Response to Sept 24th directive

Emersa Maine

Draft Plan to Provide Long term Transmission System Reliability to its Customers in Northern Maine

Briefing Paper

[Jan 17th, 2014]
Table of Contents

Introduction & Acknowledgements.............................................................2
Executive Summary.................................................................................4
Current Situation.....................................................................................6
Reliability Issues...................................................................................8
Description of Potential Solutions.........................................................9
Evaluation of Alternative Solutions.......................................................13
Other Factors.........................................................................................19
Introduction & Acknowledgements

Emera Maine (formerly Maine Public Service Company) prepared this briefing paper to provide explanation of its draft plan to ensure long term transmission system reliability criteria are met for the next 10 years, and is in alignment with Emera Maine’s long term planning process contained in Attachment R to its FERC approved transmission tariff.

On December 18th 2013, the draft reliability plan and briefing paper were provided to, and discussed with stakeholders, including the Planning Advisory Group (“PAG”) defined in Attachment R. During and subsequent to that discussion, Emera Maine received feedback, questions and suggestions regarding the plan and briefing paper, and has made some additions and edits to improve clarity.

The briefing paper shared with stakeholders on December 18th had Emera Maine’s cost estimates and some other information related to the Loring generator option redacted. Subsequently, Emera Maine applied for a protective order in relation to information in its draft plan and supporting materials, the MPUC heard arguments from a variety of parties on the matter, and a decision was issued on Jan 14th 2014 (Order Denying Protective Order). Based on this order, costing information is to be shared publicly, but confidential Loring information remains protected.

In compliance with the Jan 14th 2014 order, this briefing paper was updated to include all the costing numbers previously redacted, and some editing has been done (in consultation with Loring) to the language describing the in region generation options. This briefing paper now contains no redactions.

The draft plan, this briefing paper, and other supporting materials are being filed today, Jan 17th, 2014 in the Maine Public Utilities Commission’s (“MPUC’s”) Northern Maine Reliability Docket 2012-00589, with a link posted on Emera Maine’s Maine Public District OASIS website.

The plan to ensure long term reliability, along with other planned changes (for example, those associated with end of life replacements) will form Emera Maine’s overall Transmission plan for its Maine Public District as defined in Attachment R.

The draft reliability plan represents Emera Maine’s current thinking and conclusions regarding the best course of action to ensure long term transmission system reliability. Under the terms of Attachment R, the reliability plan is considered in “draft” form, in order to gather further input and feedback from stakeholders. After consideration of input and feedback from the PAG members on the Draft Plan, Emera Maine will issue its final reliability plan, following approval of Emera Maine’s Board of Directors.

To determine which path forward is best for its customers, Emera Maine had to reach conclusions on a number of key questions, including but not limited to:

1. What solutions would meet the long term reliability planning criteria? (i.e., ensure reliable service over 10 years or more)
2. What effect would each solution have on the transmission costs paid by Emera Maine and other Northern Maine customers?
3. What effect would each solution have on the supply costs paid by Emera Maine and other Northern Maine customers?
In reaching its conclusions, Emera Maine considered a great deal of information, including, but not limited to, past technical and market studies, previous regulatory proceedings, new technical analysis of the current reliability situation in Northern Maine, and input obtained through the stakeholder and PAG consultations and the MPUC Northern Maine Reliability NOI process.

Emera Maine wishes to acknowledge and thank all those who provided input and ideas pertaining to the Northern Maine reliability issues and possible solutions, both in the past and in the recent processes.

Finally, Emera Maine would like to emphasize some of the unique complexities of developing a long term transmission system plan in this case, which stem from the fact that the issues and solution options are heavily related to supply. With respect to the transmission components of the proposed solution, Emera Maine can and will advance these components in its role as transmission owner. With respect to any supply components to a solution, Emera Maine will recommend those for adoption by the organization(s) responsible.
Executive Summary

Based on its analysis of the long term reliability issues facing Northern Maine, and the potential solutions to these issues, Emera Maine has concluded that increasing the strength of its transmission system interconnection to New Brunswick is the least cost option to provide long term transmission system reliability to its customers.

Specifically, constructing a new 138kV transmission tie line to connect the New Brunswick Power system near Woodstock to Emera Maine’s transmission system north of Houlton, along with a number of smaller changes to both systems, will meet Emera Maine’s long term reliability criteria at a lower cost to Emera Maine and other Northern Maine electricity customers than the in-region generation options, or the options involving connection to the ISO-NE grid. Both transmission cost and supply cost effects were considered in the analysis.

In its analysis of supply costs, Emera Maine assumed that import prices from NBP would continue to track ISO-NE market prices, and so the NBP and ISO-NE connection options were basically the same with respect to their effect on supply costs.

Emera Maine recognizes that the historical relationship of the price of imports across the ties to New Brunswick to prices available in ISO-NE is not necessarily a predictor of what will happen in the future, particularly given the relative illiquidity of the Northern Maine supply market. If Emera Maine’s prices of supply imported across the ties to New Brunswick continue to track (or beat) prices in ISO-NE, then the recommended option will clearly have been the best economic choice. Having said that, the downside risk of choosing this option clearly relates to the possibility that prices of imports across the New Brunswick ties end up in the future to be higher than could have been realized through a direct connection to ISO-NE.

Emera Maine believes that it is in the best interest of its customers to mitigate this risk by putting in place a long term (10 year) supply contract which is indexed to prices in Bangor (or another suitable part of ISO-NE). Emera Maine believes that New Brunswick Energy Marketing is also interested in a longer term supply contract, and would be willing to provide pricing indexed to the ISO-NE part of Maine.

By taking this additional step in conjunction with reinforcing the transmission connections with New Brunswick, Emera Maine customers would achieve substantial certainty around both key effects on their electric bills – the cost of the transmission and the cost of supply. This combined action would in effect ensure that Emera Maine customers’ supply prices will remain competitive with those received by customers in the more liquid ISO-NE market, without having to incur the higher transmission costs associated with connecting to, and potentially joining ISO-NE.

Emera Maine would also recommend that in year 6 of the 10 year contract, assuming no significant change in the market, supply for years 11 to 15 would be sought through an RFP process. The offered prices and terms would then again be compared to the other alternatives, including a connection to ISO-NE, which if chosen, could be permitted and built over the subsequent four years. This approach is recommended so that the option of a connection is maintained as a viable alternative to supply prices from NBP. The process would continue on a five-year cycle, i.e., year 6 RFP for years 11 to 15 supply; year 11 RFP for years 16 to 20 supply, and so on.
Emera Maine acknowledges that Houlton Water Company ("Houlton"), Van Buren Light and Power ("Van Buren"), and Eastern Maine Electric Coop ("EMEC") would need to decide whether to pursue the same type of supply contract.
Current Situation

Customers, Electrical Demand, and Electricity Bills

There are approximately 36,000 electricity customers currently in Northern Maine. The transmission system supplying these customers is owned for the most part by Emera Maine, with a small section in the southwest owned by EMEC. Distribution is provided by four utilities: Emera Maine, EMEC, Houlton, and Van Buren.

The total net system requirement (customer usage plus system losses) is estimated to average in the 700 GWh per year range over the 10 year period (2017-2026), with the average of monthly peak loads in the range of 100 MW. The annual system peak is in the range of 120 to 130 MW and occurs in the winter.

Total electricity billings for the Northern Maine market are estimated to be in the range of $80 million USD, with the split estimated to be approximately $40m supply, $5m transmission, $35 million distribution.

Retail Market and Competition for Supply

In the 1999 to 2001 time frame, changes in state and federal law resulted in the deregulation of the Northern Maine market, separation of generation from Transmission, and standard offer and Competitive Electricity Provider (“CEP”) options. Related changes came in the form of open access transmission tariffs, and the establishment of a market administrator, NMISA.

Being a much smaller size, and not directly connected to / part of ISO-NE, the Northern Maine market has never been and is not today as liquid or competitive as the ISO-NE market.

Today, for all practical purposes, the retail market in Northern Maine is supplied by the electricity marketing units of two companies, Algonquin and New Brunswick Power. Most of this is through standard offer supply contracts, with a smaller amount through their roles as Competitive Electricity Providers.

Algonquin has in-region hydro generation at Tinker and also has a long term reservation for a portion of the transmission capacity from New Brunswick to Northern Maine. New Brunswick Power owns no in-region generation, and its marketing arm has a long term reservation for the remainder of the currently available transmission capacity into Northern Maine.

Historically, standard offer prices for Emera Maine’s northern customers (formally MPS) have tracked those received in the ISO-NE parts of Maine, and for the most part have been slightly lower (for MPS), but recently and currently are slightly higher. Exact comparisons are not possible due to differences in rate designs and the design and timing of the standard offer solicitations and contracts. The MPUC recently announced new standard offer prices for Emera Maine’s Northern Maine customers, and new standard offer prices for its southern customers are expected March 1, 2014.

One key difference in the markets is that the percentage of customers supplied by CEP’s (versus standard offer) is significantly higher in the ISO-NE sections of Maine, as is the number of different CEPs actually supplying those customers.
Transmission System

The current situation in Northern Maine is such that the reliability of the transmission system is significantly dependent on in-region generation. This point was reinforced recently when an in-region generator’s application for permission to shut down was denied by NMISA, and the unit was required to continue to run under a Reliability Must Run (RMR) contract.

The emergence of this issue had been previously documented by NMISA and some actions had been previously identified to help mitigate the issue. Some of those actions were successfully implemented while others were not for a number of reasons.

The application by Fort Fairfield to shut down and the lack of success with one of the previously identified plans to upgrade a transformer at Tinker, prompted Emera Maine (and others) to launch a more thorough technical study of the reliability issues and possible solutions, in order to produce a long term transmission reliability plan.

This study work, led on behalf of Emera Maine by RLC Engineering (“RLC”), provided much greater insight into the Emera Maine /Northern Maine transmission system, and the parts of the NBP transmission system with which it is connected, and upon which it currently depends for integrated system reliability.

The analysis and findings of the RLC work have been documented and shared with stakeholders during the study process. As greater understanding was gained, in particular with respect to the assets and operational practices in place in New Brunswick, preliminary conclusions were updated and shared with stakeholders.

The key conclusions about the current system include:

- The system was designed based on having in-region generation, and meets Emera Maine’s long term reliability criteria if there are at least 2 in region dispatchable generators, each greater than 30 MW. The reason that 2 units are required to meet long term reliability criteria is that the system must be able to perform reliably even when the largest unit is offline.
- To meet short term reliability criteria, one unit must be available and running during certain load levels. This is essentially the reason for the Fort Fairfield RMR.
- Without the 2 in region generators available, a number of reliability issues are evident. These will be described in the next section.
Reliability Issues

In the absence of sufficient in-region generation, a number of Emera Maine’s long term reliability criteria are violated, which means that under certain scenarios in New Brunswick or Northern Maine, unacceptable voltages, equipment loading levels, maintenance conditions, or outages occur.

A particularly bad result is something referred to as voltage collapse, where system voltages drop and don’t recover, leading to widespread (and somewhat unpredictable) outages, with potential damage to customer and utility equipment during the disturbance.

It is important to note that the type of reliability issues being analyzed here could be described as infrequent, but with significant consequences, for example something that might happen only once in 10 years, but result in a widespread blackout, significant and lengthy outages, and /or significant utility or customer equipment damage.

A draft version of the final report from RLC has been received by Emera Maine, and is being reviewed and checked internally. Once this review is completed, the full report (less redacted Critical Energy Infrastructure Information) will be filed in the NOI docket 2012-00589, with a link posted on Emera Maine’s Maine Public District OASIS website.
Description of Potential Solutions

Emera Maine has narrowed its analysis to three categories and eight specific alternatives to ensure long term reliability criteria are met over the next 10 years:

1. Secure sufficient in-region generation through long term contracts
   a. Two existing Biomass generators
      i. One exporting; one as capacity reserve
      ii. Two in capacity reserve
      iii. Two base-loaded
   b. Two New Combined cycle gas fired generators

2. Strengthen transmission ties to New Brunswick
   a. New 138 kV line connecting NBP Power’s transmission near Woodstock, NBP to Emera Maine’s transmission system north of Houlton, Maine, plus a number of smaller upgrades

3. Connect Emera Maine directly to the ISO-NE transmission grid
   a. New 115kV line from Houlton to Haynesville
   b. Extension of the 115kV Oakfield generator lead from Oakfield to Emera Maine’s system near Houlton
   c. Connection of the 345kV EDP generator lead to the Emera Maine system north of Houlton

These alternatives are discussed further in the following sections.

In-Region Generation

Emera Maine does not have in house generation expertise, and so it contracted with Hatch Ltd to conduct an analysis of in region generation options on its behalf. A number of possible generation types and operating modes were considered, and 39 separate scenarios modeled, all of which met the minimum long term reliability planning criteria. Emera Maine has chosen to present its top four sub-alternatives in this report.

In modeling the generation options, the cost of the output from each of the in-region generators was estimated.

In the case of the biomass units, Hatch used publicly available information and its industry knowledge to estimate key parameters such as heat rate and fuel costs. These estimates were entirely done by Emera Maine and its consultant, and were not provided by the owner of the units ReEnergy. Emera Maine did not have access to any proprietary information in producing these cost estimates.

In the case of the natural gas fired options, Emera Maine did have access to and considered confidential information provided by Loring Holdings, LLC. However, Emera Maine and its consultant also applied our own assumptions and judgment related to key cost drivers, operating modes, etc. For example the cost per MWh of each gas fired option will vary significantly with capacity factor – an assumption Emera Maine and its consultant made.
The cost range estimate provided in these materials for in region gas fired generation is therefore not Loring Holdings LLC’s confidential information, including its bid, nor is it their business case, which may include other value unrelated to solving the reliability issue.

In all cases, the Tinker Hydro generation was assumed to be running and serving in region load. The remaining load requirement (about 560 GWh on average over 10 years) was supplied by the in region generators and imports, based on the scenario being modeled. For example when modeling two units in capacity reserve, more energy was imported than the scenario involving two base-loaded units.

The cost of the imported power from New Brunswick was assumed to track ISO-NE market prices. This approach is consistent with that used by MPUC staff in evaluating recent long term supply contract proposals for Northern Maine.

**Biomass Generators**

The most straightforward in-region generation options considered by Emera Maine involve two biomass fueled generators at Fort Fairfield and Ashland. These units exist today and are connected to the existing transmission system. One of the units Fort Fairfield (FF) operates today under a reliability must run (RMR) contract.

Emera Maine believes the units have higher energy production costs than imports from New Brunswick. On the other hand, the FF unit has additional value, having recently been qualified for Class 1 RECs, and is being considered by Connecticut in a renewable RFP process.

Emera Maine has concluded that the most cost effective scenario, where these units would be used to solve reliability issues, would be if the FF unit was running under a long term export contract with a third party (for example CT), and the second unit was running under a long term capacity reserve contract with Emera Maine or NMISA.

This approach would allow FF to receive higher value for their renewable attributes, while allowing Emera Maine energy to be supplied with lower priced imports from NBP. Long term reliability criteria require the second unit for capacity reserve to ensure reliability is maintained even with the loss of the FF unit.

If FF is not operating under an export contract, then the next best option would be to have both units under long term capacity reserve agreements. In that case the generators would provide the reliability benefit required, but would not run at high capacity factors for in region load. The third best biomass related option would be for both units to run at high capacity factors (base loaded), supplying in region load under long term contract with Emera Maine.

**Loring CCGT**

Emera Maine has also included in this report, its evaluation of a proposal for two CCGT, natural gas fired power generators at Loring. As was communicated by the project developer at an earlier PAG group meeting, this proposal was also made to the MPUC in response to its long term contract RFP, Docket No. 2012-00504.

The Loring proposal itself provided a number of alternative type and size options. Emera Maine concluded that the option which would have the greatest ability to compete with other reliability
solutions was the option of two combined cycle gas turbines (CCGTs), running at high capacity factors to supply in region load, and has included its evaluation of this option in this report.

Transmission Ties to NBP

If in-region generation is not the solution to Emera Maine’s reliability issues, then additional transmission ties are required, either to NBP or to the ISO-NE grid.

In the case of ties to New Brunswick, there were many possible options and combinations of options to consider. Based on input and feedback from stakeholders, and the extensive modeling conducted by RLC Engineering, Emera Maine has concluded that the best way to solve our reliability issues through stronger New Brunswick transmission ties would be to construct a new 138kV line connecting the New Brunswick Transmission system near Woodstock, to Emera Maine’s transmission system north of Houlton. A new substation would be constructed in Maine which would step the voltage down from 138kV to 69kV, and tie into Emera Maine’s existing 69kV transmission system.

In addition to this central feature, a number of other smaller, but essential changes will need to be made to Emera Maine’s and New Brunswick Power’s transmission system. New Brunswick Power and Emera Maine transmission engineers have reviewed these changes and are in agreement that they resolve the reliability issue. A number of New Brunswick Power operating practices have also been identified as critical to meeting Emera Maine’s long term reliability criteria, and would need to continue.

In this option, Emera Maine assumed a similar cost sharing approach to the Northeast Energy Link. New Brunswick Power would fund the transmission changes in New Brunswick, and Emera Maine would fund the changes in Maine. The transmission capacity created by the transmission changes would be sold through an open season or equivalent process.

Emera Maine has learned from past experience that inter-jurisdictional issues can be a significant challenge to any cross-border solutions. To minimize any potential issues of this nature, Emera Maine will seek legally binding agreements with New Brunswick Power with respect to the system changes and operational practices required for this option.

Connect to ISO-NE

Connection of Emera Maine’s transmission system to ISO-NE has been proposed and studied in a number of forms and forums. Emera Maine has benefited from the work done previously by those involved, and has considered ideas and opinions documented previously.

Among the most important of these, from Emera Maine’s perspective, is the 2012 NES study done for NMISA, and posted on NMISA’s website. This study was recent, and most applicable to the situations involved with the ISO-NE connection options Emera Maine has identified as potential reliability solutions.

Having said that, Emera Maine made a point, as much as possible, to enter the analysis of potential reliability solutions without pre-conceived ideas, and to reach our conclusions as independently as possible from what may have been previously concluded. Particularly with respect to the ISO-NE connection options, Emera Maine used past work to flag things that we
needed to consider and think through, versus using the past work as the source of definitive conclusions.

In some cases, Emera Maine considered areas previously debated and reached a conclusion. In other cases the areas identified were not necessary to conclude upon in order to reach our decision, and so Emera Maine did not consider those further. An example would be some of the technical uncertainties related to establishing a third path connecting New Brunswick with ISO-NE (through Emera Maine’s system). If any of the ISO-NE options were pursued, further technical studies, including stability studies would be required.

The three leading ISO-NE connection options considered in Emera Maine’s analysis were as follows.

**Houlton to Haynesville – 115 kV**

In this option, Emera Maine would construct a new 115kV transmission line from Houlton to Haynesville. Substation equipment would be installed at both ends, including 115kV / 69kV transformation to connect to Emera Maine’s system at Houlton and 115 kV/ 345kV transformation to connect the line to the existing MEPCO line.

**Oakfield (Maine GenLead) Option -115kV**

This option would involve constructing a new 115kV line from the Oakfield generator lead (about to begin construction) to Emera Maine’s system near Houlton. Substation equipment would be installed at both ends, including a 115 kV to 69kV transformer to connect to Emera Maine’s existing transmission system. The connection to ISO-NE would be the other end of the generator lead, at Keene Road substation.

This connection option was proposed by the owner of this generator lead (Maine GenLead, LLC), in a filing in MPUC docket 2012-00589, an Investigation into the Reliability of Electric Service in Northern Maine.

**Number Nine Mountain (EDP) Option**

EDP is developing a 250MW wind farm at Number Nine Mountain, and plans to construct a 345kV generator lead to connect to the MEPCO line (ISO-NE) at Haynesville. Emera Maine has also considered the possibility that this generator lead could be used to connect to Emera Maine’s northern transmission system, as an option to solve its reliability issues.

Emera Maine assumed it would construct a substation to tap the 345 kV generator lead, transform the voltage to 69kV, and connect to Emera Maine’s existing 69 kV transmission system north of Houlton.
Evaluation of Alternative Solutions

As a solution to reliability issues

All of the options discussed above meet the minimum required long term reliability criteria.

Effect on Transmission Costs

Emera Maine’s view of the effect of the alternatives on transmission costs is shown in the following chart.

The reference assumption for this analysis assumes no wheeling revenues from the existing biomass plants. An estimate of these wheeling revenues is credited back in the biomass related alternatives where these would be expected. Emera Maine also assumed in this analysis that transmission costs to connect any new generators will be minimal or are included as part of the generation cost.

In the case of the New Brunswick transmission option, capital costs will be incurred on both sides of the US/Canada border. The New Brunswick improvements are assumed to be funded by New Brunswick Power and collected through New Brunswick’s tariff. The Maine side changes
are assumed to be funded by Emera Maine, and recovered through the transmission tariff of Emera Maine. This approach was also used with the Northeast Reliability Interconnect.

The most straightforward of the ISO options to model is the 115kV line from Houlton to Haynesville which Emera Maine could construct. Emera Maine has therefore estimated its own cost of constructing this line, and used this estimate in its analysis. Having said that there are three other questions which Emera Maine had to consider:

1. Would Emera Maine (North) join ISO-NE under this scenario?
2. If not, will there be a reciprocity agreement between ISO-NE and NMISA?
3. What effect will the line have on exports and associated wheeling revenue credits to Emera Maine customers?

Emera Maine concluded that the best option would be to connect to, but not join, ISO-NE, and to assume that a reciprocity agreement is put in place between ISO-NE and NMISA. The reciprocity agreement would mean that exporting generators (from ISO to NMISA, or from NMISA to ISO-NE) would not pay transmission tariffs (out charges) to leave their home systems.

Emera Maine’s conclusion that it would be best not to join ISO-NE at this time is based on its belief the resulting new Regional Network Service (RNS) transmission charges to Emera Maine customers would be greater than the revenue requirement associated with capital costs of making the connection, and that this additional cost would not be offset by incremental supply side savings, because Emera Maine’s price for supply imported across the New Brunswick ties already tracks ISO-NE pricing (often lower).

Assuming a reciprocity agreement was determined to be the best choice for this option because although there would be a loss of some Mars Hill related transmission wheeling revenues (modeled in the transmission cost of those options), this was more than offset by avoiding the out charges which would otherwise apply to supply from ISO-NE.

With respect to the two options involving utilization of generator leads (Number Nine Mountain or Oakfield), Emera Maine’s assumptions regarding joining ISO-NE and reciprocity would be the same as described above. Emera Maine further assumes that in these alternatives, it would need to purchase from the wind developer/generator lead owner the portion of the transmission line necessary to connect Emera Maine to ISO-NE, and the portion not necessary for that purpose would remain as a generator lead. Emera Maine assumes the wind farm developer would retain rights to the transmission capacity it needed for its wind generation. Emera Maine assumes the net result in these options is that Emera Maine customers would own a transmission line for less than if Emera Maine built the same line on its own for its own customers’ use, in effect the wind developer and the utility would be sharing the capital cost of the line.

Emera Maine acknowledges that the price the wind developer/generator lead owner would be willing to sell its line for would have to be negotiated. For this analysis, Emera Maine included what it believes is a reasonable potential range of values. This uncertainty results in these options having more transmission cost uncertainty than the Emera Maine Houlton to Haynesville and New Brunswick transmission options.

In its submission to the NOI, Maine Gen Lead suggested that the line could be socialized and paid for by the ISO-NE transmission owners. Emera Maine however has concluded that joining
ISO-NE is not the best option for Emera Maine customers, and so modeled the Oakfield option based on a cost sharing model, which Emera Maine concluded would be the most competitive with other options. The increased cost to Emera Maine customers of joining ISO-NE has been documented previously and results from the fact that Emera Maine would need to pay its load ratio share (approximately 0.5%) of ISO-NE’s overall annual revenue requirement, which is expected to exceed $2 Billion by 2017. In considering this question, Emera Maine estimated the results of joining ISO-NE versus the other transmission options, and also modeled the possibility that Emera Maine could negotiate a 10 or 20-year phase-in period. This is shown below:

![Graph showing cost comparison between joining ISO-NE and not joining.]

Emera Maine concludes that joining ISO-NE would clearly be more expensive over a 10-year period, and this option would be expected to be even less competitive if a longer study period were chosen, because the costs of new Emera Maine owned tie lines would depreciate over time, while additional build out in ISO-NE is anticipated to continue upward pressure on its revenue requirement.

Emera Maine acknowledges that if a 20-year phase in period were granted to Emera Maine, then the costs for the first 10-years would be much improved (but still not as low as the New Brunswick Option). As well, to Emera Maine’s knowledge a 20 year phase in has not been done before.

Finally, Emera Maine would also observe that the years 11 to 20 would see continued significant increases in Emera Maine’s ISO-NE charges (reaching full load share in year 20),
while the cost of the New Brunswick tie line investments would continue to require less revenue from Emera Maine customers.
Effect on Supply costs

Emera Maine views the effect of the alternatives on supply costs as shown in the following chart.

In order to estimate the effect of each option on supply costs to Emera Maine and other Northern Maine customers, Emera Maine reviewed previous studies of the issue, as well as relevant information it had access to as part of other regulatory processes, in particular the MPUC’s docket dealing with long term supply contract proposals.

After careful consideration, Emera Maine concluded that the approach used by the MPUC staff in their analysis of recent long term contract proposals is the best choice for this analysis. Emera Maine assumes that Maine Public’s alternative to an in region generator will approximate ISO-NE prices, even without a direct connection to ISO-NE. The 2012 market study done by NES for NMISA also concluded that Northern Maine prices for imports across the New Brunswick ties would track ISO-NE prices.

An important reason for Emera Maine to use the same approach as the MPUC staff is that Emera Maine believes the MPUC will have to approve the analysis in any scenario. In the case of Emera Maine’s recommended solution, the MPUC will need to be satisfied as part of a CPCN process, that Emera Maine has properly evaluated all the alternatives to its proposed solution, including in-region generators and connection options to ISO-NE, and including the effects of each alternative on supply prices for customers. As previously mentioned, Emera Maine is not in the supply business. By aligning our analysis approach to that used by MPUC staff, Emera Maine seeks to ensure alignment with the Commission’s thinking in this area.
Economic Comparison of Alternatives

Emera Maine’s conclusion from its analysis is that on an economic basis, the New Brunswick option is the best alternative. Using the mid-range estimates for each alternative would give the following picture.

Emera Maine concludes that reinforcing its ties to New Brunswick can be achieved at a lower cost than the increase in supply costs which would be needed to solve the reliability with in region generation, and at a lower transmission cost than connecting Emera Maine to ISO-NE. Emera Maine also concludes that the New Brunswick option and the ISO options are likely to yield similar supply costs, both tracking against New England electricity market prices.
Other Factors

Emera Maine’s primary objective in its planning analysis was to identify the solution which would meet all of the minimum long term reliability criteria for the lowest cost (transmission and supply) to its customers and the other customers in Northern Maine.

Other factors were also considered and evaluated by Emera Maine, in particular so that they might be used to choose between options which met reliability and were equal economically. Technical uncertainty and commercial uncertainty, and reliability differences beyond meeting the minimum requirements were three key areas where differences between the alternatives were identified. Two of these areas are discussed further in the following sections.

Technical Uncertainty

Emera Maine considers the four in-region generation options to have minimal technical uncertainty; that is to say the technologies considered are already in service (biomass generators) or are well known and commercially available (CCGTs), and Emera Maine does not see any special technical challenges to the options considered.

Similarly, Emera Maine considers the New Brunswick option to involve minimal technical uncertainty, with the only question being whether a stability study would be required.

The ISO-NE connection options have the greatest technical uncertainty, because of the significance of the change to the electrical system in creating a third path between New Brunswick and ISO-NE (through the Northern Maine Transmission System). Two of these options also have specific technical uncertainties with respect to connecting to the MEPCO line at Haynesville, without violating important ISO-NE/NBSO operating criteria. A number of these technical uncertainties were documented in the earlier NES report commissioned by NMISA in 2008.

To address these uncertainties, additional studies involving all parties affected would need to be conducted, including stability studies.

Commercial Uncertainty

Maine Public considers the natural gas in region generation options to have significant commercial uncertainty, given that there is no natural gas pipeline serving the area today, and the likely distance involved to do so. As this option was not selected, further analysis of the commercial uncertainties was not necessary.

Emera Maine considers that both the Oakfield and Number Nine Mountain wind farms are commercially viable on their own as they have secured power purchase agreements which Emera Maine assumes are sufficient for their overall economics, including their associated generator leads, without any link to the Northern Maine Transmission System.

Emera Maine also believes the New Brunswick option has minimal commercial uncertainty, as it expects that costs incurred by the utilities involved will be recoverable from customers.