10	14.17	14.24	14.32	14.39	14.46	14.53	14.60	14.68	14.75	14.82	14.90	14.97	15.05	15.12	15.20
EMEC RNS Cost ($K)		702	925	3,612	4,044	4,330	4,624	4,897	4,956	5,007	5,050	5,076	5,102	5,129	5,155	5,182	5,209	5,236	5,263	5,291	5,318	5,346	5,374
OTHER APPLICABLE ISO/NEPOOL EXPENSES ($K)																							
NEPOOL Expenses	2008 Budget, 3% Esc.. Assumes load ultimately pays the cost so 100% inlcuded in trans. Actual cost spread among sectors.	4	4	4	4	4	4	4	4	5	5	5	5	5	5	6	6	6	6	6	6	7	7
ISO Tariff Schedule 1 (System Control & Disp.)	2008 ISO Tariff, 3% Esc.	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3
ISO Tariff Schedule 4 (FERC Annual charges)	Actual 2007 Tariff Rate, 3% Esc.	4	4	4	5	5	5	5	5	5	5	6	6	6	6	6	6	7	7	7	7	7	8
ISO Tariff Schedule 5 (NESCOE)	2008 ISO Tariff, 09/10 Bud., 3% Esc.	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3
OATT Schedule 2 - VAR	Actual 2007, 3% Esc.	43	44	45	47	48	50	51	53	54	56	57	59	61	63	65	67	69	71	73	75	77	80
OATT Schedule 16 - Black Start	Actual 2007, 3% Esc.	7	7	7	7	8	8	8	8	9	9	9	9	10	10	10	11	11	11	12	12	12	13
OATT Schedule 19 - Special Const Resources	Assumed $0. Past/Potential future costs.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Response Programs	Actual 2007, 3% Esc.	9	9	10	10	10	11	11	11	12	12	12	13	13	13	14	14	15	15	16	16	17	17
Demand Response Program	Actual 2007, 3% Esc.	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2
Total Other Expenses ($K)		70	72	75	77	79	82	84	87	89	92	95	97	100	103	106	110	113	116	120	123	127	131
Total EMEC (South Region) Transmission Costs (Join ISO-NE) ($K)		**772**	**998**	**3,687**	**4,121**	**4,409**	**4,705**	**4,981**	**5,043**	**5,096**	**5,142**	**5,170**	**5,200**	**5,229**	**5,259**	**5,288**	**5,319**	**5,349**	**5,380**	**5,410**	**5,442**	**5,473**	**5,505**
Total EMEC (South Region) Transmission Costs ($/kwyr)		57.82	73.98	270.70	299.59	317.32	335.31	353.18	355.77	357.75	359.16	359.38	359.61	359.84	360.08	360.32	360.57	360.83	361.09	361.35	361.63	361.91	362.20
NMISA South Region Transmission Cost/(Benefit) to Join ISO-NE ($K)		**347**	**566**	**3,248**	**3,675**	**3,956**	**4,245**	**4,515**	**4,571**	**4,619**	**4,660**	**4,683**	**4,706**	**4,730**	**4,754**	**4,778**	**4,802**	**4,826**	**4,851**	**4,875**	**4,900**	**4,925**	**4,950**

ATTACHMENT 7

ISO-NE MA Hub Forward Energy Price Projection

ATTACHMENT 7

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
ISO-NE (MA Hub) Forward Energy Price Projection
November 12, 2008

FORWARD HENRY HUB NATURAL GAS PRICE (as of November 11, 2008, NYMEX Close through 2020, then 2020/2019 annual escalation thereafter)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Jan	6.85	8.28	8.68	8.69	8.65	8.65	8.75	8.93	9.07	9.25	9.41	9.57	9.73	9.90	10.07	10.24	10.41	10.59	10.77	10.95	11.14	11.33
Feb	6.92	8.28	8.67	8.67	8.63	8.64	8.75	8.92	9.06	9.24	9.40	9.56	9.72	9.88	10.05	10.22	10.40	10.57	10.75	10.94	11.12	11.31
Mar	6.89	8.10	8.43	8.43	8.38	8.41	8.52	8.70	8.84	9.01	9.17	9.33	9.49	9.65	9.82	9.99	10.17	10.35	10.53	10.71	10.90	11.09
Apr	6.84	7.48	7.66	7.64	7.59	7.62	7.77	7.91	8.04	8.19	8.33	8.50	8.67	8.85	9.03	9.21	9.40	9.59	9.79	9.99	10.19	10.40
May	6.89	7.44	7.58	7.55	7.52	7.57	7.74	7.89	8.02	8.17	8.31	8.48	8.65	8.83	9.01	9.20	9.38	9.58	9.77	9.97	10.18	10.38
Jun	7.00	7.54	7.66	7.63	7.61	7.65	7.82	7.97	8.10	8.25	8.39	8.56	8.73	8.91	9.09	9.28	9.46	9.66	9.85	10.05	10.25	10.46
Jul	7.13	7.65	7.76	7.72	7.70	7.74	7.92	8.06	8.19	8.34	8.48	8.65	8.82	9.00	9.18	9.37	9.55	9.74	9.94	10.14	10.34	10.55
Aug	7.21	7.73	7.84	7.80	7.77	7.81	7.99	8.11	8.25	8.40	8.54	8.70	8.86	9.03	9.20	9.37	9.55	9.73	9.91	10.09	10.28	10.48
Sep	7.25	7.76	7.87	7.83	7.80	7.84	8.02	8.13	8.27	8.42	8.56	8.72	8.88	9.05	9.22	9.39	9.57	9.75	9.93	10.11	10.30	10.50
Oct	7.33	7.83	7.94	7.91	7.87	7.93	8.10	8.21	8.35	8.51	8.65	8.81	8.97	9.14	9.31	9.48	9.66	9.84	10.02	10.20	10.39	10.58
Nov	7.66	8.10	8.19	8.15	8.13	8.19	8.38	8.51	8.66	8.82	8.96	9.13	9.30	9.48	9.66	9.84	10.03	10.22	10.41	10.61	10.81	11.02
Dec	8.03	8.45	8.46	8.42	8.42	8.52	8.71	8.85	9.01	9.17	9.33	9.52	9.71	9.91	10.11	10.32	10.53	10.75	10.96	11.19	11.41	11.65
Average	7.17	7.88	8.06	8.03	8.00	8.04	8.20	8.35	8.49	8.65	8.79	8.96	9.13	9.30	9.48	9.66	9.84	10.03	10.22	10.41	10.61	10.81

FORWARD MA HUB (ONPEAK) (As of November 11, 2008 NYMEX Close through 2013, then 2013 Heat Rate and Natural Gas Forwards thereafter)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Jan	86.26	101.00	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Feb	86.26	101.00	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Mar	73.25	81.25	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Apr	71.15	81.25	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
May	71.08	76.75	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Jun	75.49	79.75	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Jul	84.16	92.60	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Aug	84.16	92.60	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Sep	72.92	81.00	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Oct	79.15	82.50	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Nov	79.15	82.50	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Dec	79.15	82.50	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
Average	78.52	86.23	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93

FORWARD MA HUB (OFFPEAK) (As of November 11, 2008 NYMEX Close through 2013, then 2013 Heat Rate and Natural Gas Forwards thereafter)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Jan	70.99	80.16	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Feb	70.99	80.16	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Mar	58.50	61.28	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Apr	56.50	61.28	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
May	55.00	57.28	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Jun	56.00	59.53	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Jul	61.00	64.28	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Aug	61.00	64.28	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Sep	56.50	60.78	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Oct	62.01	62.78	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Nov	62.01	62.78	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Dec	62.01	62.78	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Average	61.04	64.78	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19

FORWARD MA HUB (ATC) (Assumes 47% of Hours Onpeak and 53% of Hours Offpeak)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Jan	78.17	89.95	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Feb	78.17	89.95	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Mar	65.43	70.67	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Apr	63.39	70.67	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
May	62.56	66.43	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Jun	65.16	69.03	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Jul	71.89	77.59	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Aug	71.89	77.59	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Sep	64.22	70.28	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Oct	70.07	72.05	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Nov	70.07	72.05	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Dec	70.07	72.05	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76
Average	69.25	74.86	74.68	74.12	73.86	74.23	75.69	77.01	78.33	79.78	81.14	82.68	84.24	85.84	87.47	89.12	90.81	92.54	94.29	96.08	97.90	99.76

ATTACHMENT 8

Historical Regional Energy Prices

ATTACHMENT 8

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
Historical Northeast Regional Energy Clearing Prices
November 12, 2008

		ATC Keswick	ATC Loss Adj. Keswick	ATC ME Zone	ATC 98% of Hub	ATC Hub	Onpeak Keswick	Onpeak Loss Adj. Keswick	Onpeak ME Zone	Onpeak 98% of Hub	Onpeak Hub	Offpeak Keswick	Offpeak Loss Adj. Keswick	Offpeak ME Zone	Offpeak 98% of Hub	Offpeak Hub	Hub Offpeak Perc of Onpeak
2004	January	73.10	73.33	73.63	79.55	81.17	90.35	90.60	90.93	98.43	100.44	58.88	59.10	59.39	63.99	65.30	65.0%
2004	February	45.38	45.59	45.84	50.19	51.21	48.26	48.49	48.81	54.81	55.93	42.93	43.13	43.32	46.26	47.20	84.4%
2004	March	44.07	44.20	44.31	46.98	47.94	48.49	48.63	48.72	51.89	52.95	39.74	39.86	39.99	42.17	43.03	81.3%
2004	April	45.96	46.23	46.62	51.44	52.49	49.93	50.25	50.67	57.24	58.41	42.16	42.39	42.73	45.87	46.81	80.1%
2004	May	48.57	49.01	49.30	54.48	55.59	53.66	54.21	54.39	62.36	63.63	44.73	45.09	45.45	48.53	49.52	77.8%
2004	June	46.87	47.56	48.32	51.94	53.00	52.33	53.09	53.97	59.29	60.50	41.64	42.27	42.91	44.91	45.83	75.8%
2004	July	41.60	43.18	45.10	49.39	50.40	45.40	47.16	49.60	55.31	56.44	38.20	39.60	41.06	44.07	44.97	79.7%
2004	August	38.68	40.28	42.26	46.79	47.74	42.72	44.51	47.05	52.44	53.51	35.04	36.49	37.96	41.70	42.55	79.5%
2004	September	35.93	37.07	38.32	43.03	43.91	41.76	43.05	44.56	49.53	50.54	30.83	31.83	32.85	37.35	38.11	75.4%
2004	October	46.17	46.98	47.91	49.25	50.26	52.34	53.25	54.45	56.06	57.20	41.08	41.82	42.54	43.66	44.55	77.9%
2004	November	45.23	46.14	47.05	49.97	50.99	51.70	52.80	53.90	57.79	58.97	39.57	40.32	41.06	43.13	44.01	74.6%
2004	December	51.78	52.93	54.12	58.16	59.35	56.66	57.92	59.26	64.66	65.98	47.00	48.04	49.09	51.81	52.87	80.1%
2004	Average	46.94	47.71	48.57	52.60	53.67	52.80	53.66	54.69	59.98	61.21	41.82	42.49	43.20	46.12	47.06	77.6%
2005	January	63.39	64.14	64.91	68.29	69.68	72.77	73.62	74.49	78.63	80.24	55.67	56.33	57.01	59.77	60.99	76.0%
2005	February	50.40	51.28	52.07	55.26	56.39	54.98	55.93	56.89	60.59	61.83	46.23	47.05	47.69	50.41	51.44	83.2%
2005	March	55.99	57.33	58.63	61.94	63.21	60.13	61.56	63.00	66.63	67.99	51.94	53.18	54.35	57.35	58.52	86.1%
2005	April	53.48	55.18	57.40	62.75	64.03	56.21	58.14	61.09	68.88	70.29	51.10	52.58	54.16	57.39	58.56	83.3%
2005	May	48.18	49.22	50.38	56.58	57.74	53.24	54.44	55.81	63.71	65.01	44.00	44.91	45.92	50.71	51.75	79.6%
2005	June	54.09	55.39	57.67	66.74	68.10	60.53	62.06	65.00	77.76	79.35	47.93	49.00	50.65	56.20	57.35	72.3%
2005	July	62.08	63.67	65.29	73.61	75.11	73.56	75.56	77.60	90.79	92.64	53.42	54.70	56.00	60.64	61.87	66.8%
2005	August	73.38	75.71	78.07	87.78	89.57	81.35	83.98	86.62	99.14	101.16	65.58	67.62	69.70	76.66	78.22	77.3%
2005	September	91.73	93.00	94.02	101.09	103.16	103.74	105.23	106.46	116.44	118.82	81.22	82.29	83.14	87.67	89.45	75.3%
2005	October	93.18	96.43	100.30	110.19	112.44	102.37	106.10	110.87	123.66	126.19	85.61	88.47	91.58	99.10	101.12	80.1%
2005	November	69.20	71.01	72.82	78.03	79.62	78.34	80.40	82.47	88.55	90.36	61.20	62.78	64.37	68.82	70.22	77.7%
2005	December	92.15	94.28	96.40	99.32	101.35	101.22	103.58	105.92	109.20	111.43	84.00	85.93	87.85	90.45	92.30	82.8%
2005	Average	67.27	68.89	70.66	76.80	78.37	74.87	76.72	78.85	87.00	88.77	60.66	62.07	63.54	67.93	69.32	78.4%
2006	January	66.92	68.45	69.99	72.88	74.36	72.82	74.51	76.21	80.64	82.29	61.62	63.01	64.41	65.91	67.25	81.7%
2006	February	64.14	64.98	65.89	69.33	70.74	67.51	68.43	69.47	73.97	75.48	61.07	61.85	62.64	65.11	66.44	88.0%
2006	March	56.72	57.32	57.91	59.34	60.55	61.48	62.14	62.79	64.60	65.92	52.06	52.60	53.14	54.19	55.29	83.9%
2006	April	56.63	57.65	58.67	59.58	60.79	64.17	65.30	66.43	67.56	68.94	50.61	51.53	52.45	53.20	54.28	78.7%
2006	May	51.53	52.51	53.43	55.21	56.34	59.70	60.88	62.05	63.64	64.94	44.19	45.00	45.70	47.65	48.62	74.9%
2006	June	52.16	53.02	53.90	57.24	58.41	60.30	61.38	62.59	67.35	68.72	44.38	45.02	45.60	47.57	48.54	70.6%
2006	July	55.98	57.35	58.91	62.12	63.38	68.04	69.72	71.83	75.55	77.09	46.88	48.01	49.16	51.98	53.04	68.8%
2006	August	57.25	58.86	61.16	65.89	67.23	65.20	67.13	70.47	77.52	79.10	49.47	50.76	52.05	54.51	55.62	70.3%
2006	September	42.78	43.01	43.71	44.51	45.41	48.75	48.96	50.14	51.15	52.20	38.00	38.24	38.57	39.19	39.99	76.6%
2006	October	47.72	48.23	50.24	52.57	53.65	53.14	53.70	56.99	60.16	61.39	42.86	43.32	44.17	45.76	46.69	76.1%
2006	November	56.95	58.17	59.37	62.74	64.02	64.98	66.37	67.77	72.27	73.75	49.92	50.99	52.01	54.41	55.52	75.3%
2006	December	50.42	51.78	52.74	55.52	56.65	56.60	58.19	59.20	63.20	64.49	45.76	46.94	47.86	49.72	50.74	78.7%
2006	Average	54.93	55.94	57.16	59.74	60.96	61.89	63.06	64.66	68.13	69.52	48.90	49.77	50.65	52.43	53.50	77.0%
2007	January	56.04	56.87	57.39	61.98	63.25	61.23	62.15	62.71	70.28	71.71	51.39	52.12	52.61	54.53	55.65	77.6%
2007	February	75.93	76.84	77.70	79.68	81.30	80.42	81.41	82.38	85.29	87.03	71.84	72.68	73.45	74.57	76.09	87.4%
2007	March	61.80	63.05	64.34	67.92	69.31	68.24	69.65	71.15	76.50	78.06	56.01	57.12	58.23	60.22	61.45	78.7%
2007	April	62.31	63.97	66.10	69.06	70.47	69.86	71.74	74.53	78.81	80.42	55.71	57.17	58.71	60.53	61.77	76.8%
2007	May	58.77	60.16	61.63	65.98	67.33	65.42	67.02	68.81	75.48	77.02	52.80	53.99	55.18	57.45	58.62	76.1%
2007	June	58.06	58.97	59.87	62.47	63.74	66.41	67.47	68.51	71.94	73.41	50.75	51.53	52.30	54.17	55.28	75.3%
2007	July	56.30	56.98	57.75	59.59	60.81	64.40	65.17	66.09	68.67	70.07	49.62	50.23	50.89	52.11	53.18	75.9%
2007	August	60.49	61.66	62.74	65.02	66.34	68.61	69.95	71.08	74.07	75.58	52.54	53.55	54.58	56.15	57.30	75.8%
2007	September	55.61	56.08	55.23	57.75	58.93	65.52	66.10	64.54	68.17	69.57	48.37	48.77	48.43	50.13	51.15	73.5%
2007	October	59.73	59.62	59.43	58.68	59.87	68.47	68.35	68.11	67.18	68.55	51.17	51.07	50.95	50.35	51.38	75.0%
2007	November	58.62	59.58	60.51	61.46	62.72	65.70	66.77	67.77	69.10	70.51	52.42	53.29	54.17	54.78	55.90	79.3%
2007	December	90.48	90.48	90.26	90.49	92.33	101.54	101.54	101.41	102.17	104.25	82.13	82.13	81.84	81.67	83.33	79.9%
2007	Average	62.85	63.69	64.41	66.67	68.03	70.49	71.44	72.26	75.64	77.18	56.23	56.97	57.61	58.89	60.09	77.6%
2004 thru 2007 Avg		58.00	59.06	60.20	63.95	65.26	65.01	66.22	67.62	72.69	74.17	51.90	52.83	53.75	56.34	57.49	
Basis to Hub		88.9%	90.5%	92.2%	98.0%		87.7%	89.3%	91.2%	98.0%		90.3%	91.9%	93.5%	98.0%		

ATTACHMENT 9

NMISA Load and Generation Assumptions
North Region

ATTACHMENT 9

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
NMISA Load and Generation Assumptions - Northern Region
November 12, 2008

Year	NMISA North & South Energy MWh	Northern % of Load	NMISA North Energy	Peak		Tinker Hydro	Caribou Hydro	Squa Pan Hydro	Boralex Fort Fairfield	Boralex Ashland	Boralex Sherman	Evergreen Wind (MH)	Caribou Steam	Tinker Diesel	Caribou Diesel	Flo's Inn Diesel	Loring Diesel	Total	% of Load Served by In Region Generation
					MW ==>	34.6	0.9	1.4	33	37	19	42	23	1	7	4.2	5.1	208.2	
					Assumed CF (when operating)==>	45%	64%	7%	80%	80%	80%	35%	0%	0%	0%	0%	0%	29%	
2009	833,400	89.80%	748,393	142		136,816	5,055	845	231,886	-	-	128,772	101	-	-	-	-	503,475	67%
2010	841,734	89.80%	755,877	144		136,816	5,055	845	231,886	-	-	128,772	101	-	-	-	-	503,475	67%
2011	850,151	89.80%	763,436	145		136,816	5,055	845	231,886	-	-	128,772	101	-	-	-	-	503,475	66%
2012	858,652	89.80%	771,069	147		136,816	5,055	845	231,886	-	-	128,772	101	-	-	-	-	503,475	65%
2013	867,239	89.80%	778,781	148		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	82%
2014	875,911	89.80%	786,568	150		136,816	5,055	845	231,886	-	-	128,772	101	-	-	-	-	503,475	64%
2015	884,670	89.80%	794,434	136		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	80%
2016	893,517	89.80%	802,378	137		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	79%
2017	902,452	89.80%	810,402	138		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	79%
2018	911,476	89.80%	818,506	140		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	78%
2019	920,591	89.80%	826,691	141		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	77%
2020	929,797	89.80%	834,958	143		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	76%
2021	939,095	89.80%	843,307	144		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	75%
2022	948,486	89.80%	851,741	146		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	75%
2023	957,971	89.80%	860,258	147		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	74%
2024	967,551	89.80%	868,861	148		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	73%
2025	977,226	89.80%	877,549	150		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	73%
2026	986,998	89.80%	886,325	151		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	72%
2027	996,868	89.80%	895,188	153		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	71%
2028	1,006,837	89.80%	904,140	155		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	70%
2029	1,016,905	89.80%	913,181	156		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	70%
2030	1,027,075	89.80%	922,313	158		136,816	5,055	845	231,886	-	133,152	128,772	101	-	-	-	-	636,627	69%

ATTACHMENT 10

MPS Status Quo Power Supply Cost Projection
NMISA North

ATTACHMENT 10

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
MPS Status Quo Power Supply Cost Projection – NMISA North
November 12, 2008

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ISO-NE MA Hub Forward	Onpeak	78.52	86.23	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
ISO-NE MA Hub Forward	Offpeak	61.04	64.78	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
Salisbury Basis	Onpeak	89.3%	89.3%	89.3%	89.3%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%
Salisbury Basis	Offpeak	91.9%	91.9%	91.9%	91.9%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%	96.4%
(Salisbury/Keswick basis based on (1) historical 2005-07 adjusted for 50% reduced losses from ME Zone to Keswick to reflect NRI loss impact and (2) reduced losses starting 2012 as a result of regionwide transmission additions).																							
Salisbury Node Forward	Onpeak	70.10	76.98	75.69	75.52	81.08	81.48	83.09	84.54	85.98	87.58	89.07	90.76	92.48	94.23	96.02	97.84	99.69	101.58	103.51	105.47	107.47	109.51
Salisbury Node Forward	Offpeak	56.09	59.52	60.39	59.58	62.23	62.54	63.77	64.88	65.99	67.22	68.36	69.66	70.98	72.32	73.69	75.09	76.51	77.96	79.44	80.95	82.49	84.05
Salisbury Node Forward	Around-The-Clock (ATC)	62.67	67.73	67.58	67.07	71.09	71.44	72.85	74.12	75.39	76.79	78.09	79.57	81.08	82.62	84.19	85.78	87.41	89.07	90.75	92.48	94.23	96.02
NET BACK TO NMISA (North Region) - ATC																							
ISO-NE Schedule 2 (adj. for losses)		0.21	0.22	0.22	0.23	0.24	0.24	0.25	0.26	0.27	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39
NB Transmission Losses (2.5%)		1.53	1.65	1.65	1.64	1.74	1.74	1.78	1.81	1.84	1.88	1.91	1.94	1.98	2.02	2.06	2.10	2.13	2.18	2.22	2.26	2.30	2.35
NB Trans Tariff (2008 Tariff, 80% CF, 0.5%/yr esc., 83% exch rate)		3.47	3.48	3.50	3.52	3.54	3.55	3.57	3.59	3.61	3.62	3.64	3.66	3.68	3.70	3.72	3.73	3.75	3.77	3.79	3.81	3.83	3.85
MPS Transmission Losses (2.3%)		1.44	1.56	1.56	1.54	1.64	1.65	1.68	1.71	1.74	1.77	1.80	1.83	1.87	1.90	1.94	1.98	2.01	2.05	2.09	2.13	2.17	2.21
MPS Tariff ($/MWh) (Projected Annual Rate @ 80% CF)		3.24	3.62	4.12	4.30	4.28	4.36	4.34	4.38	4.39	4.41	4.43	4.45	4.47	4.49	4.51	4.53	4.55	4.57	4.60	4.62	4.64	4.67
NMISA Tariff ($/MWh)		0.60	0.61	0.62	0.64	0.65	0.67	0.68	0.70	0.71	0.73	0.74	0.76	0.78	0.79	0.81	0.83	0.85	0.87	0.89	0.90	0.92	0.94
Total Netback		10.49	11.15	11.68	11.87	12.08	12.21	12.31	12.44	12.55	12.68	12.80	12.94	13.07	13.21	13.35	13.49	13.64	13.79	13.94	14.09	14.25	14.41
Status Quo Netback Energy Opportunity - ATC (Northern Region)		52.18	56.58	55.90	55.20	59.01	59.23	60.55	61.68	62.84	64.11	65.29	66.64	68.01	69.41	70.84	72.29	73.77	75.28	76.82	78.38	79.98	81.61
Status Quo Must Run Northern Region Netback MWh		271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589	271,589
Fort Fairfield Marginal Cost ($/MWh)		54.56	57.28	58.19	58.45	58.70	59.20	60.10	60.96	61.83	62.76	63.67	64.65	65.66	66.70	67.76	68.84	69.95	71.09	72.25	73.44	74.66	75.91
Eff, Rate for Fort Fairfield ($/MWh) (At least $3/MWh over MC)		57.56	60.28	61.19	61.45	61.70	62.20	63.10	63.96	64.83	65.76	66.67	67.65	68.66	69.70	70.84	72.29	73.77	75.28	76.82	78.38	79.98	81.61
Fort Fairfield Generation (MWh)		231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886	231,886
Ashland Marginal Cost ($/MWh)		54.56	57.28	58.19	58.45	58.70	59.20	60.10	60.96	61.83	62.76	63.67	64.65	65.66	66.70	67.76	68.84	69.95	71.09	72.25	73.44	74.66	75.91
Effective Rate for Ashland ($/MWh) (At least $3/MWh over MC)		57.56	60.28	61.19	61.45	61.70	62.20	63.10	63.96	64.83	65.76	66.67	67.65	68.66	69.70	70.84	72.29	73.77	75.28	76.82	78.38	79.98	81.61
Ashland Generation (MWh) - (Assumed Exported, CT REC Value)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherman Marginal Cost ($/MWh)		63.03	66.12	67.21	67.57	67.93	68.56	69.64	70.68	71.74	72.86	73.96	75.16	76.38	77.63	78.91	80.22	81.57	82.94	84.36	85.80	87.28	88.80
Effective Rate for Sherman ($/MWh) (At least $3/MWh over MC)		66.03	69.12	70.21	70.57	70.93	71.56	72.64	73.68	74.74	75.86	76.96	78.16	79.38	80.63	81.91	83.22	84.57	85.94	87.36	88.80	90.28	91.80
Sherman Generation (MWh)		-	-	-	-	133,152	-	133,152	133,152	133,152	133,152	133,152	133,152	133,152	133,152	133,152	133,152	133,152	133,152	133,152	133,152	133,152	133,152
Status Quo Wholesale Energy Cost (Northern Region) ($/MWh)		54.66	58.28	58.34	58.08	62.48	60.59	64.01	65.02	66.05	67.17	68.23	69.42	70.63	71.86	73.15	74.58	76.03	77.51	79.02	80.56	82.14	83.74
NMISA Northern Region (Avg Generation MW)		57	57	57	57	73	57	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
NMISA Northern Region Load																							
Onpeak Avg MW		97	97	98	99	100	101	102	103	105	106	107	108	109	110	111	112	113	114	115	117	118	119
Offpeak Avg MW		76	76	77	78	79	79	80	81	82	83	84	84	85	86	87	88	89	90	90	91	92	93
ATC Avg MW		85	86	87	88	89	90	91	92	93	93	94	95	96	97	98	99	100	101	102	103	104	105
NB Control Area Generation Purchases																							
NMISA Northern Region Load - Onpeak Avg MW		39	40	41	42	28	44	30	31	32	33	34	35	36	37	38	39	41	42	43	44	45	46
NMISA Northern Region Load - Offpeak Avg MW		18	19	20	20	6	22	8	8	9	10	11	12	13	13	14	15	16	17	18	19	20	20
NMISA Northern Region Load - ATC Avg MW		28	29	30	31	16	32	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
Status Quo Wholesale Energy Cost (NB Control Area) ($/MWh)		65.28	70.92	70.32	69.87	77.39	74.65	78.79	79.92	81.08	82.38	83.59	84.99	86.43	87.91	89.42	90.97	92.56	94.18	95.84	97.53	99.26	101.03
NMISA Northern Region Wholesale Energy Cost ($/MWh)																							
Northern Region Generation		54.66	58.28	58.34	58.08	62.48	60.59	64.01	65.02	66.05	67.17	68.23	69.42	70.63	71.86	73.15	74.58	76.03	77.51	79.02	80.56	82.14	83.74
NB Control Area Generation (Salisbury)		65.28	70.92	70.32	69.87	77.39	74.65	78.79	79.92	81.08	82.38	83.59	84.99	86.43	87.91	89.42	90.97	92.56	94.18	95.84	97.53	99.26	101.03
Load Following Premium (3% of Salisbury, Load Weighted)		1.91	2.06	2.06	2.04	2.17	2.18	2.22	2.26	2.30	2.34	2.38	2.43	2.47	2.52	2.57	2.62	2.66	2.72	2.77	2.82	2.87	2.93
Percent of Load Served by Northern Region		67%	67%	66%	65%	82%	64%	80%	79%	79%	78%	77%	76%	75%	75%	74%	73%	73%	72%	71%	70%	70%	69%
Percent of Load Served by NB Control Area		33%	33%	34%	35%	18%	36%	20%	21%	21%	22%	23%	24%	25%	25%	26%	27%	27%	28%	29%	30%	30%	31%
NMISA Northern Region Energy Cost ($/MWh)		60.04	64.57	64.47	64.21	67.37	67.83	69.16	70.36	71.57	72.89	74.14	75.54	76.97	78.43	79.95	81.57	83.23	84.92	86.64	88.40	90.19	92.02
Status Quo Capacity Cost ($/kw-mo) - Assumes 50% of ISO-NE.		1.98	2.17	3.55	4.61	4.75	4.89	5.04	5.19	5.35	5.51	5.67	5.84	6.02	6.20	6.38	6.58	6.77	6.98	7.19	7.40	7.62	7.85
Capacity Cost ($/MWh)(66.8% LF per NMISA 7 Year Outlook)		4.05	4.44	7.28	9.46	9.74	10.03	10.33	10.64	10.96	11.29	11.63	11.98	12.34	12.71	13.09	13.48	13.89	14.31	14.74	15.18	15.63	16.10
NMISA Northern Region Energy Cost and Capacity Cost ($/MWh)		64.10	69.01	71.75	73.67	77.11	77.87	79.50	81.00	82.54	84.18	85.78	87.52	89.31	91.14	93.04	95.06	97.12	99.23	101.38	103.58	105.83	108.12
		64.50	70.20	72.77	74.51	79.02	79.70	81.47	83.10	84.73	86.52	88.21											
Other Wholesale Load Serving Costs																							
Reserves ($/MWh) (2008 NB Tariff, plus 3% per year)																							
10 Minute Synchronous Req.	0.1 MW @ $2090/mwyr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 Minute Non-Synch. Req.	21.2 MW @ $5054/mwyr	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24
30 Minute Non-Synch. Req.	6.2 MW @ $3480/mwyr	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
NMISA Fees ($/MWh) (inlcuded in Northern Region Trans)		0.30	0.31	0.31	0.32	0.33	0.33	0.34	0.35	0.36	0.36	0.37	0.38	0.39	0.40	0.41	0.41	0.42	0.43	0.44	0.45	0.46	0.47
Total Other Wholesale Costs ($/MWh)		0.45	0.46	0.48	0.49	0.50	0.51	0.53	0.54	0.55	0.57	0.58	0.59	0.61	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.74	0.76
Total Stand Alone Wholesale Power Supply Costs ($/MWh)		64.55	69.47	72.23	74.16	77.61	78.38	80.02	81.54	83.09	84.75	86.36	88.12	89.92	91.77	93.68	95.71	97.79	99.92	102.09	104.30	106.57	108.88
NMISA North Region Load (MWh)		748,393	755,877	763,436	771,069	778,781	786,568	794,434	802,378	810,402	818,506	826,691	834,958	843,307	851,741	860,258	868,861	877,549	886,325	895,188	904,140	913,181	922,313
North Region Stand Alone Wholesale Power Supply Costs ($K)		48,310	52,514	55,143	57,183	60,442	61,650	63,574	65,427	67,334	69,367	71,390	73,574	75,831	78,162	80,589	83,162	85,817	88,557	91,386	94,304	97,317	100,425

ATTACHMENT 11

MPS Joins ISO-NE Power Supply Cost Projection
NMISA North

ATTACHMENT 11

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Wholesale Power Supply Market Cost/Benefit Assessment
MPS Joins ISO-NE Power Supply Cost Projection – NMISA North
November 12, 2008

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MA Hub	Onpeak	78.52	86.23	84.78	84.59	84.35	84.77	86.45	87.95	89.46	91.12	92.67	94.42	96.21	98.04	99.89	101.79	103.72	105.68	107.69	109.73	111.81	113.93
MA Hub	Offpeak	61.04	64.78	65.72	64.84	64.55	64.87	66.16	67.31	68.46	69.73	70.91	72.26	73.63	75.02	76.45	77.89	79.37	80.88	82.41	83.97	85.57	87.19
ME Zone Basis	Onpeak	91.8%	91.8%	91.8%	91.8%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
ME Zone Basis	Offpeak	94.0%	94.0%	94.0%	94.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
(MA Hub to ME Zone basis percentage increases from historical basis in 2012 as a result of assumed reduction in losses and congestion that may would result from regional transmission additions)																							
ME Zone	Onpeak	72.08	79.15	77.83	77.65	82.66	83.08	84.72	86.19	87.67	89.30	90.81	92.53	94.29	96.07	97.90	99.75	101.64	103.57	105.53	107.54	109.58	111.65
ME Zone	Offpeak	57.38	60.89	61.78	60.95	63.26	63.58	64.83	65.96	67.09	68.34	69.50	70.81	72.15	73.52	74.92	76.34	77.78	79.26	80.76	82.29	83.85	85.45
Historical NMISA Energy Usage	Onpeak	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%	53.1%
Historical NMISA Energy Usage	Offpeak	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%	46.9%
Load Following Premium (3% of ME Zone, Load Weighted)		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
ME Zone Energy Usage Weighted Energy Cost		67.14	72.71	72.41	71.91	75.77	76.15	77.65	79.00	80.36	81.85	83.24	84.82	86.42	88.06	89.73	91.43	93.17	94.93	96.73	98.57	100.44	102.34
Other Wholesale Load Serving Costs																							
Capacity ($/kw-mo) (Trans Period, then ISO 2005 $7.50 est adj for inflation)		3.95	4.33	7.10	9.22	9.50	9.79	10.08	10.38	10.69	11.01	11.34	11.68	12.04	12.40	12.77	13.15	13.55	13.95	14.37	14.80	15.25	15.70
Capacity ($/MWh) (66.8% Load Factor per NMISA 7 Yr Outlook)		8.11	8.89	14.56	18.92	19.48	20.07	20.67	21.29	21.93	22.59	23.26	23.96	24.68	25.42	26.18	26.97	27.78	28.61	29.47	30.35	31.26	32.20
Regulation	(Actual 2007, ISO WCR, 3% Esc.)	0.35	0.36	0.37	0.38	0.39	0.41	0.42	0.43	0.44	0.46	0.47	0.48	0.50	0.51	0.53	0.55	0.56	0.58	0.60	0.61	0.63	0.65
Forward Reserve Mkt	(Actual 2007, ISO WCR+128%, 3% Esc.)	0.74	0.76	0.78	0.81	0.83	0.86	0.88	0.91	0.94	0.96	0.99	1.02	1.05	1.08	1.12	1.15	1.18	1.22	1.26	1.29	1.33	1.37
ISO Tariff Schedule 2 (EAS)	(Actual 2008 RR, 50% to Load, 3% Esc.)	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25	0.25	0.26	0.27	0.28	0.29	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
ISO Tariff Schedule 3 (RAS)	(Actual 2008 RR/Tariff, 3% Esc.)	0.36	0.37	0.38	0.39	0.40	0.41	0.43	0.44	0.45	0.46	0.48	0.49	0.51	0.52	0.54	0.55	0.57	0.59	0.61	0.62	0.64	0.66
NCPC/RMR	(Actual 2007, ISO WCR, 3% Esc.)	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.30	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
Other (Inad./Emer.En, RT Reserve)	(Actual 2007, ISO WCR, 3% Esc.)	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20
Marginal Loss Revenue Fund	(Actual 2007 ISO WCR Percentage)	(0.65)	(0.71)	(0.70)	(0.70)	(0.73)	(0.74)	(0.75)	(0.77)	(0.78)	(0.79)	(0.81)	(0.82)	(0.84)	(0.85)	(0.87)	(0.89)	(0.90)	(0.92)	(0.94)	(0.96)	(0.97)	(0.99)
NEPOOL Expenses	Included in Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generation Information System	(Actual 2007, 3% Esc.)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Demand Response Program	Accounted for in Trans (Network Load)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Wholesale Power Supply Costs ($/MWh)		9.42	10.20	15.94	20.36	20.96	21.61	22.26	22.94	23.64	24.35	25.10	25.86	26.64	27.45	28.28	29.14	30.03	30.94	31.88	32.84	33.84	34.86
Total Join ISO-NE Wholesale Power Supply Costs ($/MWh)		**76.56**	**82.91**	**88.35**	**92.28**	**96.73**	**97.75**	**99.92**	**101.94**	**103.99**	**106.21**	**108.34**	**110.67**	**113.07**	**115.51**	**118.02**	**120.58**	**123.19**	**125.87**	**128.61**	**131.41**	**134.28**	**137.21**
Total NMISA North Region Wholesale Power Supply Costs ($K)		**57,298**	**62,671**	**67,448**	**71,153**	**75,330**	**76,890**	**79,377**	**81,796**	**84,276**	**86,930**	**89,560**	**92,409**	**95,350**	**98,388**	**101,524**	**104,763**	**108,108**	**111,562**	**115,129**	**118,813**	**122,618**	**126,548**
STATUS QUO vs JOIN ISO-NE																							
Status Quo Wholesale Power Supply Costs ($/MWh)		64.55	69.47	72.23	74.16	77.61	78.38	80.02	81.54	83.09	84.75	86.36	88.12	89.92	91.77	93.68	95.71	97.79	99.92	102.09	104.30	106.57	108.88
Join ISO-NE Wholesale Power Supply Costs ($/MWh)		76.56	82.91	88.35	92.28	96.73	97.75	99.92	101.94	103.99	106.21	108.34	110.67	113.07	115.51	118.02	120.58	123.19	125.87	128.61	131.41	134.28	137.21
Wholesale Market Costs (Benefits) for Joining ISO-NE ($/MWh)		12.01	13.44	16.12	18.12	19.12	19.38	19.89	20.40	20.91	21.46	21.98	22.56	23.15	23.75	24.34	24.86	25.40	25.96	26.52	27.11	27.71	28.32
NMISA Northern Region Load (MWh)		748,393	755,877	763,436	771,069	778,781	786,568	794,434	802,378	810,402	818,506	826,691	834,958	843,307	851,741	860,258	868,861	877,549	886,325	895,188	904,140	913,181	922,313
NMISA Northern Region Wholesale Market Costs (Benefits) ($K)		8,988	10,158	12,305	13,970	14,887	15,240	15,803	16,370	16,942	17,563	18,170	18,834	19,519	20,226	20,936	21,602	22,291	23,005	23,744	24,509	25,301	26,122

ATTACHMENT 12

EMEC Status Quo and Joins ISO-NE
Power Supply Cost Projection
NMISA South

ATTACHMENT 12

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Wholesale Power Supply Cost/Benefit Assessment
Eastern Maine Electric Cooperative (EMEC/NMISA South) Status Quo and Join ISONE Power Supply Cost Projection
November 12, 2008

WHOLESALE POWER SUPPLY COST

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Status Quo																							
Salisbury Node Forward	Onpeak	70.10	76.98	75.69	75.52	81.08	81.48	83.09	84.54	85.98	87.58	89.07	90.76	92.48	94.23	96.02	97.84	99.69	101.58	103.51	105.47	107.47	109.51
Salisbury Node Forward	Offpeak	56.09	59.52	60.39	59.58	62.23	62.54	63.77	64.88	65.99	67.22	68.36	69.66	70.98	72.32	73.69	75.09	76.51	77.96	79.44	80.95	82.49	84.05
Salisbury Node Forward	ATC	62.67	67.73	67.58	67.07	71.09	71.44	72.85	74.12	75.39	76.79	78.09	79.57	81.08	82.62	84.19	85.78	87.41	89.07	90.75	92.48	94.23	96.02
NET BACK TO NMISA ($/MWH) (South Region)																							
ISO-NE Schedule 2 (adj. for losses)		0.21	0.22	0.22	0.23	0.24	0.24	0.25	0.26	0.27	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39
NB Transmission Losses (2.5%)		1.60	1.73	1.72	1.71	1.81	1.82	1.86	1.89	1.92	1.96	1.99	2.03	2.07	2.11	2.15	2.19	2.23	2.27	2.31	2.36	2.40	2.45
NB Transmission Tariff (2008 Tariff Rate @ 80% CF, 0.5%/yr esc., 83% exchange rate)		3.47	3.48	3.50	3.52	3.54	3.55	3.57	3.59	3.61	3.62	3.64	3.66	3.68	3.70	3.72	3.73	3.75	3.77	3.79	3.81	3.83	3.85
EMEC Transmission Losses (2.0%)		1.25	1.35	1.35	1.34	1.42	1.43	1.46	1.48	1.51	1.54	1.56	1.59	1.62	1.65	1.68	1.72	1.75	1.78	1.82	1.85	1.88	1.92
EMEC Tariff ($/MWh) (2008 Tariff, non-firm hourly rate, 0.5% annual esc.)		0.94	0.95	0.95	0.96	0.96	0.97	0.97	0.98	0.98	0.99	0.99	1.00	1.00	1.01	1.01	1.02	1.02	1.03	1.03	1.04	1.04	1.05
NMISA Tariff ($/MWh)		0.60	0.61	0.62	0.64	0.65	0.67	0.68	0.70	0.71	0.73	0.74	0.76	0.78	0.79	0.81	0.83	0.85	0.87	0.89	0.90	0.92	0.94
Total Netback		8.07	8.34	8.37	8.39	8.62	8.68	8.79	8.89	9.00	9.11	9.21	9.33	9.45	9.56	9.69	9.81	9.94	10.06	10.19	10.33	9.54	9.65
Generation Wholesale Energy Opportunity Value (Southern Region)		54.61	59.39	59.21	58.68	62.47	62.76	64.07	65.23	66.39	67.69	68.88	70.25	71.64	73.05	74.50	75.97	77.47	79.00	80.56	82.15	84.69	86.36
Status Quo Must Run Northern Region Netback (MWh)		52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560	52,560
NMISA Southern Region (Avg ATC Generation MW)		6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
NMISA Southern Region Load																							
Onpeak Avg MW		11	11	11	11	11	12	12	12	12	12	12	12	12	12	13	13	13	13	13	13	13	14
Offpeak Avg MW		9	9	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	11
ATC Avg MW		10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	12	12	12	12
NB Control Area Generation Purchases																							
NMISA Northern Region Load - Onpeak Avg MW		5	5	5	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	8
NMISA Northern Region Load - Offpeak Avg MW		3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	5
NMISA Northern Region Load - ATC Avg MW		4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	6	6	6	6
Status Quo Wholesale Energy Cost (NB Control Area) ($/MWh)		64.91	70.47	69.95	69.50	73.92	74.25	75.68	76.95	78.23	79.65	80.96	82.46	83.99	85.55	87.13	88.75	90.40	92.08	93.79	95.54	97.32	99.13
NMISA Southern Region Wholesale Energy Cost ($/MWh)																							
Southern Region Generation		54.61	59.39	59.21	58.68	62.47	62.76	64.07	65.23	66.39	67.69	68.88	70.25	71.64	73.05	74.50	75.97	77.47	79.00	80.56	82.15	84.69	86.36
NB Control Area Generation (Salisbury)		64.91	70.47	69.95	69.50	73.92	74.25	75.68	76.95	78.23	79.65	80.96	82.46	83.99	85.55	87.13	88.75	90.40	92.08	93.79	95.54	97.32	99.13
Load Following Premium (3% of Salisbury, Load Weighted)		1.91	2.06	2.06	2.04	2.17	2.18	2.22	2.26	2.30	2.34	2.38	2.43	2.47	2.52	2.57	2.62	2.66	2.72	2.77	2.82	2.87	2.93
Percent of Load Served by Southern Region Generation		62%	61%	61%	60%	59%	59%	58%	58%	57%	57%	56%	55%	55%	54%	54%	53%	53%	52%	52%	51%	51%	50%
Percent of Load Served by NB Control Area Generation		38%	39%	39%	40%	41%	41%	42%	42%	43%	43%	44%	45%	45%	46%	46%	47%	47%	48%	48%	49%	49%	50%
NMISA Southern Region Energy Cost ($/MWh)		60.45	65.75	65.49	65.05	69.28	69.67	71.13	72.45	73.77	75.23	76.58	78.12	79.68	81.28	82.90	84.56	86.25	87.97	89.72	91.51	93.79	95.65
Capacity ($/MWh) (50% of ISO-NE)		4.05	4.44	7.28	9.46	9.74	10.03	10.33	10.64	10.96	11.29	11.63	11.98	12.34	12.71	13.09	13.48	13.89	14.31	14.74	15.18	15.63	16.10
NMISA Southern Region Energy and Capacity Cost ($/MWh)		64.50	70.20	72.77	74.51	79.02	79.70	81.47	83.10	84.73	86.52	88.21	90.10	92.02	93.99	96.00	98.04	100.14	102.27	104.45	106.68	109.43	111.76
Other Wholesale Load Serving Costs																							
Reserves (2008 NB Tariff)																							
10 Minute Synchronous Req.	0.1 MW @ $2090/mwyr, 3% Esc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10 Minute Non-Synch. Req.	21.2 MW @ $5054/mwyr, 3% Esc.	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24
30 Minute Non-Synch. Req.	6.2 MW @ $3480/mwyr, 3% Esc.	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
NMISA Fees ($/MWh) (Incl. in Northern Region Trans)		0.30	0.31	0.31	0.32	0.33	0.33	0.34	0.35	0.36	0.36	0.37	0.38	0.39	0.40	0.41	0.41	0.42	0.43	0.44	0.45	0.46	0.47
Total Other Wholesale Costs ($/MWh)		0.45	0.46	0.48	0.49	0.50	0.51	0.53	0.54	0.55	0.57	0.58	0.59	0.61	0.62	0.64	0.66	0.67	0.69	0.71	0.72	0.74	0.76
Total Status Quo EMEC (South Region) Wholesale Power Supply Cost ($/MWh)		64.95	70.66	73.25	74.99	79.52	80.21	81.99	83.63	85.29	87.09	88.79	90.69	92.63	94.61	96.63	98.70	100.81	102.96	105.16	107.41	110.17	112.52
EMEC Joins ISO-NE (Assume NB & EMEC Transmission Tariff included for RNS Settlement, ISO-NE Outservice Waived)																							
Weighted ME Zone Energy Price (Including Load Following Premium) ($/MWh)		67.14	72.71	72.41	71.91	75.77	76.15	77.65	79.00	80.36	81.85	83.24	84.82	86.42	88.06	89.73	91.43	93.17	94.93	96.73	98.57	100.44	102.34
Capacity ($/MWh)		8.11	8.89	14.56	18.92	19.48	20.07	20.67	21.29	21.93	22.59	23.26	23.96	24.68	25.42	26.18	26.97	27.78	28.61	29.47	30.35	31.26	32.20
Regulation	(Actual 2007, ISO WCR, 3% Esc.)	0.35	0.36	0.37	0.38	0.39	0.41	0.42	0.43	0.44	0.46	0.47	0.48	0.50	0.51	0.53	0.55	0.56	0.58	0.60	0.61	0.63	0.65
Forward Reserve Mkt	(Actual 2007, ISO WCR+128%, 3% Esc.)	0.74	0.76	0.78	0.81	0.83	0.86	0.88	0.91	0.94	0.96	0.99	1.02	1.05	1.08	1.12	1.15	1.18	1.22	1.26	1.29	1.33	1.37
ISO Tariff Schedule 2 (EAS)	(Actual 2008 RR, 50% to Load, 3% Esc.)	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25	0.25	0.26	0.27	0.28	0.29	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
ISO Tariff Schedule 3 (RAS)	(Actual 2008 RR/Tariff, 3% Esc.)	0.36	0.37	0.38	0.39	0.40	0.41	0.43	0.44	0.45	0.46	0.48	0.49	0.51	0.52	0.54	0.55	0.57	0.59	0.61	0.62	0.64	0.66
NCPC	(Actual 2007, ISO WCR, 3% Esc.)	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25	0.26	0.26	0.27	0.28	0.29	0.30	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37
Other Energy Obl (Inad/Em En, RT Res)	(Actual 2007, ISO WCR, 3% Esc.)	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20
Marginal Loss Revenue Fund	(Actual 2007 ISO WCR Percentage)	(0.65)	(0.71)	(0.70)	(0.70)	(0.73)	(0.74)	(0.75)	(0.77)	(0.78)	(0.79)	(0.81)	(0.82)	(0.84)	(0.85)	(0.87)	(0.89)	(0.90)	(0.92)	(0.94)	(0.96)	(0.97)	(0.99)
NEPOOL Expenses	Included in Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generation Information System	(Actual 2007, 3% Esc.)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Demand Response Program	Accounted for in Trans (Network Load)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
NB Losses	2.5%	2.04	2.20	2.34	2.44	2.55	2.57	2.63	2.68	2.73	2.78	2.84	2.90	2.95	3.02	3.08	3.14	3.21	3.27	3.34	3.41	3.49	3.56
Total EMEC Join ISO-NE (South Region) Wholesale Power Supply Costs ($/MWh)		78.60	85.11	90.68	94.71	99.27	100.33	102.54	104.62	106.72	108.99	111.17	113.57	116.02	118.53	121.09	123.72	126.40	129.15	131.95	134.82	137.76	140.77
EMEC South Wholesale Pwr Supply Cost (Benefit) for Joining ISO-NE ($/MWh)		13.65	14.45	17.44	19.72	19.75	20.11	20.55	20.99	21.43	21.90	22.38	22.88	23.39	23.92	24.46	25.02	25.59	26.18	26.79	27.42	27.59	28.25
Total EMEC (South Region) Load (MWh)		85,007	85,857	86,715	87,583	88,458	89,343	90,236	91,139	92,050	92,971	93,900	94,839	95,788	96,746	97,713	98,690	99,677	100,674	101,681	102,697	103,724	104,762
Total EMEC (South Region) Wholesale Power Supply Cost (Benefit) ($K)		1,160	1,241	1,512	1,727	1,747	1,797	1,854	1,913	1,973	2,036	2,101	2,170	2,240	2,314	2,390	2,469	2,551	2,636	2,724	2,816	2,862	2,960

ATTACHMENT 13

Summary
Maine Only Buildout Case
Cost/Benefit Assessment

ATTACHMENT 13

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
Maine Only Buildout Transmission and Wholesale Power Supply Markets Cost/Benefit Assessment
Summary
November 12, 2008

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Transmission Cost ($K)																				
Northern Region	8,356	8,743	9,383	9,683	9,985	10,186	10,326	10,542	10,613	10,684	10,756	10,829	10,903	10,979	11,056	11,133	11,213	11,293	11,360	11,443
Southern Region	770	817	881	917	945	967	979	1,001	1,005	1,010	1,015	1,020	1,026	1,031	1,036	1,042	1,047	1,053	1,057	1,062
Total	9,126	9,559	10,264	10,600	10,930	11,152	11,305	11,542	11,619	11,694	11,771	11,849	11,929	12,010	12,092	12,175	12,260	12,346	12,417	12,505
Cumulative	9,126	18,685	28,950	39,549	50,479	61,631	72,936	84,478	96,097	107,791	119,562	131,412	143,341	155,351	167,442	179,617	191,877	204,223	216,639	229,145
Average	9,126	9,343	9,650	9,887	10,096	10,272	10,419	10,560	10,677	10,779	10,869	10,951	11,026	11,096	11,163	11,226	11,287	11,346	11,402	11,457
Wholesale Markets Cost ($K)																				
Northern Region	12,305	13,970	14,887	15,240	15,803	16,370	16,942	17,563	18,170	18,834	19,519	20,226	20,936	21,602	22,291	23,005	23,744	24,509	25,301	26,122
Southern Region	1,512	1,727	1,747	1,797	1,854	1,913	1,973	2,036	2,101	2,170	2,240	2,314	2,390	2,469	2,551	2,636	2,724	2,816	2,862	2,960
Total	13,817	15,697	16,635	17,037	17,657	18,282	18,915	19,599	20,271	21,004	21,760	22,540	23,326	24,071	24,842	25,641	26,468	27,325	28,164	29,082
Cumulative	13,817	29,514	46,149	63,186	80,843	99,125	118,041	137,640	157,911	178,915	200,675	223,215	246,540	270,611	295,453	321,094	347,562	374,887	403,050	432,132
Average	13,817	14,757	15,383	15,797	16,169	16,521	16,863	17,205	17,546	17,892	18,243	18,601	18,965	19,329	19,697	20,068	20,445	20,827	21,213	21,607
Total Cost (Benefit) ($K)																				
Northern Region	20,661	22,713	24,271	24,923	25,788	26,555	27,268	28,104	28,783	29,518	30,275	31,055	31,839	32,580	33,347	34,138	34,956	35,802	36,662	37,565
Southern Region	2,282	2,544	2,628	2,714	2,799	2,879	2,952	3,037	3,107	3,180	3,256	3,334	3,416	3,500	3,587	3,678	3,771	3,868	3,919	4,022
Total	22,943	25,257	26,899	27,637	28,587	29,434	30,220	31,141	31,890	32,698	33,531	34,389	35,255	36,080	36,934	37,816	38,728	39,670	40,580	41,587
Cumulative	22,943	48,200	75,099	102,735	131,322	160,757	190,977	222,118	254,008	286,706	320,238	354,627	389,881	425,962	462,895	500,711	539,439	579,109	619,690	661,277
Average	22,943	24,100	25,033	25,684	26,264	26,793	27,282	27,765	28,223	28,671	29,113	29,552	29,991	30,426	30,860	31,294	31,732	32,173	32,615	33,064
Transmission Cost ($/MWh)																				
Northern Region	10.95	11.34	12.05	12.31	12.57	12.69	12.74	12.88	12.84	12.80	12.75	12.71	12.67	12.64	12.60	12.56	12.53	12.49	12.44	12.41
Southern Region	8.88	9.32	9.96	10.26	10.47	10.60	10.63	10.76	10.71	10.65	10.60	10.55	10.50	10.45	10.40	10.35	10.30	10.25	10.19	10.14
Total	10.73	11.13	11.84	12.10	12.35	12.48	12.53	12.66	12.62	12.58	12.53	12.49	12.45	12.41	12.37	12.34	12.30	12.26	12.21	12.18
Wholesale Markets Cost ($/MWh)																				
Northern Region	16.12	18.12	19.12	19.38	19.89	20.40	20.91	21.46	21.98	22.56	23.15	23.75	24.34	24.86	25.40	25.96	26.52	27.11	27.71	28.32
Southern Region	17.44	19.72	19.75	20.11	20.55	20.99	21.43	21.90	22.38	22.88	23.39	23.92	24.46	25.02	25.59	26.18	26.79	27.42	27.59	28.25
Total	16.25	18.28	19.18	19.45	19.96	20.46	20.96	21.50	22.02	22.59	23.17	23.76	24.35	24.88	25.42	25.98	26.55	27.14	27.70	28.32
Total Cost (Benefit) ($/MWh)																				
Northern Region	27.06	29.46	31.16	31.69	32.46	33.10	33.65	34.34	34.82	35.35	35.90	36.46	37.01	37.50	38.00	38.52	39.05	39.60	40.15	40.73
Southern Region	26.31	29.04	29.71	30.37	31.02	31.59	32.07	32.67	33.09	33.53	33.99	34.47	34.96	35.46	35.99	36.53	37.09	37.67	37.78	38.39
Total	26.99	29.41	31.02	31.55	32.31	32.94	33.49	34.17	34.64	35.17	35.71	36.26	36.80	37.29	37.79	38.31	38.85	39.40	39.91	40.49

ATTACHMENT 14

Summary
New England Buildout Case
Cost/Benefit Assessment

ATTACHMENT 14

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
New England Buildout Transmission and Wholesale Power Supply Markets Cost/Benefit Assessment
Summary
November 12, 2008

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Transmission Cost ($K)																				
Northern Region	30,175	33,910	36,452	38,983	41,416	41,923	42,378	42,755	42,989	43,222	43,459	43,696	43,936	44,178	44,422	44,668	44,916	45,166	45,403	45,657
Southern Region	3,248	3,675	3,956	4,245	4,515	4,571	4,619	4,660	4,683	4,706	4,730	4,754	4,778	4,802	4,826	4,851	4,875	4,900	4,925	4,950
Total	33,423	37,585	40,408	43,228	45,931	46,495	46,998	47,415	47,672	47,929	48,189	48,450	48,714	48,980	49,248	49,518	49,791	50,066	50,328	50,608
Cumulative	33,423	71,009	111,416	154,644	200,576	247,071	294,068	341,483	389,156	437,084	485,273	533,723	582,437	631,417	680,665	730,183	779,974	830,040	880,368	930,975
Average	33,423	35,504	37,139	38,661	40,115	41,178	42,010	42,685	43,240	43,708	44,116	44,477	44,803	45,101	45,378	45,636	45,881	46,113	46,335	46,549
Wholesale Markets Cost ($K)																				
Northern Region	12,305	13,970	14,887	15,240	15,803	16,370	16,942	17,563	18,170	18,834	19,519	20,226	20,936	21,602	22,291	23,005	23,744	24,509	25,301	26,122
Southern Region	1,512	1,727	1,747	1,797	1,854	1,913	1,973	2,036	2,101	2,170	2,240	2,314	2,390	2,469	2,551	2,636	2,724	2,816	2,862	2,960
Total	13,817	15,697	16,635	17,037	17,657	18,282	18,915	19,599	20,271	21,004	21,760	22,540	23,326	24,071	24,842	25,641	26,468	27,325	28,164	29,082
Cumulative	13,817	29,514	46,149	63,186	80,843	99,125	118,041	137,640	157,911	178,915	200,675	223,215	246,540	270,611	295,453	321,094	347,562	374,887	403,050	432,132
Average	13,817	14,757	15,383	15,797	16,169	16,521	16,863	17,205	17,546	17,892	18,243	18,601	18,965	19,329	19,697	20,068	20,445	20,827	21,213	21,607
Total Cost (Benefit) ($K)																				
Northern Region	42,480	47,880	51,339	54,223	57,219	58,293	59,321	60,318	61,159	62,057	62,978	63,922	64,872	65,780	66,713	67,672	68,659	69,675	70,705	71,780
Southern Region	4,760	5,402	5,703	6,042	6,369	6,484	6,592	6,696	6,784	6,876	6,970	7,068	7,168	7,271	7,377	7,487	7,599	7,716	7,787	7,910
Total	47,241	53,283	57,042	60,265	63,588	64,777	65,913	67,014	67,944	68,933	69,948	70,990	72,040	73,050	74,090	75,159	76,259	77,390	78,492	79,689
Cumulative	47,241	100,523	157,566	217,830	281,419	346,196	412,109	479,123	547,067	616,000	685,948	756,938	828,978	902,028	976,118	1,051,277	1,127,536	1,204,926	1,283,418	1,363,108
Average	47,241	50,262	52,522	54,458	56,284	57,699	58,873	59,890	60,785	61,600	62,359	63,078	63,768	64,431	65,075	65,705	66,326	66,940	67,548	68,155
Transmission Cost ($/MWh)																				
Northern Region	39.53	43.98	46.81	49.56	52.13	52.25	52.29	52.24	52.00	51.77	51.53	51.30	51.07	50.85	50.62	50.40	50.17	49.95	49.72	49.50
Southern Region	37.46	41.96	44.72	47.51	50.04	50.16	50.18	50.12	49.87	49.62	49.38	49.14	48.90	48.66	48.42	48.18	47.95	47.71	47.48	47.25
Total	39.31	43.77	46.59	49.35	51.92	52.04	52.08	52.02	51.78	51.55	51.31	51.08	50.85	50.62	50.40	50.17	49.95	49.73	49.49	49.27
Wholesale Markets Cost ($/MWh)																				
Northern Region	16.12	18.12	19.12	19.38	19.89	20.40	20.91	21.46	21.98	22.56	23.15	23.75	24.34	24.86	25.40	25.96	26.52	27.11	27.71	28.32
Southern Region	17.44	19.72	19.75	20.11	20.55	20.99	21.43	21.90	22.38	22.88	23.39	23.92	24.46	25.02	25.59	26.18	26.79	27.42	27.59	28.25
Total	16.25	18.28	19.18	19.45	19.96	20.46	20.96	21.50	22.02	22.59	23.17	23.76	24.35	24.88	25.42	25.98	26.55	27.14	27.70	28.32
Total Cost (Benefit) ($/MWh)																				
Northern Region	55.64	62.10	65.92	68.94	72.02	72.65	73.20	73.69	73.98	74.32	74.68	75.05	75.41	75.71	76.02	76.35	76.70	77.06	77.43	77.83
Southern Region	54.89	61.68	64.47	67.62	70.58	71.14	71.62	72.02	72.25	72.50	72.77	73.05	73.36	73.67	74.01	74.36	74.74	75.13	75.08	75.50
Total	55.57	62.05	65.77	68.80	71.88	72.50	73.04	73.52	73.80	74.14	74.48	74.85	75.20	75.50	75.82	76.15	76.50	76.86	77.19	77.59

ATTACHMENT 15

Summary
External Interconnection Buildout Case
Cost/Benefit Assessment

ATTACHMENT 15

Northern Maine Independent System Adminstrator (NMISA)
Maine Power Connection Interconnection Request (NMISA to ISO-NE)
External Interconnection Buildout Transmission and Wholesale Power Supply Markets Cost/Benefit Assessment
Summary
November 12, 2008

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Transmission Cost ($K)																				
Northern Region	30,175	44,639	47,202	49,882	52,417	53,032	53,597	54,031	54,322	54,612	54,905	55,201	55,498	55,798	56,101	56,405	56,712	57,022	57,319	57,633
Southern Region	3,248	4,894	5,177	5,483	5,765	5,833	5,894	5,940	5,970	6,000	6,030	6,060	6,091	6,122	6,153	6,184	6,215	6,247	6,279	6,311
Total	33,423	49,533	52,379	55,364	58,182	58,866	59,491	59,971	60,292	60,612	60,935	61,261	61,589	61,920	62,253	62,589	62,927	63,268	63,597	63,944
Cumulative	33,423	82,956	135,335	190,699	248,882	307,747	367,238	427,209	487,501	548,113	609,048	670,309	731,899	793,819	856,072	918,661	981,588	1,044,857	1,108,454	1,172,398
Average	33,423	41,478	45,112	47,675	49,776	51,291	52,463	53,401	54,167	54,811	55,368	55,859	56,300	56,701	57,071	57,416	57,740	58,048	58,340	58,620
Wholesale Markets Cost ($K)																				
Northern Region	12,305	13,970	14,887	15,240	15,803	16,370	16,942	17,563	18,170	18,834	19,519	20,226	20,936	21,602	22,291	23,005	23,744	24,509	25,301	26,122
Southern Region	1,512	1,727	1,747	1,797	1,854	1,913	1,973	2,036	2,101	2,170	2,240	2,314	2,390	2,469	2,551	2,636	2,724	2,816	2,862	2,960
Total	13,817	15,697	16,635	17,037	17,657	18,282	18,915	19,599	20,271	21,004	21,760	22,540	23,326	24,071	24,842	25,641	26,468	27,325	28,164	29,082
Cumulative	13,817	29,514	46,149	63,186	80,843	99,125	118,041	137,640	157,911	178,915	200,675	223,215	246,540	270,611	295,453	321,094	347,562	374,887	403,050	432,132
Average	13,817	14,757	15,383	15,797	16,169	16,521	16,863	17,205	17,546	17,892	18,243	18,601	18,965	19,329	19,697	20,068	20,445	20,827	21,213	21,607
Total Cost (Benefit) ($K)																				
Northern Region	42,480	58,609	62,089	65,122	68,220	69,402	70,540	71,594	72,492	73,446	74,425	75,426	76,434	77,400	78,392	79,410	80,456	81,531	82,620	83,755
Southern Region	4,760	6,621	6,924	7,280	7,619	7,746	7,867	7,977	8,071	8,170	8,271	8,374	8,481	8,591	8,704	8,820	8,939	9,062	9,141	9,270
Total	47,241	65,230	69,013	72,401	75,839	77,148	78,406	79,570	80,563	81,616	82,695	83,801	84,915	85,991	87,095	88,230	89,395	90,593	91,761	93,025
Cumulative	47,241	112,471	181,484	253,885	329,725	406,873	485,279	564,849	645,412	727,028	809,723	893,524	978,439	1,064,430	1,151,525	1,239,755	1,329,150	1,419,743	1,511,505	1,604,530
Average	47,241	56,235	60,495	63,471	65,945	67,812	69,326	70,606	71,712	72,703	73,611	74,460	75,265	76,031	76,768	77,485	78,185	78,875	79,553	80,227
Transmission Cost ($/MWh)																				
Northern Region	39.53	57.89	60.61	63.42	65.98	66.09	66.14	66.01	65.71	65.41	65.11	64.81	64.51	64.22	63.93	63.64	63.35	63.07	62.77	62.49
Southern Region	37.46	55.88	58.52	61.37	63.89	64.00	64.03	63.89	63.58	63.27	62.95	62.64	62.34	62.03	61.73	61.42	61.12	60.83	60.53	60.24
Total	39.31	57.69	60.40	63.21	65.77	65.88	65.92	65.80	65.49	65.19	64.89	64.59	64.29	64.00	63.70	63.41	63.13	62.84	62.54	62.26
Wholesale Markets Cost ($/MWh)																				
Northern Region	16.12	18.12	19.12	19.38	19.89	20.40	20.91	21.46	21.98	22.56	23.15	23.75	24.34	24.86	25.40	25.96	26.52	27.11	27.71	28.32
Southern Region	17.44	19.72	19.75	20.11	20.55	20.99	21.43	21.90	22.38	22.88	23.39	23.92	24.46	25.02	25.59	26.18	26.79	27.42	27.59	28.25
Total	16.25	18.28	19.18	19.45	19.96	20.46	20.96	21.50	22.02	22.59	23.17	23.76	24.35	24.88	25.42	25.98	26.55	27.14	27.70	28.32
Total Cost (Benefit) ($/MWh)																				
Northern Region	55.64	76.01	79.73	82.79	85.87	86.50	87.04	87.47	87.69	87.96	88.25	88.56	88.85	89.08	89.33	89.59	89.88	90.17	90.48	90.81
Southern Region	54.89	75.60	78.27	81.48	84.43	84.99	85.46	85.80	85.96	86.14	86.34	86.56	86.80	87.05	87.32	87.61	87.92	88.24	88.13	88.49
Total	55.57	75.97	79.58	82.66	85.73	86.34	86.88	87.30	87.51	87.78	88.06	88.35	88.64	88.87	89.13	89.39	89.68	89.98	90.24	90.57