NON-CONFIDENTIAL

Request IR-201:

With reference to Appendix 3.01, pages 80-81, how long would the one pole outage be expected to last at the Maritime Link if a converter transformer fails and the:

(a) converter station is equipped with a spare transformer;

(b) converter station is not equipped with a spare transformer.

Response IR-201:

a) If a spare converter transformer was stored on site, replacement of a failed transformer would take between 1-2 weeks, depending on the availability of experienced construction crews and equipment.

b) With no spare converter transformers, procurement, manufacture, shipping, installation and commissioning of a replacement transformer would require a year or more, depending on loading at the manufacturing plant, particularly the facility where the transformer originated.

NON-CONFIDENTIAL

Request IR-202:

With reference to Appendix 3.01, page 82:

(a) Please explain why the specialized nature of the converter equipment requires procurement under a fixed price design-supply-install (EPC) contract?

(b) Explain if there is any difference between the fixed price design-supply-install contract and a fixed price Engineering, Procurement and Construction (EPC) contract.

Response IR-202:

(a) The equipment is highly specialized and proprietary, and the engineering of the individual components and their integration is an integral part of the proprietary knowledge of the converter vendors. The installation and commissioning of this equipment is critical to the success of the project, and the equipment vendors will not warrant the equipment or the overall facility unless they directly employ the personnel who install the equipment or they approve the installation and commissioning contractors and direct their work. For these reasons, the equipment supply, the engineering of the integrated installation and the construction and commissioning are all an integral part of the finished product, and all should be captured in a single procurement process.

(b) The terminology of design-supply-install is functionally and contractually identical to an Engineering-Procurement-Construction contract.

NON-CONFIDENTIAL

Request IR-203:

With reference to Appendix 3.01, page 82, please provide a list of the suppliers of the HVDC converter stations based on the VSC technology.

Response IR-203:

The main suppliers of IGBT-based VSCs are Siemens, ABB and Alstom Grid.

NON-CONFIDENTIAL

Request IR-204:

With reference to Appendix 3.01, page 83, does the requirement for the five pole forced outages per year specify five as the maximum number of one-pole outages (with the reduction from 500 MW to 250 MW capability), or does it also include the bipole forced outages (with the reduction from 500 MW to 0 MW capability), e.g., not more than 2 bipole outages and 1 one pole outage per year (total 5)?

Response IR-204:

A total of five (5) forced pole outages and one scheduled outage were considered at the preliminary stage of Specifications development; the bipole forced outages were <0.1 occurrence per year. The pole outage cannot be simply equated to bipole outage; a bipole outage involves loss of total transmission capacity. The referenced section of the application relates to impacts on the grounding site, and a bipole outage is not recorded here since it does not result in earth return operation. The pole outage rate has been revised in the final Converter Station Specifications from 5 to 4 pole outages per year and the bipole outage rate remains at <0.1 per year.

NON-CONFIDENTIAL

Request IR-205:

With reference to Appendix 3.01, page 83:

(a) What is the requirement for the forced outage total annual duration and rate?

(b) Would it include partial unavailability and derating due to a one pole failure, or be based on the complete force outage of both poles?

Response IR-205:

The number of outages and average outage time is established for estimating the grounding site operating duty. For the performance of the HVdc scheme, Energy Availability (EA), Forced Energy Unavailability (FEA) and Schedules Energy Unavailability (SEU) are reported in accordance with Cigre Publication 346:

Protocol for reporting the operational performance of hvdc transmission systems.

The target values based on the final specifications for the Maritime Link are as follows:

- FEU ≤1%
- SEU ≤1.5%
- EA ≥98% (considering forced outages, recommended maintenance and repair outages)

The number of pole outages allowed are 4 per year and bipole outage <0.1 per year.

NON-CONFIDENTIAL

Request IR-206:

With reference to Appendix 3.01, page 83, what are the specific requirements for the tolerated bipolar imbalances in the Maritime Link as related to the earth grounding resistance?

Response IR-206:

The bipolar imbalance is a function of the converter controls and is typically less than 1 percent of the rated current. The bipolar imbalance does not raise any safety concerns or cause electrical interference. These sustained imbalance currents play a role in cumulative processes such as corrosion of metallic infrastructure immersed in the soil. Design studies consider a 1 percent bipolar imbalance for initial investigations of prospective corrosion on nearby infrastructure, and then qualify those studies based on actual imbalance values advised by the converter supplier. The grounding site resistance is not a primary parameter to define acceptable levels of bipolar imbalance.

NON-CONFIDENTIAL

Request IR-207:

With reference to Appendix 3.01, page 102:

(a) What is the current operational status of the "aged gas turbine facility" connected to line 209 near Stephenville?

(b) How long would the period of reliance on the gas turbine facility be for supply Stephenville and other parts of south west Newfoundland while the existing circuits will be transferred from the existing substation to the new substation?

Response IR-207:

(a) Although the turbines have not operated under significant load for many years, they are maintained in a state of operational readiness in case they are needed.

(b) The transfer of each of existing line TL 209 – to Stephenville will require the line to be out of service for up to two days, and the turbines would be needed for this period, in the event that use of the turbines is found to be the best solution.

NON-CONFIDENTIAL

Request IR-208:

With reference to Appendix 3.01, page 103:

(a) Do plausible scenarios exist with a common mode failure of both poles of the Maritime Link facility?

(b) If so, please identify such scenarios and estimate likelihood of such events.

Response IR-208:

(a) Yes.

(b) The unlikely scenario is the failure of a support structure on the overhead HVdc lines in Newfoundland or Cape Breton, which might be expected to occur once in 50 years or more. Other scenarios are far less likely, and include extreme cases of human interference, geo-magnetic storms that might trip both converter transformers, or complete failure of the buildings at either the converter stations or the overhead/underground transition sites. None of these low-probability scenarios can be predicted with any confidence or assigned a frequency.

NON-CONFIDENTIAL

Request IR-209:

With reference to Appendix 3.01, page 104, with regard to the operation after equipment failures, if the conductor of the failed pole is intact, would the preferred mode of operation after the failure be the Monopolar Metallic Return Mode (per bullet 3 on page 74) with the return through the second pole cable rather than using the earth as the return path?

Response IR-209:

Yes. Immediately after the fault, return current will automatically divert to the earth return path, and the earth return path is designed to carry the return current for an indefinite period of time. Since some of the impacts of the shoreline grounding sites are cumulative over time, it will be desirable to switch over from earth return to metallic return whenever a continuous metallic return path is available, and operators will generally make this decision if a pole failure occurs within a converter station and it appears that the forced outage could last for several days.

NON-CONFIDENTIAL

Request IR-210:

With reference to Appendix 3.01, page 104:

(a) Who are the "maintenance forces" that will be dispatched to the site of the failed converter?

(b) If these forces are staffed with the NSPML personnel, do they have enough expertise in the HVDC/ VSC technology to troubleshoot and repair the converters efficiently?

Response IR-210:

(a) Maintenance forces will be a combination of both local personnel and contracted support services from the Converter Supplier.

(b) All NSPML personnel who will be assigned to service and maintain the Converters will be thoroughly trained by the Converter supplier. In addition, Maintenance and Operations Service Contracts will be put in place to ensure expert resources are also available.

NON-CONFIDENTIAL

Request IR-211:

With reference to Appendix 3.01, page 104:

(a) Does NSPML plan to purchase a cable insurance policy that would protect from immense financial losses in the event of the extended forced outages due to the cables' damage?

(b) Do ship owners carry insurance policies that would cover for these types of damages?

(c) Provide a complete list of insurance policies intended for the Maritime Link facility.

Response IR-211:

(a-c) The insurance program for the Maritime Link is under development at this time.

Construction Phase - NSPML will be procuring project insurance policies to provide Builders All Risk and Wrap Up Liability coverage, including Pollution Liability.

Operating Phase - NSPML will be procuring physical damage and third party liability insurance for both marine and subsea portions of the Maritime Link, the scope and limits of which will be subject to insurance market conditions at the time.

(b) Construction phase - Ship owners would not ordinarily carry insurance to cover consequential economic loss, however, NSPML is considering the appropriate scope and level of marine transit insurance to require of contractors shipping materials or equipment to the Maritime Link site.

NON-CONFIDENTIAL

(c) Operating phase - If a ship hits the cable during operation, vessels generally carry liability insurance to address their legal obligations in the event that they cause loss or damage to third parties, including loss or damage to underwater cable. However, the extent of their liability would be governed by law, and would not likely address consequential loss due to an outage.

NON-CONFIDENTIAL

Request IR-212:

Please provide an Excel file of the cost model presented in Appendix 4.01 with all formulae and cell references intact.

Response IR-212:

Please refer to Synapse IR-16 Attachment 1.

NON-CONFIDENTIAL

Request IR-213:

With reference to Appendix 4.01:

(a) Are the indicated monthly and annual capital outlays expressed in constant dollars or nominal dollars?

(b) What rate of inflation is assumed?

Response IR-213:

(a) The amounts are as spent, nominal dollars.

(b) Inflation was assumed to be 2 percent per annum.

Request IR-214:

With reference to Appendix 4.01 and the indicated monthly and annual capital outlays, which total $1,514.2 million:

(a) Do these outlays represent 20% of the total combined cost (excluding AFUDC) of LCP Phase 1 and the ML, or do they represent the outlays associated with the ML by itself?

(b) If the answer to (a) above is the latter, how are any differences resolved in the cost model? What would be the timing of any true-up cash settlement between NSPML and Nalcor?

(c) If the answer to (a) above is the former, are the monthly outlays for LCP Phase 1 facilities fixed in time to the same extent that they are fixed in total amount at $6.2 billion? (Application Section 4.2, page 75, line 15)

Response IR-214:

(a) The $1.514 billion capital cost estimate represents 20 percent of the total combined capital cost estimate (excluding AFUDC) of LCP Phase 1 and the ML. It is comprised of the cost to construct the ML facilities and an estimated true up payment to Nalcor. The true up may be dealt with via a cash payment or an energy adjustment as described in section 3 of the Sanction Agreement as contained in Appendix 2.15.

(b) The model assumes a payment to Nalcor in January 2014. Section 3 of the Sanction Agreement provides more detail on timing.

(c) The $6.2 billion estimate for LCP Phase I is fixed. The timing of when these outlays are actually incurred does not affect the calculation.

Request IR-215:

With reference to Appendix 4.01 and Application Section 4.10 (pp 88-90), please provide in table or spreadsheet form details of the annual O&M cost estimates for the Maritime Link facilities and for the LCP Phase 1 facilities, as used in Appendix 4.01. To the extent possible, annual costs should be broken down into categories such as staffing, contract services, materials, and capital replacements. Please indicate whether the annual O&M amounts are expressed in constant dollar form or in nominal dollar form, and identify the annual rate of inflation assumed.

Response IR-215:

NSPML is not seeking approval of specific O&M costs at this time. More detailed information will be provided when NSPML requests a specific rate revenue requirement during the operational phase of the Project. Please also refer to responses in NSUARB IR-34 and 35.

NON-CONFIDENTIAL

Request IR-216:

With reference to Appendix 4.01, please explain the calculation of the regulated asset or liability amount (O&M true-up) and provide reference to appropriate cells of the model requested in Request IR-212.

Response IR-216:

Please refer to NSUARB IR-105.

NON-CONFIDENTIAL

Request IR-217:

With reference to Appendix 5.01, provide a copy of all Water Management Agreements that govern the use and allocation of water in the Churchill River, Churchill Falls reservoir, Muskrat Falls reservoir, Gull Island reservoir, and any other downstream impoundments.

Response IR-217:

Please refer to NSUARB IR-70 and NSUARB IR-111.

NON-CONFIDENTIAL

Request IR-218:

With reference to Appendix 5.01, page 15, provide a copy of any documents that set forth environmental flow standards for the lower Churchill River with respect to flows (magnitude, frequency, duration, timing, and rate of change).

Response IR-218:

Neither PDF page 15, nor report page 15 of Appendix 5.01 contains a reference to environmental flow standards or the documents identified by this request.

NON-CONFIDENTIAL

Request IR-219:

With reference to Appendix 5.01, page 15, provide a copy of any hydrologic studies of the Muskrat Falls project that analyze the power generation potential of the Lower Churchill River.

Response IR-219:

Neither PDF page 15, nor report page 15 of Appendix 5.01 contains a reference to hydrologic studies.

CONFIDENTIAL (Attachment Only)

Request IR-220:

With reference to Appendix 6.02, pages 4, 21-22, 30:

(a) Please provide a narrative summary of the status and history of the proposed new 345kV circuit between Salisbury, New Brunswick and Onslow, Nova Scotia, or any other proposal to increase the transmission capacity between Nova Scotia and New Brunswick, as well as any and all related materials including but not limited to planning studies, cost estimates, regulatory filings and permit applications.

(b) Please explain why the proposed new 345kV circuit between Salisbury, New Brunswick and Onslow, Nova Scotia is marked as not applicable for system ramping requirements in Table 1.2 on page 4 considering recommendation 2 on page 30, which implies that the current tie-line limits contribute to the ramping challenge.

Response IR-220:

(a) A narrative summary of the history of the proposed new 345 kV circuit between Salisbury New Brunswick and Onslow, Nova Scotia is found in Attachment 4. Other documents related to this transmission include:

- Appendix 6.05 of the Application
- SBA IR-27
- SBA IR-53(a)
- NBSO 10-Year Outlook 2012 – 2022 (Sections 5.3 and 6.4)
- NSPI 10-Year System Outlook 2012 – 2021 (Section 7.5 and Appendix B)
- Attachment 1 CONFIDENTIAL
- Attachment 2 CONFIDENTIAL ELECTRONIC

- Attachment 3 CONFIDENTIAL ELECTRONIC
- Attachment 4
- Attachment 5
- Attachment 6 CONFIDENTIAL

(b) The footnote to Table 1.2 states that "and X indicates that the solution **may** not be applicable for the challenge" (emphasis added). This is because the issue of System Ramping is **not only** limited by tie-line capacity issues. Nova Scotia is a NERC Balancing Area and NS Power is required by NERC BAL Standards (http://www.nerc.com/page.php?cid=2|20) to maintain the tie-line within limits of a scheduled value regardless of the capacity of the tie. Section B.2 System Ramping Requirements addresses the impact of load and wind generation variations on tie-line control, the speed at which these variations occur, and therefore the performance metrics of meeting NERC BAL Standards.

CA/SBA IR-220 Attachment 1 has been removed due to confidentiality.

CA/SBA IR-220 Attachment 2 has been removed due to confidentiality.

CA/SBA IR-220 Attachment 3 has been removed due to confidentiality.

NOVA SCOTIA POWER
An Emera Company

June 30, 2009

Nancy McNeil
Clerk of the Board
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
PO Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: Report to the Nova Scotia Utility and Review Board Regarding NSPI/NB Power Interconnection

Dear Ms. McNeil:

In the November 5, 2008 Decision in respect of the 2009 General Rate Application, the Nova Scotia Utility and Review Board (the Board) directed Nova Scotia Power Inc (NSPI) to prepare a report outlining its plans for improvements to its transmission capacity to facilitate power imports. The Board directed:

> [39] The Board also accepts Liberty's comments on the second issue relating to NSPl's transmission capacity to import and export power. NSPI is directed to consider this issue and file a report with the Board no later than June 30, 2009, outlining its plans for improvements to its transmission capacity to facilitate power imports. The Board is mindful that NSPI has, in the 2008 ACE Plan, included a request for capital expenditures related to this issue.

The attached report provides information regarding the NSPI/NB Power interconnection.

Yours truly,

Rene Gallant
General Manager Regulatory Affairs

cc: Eric Ferguson

Report to the Nova Scotia Utility and Review Board Regarding NSPI/NB Power Interconnection

June 2009

NOVA SCOTIA POWER
An Emera Company

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Executive Summary

In its November 5, 2008 Decision regarding NSPI's 2009 General Rate Application, the Nova Scotia Utility and Review Board (UARB, Board) directed Nova Scotia Power Inc (NSPI, the Company) to file a report, no later than June 30, 2009, outlining its plans to address transmission capacity to facilitate the import of electricity. This report is provided in response to that directive.

The Nova Scotia/New Brunswick interconnection is an important element of the provinces' bulk power systems, central to the delivery of reliable electric service to customers in Nova Scotia and New Brunswick. Through the inter-tie, NSPI is connected with the North American Eastern Interconnect power grid and NSPI's customers enjoy the power system stability, reliability and cost benefits this provides.

In addition to the system reliability function NSPI is able to import and export electricity across the inter-tie, thereby reducing the cost of fuel for customers. The volume of import and export transactions is limited by activity on the NSPI and NB Power systems. To date the potential savings associated with commerce across the inter-tie have not been sufficient to undertake material upgrades to the interconnection.

Circumstances are changing. Anticipated material increases to non-dispatchable generation in Nova Scotia and New Brunswick may require reinforcement of the provincial inter-tie. Proposed large-scale generation developments outside of Nova Scotia, if pursued, could provide material benefits for NSPI customers which would justify the addition of a second inter-tie.

NSPI is monitoring these developments and working with the New Brunswick System Operator (NBSO) and other stakeholders to assess the requirement and timing for reinforcement of the inter-tie. It appears likely that over the next decade, a second inter-tie may become necessary.

NSPI anticipates an application to the Board to acquire the rights-of-way (ROW) necessary to site a second inter-tie. Subject to Board approval, proceeding with this work in advance of a decision to construct the second inter-tie is warranted because the ROW work is time-consuming but of relatively low cost compared to construction of a second interconnection line. The specific schedule and configuration of the second inter-tie has not been determined. Route and ROW acquisition planning has commenced.

Introduction

In its statement to the Board concerning the 2009 General Rate Application Settlement, the Board's consultant, The Liberty Consulting Group (Liberty), provided the following with respect to the import of electric power:

> Another matter our evidence addressed is the value that imports of electric power produce for NSPI's customers. Such imports have grown rapidly over the last several years. NSPI acknowledges the attraction of low-cost power imports, but points to practical limits that constrain its ability to make more comparatively economical imports. One example is the transmission capacity connecting Nova Scotia to New Brunswick. Liberty believes that it will be important in the near term for NSPI to analyze and pursue all measures that may serve at reasonable cost to eliminate barriers to making economical, off-system electricity purchases, and to demonstrate to the Board that it is doing so.

The Board's Decision in the matter, dated November 5, 2008 contained the following directive:

> [39] The Board also accepts Liberty's comments on the second issue relating to NSPI's transmission capacity to import and export power. NSPI is directed to consider this issue and file a report with the Board no later than June 30, 2009, outlining its plans for improvements to its transmission capacity to facilitate power imports. The Board is mindful that NSPI has, in the 2008 ACE Plan, included a request for capital expenditures related to this issue.

In November, 2005, NSPI filed a report with the Board that discussed operational and economic matters associated with the management of the Nova Scotia/New Brunswick inter-tie. Key findings of that work, related to expansion of the inter-tie are discussed in this report. The balance of this report serves to apprise the Board of issues which influence expansion of the inter-tie and NSPI's current activities.

As will be evident from the information presented, expansion of the capacity of the inter-tie is a significant undertaking, which must consider reliability and economic concerns of both NSPI and NB Power. The benefits of a second inter-tie, in respect of importing low-cost power when available, must be considered in context with reliability and resource planning developments, inside and outside of Nova Scotia.

Nova Scotia/New Brunswick Interconnection Overview

The power systems of Nova Scotia and New Brunswick are interconnected via three overhead transmission lines; one 345kV line from Onslow, Nova Scotia to Memramcook, New Brunswick, and two 138kV lines from Springhill, Nova Scotia to Memramcook, New Brunswick. The primary function of the interconnection is to support system reliability.

Power is imported or exported over the inter-tie in proportion to the electrical characteristics of the lines. The 345kV line carries approximately 80 percent of the total power transmitted.

Power systems are designed to accommodate a single contingency loss (i.e. loss of the largest element) and since the 345kV line carries the majority of the flow, loss of the 345kV line becomes the limiting factor. Flow on the 138kV lines is also influenced by the loads in Prince Edward Island; Sackville, New Brunswick; and Amherst, Nova Scotia.

Import and export limits on the inter-tie have been established to ensure the Nova Scotia system can survive single contingency loss. The limits have been described as up to 350MW export and up to 300MW import. These figures represent limits under predefined system conditions. Conditions which determine the actual limit of the interconnection are:

Export	**Import**
Number of thermal units armed for generation rejection (maximum two)	NS system load level (Import less than 22% of total system load)
Reactive Power Support level in the Halifax Regional Municipality	Percentage of dispatchable generation
Arming of Special Protection Systems	NB export level to PEI and/or New England
Real time line ratings (climatological conditions in northern NS)	Real Time Line Ratings (climatological conditions in Northern NS)
NS System load level	Load level in Moncton area
Largest single load contingency in NS	Largest single generation contingency in NS

If the NSPI system is separated during export (i.e. the inter-tie trips) system frequency (cycles/second) will rise, risking unstable plant operation and possible damage. To address this NSPI uses fast-acting Special Protection Systems to reject generation and stabilize the system.

If the NSPI system is separated during import, system frequency will drop. Depending on the current system characteristics at the time of the disruption, and the size of the import generation that was lost, the system will respond and re-balance. It does this by rejecting load through under-frequency load shedding (UFLS) protection systems as required.

The loss of the 345kV line between Onslow, NS and Memramcook, NB is not the only contingency that can result in Nova Scotia becoming separated from the NB Power system while importing power. All power imported to Nova Scotia flows through the Moncton/Salisbury area of New Brunswick. Since there is no generation in the Moncton/Salisbury area, and only a limited amount of generation in Prince Edward Island, power flowing into Nova Scotia is added and shares transmission capacity with the entire load of Moncton, Memramcook, and PEI.

The New Brunswick System Operator restricts export to Nova Scotia to a level such that any single contingency does not cause adverse impacts on NB or PEI load. Any transmission reinforcement proposed to improve reliability, increase import capacity or prevent the activation of UFLS in Nova Scotia must also consider the reinforcement of the southeast area of the New Brunswick transmission system.

Nova Scotia Market Developments re: the NSPI/NB Power Inter-tie

<u>Balancing of Non-Dispatchable Generation Sources</u>

Nova Scotia legislation requires that effective 2010, 5 percent of NSPI generation must be provided by non-NSPI renewable sources constructed in Nova Scotia after 2001. By 2013, the required percentage increases to 10 percent (at this point the figure may include NSPI-owned renewable generation constructed in Nova Scotia after 2001). Provincial Government policy suggests the requirement for energy from renewable resources will meet or exceed 25 percent by 2020.

NSPI expects that a portion of the Renewable Energy Standard (RES) requirement will be met through wind generation. The siting of this generation will align with area wind regimes and is likely to emerge as distributed developments across the Province. It is unlikely that the wind developments will be able to be interconnected to the provincial power system without reinforcement of the transmission system. The required system upgrades will be influenced by, and have implications on, the inter-tie.

Because wind generation is non-dispatchable and intermittent (i.e. the wind cannot be scheduled), it will be necessary to provide fast response backup for this generation in order to maintain system stability. This can be provided by fast-starting generator plants or energy storage devices within the Province or the purchase of load balancing energy across the inter-tie.

Regardless of the backup portfolio employed, NSPI recognizes that it is likely that the inter-tie will need to be reinforced in order to provide the required flexibility. This is a concern shared by the New Brunswick System Operator, where the same challenges concerning renewable generation are being faced.

NSPI and NBSO are currently working together to consider options for addressing the integration of wind generation. The opportunity to expand the transfer capacity of the existing inter-tie, and the reliability and operating criteria and market needs/opportunities in the region are central to these discussions. These issues may trigger the requirement for a second inter-tie.

Imports/Exports

Since the year 2000, annual electricity imports and exports have averaged approximately 200 gigawatt hours (each way). Expressed as a percentage of total provincial electricity production, each amounts to approximately 2 percent.

While access to this generation has contributed to reducing the cost of fuel borne by NSPI customers, to date an economic case has not been developed to justify expansion of the provincial interconnection. The inter-tie remains primarily a tool to support regional reliability, not regional electricity commerce.

Should the large-scale generation developments outside of Nova Scotia (e.g. Lower Churchill Falls, Point Lepreau 2) come to fruition, this situation will change. These sources could become important low-cost means of meeting NSPI's requirements for low emission generation in the long-term. Access to this generation would require expansion of the inter-tie. NSPI continues to monitor these developments.

Similarly, large-scale generation developments inside Nova Scotia by independent developers planning to export to markets outside the province would likely require firm transmission access on the inter-tie. Capacity on the inter-tie is first provided to support the reliability requirements of NS and NB and then made available for market opportunities. Although not the case yet, at some point market needs may exceed the available capacity, which could support/require additional inter-tie capacity.

NSPI Activities Involving the NSPI/NB Power Inter-tie

NSPI/NBSO/NB Power cooperation

In 2008 a Maritimes Area Technical Planning Committee was established to review intra-area plans for Maritimes Area resource adequacy and transmission reliability. This Committee will project congestion levels in regards to the total transfer capabilities on the utility interfaces. This information will be used as part of assessments of potential upgrades or expansions of the inter-ties, including any potential new inter-tie between Nova Scotia and New Brunswick.

The Technical Planning Committee has transmission planning representation from Nova Scotia Power, New Brunswick System Operator, Maritime Electric Company Ltd., Northern Maine Independent System Administrator and NB Power Transmission.

2009 IRP Update

In 2007, NSPI filed an Integrated Resource Plan (IRP). The 2007 IRP Reference Plan relied on Demand-Side Management (DSM) and Renewables (Wind) to meet customer load in compliance with increasingly stringent emissions limits over the first decade.

The 2007 IRP did not propose changes to the transmission system. It was understood that as the DSM and Renewables programs matured, the requirement for new transmission, including implications for the inter-tie, would be determined.

To this end, in 2007, the Province commissioned Hatch Ltd. (Hatch) to complete a study concerning the integration of large-scale wind generation within the Provincial power grid. The report was completed in 2008 and concluded, in general, that the current system could accommodate the increases in renewable generation mandated for 2010 and 2013.

The Hatch report acknowledged the 2013 requirement would require more detailed study in order to understand the cost and technical implications related to potential transmission upgrades. The report concluded that increases beyond the 2013 RES requirement would require significant upgrades to the transmission system and this would be influenced, in particular, by the operation of the inter-tie.

NSPI is currently completing an update to the 2007 IRP. While additional effort has been applied to estimate the potential cost of transmission upgrades, it is understood that this work remains preliminary. While the 2009 IRP Update may provide direction regarding the long-term benefit of transmission system expansion, the timing and configuration of this will only be determined once developments, inside and outside of Nova Scotia, are better understood.

NSPI Capital Item CI# 29009 Right-of-Way Purchase Northern NS

In jurisdictions across North America, it is becoming difficult to obtain access to the land and the rights-of-way necessary to undertake transmission projects. It is estimated that the addition of a second inter-tie will cost approximately $200 million and require at least 5 years to procure the required permits and complete construction.

The timing and configuration of an expansion to the provincial inter-tie has yet to be determined. However, given the dynamic nature of the provincial and regional electricity markets it is likely that an upgrade may be required over the next decade. Similarly it is possible to identify the preferred route of the new line.

To this end, NSPI has identified a future capital item in the 2009 Annual Capital Expenditure (ACE) Plan to commence the planning and acquisition of land right-of-way for a second 345kV line to New Brunswick. The reasons for moving forward at this time are:

1. To identify land issues and ensure the appropriate easements are in place in advance of a decision to construct a second inter-tie; and
2. To identify a route so that more accurate estimates and plans can be established for construction of the second inter-tie.

The project cost estimate included in the ACE Plan is $4.7 million. The project cost and scope will be refined prior to applying to the Board for approval.

Conclusion

Over the next decade, electricity market developments in Nova Scotia and across the region will place increased demands on the Nova Scotia/New Brunswick interconnection. A more robust and flexible inter-tie will likely be required to respond to the addition of dynamic generation in the Province, support increased power system reliability, and, potentially, enable imports and exports from large-scale generation developments.

The primary function of the inter-tie is to support system reliability. The inter-tie continues to support regional reliability more than regional electricity commerce.

The technical and economic analyses necessary to make a determination in this regard remain in the early stages and are subject to developments inside and outside of Nova Scotia. Work can be undertaken in the interim, at low risk to NSPI customers, which will facilitate a timely response should a decision be made to add a second inter-tie. Moving forward with the right-of-way purchase, and continued analysis and monitoring, are the best next steps to take.

Nova Scotia Utility and Review Board

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July 21, 2010

By E-mail and Courier
Ms. Lee Thomson-Lutz
Capital Manager
Nova Scotia Power Inc.
14th Floor, Barrington Tower
Halifax, NS B3J 2W5

Dear Ms. Thomson-Lutz:

NSPI - Request for Approval of 2010 ACE Plan Work Order - P-128.10
CI# 29009 - Right-of-Way Purchase, Northern Nova Scotia

The Board has reviewed Nova Scotia Power Inc.'s ("NSPI") letter dated June 30, 2010, requesting Board approval for the following **confidential** 2010 ACE Plan Work Order:

CI# 29009 Right-of-Way Purchase, Northern Nova Scotia $4,462,493

As NSPI is aware, in the Board's decision dated November 5, 2008, on NSPI's application for revisions to rates, the need for improvements in transmission planning was identified by the Board. It stated that:

> [39] The Board also accepts Liberty's comments on the second issue relating to NSPI's transmission capacity to import and export power. NSPI is directed to consider this issue and file a report with the Board no later than June 30, 2009, outlining its plans for improvements to its transmission capacity to facilitate power imports. The Board is mindful that NSPI has, in the 2008 ACE Plan, included a request for capital expenditures related to this issue.

In addition, limitations with respect to the existing inter-tie was raised during the 2005 Power Outage Review proceeding.

Board staff issued Information Requests on February 5, 2010 as a part of NSPI's 2010 ACE Plan, and NSPI's responses were received by the Board on March 5, 2010.

The Board understands that the purpose of the project is to provide an easement for a second 345kV transmission line that will parallel the existing 345kV transmission line inter-tie now in place with New Brunswick. The Board also understands that this project is being undertaken in order that the route of the line will be established and complementary studies for environmental permits and detailed line design can be advanced.

The Board agrees that the project is necessary and is a key first step in the planning for strengthening of the transmission inter-tie with New Brunswick. Accordingly, this will confirm that the Board has approved NSPI's request for the amount of $4,462,493 with respect to this **confidential** Work Order.

Yours very truly,

Margaret A. M. Shears, Q.C.
Vice-chair

Enclosure

cc Eric Ferguson, Director Regulatory Affairs by e-mail

CA/SBA IR-220 Attachment 6 has been removed due to confidentiality.

NON-CONFIDENTIAL

Request IR-221:

With reference to Appendix 6.02, page 9, Table 2.1, please provide historical hourly production data for each existing Nova Scotia wind resource for all years that each has operated. If hourly data is not available, please provide the most detailed data available, for example by month, on-peak and off-peak.

Response IR-221:

Please refer to Synapse IR-5.

NON-CONFIDENTIAL

Request IR-222:

With reference to Appendix 6.02, page 16, the estimated cost of providing additional reserves to support wind generation is listed as $8 to $16 per MWh of wind generation.

(a) Was this cost included in the analysis of the Indigenous Wind Alternative? Various references to a cost adder of $10 per MWh have been included in the Application. Please reconcile the use of the different costs?

(b) What are the assumptions regarding capital and operating costs, capacity requirements, technologies, operating regimes, and timing underlying the $8 to $16 per MWh estimate?

Response IR-222:

(a) The cited reference in Appendix 6.02 presents experiences from elsewhere. Neither this estimate or the $10/MWh cost used in previous work like the IRP have been used in the analysis of the Indigenous Wind Alternative. NS Power and the industry continue to refine integration cost estimates as operational experience with wind increases.

(b) Please refer to CA IR-28 for more information on the source of these estimnates.

NON-CONFIDENTIAL

Request IR-223:

With reference to Appendix 6.02, page 20 (Reactive Power and High Speed Voltage Control), please confirm that lack of control of wind speeds is a concern only for real power and not reactive power.

Response IR-223:

That is confirmed. NSPML apologizes for this error.

NON-CONFIDENTIAL

Request IR-224:

With reference to Appendix 6.02, page 22 (General Transmission Upgrades), please confirm that the current reliance on the Lingan units is immaterial in this analysis because the Lingan units are assumed to retire.

Response IR-224:

In the cited reference, the reliance on Lingan units could be considered immaterial if the special protection system role played by these units can be transferred to the Maritime Link or another source of generation.

Request IR-225:

With reference to Appendix 6.02, Figures 3.4 (page 26), 3.5 (page 27) and 3.6 (page 29):

(a) Please provide all calculations, spreadsheets, reports, other work papers, Strategist inputs and outputs, and any other materials used to prepare these graphs.

(b) Please explain how the aggregate hourly wind generation was forecast for multiple units totaling 785 MW capacity was prepared, including discussion of how the geographical distribution of the individual projects would reduce variability of the aggregate generation relative to the variability of the individual units.

(c) Please explain to what extent the preparation of these graphs includes the curtailments included in the analysis of the Indigenous Wind alternative as described in section 6.3.2 of the application.

Response IR-225:

(a) The load-net-wind versus load alone ramp rate analysis is provided in SBA IR-225 ELECTRONIC Attachment 1. Figure 3.6 was taken from the cited Eirgrid reference.

(b) For the purpose of the analysis, NS Power extrapolated the current distribution of wind projects across the province which is a diverse distribution of units and locations today, from Pubnico to Lingan NS Power's experience would indicate that the extrapolation is a reasonable proxy for a wind regime which, based upon the sites in operation today and their contribution to system requirements, is generally homogenous.

(c) The load-net-wind versus load alone ramp rate analysis is independent of the wind curtailment analysis.

This file has been provided in Electronic Excel spreadsheet format only.

It is available for viewing on

http://www.nsuarb.ca

under Matter Title ML-2013-01 Maritime Link Application (Muskrat Falls)

NON-CONFIDENTIAL

Request IR-226:

With reference to Appendix 6.02, page 32 (Transmission Links with Neighboring Areas):

(a) Please explain how the geographical separation between wind generators in New Brunswick and Nova Scotia would reduce the variability of generation in the two provinces in the aggregate relative to the variability in the individual provinces.

(b) Was the diversity in wind energy profiles across the provinces reflected in the Strategist model? If so, how?

Response IR-226:

(a) NSPI does not have information available to prove the assertion.

(b) No, the wind regime in New Brunswick was not modeled.

NON-CONFIDENTIAL

Request IR-227:

With reference to Appendix 6.02, Figure 3.9:

(a) **Please provide all calculations, spreadsheets, reports, other work papers Strategist inputs and outputs and any other materials used to prepare this graph.**

(b) **Please explain how the hourly wind generation was "scaled up" to 785 MW capacity from actual wind generation including discussion of how the geographical distribution of the individual projects would reduce the variability of the aggregate generation relative to the variability of individual units.**

(c) **Please explain to what extent the preparation of this graph includes the type of curtailments included in the analysis of the Indigenous Wind alternative as described in section 6.3.2 of the application**.

Response IR-227:

(a) Please refer to Attachment 1.

(b) Please refer to Attachment 1. Figure 3.9 was intended to demonstrate the complexities of dispatching generation to serve load net of wind under a high wind penetration example. Detailed forecasts of wind generation were not undertaken for the purpose of deriving the example.

(c) The Figure is indicative of the circumstances which would lead to the curtailments described. This work was not the source of the curtailment derivation.

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserv					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
0	2012-12-04 00:00	1,050.4	800.4	89.3	246.0	961.1	711.1	804.4	554.4	1,053.4	460	869	1257		31%
	2012-12-04 00:05	1,063.7	813.7	86.3	237.6	977.4	727.4	826.0	576.0	1,075.0	460	869	1257		29%
	2012-12-04 00:10	1,066.1	816.1	84.0	231.5	982.1	732.1	834.6	584.6	1,083.6	460	869	1257		28%
	2012-12-04 00:15	1,061.0	811.0	78.4	216.0	982.6	732.6	845.0	595.0	1,094.0	460	869	1257		27%
	2012-12-04 00:20	1,058.1	808.1	87.1	239.9	971.0	721.0	818.2	568.2	1,067.2	460	869	1257		30%
	2012-12-04 00:25	1,054.6	804.6	79.7	219.4	975.0	725.0	835.2	585.2	1,084.2	460	869	1257		27%
	2012-12-04 00:30	1,048.3	798.3	91.5	252.2	956.8	706.8	796.1	546.1	1,045.1	460	869	1257		32%
	2012-12-04 00:35	1,044.1	794.1	92.7	255.3	951.4	701.4	788.8	538.8	1,037.8	460	869	1257		32%
	2012-12-04 00:40	1,043.1	793.1	95.0	261.5	948.2	698.2	781.6	531.6	1,030.6	460	869	1257		33%
	2012-12-04 00:45	1,040.5	790.5	95.5	263.0	945.0	695.0	777.5	527.5	1,026.5	460	869	1257		33%
	2012-12-04 00:50	1,035.3	785.3	88.7	244.3	946.6	696.6	791.0	541.0	1,040.0	460	869	1257		31%
	2012-12-04 00:55	1,033.0	783.0	94.2	259.4	938.8	688.8	773.6	523.6	1,022.6	460	869	1257		33%
	2012-12-04 01:00	1,032.4	782.4	96.0	264.4	936.4	686.4	768.0	518.0	1,017.0	460	869	1257		34%
	2012-12-04 01:05	1,027.5	777.5	84.4	232.5	943.1	693.1	795.0	545.0	1,044.0	460	869	1257		30%
	2012-12-04 01:10	1,024.1	774.1	75.3	207.5	948.8	698.8	816.6	566.6	1,065.6	460	869	1257		27%
	2012-12-04 01:15	1,020.2	770.2	71.5	197.0	948.7	698.7	823.3	573.3	1,072.3	460	869	1257		26%
	2012-12-04 01:20	1,010.1	760.1	70.3	193.5	939.8	689.8	816.6	566.6	1,065.6	460	869	1257		25%
	2012-12-04 01:25	1,008.4	758.4	73.3	201.8	935.1	685.1	806.6	556.6	1,055.6	460	869	1257		27%
	2012-12-04 01:30	1,016.4	766.4	73.7	202.9	942.8	692.8	813.5	563.5	1,062.5	460	869	1257		26%
	2012-12-04 01:35	1,007.0	757.0	72.8	200.5	934.2	684.2	806.5	556.5	1,055.5	460	869	1257		26%
	2012-12-04 01:40	1,008.2	758.2	70.9	195.3	937.3	687.3	812.9	562.9	1,061.9	460	869	1257		26%
	2012-12-04 01:45	1,006.8	756.8	75.8	208.7	931.0	681.0	798.1	548.1	1,047.1	460	869	1257		28%
	2012-12-04 01:50	1,002.1	752.1	75.4	207.8	926.6	676.6	794.3	544.3	1,043.3	460	869	1257		28%
	2012-12-04 01:55	1,001.9	751.9	77.8	214.3	924.1	674.1	787.6	537.6	1,036.6	460	869	1257		28%
2	2012-12-04 02:00	992.0	742.0	78.6	216.6	913.4	663.4	775.4	525.4	1,024.4	460	869	1257		29%
	2012-12-04 02:05	997.8	747.8	74.0	203.8	923.8	673.8	794.0	544.0	1,043.0	460	869	1257		27%
	2012-12-04 02:10	993.3	743.3	70.6	194.5	922.7	672.7	798.9	548.9	1,047.9	460	869	1257		26%
	2012-12-04 02:15	990.2	740.2	69.3	191.0	920.8	670.8	799.2	549.2	1,048.2	460	869	1257		26%
	2012-12-04 02:20	987.9	737.9	74.2	204.4	913.6	663.6	783.4	533.4	1,032.4	460	869	1257		28%
	2012-12-04 02:25	979.9	729.9	77.1	212.2	902.8	652.8	767.6	517.6	1,016.6	460	869	1257		29%
	2012-12-04 02:30	980.7	730.7	77.1	212.4	903.6	653.6	768.3	518.3	1,017.3	460	869	1257		29%
	2012-12-04 02:35	974.7	724.7	79.1	217.9	895.6	645.6	756.8	506.8	1,005.8	460	869	1257		30%
	2012-12-04 02:40	969.7	719.7	77.1	212.4	892.6	642.6	757.3	507.3	1,006.3	460	869	1257		30%
	2012-12-04 02:45	967.6	717.6	74.5	205.3	893.1	643.1	762.3	512.3	1,011.3	460	869	1257		29%
	2012-12-04 02:50	965.0	715.0	76.7	211.2	888.3	638.3	753.8	503.8	1,002.8	460	869	1257		30%
	2012-12-04 02:55	966.2	716.2	71.7	197.4	894.5	644.5	768.8	518.8	1,017.8	460	869	1257		28%
	2012-12-04 03:00	961.4	711.4	74.7	205.7	886.8	636.8	755.7	505.7	1,004.7	460	869	1257		29%
	2012-12-04 03:05	964.6	714.6	75.9	208.9	888.7	638.7	755.6	505.6	1,004.6	460	869	1257		29%
	2012-12-04 03:10	959.2	709.2	72.2	198.9	887.0	637.0	760.4	510.4	1,009.4	460	869	1257		28%
	2012-12-04 03:15	958.1	708.1	66.1	182.1	892.0	642.0	776.1	526.1	1,025.1	460	869	1257		26%
	2012-12-04 03:20	959.2	709.2	65.1	179.3	894.0	644.0	779.8	529.8	1,028.8	460	869	1257		25%
	2012-12-04 03:25	960.4	710.4	60.2	165.7	900.2	650.2	794.6	544.6	1,043.6	460	869	1257		23%
	2012-12-04 03:30	962.8	712.8	56.4	155.5	906.3	656.3	807.3	557.3	1,056.3	460	869	1257		22%
	2012-12-04 03:35	960.0	710.0	52.6	145.0	907.4	657.4	815.1	565.1	1,064.1	460	869	1257		20%
	2012-12-04 03:40	955.2	705.2	46.2	127.2	909.1	659.1	828.1	578.1	1,077.1	460	869	1257		18%
	2012-12-04 03:45	962.0	712.0	43.8	120.6	918.2	668.2	841.3	591.3	1,090.3	460	869	1257		17%
	2012-12-04 03:50	960.6	710.6	44.9	123.6	915.8	665.8	837.1	587.1	1,086.1	460	869	1257		17%
	2012-12-04 03:55	961.8	711.8	41.5	114.2	920.3	670.3	847.6	597.6	1,096.6	460	869	1257		16%
4	2012-12-04 04:00	963.6	713.6	43.3	119.3	920.3	670.3	844.3	594.3	1,093.3	460	869	1257		17%
	2012-12-04 04:05	968.1	718.1	43.5	119.8	924.5	674.5	848.2	598.2	1,097.2	460	869	1257		17%
	2012-12-04 04:10	968.2	718.2	51.1	140.6	917.2	667.2	827.6	577.6	1,076.6	460	869	1257		20%
	2012-12-04 04:15	967.3	717.3	49.9	137.5	917.4	667.4	829.9	579.9	1,078.9	460	869	1257		19%
	2012-12-04 04:20	969.7	719.7	48.5	133.7	921.2	671.2	836.0	586.0	1,085.0	460	869	1257		19%
	2012-12-04 04:25	968.8	718.8	50.5	139.0	918.4	668.4	829.8	579.8	1,078.8	460	869	1257		19%
	2012-12-04 04:30	973.9	723.9	48.4	133.3	925.5	675.5	840.6	590.6	1,089.6	460	869	1257		18%
	2012-12-04 04:35	977.2	727.2	43.7	120.5	933.5	683.5	856.7	606.7	1,105.7	460	869	1257		17%
	2012-12-04 04:40	979.9	729.9	42.2	116.4	937.7	687.7	863.6	613.6	1,112.6	460	869	1257		16%
	2012-12-04 04:45	989.3	739.3	45.8	126.2	943.5	693.5	863.1	613.1	1,112.1	460	869	1257		17%
	2012-12-04 04:50	995.2	745.2	45.5	125.4	949.7	699.7	869.8	619.8	1,118.8	460	869	1257		17%
	2012-12-04 04:55	995.3	745.3	50.4	138.9	944.9	694.9	856.5	606.5	1,105.5	460	869	1257		19%
	2012-12-04 05:00	996.8	746.8	47.9	131.9	949.0	699.0	865.0	615.0	1,114.0	460	869	1257		18%
	2012-12-04 05:05	1,014.4	764.4	47.2	130.0	967.2	717.2	884.4	634.4	1,133.4	460	869	1257		17%
	2012-12-04 05:10	1,019.7	769.7	44.7	123.2	974.9	724.9	896.4	646.4	1,145.4	460	869	1257		16%
	2012-12-04 05:15	1,027.6	777.6	44.0	121.2	983.6	733.6	906.4	656.4	1,155.4	460	869	1257		16%
	2012-12-04 05:20	1,029.6	779.6	42.7	117.5	986.9	736.9	912.1	662.1	1,161.1	460	869	1257		15%
	2012-12-04 05:25	1,035.9	785.9	41.9	115.4	994.0	744.0	920.5	670.5	1,169.5	460	869	1257		15%
	2012-12-04 05:30	1,042.1	792.1	42.6	117.4	999.5	749.5	924.7	674.7	1,173.7	460	869	1257		15%
	2012-12-04 05:35	1,050.5	800.5	49.9	137.4	1,000.6	750.6	913.1	663.1	1,162.1	460	869	1257		17%
	2012-12-04 05:40	1,053.9	803.9	55.8	153.6	998.1	748.1	900.3	650.3	1,149.3	460	869	1257		19%
	2012-12-04 05:45	1,060.2	810.2	52.8	145.4	1,007.4	757.4	914.8	664.8	1,163.8	460	869	1257		18%
	2012-12-04 05:50	1,075.6	825.6	55.2	152.2	1,020.3	770.3	923.4	673.4	1,172.4	460	869	1257		18%
	2012-12-04 05:55	1,083.9	833.9	55.4	152.7	1,028.5	778.5	931.3	681.3	1,180.3	460	869	1257		18%
6	2012-12-04 06:00	1,101.1	851.1	56.5	155.5	1,044.6	794.6	945.5	695.5	1,194.5	460	869	1257		18%
	2012-12-04 06:05	1,133.2	883.2	49.9	137.5	1,083.2	833.2	995.7	745.7	1,244.7	460	869	1257		16%
	2012-12-04 06:10	1,151.9	901.9	50.3	138.4	1,101.6	851.6	1013.4	763.4	1,262.4	460	869	1257		15%
	2012-12-04 06:15	1,171.0	921.0	52.9	145.8	1,118.1	868.1	1025.2	775.2	1,274.2	460	869	1257		16%
	2012-12-04 06:20	1,185.5	935.5	54.1	149.1	1,131.3	881.3	1036.3	786.3	1,285.3	460	869	1257		16%
	2012-12-04 06:25	1,194.4	944.4	46.8	129.0	1,147.6	897.6	1065.4	815.4	1,314.4	460	869	1257		14%
	2012-12-04 06:30	1,211.1	961.1	43.5	119.8	1,167.6	917.6	1091.3	841.3	1,340.3	460	869	1257		12%
	2012-12-04 06:35	1,230.3	980.3	41.1	113.3	1,189.2	939.2	1117.0	867.0	1,366.0	460	869	1257		12%
	2012-12-04 06:40	1,244.9	994.9	51.4	141.5	1,193.5	943.5	1103.4	853.4	1,352.4	460	869	1257		14%
	2012-12-04 06:45	1,259.8	1,009.8	50.5	139.2	1,209.2	959.2	1120.6	870.6	1,369.6	460	869	1257		14%
	2012-12-04 06:50	1,272.0	1,022.0	45.4	125.0	1,226.6	976.6	1147.0	897.0	1,396.0	460	869	1257		12%
	2012-12-04 06:55	1,286.4	1,036.4	36.9	101.7	1,249.5	999.5	1184.7	934.7	1,433.7	460	869	1257		10%
	2012-12-04 07:00	1,293.0	1,043.0	36.5	100.5	1,256.5	1,006.5	1192.5	942.5	1,441.5	460	869	1257		10%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserv					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-04 07:05	1,304.0	1,054.0	34.7	95.7	1,269.3	1,019.3	1208.3	958.3	1,457.3	460	869	1257		9%
	2012-12-04 07:10	1,316.4	1,066.4	35.3	97.3	1,281.1	1,031.1	1219.1	969.1	1,468.1	460	869	1257		9%
	2012-12-04 07:15	1,321.7	1,071.7	39.6	109.0	1,282.2	1,032.2	1212.7	962.7	1,461.7	460	869	1257		10%
	2012-12-04 07:20	1,335.0	1,085.0	44.5	122.5	1,290.5	1,040.5	1212.5	962.5	1,461.5	460	869	1257		11%
	2012-12-04 07:25	1,340.0	1,090.0	40.3	111.1	1,299.6	1,049.6	1228.9	978.9	1,477.9	460	869	1257		10%
	2012-12-04 07:30	1,353.3	1,103.3	37.8	104.2	1,315.5	1,065.5	1249.1	999.1	1,498.1	460	869	1257		9%
	2012-12-04 07:35	1,355.5	1,105.5	32.2	88.7	1,323.3	1,073.3	1266.8	1,016.8	1,515.8	460	869	1257		8%
	2012-12-04 07:40	1,358.8	1,108.8	35.9	98.8	1,322.9	1,072.9	1259.9	1,009.9	1,508.9	460	869	1257		9%
	2012-12-04 07:45	1,362.7	1,112.7	36.8	101.4	1,325.9	1,075.9	1261.4	1,011.4	1,510.4	460	869	1257		9%
	2012-12-04 07:50	1,360.5	1,110.5	37.2	102.5	1,323.3	1,073.3	1258.0	1,008.0	1,507.0	460	869	1257		9%
	2012-12-04 07:55	1,363.0	1,113.0	36.4	100.3	1,326.6	1,076.6	1262.7	1,012.7	1,511.7	460	869	1257		9%
8	2012-12-04 08:00	1,366.3	1,116.3	37.6	103.7	1,328.6	1,078.6	1262.6	1,012.6	1,511.6	460	869	1257		9%
	2012-12-04 08:05	1,370.0	1,120.0	38.6	106.2	1,331.5	1,081.5	1263.8	1,013.8	1,512.8	460	869	1257		9%
	2012-12-04 08:10	1,376.4	1,126.4	32.5	89.6	1,343.8	1,093.8	1286.8	1,036.8	1,535.8	460	869	1257		8%
	2012-12-04 08:15	1,376.2	1,126.2	28.1	77.4	1,348.1	1,098.1	1298.8	1,048.8	1,547.8	460	869	1257		7%
	2012-12-04 08:20	1,377.2	1,127.2	23.0	63.4	1,354.2	1,104.2	1313.8	1,063.8	1,562.8	460	869	1257		6%
	2012-12-04 08:25	1,379.3	1,129.3	18.2	50.3	1,361.1	1,111.1	1329.1	1,079.1	1,578.1	460	869	1257		4%
	2012-12-04 08:30	1,381.2	1,131.2	14.6	40.2	1,366.6	1,116.6	1341.0	1,091.0	1,590.0	460	869	1257		4%
	2012-12-04 08:35	1,379.0	1,129.0	14.3	39.4	1,364.7	1,114.7	1339.6	1,089.6	1,588.6	460	869	1257		3%
	2012-12-04 08:40	1,375.7	1,125.7	10.9	30.0	1,364.8	1,114.8	1345.7	1,095.7	1,594.7	460	869	1257		3%
	2012-12-04 08:45	1,372.5	1,122.5	10.9	30.0	1,361.5	1,111.5	1342.4	1,092.4	1,591.4	460	869	1257		3%
	2012-12-04 08:50	1,374.7	1,124.7	13.9	38.4	1,360.7	1,110.7	1336.3	1,086.3	1,585.3	460	869	1257		3%
	2012-12-04 08:55	1,378.5	1,128.5	20.2	55.5	1,358.3	1,108.3	1322.9	1,072.9	1,571.9	460	869	1257		5%
	2012-12-04 09:00	1,374.5	1,124.5	17.7	48.7	1,356.8	1,106.8	1325.8	1,075.8	1,574.8	460	869	1257		4%
	2012-12-04 09:05	1,374.3	1,124.3	17.1	47.2	1,357.1	1,107.1	1327.0	1,077.0	1,576.0	460	869	1257		4%
	2012-12-04 09:10	1,376.8	1,126.8	17.3	47.7	1,359.5	1,109.5	1329.2	1,079.2	1,578.2	460	869	1257		4%
	2012-12-04 09:15	1,371.4	1,121.4	16.2	44.6	1,355.2	1,105.2	1326.8	1,076.8	1,575.8	460	869	1257		4%
	2012-12-04 09:20	1,378.7	1,128.7	11.4	31.4	1,367.3	1,117.3	1347.3	1,097.3	1,596.3	460	869	1257		3%
	2012-12-04 09:25	1,374.0	1,124.0	11.1	30.5	1,362.9	1,112.9	1343.5	1,093.5	1,592.5	460	869	1257		3%
	2012-12-04 09:30	1,370.4	1,120.4	11.0	30.2	1,359.5	1,109.5	1340.3	1,090.3	1,589.3	460	869	1257		3%
	2012-12-04 09:35	1,370.7	1,120.7	11.1	30.5	1,359.6	1,109.6	1340.2	1,090.2	1,589.2	460	869	1257		3%
	2012-12-04 09:40	1,364.8	1,114.8	13.7	37.6	1,351.1	1,101.1	1327.2	1,077.2	1,576.2	460	869	1257		3%
	2012-12-04 09:45	1,361.4	1,111.4	13.9	38.2	1,347.5	1,097.5	1323.2	1,073.2	1,572.2	460	869	1257		3%
	2012-12-04 09:50	1,363.6	1,113.6	11.8	32.4	1,351.9	1,101.9	1331.2	1,081.2	1,580.2	460	869	1257		3%
	2012-12-04 09:55	1,359.4	1,109.4	11.5	31.7	1,347.9	1,097.9	1327.7	1,077.7	1,576.7	460	869	1257		3%
10	2012-12-04 10:00	1,354.7	1,104.7	11.1	30.6	1,343.5	1,093.5	1324.0	1,074.0	1,573.0	460	869	1257		3%
	2012-12-04 10:05	1,356.0	1,106.0	12.8	35.4	1,343.1	1,093.1	1320.6	1,070.6	1,569.6	460	869	1257		3%
	2012-12-04 10:10	1,351.3	1,101.3	8.9	24.4	1,342.4	1,092.4	1326.9	1,076.9	1,575.9	460	869	1257		2%
	2012-12-04 10:15	1,349.8	1,099.8	9.8	26.9	1,340.1	1,090.1	1322.9	1,072.9	1,571.9	460	869	1257		2%
	2012-12-04 10:20	1,349.2	1,099.2	8.0	22.0	1,341.2	1,091.2	1327.2	1,077.2	1,576.2	460	869	1257		2%
	2012-12-04 10:25	1,351.8	1,101.8	8.2	22.5	1,343.6	1,093.6	1329.3	1,079.3	1,578.3	460	869	1257		2%
	2012-12-04 10:30	1,349.7	1,099.7	9.1	25.1	1,340.6	1,090.6	1324.6	1,074.6	1,573.6	460	869	1257		2%
	2012-12-04 10:35	1,353.8	1,103.8	9.1	24.9	1,344.7	1,094.7	1328.8	1,078.8	1,577.8	460	869	1257		2%
	2012-12-04 10:40	1,354.5	1,104.5	7.3	20.0	1,347.2	1,097.2	1334.5	1,084.5	1,583.5	460	869	1257		2%
	2012-12-04 10:45	1,355.2	1,105.2	6.5	17.8	1,348.7	1,098.7	1337.4	1,087.4	1,586.4	460	869	1257		2%
	2012-12-04 10:50	1,354.6	1,104.6	5.0	13.6	1,349.6	1,099.6	1340.9	1,090.9	1,589.9	460	869	1257		1%
	2012-12-04 10:55	1,358.0	1,108.0	4.4	12.0	1,353.6	1,103.6	1346.0	1,096.0	1,595.0	460	869	1257		1%
	2012-12-04 11:00	1,358.5	1,108.5	4.4	12.0	1,354.1	1,104.1	1346.5	1,096.5	1,595.5	460	869	1257		1%
	2012-12-04 11:05	1,363.3	1,113.3	3.5	9.6	1,359.8	1,109.8	1353.6	1,103.6	1,602.6	460	869	1257		1%
	2012-12-04 11:10	1,364.9	1,114.9	3.5	9.6	1,361.4	1,111.4	1355.3	1,105.3	1,604.3	460	869	1257		1%
	2012-12-04 11:15	1,363.0	1,113.0	3.4	9.4	1,359.6	1,109.6	1353.6	1,103.6	1,602.6	460	869	1257		1%
	2012-12-04 11:20	1,364.2	1,114.2	3.4	9.4	1,360.8	1,110.8	1354.8	1,104.8	1,603.8	460	869	1257		1%
	2012-12-04 11:25	1,361.7	1,111.7	1.6	4.4	1,360.1	1,110.1	1357.3	1,107.3	1,606.3	460	869	1257		0%
	2012-12-04 11:30	1,360.1	1,110.1	1.6	4.4	1,358.5	1,108.5	1355.7	1,105.7	1,604.7	460	869	1257		0%
	2012-12-04 11:35	1,357.9	1,107.9	1.1	3.1	1,356.7	1,106.7	1354.7	1,104.7	1,603.7	460	869	1257		0%
	2012-12-04 11:40	1,359.5	1,109.5	1.1	3.1	1,358.4	1,108.4	1356.4	1,106.4	1,605.4	460	869	1257		0%
	2012-12-04 11:45	1,358.1	1,108.1	1.1	3.1	1,357.0	1,107.0	1355.0	1,105.0	1,604.0	460	869	1257		0%
	2012-12-04 11:50	1,360.6	1,110.6	1.1	3.1	1,359.5	1,109.5	1357.5	1,107.5	1,606.5	460	869	1257		0%
	2012-12-04 11:55	1,359.7	1,109.7	2.2	6.1	1,357.5	1,107.5	1353.6	1,103.6	1,602.6	460	869	1257		1%
12	2012-12-04 12:00	1,362.4	1,112.4	2.2	6.1	1,360.2	1,110.2	1356.3	1,106.3	1,605.3	460	869	1257		1%
	2012-12-04 12:05	1,371.7	1,121.7	3.1	8.4	1,368.6	1,118.6	1363.2	1,113.2	1,612.2	460	869	1257		1%
	2012-12-04 12:10	1,376.5	1,126.5	3.1	8.4	1,373.4	1,123.4	1368.0	1,118.0	1,617.0	460	869	1257		1%
	2012-12-04 12:15	1,374.1	1,124.1	5.5	15.1	1,368.6	1,118.6	1358.9	1,108.9	1,607.9	460	869	1257		1%
	2012-12-04 12:20	1,371.6	1,121.6	4.7	13.0	1,366.9	1,116.9	1358.6	1,108.6	1,607.6	460	869	1257		1%
	2012-12-04 12:25	1,366.2	1,116.2	5.0	13.9	1,361.1	1,111.1	1352.3	1,102.3	1,601.3	460	869	1257		1%
	2012-12-04 12:30	1,360.7	1,110.7	5.0	13.9	1,355.7	1,105.7	1346.8	1,096.8	1,595.8	460	869	1257		1%
	2012-12-04 12:35	1,359.9	1,109.9	3.4	9.4	1,356.5	1,106.5	1350.5	1,100.5	1,599.5	460	869	1257		1%
	2012-12-04 12:40	1,366.2	1,116.2	4.5	12.3	1,361.7	1,111.7	1353.8	1,103.8	1,602.8	460	869	1257		1%
	2012-12-04 12:45	1,361.5	1,111.5	3.0	8.2	1,358.5	1,108.5	1353.3	1,103.3	1,602.3	460	869	1257		1%
	2012-12-04 12:50	1,369.6	1,119.6	3.0	8.2	1,366.6	1,116.6	1361.4	1,111.4	1,610.4	460	869	1257		1%
	2012-12-04 12:55	1,367.1	1,117.1	3.8	10.5	1,363.3	1,113.3	1356.6	1,106.6	1,605.6	460	869	1257		1%
	2012-12-04 13:00	1,368.4	1,118.4	3.4	9.3	1,365.1	1,115.1	1359.1	1,109.1	1,608.1	460	869	1257		1%
	2012-12-04 13:05	1,364.1	1,114.1	4.6	12.6	1,359.5	1,109.5	1351.5	1,101.5	1,600.5	460	869	1257		1%
	2012-12-04 13:10	1,359.6	1,109.6	4.6	12.6	1,355.1	1,105.1	1347.0	1,097.0	1,596.0	460	869	1257		1%
	2012-12-04 13:15	1,359.8	1,109.8	5.5	15.0	1,354.3	1,104.3	1344.7	1,094.7	1,593.7	460	869	1257		1%
	2012-12-04 13:20	1,360.9	1,110.9	6.4	17.7	1,354.5	1,104.5	1343.2	1,093.2	1,592.2	460	869	1257		2%
	2012-12-04 13:25	1,363.0	1,113.0	6.8	18.7	1,356.2	1,106.2	1344.3	1,094.3	1,593.3	460	869	1257		2%
	2012-12-04 13:30	1,359.9	1,109.9	9.6	26.4	1,350.3	1,100.3	1333.5	1,083.5	1,582.5	460	869	1257		2%
	2012-12-04 13:35	1,359.1	1,109.1	10.7	29.5	1,348.4	1,098.4	1329.6	1,079.6	1,578.6	460	869	1257		3%
	2012-12-04 13:40	1,360.4	1,110.4	9.4	25.9	1,351.0	1,101.0	1334.5	1,084.5	1,583.5	460	869	1257		2%
	2012-12-04 13:45	1,353.9	1,103.9	7.2	19.9	1,346.7	1,096.7	1334.0	1,084.0	1,583.0	460	869	1257		2%
	2012-12-04 13:50	1,353.0	1,103.0	7.2	19.9	1,345.8	1,095.8	1333.2	1,083.2	1,582.2	460	869	1257		2%
	2012-12-04 13:55	1,349.3	1,099.3	7.5	20.6	1,341.8	1,091.8	1328.7	1,078.7	1,577.7	460	869	1257		2%
14	2012-12-04 14:00	1,350.6	1,100.6	8.1	22.4	1,342.5	1,092.5	1328.3	1,078.3	1,577.3	460	869	1257		2%
	2012-12-04 14:05	1,349.4	1,099.4	9.5	26.3	1,339.9	1,089.9	1323.1	1,073.1	1,572.1	460	869	1257		2%

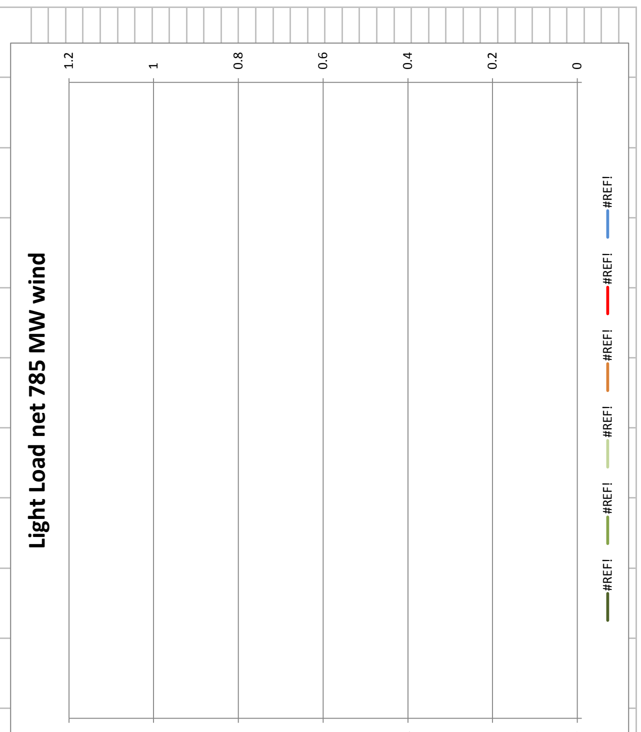
			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserv					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-04 14:10	1,348.8	1,098.8	12.1	33.5	1,336.6	1,086.6	1315.3	1,065.3	1,564.3	460	869	1257		3%
	2012-12-04 14:15	1,354.8	1,104.8	11.5	31.7	1,343.3	1,093.3	1323.1	1,073.1	1,572.1	460	869	1257		3%
	2012-12-04 14:20	1,349.2	1,099.2	16.4	45.2	1,332.8	1,082.8	1304.0	1,054.0	1,553.0	460	869	1257		4%
	2012-12-04 14:25	1,356.1	1,106.1	17.0	46.9	1,339.1	1,089.1	1309.2	1,059.2	1,558.2	460	869	1257		4%
	2012-12-04 14:30	1,358.0	1,108.0	18.9	52.0	1,339.1	1,089.1	1306.0	1,056.0	1,555.0	460	869	1257		5%
	2012-12-04 14:35	1,352.5	1,102.5	19.7	54.3	1,332.8	1,082.8	1298.2	1,048.2	1,547.2	460	869	1257		5%
	2012-12-04 14:40	1,353.5	1,103.5	20.4	56.2	1,333.1	1,083.1	1297.3	1,047.3	1,546.3	460	869	1257		5%
	2012-12-04 14:45	1,357.0	1,107.0	22.8	62.9	1,334.1	1,084.1	1294.1	1,044.1	1,543.1	460	869	1257		6%
	2012-12-04 14:50	1,359.8	1,109.8	22.2	61.2	1,337.5	1,087.5	1298.5	1,048.5	1,547.5	460	869	1257		6%
	2012-12-04 14:55	1,357.7	1,107.7	21.3	58.7	1,336.4	1,086.4	1299.0	1,049.0	1,548.0	460	869	1257		5%
	2012-12-04 15:00	1,360.2	1,110.2	23.0	63.4	1,337.2	1,087.2	1296.8	1,046.8	1,545.8	460	869	1257		6%
	2012-12-04 15:05	1,361.9	1,111.9	22.1	60.9	1,339.7	1,089.7	1300.9	1,050.9	1,549.9	460	869	1257		5%
	2012-12-04 15:10	1,368.8	1,118.8	19.8	54.5	1,349.0	1,099.0	1314.3	1,064.3	1,563.3	460	869	1257		5%
	2012-12-04 15:15	1,375.9	1,125.9	20.4	56.1	1,355.6	1,105.6	1319.8	1,069.8	1,568.8	460	869	1257		5%
	2012-12-04 15:20	1,375.6	1,125.6	21.3	58.8	1,354.2	1,104.2	1316.8	1,066.8	1,565.8	460	869	1257		5%
	2012-12-04 15:25	1,386.3	1,136.3	19.8	54.5	1,366.6	1,116.6	1331.9	1,081.9	1,580.9	460	869	1257		5%
	2012-12-04 15:30	1,390.7	1,140.7	20.1	55.2	1,370.6	1,120.6	1335.5	1,085.5	1,584.5	460	869	1257		5%
	2012-12-04 15:35	1,395.0	1,145.0	21.1	58.2	1,373.9	1,123.9	1336.8	1,086.8	1,585.8	460	869	1257		5%
	2012-12-04 15:40	1,402.1	1,152.1	23.6	65.0	1,378.5	1,128.5	1337.1	1,087.1	1,586.1	460	869	1257		6%
	2012-12-04 15:45	1,405.4	1,155.4	24.3	66.9	1,381.1	1,131.1	1338.4	1,088.4	1,587.4	460	869	1257		6%
	2012-12-04 15:50	1,412.4	1,162.4	24.7	68.0	1,387.7	1,137.7	1344.5	1,094.5	1,593.5	460	869	1257		6%
	2012-12-04 15:55	1,418.6	1,168.6	25.7	70.9	1,392.8	1,142.8	1347.7	1,097.7	1,596.7	460	869	1257		6%
16	2012-12-04 16:00	1,428.8	1,178.8	24.9	68.7	1,403.9	1,153.9	1360.1	1,110.1	1,609.1	460	869	1257		6%
	2012-12-04 16:05	1,428.4	1,178.4	23.3	64.1	1,405.2	1,155.2	1364.3	1,114.3	1,613.3	460	869	1257		5%
	2012-12-04 16:10	1,441.5	1,191.5	23.0	63.4	1,418.5	1,168.5	1378.1	1,128.1	1,627.1	460	869	1257		5%
	2012-12-04 16:15	1,447.3	1,197.3	22.8	62.8	1,424.5	1,174.5	1384.5	1,134.5	1,633.5	460	869	1257		5%
	2012-12-04 16:20	1,459.9	1,209.9	26.5	72.9	1,433.4	1,183.4	1387.0	1,137.0	1,636.0	460	869	1257		6%
	2012-12-04 16:25	1,477.4	1,227.4	26.3	72.4	1,451.1	1,201.1	1405.0	1,155.0	1,654.0	460	869	1257		6%
	2012-12-04 16:30	1,492.6	1,242.6	27.9	76.9	1,464.7	1,214.7	1415.7	1,165.7	1,664.7	460	869	1257		6%
	2012-12-04 16:35	1,496.1	1,246.1	25.5	70.3	1,470.6	1,220.6	1425.8	1,175.8	1,674.8	460	869	1257		6%
	2012-12-04 16:40	1,513.0	1,263.0	24.9	68.6	1,488.1	1,238.1	1444.4	1,194.4	1,693.4	460	869	1257		5%
	2012-12-04 16:45	1,525.0	1,275.0	23.7	65.2	1,501.3	1,251.3	1459.8	1,209.8	1,708.8	460	869	1257		5%
	2012-12-04 16:50	1,534.5	1,284.5	24.9	68.7	1,509.5	1,259.5	1465.8	1,215.8	1,714.8	460	869	1257		5%
	2012-12-04 16:55	1,542.1	1,292.1	21.9	60.4	1,520.1	1,270.1	1481.7	1,231.7	1,730.7	460	869	1257		5%
	2012-12-04 17:00	1,547.6	1,297.6	24.1	66.4	1,523.5	1,273.5	1481.2	1,231.2	1,730.2	460	869	1257		5%
	2012-12-04 17:05	1,548.9	1,298.9	22.4	61.6	1,526.5	1,276.5	1487.3	1,237.3	1,736.3	460	869	1257		5%
	2012-12-04 17:10	1,552.2	1,302.2	22.3	61.4	1,529.9	1,279.9	1490.8	1,240.8	1,739.8	460	869	1257		5%
	2012-12-04 17:15	1,558.3	1,308.3	21.3	58.8	1,536.9	1,286.9	1499.5	1,249.5	1,748.5	460	869	1257		4%
	2012-12-04 17:20	1,561.7	1,311.7	22.8	62.8	1,538.9	1,288.9	1498.9	1,248.9	1,747.9	460	869	1257		5%
	2012-12-04 17:25	1,561.7	1,311.7	24.2	66.6	1,537.5	1,287.5	1495.1	1,245.1	1,744.1	460	869	1257		5%
	2012-12-04 17:30	1,558.9	1,308.9	26.4	72.8	1,532.5	1,282.5	1486.1	1,236.1	1,735.1	460	869	1257		6%
	2012-12-04 17:35	1,555.8	1,305.8	29.0	79.8	1,526.8	1,276.8	1476.0	1,226.0	1,725.0	460	869	1257		6%
	2012-12-04 17:40	1,553.1	1,303.1	30.7	84.6	1,522.4	1,272.4	1468.5	1,218.5	1,717.5	460	869	1257		6%
	2012-12-04 17:45	1,548.1	1,298.1	33.1	91.1	1,515.1	1,265.1	1457.1	1,207.1	1,706.1	460	869	1257		7%
	2012-12-04 17:50	1,546.7	1,296.7	34.4	94.8	1,512.3	1,262.3	1451.9	1,201.9	1,700.9	460	869	1257		7%
	2012-12-04 17:55	1,543.7	1,293.7	38.1	105.1	1,505.6	1,255.6	1438.6	1,188.6	1,687.6	460	869	1257		8%
18	2012-12-04 18:00	1,533.3	1,283.3	38.9	107.1	1,494.4	1,244.4	1426.1	1,176.1	1,675.1	460	869	1257		8%
	2012-12-04 18:05	1,527.8	1,277.8	37.2	102.4	1,490.6	1,240.6	1425.4	1,175.4	1,674.4	460	869	1257		8%
	2012-12-04 18:10	1,522.0	1,272.0	39.5	108.9	1,482.5	1,232.5	1413.1	1,163.1	1,662.1	460	869	1257		9%
	2012-12-04 18:15	1,516.6	1,266.6	43.2	119.0	1,473.4	1,223.4	1397.6	1,147.6	1,646.6	460	869	1257		9%
	2012-12-04 18:20	1,520.4	1,270.4	40.1	110.4	1,480.3	1,230.3	1410.0	1,160.0	1,659.0	460	869	1257		9%
	2012-12-04 18:25	1,512.4	1,262.4	39.7	109.3	1,472.8	1,222.8	1403.2	1,153.2	1,652.2	460	869	1257		9%
	2012-12-04 18:30	1,512.7	1,262.7	39.3	108.4	1,473.3	1,223.3	1404.3	1,154.3	1,653.3	460	869	1257		9%
	2012-12-04 18:35	1,504.2	1,254.2	43.3	119.3	1,460.9	1,210.9	1384.9	1,134.9	1,633.9	460	869	1257		10%
	2012-12-04 18:40	1,496.8	1,246.8	43.8	120.5	1,453.0	1,203.0	1376.2	1,126.2	1,625.2	460	869	1257		10%
	2012-12-04 18:45	1,499.3	1,249.3	43.2	118.9	1,456.1	1,206.1	1380.4	1,130.4	1,629.4	460	869	1257		10%
	2012-12-04 18:50	1,499.8	1,249.8	41.9	115.5	1,457.8	1,207.8	1384.2	1,134.2	1,633.2	460	869	1257		9%
	2012-12-04 18:55	1,495.3	1,245.3	43.0	118.4	1,452.3	1,202.3	1376.9	1,126.9	1,625.9	460	869	1257		10%
	2012-12-04 19:00	1,494.8	1,244.8	44.5	122.7	1,450.3	1,200.3	1372.1	1,122.1	1,621.1	460	869	1257		10%
	2012-12-04 19:05	1,491.6	1,241.6	53.2	146.5	1,438.4	1,188.4	1345.1	1,095.1	1,594.1	460	869	1257		12%
	2012-12-04 19:10	1,488.5	1,238.5	52.2	143.9	1,436.3	1,186.3	1344.6	1,094.6	1,593.6	460	869	1257		12%
	2012-12-04 19:15	1,488.8	1,238.8	55.9	154.1	1,432.9	1,182.9	1334.8	1,084.8	1,583.8	460	869	1257		12%
	2012-12-04 19:20	1,490.8	1,240.8	64.8	178.4	1,426.1	1,176.1	1312.5	1,062.5	1,561.5	460	869	1257		14%
	2012-12-04 19:25	1,486.5	1,236.5	69.7	191.9	1,416.9	1,166.9	1294.7	1,044.7	1,543.7	460	869	1257		16%
	2012-12-04 19:30	1,481.3	1,231.3	75.0	206.7	1,406.2	1,156.2	1274.6	1,024.6	1,523.6	460	869	1257		17%
	2012-12-04 19:35	1,482.7	1,232.7	80.4	221.5	1,402.3	1,152.3	1261.2	1,011.2	1,510.2	460	869	1257		18%
	2012-12-04 19:40	1,474.1	1,224.1	82.9	228.3	1,391.2	1,141.2	1245.9	995.9	1,494.9	460	869	1257		19%
	2012-12-04 19:45	1,468.2	1,218.2	83.9	231.1	1,384.3	1,134.3	1237.1	987.1	1,486.1	460	869	1257		19%
	2012-12-04 19:50	1,467.6	1,217.6	87.0	239.8	1,380.5	1,130.5	1227.8	977.8	1,476.8	460	869	1257		20%
	2012-12-04 19:55	1,463.0	1,213.0	90.1	248.3	1,372.8	1,122.8	1214.7	964.7	1,463.7	460	869	1257		20%
20	2012-12-04 20:00	1,462.1	1,212.1	94.7	260.9	1,367.4	1,117.4	1201.2	951.2	1,450.2	460	869	1257		22%
	2012-12-04 20:05	1,455.5	1,205.5	96.1	264.8	1,359.4	1,109.4	1190.7	940.7	1,439.7	460	869	1257		22%
	2012-12-04 20:10	1,457.2	1,207.2	95.7	263.6	1,361.5	1,111.5	1193.6	943.6	1,442.6	460	869	1257		22%
	2012-12-04 20:15	1,451.7	1,201.7	100.1	275.7	1,351.6	1,101.6	1176.0	926.0	1,425.0	460	869	1257		23%
	2012-12-04 20:20	1,442.6	1,192.6	97.0	267.2	1,345.6	1,095.6	1175.4	925.4	1,424.4	460	869	1257		22%
	2012-12-04 20:25	1,446.5	1,196.5	95.0	261.6	1,351.5	1,101.5	1184.8	934.8	1,433.8	460	869	1257		22%
	2012-12-04 20:30	1,442.2	1,192.2	95.4	262.7	1,346.8	1,096.8	1179.4	929.4	1,428.4	460	869	1257		22%
	2012-12-04 20:35	1,435.3	1,185.3	100.3	276.3	1,335.0	1,085.0	1159.0	909.0	1,408.0	460	869	1257		23%
	2012-12-04 20:40	1,436.8	1,186.8	100.2	275.9	1,336.6	1,086.6	1160.9	910.9	1,409.9	460	869	1257		23%
	2012-12-04 20:45	1,426.8	1,176.8	112.0	308.5	1,314.8	1,064.8	1118.3	868.3	1,367.3	460	869	1257		26%
	2012-12-04 20:50	1,422.3	1,172.3	110.8	305.2	1,311.5	1,061.5	1117.1	867.1	1,366.1	460	869	1257		26%
	2012-12-04 20:55	1,408.4	1,158.4	116.1	319.9	1,292.3	1,042.3	1088.5	838.5	1,337.5	460	869	1257		28%
	2012-12-04 21:00	1,404.0	1,154.0	118.3	325.8	1,285.7	1,035.7	1078.1	828.1	1,327.1	460	869	1257		28%
	2012-12-04 21:05	1,390.3	1,140.3	114.2	314.7	1,276.0	1,026.0	1075.6	825.6	1,324.6	460	869	1257		28%
	2012-12-04 21:10	1,382.8	1,132.8	110.8	305.2	1,272.0	1,022.0	1077.6	827.6	1,326.6	460	869	1257		27%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserv					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-04 21:15	1,372.4	1,122.4	111.0	305.9	1,261.4	1,011.4	1066.6	816.6	1,315.6	460	869	1257		27%
	2012-12-04 21:20	1,368.7	1,118.7	114.0	314.0	1,254.7	1,004.7	1054.7	804.7	1,303.7	460	869	1257		28%
	2012-12-04 21:25	1,360.6	1,110.6	113.1	311.5	1,247.5	997.5	1049.2	799.2	1,298.2	460	869	1257		28%
	2012-12-04 21:30	1,351.3	1,101.3	110.9	305.5	1,240.4	990.4	1045.8	795.8	1,294.8	460	869	1257		28%
	2012-12-04 21:35	1,342.4	1,092.4	112.5	310.0	1,229.9	979.9	1032.4	782.4	1,281.4	460	869	1257		28%
	2012-12-04 21:40	1,340.0	1,090.0	115.2	317.4	1,224.8	974.8	1022.7	772.7	1,271.7	460	869	1257		29%
	2012-12-04 21:45	1,326.9	1,076.9	114.1	314.3	1,212.7	962.7	1012.5	762.5	1,261.5	460	869	1257		29%
	2012-12-04 21:50	1,314.9	1,064.9	118.2	325.5	1,196.7	946.7	989.4	739.4	1,238.4	460	869	1257		31%
	2012-12-04 21:55	1,307.5	1,057.5	124.4	342.6	1,183.1	933.1	964.8	714.8	1,213.8	460	869	1257		32%
22	2012-12-04 22:00	1,289.5	1,039.5	126.8	349.3	1,162.6	912.6	940.2	690.2	1,189.2	460	869	1257		34%
	2012-12-04 22:05	1,268.8	1,018.8	134.4	370.1	1,134.4	884.4	898.7	648.7	1,147.7	460	869	1257		36%
	2012-12-04 22:10	1,263.2	1,013.2	135.8	374.2	1,127.4	877.4	889.0	639.0	1,138.0	460	869	1257		37%
	2012-12-04 22:15	1,259.8	1,009.8	129.4	356.3	1,130.5	880.5	903.5	653.5	1,152.5	460	869	1257		35%
	2012-12-04 22:20	1,252.6	1,002.6	136.5	375.8	1,116.2	866.2	876.8	626.8	1,125.8	460	869	1257		37%
	2012-12-04 22:25	1,244.4	994.4	141.6	390.1	1,102.7	852.7	854.3	604.3	1,103.3	460	869	1257		39%
	2012-12-04 22:30	1,238.2	988.2	142.7	393.0	1,095.5	845.5	845.2	595.2	1,094.2	460	869	1257		40%
	2012-12-04 22:35	1,228.9	978.9	141.4	389.5	1,087.5	837.5	839.4	589.4	1,088.4	460	869	1257		40%
	2012-12-04 22:40	1,218.3	968.3	140.0	385.7	1,078.3	828.3	832.6	582.6	1,081.6	460	869	1257		40%
	2012-12-04 22:45	1,204.5	954.5	136.6	376.4	1,067.9	817.9	828.1	578.1	1,077.1	460	869	1257		39%
	2012-12-04 22:50	1,197.3	947.3	133.6	368.0	1,063.7	813.7	829.3	579.3	1,078.3	460	869	1257		39%
	2012-12-04 22:55	1,188.3	938.3	125.1	344.5	1,063.2	813.2	843.8	593.8	1,092.8	460	869	1257		37%
	2012-12-04 23:00	1,178.1	928.1	114.0	314.0	1,064.0	814.0	864.0	614.0	1,113.0	460	869	1257		34%
	2012-12-04 23:05	1,187.6	937.6	118.3	325.8	1,069.3	819.3	861.8	611.8	1,110.8	460	869	1257		35%
	2012-12-04 23:10	1,190.5	940.5	120.4	331.5	1,070.2	820.2	859.0	609.0	1,108.0	460	869	1257		35%
	2012-12-04 23:15	1,177.8	927.8	119.6	329.5	1,058.2	808.2	848.4	598.4	1,097.4	460	869	1257		36%
	2012-12-04 23:20	1,174.3	924.3	111.4	306.9	1,062.9	812.9	867.4	617.4	1,116.4	460	869	1257		33%
	2012-12-04 23:25	1,167.4	917.4	112.5	309.9	1,054.8	804.8	857.4	607.4	1,106.4	460	869	1257		34%
	2012-12-04 23:30	1,151.9	901.9	111.6	307.4	1,040.3	790.3	844.5	594.5	1,093.5	460	869	1257		34%
	2012-12-04 23:35	1,142.4	892.4	121.1	333.5	1,021.3	771.3	808.9	558.9	1,057.9	460	869	1257		37%
	2012-12-04 23:40	1,135.9	885.9	123.3	339.6	1,012.6	762.6	796.2	546.2	1,045.2	460	869	1257		38%
	2012-12-04 23:45	1,120.3	870.3	124.8	343.7	995.6	745.6	776.7	526.7	1,025.7	460	869	1257		39%
	2012-12-04 23:50	1,116.1	866.1	130.4	359.2	985.7	735.7	756.9	506.9	1,005.9	460	869	1257		41%
	2012-12-04 23:55	1,104.7	854.7	128.6	354.3	976.1	726.1	750.4	500.4	999.4	460	869	1257		41%
0	2012-12-05 00:00	1,100.6	850.6	133.6	368.0	967.0	717.0	732.6	482.6	981.6	460	869	1257		43%
	2012-12-05 00:05	1,114.1	864.1	144.2	397.2	969.9	719.9	716.9	466.9	965.9	460	869	1257		46%
	2012-12-05 00:10	1,116.9	866.9	147.0	405.0	969.9	719.9	711.9	461.9	960.9	460	869	1257		47%
	2012-12-05 00:15	1,107.8	857.8	146.2	402.8	961.5	711.5	705.0	455.0	954.0	460	869	1257		47%
	2012-12-05 00:20	1,101.5	851.5	154.8	426.4	946.7	696.7	675.1	425.1	924.1	460	869	1257		50%
	2012-12-05 00:25	1,096.7	846.7	161.3	444.2	935.4	685.4	652.5	402.5	901.5	460	869	1257		52%
	2012-12-05 00:30	1,081.5	831.5	169.4	466.5	912.1	662.1	614.9	364.9	863.9	460	869	1257		56%
	2012-12-05 00:35	1,080.7	830.7	171.7	473.0	909.0	659.0	607.7	357.7	856.7	460	869	1257		57%
	2012-12-05 00:40	1,074.7	824.7	173.9	479.0	900.8	650.8	595.7	345.7	844.7	460	869	1257		58%
	2012-12-05 00:45	1,069.2	819.2	177.0	487.6	892.2	642.2	581.6	331.6	830.6	460	869	1257		60%
	2012-12-05 00:50	1,067.5	817.5	186.3	513.0	881.3	631.3	554.5	304.5	803.5	460	869	1257		63%
	2012-12-05 00:55	1,063.7	813.7	201.4	554.8	862.3	612.3	508.9	258.9	757.9	460	869	1257		68%
	2012-12-05 01:00	1,058.8	808.8	191.0	526.2	867.7	617.7	532.5	282.5	781.5	460	869	1257		65%
	2012-12-05 01:05	1,056.9	806.9	185.1	509.8	871.8	621.8	547.1	297.1	796.1	460	869	1257		63%
	2012-12-05 01:10	1,045.1	795.1	197.6	544.1	847.5	597.5	500.9	250.9	749.9	460	869	1257		68%
	2012-12-05 01:15	1,048.8	798.8	195.6	538.7	853.2	603.2	510.1	260.1	759.1	460	869	1257		67%
	2012-12-05 01:20	1,042.0	792.0	203.6	560.9	838.4	588.4	481.2	231.2	730.2	460	869	1257		71%
	2012-12-05 01:25	1,033.0	783.0	201.2	554.3	831.8	581.8	478.7	228.7	727.7	460	869	1257		71%
	2012-12-05 01:30	1,032.5	782.5	197.5	544.0	835.0	585.0	488.5	238.5	737.5	460	869	1257		70%
	2012-12-05 01:35	1,026.4	776.4	199.6	549.7	826.9	576.9	476.8	226.8	725.8	460	869	1257		71%
	2012-12-05 01:40	1,026.6	776.6	191.2	526.6	835.4	585.4	500.0	250.0	749.0	460	869	1257		68%
	2012-12-05 01:45	1,027.7	777.7	192.0	528.8	835.7	585.7	498.9	248.9	747.9	460	869	1257		68%
	2012-12-05 01:50	1,021.8	771.8	193.6	533.4	828.2	578.2	488.5	238.5	737.5	460	869	1257		69%
	2012-12-05 01:55	1,018.2	768.2	193.6	533.3	824.6	574.6	484.9	234.9	733.9	460	869	1257		69%
2	2012-12-05 02:00	1,012.4	762.4	196.0	539.9	816.4	566.4	472.6	222.6	721.6	460	869	1257		71%
	2012-12-05 02:05	1,005.3	755.3	197.4	543.8	807.8	557.8	461.5	211.5	710.5	460	869	1257		72%
	2012-12-05 02:10	1,001.5	751.5	200.7	552.9	800.8	550.8	448.7	198.7	697.7	460	869	1257		74%
	2012-12-05 02:15	1,000.6	750.6	203.0	559.0	797.6	547.6	441.6	191.6	690.6	460	869	1257		74%
	2012-12-05 02:20	995.2	745.2	206.2	567.9	789.0	539.0	427.3	177.3	676.3	460	869	1257		76%
	2012-12-05 02:25	995.7	745.7	205.9	567.0	789.8	539.8	428.6	178.6	677.6	460	869	1257		76%
	2012-12-05 02:30	984.6	734.6	203.4	560.2	781.2	531.2	424.5	174.5	673.5	460	869	1257		76%
	2012-12-05 02:35	984.1	734.1	199.5	549.5	784.6	534.6	434.6	184.6	683.6	460	869	1257		75%
	2012-12-05 02:40	981.4	731.4	203.4	560.3	778.0	528.0	421.2	171.2	670.2	460	869	1257		77%
	2012-12-05 02:45	983.9	733.9	214.3	590.2	769.6	519.6	393.7	143.7	642.7	460	869	1257		80%
	2012-12-05 02:50	981.1	731.1	208.5	574.3	772.6	522.6	406.8	156.8	655.8	460	869	1257		79%
	2012-12-05 02:55	971.2	721.2	211.4	582.2	759.8	509.8	389.0	139.0	638.0	460	869	1257		81%
	2012-12-05 03:00	971.7	721.7	212.9	586.4	758.8	508.8	385.3	135.3	634.3	460	869	1257		81%
	2012-12-05 03:05	973.2	723.2	214.9	591.9	758.3	508.3	381.3	131.3	630.3	460	869	1257		82%
	2012-12-05 03:10	971.2	721.2	211.2	581.7	760.0	510.0	389.5	139.5	638.5	460	869	1257		81%
	2012-12-05 03:15	974.4	724.4	207.1	570.4	767.3	517.3	403.9	153.9	652.9	460	869	1257		79%
	2012-12-05 03:20	965.3	715.3	211.2	581.6	754.2	504.2	383.7	133.7	632.7	460	869	1257		81%
	2012-12-05 03:25	969.3	719.3	216.5	596.4	752.8	502.8	373.0	123.0	622.0	460	869	1257		83%
	2012-12-05 03:30	960.8	710.8	219.0	603.2	741.7	491.7	357.5	107.5	606.5	460	869	1257		85%
	2012-12-05 03:35	963.2	713.2	217.6	599.2	745.7	495.7	364.0	114.0	613.0	460	869	1257		84%
	2012-12-05 03:40	963.4	713.4	222.4	612.7	741.0	491.0	350.7	100.7	599.7	460	869	1257		86%
	2012-12-05 03:45	958.6	708.6	218.3	601.2	740.3	490.3	357.3	107.3	606.3	460	869	1257		85%
	2012-12-05 03:50	963.7	713.7	219.6	604.8	744.1	494.1	358.9	108.9	607.9	460	869	1257		85%
	2012-12-05 03:55	959.4	709.4	211.3	582.0	748.1	498.1	377.4	127.4	626.4	460	869	1257		82%
4	2012-12-05 04:00	957.0	707.0	213.6	588.2	743.5	493.5	368.8	118.8	617.8	460	869	1257		83%
	2012-12-05 04:05	966.3	716.3	214.6	591.0	751.7	501.7	375.3	125.3	624.3	460	869	1257		83%
	2012-12-05 04:10	963.1	713.1	212.8	586.2	750.3	500.3	376.9	126.9	625.9	460	869	1257		82%
	2012-12-05 04:15	959.2	709.2	219.3	604.0	739.9	489.9	355.2	105.2	604.2	460	869	1257		85%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserv					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-05 04:20	963.7	713.7	224.6	618.7	739.1	489.1	345.0	95.0	594.0	460	869	1257		87%
	2012-12-05 04:25	967.2	717.2	225.4	620.9	741.7	491.7	346.3	96.3	595.3	460	869	1257		87%
	2012-12-05 04:30	960.3	710.3	226.4	623.7	733.8	483.8	336.6	86.6	585.6	460	869	1257		88%
	2012-12-05 04:35	962.5	712.5	227.6	626.8	734.9	484.9	335.7	85.7	584.7	460	869	1257		88%
	2012-12-05 04:40	966.5	716.5	226.9	624.9	739.6	489.6	341.6	91.6	590.6	460	869	1257		87%
	2012-12-05 04:45	971.6	721.6	226.4	623.5	745.2	495.2	348.1	98.1	597.1	460	869	1257		86%
	2012-12-05 04:50	975.7	725.7	227.5	626.6	748.2	498.2	349.0	99.0	598.0	460	869	1257		86%
	2012-12-05 04:55	977.7	727.7	229.2	631.3	748.5	498.5	346.4	96.4	595.4	460	869	1257		87%
	2012-12-05 05:00	972.8	722.8	234.1	644.8	738.7	488.7	327.9	77.9	576.9	460	869	1257		89%
	2012-12-05 05:05	986.0	736.0	234.5	645.9	751.5	501.5	340.1	90.1	589.1	460	869	1257		88%
	2012-12-05 05:10	996.7	746.7	230.1	633.8	766.6	516.6	362.8	112.8	611.8	460	869	1257		85%
	2012-12-05 05:15	996.9	746.9	232.1	639.2	764.8	514.8	357.7	107.7	606.7	460	869	1257		86%
	2012-12-05 05:20	999.9	749.9	230.7	635.4	769.2	519.2	364.5	114.5	613.5	460	869	1257		85%
	2012-12-05 05:25	1,005.4	755.4	230.5	634.8	774.9	524.9	370.5	120.5	619.5	460	869	1257		84%
	2012-12-05 05:30	1,008.8	758.8	230.0	633.4	778.9	528.9	375.4	125.4	624.4	460	869	1257		83%
	2012-12-05 05:35	1,024.2	774.2	229.2	631.3	795.0	545.0	392.8	142.8	641.8	460	869	1257		82%
	2012-12-05 05:40	1,032.5	782.5	229.8	632.9	802.7	552.7	399.6	149.6	648.6	460	869	1257		81%
	2012-12-05 05:45	1,034.6	784.6	231.4	637.4	803.2	553.2	397.2	147.2	646.2	460	869	1257		81%
	2012-12-05 05:50	1,046.7	796.7	236.0	650.1	810.7	560.7	396.6	146.6	645.6	460	869	1257		82%
	2012-12-05 05:55	1,050.5	800.5	237.6	654.4	813.0	563.0	396.1	146.1	645.1	460	869	1257		82%
6	2012-12-05 06:00	1,068.1	818.1	239.7	660.4	828.3	578.3	407.7	157.7	656.7	460	869	1257		81%
	2012-12-05 06:05	1,090.9	840.9	241.5	665.1	849.5	599.5	425.9	175.9	674.9	460	869	1257		79%
	2012-12-05 06:10	1,104.3	854.3	236.9	652.5	867.4	617.4	451.8	201.8	700.8	460	869	1257		76%
	2012-12-05 06:15	1,120.7	870.7	236.4	651.2	884.3	634.3	469.5	219.5	718.5	460	869	1257		75%
	2012-12-05 06:20	1,130.9	880.9	236.7	652.1	894.2	644.2	478.9	228.9	727.9	460	869	1257		74%
	2012-12-05 06:25	1,137.3	887.3	233.1	642.2	904.2	654.2	495.1	245.1	744.1	460	869	1257		72%
	2012-12-05 06:30	1,153.2	903.2	242.9	669.2	910.3	660.3	484.1	234.1	733.1	460	869	1257		74%
	2012-12-05 06:35	1,164.2	914.2	246.4	678.8	917.7	667.7	485.4	235.4	734.4	460	869	1257		74%
	2012-12-05 06:40	1,174.6	924.6	239.0	658.3	935.6	685.6	516.3	266.3	765.3	460	869	1257		71%
	2012-12-05 06:45	1,186.8	936.8	242.5	668.0	944.3	694.3	518.8	268.8	767.8	460	869	1257		71%
	2012-12-05 06:50	1,203.2	953.2	248.8	685.3	954.4	704.4	517.9	267.9	766.9	460	869	1257		72%
	2012-12-05 06:55	1,218.7	968.7	249.7	687.7	969.0	719.0	531.0	281.0	780.0	460	869	1257		71%
	2012-12-05 07:00	1,228.8	978.8	247.6	682.0	981.2	731.2	546.8	296.8	795.8	460	869	1257		70%
	2012-12-05 07:05	1,242.9	992.9	244.6	673.8	998.3	748.3	569.1	319.1	818.1	460	869	1257		68%
	2012-12-05 07:10	1,257.0	1,007.0	238.7	657.4	1,018.3	768.3	599.6	349.6	848.6	460	869	1257		65%
	2012-12-05 07:15	1,272.2	1,022.2	228.2	628.5	1,044.0	794.0	643.6	393.6	892.6	460	869	1257		61%
	2012-12-05 07:20	1,283.8	1,033.8	235.2	647.9	1,048.6	798.6	635.9	385.9	884.9	460	869	1257		63%
	2012-12-05 07:25	1,296.8	1,046.8	232.7	641.0	1,064.1	814.1	655.8	405.8	904.8	460	869	1257		61%
	2012-12-05 07:30	1,302.5	1,052.5	240.6	662.8	1,061.9	811.9	639.7	389.7	888.7	460	869	1257		63%
	2012-12-05 07:35	1,306.2	1,056.2	236.7	651.8	1,069.6	819.6	654.4	404.4	903.4	460	869	1257		62%
	2012-12-05 07:40	1,311.6	1,061.6	237.2	653.3	1,074.4	824.4	658.3	408.3	907.3	460	869	1257		62%
	2012-12-05 07:45	1,315.2	1,065.2	239.7	660.3	1,075.5	825.5	654.9	404.9	903.9	460	869	1257		62%
	2012-12-05 07:50	1,320.0	1,070.0	240.9	663.6	1,079.1	829.1	656.4	406.4	905.4	460	869	1257		62%
	2012-12-05 07:55	1,322.7	1,072.7	240.9	663.6	1,081.8	831.8	659.1	409.1	908.1	460	869	1257		62%
8	2012-12-05 08:00	1,325.8	1,075.8	243.7	671.4	1,082.1	832.1	654.5	404.5	903.5	460	869	1257		62%
	2012-12-05 08:05	1,329.8	1,079.8	239.0	658.4	1,090.8	840.8	671.4	421.4	920.4	460	869	1257		61%
	2012-12-05 08:10	1,329.5	1,079.5	236.8	652.3	1,092.7	842.7	677.2	427.2	926.2	460	869	1257		60%
	2012-12-05 08:15	1,328.8	1,078.8	241.7	665.6	1,087.1	837.1	663.1	413.1	912.1	460	869	1257		62%
	2012-12-05 08:20	1,338.4	1,088.4	240.6	662.7	1,097.8	847.8	675.6	425.6	924.6	460	869	1257		61%
	2012-12-05 08:25	1,332.0	1,082.0	243.8	671.5	1,088.2	838.2	660.5	410.5	909.5	460	869	1257		62%
	2012-12-05 08:30	1,323.8	1,073.8	244.1	672.3	1,079.7	829.7	651.4	401.4	900.4	460	869	1257		63%
	2012-12-05 08:35	1,329.1	1,079.1	243.4	670.4	1,085.7	835.7	658.7	408.7	907.7	460	869	1257		62%
	2012-12-05 08:40	1,322.7	1,072.7	240.3	661.8	1,082.4	832.4	660.9	410.9	909.9	460	869	1257		62%
	2012-12-05 08:45	1,319.0	1,069.0	242.0	666.5	1,077.0	827.0	652.5	402.5	901.5	460	869	1257		62%
	2012-12-05 08:50	1,320.9	1,070.9	241.8	666.1	1,079.0	829.0	654.7	404.7	903.7	460	869	1257		62%
	2012-12-05 08:55	1,319.5	1,069.5	239.4	659.5	1,080.1	830.1	660.0	410.0	909.0	460	869	1257		62%
	2012-12-05 09:00	1,322.0	1,072.0	243.5	670.7	1,078.5	828.5	651.3	401.3	900.3	460	869	1257		63%
	2012-12-05 09:05	1,319.7	1,069.7	247.6	681.9	1,072.1	822.1	637.8	387.8	886.8	460	869	1257		64%
	2012-12-05 09:10	1,314.3	1,064.3	242.8	668.9	1,071.4	821.4	645.4	395.4	894.4	460	869	1257		63%
	2012-12-05 09:15	1,316.7	1,066.7	240.2	661.6	1,076.5	826.5	655.1	405.1	904.1	460	869	1257		62%
	2012-12-05 09:20	1,314.5	1,064.5	233.7	643.6	1,080.8	830.8	670.9	420.9	919.9	460	869	1257		60%
	2012-12-05 09:25	1,319.2	1,069.2	234.7	646.5	1,084.5	834.5	672.7	422.7	921.7	460	869	1257		60%
	2012-12-05 09:30	1,313.6	1,063.6	229.7	632.8	1,083.8	833.8	680.8	430.8	929.8	460	869	1257		59%
	2012-12-05 09:35	1,312.8	1,062.8	235.8	649.6	1,077.0	827.0	663.2	413.2	912.2	460	869	1257		61%
	2012-12-05 09:40	1,311.6	1,061.6	246.5	678.9	1,065.2	815.2	632.8	382.8	881.8	460	869	1257		64%
	2012-12-05 09:45	1,313.0	1,063.0	244.6	673.6	1,068.5	818.5	639.4	389.4	888.4	460	869	1257		63%
	2012-12-05 09:50	1,304.5	1,054.5	246.8	679.8	1,057.7	807.7	624.7	374.7	873.7	460	869	1257		64%
	2012-12-05 09:55	1,308.0	1,058.0	242.1	666.9	1,065.9	815.9	641.2	391.2	890.2	460	869	1257		63%
10	2012-12-05 10:00	1,305.6	1,055.6	248.8	685.2	1,056.8	806.8	620.3	370.3	869.3	460	869	1257		65%
	2012-12-05 10:05	1,302.8	1,052.8	255.6	704.0	1,047.2	797.2	598.8	348.8	847.8	460	869	1257		67%
	2012-12-05 10:10	1,304.3	1,054.3	252.3	695.0	1,052.0	802.0	609.3	359.3	858.3	460	869	1257		66%
	2012-12-05 10:15	1,302.5	1,052.5	243.2	669.9	1,059.3	809.3	632.6	382.6	881.6	460	869	1257		64%
	2012-12-05 10:20	1,300.7	1,050.7	239.2	658.8	1,061.5	811.5	641.8	391.8	890.8	460	869	1257		63%
	2012-12-05 10:25	1,303.0	1,053.0	235.5	648.7	1,067.4	817.4	654.3	404.3	903.3	460	869	1257		62%
	2012-12-05 10:30	1,296.5	1,046.5	237.1	653.2	1,059.4	809.4	643.4	393.4	892.4	460	869	1257		62%
	2012-12-05 10:35	1,292.3	1,042.3	235.7	649.3	1,056.6	806.6	643.0	393.0	892.0	460	869	1257		62%
	2012-12-05 10:40	1,295.3	1,045.3	240.5	662.5	1,054.8	804.8	632.8	382.8	881.8	460	869	1257		63%
	2012-12-05 10:45	1,293.7	1,043.7	231.7	638.1	1,062.0	812.0	655.6	405.6	904.6	460	869	1257		61%
	2012-12-05 10:50	1,291.6	1,041.6	228.0	628.0	1,063.6	813.6	663.6	413.6	912.6	460	869	1257		60%
	2012-12-05 10:55	1,293.4	1,043.4	229.3	631.7	1,064.0	814.0	661.7	411.7	910.7	460	869	1257		61%
	2012-12-05 11:00	1,296.8	1,046.8	229.7	632.8	1,067.1	817.1	664.0	414.0	913.0	460	869	1257		60%
	2012-12-05 11:05	1,297.6	1,047.6	231.7	638.1	1,065.9	815.9	659.5	409.5	908.5	460	869	1257		61%
	2012-12-05 11:10	1,290.3	1,040.3	233.0	641.7	1,057.3	807.3	648.6	398.6	897.6	460	869	1257		62%
	2012-12-05 11:15	1,296.1	1,046.1	227.0	625.3	1,069.1	819.1	670.8	420.8	919.8	460	869	1257		60%
	2012-12-05 11:20	1,295.6	1,045.6	218.0	600.6	1,077.5	827.5	695.0	445.0	944.0	460	869	1257		57%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserv					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitm ent	Turn up of Minimum Commitm ent	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-05 11:25	1,277.3	1,027.3	213.9	589.2	1,063.4	813.4	688.1	438.1	937.1	460	869	1257		57%
	2012-12-05 11:30	1,292.2	1,042.2	223.5	615.5	1,068.7	818.7	676.7	426.7	925.7	460	869	1257		59%
	2012-12-05 11:35	1,277.4	1,027.4	222.4	612.5	1,055.0	805.0	664.9	414.9	913.9	460	869	1257		60%
	2012-12-05 11:40	1,277.2	1,027.2	221.1	609.0	1,056.1	806.1	668.2	418.2	917.2	460	869	1257		59%
	2012-12-05 11:45	1,293.5	1,043.5	219.8	605.3	1,073.7	823.7	688.1	438.1	937.1	460	869	1257		58%
	2012-12-05 11:50	1,289.0	1,039.0	227.6	626.9	1,061.4	811.4	662.1	412.1	911.1	460	869	1257		60%
	2012-12-05 11:55	1,287.6	1,037.6	226.6	624.0	1,061.0	811.0	663.6	413.6	912.6	460	869	1257		60%
12	2012-12-05 12:00	1,271.8	1,021.8	226.2	622.9	1,045.7	795.7	648.9	398.9	897.9	460	869	1257		61%
	2012-12-05 12:05	1,274.6	1,024.6	219.5	604.5	1,055.1	805.1	670.0	420.0	919.0	460	869	1257		59%
	2012-12-05 12:10	1,274.3	1,024.3	222.9	613.9	1,051.4	801.4	660.4	410.4	909.4	460	869	1257		60%
	2012-12-05 12:15	1,280.5	1,030.5	221.9	611.2	1,058.6	808.6	669.3	419.3	918.3	460	869	1257		59%
	2012-12-05 12:20	1,273.1	1,023.1	236.3	650.8	1,036.8	786.8	622.4	372.4	871.4	460	869	1257		64%
	2012-12-05 12:25	1,269.1	1,019.1	225.0	619.7	1,044.1	794.1	649.4	399.4	898.4	460	869	1257		61%
	2012-12-05 12:30	1,262.7	1,012.7	226.4	623.6	1,036.3	786.3	639.2	389.2	888.2	460	869	1257		62%
	2012-12-05 12:35	1,258.4	1,008.4	242.1	666.8	1,016.3	766.3	591.6	341.6	840.6	460	869	1257		66%
	2012-12-05 12:40	1,259.4	1,009.4	240.5	662.3	1,018.9	768.9	597.0	347.0	846.0	460	869	1257		66%
	2012-12-05 12:45	1,255.7	1,005.7	248.7	685.1	1,007.0	757.0	570.7	320.7	819.7	460	869	1257		68%
	2012-12-05 12:50	1,247.6	997.6	242.9	669.1	1,004.7	754.7	578.5	328.5	827.5	460	869	1257		67%
	2012-12-05 12:55	1,244.5	994.5	239.4	659.3	1,005.2	755.2	585.2	335.2	834.2	460	869	1257		66%
	2012-12-05 13:00	1,248.5	998.5	245.0	674.9	1,003.4	753.4	573.6	323.6	822.6	460	869	1257		68%
	2012-12-05 13:05	1,243.6	993.6	240.1	661.4	1,003.5	753.5	582.2	332.2	831.2	460	869	1257		67%
	2012-12-05 13:10	1,246.4	996.4	243.1	669.6	1,003.3	753.3	576.8	326.8	825.8	460	869	1257		67%
	2012-12-05 13:15	1,271.9	1,021.9	258.3	711.6	1,013.6	763.6	560.4	310.4	809.4	460	869	1257		70%
	2012-12-05 13:20	1,266.0	1,016.0	259.0	713.4	1,007.0	757.0	552.6	302.6	801.6	460	869	1257		70%
	2012-12-05 13:25	1,263.5	1,013.5	258.0	710.5	1,005.6	755.6	553.0	303.0	802.0	460	869	1257		70%
	2012-12-05 13:30	1,265.3	1,015.3	257.3	708.8	1,008.0	758.0	556.5	306.5	805.5	460	869	1257		70%
	2012-12-05 13:35	1,264.1	1,014.1	257.5	709.2	1,006.6	756.6	554.9	304.9	803.9	460	869	1257		70%
	2012-12-05 13:40	1,263.1	1,013.1	252.5	695.5	1,010.5	760.5	567.5	317.5	816.5	460	869	1257		69%
	2012-12-05 13:45	1,266.5	1,016.5	262.7	723.6	1,003.8	753.8	542.9	292.9	791.9	460	869	1257		71%
	2012-12-05 13:50	1,257.5	1,007.5	263.8	726.5	993.8	743.8	531.0	281.0	780.0	460	869	1257		72%
	2012-12-05 13:55	1,263.3	1,013.3	264.6	728.8	998.7	748.7	534.6	284.6	783.6	460	869	1257		72%
14	2012-12-05 14:00	1,262.8	1,012.8	257.0	708.0	1,005.7	755.7	554.8	304.8	803.8	460	869	1257		70%
	2012-12-05 14:05	1,263.5	1,013.5	250.7	690.5	1,012.8	762.8	573.0	323.0	822.0	460	869	1257		68%
	2012-12-05 14:10	1,258.2	1,008.2	257.9	710.3	1,000.4	750.4	548.0	298.0	797.0	460	869	1257		70%
	2012-12-05 14:15	1,265.4	1,015.4	261.0	718.8	1,004.5	754.5	546.6	296.6	795.6	460	869	1257		71%
	2012-12-05 14:20	1,260.5	1,010.5	262.6	723.4	997.9	747.9	537.1	287.1	786.1	460	869	1257		72%
	2012-12-05 14:25	1,256.5	1,006.5	249.7	687.9	1,006.8	756.8	568.7	318.7	817.7	460	869	1257		68%
	2012-12-05 14:30	1,260.2	1,010.2	248.4	684.3	1,011.8	761.8	575.9	325.9	824.9	460	869	1257		68%
	2012-12-05 14:35	1,255.3	1,005.3	241.1	664.0	1,014.2	764.2	591.3	341.3	840.3	460	869	1257		66%
	2012-12-05 14:40	1,252.6	1,002.6	232.5	640.4	1,020.1	770.1	612.2	362.2	861.2	460	869	1257		64%
	2012-12-05 14:45	1,258.0	1,008.0	224.3	617.9	1,033.7	783.7	640.1	390.1	889.1	460	869	1257		61%
	2012-12-05 14:50	1,256.8	1,006.8	223.4	615.2	1,033.5	783.5	641.6	391.6	890.6	460	869	1257		61%
	2012-12-05 14:55	1,247.7	997.7	227.2	625.8	1,020.5	770.5	621.9	371.9	870.9	460	869	1257		63%
	2012-12-05 15:00	1,256.5	1,006.5	219.8	605.3	1,036.7	786.7	651.1	401.1	900.1	460	869	1257		60%
	2012-12-05 15:05	1,265.8	1,015.8	202.7	558.3	1,063.1	813.1	707.5	457.5	956.5	460	869	1257		55%
	2012-12-05 15:10	1,275.5	1,025.5	195.7	538.9	1,079.8	829.8	736.6	486.6	985.6	460	869	1257		53%
	2012-12-05 15:15	1,263.0	1,013.0	194.1	534.7	1,068.9	818.9	728.3	478.3	977.3	460	869	1257		53%
	2012-12-05 15:20	1,269.7	1,019.7	198.9	547.9	1,070.8	820.8	721.8	471.8	970.8	460	869	1257		54%
	2012-12-05 15:25	1,276.8	1,026.8	195.8	539.2	1,081.0	831.0	737.5	487.5	986.5	460	869	1257		53%
	2012-12-05 15:30	1,300.4	1,050.4	203.2	559.6	1,097.3	847.3	740.9	490.9	989.9	460	869	1257		53%
	2012-12-05 15:35	1,300.5	1,050.5	202.0	556.3	1,098.5	848.5	744.2	494.2	993.2	460	869	1257		53%
	2012-12-05 15:40	1,306.6	1,056.6	209.7	577.7	1,096.9	846.9	728.9	478.9	977.9	460	869	1257		55%
	2012-12-05 15:45	1,312.1	1,062.1	205.6	566.4	1,106.4	856.4	745.7	495.7	994.7	460	869	1257		53%
	2012-12-05 15:50	1,315.4	1,065.4	200.8	553.0	1,114.6	864.6	762.4	512.4	1,011.4	460	869	1257		52%
	2012-12-05 15:55	1,317.6	1,067.6	199.2	548.7	1,118.3	868.3	768.8	518.8	1,017.8	460	869	1257		51%
16	2012-12-05 16:00	1,322.7	1,072.7	204.9	564.3	1,117.8	867.8	758.4	508.4	1,007.4	460	869	1257		53%
	2012-12-05 16:05	1,339.2	1,089.2	190.6	525.0	1,148.6	898.6	814.3	564.3	1,063.3	460	869	1257		48%
	2012-12-05 16:10	1,344.0	1,094.0	185.0	509.5	1,159.0	909.0	834.5	584.5	1,083.5	460	869	1257		47%
	2012-12-05 16:15	1,358.5	1,108.5	182.8	503.6	1,175.7	925.7	854.9	604.9	1,103.9	460	869	1257		45%
	2012-12-05 16:20	1,372.5	1,122.5	174.6	481.0	1,197.9	947.9	891.6	641.6	1,140.6	460	869	1257		43%
	2012-12-05 16:25	1,394.7	1,144.7	167.5	461.2	1,227.3	977.3	933.5	683.5	1,182.5	460	869	1257		40%
	2012-12-05 16:30	1,400.8	1,150.8	168.8	464.9	1,232.1	982.1	935.9	685.9	1,184.9	460	869	1257		40%
	2012-12-05 16:35	1,409.3	1,159.3	163.2	449.7	1,246.1	996.1	959.7	709.7	1,208.7	460	869	1257		39%
	2012-12-05 16:40	1,416.5	1,166.5	161.5	444.7	1,255.1	1,005.1	971.8	721.8	1,220.8	460	869	1257		38%
	2012-12-05 16:45	1,424.7	1,174.7	158.6	436.9	1,266.1	1,016.1	987.8	737.8	1,236.8	460	869	1257		37%
	2012-12-05 16:50	1,436.6	1,186.6	140.9	388.0	1,295.7	1,045.7	1048.6	798.6	1,297.6	460	869	1257		33%
	2012-12-05 16:55	1,442.3	1,192.3	142.0	391.2	1,300.2	1,050.2	1051.1	801.1	1,300.1	460	869	1257		33%
	2012-12-05 17:00	1,447.0	1,197.0	137.4	378.4	1,309.6	1,059.6	1068.5	818.5	1,317.5	460	869	1257		32%
	2012-12-05 17:05	1,449.4	1,199.4	132.5	365.0	1,316.9	1,066.9	1084.4	834.4	1,333.4	460	869	1257		30%
	2012-12-05 17:10	1,453.4	1,203.4	128.8	354.7	1,324.6	1,074.6	1098.7	848.7	1,347.7	460	869	1257		29%
	2012-12-05 17:15	1,460.7	1,210.7	128.0	352.5	1,332.7	1,082.7	1108.2	858.2	1,357.2	460	869	1257		29%
	2012-12-05 17:20	1,458.2	1,208.2	132.9	366.0	1,325.4	1,075.4	1092.3	842.3	1,341.3	460	869	1257		30%
	2012-12-05 17:25	1,463.2	1,213.2	136.5	375.9	1,326.7	1,076.7	1087.3	837.3	1,336.3	460	869	1257		31%
	2012-12-05 17:30	1,456.8	1,206.8	129.7	357.2	1,327.2	1,077.2	1099.6	849.6	1,348.6	460	869	1257		30%
	2012-12-05 17:35	1,455.7	1,205.7	120.6	332.3	1,335.1	1,085.1	1123.4	873.4	1,372.4	460	869	1257		28%
	2012-12-05 17:40	1,455.1	1,205.1	116.0	319.6	1,339.1	1,089.1	1135.6	885.6	1,384.6	460	869	1257		27%
	2012-12-05 17:45	1,455.9	1,205.9	117.5	323.7	1,338.4	1,088.4	1132.2	882.2	1,381.2	460	869	1257		27%
	2012-12-05 17:50	1,453.3	1,203.3	125.3	345.2	1,328.0	1,078.0	1108.1	858.1	1,357.1	460	869	1257		29%
	2012-12-05 17:55	1,452.7	1,202.7	130.5	359.5	1,322.2	1,072.2	1093.2	843.2	1,342.2	460	869	1257		30%
18	2012-12-05 18:00	1,443.2	1,193.2	137.5	378.7	1,305.8	1,055.8	1064.5	814.5	1,313.5	460	869	1257		32%
	2012-12-05 18:05	1,430.6	1,180.6	134.8	371.2	1,295.8	1,045.8	1059.4	809.4	1,308.4	460	869	1257		31%
	2012-12-05 18:10	1,426.6	1,176.6	117.3	323.2	1,309.2	1,059.2	1103.4	853.4	1,352.4	460	869	1257		27%
	2012-12-05 18:15	1,428.8	1,178.8	118.6	326.6	1,310.2	1,060.2	1102.2	852.2	1,351.2	460	869	1257		28%
	2012-12-05 18:20	1,426.1	1,176.1	113.5	312.6	1,312.6	1,062.6	1113.6	863.6	1,362.6	460	869	1257		27%
	2012-12-05 18:25	1,420.5	1,170.5	120.9	333.1	1,299.6	1,049.6	1087.5	837.5	1,336.5	460	869	1257		28%

			Load -250MW			Load net wind (existing)		Load net wind (785)		Load net wind (785) with Reg and Reserv					
		Load	Low Load	Wind 285 Installed	Wind 785 Installed	285 MW	Low Load Net of 285MW	785 MW	Low Load Net of 785MW	Load net wind (785) with Reg and Reserve	Minimum Unit Commitment	Turn up of Minimum Commitment	Turn up with 2 Shift Units		Wind as a Percentage of Load
	2012-12-05 18:30	1,419.1	1,169.1	146.8	404.5	1,272.3	1,022.3	1014.6	764.6	1,263.6	460	869	1257		35%
	2012-12-05 18:35	1,411.0	1,161.0	154.5	425.6	1,256.5	1,006.5	985.4	735.4	1,234.4	460	869	1257		37%
	2012-12-05 18:40	1,414.0	1,164.0	148.1	407.8	1,265.9	1,015.9	1006.2	756.2	1,255.2	460	869	1257		35%
	2012-12-05 18:45	1,411.3	1,161.3	155.3	427.6	1,256.0	1,006.0	983.6	733.6	1,232.6	460	869	1257		37%
	2012-12-05 18:50	1,405.2	1,155.2	160.4	441.8	1,244.8	994.8	963.3	713.3	1,212.3	460	869	1257		38%
	2012-12-05 18:55	1,405.1	1,155.1	155.5	428.4	1,249.5	999.5	976.7	726.7	1,225.7	460	869	1257		37%
	2012-12-05 19:00	1,397.5	1,147.5	159.8	440.1	1,237.7	987.7	957.4	707.4	1,206.4	460	869	1257		38%
	2012-12-05 19:05	1,394.1	1,144.1	159.5	439.3	1,234.6	984.6	954.7	704.7	1,203.7	460	869	1257		38%
	2012-12-05 19:10	1,392.5	1,142.5	162.7	448.1	1,229.8	979.8	944.4	694.4	1,193.4	460	869	1257		39%
	2012-12-05 19:15	1,391.1	1,141.1	160.0	440.8	1,231.1	981.1	950.3	700.3	1,199.3	460	869	1257		39%
	2012-12-05 19:20	1,391.0	1,141.0	166.1	457.6	1,224.8	974.8	933.3	683.3	1,182.3	460	869	1257		40%
	2012-12-05 19:25	1,388.8	1,138.8	162.0	446.2	1,226.8	976.8	942.6	692.6	1,191.6	460	869	1257		39%
	2012-12-05 19:30	1,385.6	1,135.6	166.3	458.0	1,219.3	969.3	927.6	677.6	1,176.6	460	869	1257		40%
	2012-12-05 19:35	1,380.2	1,130.2	167.6	461.7	1,212.6	962.6	918.5	668.5	1,167.5	460	869	1257		41%
	2012-12-05 19:40	1,382.2	1,132.2	163.2	449.4	1,219.0	969.0	932.8	682.8	1,181.8	460	869	1257		40%
	2012-12-05 19:45	1,373.8	1,123.8	160.7	442.7	1,213.1	963.1	931.1	681.1	1,180.1	460	869	1257		39%
	2012-12-05 19:50	1,377.7	1,127.7	159.3	438.7	1,218.4	968.4	939.0	689.0	1,188.0	460	869	1257		39%
	2012-12-05 19:55	1,367.1	1,117.1	161.3	444.3	1,205.8	955.8	922.9	672.9	1,171.9	460	869	1257		40%
20	2012-12-05 20:00	1,365.4	1,115.4	157.7	434.5	1,207.6	957.6	930.9	680.9	1,179.9	460	869	1257		39%
	2012-12-05 20:05	1,355.7	1,105.7	156.2	430.3	1,199.5	949.5	925.4	675.4	1,174.4	460	869	1257		39%
	2012-12-05 20:10	1,360.5	1,110.5	161.6	445.0	1,199.0	949.0	915.5	665.5	1,164.5	460	869	1257		40%
	2012-12-05 20:15	1,353.3	1,103.3	165.7	456.4	1,187.6	937.6	896.9	646.9	1,145.9	460	869	1257		41%
	2012-12-05 20:20	1,350.3	1,100.3	169.8	467.8	1,180.5	930.5	882.6	632.6	1,131.6	460	869	1257		43%
	2012-12-05 20:25	1,351.5	1,101.5	174.8	481.5	1,176.7	926.7	869.9	619.9	1,118.9	460	869	1257		44%
	2012-12-05 20:30	1,343.9	1,093.9	169.9	467.9	1,174.0	924.0	876.0	626.0	1,125.0	460	869	1257		43%
	2012-12-05 20:35	1,342.2	1,092.2	168.2	463.3	1,174.0	924.0	878.9	628.9	1,127.9	460	869	1257		42%
	2012-12-05 20:40	1,342.4	1,092.4	171.9	473.5	1,170.5	920.5	868.9	618.9	1,117.9	460	869	1257		43%
	2012-12-05 20:45	1,339.9	1,089.9	175.9	484.4	1,164.0	914.0	855.4	605.4	1,104.4	460	869	1257		44%
	2012-12-05 20:50	1,333.9	1,083.9	179.6	494.6	1,154.3	904.3	839.3	589.3	1,088.3	460	869	1257		46%
	2012-12-05 20:55	1,329.5	1,079.5	187.5	516.4	1,142.0	892.0	813.0	563.0	1,062.0	460	869	1257		48%
	2012-12-05 21:00	1,318.2	1,068.2	179.2	493.7	1,139.0	889.0	824.5	574.5	1,073.5	460	869	1257		46%
	2012-12-05 21:05	1,302.3	1,052.3	187.4	516.2	1,114.8	864.8	786.0	536.0	1,035.0	460	869	1257		49%
	2012-12-05 21:10	1,303.9	1,053.9	189.5	522.1	1,114.4	864.4	781.9	531.9	1,030.9	460	869	1257		50%
	2012-12-05 21:15	1,291.6	1,041.6	193.3	532.4	1,098.3	848.3	759.1	509.1	1,008.1	460	869	1257		51%
	2012-12-05 21:20	1,284.8	1,034.8	182.6	502.9	1,102.2	852.2	781.8	531.8	1,030.8	460	869	1257		49%
	2012-12-05 21:25	1,277.8	1,027.8	183.6	505.8	1,094.1	844.1	772.0	522.0	1,021.0	460	869	1257		49%
	2012-12-05 21:30	1,272.7	1,022.7	184.1	507.1	1,088.6	838.6	765.6	515.6	1,014.6	460	869	1257		50%
	2012-12-05 21:35	1,261.5	1,011.5	182.4	502.4	1,079.1	829.1	759.2	509.2	1,008.2	460	869	1257		50%
	2012-12-05 21:40	1,254.3	1,004.3	191.9	528.7	1,062.3	812.3	725.6	475.6	974.6	460	869	1257		53%
	2012-12-05 21:45	1,248.3	998.3	201.5	555.1	1,046.7	796.7	693.2	443.2	942.2	460	869	1257		56%
	2012-12-05 21:50	1,243.1	993.1	205.8	566.9	1,037.3	787.3	676.3	426.3	925.3	460	869	1257		57%
	2012-12-05 21:55	1,231.8	981.8	202.4	557.4	1,029.4	779.4	674.4	424.4	923.4	460	869	1257		57%
22	2012-12-05 22:00	1,232.2	982.2	195.8	539.3	1,036.4	786.4	692.9	442.9	941.9	460	869	1257		55%
	2012-12-05 22:05	1,218.4	968.4	201.7	555.4	1,016.8	766.8	663.0	413.0	912.0	460	869	1257		57%
	2012-12-05 22:10	1,212.3	962.3	200.3	551.7	1,012.0	762.0	660.6	410.6	909.6	460	869	1257		57%
	2012-12-05 22:15	1,198.6	948.6	194.2	534.9	1,004.4	754.4	663.7	413.7	912.7	460	869	1257		56%
	2012-12-05 22:20	1,187.9	937.9	199.3	548.9	988.6	738.6	639.0	389.0	888.0	460	869	1257		59%
	2012-12-05 22:25	1,166.9	916.9	195.3	538.0	971.6	721.6	628.9	378.9	877.9	460	869	1257		59%
	2012-12-05 22:30	1,164.3	914.3	200.2	551.4	964.1	714.1	612.9	362.9	861.9	460	869	1257		60%
	2012-12-05 22:35	1,152.4	902.4	197.6	544.2	954.9	704.9	608.2	358.2	857.2	460	869	1257		60%
	2012-12-05 22:40	1,143.6	893.6	201.2	554.3	942.4	692.4	589.4	339.4	838.4	460	869	1257		62%
	2012-12-05 22:45	1,137.3	887.3	207.0	570.2	930.2	680.2	567.0	317.0	816.0	460	869	1257		64%
	2012-12-05 22:50	1,123.7	873.7	198.0	545.3	925.7	675.7	578.3	328.3	827.3	460	869	1257		62%
	2012-12-05 22:55	1,119.4	869.4	197.8	544.8	921.6	671.6	574.7	324.7	823.7	460	869	1257		63%
	2012-12-05 23:00	1,113.2	863.2	205.0	564.5	908.3	658.3	548.7	298.7	797.7	460	869	1257		65%
	2012-12-05 23:05	1,124.8	874.8	211.4	582.4	913.4	663.4	542.4	292.4	791.4	460	869	1257		67%
	2012-12-05 23:10	1,127.1	877.1	205.0	564.6	922.1	672.1	562.5	312.5	811.5	460	869	1257		64%
	2012-12-05 23:15	1,108.4	858.4	206.6	569.0	901.8	651.8	539.3	289.3	788.3	460	869	1257		66%
	2012-12-05 23:20	1,104.4	854.4	204.4	563.1	900.0	650.0	541.3	291.3	790.3	460	869	1257		66%
	2012-12-05 23:25	1,090.9	840.9	199.6	549.9	891.3	641.3	541.1	291.1	790.1	460	869	1257		65%
	2012-12-05 23:30	1,091.7	841.7	199.7	550.1	891.9	641.9	541.5	291.5	790.5	460	869	1257		65%
	2012-12-05 23:35	1,075.9	825.9	202.6	558.1	873.3	623.3	517.9	267.9	766.9	460	869	1257		68%
	2012-12-05 23:40	1,066.1	816.1	209.7	577.5	856.5	606.5	488.6	238.6	737.6	460	869	1257		71%
	2012-12-05 23:45	1,060.7	810.7	220.7	607.8	840.1	590.1	453.0	203.0	702.0	460	869	1257		75%
	2012-12-05 23:50	1,052.1	802.1	219.5	604.7	832.6	582.6	447.4	197.4	696.4	460	869	1257		75%
	2012-12-05 23:55	1,050.5	800.5	216.0	595.0	834.5	584.5	455.5	205.5	704.5	460	869	1257		74%
0	2012-12-06 00:00	1,045.0	795.0	217.2	598.4	827.8	577.8	446.7	196.7	695.7	460	869	1257		75%


Light Load net 785 MW wind
1.2
1
0.8
0.6
0.4
0.2
0
#REF!
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#REF!

Wind Range (Installed Capacity)	785			
System typical daily Max/Min Delta	580			
Regulating Reserve	25			
Operating Reserves	224			
Total Capacity Range (Net System Min+Delta+Reserves)	1614			
Minimum Units Committed+MR & Reg	5	6	7	8
Min Unit Commitment	460	520	580	640
Turn-up capability of Min Commitment	409	499	590	680
Two Shift Capability (TC2, TC3, TC4,5,6)	388	388	388	388
GT's for reserve	210	210	210	210
Available turn-up plus GT's	1007	1097	1188	1278
Remaining for Hydro, Wind or Imports	607	517	426	336

Request IR-228:

With reference to Appendix 6.02, page 37, and Appendix 6.06, pages 1 and 4:

(a) **Please confirm that the 50 MW simple cycle combustion turbines added in 2019 as shown on pages 1 and 4 of Appendix 6.06 are the only gas fired units that were added to resolve operating problems ascribable to intermittent generation.**

(b) **Was the capital cost for the 50 MW simple cycle combustion turbines added in 2019 included in the "Capital investment for wind integration" or is otherwise included as an investment in addition to the "Capital investment for wind integration."?**

Response IR-228:

(a) The simple cycle turbine added in 2019 was to provide the capacity necessary to allow for the retirement of Lingan 1 in that year. Once built it is recognized that it would countribute to addressing wind integration dispatch challenges.

(b) Fast acting generation is included in the estimates of capital cost to support wind integration in Appendix 6.02.

When the capital costs for wind integration were developed for the alternative modeling, as presented in Appendix 6.06, it was recognized that gas generation that was added for purposes other than wind integration could and would also serve those purposes. Accordingly when capitals costs for wind integration were incorporated into the modeling, the fast acting generation costs were removed so as to not double count these additions in the wind alternatives.

Request IR-229:

With reference to Appendix 6.02, page 40-41, please provide copies of all documents listed in Appendix A: Bibliography.

Response IR-229:

Please note that all of the references cited in Appendix A: Bibliography include web links to the original documents with four exceptions; links to these four publications are provided below.

GE Energy. "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements." 2008. http://www.uwig.org/AttchB-ERCOT_A-S_Study_Final_Report.pdf (accessed March 7, 2013).

Goransson, Lisa, and Filip Johnsson. "Large Scale Integration of Wind Power in Thermal Power Systems." Edited by S M Muyeen. 2010. http://cdn.intechweb.org/pdfs/9572.pdf (accessed March 7, 2013).

New York Independent System Operator. "Growing Wind - Final Report of the NYISO 2010 Wind Generation Study." 2010. http://www.nyiso.com/public/webdocs/media_room/press_releases/2010/Child_New_York_Grid_Ready_for_More_Wind_093010/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf (accessed March 7, 2013).

Niamh, Troy, Denny Eleanor, and Mark O'Malley. "Evaluating which forms of flexibility most effectively reduce base-load cycling at large wind Penetrations." October 2009. http://researchrepository.ucd.ie/bitstream/handle/10197/3278/Troy%2cN.%20O%27Malley%2cM.%20Denny%2cE%20Evaluating%20which%20forms%20of%20flexibility%20most%20effectively%20reduce%20base%20load%20cycling.pdf (accessed March 7, 2013).

NON-CONFIDENTIAL

Request IR-230:

With reference to Appendix 6.03, page 2:

(a) Is the "database model" developed by NSPI a Strategist database?

(b) If yes, what aspects of database model development did Ventyx have sole or partial responsibility for?

(c) If no, how does this "database model" differ from the database used by Ventyx?

Response IR-230:

(a-c) The “database model” refers to the input assumptions that were developed by NSPML and NS Power for use in the Strategist model.

NON-CONFIDENTIAL

Request IR-231:

With reference to Appendix 6.03, page 3, "Study years 2015 to 2040":

(a) Did the Strategist Planning Period cover calendar years 2015 to 2040?

(b) If yes, please reconcile with the statement in the Application that the Strategist Planning Period is 25 years.

(c) If no, please provide the start and end dates (mm/dd/yyyy) of the Study years.

(d) What was the end date (mm/dd/yyyy) of the Strategist Study Period (described in the Application as 35 years)?

Response IR-231:

(a) Yes.

(b-c) The planning period is the base year plus 25 years.

(d) Please refer to SBA IR-30 (b).

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Request IR-232:

With reference to Appendix 6.03, page 3, please provide the basis for assuming continued reductions in air emissions limits.

Response IR-232:

Discussions with federal and provincial governments have provided clear indication that emission limits would continue to reduce beyond 2020. The 2012 federal carbon dioxide emissions regulation is the first example of regulatory certainty for these reductions post 2020. In addition, NS Power has participated for the last year in a multistakeholder initiative led by the federal and provincial governments examining the appropriate steps to take for future air quality protection including the identification of stack-specific emission limits. Within the range of limits under consideration, NS Power included the most likely as assumptions for the modeling.

Request IR-233:

With reference to Appendix 6.03, page 3, please explain why high and low power and gas price sensitivity cases were not run against the low load forecast case.

Response IR-233:

It is not practical to include every sensitivity on every scenario in robustness testing. Robustness sensitivities showed that varying load did not change the preferred option and varying prices did not change the preferred option.

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Request IR-234:

With reference to Appendix 6.03, page 6, please provide an Excel file table that extends the annual load forecast values to include all the years used by Strategist for its Study Period.

Response IR-234:

Please refer to SBA IR-30 (b).

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Request IR-235:

With reference to Appendix 6.03, pages 8-9:

(a) Please explain what this chart and table represent.

(b) Please provide all work papers, models, and analyses that were used to prepare the chart and table.

(c) Do the chart and table on these pages represent the Base Load or Low Load Case?

(d) Explain why each constituent – CO_2, NOx, SO_2, and Hg – declines in a stepwise period over the study period.

(e) What are the reductions beyond 2020 attributable to?

Response IR-235:

(a) The graphs on page 8 are a visual representation of the data presented on page 9. The carbon dioxide numbers are based on federal/provincial equivalency agreement limits up to 2030 and then declining to 2040. Up to 2020, the sulphur dioxide, carbon dioxide and mercury limits are based on the Environment Act. Beyond 2020 sulphur dioxide and nitrogen oxide numbers are based on provincial indications of future emission reductions and the small reduction in mercury emissions acknowledges the practical limitations of reducing that pollutant.

(b) The Table on page 9 provides the numerical basis for the graphs.

(c) These limits apply to both the Base Load and Low load cases.

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(d) The Carbon Dioxide levels up to 2020 are based on the limits in the provincial regulations for GHGs, while the 2020-2030 numbers are based on the proposed limits in the draft equivalency agreement. The sulphur dioxide and nitrogen dioxide numbers are based on the milestone limits proposed by NSE for 2025 and 2030. The steps follow the form of the existing provincial air quality regulations. The mercury uses a similar approach after 2020.

(e) As a result of discussions between the federal and provincial governments, Nova Scotia Environment has identified draft potential targets for the designated emissions for the 2020-2030 period. Those have been communicated to NS Power and NS Power has therefore used them in this analysis.

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Request IR-236:

With reference to Appendix 6.03, page 9, please provide the assumptions that extend the annual emission limit values in the table to include all the years used by Strategist for its Study Period.

Response IR-236:

The annual emission limits in the end effects period are based on the limits in 2040 and are assumed to be held constant each year beyond 2040. Please refer to SBA IR-30 for the length of the study period.

NON-CONFIDENTIAL

Request IR-237:

With reference to Appendix 6.03, page 10, please explain the method for determining how the capacity contribution of wind generation affects planning reserve margin. Provide all work papers and reports that provide calculation details.

Response IR-237:

NS Power has assumed a 20 percent capacity value assignment for NRIS wind projects. The use of this capacity value is reflected in the load and resource tables provided in SBA IR-243 Attachment 2.

Request IR-238:

With respect to Appendix 6.03, pages 10-11:

(a) Define "REA Contribution"

(b) Explain what is meant by the statement "capacity contribution affects planning reserve margin calculations which influences unit retirement decisions."

(c) Provide all analyses, calculations, models, spreadsheets, and work papers that relate to the unit retirement decisions referenced in part (b) above.

(d) Explain how the renewable electricity resources assumed in this analysis comply with the requirements of the Renewable Electricity Regulations made under Section 5 of the Electricity Act to supply a minimum percentage of renewable energy from independent power producers.

Response IR-238:

(a) "REA Contribution" refers to the contribution from the recent Renewable Electricity Administrator Request for Proposal (RFP) award.

(b) NS Power maintains a minimum planning reserve margin of 20 percent above firm system peak (that is total firm capacity is at least 1.2 times firm system peak). The assumed firm capacity contribution of existing and future wind projects are included in the total firm capacity. If the assumed contribution from wind increases or decreases the firm system capacity increases or decreases. This would be a factor in determining the timing of unit retirements.

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(c) Please refer to Synapse IR-12 and NSUARB IR-100 and SBA IR-243 Attachment 2.

(d) The Renewable Electricity Regulations require that in 2020, 40 percent of electricity supplied is to come from renewable sources, with at least 5 percent of total annual sales to continue to come from IPPs, PLUS the additional 300 GWh that must come from IPPs (REA Contribution), and 20 percent to come from Muskrat Falls if in operation and approved under the Martime Link Act. NS Power will comply with these regulations.

NON-CONFIDENTIAL

Request IR-239:

With reference to Appendix 6.03, page 12, are the differences in Lingan 1 retirement dates across the alternative resource plans Strategist input assumptions, or the output of Strategist optimization?

Response IR-239:

Lingan 1 unit retirement dates are input assumptions based on assuming two unit retirements by 2020 in each of the three Alternatives.

NON-CONFIDENTIAL

Request IR-240:

With reference to Appendix 6.03, page 12, please provide the confidential net average heat rates from the July 2012 GRA-Refresh for each of the thermal units and combustion turbine units.

Response IR-240:

Please refer to CA IR-10.

NON-CONFIDENTIAL

Request IR-241:

With reference to Appendix 6.03, page 13, please provide the corresponding assumptions for Strategist modeling of the Other Imports and Indigenous Wind alternatives:

(a) Lingan 3 must-run assumptions

(b) Forced gas burn during Dec-Jan-Feb each year

(c) Lingan 1 and 2 seasonal shutdown between March 1 and November 30

Response IR-241:

(a-c) These assumptions were common to the three alternatives.

NON-CONFIDENTIAL

Request IR-242:

With reference to Appendix 6.03, page 13:

(a) Why is Tufts Cove 1 unavailable for two shifting?

(b) Are the coal units available for cycling between normal minimum load and maximum capacity? If yes, how did Strategist model this operational flexibility?

Response IR-242:

(a) Tufts Cove unit 1 was originally a coal fired station built in 1965. The configuration of the boiler and the turbine is not a flexible design and will not tolerate the heating and cooling cycle that a two shift unit needs to endure.

(b) Yes, Strategist has the individual unit characteristics modeled, including the minimum and maximum loads for the units. This is used in the economic dispatch algorithm to develop the lowest dispatch costs.

NON-CONFIDENTIAL

Request IR-243:

With reference to Appendix 6.03, page 14, base load forecast comparison:

(a) Provide an annual peak load and resources balance table (with all units and transactions as separate rows) for the years 2015 to 2040 for each of the three alternatives. Provide as an Excel file with all formulae and cell references intact.

(b) Provide a monthly energy and energy supply balance table for the 7x16 and 7x8 daily periods (with all units, transactions, and imports/exports as separate rows) for the years 2015 to 2040 for each of the three alternatives. Provide as an Excel file with all formulae and cell references intact.

Response IR-243:

(a) Please refer to Attachments 1 and 2.

(b) Please refer to Attachment 3.

The data is provided in the format used by NS Power. Further analysis is required in order to provide data in the format requested. This analysis has not been completed.

Firm Capacity
Existing Resources (MW)

PT ACONI 1	171
LINGAN 1	153
LINGAN 2	153
LINGAN 3	153
LINGAN 4	153
TUPPER 2	152
TRENTON 5	150
TRENTON 6	157
Tufts Cove 1	81
Tufts Cove 2	93
Tufts Cove 3	147
Tufts Cove 6	147
TUSKET 1	24
Victoria Junction 1	33
Victoria Junction 2	33
BURNSIDE 1	33
BURNSIDE 2	33
BURNSIDE 3	33
BURNSIDE 4	0
Total Thermal	**1899**

WRECKCOVE	210
ANNAPLIS	4
AVON	7
BLACK	23
NICTAUX	8
LEQUILLE	11
PARADISE	5
MERSEY	43
SISSIBOO	24
BEAR	13
TUSKET	2
ROSEWAY	2
MARGRETS	11
SHEETHBR	11
DICKIEBR	4
FALLRIVR	1
Total Hydro	**377**

Firm Capacity
Existing Resources (MW)

NSP-WIND	6
PHBM	0
Pubnico	6
Lingan	3
Glace Bay 1B	0
Donkin (Glace Bay Power)	0
Gillis Cove	0
Tiverton	0
Springhill	0
Higgins Mountain	1
Goodwood	0
Brookfield	0
Fitzpatrick Mountain	0
Point Tupper 1	0
Digby	0
Tatamagouche	0
Amherst	6
Dalhousie Mountain	0
Glen Dhu North	0
Maryvale	1
Point Tupper 3	4
Watts Section	0
Fairmont	1
Dunvegan	0
Granville Ferry	0
Isle Madame	0
Creignish rear	0
Irish Mountain	0
South Cape Mabou	0
Spiddle Hill	0
Cape North	0
Donkin	0
Halifax Landfill	2
Black River Hydro	0
Brooklyn Power	24
Morgan falls Company	1
Taylor Lumber Company	1
Small Biomass	0
COMFIT	3
Total IPP and NSP Wind	**64**
Existing Resources	**2340**

Maritime Link Project - Low Load
Load and Resources Table (All values in MW except as noted)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Firm Peak	1885	1877	1870	1860	1857	1849	1840	1827	1817	1803	1788	1775	1761
Required Reserve	377	375	374	372	371	370	368	365	363	361	358	355	352
Required Capacity	2262	2252	2245	2232	2228	2218	2208	2193	2180	2164	2146	2130	2113
Existing Resources	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340
Resource Additions:													
Burnside #4		33											
Community Feed-in-Tariff	3	3	5	5									
REA Wind	23												
Maritime Link Project				153									
Biomass		55				8							
Incremental Wind													
Assumed Unit Retirement		-153		-153		-81							
Natural Gas Unit													
Total Annual Additions	27	-62	5	5	0	-73	0	0	0	0	0	0	0
Total Cumulative Additions	27	-35	-30	-25	-25	-98	-98	-98	-98	-98	-98	-98	-98
Total Firm Capacity	2367	2305	2310	2315	2315	2242	2242	2242	2242	2242	2242	2242	2242
Surplus (Deficit)	105	53	65	83	87	24	35	49	62	78	96	113	129
Reserve Margin %	26%	23%	23%	24%	25%	21%	22%	23%	23%	24%	25%	26%	27%

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Firm Peak	1746	1734	1722	1711	1698	1698	1698	1698	1698	1698	1698	1698	1698
Required Reserve	349	347	344	342	340	340	340	340	340	340	340	340	340
Required Capacity	2095	2080	2067	2053	2038	2038	2038	2038	2038	2038	2038	2038	2038
Existing Resources	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340
Resource Additions:													
Burnside #4													
Community Feed-in-Tariff													
REA Wind													
Maritime Link Project													
Biomass													
Incremental Wind													
Assumed Unit Retirement		-153											
Natural Gas Unit													
Total Annual Additions	0	-153	0	0	0	0	0	0	0	0	0	0	0
Total Cumulative Additions	-98	-251	-251	-251	-251	-251	-251	-251	-251	-251	-251	-251	-251
Total Firm Capacity	2242	2089	2089	2089	2089	2089	2089	2089	2089	2089	2089	2089	2089
Surplus (Deficit)	147	9	22	36	51	51	51	51	51	51	51	51	51
Reserve Margin %	28%	21%	21%	22%	23%	23%	23%	23%	23%	23%	23%	23%	23%

Other Import Alternative - Low Load
Load and Resources Table (All values in MW except as noted)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Firm Peak	1885	1877	1870	1860	1857	1849	1840	1827	1817	1803	1788	1775	1761	1746	1734	1722	1711	1698	1698	1698	1698	1698	1698	1698	1698	1698
Required Reserve	377	375	374	372	371	370	368	365	363	361	358	355	352	349	347	344	342	340	340	340	340	340	340	340	340	340
Required Capacity	2262	2252	2245	2232	2228	2218	2208	2193	2180	2164	2146	2130	2113	2095	2080	2067	2053	2038	2038	2038	2038	2038	2038	2038	2038	2038
Existing Resources	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340
Resource Additions:																										
Burnside #4		33																								
Community Feed-in-Tariff	3	3	5	5																						
REA Wind	23																									
Other Import				160																						
Biomass		55				8																				
Incremental Wind																										
Assumed Unit Retirement		-153		-153		-81									-153											
Natural Gas Unit																										
Total Annual Additions	27	-62	5	12	0	-73	0	0	0	0	0	0	0	0	-153	0	0	0	0	0	0	0	0	0	0	0
Total Cumulative Additions	27	-35	-30	-19	-19	-92	-92	-92	-92	-92	-92	-92	-92	-92	-245	-245	-245	-245	-245	-245	-245	-245	-245	-245	-245	-245
Total Firm Capacity	2367	2305	2310	2321	2321	2248	2248	2248	2248	2248	2248	2248	2248	2248	2095	2095	2095	2095	2095	2095	2095	2095	2095	2095	2095	2095
Surplus (Deficit)	105	53	65	89	93	30	41	56	68	84	102	119	135	153	15	29	42	57	57	57	57	57	57	57	57	57
Reserve Margin %	26%	23%	23%	25%	25%	22%	22%	23%	24%	25%	26%	27%	28%	29%	21%	22%	22%	23%	23%	23%	23%	23%	23%	23%	23%	23%

Indigenous Wind Alternative Low Load
Load and Resources Table (All values in MW except as noted)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Firm Peak	1885	1877	1870	1860	1857	1849	1840	1827	1817	1803	1788	1775	1761	1746	1734	1722	1711	1698	1698	1698	1698	1698	1698	1698	1698	1698
Required Reserve	377	375	374	372	371	370	368	365	363	361	358	355	352	349	347	344	342	340	340	340	340	340	340	340	340	340
Required Capacity	2262	2252	2245	2232	2228	2218	2208	2193	2180	2164	2146	2130	2113	2095	2080	2067	2053	2038	2038	2038	2038	2038	2038	2038	2038	2038
Existing Resources	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340
Resource Additions:																										
Burnside #4		33																								
Community Feed-in-Tariff	3	3	5	5																						
REA Wind	23																									
Biomass		55				8																				
Incremental Wind					50																					
Assumed Unit Retirement		-153			-153																					
Natural Gas Unit					49											250					250					
Total Annual Additions	27	-62	5	5	-54	8	0	0	0	0	0	0	0	0	0	250	0	0	0	0	250	0	0	0	0	0
Total Cumulative Additions	27	-35	-30	-25	-79	-71	-71	-71	-71	-71	-71	-71	-71	-71	-71	179	179	179	179	179	429	429	429	429	429	429
Total Firm Capacity	2367	2305	2310	2315	2261	2269	2269	2269	2269	2269	2269	2269	2269	2269	2269	2519	2519	2519	2519	2519	2769	2769	2769	2769	2769	2769
Surplus (Deficit)	105	53	65	82	33	50	61	76	88	105	123	139	156	173	188	452	466	481	481	481	731	731	731	731	731	731
Reserve Margin %	26%	23%	23%	24%	22%	23%	23%	24%	25%	26%	27%	28%	29%	30%	31%	46%	47%	48%	48%	48%	63%	63%	63%	63%	63%	63%

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Maritime Link Project - Base Load
Load and Resources Table (All values in MW except as noted)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Firm Peak	1891	1890	1892	1888	1890	1889	1890	1891	1895	1897	1898	1901	1904	1906	1911	1917	1924	1930	1948	1968	1987	2007	2028	2048	2069	2090
Required Reserve	378	378	378	378	378	378	378	378	379	379	380	380	381	381	382	383	385	386	390	394	397	401	406	410	414	418
Required Capacity	2270	2268	2270	2266	2268	2267	2267	2269	2274	2276	2278	2281	2285	2288	2293	2301	2308	2315	2338	2361	2385	2409	2433	2458	2483	2508
Existing Resources	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340
Resource Additions:																										
Burnside #4		33																								
Community Feed-in-Tariff	3	3	5	5																						
REA Wind	23																									
Maritime Link Project				153																						
Biomass		55																								
Incremental Wind																										
Assumed Unit Retirement		-153		-153												-153					-153					
Natural Gas Unit																250					250					
Total Annual Additions	27	-62	5	5	0	0	0	0	0	0	0	0	0	0	0	97	0	0	0	0	97	0	0	0	0	0
Total Cumulative Additions	27	-35	-30	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	72	72	72	72	72	169	169	169	169	169	169
Total Firm Capacity	2367	2305	2310	2315	2315	2315	2315	2315	2315	2315	2315	2315	2315	2315	2315	2412	2412	2412	2412	2412	2509	2509	2509	2509	2509	2509
Surplus (Deficit)	97	36	40	49	47	48	48	46	41	39	37	34	30	27	22	111	104	97	74	51	124	100	76	51	27	1
Reserve Margin %	25%	22%	22%	23%	22%	23%	23%	22%	22%	22%	22%	22%	22%	21%	21%	26%	25%	25%	24%	23%	26%	25%	24%	23%	21%	20%

Other Import Alternative - Base Load
Load and Resources Table (All values in MW except as noted)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Firm Peak	1891	1890	1892	1888	1890	1889	1890	1891	1895	1897	1898	1901	1904	1906	1911	1917	1924	1930	1948	1968	1987	2007	2028	2048	2069	2090
Required Reserve	378	378	378	378	378	378	378	378	379	379	380	380	381	381	382	383	385	386	390	394	397	401	406	410	414	418
Required Capacity	2270	2268	2270	2266	2268	2267	2267	2269	2274	2276	2278	2281	2285	2288	2293	2301	2308	2315	2338	2361	2385	2409	2433	2458	2483	2508
Existing Resources	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340
Resource Additions:																										
Burnside #4		33																								
Community Feed-in-Tariff	3	3	5	5																						
REA Wind	23																									
Other Import				160																						
Biomass		55																								
Incremental Wind																										
Assumed Unit Retirement		-153		-153															-153							
Natural Gas Unit															49	49			250							
Total Annual Additions	27	-62	5	12	0	0	0	0	0	0	0	0	0	0	49	49	0	0	97	0	0	0	0	0	0	0
Total Cumulative Additions	27	-35	-30	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	30	79	79	79	176	176	176	176	176	176	176	176
Total Firm Capacity	2367	2305	2310	2321	2321	2321	2321	2321	2321	2321	2321	2321	2321	2321	2370	2419	2419	2419	2516	2516	2516	2516	2516	2516	2516	2516
Surplus (Deficit)	97	36	40	55	53	55	54	52	47	45	43	40	36	34	77	119	111	104	178	155	132	108	83	59	34	8
Reserve Margin %	25%	22%	22%	23%	23%	23%	23%	23%	22%	22%	22%	22%	22%	22%	24%	26%	26%	25%	29%	28%	27%	25%	24%	23%	22%	20%

Indigenous Wind Alternative - Base Load
Load and Resources Table (All values in MW except as noted)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Firm Peak	1891	1890	1892	1888	1890	1889	1890	1891	1895	1897	1898	1901	1904	1906	1911	1917	1924	1930	1948	1968	1987	2007	2028	2048	2069	2090
Required Reserve	378	378	378	378	378	378	378	378	379	379	380	380	381	381	382	383	385	386	390	394	397	401	406	410	414	418
Required Capacity	2270	2268	2270	2266	2268	2267	2267	2269	2274	2276	2278	2281	2285	2288	2293	2301	2308	2315	2338	2361	2385	2409	2433	2458	2483	2508
Existing Resources	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340	2340
Resource Additions:																										
Burnside #4		33																								
Community Feed-in-Tariff	3	3	5	5																						
REA Wind	23																									
Biomass		55																								
Incremental Wind					85									10						10						
Assumed Unit Retirement		-153			-153							-153				-153					-152					
Natural Gas Unit					49							250				147					250					
Total Annual Additions	27	-62	5	5	-19	0	0	0	0	0	0	97	0	10	0	-6	0	0	0	10	98	0	0	0	0	0
Total Cumulative Additions	27	-35	-30	-25	-44	-44	-44	-44	-44	-44	-44	53	53	63	63	57	57	57	57	67	165	165	165	165	165	165
Total Firm Capacity	2367	2305	2310	2315	2296	2296	2296	2296	2296	2296	2296	2393	2393	2403	2403	2397	2397	2397	2397	2407	2505	2505	2505	2505	2505	2505
Surplus (Deficit)	97	36	40	49	28	29	28	27	22	19	18	112	108	115	109	96	88	81	59	45	120	96	72	47	22	(3)
Reserve Margin %	25%	22%	22%	23%	21%	22%	21%	21%	21%	21%	21%	26%	26%	26%	26%	25%	25%	24%	23%	22%	26%	25%	24%	22%	21%	20%

Energy by resource type [GWh]

Maritime Link Base Load

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Coal, Petcoke, Oil	6471	6748	5782	4391	4407	4411	4411	4481	4493	4490	4447	4463	4466	4485	4420	3606	3767	3625	3399	3231	2804	2754	2541	2279	2028	1825
Natural Gas	1522	1160	741	397	396	396	389	391	391	393	389	387	387	392	389	1258	1122	1281	1542	1748	2371	2445	2762	3123	3417	3695
Renewables (NSPI Owned and IPPs)	2959	3041	3112	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192
Maritime Link (Base Block and Supplemental)	0	0	323	1135	1135	1139	1135	1038	895	897	895	895	895	897	895	895	895	897	895	895	895	897	895	895	895	897
Imports *	0	0	1001	1834	1829	1812	1836	1876	2037	2049	2122	2131	2156	2149	2259	2248	2268	2286	2364	2433	2346	2426	2444	2457	2530	2565
	10,952	**10,949**	**10,959**	**10,944**	**10,954**	**10,950**	**10,958**	**10,972**	**11,002**	**11,022**	**11,039**	**11,064**	**11,091**	**11,114**	**11,150**	**11,193**	**11,239**	**11,281**	**11,386**	**11,494**	**11,603**	**11,714**	**11,828**	**11,941**	**12,057**	**12,174**

* Imports over the NS-NB Tieline and surplus energy from Maritime Link

Energy by resource type [GWh]
Other Import Base Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal, Petcoke, Oil	6471	6748	5609	3901	3947	3940	3921	3962	3952	3965	3935	3930	3952	3968	3959	3783	3803	3772	3080	2517	2273	2331	2464	2548	2452	2329
Natural Gas	1522	1160	761	393	394	394	387	387	385	389	387	386	385	389	389	387	389	394	1121	1701	1957	1981	1970	1983	2177	2341
Renewables (NSPI Owned and IPPs)	2959	3041	3112	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192
Other Import (Contract Energy)	0	0	235	932	932	934	932	932	932	934	932	932	932	934	932	932	932	934	932	932	932	934	932	932	932	934
Imports *	0	0	1241	2532	2494	2490	2531	2505	2546	2541	2599	2629	2636	2632	2684	2905	2928	2989	3067	3158	3255	3276	3276	3291	3310	3379
	10,952	**10,949**	**10,959**	**10,944**	**10,954**	**10,950**	**10,958**	**10,972**	**11,002**	**11,022**	**11,039**	**11,064**	**11,091**	**11,114**	**11,150**	**11,193**	**11,239**	**11,281**	**11,386**	**11,494**	**11,603**	**11,714**	**11,828**	**11,941**	**12,057**	**12,174**

* Imports over the upgraded NS-NB Tieline

Energy by resource type [GWh]

Incremental Wind																										
Wind 425MW (repowered)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1303	1308
Wind 50 MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	140	140	140	141
Wind 50 MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	140	140	141	140	140	140	141
Wind 50 MW	0	0	0	0	0	0	0	0	0	0	0	0	0	141	140	140	140	141	140	140	140	141	140	140	140	141
Wind 425MW	0	0	0	0	1303	1308	1303	1303	1303	1308	1303	1303	1303	1308	1303	1303	1303	1308	1303	1303	1303	1308	1303	1303	0	0
	0	**0**	**0**	**0**	**1,303**	**1,308**	**1,303**	**1,303**	**1,303**	**1,308**	**1,303**	**1,303**	**1,303**	**1,449**	**1,443**	**1,443**	**1,443**	**1,449**	**1,443**	**1,583**	**1,583**	**1,589**	**1,724**	**1,724**	**1,724**	**1,730**
Total Renewables (incl new wind)	1974	2056	2126	2201	3504	3514	3504	3504	3504	3514	3504	3504	3504	3655	3644	3644	3644	3655	3644	3785	3785	3796	3925	3925	3925	3936

Wind Base Load

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Coal, Petcoke, Oil	6471	6748	6306	6258	5872	5849	5935	5946	5960	5780	5150	4829	4360	3974	3471	2887	2541	2252	1966	1786	1736	1488	1331	929	674	280
Natural Gas	1522	1160	816	756	684	705	612	610	616	762	1403	1815	2247	2506	3053	3680	4071	4391	4793	4941	5103	5450	5591	6106	6476	6976
Renewables (NSPI Owned and IPPs)	2959	3041	3112	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192	3187	3187	3187	3192
Incremental Wind	0	0	0	0	1303	1308	1303	1303	1303	1308	1303	1303	1303	1449	1443	1443	1443	1449	1443	1583	1583	1589	1724	1724	1724	1730
Imports *	0	0	725	744	-92	-104	-79	-74	-63	-20	-4	-70	-7	-5	-3	-3	-3	-3	-3	-3	-6	-4	-5	-4	-3	-3
	10,952	**10,949**	**10,959**	**10,944**	**10,954**	**10,950**	**10,958**	**10,972**	**11,002**	**11,022**	**11,039**	**11,064**	**11,091**	**11,114**	**11,150**	**11,193**	**11,239**	**11,281**	**11,386**	**11,494**	**11,603**	**11,714**	**11,828**	**11,941**	**12,057**	**12,174**

* Exports over the NS-NB Tieline.

Energy by resource type [GWh]

Maritime Link Low Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal, Petcoke, Oil	6463	6778	5781	4354	4344	3502	3457	3484	3527	3361	3276	3231	3181	3138	2986	2919	2890	2865	2838	2826	2795	2797	2787	2788	2788	2787
Natural Gas	1500	1064	716	398	398	388	383	382	384	388	384	383	383	387	385	385	384	389	384	385	385	389	385	385	385	389
Renewables (NSPI Owned and IPPs)	2959	3041	3112	3187	3187	3253	3248	3248	3248	3253	3248	3248	3248	3253	3248	3248	3248	3253	3248	3248	3248	3253	3248	3248	3248	3253
Maritime Link (Base Block and Supplemental)	0	0	323	1135	1135	1139	1135	1038	895	897	895	895	895	897	895	895	895	897	895	895	895	897	895	895	895	897
Imports *	0	0	922	1728	1718	1323	1337	1347	1394	1481	1503	1481	1463	1421	1520	1530	1504	1456	1494	1505	1537	1523	1544	1544	1544	1533
	10,922	**10,883**	**10,852**	**10,802**	**10,783**	**9,605**	**9,560**	**9,499**	**9,448**	**9,380**	**9,306**	**9,237**	**9,169**	**9,096**	**9,034**	**8,977**	**8,920**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**

* Imports over the NS-NB Tieline and surplus energy from Maritime Link

Energy by resource type [GWh]

Other Import Low Load

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Coal, Petcoke, Oil	6463	6778	5613	3915	3840	3275	3243	3295	3169	3072	2950	2933	2910	2892	2748	2649	2598	2606	2561	2577	2533	2456	2490	2528	2514	2522
Natural Gas	1500	1064	677	394	394	387	382	382	382	386	382	382	382	386	383	383	383	387	383	383	383	387	383	383	383	387
Renewables (NSPI Owned and IPPs)	2959	3041	3112	3187	3187	3253	3248	3248	3248	3253	3248	3248	3248	3253	3248	3248	3248	3253	3248	3248	3248	3253	3248	3248	3248	3253
Other Import (Contract Energy)	0	0	235	932	932	934	932	932	932	934	932	932	932	934	932	932	932	934	932	932	932	934	932	932	932	934
Imports *	0	0	1216	2375	2431	1756	1756	1643	1717	1735	1794	1743	1698	1632	1723	1765	1760	1679	1735	1720	1765	1829	1807	1769	1783	1764
	10,922	**10,883**	**10,852**	**10,802**	**10,783**	**9,605**	**9,560**	**9,499**	**9,448**	**9,380**	**9,306**	**9,237**	**9,169**	**9,096**	**9,034**	**8,977**	**8,920**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**

* Imports over the upgraded NS-NB Tieline

Energy by resource type [GWh]

Incremental Wind

	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 250MW (repowered)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	657	659
Wind 250MW	0	0	0	0	657	659	657	657	657	659	657	657	657	659	657	657	657	659	657	657	657	659	657	657	0	0
	0	**0**	**0**	**0**	**657**	**659**	**657**	**657**	**657**	**659**	**657**	**657**	**657**	**659**	**657**	**657**	**657**	**659**	**657**	**657**	**657**	**659**	**657**	**657**	**657**	**659**
Total Renewables (incl new wind)	1974	2056	2126	2201	2858	2927	2919	2919	2919	2927	2919	2919	2919	2927	2919	2919	2919	2927	2919	2919	2919	2927	2919	2919	2919	2927

Wind Low Load

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Coal, Petcoke, Oil	6463	6778	6310	6274	6205	5345	5383	5343	5295	5238	5165	5108	5055	4692	4280	3628	3207	3431	3061	3172	2792	2642	2501	2368	2186	2086
Natural Gas	1500	1064	799	631	777	508	461	454	446	445	434	425	422	521	852	1729	1924	1747	1999	1909	2553	2709	2838	2960	3103	3138
Renewables (NSPI Owned and IPPs)	2959	3041	3112	3187	3187	3253	3248	3248	3248	3253	3248	3248	3248	3253	3248	3248	3248	3253	3248	3248	3248	3253	3248	3248	3248	3253
Incremental Wind	0	0	0	0	657	659	657	657	657	659	657	657	657	659	657	657	657	659	657	657	657	659	657	657	657	659
Imports *	0	0	631	709	-42	-160	-189	-202	-198	-215	-198	-201	-213	-29	-2	-285	-115	-231	-105	-127	-390	-404	-384	-374	-334	-277
	10,922	**10,883**	**10,852**	**10,802**	**10,783**	**9,605**	**9,560**	**9,499**	**9,448**	**9,380**	**9,306**	**9,237**	**9,169**	**9,096**	**9,034**	**8,977**	**8,920**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**	**8,859**

* Exports over the NS-NB Tieline.

NON-CONFIDENTIAL

Request IR-244:

With reference to Appendix 6.03, pages 14-15, and Appendix 6.06, what is the basis for the different number and schedule of coal plant retirements among the three alternatives and two scenarios shown?

Response IR-244:

Please refer to SBA IR-238, parts (b) and (c).

NON-CONFIDENTIAL

Request IR-245:

With reference to Appendix 6.03, page 15, low load forecast comparison:

(a) Provide an annual peak load and resources balance table (with all units and transactions as separate rows) for the years 2015 to 2040 for each of the three alternatives. Provide as an Excel file with all formulae and cell references intact.

(b) Provide a monthly energy and energy supply balance table for the standard 5x16, 2x16, and 7x8 daily energy market periods (with all units, transactions, and imports/exports as separate rows) for the years 2015 to 2040 for each of the three alternatives. Provide as an Excel file with all formulae and cell references intact.

Response IR-245:

(a-b) Please refer to SBA IR-243 Attachments 1 though 3.

NON-CONFIDENTIAL

Request IR-246:

With reference to Appendix 6.03, page 19:

(a) For each natural gas resource option, provide start cost assumptions.

(b) If start costs were not modeled by Strategist, explain whether start costs were included in variable O&M cost or fuel use over an assumed daily run time, or were omitted.

Response IR-246:

(a-b) For the units for which we have experience, the start-up costs are captured in the historical average heat rate. For units that are not currently used, the manufacturer's heat rate has been used.

NON-CONFIDENTIAL

Request IR-247:

With reference to Appendix 6.04, page 2:

(a) What assumptions and methodology are associated with the development of the coal price forecasts?

(b) Please identify the supply sources, transportation modes, and costs that form the basis for these forecasts.

(c) Were these forecasts purchased from an outside consultant or developed internally by the NSPI Fuels Group for the July 2012 long-term update?

(d) What is the relationship between the most recent actual delivered coal costs and the 2015 starting prices for the coal price forecasts?

(e) Are the interim prices tied to the API4 futures prices?

Response IR-247:

(a-c) Please refer to Liberty IR-1.

(d) Please refer to Liberty IR-2.

(e) No. API4 is not currently believed to be a good proxy for Colombia coal and the Atlantic market because of the increased demand in the Pacific market and the swing in South African coal into this market.

NON-CONFIDENTIAL

Request IR-248:

With reference to Appendix 6.04, page 3, natural gas price forecasts:

(a) **What methodology did the NSPI Fuels Group utilize to develop the natural gas price forecasts?**

(b) **What assumptions were made in the gas price forecasts regarding short and long-term sources of gas supply that would be available to meet NSPI's fuel needs?**

(c) **Were recent developments regarding the resource potential of tight sands and shale gas resources in New Brunswick and coalbed methane resources in Nova Scotia evaluated as potential long-term sources of supply in preparing the natural gas price forecasts? If no, why not?**

(d) **How were the starting year (2015) prices in the forecasts developed?**

(e) **What assumptions were made regarding the components of the delivered price to TUC, including the cost of gas at the supply source, the cost of transportation and delivery to TUC and how were these costs escalated?**

(f) **Please identify the sources of gas assumed and the transmission pathways that were assumed for delivery to TUC.**

(g) **What was the long-term supply and demand balance that was assumed for the North American gas market?**

(h) **What assumptions were made regarding the long-term availability and cost of LNG that could be delivered to Canaport?**

(i) Was an analysis of the global LNG market conducted to support the contention in section 6.2.1 of the Application (page 108 lines 13 and 14) that LNG imports at Canaport are expected to remain low?

(j) Are the assumptions and North American price forecast underlying the gas price forecasts consistent with the contention in section 6.2.1 of the Application (page 108, lines 14-15) that North American gas prices remain low relative to global LNG prices, presumably over the 35 year life of the ML agreements?

(k) In this regard, was a comparative analysis of the North American gas price forecast and the future cost of LNG through 2040 conducted? If yes, provide the results of this analysis.

(l) Were the widely anticipated significant increases in global LNG supplies resulting from new liquefaction facilities coming on-line starting in 2015 taken into consideration in the gas price forecasts?

(m) Were long-term developments involving growing global LNG supplies and increasing development of shale gas resources worldwide, especially in major consuming nations like China, taken into consideration in these forecasts for the year beyond 2020?

(n) What view of long-run global gas supply and demand is consistent with the NSPI Fuels Group forecasts over the 35-year project forecast horizon?

Response IR-248:

Please refer to Liberty IR-4 and Liberty IR-5. The prices used were based upon the PIRA long-term forecast. This is a multi-fuel, world wide supply and demand model. Prices of alternative fuels and international demand and supply would be imbedded in this model.

Request IR-249:

With reference to Appendix 6.04, page 3, HFO and LFO price forecasts:

(a) How were the HFO and LFO fuel price forecasts developed?

(b) Please explain the methodology that was utilized to develop these forecasts.

(c) Are these forecasts obtained from or based on oil price forecasts prepared by an outside consultant? If yes, please identify the consultant(s) and summarize the forecasts.

(d) What assumptions regarding the underlying long-term crude oil price trend and the global oil supply/demand balance formed the basis for the price forecasts presented in Appendix 6.04?

Response IR-249:

(a-d) Please refer to Liberty IR-5.

NON-CONFIDENTIAL

Request IR-250:

With reference to Appendix 6.04, page 5:

(a) Please provide the ESAI Q3 2012 Forecast report.

(b) Please provide the date (mm/dd/yyyy) of the forecast.

(c) Please explain whether NSPI or ESAI provided the high and low energy price forecasts.

(d) Please explain how the ESAI forecast of MassHub energy prices is consistent with the natural gas price forecasts for each of the three market price scenarios.

Response IR-250:

(a) Please refer to NSUARB IR-037 Att 1.

(b) Q3 2012.

(c) ESAI.

(d) Please refer to Synapse IR-033.

NON-CONFIDENTIAL

Request IR-251:

With reference to Appendix 6.04, page 7:

(a) Did the Strategist modeling of the natural gas resource options allow for cycling between normal minimum load and maximum capacity in dispatch optimization?

(b) If yes, was the average heat rate modeled as a constant heat rate over the range between normal minimum load and maximum capacity?

(c) If no to part (b), explain how the heat rate curve was modeled for the CC options.

(d) If no to part (a), explain the extent to which this omission in modeling of dispatch contributed to wind energy generation curtailment.

Response IR-251:

(a) Yes.

(b) No.

(c) Natural gas combined cycle options were modeled with a piecewise linear heat rate curve corresponding to average heat rates at varying load points.

(d) Please refer to part (a).

NON-CONFIDENTIAL

Request IR-252:

Page 8 of Appendix 6.05, states that "…In order to have a capacity purchase from Hydro Quebec be accredited as valid capacity in Nova Scotia and contribute to NSPI's adequacy obligations under NERC reliability standards and NPCC reliability criteria it is necessary that it be delivered via firm transmission…":

(a) Is the Hydro Quebec purchase intended to contribute to NSPI's adequacy obligations under NERC reliability standards and NPCC reliability criteria or is the purchase meant to be an alternative to the Maritime Link, *i.e.* the provision of renewable electricity?

(b) If the Hydro Quebec purchase is meant to address NERC and NPCC reliability, please identify the reliability criteria that the report relied on.

(c) If the Hydro Quebec purchase is meant to serve the purpose of an alternative to the Maritime Link, *i.e.* the provision of renewable energy, please explain why it is absolutely necessary to consider only firm transmission.

(d) Is the Maritime Link being proposed to provide renewable electricity or to meet Nova Scotia's future reliability requirements, or both?

(e) If the Maritime Link is being proposed to meet Nova Scotia's future reliability requirements, please explain why a reliability analysis was not provided as part of the Application.

Response IR-252:

(a) The purchase provides 165 MW of accredited capacity that will contribute to the adequacy obligation of NS Power in addition to the provision of renewable electric energy.

(b-c) It has always been the understanding of WKM Energy that resource adequacy requires that sufficient resource capacity (including generation capacity) be available to be delivered via firm transmission to supply firm load. This is supported in the NPCC Generation Reliability criterion (from *NPCC Directory #1 Appendix D, Guidelines for Area Review of Resource Adequacy (Adopted: December 1, 2009*) which states:

> The probability (or risk) of disconnecting **firm load** due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or **load** relief from available operating procedures.

(d) The Maritime Link Project provides accredited capacity that will contribute to the adequacy obligation of NS Power in addition to the provision of renewable electric energy.

(e) The modelling tool used to determine the relative economics of the different options was the Strategist integrated resource modelling program. The future reliability requirement of NS Power is to have sufficient capacity resources to meet the firm peak load each year plus a reserve of 20 percent of the firm peak load. The data used to complete the analyses is set out in Appendix 6.03 of the Application and in addition to the forecast loads to be met the capacity contribution of the different types of supply options is also provided.

Strategist determines the least cost development to meet the reliability obligation. A separate “reliability analysis” is not required.

NON-CONFIDENTIAL

Request IR-253:

Page 9 of Appendix 6.05 states that "…Under the NB OATT if a transmission customer requests service and there is not sufficient capability to provide the requested service (as is the case currently at the NB-NS and HQ-NB interfaces), then the Transmission Provider, NBSO, is obligated to conduct any requested system impact studies and facilities studies to determine upgrades that may be required to provide it…"

(a) Please explain whether or not the WKM report performed any system impact studies and facilities studies to determine the upgrades that may be required at the NB-NS and HQ-NB interfaces. If such studies were conducted please provide copies of all reports and work papers.

(b) If no system impact and facilities studies were conducted please provide the justification for the transmission upgrades being assumed in the WKM report.

Response IR-253:

WKM would not be the party to conduct system impact studies, which are the responsibility of the NBSO. WKM did rely upon the most recent system studies completed under the Atlantic Energy Gateway and industry experience to assess the interfaces.

NON-CONFIDENTIAL

Request IR-254:

With reference to Appendix 6.05, page 9, footnote 18, please provide a copy of the New Brunswick Energy Blueprint.

Response IR-254:

Please refer to CanWEA IR-53 (a).

NON-CONFIDENTIAL

Request IR-255:

With reference to Appendix 6.05, page 10:

(a) What is the basis for the statement that "…At the New Brunswick-Nova Scotia interconnection the supply of 500 MW of firm transmission capability to NSPI requires that the New Brunswick Power system be reinforced back to Coleson Cove…"?

(b) Please also explain why such a transmission expansion would be 345 kV and connect as a minimum at the Salisbury terminal near Moncton and extend to the Onslow terminal near Truro in Nova Scotia.

Response IR-255:

(a) The rationale behind the statement is provided in footnote 19 in the WKM Energy report. It is also provided here.

> The primary contingency that limits firm transfer between NB and NS is loss of a 345 kV line segment between Coleson Cove and Norton, between Norton and Salisbury, or between Salisbury and Memramcook. This loss severely limits delivery to the southeast corner of NB which includes supply to PEI and to NS. To overcome the problem there are two options. Either construct new generation in this southeast area (which currently is not needed for resource supply) or reinforce the transmission.

(b) The NB bulk transmission system is built to 345 kV as is the existing interface. When Point Lepreau came online in 1983 the transmission between NB and NS to help support it was 345 kV line from Coleson Cove to Onslow with a connection and step down transformation at Salisbury. Subsequently a connection was made at Norton to improve supply to the Saint John area and a connection was made at Memramcook to improve supply to the Moncton area. The minimum transmission to add 500 MW of firm capacity to the NB-NS interconnection is a repeat of the 1983 upgrades.

NON-CONFIDENTIAL

Request IR-256:

With reference to Appendix 6.05, page 10, footnote 22, please provide a copy of the Atlantic Gateway studies that are being used as a source for the cost for the transmission expansion for the NB-NS interconnection and the NB-PEI cable expansion.

Response IR-256:

The Atlantic Energy Gateway studies used as information sources for the WKM Energy report in Appendix 6.05 are the Resource Development Modeling Study and the Transmission Modeling Study. They are attached as Attachment 1 and Attachment 2, respectively.

Atlantic Energy Gateway

Resource Development Modelling Study

A Study of Potential Savings for the Combined Resource Planning of Atlantic Canadian Utilities

March 2012

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AEG Resource Development Modelling Committee	
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Atlantic Energy Gateway Resource Development Modelling Study Report

A Study of Potential Savings for the Combined Resource Planning of Atlantic Canadian Utilities

Executive Summary

The Atlantic Energy Gateway (AEG) project is a regional initiative of the federal government, the Atlantic provincial governments, electric utilities of Atlantic Canada and the system operators in New Brunswick and Nova Scotia. The objective of the AEG project is to contribute to the development of Atlantic Canada's clean energy resources by identifying the opportunities and assisting in evaluating the advantages of the region's substantial and diversified renewable energy potential for wind, tidal, biomass/biofuels, and hydro.

The AEG is focused on contributing to identifying greater regional cooperation, benefits, and efficiencies among the various participants in the electricity and clean renewable energy sectors. This particular study was conducted by ABB Technology Ltd (Ventyx) under the direction of the Resource Development Modelling Committee of the AEG. It was undertaken at the request of the AEG Steering Committee and has involved collaborative efforts by the Governments of Canada, the Atlantic Provinces and the Atlantic region electric utilities. This document is the final report of the AEG - Resource Development Modelling Committee.

The fundamental hypothesis behind this study is that benefits can be achieved by regional planning of future electric generating resources rather than planning separately as is done today. Each of the Atlantic utilities currently develops an integrated resource plan (IRP) for its medium and long term future generation development. The objective in this study was to model a more integrated view of the region and determine the economic and environmental benefits compared to the individual provincial models.

Resource development planning identifies the long term optimization of power system supply, demand and transmission resources to meet projected reliability, environmental and economic targets. To achieve the study results, an optimization computer simulation tool called *Strategist*® was used. NB Power, NS Power and NL Hydro currently utilize *Strategist*® and had developed a partial Atlantic simulation model to evaluate the Muskrat Falls portion of the Lower Churchill hydro development entering the region, including the transmission links from Labrador to Newfoundland and from Newfoundland to Nova Scotia. By adding PEI and Northern Maine to this existing model plus revised representations of the Hydro Québec and ISO New England markets, a more detailed expansion simulation was developed for Atlantic Canada.

Study parameters and assumptions were developed by the Resource Development Modelling Committee with assistance from Ventyx. Commercially sensitive confidential utility data was

supplied directly to Ventyx and protected via non-disclosure agreements. Ventyx executed the *Strategist*® model to recreate the proposed IRPs of the four provincial utilities and then compared the sum of their costs against the costs of operating the combined Atlantic region. All of the resource development options particular to each utility's IRP were available in the analysis which included the renewable energy potential for wind, tidal, biomass, and hydro plus nuclear and natural gas options. Several environmental regulations were included as development constraints. These included: renewable energy standards, SO_2 and NO_x requirements for each province, CO_2 emission reduction to 5 Mte by 2020 in Nova Scotia and the federal requirement for coal fired power plants to emit CO_2 equivalent to a combined cycle natural gas plant or better or retire after a 45 year life. In this study, coal fired power plant retirement was assumed for New Brunswick but an equivalent cap of 5 Mte by 2030 and 4.5 Mte by 2040 was assumed by Nova Scotia. While this does not exactly match the profile of the CO_2 emission cap of the proposed equivalency agreement between the province of Nova Scotia and the federal government related to the GHG Regulations (as these limits were still under negotiation during this study work), this assumption is sufficiently close to give confidence in the results.

The systems were simulated in detail for the study period of 2015 through 2040 with the capital costs of each new generation resource charged at its escalating economic carrying cost. This approach treated projects of differing lives within the study period on a level playing field and eliminated the need to conduct an end effects analysis beyond 2040. Analysis was completed to determine Least Cost resource model results for a reasonable forecast of future conditions (Base Case scenario), for a High Natural Gas Price future, for a Low Load future and a scenario with Limited Transmission Expansion between NB and NS. In each of these cases (except for the Limited Transmission Expansion), expansion of the NB-PEI and NB-NS interconnections was assumed to be increased significantly above current transfer levels and the cost of the assumed transmission expansion is not included in the resource models. In addition to Least Cost model results several "Plans of Interest" were selected to reflect development strategies that focused on Natural Gas, Nuclear in NB and High Renewable Penetration if these were not part of the least cost model. These resulting models were subsequently simulated in greater detail to determine annual energy sources and emission levels. The results of the net present value (NPV) analysis of resources options are provided in Figure 1.

A number of resource options (Lower Churchill project for NL Hydro, Lower Churchill participation for NS Power and Grand Falls Redevelopment and Coleson Cove units 1 and 3 conversion to natural gas) are committed in the provincial base case as part of their IRP's and by such their costs and benefits relative to existing resources today are not captured in these model results.

Figure 1
NPV Costs of Different Resource Development Plans
($Millions)

	Sum of Standalone Provincial Systems with Existing Transmission			Combined Regional System with Expanded Transmission			Combined Regional
Scenarios:	Base Case	High Gas Price	Low Load	Base Case	High Gas Price	Low Load	Limited Transmission
Plans of Interest:							
Nuclear (least Cost)	**$22,395**	**$24,228**	**$17,730**	**$21,516**	**$23,199**	**$17,146**	**$21,608**
Natural Gas	**$22,453**	**$24,465**	**$17,769**	**$21,624**	**$23,534**	**$17,232**	**$21,710**
High Renewable	**$22,408**	**$24,475**	**$17,769**	**$21,635**	**$23,541**	**$17,249**	**$21,718**

In viewing these modeled potential resource results the reader is cautioned that they are indicative and directional in nature. Simulation of power system expansion over a period of 30 years is an approximate exercise subject to many assumptions. The optimization model results were derived from the assumption set and hold true only to the extent that the assumptions are accurate. It is important to understand that the results are not the total revenue requirement for the region but only the costs of fuel, optional new generation O&M and capital, and new generator interconnection capital. There is no consideration of any existing or future costs for in province distribution and transmission and there is no consideration of capital for existing generation resources. It is generally accepted that these will be common across the Cases and net-out of the comparative analysis. Finally, the opportunity to achieve NPV benefits resulting from combined regional planning have not been segregated by province. Opportunities are shown from an Atlantic region perspective only.

Comparison of the different resource scenarios and development plans provided the following findings:

> The Nuclear in NB plan, based on cost assumptions, is the least cost expansion for the Base Case scenario and the combined regional resource plan is $879 million less cost than the sum of the separate provincial plans. This resource benefit is sufficient to pay the cost of the transmission expansions estimated at $565 million in 2015 and provide a net benefit to the ratepayers of the region of $314 million. The primary development components, other than Nuclear in NB in 2038, are 114 MW of wind in NS in 2015, three small hydro projects in NL in 2019, 2021 and 2023, a 250 MW combined cycle gas unit in NS in 2030, a 400 MW combined cycle gas unit in NB in 2032 and a 130 MW combined cycle gas unit in PEI in 2033. The higher gas price in the High Natural Gas Price scenario makes the nuclear plan even more economic than the Base Case Scenario and the regional plan has a NPV benefit of $1029 million (net benefit of $464 million) compared to the High Gas stand-alone provincial plans. Other than installation of 100 MW of wind in each of NS in 2035 and NL in 2039, this High Gas Scenario has the same combined regional resource expansion plan as the Base Case.
>
> In the Low Load Scenario the least cost plan is still the nuclear expansion but with the combined regional resource NPV benefits reduced to $584 million (net benefit of $19 million). The Low Load Scenario development plan is similar to the Base Case except that a 400 MW combined cycle gas unit in NB was deferred from 2032 to 2039.
>
> The Limited Transmission sensitivity reduces transfer capabilities from the Expanded Transmission Cases and increases the NPV cost of supply resources by $92 million compared to the combined regional system Base Case. The expansion plan is the same as the High Gas plan except that the 100 MW of wind in NL is delayed from 2039 to 2040. The wind in NS and NL occurs because the limited interconnection reduces the opportunity for economy transfers from NB to NS so it is needed to enable NS to operate within its CO_2 cap.

The value of any development plan is not just measured in financial differences. Given the global concerns regarding climate change and associated policies to reduce greenhouse gas (GHG) emissions, the amount of emissions from a particular plan is extremely important. Under the Expanded Transmission Base Case, overall regional emissions are reduced by 64% from 2005 levels.

The relative energy mix in a resource development plan is also of interest, not just because of its influence on emissions, but also from the perspective of diversity of fuel source risk and fuel price volatility. Fuel sources of coal and oil are imported and depend on world markets for cost and availability while wind and hydro are local and natural gas is currently an indigenous resource (though subject to international market pricing). In the Expanded Transmission Base Case the large increase in hydro by 2020 combined with natural gas and a large nuclear after 2030 reduces coal and oil generation from its 49% share in 2005 to only 6% by 2040.

Preliminary estimates have determined that the cost of the two transmission expansions between NB-PEI and NB-NS is $565 million in 2015. With an Expanded Transmission Base Case resource benefit of $879 million the transmission can be paid for and still provide $314 million of benefit for regional ratepayers. However, the Limited Transmission Sensitivity suggests a benefit of $787 million. These preliminary estimates require further analysis and would need to be confirmed through a comprehensive transmission study. While this particular Sensitivity assumed no expansion of the existing transmission interties, based on current system operating conditions transmission expenditures will be necessary to maintain the present transfer limits into the future. Accordingly, the benefit of the Limited Transmission Sensitivity is somewhat inflated. Regardless, the resource benefits derived in this study are only one component of total benefit of transmission and the other considerations (reliability) need to be analysed and understood prior to any commitment to expand the interconnections. In short, more detailed transmission analysis work is required and it must be integrated with additional resource analysis in order to determine an optimum expansion plan for the region.

While much of this discussion has been focussed on the benefits derived in the model, important areas for policy consideration which establish the winning conditions for renewables described in the modeling are as follows:

- <u>Natural Gas Supply and Infrastructure</u> - This resource modeling study shows increased use of natural gas for electricity generation in all scenarios examined. Development of a long-term regional plan focussed on security of natural gas supply and pipeline infrastructure needs would help ensure that the region could enjoy the forecasted cost and the air emission benefits of natural gas generation.

- <u>Enhanced Transmission Interties</u> - Transmission transfer capacity within the region promotes the sharing of renewable resources and is an important enabler of regional cooperation. There are significant transmission expansion decisions to be made in the near- to mid-term. A finding of this resource modeling study is that additional transmission analysis is required by the utilities in order to determine an optimal plan for transmission intertie expansion within the region.

- <u>Hydroelectric Power</u> - Hydroelectric generation grows to approximately 45% of the region's electricity supply by 2040. Hydro provides renewable energy but, equally important, it can supply valuable regulation and load following capacity which is a critical enabler of wind and tidal generation. Efforts to promote new and protect existing hydro generating resources are important to allow the progress of other renewables in the region.

Background

The Atlantic Energy Gateway ("AEG") is an Atlantic Canada electricity and clean renewable energy project funded and coordinated by the Federal Government Department of Natural Resources Canada ("NRCan") and The Atlantic Canada Opportunities Agency ("ACOA"), with participation from the Governments of New Brunswick ("NB"), Prince Edward Island ("PEI"), Nova Scotia ("NS"), and Newfoundland and Labrador ("NL"); four of the region's major electrical utilities: New Brunswick Power Group of Companies ("NB Power"), Maritime Electric Company Limited ("MECL"), Nova Scotia Power/Emera Inc. ("NS Power"), and Nalcor/Newfoundland and Labrador Hydro Corporation ("NL Hydro"); and the region's two system operators, New Brunswick System Operator ("NBSO") and Nova Scotia Power System Operator ("NSPSO").

The AEG is focused on contributing to identifying greater regional cooperation, benefits, and efficiencies among the various participants in the electricity and clean renewable energy sectors through increased collaboration, discussion and analysis of existing utility assets, and future requirements including additional clean and renewable energy resources for regional and export purposes.

The AEG participants have worked collaboratively over the past two years sharing existing information pertaining to the electricity systems, development of Atlantic Canada's clean and renewable energy resources, and where necessary, undertaking new analysis to improve the understanding of the region's electricity industry.

Some of the major components of the AEG work included: workshops on individual energy components in each of the four Atlantic Provinces; working committees on functional sectors such as transmission, resource generation, system operations; meetings and conference calls; participation by industry experts; and a number of professional external studies designed to provide a strategic and factual foundation on topics such as renewable energy financing, renewable energy R&D, supply chain development, and a study of the Eastern Canada and Northeast United States marketplace for electricity.

This ***Resource Development Modelling Study*** is one of those professional external studies with the purpose of determining if there are long term economic and environmental benefits arising from the coordination of planning the development of regional generating assets compared to planning within the utilities current provincial jurisdiction. Resource development planning is a complex iterative process that needs technical skill sets supported with specialized computer simulation models to determine optimization of power system supply, energy demand profiles and transmission infrastructure. The operational requirements are established by the market rules, procedures and tariffs applicable to the operation of the systems under study. The issues of reliability, environmental emission targets and economic targets influence the rules established by government policy and regulators.

A Resource Development Modelling Technical Committee (comprised of modelling experts from the modeling consultant Ventyx, the Atlantic utilities, and independent consultants) provided advice to the Steering Committee of government officials. The committee selected technical support from Ventyx through consultation with utilities, consultants and experts because of their current role of providing similar services to the regional utilities and professional reputation. This Technical Committee developed terms of reference for the study implementation and provided necessary data and technical support to Ventyx for the modelling work. Each utility entered Non-Disclosure Agreements with Ventyx to protect data and detailed study results deemed to be commercially sensitive.

Study Approach

Overview

Each of the regional utilities currently develops an integrated resource plan (IRP) for its medium- and long- term future generation and transmission development. These IRPs are often reviewed by provincial regulators and, although the results are made public through the regulatory process, confidential data is withheld from public scrutiny. The approach in this study was to develop a potential regional IRP and determine the economic and environmental savings from taking a regional planning and development approach.

To do so required that a regional simulation model be developed so that its IRP profile could be compared to the sum of the individual utility IRPs. The terms of reference sought a model that would determine the least cost base case plan as well as plans that integrate increasing amounts of clean, renewable and non-emitting energy sources for varying domestic and export loads. The modelling approach followed three steps as follows:

- Simulation Model Development and Database Adaptation
- Base Case Analysis
- Sensitivity Analysis

Progress and results were reported by Ventyx to the Technical Committee on a continuous basis and updates were provided to the Steering Committee at the conclusion of each phase.

Simulation Model Development and Database Adaption

An IRP involves a computer optimization simulation tool that selects a set of generation expansion options at future years that will result in the least net present value (NPV) cost for the selected time period. This requires detailed modelling of projected generation construction and operation and associated costs for the study period (2015 to 2040 for this study). It also requires consideration of the economic value of the model results beyond the study period because power system generators have very long and differing length lives (in this study the economic carrying charge method was used to deal with this issue). The generation related options available (wind, biomass, tidal, natural gas, nuclear, demand side management, etc.) can be numerous with varying sizes.

The foundation for the simulation model was established using the base model for each utility including the existing systems and the commitments already made respecting future generation sources. This enabled the optimization simulation to operate efficiently and produce feasible model results for generation development in the region. For this study screening was done collaboratively by the Technical Committee and the detailed development plan modelling was completed by Ventyx with its *Strategist*® IRP optimization tool for plan development.

The existing data sets from the three regional utilities that license *Strategist*® (NS Power, NB Power & NL Hydro) formed the basis of the regional model, and were supplemented with data for PEI. Market data for Quebec, New England and Northern Maine were included as well. The Technical Committee reviewed common data and adjusted where necessary to create a consistent dataset for the region. Confidential data (such as heat rates of existing units, unique parameters of a new option, etc.) were provided directly to Ventyx by each utility and protected via the non-disclosure agreements. Ventyx reviewed this confidential data and provided assurance to the Technical Committee that it was reasonable and consistent. Adjustments to necessary items were made by Ventyx in confidence through discussions with the utility owning such data.

It should be noted that *Strategist®* is not a transmission optimization model. Accordingly the Technical Committee made assumptions about existing and expanded transmission capability, particularly related to transmission interties between companies. These assumptions were evaluated in relation to utility import and export outputs from the model.

The *Strategist®* database was used to conduct PROVIEW module optimization runs that generated multiple resource development models and their associated NPV costs. Because PROVIEW does not store all the information of interest for every plan that it produces greater detail on specific models were generated by the Generation And Fuel (GAF) module to provide annual generation, cost and emissions results.

Base Case Analysis

The Base Case was based on the projected load, fuel and market prices, and generator cost and performance parameter updates deemed necessary by the participating provincial utilities. The following assumptions were also included:

- 45 year retirement of coal plants in New Brunswick
- CO_2 emission hard caps to 2030 and beyond for Nova Scotia in alignment with the assumed provisions of an equivalence agreement with Environment Canada
- Natural gas prices based on current futures and the US Energy Information Agency outlooks with appropriate tolls applied (forecast derived with information available in December 2011)
- Load forecasts and generating options
- For the combined system, 500/250 MW transfer capability between NL-NS, 800 MW between NS-NB and 350 MW between NB-PEI
- For the individual system runs the existing intertie transfer capabilities were used for NB-NS and NB-PEI (although the NS import from NB was reduced to 100 MW to better reflect the limitations that have emerged on this interface)

Running the Base Case required five separate PROVIEW optimization runs: one for each of the four provincial models with plan optimality and rankings selected on the basis of what is best for a single province and a final combined optimization model with the plans optimized across the entire region. For the individual provincial models it was necessary to "fix" the future resource plans for the remaining three provinces. The "fixed" plans used were the same models that resulted from the separate databases before combining them.

The Base Case output from PROVIEW produced numerous potential generation development scenarios from which was identified the models most in line with the development strategies of – least cost plan, natural gas expansion, high renewable expansion and nuclear expansion. Once these models were selected, GAF runs of each model were completed to determine more detailed energy utilization, cost and emission impacts by year.

Sensitivity Analysis

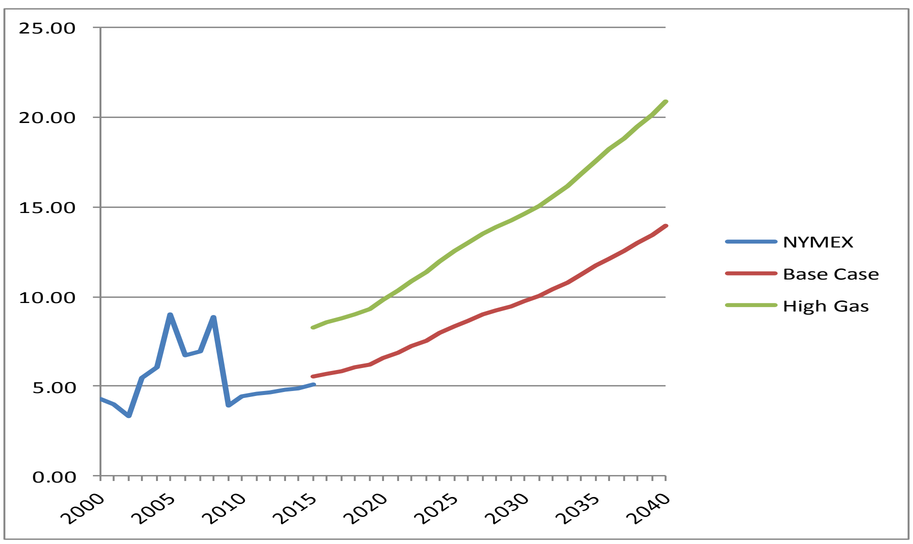
A sensitivity analysis was conducted against the Base Case Scenario to produce a High Natural Gas Price Scenario and a Low Load Growth Scenario for both individual provinces and combined regional system models. A separate model of a Limited Transmission Scenario was undertaken for the combined regional model to assess the impact of transmission restrictions. The primary focus in the sensitivity analysis was to determine the least cost plans for all scenarios and compare resulting NPV costs to the base case. The computer simulation runs required for the various scenarios are provided in Figure 2.

Figure 2
Resource Development Modelling Study Computer Model Runs

	Standalone Provincial Systems with Existing Transmission Interties			Combined Regional System with Expanded Transmission Interties			Combined System: Limited Trans-mission
Scenarios (Proview Runs)	Base Case	High NG Price	Low Load	Base Case	High NG Price	Low Load	
Plans of Interest: (Devel. Themes)	1A Least Cost	2A Least Cost	3A Least Cost	4A Least Cost	5A Least Cost	6A Least Cost	7A Least Cost
	1B Gas	2B Gas	3B Gas	4B Gas	5B Gas	6B Gas	7B Gas
	1C High Renewable Penetration	2C High Renewable Penetration	3C High Renewable Penetration	4C High Renewable Penetration	5C High Renewable Penetration	6C High Renewable Penetration	7C High Renewable Penetration
	1D New Nuclear in NB	2D New Nuclear in NB	3D New Nuclear in NB	4D New Nuclear in NB	5D New Nuclear in NB	6D New Nuclear in NB	7D New Nuclear in NB

The High Natural Gas Price Scenario applied the same assumptions as the Base Case except that it increased natural gas prices by 50% as shown in Figure 3.

Figure 3
Natural Gas Prices ($/MMBtu)



The objective with this High Natural Gas Price case was to determine the relative impact of low capital cost generation with high fuel risk (gas combined cycle) compared to high capital cost generation options with low fuel risk (wind and nuclear). Figure 3 illustrates the natural gas prices used for the sensitivity (high gas) and base case analyses. Note that historic and projected NYMEX prices at Henry Hub are provided for 2000 through 2015. The prices shown for the Base Case are the annual average natural gas prices from the Annual Energy Outlook 2012 produced by the Energy Information Agency of the US Department of Energy, with a basis differential adder of $0.45/MMBtu for pipeline transportation between Henry Hub and the Maritimes. In the actual modelling these were applied at 95% for summer (April-October) and 110% for winter

(November-March). This seasonal differential reflects both the seasonal nature of NYMEX price variation and especially the seasonal basis differential for pipeline congestion.

The High Gas price was also applied at 95% for summer and 110% for winter. It is worth noting that the natural gas prices applied in the study may seem high considering the current low price of natural gas at Henry Hub (recently in the $2.50/MMBtu range). This current low price is considered an anomaly by industry because of a number of factors (unusually warm winter, high storages, high value of wet gas liquids, locked in discoveries). The forward prices are much higher and consistent with the forecasts of the Energy Information Agency of the US Department of Energy. The High Gas price is not necessarily just a potential price increase at Henry Hub it also could result because of Atlantic Canada supply shortages such that additional basis differential would need to apply to procure natural gas from the Boston area and transport it north.

The Limited Transmission Scenario applied the same data as the Base Case except that the NB-NS interconnection was reduced from 800 MW to the existing interconnection capacities and the NB-PEI interconnection was reduced to the existing 200 MW capacity. The objective here was to determine if less transmission transfer capability (with less cost) may still achieve enough regional benefits to be a more economically attractive approach.

The Low Load Growth Scenario was completed with all the same data as the Base Case except for a lower load for each province. This reflected the potential load impacts of lower economic growth and assuming potential loss of some large industrial loads which would result in reduced energy demand/sales and reduced generation capacity requirements. The impact of higher load growth was also examined but not in detail during the regional analysis.

Summary of Results

The results of the NPV analysis of resources options produced by PROVIEW are provided in Figure 4. Note that a number of resource options (Lower Churchill project for NL Hydro, Lower Churchill participation for NS Power and Grand Falls Redevelopment and Coleson Cove units 1 and 3 conversion to natural gas) are committed in the provincial base case as part of their IRP's or commercial arrangements and as such their costs and benefits relative to existing resources today are not captured in these model results.

Figure 4
NPV Costs of Different Resource Development Plans
($Millions)

	Sum of Standalone Provincial Systems with Existing Transmission			Combined Regional System with Expanded Transmission			Combined Regional
Scenarios:	Base Case	High Gas Price	Low Load	Base Case	High Gas Price	Low Load	Limited Transmission
Plans of Interest:							
Nuclear (least Cost)	**$22,395**	**$24,228**	**$17,730**	**$21,516**	**$23,199**	**$17,146**	**$21,608**
Natural Gas	**$22,453**	**$24,465**	**$17,769**	**$21,624**	**$23,534**	**$17,232**	**$21,710**
High Renewable	**$22,408**	**$24,475**	**$17,769**	**$21,635**	**$23,541**	**$17,249**	**$21,718**

In viewing these results the reader is cautioned that these are indicative and directional in nature. Modelling of power system demand, costs and expansion needs 30 years into the future is an approximate exercise subject to many assumptions. It is also important to understand that the results are not the total revenue requirement for the region but only the costs of fuel, generation Operations and Maintenance (O&M), new generation capital cost funding and new interconnection capital cost funding. Therefore these model outcomes are best used for comparative purposes, case to case, rather than as expressions of total system costs. Additionally, it must be noted that there is no consideration of any existing or future costs for in province distribution and transmission and there is no consideration of capital for existing generation resources. These exclusions are considered appropriate as they would be largely common across the cases. Finally, the opportunity to achieve NPV benefits resulting from combined regional planning have not been segregated by province. Opportunities are shown from an Atlantic perspective only.

The following sections analyse these results in greater detail.

Base Case Analysis Results

The Base Case analysis projected the sum of Net Present Value (NPV) costs of current standalone provincial IRP implementation compared to a combined regional IRP to determine if there were potential benefits. As shown in Figure 5 the Least Cost regional plan included the Nuclear unit in NB with a 2015 NPV benefit of $879 million. Given that the transmission upgrades to the NB-NS and NB-PEI interconnections that were assumed in the analysis are projected to cost[1] about $565 million, a combined regional plan with the transmission upgrades completed by 2015 can pay for the transmission and still produce $314 million in savings for ratepayers.

Figure 5
Base Case NPV Results
($Millions)

Plans	Standalone Provincial Systems with Existing Transmission Interties	Combined Regional System with Expanded Transmission Interties	Differences
Nuclear in NB (Least Cost)	$ 22,395	$ 21,516	$ 879
Natural Gas	$ 22,453	$ 21,624	$ 829
High Renewable	$ 22,408	$ 21,635	$ 772

The value of an alternative development plan is not just measured in financial differences. Given the global concerns regarding climate change and associated policies to reduce greenhouse gas (GHG) emissions, the amount of emissions from a particular plan is extremely important. Figure 6 plots the annual regional GHG emissions[2] over the study period for the regional Least Cost – Nuclear in NB case and compares them to actual emissions in 2005 and 2010. Overall regional emissions are reduced by 64% from 2005 levels.

[1] The cost estimates for the transmission upgrades are detailed in the "AEG Transmission Modelling Study Report."

[2] GHG emissions in the power sector are composed almost entirely of CO_2 from combustion of fossil fuels and are measured as tonnes of CO_2 equivalent.

Figure 6
Base Case Nuclear Plan Emissions
(Tonnes of CO_2)

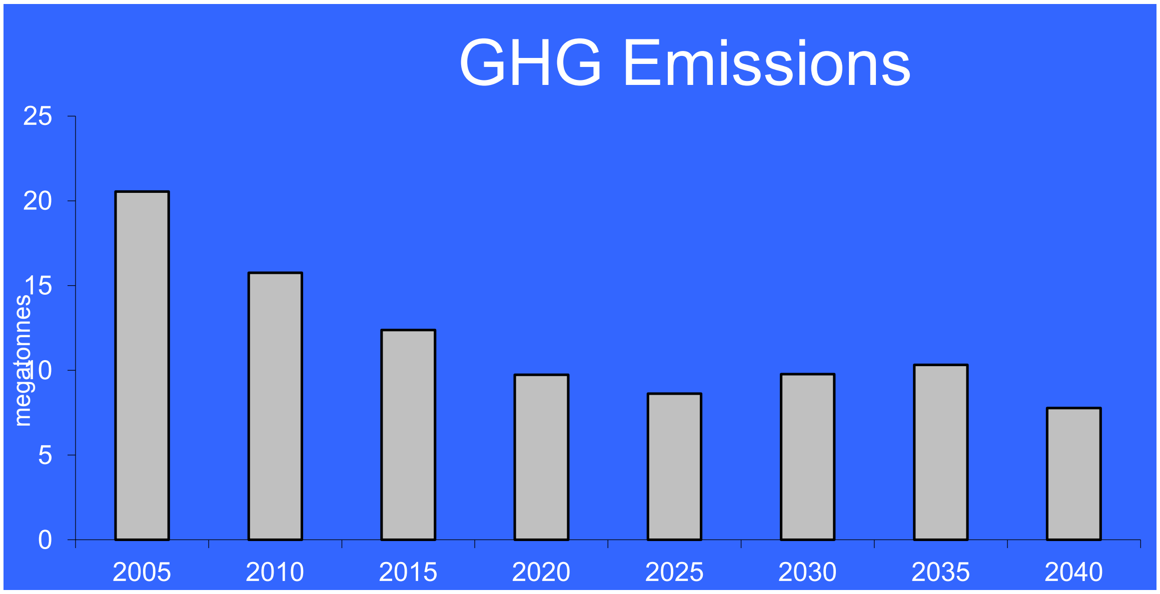
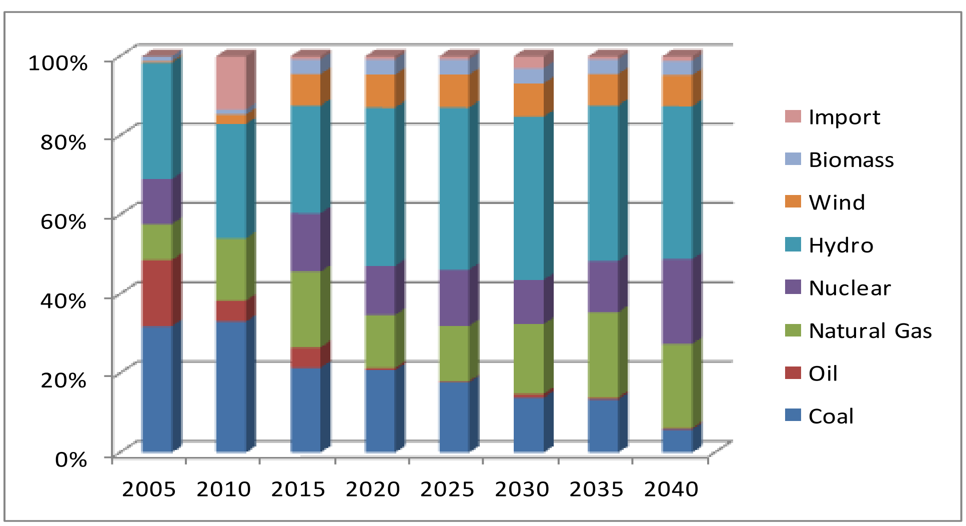


Figure 7
Generation Energy Mix (%GWh)
Base Case Least Cost – Nuclear in NB



The relative energy mix in a resource development plan is of interest, not just because of its influence on emissions, but also from the perspective of diversity of fuel source risk and fuel price volatility. Fuel sources of coal and oil are imported and depend on world markets for cost and availability while wind and hydro are local and natural gas is currently an indigenous resource. Figure 7 provides the relative energy mix for the Base Case Least Cost Plan for the study period and compares them to the actual mix that occurred in 2005 and 2010. Note the large increase in hydro by 2020 as a result of the Muskrat Falls plant and the reduction of coal and oil generation from 49% in 2005 to only 6% by 2040. Also note the amount of imports is small in all years except 2010 when large purchases occurred because of the Point Lepreau outage and low natural gas prices that made ISO-NE imports economic relative to regional oil fired generation.

Additionally, with the region's current natural gas pipeline infrastructure, it will be important to ensure that the development of natural gas units across the region does not outstrip the capacity of the pipeline facilities to deliver a reliable, secure fuel supply to existing and proposed new gas fired generation. Collaborative planning would be required by the utilities if new gas fired generation is brought on line, in order to understand the risk of generation loss to the region that could result from the interruption of fuel supply from the natural gas transmission pipelines.

Sensitivity Analysis Results

NPV sensitivity results for the High Gas Price Case scenario, the Low Load Growth Scenario and the Limited Transmission Expansion scenario are provided in Figure 8. Note that the Combined Regional System includes expanded transmission for the NB-NS and NB-PEI interconnections in the High Gas and Low Load sensitivities but not in the Limited Transmission sensitivity.

Figure 8
Sensitivity Analysis NPV Results
($Millions)

Plans	Standalone Provincial Systems with Existing Transmission Interties	Combined Regional System	Differences
High Gas Prices	$24,228	$23,199	$1,029
Low Load	$17,730	$17,146	$583
Ltd Transmission	$22,395	$21,608	$787

Comparison of these sensitivity results with the Base Case results in the previous section provides several findings of interest as follows:

- The higher gas price in the High Natural Gas Price scenario makes the nuclear plan even more economic than the Base Case Scenario and the regional plan has a NPV benefit of $1029 million compared to the High Gas stand-alone provincial plans. The stand-alone plan for NL is unchanged from the Base Case while the plans for NB, NS and PEI add wind and tidal rather than combustion turbines. Other than installation of 100 MW of wind in each of NS in 2035 and NL in 2039, this High Gas Scenario has the same combined regional resource expansion plan as the Base Case. But even with this additional wind the regional CO_2 emissions are higher by about 1.5 Mte prior to 2030 before reducing gradually from 0.8 Mte higher in 2030 to 0.4 Mte lower by 2040. This is caused mainly by increased use of coal in NB and NS which is more economic than the higher priced natural gas.

- In the Low Load Scenario the least cost plan is still the nuclear expansion but with the combined regional resource NPV benefits reduced to $583 million. The 100 MW of wind in NL that appears in both the High Gas Price case and the Limited Transmission case is not included in the Low Load case. As expected CO_2 emissions in this Low Load scenario are lower in all years by about 2 Mte.

- The Limited Transmission sensitivity reduces transfer capabilities from the Base Case and increases the NPV cost of supply resources by $92 million compared to the combined regional system Base Case. The expansion plan is the same as the High Gas Price plan except that the 100 MW of wind in NL slips its in service from 2039 to 2040. The wind in NS and NL occurs because the limited interconnection reduces the opportunity for economy transfers from NB to NS so it is needed to enable NS to operate within its CO_2 cap.

This result for the Limited Transmission is insightful. As was discussed in the Base Case Results section, preliminary estimates have determined that the cost of the two transmission expansions between NB-PEI and NB-NS is estimated at $565 million in 2015. With a Base Case resource benefit of $879 million the transmission expansion can be paid for and still provide $314 million of benefit for regional ratepayers. However, the Limited Transmission Sensitivity, as modeled, provides $787 million of net present benefit. These preliminary estimates require further analysis and would need to be confirmed through a comprehensive transmission study.

While this particular Sensitivity assumed no expansion of the existing transmission interties, the available transfer capacity of the NB to NS interface has diminished in recent years and it would be reasonable to expect that this decay will only continue over time with local load growth leaving negligible capacity available for firm or economy energy transactions. Accordingly, the benefit of the Limited Transmission Sensitivity is somewhat inflated as some level of transmission expenditures will be necessary to maintain the present transfer capacity into the future. Regardless, the resource benefit determined in this study is only one component of total benefit of transmission and the other components need to be analysed and understood prior to any commitment to expand the interconnections. In short, more detailed transmission work is required and it must be integrated with additional resource analysis in order to determine an optimum expansion for the region. However, it is apparent that a reduced amount of transmission expansion expenditure, from that assumed in the base case, can provide necessary transmission transfer capacity for energy resource optimization. Additional drivers like system reliability, inter-system balancing, reserve sharing and others could combine to require tie line capacity expansions similar to those initially assumed.

A supplemental analysis regarding the potential impact of a tidal energy development opportunity was also undertaken. This analysis determined that tidal energy development would displace CO_2, which would be positive in helping enable Nova Scotia to operate within its CO_2 cap. Large scale deployment of tidal generation would be selected if it was cost-competitive with other clean and renewable sources.

Conclusions

Combined regional planning provides an opportunity to achieve NPV savings in the range of $314 to $787 million dependent on the cost and achievable transfer capacity benefit of transmission expansion to the NB-NS and NB-PEI interconnections.

Observations arising from this study for policy consideration or for further work are as follows:

- There are few significant resource decisions to be taken in the coming decade given that many key decisions for that planning window have been already made (not all on a regional basis) before or during the AEG process.

- This resource modeling study shows increased use of natural gas for electricity generation in all scenarios examined. Development of a long-term regional plan focussed on security of natural gas supply and pipeline infrastructure needs would help ensure that the region could enjoy the forecasted cost and the air emission benefits of natural gas generation.

- Follow up to the AEG work is required for further transmission analysis. A finding of this resource modeling study is that additional transmission analysis is required by the utilities in order to determine an optimal transmission intertie expansion within the region. Transmission transfer capacity within the region promotes the sharing of renewable energy resources and is an important enabler of regional cooperation. There are significant transmission expansion decisions to be made in the near term.

- Hydroelectric generation grows to approximately 45% of the region's electricity supply by 2040. Hydro provides renewable energy but, equally important, it also provides valuable regulation and load following capacity which is a critical enabler of wind and tidal generation. Efforts to promote and protect hydro generating resources are important to allow the progress of renewables in the region.

- Further work is needed to determine how much variable generation can be integrated into the regional resource mix. The *Strategist®* simulation program, like most computer simulations of its type, is not capable of a full representation (sub-hour) of the intermittent nature of wind generation. This additional work could focus on the continued availability of existing hydro, the introduction of additional fast acting generation resources to provide for load following, or other integration options like storage, load shifting, and regional dispatch.

- While some of the resource development options identified in this study are triggered to serve load or respond to capacity retirements, compliance with environmental regulations is an equally important driver. Under the Base Plan, the region would see CO_2 emissions reduced from 15 Mte in 2010 to just under 10 Mte in 2030.

- A critical component of the follow up analysis is a determination of how costs and benefits of transmission expansion and resource development should be shared. This resource modeling study did not address this issue and the results shown are totals for the region as a whole.

Atlantic Energy Gateway Transmission Modeling Study Report

A Study of Transmission Upgrade Options

For

Atlantic Canadian Utilities

March 30, 2012

Table of Contents

AEG Transmission Planning Committee

Organization	Member
New Brunswick System Operator	Alden Briggs Scott Brown
New Brunswick Power Transmission Corporation	Randy MacDonald
Maritime Electric Company Limited	John Cunniffe
Nova Scotia Power Incorporated	Tim Leopold
Newfoundland & Labrador Hydro	Peter Thomas
Government of Nova Scotia	Scott McCoombs

Atlantic Energy Gateway Transmission Modeling Study Report

A Study of Transmission Upgrade Options for Atlantic Canadian Utilities

1. Executive Summary

The Atlantic Energy Gateway (AEG) project is a regional initiative of the federal government, the Atlantic provincial governments, electric utilities of Atlantic Canada and the system operators in New Brunswick and Nova Scotia. The objective of the AEG project is to contribute to the development of Atlantic Canada's clean energy resources by identifying the opportunities and assisting in evaluating the advantages of the region's substantial and diversified renewable energy potential for wind, tidal, solar, biomass/biofuels, geothermal and hydro.

At the heart of the AEG project is a resource assessment of the Atlantic Canada integrated regional power supply systems through the development of a representative model of the electricity system. That model was used to evaluate the current operation of the system as well as develop scenarios that integrate increasing amounts of renewable and non-emitting energy sources for domestic and export loads.

A tighter integration of the Atlantic Canada electrical system will lead to increased opportunities for inter-provincial energy trade. These opportunities are enhanced by implementing a number of key transmission upgrade options within and between provinces, not just facilities at the borders. Adequate transmission capacity is a key element to generation expansion. Lack of transmission capacity leads to congestion and results in sub-optimal generation dispatch. This results in increased electricity production costs through curtailment of low cost generation and dispatch of more costly alternatives. The addition of transmission capacity will reduce marginal electricity costs across the region.

Various potentially desirable transmission upgrade options were identified by the Transmission Planning Committee. Studies performed using the integrated resource model, under the direction of the AEG Resource Development Modeling group, identified the key interfaces as those between New Brunswick and Nova Scotia, and New Brunswick and Prince Edward Island. These interfaces have been previously studied at a high level to determine their approximate transfer capabilities and the costs to upgrade transmission facilities into this area. This information was provided to the AEG Resource Development Modeling group.

As the resource development plan becomes known and the Atlantic Canada electricity system evolves, more comprehensive transmission studies will be required to assess the impact and define the transmission upgrades necessary to implement the plan.

2. Background

The objective of the Atlantic Energy Gateway (AEG) project is to contribute to the development of Atlantic Canada's clean energy resources by identifying the opportunities, and assisting in evaluating the advantages of the region’s substantial and diversified renewable energy potential for wind, tidal, solar, biomass/biofuels, geothermal and hydro.

The AEG project is a collaboration of the four Atlantic Canada provincial energy departments, electric utilities representing each Atlantic Canada province, Atlantic Canada Opportunities Agency and Natural Resources Canada. The work includes planning for generation, transmission, and system operation, as well as electricity markets, supply chain development, research and development and regulatory improvements. The AEG project is an initiative sponsored by the government of Canada to encourage the development of additional clean and renewable energy supplies in Atlantic Canada.

A major component of the AEG work plan is the undertaking of a series of studies designed to provide a plan for the future development of the electrical system. This plan is widely known as an Integrated Resource Plan (IRP). The IRP is a resource assessment of the Atlantic Canada integrated regional power supply systems through the development of a representative model of the electricity system. The model is used to evaluate the current operation of the system as well as develop scenarios that integrate increasing amounts of generation, including renewable and non-emitting energy sources, for supply to domestic and export loads.

A tighter integration of the Atlantic Canada electrical system will lead to increased opportunities for inter-provincial energy trade. These opportunities may be enhanced by implementing a number of key transmission upgrade options within and between provinces. Adequate transmission capacity is a key element to generation expansion.

The purpose of the Transmission Modeling Study, under the direction of the Transmission Planning Committee, is to quantify the increased inter-provincial capacity that would be achieved by a number of key transmission upgrade options within Atlantic Canada. The study also provides estimates of the cost of each of the options.

The results of the study are anticipated to provide information that can be used by Atlantic Canadian governments and utilities in developing and executing energy related policies that will be based on region-wide analyses. The study will develop a greater understanding of the electricity system costs and benefits to guide the policy decision making process with the best information available.

For the purposes of the IRP, Phase I of the Lower Churchill Project is deemed to be in the base case. This consists of the Muskrat Falls generation facility, the Labrador-Island Transmission Link and the Maritime Transmission Link (Figure 1). This project delivers 500 MW via the Maritime Transmission Link to Cape Breton.

As a result of the Lower Churchill Project being in the base case, the focus of the Transmission Modeling Study is on the transmission capability in and between the Maritime Provinces. The Maritime Provinces transmission system must be capable of accommodating the 500 MW of injection into Cape Breton as well as accommodating evolving generation and load patterns in the Maritimes. The Transmission Modeling Study did not include analysis of any of the transmission which forms part of the Muskrat Falls, Labrador-Island Transmission Link or the Maritime Transmission Link.

Figure 1: Phase One – Muskrat Falls, Labrador-Island Link and Maritime Link

3. Transmission Study Approach

A Transmission Planning Committee representing governments and utilities of Atlantic Canadian provinces was formed to coordinate the efforts of the AEG transmission study. This Transmission Planning Committee was chaired by the New Brunswick System Operator (NBSO).

In Phase I of the transmission study, various potentially desirable transmission upgrade options were identified by the Transmission Planning Committee. This list is provided in Appendix 1. These transmission upgrade options were to be studied at a high level to determine their approximate transfer capabilities and associated cost. These transfer capabilities and costs were then to feed into the associated IRP study.

In Phase II of the transmission study, comprehensive transmission studies were to be preformed on the viable transmission options flowing from the IRP.

The AEG Resource Development Modeling group contracted with Ventyx to do the resource study. Ventyx's task was to develop a system model to be used in a series of production cost simulations using their planning software (Strategist). These studies were completed under the direction of the AEG Resource Development Modeling group.

Initially, Ventyx studied two scenarios. The first scenario, the 'Expanded Transmission Capability' option, assumed that transmission capacity was upgraded to achieve higher interface capabilities as follows:

- NB ← NS = 800 MW
- NB → NS = 800 MW
- NB ← PEI = 350 MW
- NB → PEI = 350 MW

The higher interface capabilities between NB, NS and PEI do not exist today. To achieve these levels, additional transmission infrastructure is required. These Transmission Upgrades are discussed in Section 5.

The second scenario, the 'Limited Transmission Capability' option, assumed that transmission capacity is as it exists today. Further detail of existing transmission interface capacity is included in section 4 and in Appendix 2.

The production modeling process identified the key interfaces as those between New Brunswick and Nova Scotia and New Brunswick and Prince Edward Island. These interfaces have been previously studied at a high level to determine their approximate transfer capabilities and associated cost. This information was provided to the AEG Resource Development Modeling group. At this time, it is unknown if there is a requirement to study any of the other transmission projects identified in Appendix 1.

4. Existing Transmission Capacity

The Total Transfer Capability (TTC) of an interface is a best engineering estimate of the total amount of electric power, measured in MW, which can be transferred over an interface in a reliable manner for a given timeframe. The TTC of an interface is determined by performing power flow and stability studies under seasonal system conditions. Note that the TTC and is a combination of firm and non-firm transactions. Further details of the methodology for calculating transmission capacity can be seen in Attachment C of the NBSO Open Access Transmission Tariff.

The existing TTC between regions as currently posted on the NBSO OASIS are shown on the map below (Figure 2). Further discussion is attached as Appendix 2 titled "Summary of Existing Firm and Non-Firm Transmission Capacity of New Brunswick Interfaces with Nova Scotia and PEI". Note that there are many factors to be considered when determining the capability of the transmission system.

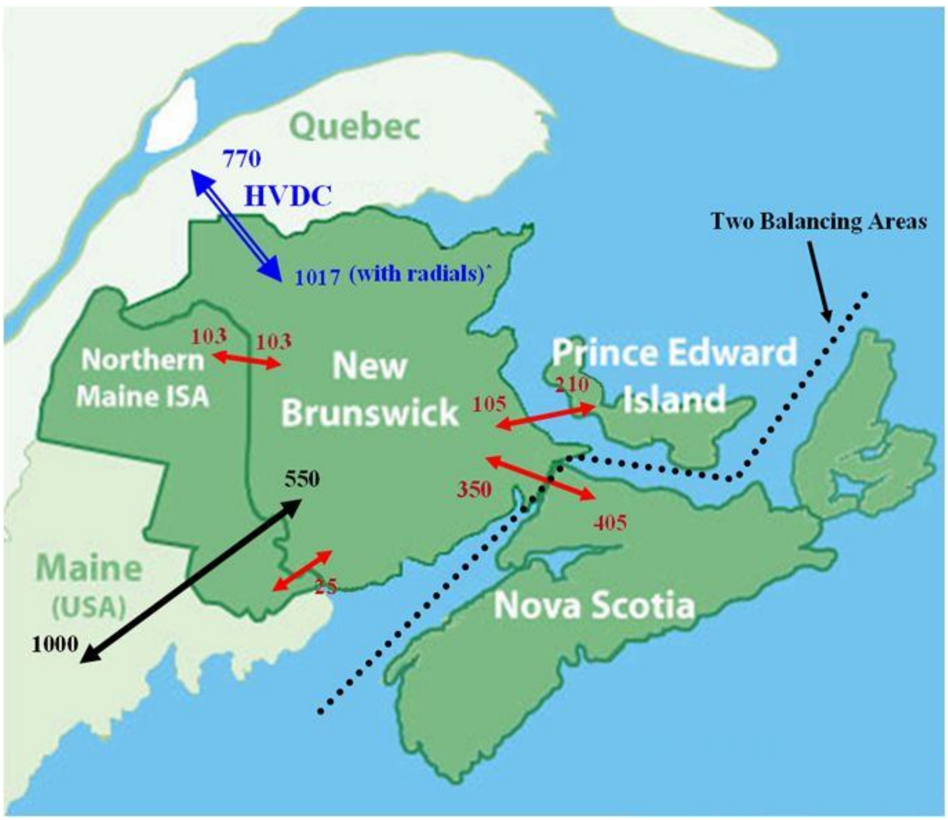


Figure 2: Existing Interface Total Transmission Capabilities (MW)

Note: The NB→NS flow is limited to 300 MW under normal conditions. This is due to an NS System Operating Limit put in place to avoid unacceptable amounts of under frequency load shedding in NS for loss of the interface.

5. Transmission Upgrades

The production modeling process identified the key interfaces as being those between:

1. New Brunswick and Nova Scotia, and
2. New Brunswick and Prince Edward Island

These interfaces have been previously studied at a high level to determine their approximate transfer capabilities and associated cost. A summary of the findings from these previous studies follow.

- <u>The New Brunswick-Nova Scotia Interface</u>

The NB-NS interface was studied by NB Power and NS Power in 2010. The study was prompted by the desire to investigate the options to increase the total transfer capabilities between NB and NS. The study team examined the options necessary to expand the 345 kV transmission system between the provinces. This study included both analysis of transmission capacity and capital cost for proposed infrastructure additions. The transmission reinforcements recommended in this report provide a potential solution to increasing the transfer capability to at least 800 MW in both directions between New Brunswick and Nova Scotia.

The recommended reinforcements of the existing system required the following:

- a second 345 kV transmission line from Onslow to Salisbury with a tap into Memramcook
- a second 345 kV transmission line from Salisbury to Coleson Cove
- a new 138 kV line from Springhill to Onslow
- additional voltage control at Norton, Salisbury and Memramcook

The estimated total cost of the transmission infrastructure additions is $411 million.

- <u>The New Brunswick-Prince Edward Island Interface</u>

The NB-PEI interface has been the subject of previous study. The study concluded that the addition of a third 138 kV cable connecting the two provinces would provide a total of at least 350 MW interface capability in both directions. The new cable would parallel the existing 138 kV cables and terminate at or near the existing submarine cable terminations in New Brunswick and PEI. The estimated cost of the new interconnection facilities is approximately $77 million.

In addition, a third line between the Memramcook and Murray Corner substations is required to fulfill the potential of 350 MW of load flow in both directions on the NB-PEI interface. The cost of this line is approximately $28 million. Further study is required to refine the route and specifics of this transmission line.

Table 1: Transmission Analysis Summary

Transmission Upgrade Option	Terminal	Terminal	Interface Capability (MW)		Cost[2] $ x million
			NS→NB	NB→NS	
345 kV Onslow/Coleson Cove	Onslow, NS	Coleson Cove, NB	800	800	$454
345 kV Onslow/Salisbury	Onslow, NS	Salisbury, NB	750	tbd	$224
345 kV Onslow/Memramcook	Onslow, NS	Memramcook, NB	500+[1]	tbd	$176

(1) The export from NB to PEI is to be added to this Transfer capability.
(2) 2010 estimate escalated to year 2015 at 2% per year.

Transmission Upgrade Option	Terminal	Terminal	Interface Capability (MW)		Cost[3] $ x million
			PEI→NB	NB→PEI	
138 kV PEI/Murray Corner	Bedeque, PEI	Murray Corner, NB	350	350	$111

(3) 2012 estimate escalated to year 2015 at 2% per year.

6. Discussion of Results

The AEG Transmission Planning Committee initially had a broad focus on potentially beneficial transmission upgrades. The production modeling process quickly identified the key interfaces as being those between New Brunswick and Nova Scotia and New Brunswick and Prince Edward Island. These interfaces had been previously studied at a high level to determine their approximate transfer capabilities and associated cost.

Findings identified in this report are preliminary. Existing studies were used where available to determine cost and identify potential operational issues. The extent of transmission studies to date is not sufficient to commit to installation and operation of transmission infrastructure required to increase tie capacity at various interfaces.

Appendix 3 identifies studies that are required to access the impact and define the requirements necessary to enhance the transmission capabilities of NB interfaces with NS and PEI that may be desirable for the horizon years 2020 and 2040. This document does not include details for additional system impact studies required for the transmission grids within Nova Scotia, PEI, and Newfoundland and Labrador. They too will need studies similar to those outlined in Appendix 3.

AEG Transmission Modeling Study
Appendix 1

Table 1: Preliminary List of AEG Regional Transmission Upgrade Options

#	Transmission Upgrade Option	Terminal (From)	Terminal (To)
1a	345 kV Onslow/Coleson Cove	Onslow, NS	Coleson Cove, NB
1b	345 kV Onslow/Salisbury	Onslow, NS	Salisbury, NB
1c	345 kV Onslow/Memramcook	Onslow, NS	Memramcook, NB
2a	138 kV PEI/Memramcook	PEI	Memramcook, NB
2b	138 kV PEI/Murray Corner	PEI	Murray Corner, NB
3	138 kV PEI/NS	PEI	NS
4	HVDC Bottom Brook/Lingan	Bottom Brook,NL	Near Lingan, NS
5	HVDC NL/Salisbury	NL	Salisbury, NB
6	Options 1a & 2a	n/a	n/a
7	Options 1a & 2a & 4	n/a	n/a
8	345 kV Lepreau/Orrington	Lepreau, NB	Orrington, Maine
9	HVDC NB/HQ	NB	HQ
10	HVDC Lepreau/NE	Lepreau, NB	tbd
11	HVDC Lepreau/NE	Lepreau, NB	tbd
12	Options 7 & 8	n/a	n/a
13	Options 7 & 9	n/a	n/a
14	Options 7 & 8 & 9	n/a	n/a
15	345 kV Digby/Lepreau	Digby, NS	Coleson Cove, NB
16	Upgrade NB & MPS Interface	tbd	tbd

AEG Transmission Modeling Study
Appendix 2

Summary of Existing Firm and Non-Firm Transmission Capacity of New Brunswick Interfaces With Nova Scotia and PEI For AEG Resource Group Modelling

1.0 Summary

The existing 2011/12 Firm and Non-Firm transmission capacities available on the New Brunswick/Nova Scotia interface and the New Brunswick/PEI interface are shown in the following table.

2011/12								
	NB / NS Interface				NB / PEI Interface			
	NB → NS		NS → NB		NB → PEI		PEI → NB	
	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm
Winter	0	300	178	350	80	210	105	105
Summer	20	300	178	350	80	210	105	105

Winter season months are November to March inclusive. Summer season months are April to October inclusive.

For AEG Resource modeling, the 2011/12 Firm and Non-Firm transmission numbers represent the Limited Transmission case in years 2020 through 2040 with the following assumptions:

- Existing reserve sharing agreements are maintained.
- Existing firm transmission reservations are renewed.
- Existing transmission numbers do not reflect future resource and load changes affecting transmission flows in the south eastern area of NB, and these changes are unknown at this time.

2.0 References

[1] *Total Transfer Capability Report of the NSPI and MECL Interfaces for Winter 2011-12 Part 1.* July 29, 2011

[2] *Total Transfer Capability Report of the NSPI and MECL Interfaces for Winter 2011-12 Part 2.* October 12, 2011

3.0 Background - Summary of 2011/12 TTC and TRM Values

2011/12								
	NB / NS Interface				NB / PEI Interface			
	NB → NS[1]		NS → NB[2]		NB → PEI[3]		PEI → NB[4]	
	TTC	TRM	TTC	TRM	TTC	TRM	TTC	TRM
Winter	405	405	350	172	210	130	105	0
Summer	405	385	350	172	210	130	105	0

[1] The NB → NS TTC value is comprised of the following two components:

- 300 MW of this TTC value is due to an NS System Operating Limit (SOL) under normal system conditions in place to avoid unacceptable amounts of under frequency load shedding in NS for loss of the NSPI interface.
- 105 MW of this TTC value allows for NS access its portion of the Maritime reserve requirement under emergency conditions.

The NB → NS TRM values account for variances in generation dispatch. Under high flows from southwest NB into southeast NB line 1149 can become overloaded for the loss of line 3004. A portion (105 MW) of the total TRM for this interface for exports from NB to NS must be set aside to allow NS access to its share of the Maritime reserve requirement. This TRM value is also related to the transfer capability constraints for simultaneous exports from NB to NS and PEI, and the current 80 MW of long-term firm reservations from NB to PEI.

[2] The NS → NB TTC value is limited by an SOL in NS. This SOL restricts imports to NB from NS in order to avoid rejecting more than two Lingan units to remain tied to the NB transmission system for the loss of the interconnecting 345 kV line 3025/8001.

The NS → NB TRM value allows for NB access to its 172 MW share of the Maritime reserve requirement.

[3] This NB → PEI TTC value is limited by the 8 hour thermal limit (105 MW at a 0.9 pf) of each 138 kV undersea cable between the Murray Corner (NB) and Bedeque (PEI) terminals. There is a Cable Overload Scheme in PEI that will shed load in PEI for the loss of one cable to protect the remaining in-service cable.

This NB → PEI TRM value accounts for variances in generation dispatch. Under high flows from southwest NB into southeast NB line 1149 can become overloaded for the loss of line 3004. This TRM value is related to the transfer capability constraints for simultaneous exports from NB to NS and PEI. Currently there are long-term firm reservations totalling 80 MW from NB to PEI across the MECL interface. These long-term firm commitments exceed the firm limit when the NB system load is slightly above 2600 MW. The possible options for meeting these long-term firm commitments include:

- The appropriate dispatch of generation.
- Implementing a temporary operational mitigation measure to monitor loading on line 1149 and take operator action as needed.

[4] This PEI → NB TTC value is limited by the eight hour thermal limit (117 MVA) of one undersea 138 kV cable between NB and PEI for the loss of the other 138 kV undersea cable. A power factor of 0.90 has been factored into the TTC limit.

There is no TRM required.

4.0 Background - Summary of 2011/12 Firm and and Non-Firm Transmission Capacity

The TTC/TRM values is section 3.0 are converted to Firm and Non-Firm as follows:

- Firm Transmission = TTC – TRM
- Non-Firm Transmission Capacity = TTC – reserve sharing amount

2011/12								
	NB / NS Interface				NB / PEI Interface			
	NB → NS		NS → NB		NB → PEI		PEI → NB	
	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm
Winter	0	300	178	350	80	210	105	105
Summer	20	300	178	350	80	210	105	105

AEG Transmission Modeling Study
Appendix 3

Scope of Transmission Studies to Accommodate the Proposed AEG Transfer Levels Via NB Interfaces with its Atlantic Neighbours 2020 to 2040

January 30, 2012

Power System Engineering
New Brunswick System Operator
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E3A 8V2

Scope of Transmission Studies to Accommodate the Proposed AEG Power Transfer Levels Via NB interfaces with its Atlantic Neighbours 2020 to 2040

1. Background Information

- The Atlantic Energy Gateway (AEG) initiative is an opportunity to promote and facilitate the development of clean and renewable energy sources in Atlantic Canada. The initiative will complement all current and future energy plans and resources being undertaken in the region in the timeframe between 2020 to 2040.

- The AEG Initiative involves work by the four Atlantic Canada energy departments, their provincial utilities and ACOA and Natural Resources Canada. The work includes planning for generation, transmission, and system operation, as well as electricity markets, supply chain development, research and development and regulatory improvements.

- Because of its geographic location New Brunswick is impacted by changes to import, export and wheeling of electrical power directly to and from Nova Scotia, Prince Edward Island, Quebec and New England, and indirectly to and from Newfoundland and Labrador.

2. Objectives of this Document:

1. Give a brief summary of the existing Total Transmission Capabilities (TTC) between NB and its neighbouring systems with focus on NB interface capabilities with NS and PEI.

2. Give a scope of the transmission studies required to assess the impact and define the requirements necessary to enhance the transmission capabilities of NB interfaces with NS and PEI, in light of the preliminary findings of the AEG Resource Modeling and Transmission groups for the horizon years 2020 and 2040.

3. Give an estimate of the man-weeks required to complete the studies.

4. This document does not include details for additional system impact studies required for the transmission grids in Nova Scotia, PEI, and Newfoundland and Labrador.

.

3. Summary of Total Transfer Capability (TTC) Values between NB and Neighbouring Systems

The geographical map of Figure 1 shows NB electrical interfaces with neighbouring systems. The existing 2011/12 export and import TTC values at various NB electrical interfaces are shown in Figures 2 and 3 respectively.

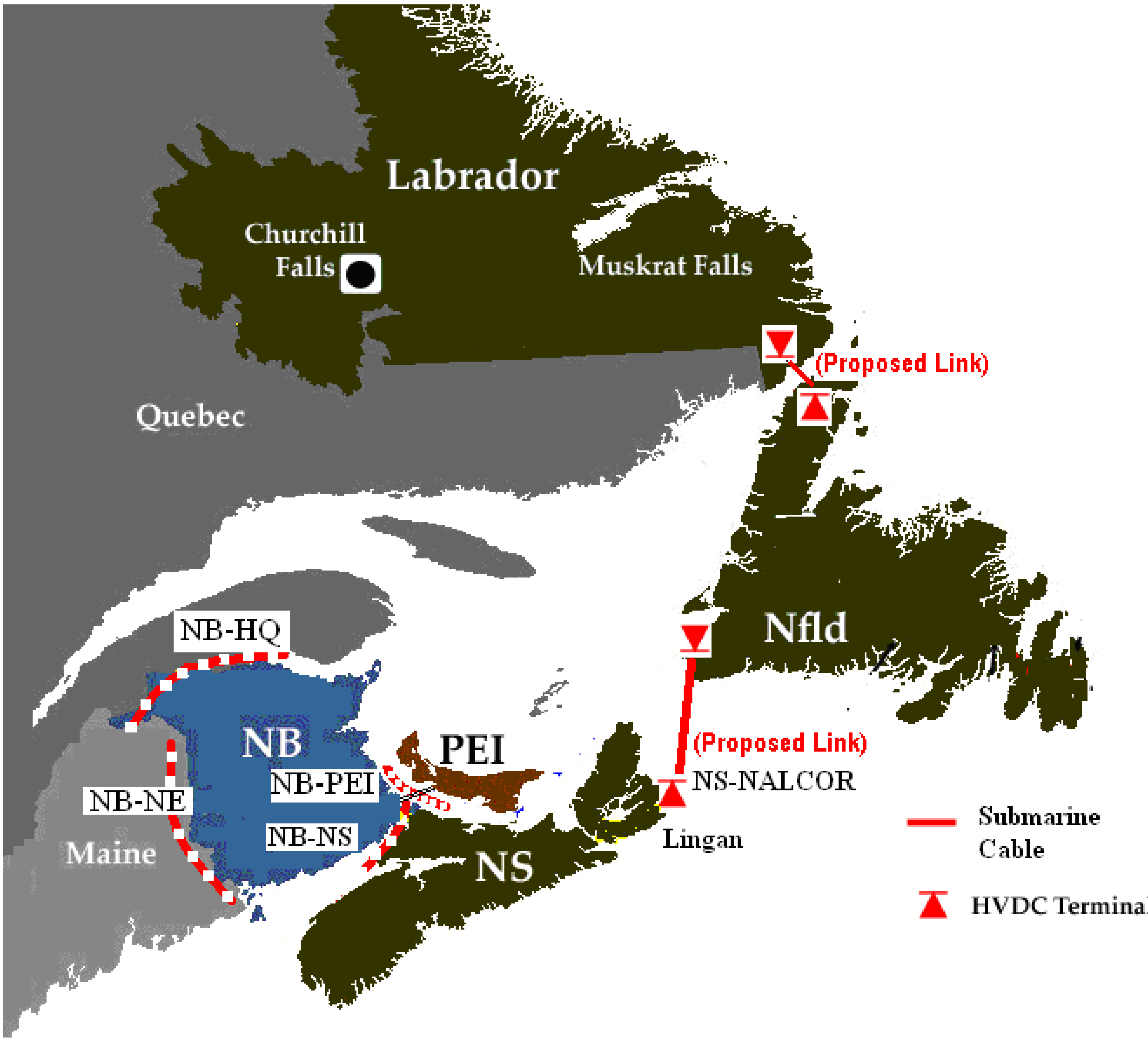

Figure 1: New Brunswick Electrical Interfaces with Neighbouring Systems

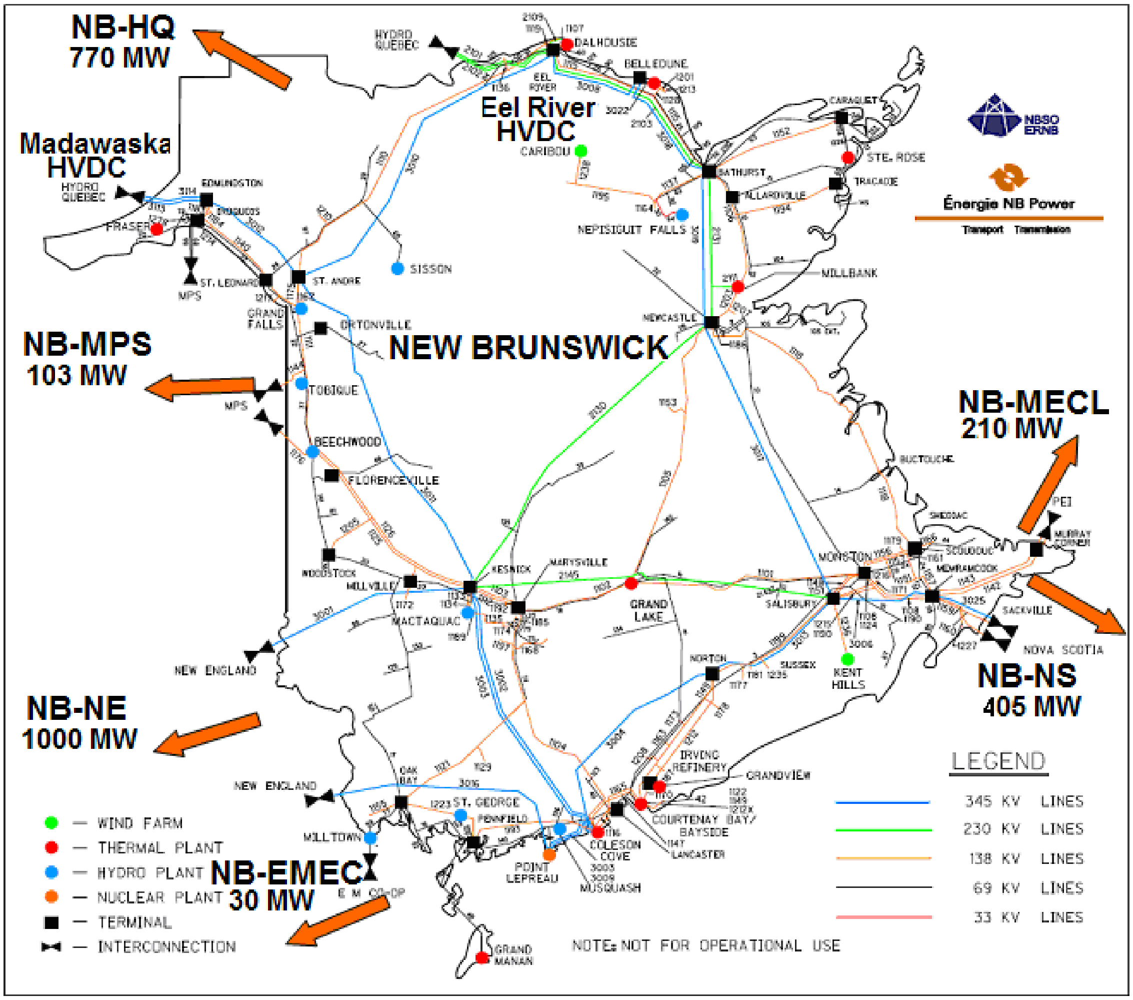

Figure 2: NB Transmission Map Showing Maximum Export TTC Values as of 2011/12

Note: The NB→NS flow is limited to 300 MW under normal conditions. This is due to an NS System Operating Limit put in place to avoid unacceptable amounts of under frequency load shedding in NS for loss of the interface.

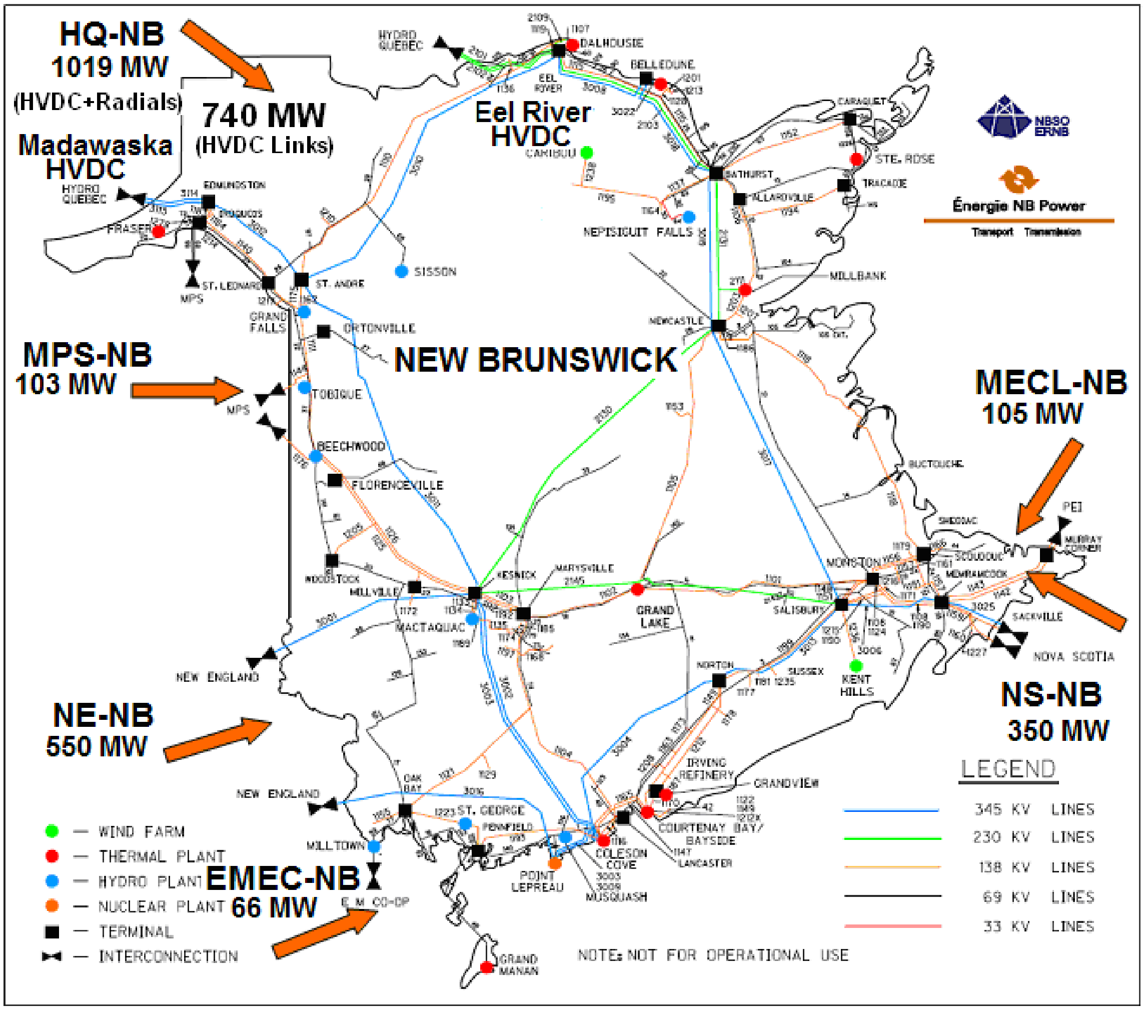

Figure 3: NB Transmission Map Showing Maximum Import TTC Values as of 2011/12

4. Firm and Non-Firm Transfer Capability of NB Interfaces with NS and PEI

The present Firm and Non-Firm transmission capacities available on the New Brunswick/Nova Scotia interface and the New Brunswick/PEI interface are shown in Table 1. For AEG Resource modeling, the 2011/12 Firm and Non-Firm transmission numbers represent the Limited Transmission case in years 2020 through 2040 with the following assumptions:

- Existing reserve sharing agreements are maintained.
- Existing firm transmission reservations are renewed.
- Existing transmission numbers do not reflect future resource and load changes affecting transmission flows in the southeastern area of NB, and these changes are unknown at this time.

Table 1: Firm and Non-Firm Capability of NB Interfaces with NS and PEI -2011/12

2011/12								
	NB / NS Interface				NB / PEI Interface			
	NB → NS		NS → NB		NB → PEI		PEI → NB	
	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm
Winter	0	300	178	350	80	210	105	105
Summer	20	300	178	350	80	210	105	105

5. Transmission Studies Required to Enhance the Capability of NB Interfaces with NS and PEI-2020 to 2040

As indicated in Table 1, the firm transfer capacity between NB and its Atlantic neighbours is almost zero. Although the tables display some non-firm numbers, the number of hours that the grid is capable of serving these non-firm quantities is expected to shrink in the future as load grows, particularly in south eastern New Brunswick. Therefore in order to meet the objectives of the AEG initiative and effectively utilize the electrical energy resources in Atlantic Canada, enhancing NB interfaces with NS and PEI may be required.

Building on previous preliminary studies between NB Power and Nova Scotia Power, this document gives the scope of additional studies required to assess the impact of three transmission development scenarios:

<u>Scenario A</u>: This scenario, shown in Figure 4, involves building 345 kV transmission lines parallel to existing lines from Coleson Cove-Salisbury-Memramcook in NB to Onslow, NS, with the objective of achieving firm bidirectional transfer capacity between NB and NS of 800 MW. This development scenario will include the necessary terminations of the new lines, reactive/voltage control facilities, and upgrade/enhancement of the underlying 138 kV systems in NB and NS. Comprehensive study is required to define the requirements to achieve that objective and assess the impact on the interconnected system. Also, study is required to assess the individual and simultaneous TTC values between the NB system and its interfaces with NS and PEI.

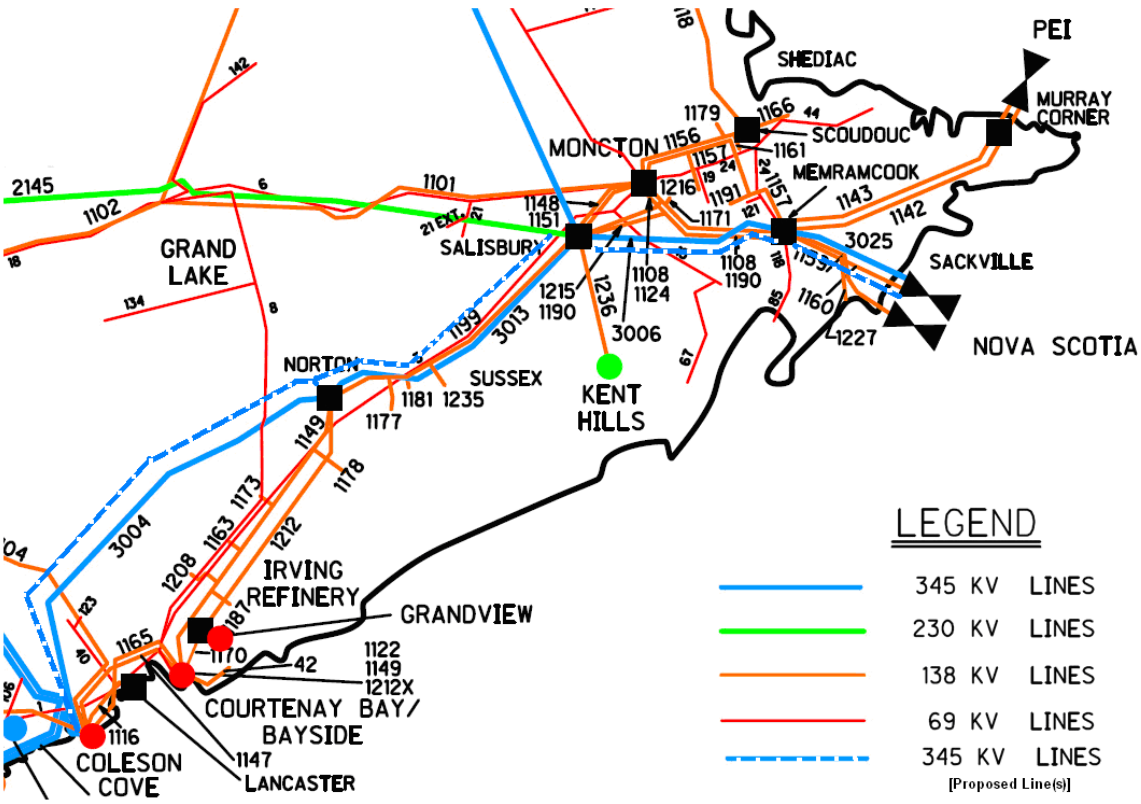

Figure 4: Transmission Development Scenario "A"

<u>Scenario B</u>: This scenario, shown in Figure 5, involves building parallel 345 kV lines only from Salisbury-Memramcook in NB to Onslow, NS. This scenario aims mainly at achieving a TTC value from NS to NB of about 750 MW, based on preliminary studies. Further comprehensive study is required to define the requirements to achieve that objective and assess the impact on the interconnected system. Also study is required to assess the individual and simultaneous TTC values between NB system and NS and PEI interfaces.

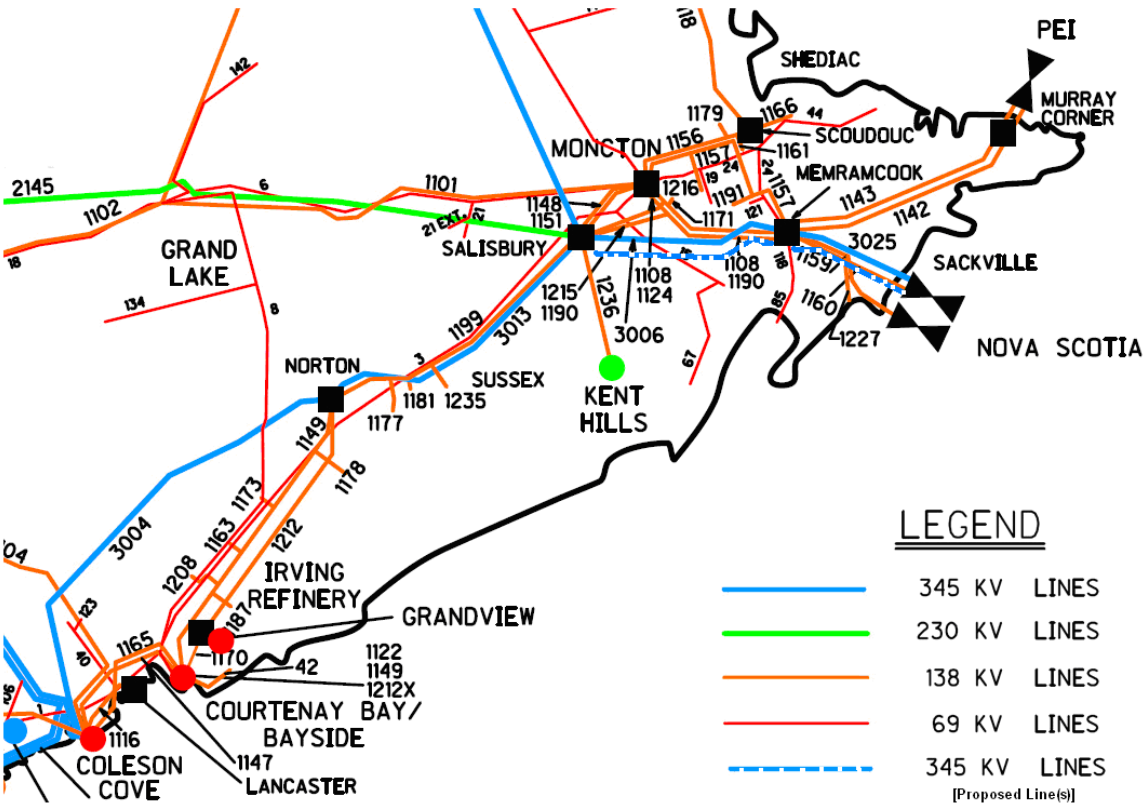

Figure 5: Transmission Development Scenario "B"

<u>Scenario C</u>: This scenario, shown in Figure 6, involves limited development of the 345 kV transmission system between Memramcook, NB and Onslow, NS. This scenario aims mainly at achieving a TTC value from NS to NB of about 500 MW, based on preliminary studies. Further comprehensive study is required to define the requirements to achieve that objective and assess the impact on the interconnected system. Also study is required to assess the individual and simultaneous TTC values between NB system and NS and PEI interfaces.

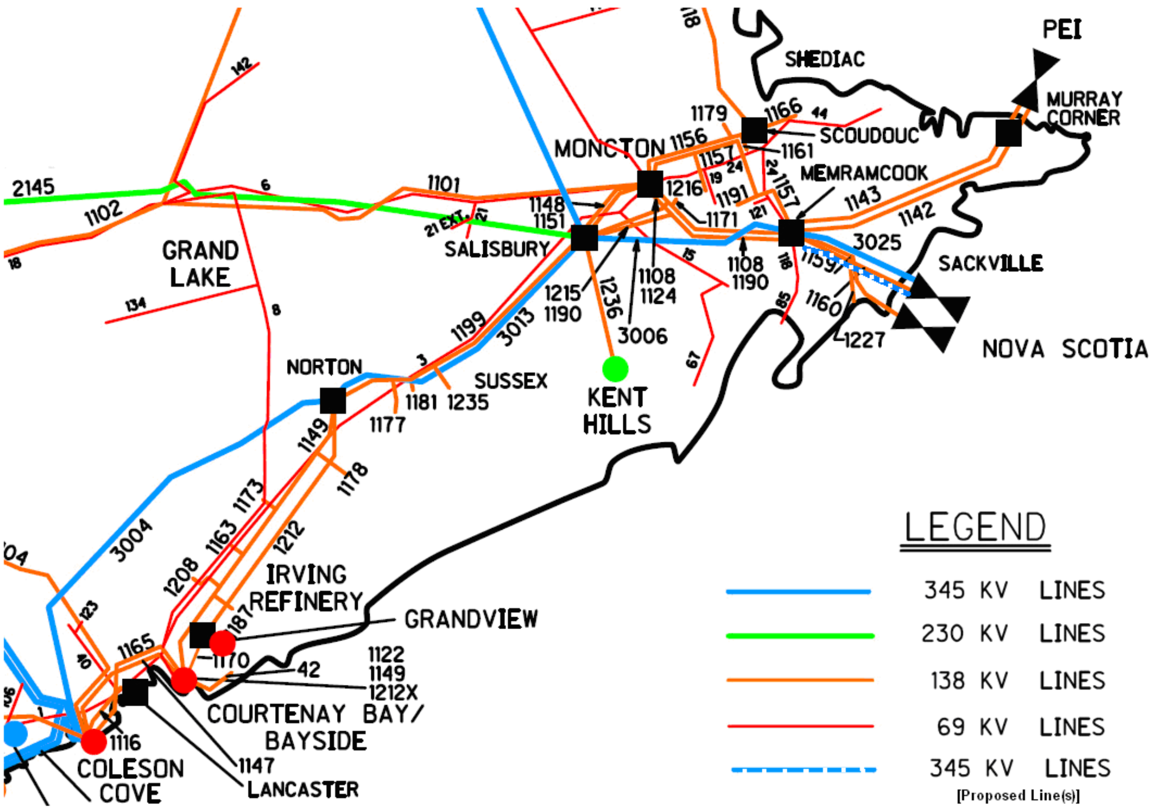

Figure 6: Transmission Development Scenario "C"

6. Study Scope for Transmission Development Scenario 'A" for 2020/2021:

Basic Assumptions**:**

- Study year 2020.
- No under voltage load shedding, no curtailment of firm load or firm transactions for design (normal criteria) contingencies as per NPCC and NERC criteria and standards.
- Size of largest acceptable loss of load in the Maritimes is 250 MW.
- Transmission development under the MPRP in Maine, USA is complete.
- Size of the largest acceptable loss of source in the Maritimes is 740 MW (Equivalent to simultaneous import from both Madawaska and Eel River).
- A third cable between PEI and NB is installed.
- Development of Muskrat Falls project.
- The HVDC interconnection between NFLD and NS has been developed.
- Any other transmission or generation projects in Atlantic Canada and Maine, USA foreseen by 2020.

Base Case Development:

- Load Levels Based on forecasted load in NB and neighbouring systems for year 2020:
  - Winter Peak
  - Summer Peak Load
  - Summer Light Load
- Generation dispatch in NB and the Maritimes in general: Include all committed wind generation or any other potential projects by 2020 as presented in the AEG resource modeling group report.
- A special Winter Peak base case without any wind generation in the Maritimes will be developed.
- Network configuration and assumptions for new transmission facilities will be modeled as in the most recent NPCC Overall Transmission Review. The base cases will be modified to incorporate any additional transmission reinforcements in NB and NS systems, which will be identified in the course of this SIS, for the purpose of accommodation of the TSRs from HQ to NS.
- Import/Export conditions over NB interconnections with, Quebec and New England will be modeled at their Total Transfer Capabilities.

Approach for Developing the Base Cases for Transmission:

- Start from Base Cases of the most recent NPCC Overall Transmission Review.
- Update load, dispatch and network for 2020/2021 as per most recent load forecast.
- Incorporate NB, NS and PEI initial modeling assumptions for their respective systems.
  - NB/NS interface upgrades
  - HVDC bus location to connect Nova Scotia with NALCOR.

  - Model other potential transmission assumptions for each of the three transmission development scenarios A, B and C (e.g. 345 kV reinforcement between Coleson Cove, Salisbury, Memramcook and Onslow).
  - Model any additional reinforcements required for the underlying 138 kV system and voltage/reactive controls.
  - Model equivalent generators to account for potential new sources in the future as documented in by the AEG resource modeling group.
- The tentative matrix of Base Cases for the study year 2020/2021, assuming the transmission scenario “A”, is shown in Table 4.

Table 4: Matrix of Base Cases for Transmission Development Scenario A 2020/2021

	Import/ Export (MW)				
	NB-NS	NB-PEI	NB-NE	NB-HQ (HVDC)	NALCOR-NS
Summer Light Load SL-D1-A SL-D2-A	-800 800	100 100	1000 1000	500[(1)] -740	500 -320
Summer Light Load (Lepreau off) SL-D3-A SL-D4-A	-800 800	-200 200	1000 1000	0 -740	500 -320
Intermediate Load (Summer Peak) SP-D1-A SP-D2-A	-800 800	-200 200	1000 1000	500[(1)] -740	500 -320
Winter Peak Load WP-D1-A WP-D2-A	-800 800	200 200	1000[(2)] 1000[(2)]	0 -740	500 -320
Winter Peak Load (Lepreau off) WP-D3-A WP-D4-A	-800 800	200 200	0 -500	-350 -740	500 -320
Winter Peak Load (All wind in Maritimes off) WP-D5-A WP-D6- A	-800 800	200 200	-500 -500	0 -740	500 -320

Notes:

1) To observe the simultaneous export limits to NE and HQ and the 250 MW maximum loss of load limit, the 500 MW export limit to HQ is composed of 250 MW at each of Eel River and Madawaska HVDC links.
2) NB to NE Transfer will be adjusted up to 1000 MW, depending on availability of generation capacities in NB.

Study and Analysis:

- Part I: All Facilities In-Service:
  - Steady State Analysis:
  - Thermal and Voltage/Reactive (V/R) analysis

- Single Contingency Load Flow Analysis
- Identify any additional facilities required to support the transfers listed in the matrix of base cases. Modify the base case as necessary.
- Normal Criteria Transient Stability and Post Contingency Analysis
- Extreme Contingency Analysis. To test if there is an adverse system impact that may require mitigation measures.
- Review of Special Protection Systems (SPSs)
- Short Circuit Analysis. To test if there is a need to upgrade the protection or switching switchgear.
- Conclusions and Recommendations for Part I

* Part II: Under Single Contingency Outage (n-1) Conditions
  - List of Facilities out-of-service.
  - For each out-of-service facility reconstruct a new base case, taking into consideration the 30 minute dispatch including adjusting the transfers between NB and its neighbouring systems.
  - Reconstruct base case import/export matrix.
  - Steady State Analysis.
  - Thermal and V/R analysis.
  - Single Contingency Load Flow Analysis
  - Normal Criteria Transient Stability and Post Contingency Analysis
  - Extreme Contingency Analysis
  - Review of Special Protection Systems (SPSs)
  - Short Circuit Analysis
  - Conclusions and Recommendations for Part II

Study Scope for Transmission Development Scenario 'A" for 2040/2041:
Modify the matrix of base cases as per the input from the AEG Resource Group. Repeat the analysis for year 2040/2041 following the same procedure as given in Section 6 for year 2020/2021.

Study Scopes for Transmission Development Scenarios 'B" and "C" are similar to "A", but require development of new matrices of base cases, based on input from the AEG Resource Group.

References:

[1] *Summary of Existing Firm and Non-Firm Transmission Capacity of New Brunswick Interfaces with Nova Scotia and PEI for AEG Resource Modeling Group, NBSO, January 18, 2012.*
[2] *Total Transfer Capability Report of the NSPI and MECL Interfaces for Winter 2011-12 Part 1.* July 29, 2011
[3] *Total Transfer Capability Report of the NSPI and MECL Interfaces for Winter 2011-12 Part 2.* October 12, 2011

NBSO Time Estimate for of Completion of the Transmission Study of the Three Proposed Transmission Scenarios for the AEG Initiative:

An estimated person-weeks for completion of the studies is given below.

Task	Estimated Time (Engineer-weeks)
Base Case Set-Up (data collection, load flow, dynamics, automation files, diagrams, etc) for year 2020/2021-Transmission Scenario A	3
Steady State Simulation and Analysis-Scenario A	3
Transient Simulation and Analysis-Scenario A	4
Repeat for year 2040/2041-Scenario A	8
Repeat for Transmission Scenario B 2020/2021 and 2040/2041	15
Repeat for Transmission Scenario C 2020/2021 and 2040/2041	10
Miscellaneous (meetings, resolving of unforeseen issues, etc)	4
Compilation of Report	4
Total Estimated Time	51

AEG Transmission Modeling Study
Appendix 4

Labrador – Island Link and Maritime Link Description

Introduction

Phase One of the Lower Churchill Project includes development of the Muskrat Falls generating facility on the lower Churchill river in Labrador, construction of high voltage ac transmission between Churchill Falls and Muskrat Falls, construction of an HVdc transmission system between Labrador and the Island of Newfoundland, high voltage ac transmission upgrades on the Island and construction of an HVdc transmission system between Newfoundland and Nova Scotia.

Muskrat Falls Generating Station

The Muskrat Falls Generating Station will consist of four 206 MW hydroelectric generator sets for a rated plant capacity of 824 MW. The electric generators will have a 0.90 power factor to provide the necessary reactive power supply to the HVdc converter station located adjacent to the plant. Kaplan turbines will be utilized as the prime mover.

Labrador Transmission Additions

The Muskrat Falls generator step-up transformers will increase the voltage from the rated terminal voltage of the machine to 315 kV. Two single circuit, 250 km long, 315 kV transmission lines will connect the Muskrat Falls switchyard to the switchyard at Churchill Falls. At Churchill Falls an extension to the 735 kV switchyard will include 735/315 kV autotransformers and the 315 kV transmission line terminations.

Labrador – Island Link (LIL)

The Labrador – Island HVdc Transmission System, or LIL, will be a ±350 kV bipole with a rating of 900 MW (450 MW per pole). The system will utilize line commutated converter technology. The transmission system includes 380 km of overhead HVdc transmission line in Labrador, a 30 km submarine cable crossing of the Strait of Belle Isle and 688 km of overhead HVdc transmission line on the Island of Newfoundland. The overhead transmission system will include optical fibre in the overhead ground wire for high speed communication between converter stations

The converter station in Labrador will be located adjacent to the Muskrat Falls Generating Station. The converter station on the Island of Newfoundland will be located on the Avalon Peninsula near the major load center at a location called Soldiers Pond. Soldiers Pond has been selected as the location of the converter station given that:

- it is located between the Holyrood Thermal Generating Station (which will cease production with the construction of the LIL) and the load center on the northeastern Avalon Peninsula; and
- all major 230 kV transmission lines in the region converge near this location, thereby reducing ac transmission line upgrades.

The LIL will have a nominal rating of 900 MW in bi-pole mode. In mono-polar mode each pole is capable of operating at 900 MW for ten minutes and 675 MW continuous. This arrangement prevents loss of load/load shedding on the Island of Newfoundland system for permanent loss of a pole. The 10 minute, 900 MW rating provides time for operators on the Island to start standby generation.

The Soldiers Pond converter station will include three high inertia synchronous condensers for voltage support, reactive power control, equivalent short circuit ratio and frequency support for the wide operating range of the LIL. The system is designed to withstand the temporary loss of the bi-pole (i.e. pole-to-pole faults). The Strait of Belle Isle cable crossing will include three cables (one energized spare) and switching arrangements at both cable transition compounds for redundancy.

System Upgrades Island of Newfoundland

Upgrades to the ac transmission system on the Island of Newfoundland include 230 kV circuit breaker replacements due to increase short circuit levels, conversion of units at Holyrood to synchronous condenser capability and thermal uprating of a number of 230 kV transmission lines.

Maritime Link (ML)

The Maritime Link will connect the 230 kV ac transmission system on the western portion of the Island of Newfoundland to Cape Breton in Nova Scotia. The system will be rated ±200 kV and 500 MW in bi-pole mode. Given the relatively weak connection points in both the Newfoundland and Nova Scotia systems, the voltage source converter technology will be employed.

The HVdc transmission system will consist of 130 km of overhead HVdc transmission line from Bottom Brook in Newfoundland to the Cabot Strait, 180 km of submarine cable across the Cabot Strait and approximately 46 km of overhead HVdc in Cape Breton to the NSPI ac transmission system.

To limit the impact of ML outages, an asymetrical bi-pole arrangement will be used for the VSC converters to permit mono-polar operation of ML. This, in turn, provides a mono-polar rating of 250 MW.

The addition of a new 230 kV transmission line from Granite Canal to Bottom Brook on the Newfoundland transmission system permits transfer of up to 250 MW via the ML for single 230 kV transmission contingencies on the Island of Newfoundland.

The ML will be bi-directional in design such that power and energy can be imported from the Maritimes to Newfoundland should there be a sustained forced bi-pole outage to the LIL.

NON-CONFIDENTIAL

Request IR-257:

Page 12 of Appendix 6.05 states that "…While there is no guarantee that all the supplemental energy purchases would be from renewable sources there is high expectation of such as Hydro Quebec has few thermal resources…" If there is no guarantee that the supplemental energy purchases would be from renewable energy sources, please explain how this supply alternative is indeed comparable to the Muskrat Falls purchase via the Maritime Link.

Response IR-257:

Please refer to page 126, lines 3-9 of the Application. Failure of the non-emitting import energy to qualify as renewable could eliminate the Other Import as a valid alternative, or require an increase in costs in order to meet RES requirements through additional renewable electricity from another source.

NON-CONFIDENTIAL

Request IR-258:

With reference to Appendix 6.05, pages 12-13, please confirm that the only way the second supply alternative (the Firm Hybrid Supply) is comparable to the Maritime Link project is if transmission is redirected such that any available supplemental energy is delivered from Hydro Quebec. If this is incorrect, please clarify.

Response IR-258:

In order to meet the regulations, it is estimated that additional renewable energy, above the firm deliveries in the Hybrid option, will be required. Delivery of supplemental energy from New England is not likely to be renewable. The most probable source of renewable energy under this option is Hydro Quebec. Only the portion of supplemental energy that is required for the regulations needs to be renewable. The remainder can be sourced from non-renewable sources in New England or elsewhere.

NON-CONFIDENTIAL

Request IR-259:

With reference to Appendix 6.05, pages 12-13, did the WKM report consider an alternative supply option where not the full 500 MW, but 165 MW is purchased from Hydro Quebec coupled with wind development in Nova Scotia?

Response IR-259:

No. Please refer to SBA IR-70.

NON-CONFIDENTIAL

Request IR-260:

With reference to Appendix 6.05, page 13, what is the basis of the 25% adder used to adjust transmission capital costs in the WKM report?

Response IR-260:

The 25 percent adder reflects the present value of the future stream of O&M and tariff related costs applicable to the transmission upgrades.

NON-CONFIDENTIAL

Request IR-261:

With reference to Appendix 6.05, Section 9 (pages 17-18):

(a) Please explain how the DC flow on the Maritime Link would respond to contingencies in Nova Scotia or on the Nova Scotia – New Brunswick interconnection.

(b) Please confirm that, under the terms of Schedule 5 of the Energy and Capacity Agreement, post-contingency support will only be available if pre-contingency deliveries are less than the NS Block Associated Capacity.

(c) Please confirm that, under the terms of Schedule 5 of the Energy and Capacity Agreement, if pre-contingency deliveries are less than the NS Block Associated Capacity, post-contingency support will be no more than the difference between the NS Block Associated Capacity and the pre-contingency deliveries.

(d) Please confirm that the New Brunswick- Nova Scotia interconnection will provide energy in excess of the scheduled flow following a contingency and that the MaritimeLink will not.

(e) Please provide the normal, short-term emergency and long-term emergency ratings for the New Brunswick- Nova Scotia interconnection for both the system as currently installed and the system with the upgrades proposed by WKM for the Other Import case.

(f) Please explain how a "second interconnection provides an opportunity for an expanded balancing area which can assist in the integration of the amount of wind committed to be added to the NSPI system." Does this statement contemplate consolidation of Nova Scotia and Newfound-Labrador into a single balancing area?

(g) **Do the proposed agreements provide for "Dynamic Interchange Schedule", (as defined in the NERC "Glossary of Terms Used in Reliability Standards") of the Maritime Link flow?**

(h) **Please explain how the DC flow on the Maritime Link can be controlled to respond to the Nova Scotia area control error.**

(i) **Please confirm that, under the terms of Schedule 5 of the Energy and Capacity Agreement, if any portion of the regulating range exceeds the NS Block Associated Capacity, that portion is non-firm.**

Response IR-261:

(a) HVDC stations have very fast acting controls that can respond almost instantly to a contingency. Given section 3(a) of Schedule 5 of the Energy and Capacity Agreement (Appendix 2.04 of the Application) it is expected that 20 MW of regulation capacity will be under automatic generator control (AGC) at the Nova Scotia end of the Maritime Link. It will be activated to help off-set any generation/load imbalance in the NSPI system. This could be for rapid wind generation changes, a generation contingency in Nova Scotia or any generation surplus or shortage for a loss of the New Brunswick interconnection.

(b) No, post-contingency support is to be available for pre-contingency deliveries at a level higher than the Nova Scotia Block Associated Capacity if Nalcor has unused transmission capacity in the Maritime Link. If Nalcor does not have unused transmission capacity then the post-contingency support will only be available if pre-contingency deliveries are less than the Nova Scotia Block Associated Capacity.

(c) No, as explained in part (b) above it is possible to have post contingency support at a level higher than the Nova Scotia Block Associated Capacity if Nalcor has unused transmission on the Maritime Link.

(d) No, it is correct that the New Brunswick interconnection will provide energy in excess of the scheduled flow to support the contingency but, as explained in parts (a), (b) and (c) above, so will the Maritime Link.

(e) This was not prepared as part of the application.

(f) The second interconnection via the Maritime Link could provide for improved balancing in two ways. Firstly, it could be through an operating agreement like that contemplated for plus or minus 40 MW of Regulation Service in Section 3 of Schedule 5 of the Capacity and Energy Agreement (Appendix 2.04 of the Application). Secondly, if that initial balancing support proves to be successful the utilities could consider moving in the future to a single balancing area.

(g) It is clear in Schedule 5 of the Energy and Capacity Agreement that “Dynamic Interchange Schedule” of the Maritime Link flow is not a consideration in the current operating plans.

(h) The Area Control Error (ACE) is the difference between the scheduled interconnection flow to/from New Brunswick and the actual flow. If the ACE exceeds a pre-set minimum amount then generators that are selected for automatic generator control (AGC) are sent a signal to increase or decrease generation. This is usually done by pulses where each pulse results in a 1 MW generation change until the ACE is below the minimum value. By sending AGC pulses to the Maritime Link HVDC controls the flow via the Maritime Link into Nova Scotia can be increased or decreased to reduce the ACE.

NON-CONFIDENTIAL

(i) Yes, Section 3(c) of Schedule 5 gives Nalcor the right to withdraw capacity above the Nova Scotia Block Associated Capacity if it does not have unused transmission capacity on the Maritime Link. This makes the portion of the regulating range above the Nova Scotia Block Associated Capacity non-firm.

Request IR-262:

With reference to Appendix 6.05, page 20, in the Background column of Appendix A to the WKM Report it is noted that, "The Tariff Model applies the Cost Allocation and Tariff methodology approved by the PUB in 2003". Please provide a copy of the Tariff methodology that was approved by the PUB in 2003.

Response IR-262:

The Tariff Methodology as approved by the New Brunswick PUB in 2003 is that which is set out in the document "NB Power Tariff Design Document June 2002" and the PowerPoint presentation "NB Tariff Panel C Presentation" which are provided as Attachment 1 and Attachment 2, respectively.

NB POWER TRANSMISSION TARIFF DESIGN

June, 2002

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1.0 INTRODUCTION

An Open Access Transmission Tariff (Tariff) is the foundation upon which competition in electricity supply can occur. It opens the transmission system to all users under consistent non-discriminatory terms and conditions, and charges rates based on the cost of providing services.

There is a significant body of jurisprudence related to the principles to be applied in the design of monopoly services. These have been developed mainly for provision of completely bundled service to end-use customers for the supply of natural gas, electricity, water and telecom services.

The accepted approach is to group similar customers into classes. Costs are then allocated to each customer class based on the principle of “cost causation”. The cost of the portion of the system required to service a customer class, which is “used and useful” for that customer class, is allocated to that class. This follows from the need for fairness so that customer classes pay for the cost of the service provided and do not unduly subsidize another class. The overall objective is that rates be “just and reasonable”, without “undue discrimination”, and based on the “revenue requirement.”

This document explains the approach employed by NB Power to design its transmission tariff. While significant advances in transmission tariff rate design have been made, it is important to note that there is, as yet, no universal industry standard. Transmission rate design and pricing methodologies continue to evolve. NB Power’s approach closely follows relevant transmission pricing developments in other jurisdictions and applies them within the public policy directions of New Brunswick.

New Brunswick has targeted 2003 for electricity supplier choice to be available for municipal wholesale and industrial customers served from the transmission system. Supply is to be available from self-generation, independent third party suppliers, and also through a standard offer service from NB Power. Implementation requires that unbundled non-discriminatory transmission service be available. In designing the transmission tariff, consideration has been given to the directions of the *White Paper: New Brunswick Energy Policy*[1] and the recommendations of the New Brunswick Market Design Committee[2] in addition to traditional rate making principles.

2.0 TRANSMISSION RATE MAKING PRINCIPLES

This section provides details about transmission rate making principles. The key points discussed are: the evolution of principles applicable to NB Power (Section 2.1); the impact of the *Transmission Pricing Policy Statement* developed by the Federal Energy Regulatory Commission (FERC) in the United States (Section 2.2); the Federal Energy Regulatory Commission's Order 888 *Pro Forma Tariff* (Section 2.3); and, the New Brunswick Market Design Committee's Recommendations (Section 2.4).

2.1 Evolution of Principles Applicable to NB Power

Rate making principles for electric transmission services have been developed only in the last decade. They have been driven mainly in North America by the FERC which is empowered to regulate the *American Federal Power Act* (FPA).

Amendments to the FPA in 1992 provided for competition in electricity supply at the wholesale level, where wholesale is defined as "purchase for resale". Since then the FERC has significantly influenced transmission tariff design with the issuance of both its *Transmission Pricing Policy Statement* (1994) and *Order 888* which includes the *Pro Forma Tariff* (1996).

[1] Written by the New Brunswick Department of Natural Resources and Energy and released in January 2001. Cited and referred to as the *Energy Policy White Paper* (http://www.gnb.ca/0078/Energy/index.htm).

[2] Established by the Minister of Natural Resources (see *Energy Policy White Paper*, 3.1.3.1) to make recommendations concerning the design, structure, and rules for the development of a wholesale electricity market. The Final Report (April 2002) is available at http://www.nbmdc-ccmnb.ca/final_report.asp

While the FERC has no jurisdiction in New Brunswick, its principles have influenced policy makers here. The New Brunswick Market Design Committee has reviewed transmission tariff issues as part of its work regarding the implementation of supplier choice in New Brunswick. The following sections outline the FERC influence and the relevant transmission tariff recommendations of the Market Design Committee.

2.2 FERC Transmission Pricing Policy

The *Transmission Pricing Policy Statement*[3], issued by the FERC on October 26, 1994, specifies five principles regarding the pricing of transmission services. Instead of promoting a particular approach to rate design, the policy statement provides flexibility in the development of transmission pricing. The FERC recognized that there are a number of workable, non-traditional transmission pricing methods that offer potential improvements in fairness, practicality, and economic efficiency.

The FERC states that the pricing of transmission "be just and reasonable and not unduly discriminatory or preferential"[4]. The Commission elected to permit more flexibility to utilities to file innovative pricing proposals that meet the traditional revenue requirement but only if they satisfy the pricing principles below:

- Transmission Pricing Must Meet the Traditional Revenue Requirement
  "First a utility must determine its total company revenue requirement, the capital component of which traditionally has been measured by embedded (depreciated original) cost. Second, a utility must allocate among individual customers or classes of customers that portion of the total revenue requirement that is attributable to providing transmission services, in a manner which appropriately reflects the costs of providing transmission service to such customers or classes of customers. Finally the utility must design rates to

[3] Inquiry concerning the Commission's pricing policy for transmission services provided by Public Utilities under Federal Power Act; Policy Statement, October 26, 1994, Docket No. RM93-19-000, 18 CFR 2, 59 FR 55031 (http://www.ferc.gov/news/policy/pages/rm93-19.pdf).

recover those allocated costs from each customer class. Different customers may pay different rates if they use the system in different ways".[5]

- Transmission Pricing Must Reflect Comparability

  This principle requires that an *"…open access tariff that is not unduly discriminatory or anti-competitive should offer third parties access on the same or comparable bases, and under the same or comparable terms and conditions, as the transmission provider's uses of its system."*[6]

- Transmission Pricing Should Promote Economic Efficiency

  The FERC specifies that transmission pricing should promote; *"…efficient expansions of transmission capacity; efficient location of new generators and new loads; efficient use of existing transmission facilities…, and, efficient dispatch of existing generating resources".*[7]

- Transmission Pricing Should Promote Fairness

  "As a general matter, transmission pricing should be fair and equitable"[8]. Current transmission customers should not pay for the cost of providing wholesale transmission services to third-parties nor should third-party customers subsidize existing customers. *"The major purpose of transmission pricing reform should be to provide more efficient price signals, particularly for new transmission uses, and not simply to reallocate sunk costs"*[9].

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[4] FERC's Transmission Pricing Policy Statement, p5.
[5] FERC's Transmission Pricing Policy Statement, p6, referenced from 67 FERC at 61, 490.
[6] From the FERC's comparability standard (*American Electric Power Service Corporation (AEP)*, 67 FERC 61,168 (1994) at 61,490.
[7] FERC's Transmission Pricing Policy Statement, p7.
[8] FERC's Transmission Pricing Policy Statement, p7.
[9] FERC's Transmission Pricing Policy Statement, p7.

- Transmission Pricing Should Be Practical

  "Transmission pricing should be practical and as easy to administer as appropriate given the other pricing principles"[10].

The FERC refers to pricing proposals as being either "conforming" or "non-conforming." Conforming pricing proposals are based on the first two principles. Initially, innovative non-conforming proposals were considered acceptable, even if they were not based on the first two principles, as long as they produced "just and reasonable" rates. However there now appears to be a preference for proposals that conformed to the first two principles. While the other three principles continue to be viewed as goals that a conforming proposal must strive to meet, achievement is balanced against the need for transmission rates that are "just and reasonable".

2.3 Order 888 Pro Forma Tariff

In 1996 the FERC issued Order 888[11] which, included the Pro Forma Tariff. The order required all utilities under FERC jurisdiction to file a tariff which specified the terms, conditions and a pricing methodology that conformed to the pricing principles. The FERC was still open to non-conforming pricing proposals, but required that the proponent demonstrate that it was superior to the *Pro Forma* approach. In addition, through Order 889[12] the FERC standardized the reservation process through which transmission services could be transacted. This includes the requirement for an Open

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[10] FERC's Transmission Pricing Policy Statement, p8.

[11] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities Order No. 888 Final Rule (Issued April 24, 1996), United States Of America 75 FERC 61,080, 18 CFR Parts 35 and 385 [Docket Nos. RM95-8-000 and RM94-7-001] (http://www.ferc.gov/news/rules/pages/order888.htm).

[12] Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct Order No. 889 Final Rule (Issued April 24, 1996), United States Of America 75 FERC 61,078, 18 CFR Part 37 [Docket No. RM95-9-000] (http://www.ferc.gov/news/rules/pages/order889.htm).

Access Same-Time Information System (OASIS) and the Standards of Conduct with respect to non-discriminatory control of third party information. Clarifications to the *Pro Forma* approach have been made through various decisions and rulings of the FERC since.[13]

2.3.1 Pro Forma Transmission Services

Under the *Pro Forma Tariff* the transmission provider is responsible for providing reliable and efficient dispatch and transportation of energy (delivery service only). These services are known as Network Integration Transmission Service (network service) and Point-to-Point Transmission Service (point-to-point service). The transmission provider is not obligated to supply either energy or generation capacity.

Network service is firm transmission service delivered to the high side of the substation transformer. It includes the delivery of both capacity and energy. "*It allows a Transmission Customer to integrate, plan, economically dispatch and regulate its Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load customers. Network Integration transmission Service also may be used by the Transmission Customer to deliver non-firm energy purchases to its Network Load without additional charge.*"[14]

The transmission provider will provide network integration transmission service on a comparable, non-discriminatory basis to network customers. The transmission provider will permit such customers to integrate their designated network resources to service their network loads on a basis that is comparable to the transmission provider's use of the transmission system. Meters will be owned, read, and maintained by the transmission provider.

[13] For Orders 888a and 888b, see (http://www.ferc.gov/news/rules/pages/order888.htm). See (http://www.ferc.gov/news/rules/pages/order889.htm) for Orders 889a and 889b.
[14] FERC Glossary (http://www.tsin.com/gloss.html).

Point-to-point service[15] refers to the reservation of capacity and/or the transmission of energy from a point of receipt to a point of delivery. This service is available on either a firm or a non-firm basis.

2.3.2 Ancillary Services and Curtailments

The *Pro Forma Tariff* requires that the transmission provider make some ancillary services available at regulated rates. Services that must be available are as follows and rates for such services are provided in the tariff under the specific numbered schedules:

- Scheduling, System Control, and Dispatch Service [Schedule 1]
- Reactive Supply and Voltage Control from Generation Sources Service [Schedule 2]
- Regulation and Frequency Response Service [Schedule 3]
- Energy Imbalance Service [Schedule 4]
- Operating Reserve - Spinning Reserve Service [Schedule 5]
- Operating Reserves – Supplemental Reserve Service [Schedule 6]

Of these services, the transmission customer must take Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service from the transmission provider. The transmission customer bears the responsibility of securing all other ancillary services, when serving load within the transmission provider's control area. They can be self-supplied, purchased from third-party suppliers or purchased under regulated rates from the transmission provider.

2.3.3 Postage Stamp Rate

A postage stamp rate[16] for electricity transmission is one that does not vary according to the location of the buyer or the seller (point of delivery and point of receipt) just as

[15] FERC Glossary (http://www.tsin.com/gloss.html).
[16] Platt's Glossary (www.platts.com).

postage stamps for letters are typically at a fixed price, regardless of their origin and destination. In the *Pro Forma*, both network service and point-to-point service are provided through postage stamp rates.

The *Pro Forma* allocates a relevant revenue requirement to users based on their contribution to the transmission system peak load. The postage stamp rate is determined by dividing the relevant revenue requirement ($/yr) by the applicable peak load (kW) to get an annual rate ($/kW/yr). While the overall method is clear, there are significant issues regarding what constitutes a relevant revenue requirement for what type of service and what peak loads should be used. How NB Power's proposal addresses these issues is detailed in Sections 3 and 4 of this report.

2.3.4 Clarifications to Order 888

Since release of Order 888 there have been a number of decisions that have clarified its application concerning the development of transmission rates. Two such decisions are worthy of note.

Kentucky Utilities Company Opinion and Order

In the original FERC code of accounts generator step up transformers (GSUs) were classified as transmission assets and many utilities included the GSU costs in their original transmission tariff rates.[17] There were a number of interventions before FERC to change this practice and they did so in the Kentucky decision as follows:

> *"Most importantly, in Order No. 888, we [FERC] required the unbundling of transmission and wholesale generation services. We believe it is appropriate to re-examine our policy on the functionalization and the recovery of costs associated with GSUs to ensure that unbundled services customers are paying only their*

[17] Note that most Canadian utilities including NB Power and Hydro-Québec did the same.

appropriate share of the cost of services which they use. …. In short, we find that GSUs are used in the provision of both generation and ancillary services, and that the costs of these facilities should be charged to the customers using the facilities. … we find a more accurate method of cost recovery is to directly assign the costs of each GSU transformer to the generator to which it is connected."[18]

Court of Appeals (D.C.)

A number of utilities challenged the legal authority of FERC to issue Orders 888 and 889 and petitioned for its review. As recently as June 30th, 2000, subsequent to Order 2000 on Regional Transmission Organizations, the US Court of Appeals found in favour of the FERC as follows:

"Open access is the essence of Orders 888 and 889. Under these orders, utilities must now provide access to their transmission lines to anyone purchasing or selling electricity in the interstate market on the same terms and conditions as they use their own lines. … Finding few defects in the orders, we uphold them in nearly all aspects."[19]

2.3.5 Influence Outside the United States

Although the FERC has no direct jurisdiction outside the United States, it has had significant influence on the implementation and design of external tariffs. First, the FERC has instituted a reciprocity requirement on all non-jurisdictional utilities that use the tariffs of jurisdictional utilities. Second, non-jurisdictional companies wishing to sell electric power at market based prices in the U.S. must acquire a power marketing authority license from the FERC. Thirdly, the license requires that the reciprocal transmission access to be provided is done under a tariff that is equal to or superior to the *Pro Forma*. The effect of this latter point has lead to the development and implementation of *Pro Forma* tariffs by utilities in Canada and Mexico. Today the

[18] November 1998, FERC document 85FERC61,274.
[19] *225 F.3d 667, 2000 U.S. App. LEXIS 15362 (June 30, 2000).*

Order 888 *Pro Forma Tariff* is the most commonly applied tariff in Canada as well as the United States.

2.4 Market Design Committee Recommendations

The *Energy Policy White Paper* has targeted April 2003 as the date by which wholesale and industrial customers served at the transmission level will have their choice of electricity suppliers. As part of the preparation process for the implementation of this level of supplier competition, a multi-stakeholder Market Design Committee was formed to make recommendations to the Minister of Natural Resources and Energy regarding the market structure. A number of these recommendations concern the design and implementation of the transmission tariff.

2.4.1 FERC Order 888 Compatible Tariff

The market structure that is recommended by the Market Design Committee is a physical bilateral contract market.[20] Such a market requires that transactions between buyers and sellers be physically balanced. This means that the power injected at the point of receipt matches the power extracted at the point of delivery. The Market Design Committee recognized the importance to the bilateral contract market of open, non-discriminatory access to the transmission system. They also acknowledged that in 1996 FERC Order 888 established the minimum open access conditions necessary to support a bilateral contract market. As a result the following recommendation was made:

> *"The MDC [Market Design Committee] recommends that the transmission system will provide open, equal non-discriminatory access to all eligible market participants under terms and conditions compatible with FERC Orders 888 and 889. The System Operator will have an Open Access Transmission Tariff* (OATT) *for network and point-to-point service covering transmission service: within the*

[20] Market Design Committee, Final Report, Recommendation 3-1, p10.

province, into the province, out of the province, and through the province The PUB shall approve the OATT."[21]

2.4.2 Charge Determinants for Tariffs and Ancillary Services Charges

The two major issues concerning charge determinants for transmission and ancillary services are (1) coincident system peak load versus non-coincident peak load by delivery point and (2) gross load versus net load for consideration of self-generation.

Although other methods have been approved and implemented, the traditional FERC approach is to allocate costs to the different service classes based on a rolling 12 month average of the monthly coincident peak loads and, where metering is sufficient, to bill individual usage on the same basis. In cases where eligible transmission customers may not have proper interval metering to determine coincident peak contributions the actual customer billing of services has to be done using other billing determinants such as non-coincident peak loads.

Proper interval metering does not exist in New Brunswick at all transmission delivery points. In addition the current billing practice for integrated service in New Brunswick is to use monthly 15-minute non-coincident peak loads for demand billing. As a result the Market Design Committee recommended that:

> *"…the transmission tariff approved by the PUB provide that ancillary services charges to distribution utilities be based on monthly net non-coincident peak demand by delivery point."*[22]

and also that

[21] Market Design Committee, Final Report (April 2002), Recommendation 6-57, p45.
[22] Market Design Committee, Final Report (April 2002), Recommendation 6-71, p54.

> *"…the transmission tariff approved by the PUB provide that network service transmission charges to distribution utilities be based on monthly net non-coincident peak demand by delivery point."*[23]

Gross versus net load is the second issue with respect to billing determinants. Under gross load billing a customer with self-generation would pay for services based on their total peak load, whether or not it was being met by their own generation. This approach was initially allowed by FERC policy[24]. Since then, however, some customers have been permitted to implement this policy in a modified manner. One alternative is that the self-generator pay for services based only on its total load net of its own generation. This approach has been implemented in Ontario.

The time interval over which net load is measured is also a factor. The longer the time interval, the closer net load billing comes to gross load, because the chances are higher that at some time the self-generation facility will not be running. The Market Design Committee noted that net load billing, with a monthly non-coincident peak charge determinant, would likely result in total charges close to those of gross load billing if the self-generator is out-of-service at least once a month for a significant number of months in a given year. The Market Design Committee recommended that:

> *"…the tariff design approved by the PUB provide that self-generators connected to the transmission system pay for ancillary services on the basis of monthly net non-coincident peak demand."*[25]

and that,

> *"…the transmission tariff approved by the PUB provide that self-generators choosing network service will be charged for transmission service on the basis of their monthly net non-coincident peak demand."*[26]

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[23] Market Design Committee, Final Report (April 2002), Recommendation 6-72, p54.
[24] See Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC_61, 006 (1998).
[25] Market Design Committee, Final Report (April 2002), Recommendation 6-67, p52.

These recommendations represent a significant change from the current treatment of self-generators. Under current practice, self-generators connected to the transmission system do not pay explicitly for either ancillary services or transmission tariffs. Instead, they can contract for interruptible supply from NB Power as a backup and pay only time-differentiated energy rates. The *Energy Policy White Paper* directed the Market Design Committee to look for ways to avoid rate shock for existing self-generators. No specific recommendations were made except that consideration of the issue should be made by NB Power when it was designing the transmission tariff. The Market Design Committee recommended that:

> *"…the design of the transmission tariff seek to mitigate potential rate shock to self-generators."*[27]

2.4.3 Metering Costs and Data Use

Metering is fundamental to the settlement of all energy flows and some of the ancillary services. All parties must therefore have a high degree of confidence in its accuracy, reliability, and data integrity.

Current practice in New Brunswick is that the NB Power Transmission Business Unit owns the meters for connection to wholesale customers. Generators are responsible for the cost of providing meters at their connection points to the transmission system. The Market Design Committee recommended continuation of this practice and specifically that:

[26] Market Design Committee, Final Report (April 2002), Recommendation 6-68, p52.
[27] Market Design Committee, Final Report (April 2002), Recommendation 6-69, p53.

" the transmission owner(s) own all meters at injection and withdrawal points from the grid.

- *Transmission owner(s) will act as "meter data service" provider*
    - *Maintain meters*
    - *Responsible for meter data security*
- *Transmission owner(s) will give the data to the system operator for use in billing and settlement*
- *The transmission owners' costs will be included in the transmission tariff."*[28]

and

"…all meters for generation or other injection points to the grid be paid for by the generator."[29]

2.4.4 Ancillary and Security Services

The Market Design Committee considered implementation of market mechanisms for the procurement and delivery of ancillary and security services but because of market power issues recommended that they at least initially be provided as regulated services through the Tariff. The Market Design Committee recommends that:

" balancing energy service be initially provided as an ancillary service through the transmission tariff and that its provision be based on the following principles:

- *It should efficiently provide economic signals that will drive behaviours appropriate for reliable operation of the system*
- *Pricing of the service should be market-based where possible through:*
    - *Offers for increments and decrements*
    - *A proxy market price*

[28] Market Design Committee, Final Report (April 2002), Recommendation 6-63, p49.
[29] Market Design Committee, Final Report (April 2002), Recommendation 6-64, p49.

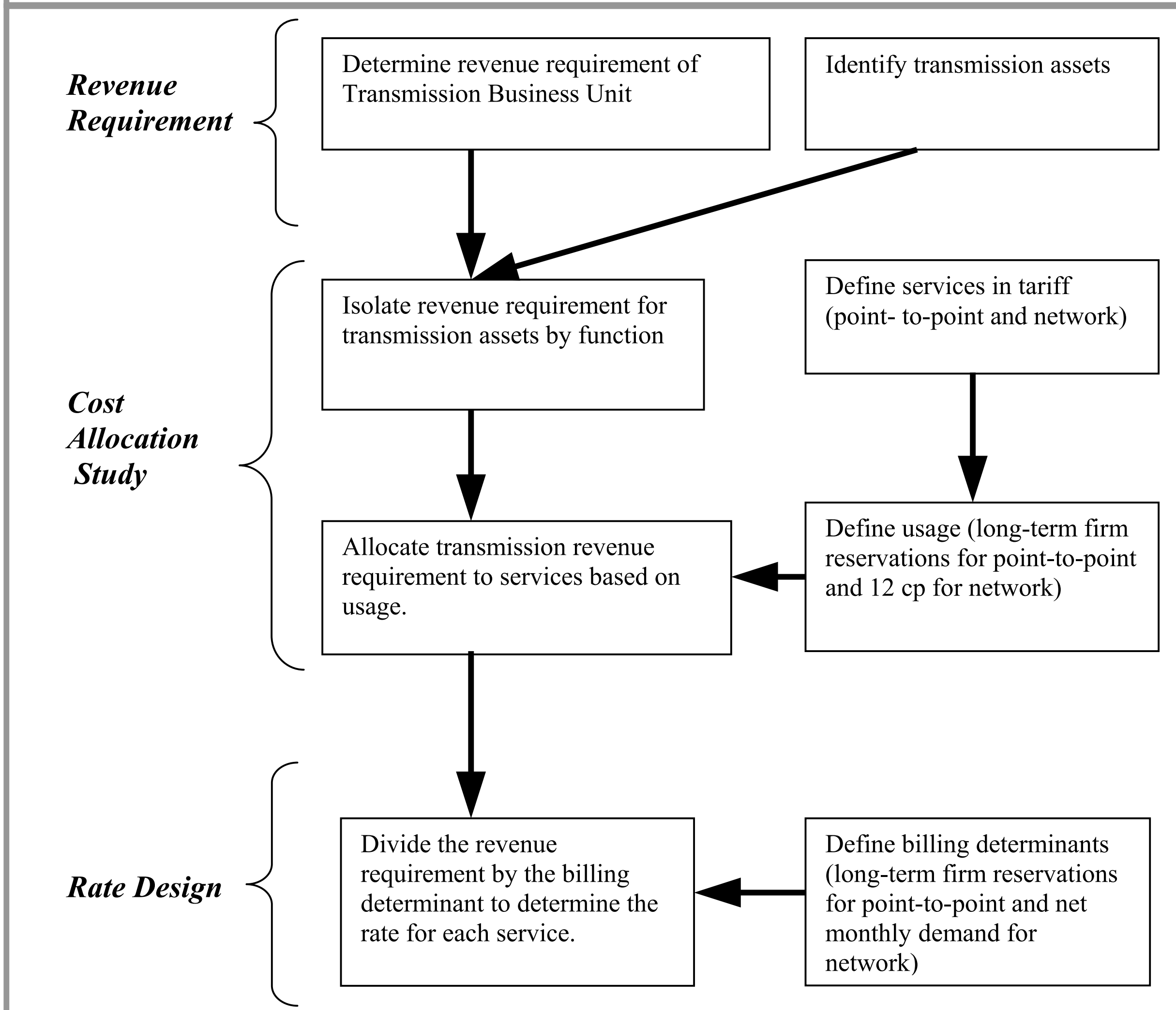
- *Ceilings and floors as necessary to protect participants."*[30]

[30] Market Design Committee, Final Report (April 2002), Recommendation 3-30, p26.

3.0 TRANSMISSION SERVICES COST ALLOCATION AND RATE DESIGN

A transmission tariff defines the terms, conditions and price under which a user (transmission customer) can gain access to the transmission provider's infrastructure (transmission assets). Although the methodology of developing efficient and equitable tariff rates is complicated, it can be simplified to the three-step process illustrated in Figure 3-1.

Figure 3-1: Overview of the Steps taken in the Development of a Tariff.



It should be noted that this process is the same as that detailed in the first pricing principle of FERC. *"First a utility must determine its total company revenue* *requirement, … Second, a utility must allocate … the total revenue requirement … in a manner which appropriately reflects the costs of providing transmission service … Finally the utility must design rates to recover those allocated costs from each customer class."*[31]

3.1 Transmission Revenue Requirement

The first step in designing an efficient and equitable transmission tariff is to determine the appropriate revenue requirement that must be recovered from the sale of services. The total revenue requirement related to transmission services for the NB Power Transmission Business Unit has been determined to be $98.4 million for the test year.

Table 3-1
Transmission System Revenue Requirement

Revenue Requirement Component	$millions
Asset amortization	18.4
OM&A	37.5
Interest, taxes and return on equity	42.4
Total	**98.4**

($0.1 difference due to rounding)

This revenue requirement includes all costs (amortization costs, operation, maintenance and administration costs, finance charges, and payments in lieu of taxes) plus a regulated return on investment. This revenue requirement relates to all transmission assets and has been determined by the Comptroller of the Transmission Business Unit. The components of the revenue requirement are summarized in Table 3-1.

In addition to the costs of all transmission lines at voltages of 69 kV or higher and terminal stations between transmission lines, the revenue requirement includes the costs

[31] Inquiry concerning the Commission's pricing policy for transmission services provided by Public Utilities under Federal Power Act; Policy Statement, October 26, 1994, Docket No. RM93-19-000, 18

associated with the generation step up transformers of NB Power generators. Because some of these assets are not associated with the transmission services offered under the tariff it is necessary to break down the revenue requirement into component pieces for all assets. Only after such a breakdown is completed can costs be allocated to specific services.

Amortization costs are able to be linked directly to specific assets because the gross and net asset value of each asset is accounted for in the company's accounting records. OM&A is allocated to each asset based on gross asset value while interest, taxes and return are allocated based on net asset value.

3.2 Cost Allocation Analysis

The purpose of the cost allocation analysis, which is the second major activity in the development of transmission rates, is to allocate the appropriate revenue requirement (i.e. the costs associated with transmission) to the appropriate services. The following steps are required to do this in a manner that is both efficient and equitable:

- Definition of the transmission services to be provided
- Definition of the basic functions of the transmission system
- Allocation of transmission revenue requirements to the different functional uses of the system
- Determination of system usage by service
- Allocation of the functional costs to the transmission services

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CFR 2, 59 FR 55031 [31,143] (http://www.ferc.gov/news/policy/pages/rm93-19.pdf).

3.2.1 Services Defined in Tariff

The Tariff defines two transmission services that are consistent with the FERC *Pro Forma Tariff*: point-to-point and network service. In addition, the ancillary service of Scheduling, System Control, and Dispatch is an obligatory service that must be provided by the transmission provider and taken by the transmission customer. The rate design of these three services are considered here in Section 3, while the rates for the other ancillary services which are supplied by generators are detailed in Section 4 of this report.

Point-to-Point Service refers to the reservation of capacity for the transmission of energy from a Point of Receipt to a Point of Delivery. An example of this would be a reservation of 100 MW from the Nova Scotia interconnection to the Hydro Quebec interconnection. This service is available on either a firm or a non-firm basis. The primary points of receipt and/or delivery can also be changed on a non-firm basis to secondary points but only if there is sufficient transmission capacity available after all other uses of the system have been accommodated. In other words, when a firm reservation is used to deliver power between secondary points of receipt or points of delivery, the service provided is subservient to all other uses of the grid, including non-firm point-to-point service. It is usually used for wholesale transactions between systems rather than for the direct supply of load within a system. However it is available for both uses at the discretion of the transmission customer.

Network Service is firm transmission service for the delivery of both capacity and energy to the high side of the substation transformer of the transmission customer. It is usually used for supply of load within the system. Network customers (large industrial and municipal customers) have the option of either owning their own substation transformer or renting this equipment from Customer Service. It is proposed that meters will be owned, read, and maintained by the transmission provider consistent with the recommendations of the Market Design Committee.[32]

[32] See Market Design Committee, Final Report (April 2002), 6.3 Metering, p48.

Scheduling, System Control, and Dispatch Service is required to schedule the movement of power into, out of, through, or within a control area. Only the system operator of the control area in which the transmission facilities are located can provide this service.

It is important to understand that the services described are independent of the voltage level at which the service is provided. In some utilities voltage related discounts are provided to large customers who receive bundled service but this has not been the practice in New Brunswick. Today, the rates for NB Power's large industrial and municipal wholesale customers are not differentiated by voltage.

Throughout North America most utilities have chosen not to provide voltage differentiated rates for unbundled transmission services. There are two main reasons for this approach. Offering different prices for service at different voltage levels would lead customers to request service at the lower price. If the infrastructure is not already in place, the transmission provider could very well incur higher costs. Such an increase would inefficiently shift costs to other users of the system. Furthermore, the transmission provider's mandate to maintain a reliable system may lead to situations where it is preferable for a particular load to be served at a particular voltage level. Where the FERC has jurisdiction, they have deemed that the entire transmission system operates as a single integrated piece of equipment and they have consistently mandated a fully rolled-in approach without voltage differentiation.

3.2.2 Transmission Functions

The services defined in the previous section use different parts of the transmission system. The purpose in this section is to identify which assets are used to provide which services. For the purposes of the NB Power Tariff, assets have been grouped into four main functional groups as follows:

- Generation Related Transmission Assets
- Bulk Network Assets which can be further subdivided into:
    - Interconnections
    - In-Province network
- Local Service Assets
- Energy Control Centre Assets

In order to be able to perform this allocation of the Transmission Business Unit assets and their associated costs it is necessary that the division point between functional groups be defined. The division points and the types of assets allocated to the different functions are explained in detail below:

> <u>Generation Related Transmission Assets (GRTAs)</u> are those assets that serve the function of connecting generation units to the shared transmission system. They consist of generator step up transformers (GSUs), a portion of the terminal assets, and transmission lines whose primary purpose is to connect a generator to the transmission system. The GSUs (also referred to as unit transformers) are easily identified because they are directly connected to the low voltage output of the generator. As noted in Section 2.3.4 these have been ruled by FERC to be assigned 100% to generation since the Kentucky Utilities decision. These GSU costs are often separated from the remaining GRTAs, which are more controversial because of the difficulty in defining a division point between GRTAs and Bulk Network assets. In the cost allocation of the NB Power transmission a portion of the total pool of terminals was allocated to the GRTA function on the basis that each individual generating unit needs a synchronizing breaker position in order to be able to synchronize and connect to the system. Also transmission lines that strictly connect a generating facility to the transmission system were also assigned to the GRTA function. These assets and the associated revenue requirements are to be recovered directly from the generation owners and not collected in the rate for the transmission tariff. For any new generation, the generator is responsible for the cost of any additional generation related

transmission assets that are required to connect the new generator. In the FERC *Pro Forma*, as well as in the filed tariff terms and conditions, these types of assets are referred to as direct assignment facilities.

<u>Bulk Network Assets</u> make up the portion of the transmission system that is highly interconnected and that serves multiple functions. The Bulk Network has two components: Interconnections and In-province assets. Interconnections are comprised of transmission lines that interconnect with external utilities at the provincial border, a portion of the terminals that connect these lines with the remaining system and the high voltage direct current (HVDC) converter station at Eel River. The In-province service consists of all remaining terminal costs (that have not been allocated as GRTAs or to Interconnections) and all transmission lines that are capable to operate as part of the integrated system within the province.

<u>Local Service Assets</u> are those parts of the transmission system which are not a part of the integrated network and used only to serve in-province loads or to connect generators in addition to supplying in province loads. The costs associated with these parts might need to be pooled and charged in a different fashion than the highly shared bulk network. Transmission lines that are configured such that they can only be operated in a radial fashion are 100% assigned to the local service function.

<u>Energy Control Centre Assets</u> that support the operation of the transmission system are in this function. The allocation was based on an assessment of the usage of the NB Power Energy Control Centre building, computer systems, and other related equipment required for system operator functions. These are the functions that are to be charged under the tariff through the service called Scheduling, System Control, and Dispatch.

3.2.3 Functional Allocation of Costs

The allocation of the transmission services revenue requirement of $98.4 million to the functional uses of the system is detailed in Attachment A and the results are summarized in Table 3-2.

Table 3-2
Functional Allocation of Revenue Requirements

Functional Use	Revenue Requirement Share ($millions)
Generator Step Up Transformers (GSUs)	5.1
Non-GSU Generator Related Transmission Assets (GRTAs)	4.5
Bulk Network Interconnections	7.2
Bulk Network In Province	70.9
Local Service	6.3
Energy Control Centre	4.4
TOTAL	98.4

The major issue to be addressed concerning these functional allocations is to determine which costs should be collected through tariff rates and which costs should be collected by direct assignment to specific users. This has been the subject of much debate in both FERC and non-FERC jurisdictions and has often been influenced more by the state/provincial regulator than by the FERC itself.

In some systems the costs associated with non-GSU GRTAs have been deemed to be substantial and are directly assigned to the generators. This also applies in some systems for local service assets and they are only charged to the customers that use them. In some systems interconnections have been included in the base transmission tariff and in some cases interconnections are charged separately from the tariff. In all systems the Energy

Control costs are allocated to the Scheduling, System Control and Dispatch ancillary service.

For the NB Power Tariff, it is proposed that interconnections and local service lines be included with the bulk network because they have relatively low costs and they provide market opportunities to both loads and suppliers. As a result the functional costs are allocated as follows:

- All GRTAs including GSU costs and non-GSU costs are allocated as direct assignment charges to generators ($9.6 million)
- Interconnections, In-province Bulk Network and Local Service costs are the common use portion of the transmission system and are allocated as revenue requirement costs to be collected from transmission services under the tariff ($84.4 million)
- Energy Control Centre costs are allocated to Scheduling, System Control and Dispatch and are to be collected through tariff rates for that service ($4.4 million)

3.2.4 Determination of System Usage

Usage of the system by various services must be defined in order to allow the revenue requirement to be allocated to the services. The challenge with usage is to select metrics for each of the services such that the cost allocation meets the appropriate rate making principles. "Cost causation" and "used and useful" principles are the two most relevant to the issue of what usage to apply for the allocation of revenue requirements.

The allocation of the transmission revenue requirement in the NB Power cost allocation analysis to point-to-point and network services is based on the approach prescribed by the FERC through Order 888. This allocation is based on the principle that the monthly coincident peak system load, or usage, is a fair measure upon which to allocate the revenue requirement of the transmission system. Coincidental peak load is defined as the sum of two or more peak loads that occur in the same time interval.[33] The use of 12 monthly coincident peaks balances the "cost causation" and "used and useful" principles of transmission tariff rate making. Use of a single coincident peak on the New Brunswick system tends to increase the allocation of revenue requirement to network services and understates the usefulness of the system to point-to-point services.

The FERC approach is incorporated in Section 34.3 of the *Pro Forma Tariff* (Determination of Transmission Provider's Monthly Transmission System Load) which states:

> *The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.*[34]

The substitution of point-to-point reservations for actual use is done in recognition of the fact that the transmission provider is fully committing the reserved capacity on a long-term firm basis. The transmission provider must design the transmission system to accommodate the full use of the reserved capacity at any time, including the time of monthly system peaks. No allowance for diversity can be made.

In the case of the NB Power system, the long-term firm reservations for the test year are 720 MW. Therefore, as prescribed by FERC, the long-term firm reservations were used rather than actual usage corresponding to the 12 monthly system peaks. The level of long-term firm reservations is based on reservations that exist today and that have end

[33] Energy Information Administration (EIA) Glossary, (http://www.eia.doe.gov/cneaf/electricity/page/glossary.html).

[34] FERC Order 888 Attachment D, the Pro Forma Tariff Terms and Conditions.

dates beyond the end of the test year. None of these reservations terminate prior to 2013. The results are reported in the Table 3-3.

Table 3-3

Transmission System Usage

Usage	Quantity (MW)
Long-term firm reservations	720
Forecasted average of network loads at the time of the 12 monthly system peaks in the fiscal year 2003/2004	2100
Total	**2820**

This information is used in the allocation of the transmission system revenue requirement.

3.2.5 Allocation of Revenue Requirements to Services

The last step in the cost allocation analysis is to allocate total transmission costs to the services that will be offered under the tariff. As noted above, these are point-to-point service, network service and the Scheduling, System Control and Dispatch Service.

The transmission revenue requirement for point-to-point and network services has been determined in Section 3.2.3 as $84.4 million/year. The transmission provider also collects revenues for the provision of services in addition to long-term firm services. These include short-term firm and non-firm point-to-point services, a grandfathered wheeling contact that pre-dates open access, and power factor penalties.

A projection of these revenues is subtracted from the gross revenue requirement prior to the allocations to point-to-point and network service. The projection of this miscellaneous revenue is $8.1 million. Therefore, the revenue requirement for allocation is adjusted to $76.3 million.

This revenue requirement is allocated to the different transmission services based on their load ratio share of the system. Applying 720 MW for point-to-point reservations and 2100 MW for network service the allocation of costs to these services is shown in Table 3-4.

Table 3-4
Transmission Services Revenue Requirements

Service	Usage (MW)	Share	Revenue Requirement ($ millions)
Point-to-Point	720	25.53%	19.47
Network	2100	74.47%	56.80
Total	2820	100.0%	76.27

The revenue requirement for each service can also be expressed on a per unit of usage basis as shown in Table 3-5. Because the allocation of the transmission revenue requirement to point-to-point and network service was done on the basis of the respective usage the cost per unit of service is the same for each. The $/kW-yr figures given represent the per unit cost of providing each of the services based on the application of the transmission pricing principles.

Table 3-5
Per Unit Transmission Services Revenue Requirements

Service	Revenue Requirement ($ millions)	Usage (MW)	Per Unit Revenue Requirement ($/kW-yr)
Point-to-Point	19.47	720	27.04
Network	56.80	2100	27.04
Total	76.27	2820	27.04

3.3 Rate Design

Now that costs have been allocated to specific services it is possible to design rates to recover these costs. This is essentially the third step referenced in the first pricing principle of FERC under which the transmission provider can recover its revenue requirement. This design of rates involves the following:

- Selection of a rate structure
- Selection of billing determinants for each service
- Determination of rates using the billing determinants to collect the revenue requirements

All of the information determined previously from the Total Revenue Requirement and the Cost Allocation Analysis is considered.

3.3.1 Postage Stamp Rate Structure

A postage stamp rate for electricity transmission is one that does not vary according to the location of the buyer or the seller (point of delivery and point of receipt) just as postage stamps for letters are typically at a fixed price, regardless of their destination. Although the most common approach in North America has been to use postage stamp rates, alternative transmission service pricing structures have been identified and used in some jurisdictions.

The alternatives to a postage stamp rate include location based (zonal or nodal) pricing, flow-based rates, and distance based rates. NB Power's current approach is a postage stamp rate that is the structure applied in the FERC Order 888 *Pro Forma Tariff*. This approach was also adopted in Saskatchewan, Manitoba, and Quebec. British Columbia, Alberta and Ontario have opted for zonal rate approaches. Most U.S. utilities have implemented the *Pro Forma* postage stamp approach but there are cases where locational-based marginal pricing, (Pennsylvania, New Jersey, Maryland Interconnection), zonal (New York Power Pool), flow gate (Midwest Independent System Operator) and distance based (Mid Area Power Pool, Maine Electric Power Company) have been approved by FERC. The decision to deviate from the postage stamp approach in these areas has been influenced by the structural nature of those systems and the markets that they serve. Systems with tightly meshed transmission networks like New Brunswick have generally all adopted the postage stamp approach.

To a large extent, the characteristics of the wholesale market will determine the ability of a transmission tariff design to promote efficient use of assets. For example, in the presence of persistent congestion it can be advantageous to use location-based pricing. Increased transmission costs across a congested interface will discourage such transactions thereby tending to alleviate the congestion. In markets where congestion is not significant, such as inside New Brunswick, there is little value in adopting a locational-based marginal pricing structure.

Additional analysis of postage stamp rates suggest that the transmission service revenue requirement must be based on shared assets that benefit multiple users in terms of efficient and reliable transmission service. It is not appropriate for the revenue requirement to include assets that are only useful for particular customers or customer classes (e.g. generation related transmission assets). Incorporating such single purpose assets into transmission rates disregards both the "cost causation" and the "used and useful" principles. This pitfall is avoided in the proposed tariff by assigning the cost of these single-purpose GRTAs to the specific users rather than including them in the transmission service revenue requirement.

The adoption of a postage stamp rate approach means that transmission customers will continue to pay the same rate for transmission service regardless of the point of delivery. This approach is consistent with the historical NB Power rate structure in that the rates are not a function of the location of the load. This consistency respects the principle of the *Energy Policy White Paper* that states that *"…the Province will entitle customers that do not select a competitive supplier to offer standard offer service under regulated prices and terms that are consistent with the service they now obtain."*[35] A transmission tariff that differentiates between different regions with respect to the recovery of the embedded cost of the grid would not be compatible with this policy principle.

The New Brunswick system has little transmission congestion, a centralized System Operator, and a desire to minimize the costs and complexity of the implementation of a transmission tariff. Given these factors, and the aforementioned discussion, NB Power proposes a postage stamp rate as the most appropriate structure for the recovery of the embedded cost of NB Power's transmission system.

3.3.2 Definition of Billing Determinants

In order to determine the price that will be charged to users of a particular service the metric, also referred to as a billing determinant, must be defined. Some of the commonly used billing determinants in the electric power industry are customer charge, kW of demand, and kWh of energy.

In defining the billing determinant one must consider issues such as measurability, simplicity, and fairness. It has already been established in the discussion above on cost allocation that transmission costs should be allocated to users based on the committed

[35] *Energy Policy White Paper* (3.1.5.3 Standard Offer Service) p24.

capacity. In the case of long-term point-to-point customers, the reserved MWs define the committed capacity. Reserved quantity can readily be used as the billing determinant for point-to-point service. In the case of network customers committed capacity is more difficult to define but, as discussed in the cost allocation section, is a function of the 12 monthly coincident peak loads.

Energy delivered can be considered as a billing determinant for a network customer's transmission usage but this approach does not follow the principle of cost causation. A customer with a very low load factor (a low quantity of energy delivered relative to the peak demand) would pay very little for transmission even though the transmission system needs to be able to meet the customer's peak demand. Such an approach would clearly lead to cross subsidization for transmission services of low load factor customers by other customers.

Historically in-province customers of NB Power have been billed for the demand component of their purchased services based on their respective demand, not on the basis of their demand relative to the system peak. The existing metering fully supports such billing but does not fully support coincident peak billing as not all wholesale customers have interval meters that capture the hourly peak readings. Without the hourly peak readings there is no way to identify the individual customer's demand at the time of the system peak for the month.

In addition to the issue of adequate metering, there is an issue with respect to the potential for customers to anticipate the system peak for the month and to minimize their demand at that time. Although in general this type of load shifting is favorable, the benefits are not so significant if it only addresses the peak for the month. If the shifting ignores the fact that there are other days in the month when the bulk network is heavily loaded and the fact that the peak loading for the local area may be most heavily loaded at hours other than the hour of system peak, then the benefits of the shifting of demand are diminished.

Another aspect of billing for transmission relates to self-generating customers and is an issue of whether to bill on net demand or gross demand. The net demand is the measurement of the demand for power at the interface between the transmission system and the customer. The gross demand is the measure of total on-site electrical load of the customer in any given interval. Net demand is the gross on-site electrical load of the customer in any given interval less any on-site generation in that interval. If the customer has no on-site generation then the net demand equals the gross demand.

This issue of net versus gross demand is also related to the issue of coincident versus non-coincident billing. A self-generator that can exercise control over the net demand at the time of system peak through reliable generation or load control would incur less cost for transmission under coincident net demand billing than under non-coincident net demand billing. Combining coincident billing with net demand billing would provide a substantial opportunity for self-generating customers to pay less. At the other extreme, combining non-coincident peak billing with gross demand billing would lead to the self-generating customer paying more.

FERC Order 888 and subsequent jurisprudence clearly state that self-generating customers must be provided with the option to choose between point-to-point service and network service.[36] If point-to-point service is chosen, the customer can reserve the transmission capacity that it requires. Transmission customers whose usage exceeds their reservation will be treated in accordance with the terms and conditions of the tariff. In many cases the treatment reflects a penalty for the use of unreserved transmission. The customer also faces the possibility of interruption or curtailment in the case of a transmission constraint. In the FERC *Pro Forma,* if the customer chooses network service the billing determinant is the load ratio share based on the gross demand at the time of system peak, not the net demand. However, some utilities with self-generation have modified this to include only a percentage of the self-generation component of the load as a means of reaching a negotiated settlement of this issue.

[36] FERC Docket Nos. RM95-8-001 and RM94-7-002, pp. 241-251

Canadian Utilities implementing tariffs have tended to adhere to the FERC *Pro Forma* by billing for network service on the basis of coincident demand on gross load. It is worth noting that in these jurisdictions they have gone to the minimum Order 888 requirement of wholesale access but not to transmission level retail access as is being done in New Brunswick based on the *Energy Policy White Paper*.

In the New Brunswick context there are additional considerations. The existing self-generating customers (and other industrial customers that purchase non-firm products) currently pay no demand charge for the portion of their load that they can meet with their own generation or reduce at the request of the System Operator. Also the *Energy Policy White Paper* directs that existing and new self-generators be treated the same.[37] The Market Design Committee was concerned that the charges for transmission could result in substantial rate increases for existing users of non-firm products. This consideration made the committee reluctant to see gross demand as the billing determinant for network service. Although some members felt that there should continue to be no demand rates for non-firm transmission, there was consensus that under such an approach customers using non-firm products would not be paying a fair share of the transmission system costs, leaving these costs to be carried by other customers. The Market Design Committee also discussed the fact that under an Order 888 type tariff many of the self-generation customers could offset the costs of ancillary services costs through self-supply. The Market Design Committee also discussed that in the new market rules self-generators would be permitted to sell ancillary services and further mitigate any new costs that might result from the introduction of the Tariff. The Market Design Committee considered the aforementioned issues and produced recommendations to bill on non-coincident net demand by delivery point.[38]

[37] Energy Policy White Paper (3.1.4.2 Self-Generation).
[38] Market Design Committee, Final Report (April 2002) 6.4.3 (Recommendations 6-70 and 6-71, p54).

Based on all the factors discussed in this section net non-coincident demand by delivery point has been selected as the billing determinant for use in the NB Power Tariff design for network service. Reserved capacity has been selected as the billing determinant for point-to-point service. The Market Design Committee also addressed the *Energy Policy White Paper* directive to examine means by which rate shock to existing self-generators can be avoided.[39] The result was a recommendation that the Tariff to be implemented by NB Power should attempt to mitigate potential rate shock to existing self-generators.[40] Rate shock is partially addressed in the Tariff where self generators have the opportunity to self-supply ancillaries. It is also anticipated that they will have the opportunity to sell any excess to the System Operator under new market rules.

Additional rate shock mitigation for self-generators can be addressed through the provision of an opportunity for a transmission customer to take network service to reduce its transmission costs by reducing its net non-coincident demand in the on-peak hours. Customers, including those that currently purchase non-firm products, could have the opportunity to shift load from on-peak hours to off-peak hours. Such a shift is consistent with overall energy efficiency goals and as proposed in the Tariff. This shifting would also potentially reduce the cost of the shared transmission assets by reducing the on-peak loading. Therefore such an economic signal is appropriate.

For network service, on-peak hours are defined as the time between the hour ending 08:00 and hour ending 23:00 Atlantic Time, Monday to Friday, except statutory holidays in New Brunswick. This shifting of demand is encouraged by considering only 71% of the net monthly non-coincident peak demand in the off-peak hours when the peak monthly demand for each customer is evaluated. Under this approach the greater of the following two demands is used as the billing determinant:

- net monthly non-coincident peak demand in the on-peak hours
- 71% of the net monthly non-coincident peak demand in the off-peak hours

[39] Energy Policy White Paper (3.1.4.2).
[40] Market Design Committee Final Report (April 2002) 6.4.2 (Recommendation 6-69, p53).

3.3.3 Determination of Rates

Given that the revenue requirement and billing determinants have been defined for each service the nominal rate is merely the revenue requirement for the service divided by the respective billing determinant. Table 3-6 illustrates the calculation of the nominal annual rate for each service.

Table 3-6
Determination of Nominal Rates by Service

Services	Revenue Requirement ($millions/yr)	Billing Determinant (kW)	Nominal Rate ($/kW/yr)
Point-to-Point Services			
Transmission	19.47	720,000	27.0
Schd, Control & Dispatch	1.030		1.43
Network Services			
Transmission	56.80	2,571,000	22.1
Schd, Control & Dispatch	3.005		1.16

For transmission service it is a common industry practice in North America to apply what is frequently referred to as Appalachian pricing. In Appalachian pricing the short term services are priced higher for an equivalent time period. This concept has been approved by FERC[41] and is used in Manitoba and Saskatchewan. This approach with minor modifications has also been applied in Quebec subject to the April 2002 decision of the Quebec regulator, the Régie de l'énergie.

[41] Appalachian Power Company, 39 FERC 61,296 (1986) and NY State Electric and Gas Company, 92 FERC 61,169 (August 17, 2000).

The Appalachian pricing approach applied by NB Power is consistent with FERC requirements and defines various short term rates as a fraction of the yearly rate as follows:

Yearly	=	nominal rate
Monthly rate	=	Yearly rate / 12
Weekly rate	=	Yearly rate / 52
On-Peak Daily rate	=	Weekly rate / 5
Off-Peak Daily rate	=	Yearly rate / 365
On-Peak Hourly rate	=	On-Peak Daily rate / 16
Off-Peak Hourly rate	=	Yearly rate / 8760

The rationale behind the On-Peak Daily and Hourly rates is that there is a difference between short-term services used for meeting peak load and those that are taking advantage of economically profitable opportunities. On-Peak hours for point-to-point service are defined by NB Power as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday. These types of transactions tend to occur on-peak and therefore in order to fully recover the appropriate revenue requirement these services are often priced with the On-Peak Daily rate at the weekly rate divided by 5 and the On-Peak Hourly rate is the On-Peak Daily rate divided by 16.

NB Power has chosen to propose rates based on the calculations shown above. This approach helps ensure adequate collection of revenues for services provided, while facilitating the use of the transmission capacity in the off-peak hours.

Based on the overall revenue requirement defined, the application of the cost allocation analysis, and the design of the end use rates just described, the rates proposed by NB Power for acceptance by the PUB are detailed in Table 3-7.

Table 3-7
Summary of Transmission Service Rates

Services	Units	Transmission Service	Scheduling, System Control & Dispatch
Yearly	$/kW-yr	27.04356	1.43052
Monthly	$/kW-m	2.25363	0.11921
Weekly	$/kW-w	0.52007	0.02751
On-Peak Daily	$/kW-d	0.10401	0.00550
Off-Peak Daily	$/kW-d	0.07409	0.00392
On-Peak Hourly	$/kW-h	0.00650	0.00034
Off-Peak Hourly	$/kW-h	0.00309	0.00016
Network	$/kW-m	1.84	0.10

3.3.4 Power Factor Penalty in the Transmission Tariff

The tariff includes a power factor penalty that will be applied for any month in which a transmission customer taking network service has a power factor of less than 90%. Under the tariff proposal the penalty paid per kVA (based on 90% of the metered kVA) that is in excess of the kW demand is 4 times the wires tariff (not to include any ancillary services) which is $7.36 (4 times $1.84). This policy applies to all customers directly connected to the transmission system.

This policy is consistent with the current NB Power policy with respect to large industrial customers. Under the current rates for large industrial customers the penalty paid per kVA (based on 90% of the metered kVA) that is in excess of the kW demand is $9.41 per month.[42] This policy also gives a new option to the Municipal customers. Under current rates Municipal customers are required to maintain an acceptable power factor. Under the proposed tariff Municipal customers will have the option to pay a power factor penalty to amend for poor power factor performance rather than being strictly obligated to make corrections to their power factor.

This approach gives large industrial customers the same flexibility that they have under current bundled rates. Also without this power factor penalty the transmission provider would not have the same tools that NB Power has today to encourage acceptable power factors. Rather than treat different classes of customers differently, the policy has been extended to directly connected customers other than large industrial customers that choose network service.

Based on the test year metering data the anticipated revenue from power factor penalties is $880,000 per year. This anticipated revenue is subtracted from the gross revenue requirement as part of the revenue requirement allocation process as noted in Section 3.2.5 of this document.

4.0 ANCILLARY SERVICES COST OF SERVICE AND RATE DESIGN

Ancillary services are the support services that are required to enable the transmission system to transmit energy. They range from the actions necessary to effect and balance a transfer of electricity between buyer and seller to services that are necessary to maintain the integrity of the transmission system and enable it to be operated reliably.

This section addresses the development of rates for all of the ancillary services that are provided from generators under the control of the System Operators at the Energy Control Centre. Scheduling, System Control, and Dispatch Service is an ancillary service supplied directly by the transmission provider and is discussed in Section 3. The services provided from generators can be grouped into two main categories. Capacity-based

[42] The large industrial rate is $9.41 per kW of the billing demand per month and the billing demand is the greater of a number of possible demands, one of which is “90% of the maximum kVA demand”.

services are provided from generation capacity that must be committed to the provision of the service and is not able to be used at the same time for other purposes. Non capacity-based services do not require the commitment of the generator capacity for provision of the service.

4.1 Capacity-Based Ancillary Services

The capacity based services are defined and provided in the tariff consistent with the numbered schedules used in the FERC *Pro Forma Tariff*. Some, however, are further unbundled into component services as follows:

- Regulation and Frequency Response from Generation Sources Service [Schedule 3 in tariff], composed of
    - Regulation; and
    - Load Following
- Operating Reserves – Spinning Reserve Service [Schedule 5 in tariff]
- Operating Reserves – Supplemental Reserve Service [Schedule 6 in tariff], composed of
    - Supplemental (10-minute); and
    - Supplemental (30-minute)

The revenue requirement for the capacity based services [Schedules 3, 5 and 6] is determined by multiplying the per unit cost of new proxy unit capacity for each service by the amount of capacity required to deliver the service. Proxy units are used rather than the embedded cost of NB Power generation because they produce a more appropriate price for the services. Once the revenue requirement is determined it is allocated to services and rates are set in a manner similar to that used for transmission services in Section 3 of this report.

4.1.1 The Choice of Proxy Units

The two key guiding principles in the selection of proxy units were the technical capability of a facility to provide a service and the simplicity of the modeling. A proxy price would not be meaningful if the proxy unit could not reasonably be argued to be the type of facility that would be built to provide the service. On the other hand, there would be little benefit to a complex model that simulated a fleet of resources to exactly meet the required quantity of resources. The approach taken was to use the costs of a reasonable proxy facility to determine the cost per unit of service provided. That unit cost was then multiplied by the required quantity to calculate the revenue requirement for the total actual quantity of the service that is to be provided under the tariff.

Regulation, Load Following, and Operating Reserve-Spinning are referred to as on-line capacity based services because they can only be provided by resources that are operating and connected to the system. A 400 MW combined cycle gas generation plant was selected as the proxy unit for the on-line ancillary services. The 400 MW configuration provides reasonable economies of scale and is a technically proven sizing. Such a unit could be on-line producing energy with some of its capacity and providing on-line capacity based ancillary services with the remainder. Also the general assumption within the energy industry is that most new generation for the production of energy in the foreseeable future will be combined cycle gas turbine. The combined cycle plant has a lower capital cost per kW of capacity than other types of generation with the technical capability to provide these on-line services.

Operating Reserve-Supplemental Reserve Services are referred to as off-line capacity based services because the resources that provide these services are not required to be operating and connected to the system. For off-line capacity based ancillary services (Operating Reserve-Supplemental Reserve Service Schedule 6 in the tariff) a 100 MW simple cycle gas turbine was used as the proxy. Such a unit could be sitting off-line most of the time and providing its full capacity as off-line ancillary services (Supplemental

Reserves). Its low capital costs make this type of unit more economical to provide the off-line reserve services than a combined cycle installation. Other types of generation with the technical capability to provide these services have higher capital costs. Note that there is a small additional cost for 10-minute reserve to account for the increased OM&A and capital costs associated with rapid start-ups.

The costs for the proxy unit to provide the capacity based ancillary services are based on previous estimates established by NB Power. They are summarized in Schedule 1.0 of Attachment B. The fixed costs of capital identify the ongoing revenue requirement associated with the initial capital investment. The fixed costs of capital are based on the transmission business unit's weighted-average cost of capital established in the financial report of this filing and an estimate of inflation. The OM&A cost reflects the ongoing operations and maintenance costs for such units. The payments in lieu of taxes reflect the taxes that would be paid on the corporate income associated with the equity portion of the financing of the assets.

4.1.2 Requirements of Capacity Based Services

As the Operator of the Maritimes Control Area, the transmission provider has a responsibility to operate in accordance with NERC and Northeast Power Coordinating Council (NPCC) criteria. This includes the responsibility to determine the need for and to procure sufficient ancillary resources to reliably operate the electrical power network.

Additionally, the NB Power Tariff obligates the transmission provider to make all ancillary services available to all transmission customers. Therefore, the transmission provider must procure adequate generation resources to do so.

Transmission customers can purchase each of the ancillary services from the transmission provider whether they are taking point-to-point or network service. Therefore, the ancillary services are priced for both services. Transmission customers can self-supply the capacity-based ancillary services, or purchase them from either the transmission provider or a third party. In fact, when a load is located outside of the Control Area, it may be technically infeasible for the customer to buy these services from New Brunswick even though the customer is supplied by power that is delivered across the NB Power transmission system. The costs of these capacity-based services are allocated on a load share ratio between NB Power loads and outside loads that are currently using these services. The NB Power system requirements for "Regulation and Frequency Response" and "Operating Reserves" are outlined below.

Regulation and Frequency Response

The total system requirements represent the total average requirements to run the New Brunswick system and are based on the actual numbers for the NB system. The determination of the amount of this service, composed of both regulation and load following, required for the NB system has been calculated using empirical methods. The method can be described as follows. The total system load is broken into two components, a slowly varying trend which represents load following and a random higher frequency component with zero mean which represents regulation.

19 MW of regulation and 53 MW of load following is required for the NB system. Given that external customers carry a load ratio share obligation, the Tariff's obligation is 16.76 MW of regulation and 46.74 MW of load following. This includes the responsibility to cover tie line variations for other utilities in the Maritimes but does not include the load in Nova Scotia. The details are in Schedule 1.2 of Attachment B.

Operating Reserves

The requirement within the tariff for operating reserves is a function of reliability criteria established by the Northeast Power Coordinating Council (NPCC). The quantity of each type of reserve will depend on both the size of the contingencies and the load being served.

Since the Maritimes Control Area is not operated as a single entity, each utility has been responsible for carrying its own reserve requirements. NPCC requires that each Control Area maintain sufficient Contingency Reserve (10-Minute Spinning and 10-Minute Supplemental)[43] to cover 100% of the largest single contingency and 30-Minute Reserve to cover 50% of the second largest contingency.

The transmission customers' reserve obligation for each of the reserve services under this tariff will be based on their load share ratio. However, it will not exceed the obligations for the respective services that would exist if the 1st and 2nd contingencies were 10% of the annual peak load for the Control Area. The portion of the 1st contingency in excess of 10% of the annual peak load (i.e. 5000 MW) for the Control Area (i.e. Maritimes Control Area) shall be the direct responsibility of the owner of the 1st contingency. Similarly, the owner of the 2nd contingency will be responsible for supplying the operating reserve capacity that is the direct result of the 2nd contingency being in excess of 10% of the annual peak load.[44] Therefore the 1st and 2nd contingencies to be addressed by the load-serving entities within the Maritimes Control Area are 500 MW and 458.1 MW respectively.

Operating Reserve sharing arrangements have been made with NS Power, Maritime Electric, and Northern Maine. NS Power provides 125 MW of Contingency Reserve for the first contingency, of which 25% (31.25 MW) is spinning and 75% (93.75 MW) is Supplemental. NS Power also provides 50 MW of 30-Minute Reserve (i.e. the second contingency). Maritime Electric, Northern Maine and NB Power assume their load ratio share of the remaining obligation. Of this, NB Power's obligations are 88.2 MW of 10-Minute Spinning and 242.5 MW of 10-Minute Non-spinning, as well as 157.9 MW of 30-minute Reserve. The details are contained in Schedule 1.2 of Attachment B.

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[43] A minimum of 25% of the 10-minute reserves must be spinning.

[44] The selection of 10% of the annual peak load is based on an historical rule-of-thumb used to determine the maximum size of a single generator for a specific system. Therefore, to the extent that a generator exceeds the 10% criteria, it must arrange for (supply, purchase or otherwise self-provide) the

4.1.3 Summary of Revenue Requirements for Capacity Based Services

The total revenue requirement for each service is the product of the quantity required multiplied by the cost per unit of service supplied as shown in Table 4-1.

Table 4-1
Revenue Requirement of Capacity Based Services

Services	Revenue Requirement ($/kW-yr)	Services Required (MW)	Revenue Requirement ($1000/yr)
Regulation	81.99	16.76	1,374
Load Following	67.87	46.74	3,172
Spinning (10-minute)	60.95	88.20	5,376
Supplemental (10-minute)	57.81	242.5	14,020
Supplemental (30-minute)	56.61	157.9	8,939

4.1.4 Capacity Based Service Rates

The annual cost of providing each service as a function of the usage is determined by dividing the total cost of providing the service by the usage of the respective service. For monthly point-to-point service and network service the annual cost of providing each service on a $/kW basis is divided by 12 to determine the monthly rate. Point-to-point customers purchasing the ancillary services on a yearly, or monthly service, as well as network service, are billed at the monthly rate at the end of each calendar month as noted in the terms and conditions of the tariff. The rate for weekly point-to-point services is 1/52nd of the annual rate and the daily rate is 1/5th of the weekly rate. Hourly

difference. This difference will be calculated annually and each generator's requirement will be rounded to the nearest 10 MW.

service is not available for the capacity based ancillary services due to the additional administrative burden of tracking how various point-to-point customers are fulfilling their obligations on an hourly basis. If hourly service were provided for the capacity based ancillary services there would be a potential impact on reliability should the policing of adequacy of reserves not be effective. The rates produced by this process are summarized in Table 4-2 and detailed in Attachment B.

Table 4-2
Nominal Rates For Capacity Based Ancillary Services

Service	Revenue Requirement ($1000/yr)	Usage (MW)	Rate $/kW-month
Regulation	1,374	2571	0.04
Load Following	3,172	2571	0.10
Contingency Reserve – Spinning	5,376	2571	0.17
Contingency Reserve – Supplemental (10-minute)	14,020	2571	0.45
Contingency Reserve – Supplemental (30-minute)	8,939	2571	0.29

4.1.5 Out-of-Order Dispatch

While the proxy unit pricing does place an appropriate value on the capacity that is used to provide capacity based ancillary services, it does not address the issue of out-of-order dispatch costs. Ignoring out of order dispatch costs would provide an opportunity for point-to-point customers using this service to purchase from the transmission provider when the market prices for energy are high, and to self-supply or purchase from a third party when the market prices for energy are low. It is often at these times that out-of-order dispatch costs are high. Paying out-of-order dispatch costs to the generator that is supplying the services to the transmission provider will help to ensure that the supplier of the service continues to receive adequate compensation and thereby ensure continued provision of the service.

The following are examples of scenarios in which out-of-order dispatch costs can occur.

<u>Hydro unit spilling:</u> A hydro unit dispatched at less than its maximum current rating, while spilling water, in order to provide an ancillary service.

<u>Hydro unit with low water and low market price:</u> A hydro unit is generating when its most economic dispatch would be to not run.

<u>Hydro unit below its economic dispatch point:</u> A hydro unit is dispatched below its economic dispatch point in order to provide an ancillary service.

<u>Thermal unit operating above its economic dispatch point:</u> A thermal unit is operating above its economic dispatch point.

<u>Thermal unit operating because of the requirement for ancillary services:</u> A thermal unit is committed to run in order to fulfill the requirement for ancillary services.

<u>Thermal unit operating below its economic dispatch point:</u> Thermal unit dispatched below its economic dispatch point in order to meet the needs of the transmission provider.

Determination of out-of-order dispatch costs requires that commitment schedules with and without provision of ancillary services be compared. The following describes the process that will be used to determine the out-of-order dispatch costs.

- The transmission provider releases day ahead obligations for ancillary services
- Generators submit day ahead generation plans to meet hourly energy obligations

- Generators submit a second day ahead proposal to meet ancillary service requirements (this second plan may not differ from the energy only generation plan of step 2)
- Transmission provider assesses the resources available to provide the ancillary services and selects the lowest cost option. The transmission provider will have the following information in order to perform the evaluation of the least cost option:
  - the generation cost information (or bids in the case of a third party provider that prefers confidentiality)
  - an estimate of the market price
  - start-up costs as provided by the generator (or price in the case of a third party supplier that prefers confidentiality)

The transmission provider will collect these out-of-order costs, if and when they occur, from transmission customers that are purchasing these services and pass the related revenue collected back to the generation providers of the service. If any additional investments are made in order to avoid out-of-order dispatch they will be included as out-of-order dispatch costs, but only up to the level of the out-of-order dispatch costs that would otherwise have been attributable to ancillary services.

4.2 Non-Capacity Based Ancillary Services

The non-capacity based ancillary services are:

- Scheduling, System Control and Dispatch [Schedule 1 in tariff]
- Reactive Supply and Voltage Control Service [Schedule 2 in tariff]
- Energy Imbalance Service [Schedule 4 in tariff]

The three-step methodology for developing rates (outlined and used above) is also employed to determine rates for these services. Rates for Scheduling, System Control and Dispatch service are derived from the transmission revenue requirements in Section 3 of this report. The remaining two non-capacity based ancillary services are considered below.

4.2.1 Reactive Supply and Voltage Control Service

The pricing for Reactive Supply and Voltage Control [Schedule 2] is determined from the proxy unit costs of supplying it and the quantities required in a manner similar to capacity based ancillary services.

The proxy selected for this service is a set of three 110 MVAR synchronous condensers. A synchronous condenser most closely simulates the Reactive Supply and Voltage Control services provided by a synchronous generator. The ability to operate at either a ‘leading’ or a ‘lagging’ power factor and the inertia that a synchronous condenser has makes it a reasonable proxy from the point of view of technical capabilities.

The total system requirement for this service from generators on the system is based on the MVAR output of in-province generators at the time of system peak plus an additional MVAR capability held in reserve to ensure dynamic system security.

Whether they are purchasing point-to-point or network service, all transmission customers use this service. Therefore the revenue requirement, net of charges for this service as provided with short-term firm and non-firm point-to-point services, is allocated to the two types of use. This allocation is done on the same basis as the allocation of the revenue requirement associated with the transmission system. This allocation to point-to-point and network services is explained in Section 3.2 of this document. The respective usages are the long-term firm point-to-point reservations and an average of 12 monthly peak network loads coincident with the system peak.

The rate design is patterned after the design of the point-to-point and network services as explained in Section 3.3 of this document. The revenue requirement for this service for users of point-to-point service is divided by the long-term firm reservation quantity. The revenue requirement of this service for users of network service is divided by the average of the 12 monthly non-coincident peak net demands for network service. The Appalachian pricing approach is applied to this service in the same fashion as it is applied to the point-to-point transmission service. The Appalachian pricing approach is explained in Section 3.3. The end result of this process is that the rates for this service are as shown in the Table 4-3.

Table 4-3
Reactive Supply and Voltage Control Service Rates

Services	Units	Rate
Yearly	$/kW-yr	1.801
Monthly	$/kW-m	0.150
Weekly	$/kW-w	0.03463
On-Peak Daily	$/kW-d	0.00693
Off-Peak Daily	$/kW-d	0.00493
On-Peak Hourly	$/kW-h	0.00043
Off-Peak Hourly	$/kW-h	0.00021
Network	$/kW-m	0.12

4.2.2 Energy Imbalance

Energy imbalance is a service that has no predictable required quantity and the cost of providing the service fluctuates with the real time cost of producing energy. For these reasons this service is discussed separately from the other services and is also priced uniquely.

The difficulty of forecasting load, the difficulty of controlling generator output, and the potential incentives for arbitrage make energy imbalances inevitable. Energy imbalance has a significant potential for cost shifting between suppliers as the quantity of the service used can be very volatile and can be intentionally varied by suppliers if it is to their advantage.

Since the users can control the usage of the energy imbalance service, the use of average embedded cost pricing would provide a substantial opportunity for users to profit from the use of the service at the expense of other suppliers. There are two common approaches to this problem in the industry. In areas that have some form of spot market (e.g. hourly energy market in New England) the spot market price is used to settle the energy imbalance differences. Because the spot market price reflects the real-time value of energy, users of the energy imbalance service pay, and the suppliers are paid, at the value of the energy. In areas that do not have a spot market, there is a tendency to price the service such that the suppliers are well protected and the users are discouraged from using the service. Paying low rates to transmission customers for over-supply and high rates to transmission customers for under-supply is a common approach used to encourage transmission customers to balance their supply with the load that they are serving.

The challenge in designing this service is to find the appropriate balance between protecting the providers of balancing energy and allowing a degree of tolerance for imbalances in the market so as not to make participation in the market impractical.

The Market Design Committee recognized the need for this balance and identified the issue in the following two recommendations concerning procurement and provision of this service:

> *"The MDC recommends that the System Operator shall operate an energy imbalance service. The System Operator can procure energy imbalance service from market participants, buying at the lowest available price within operating*

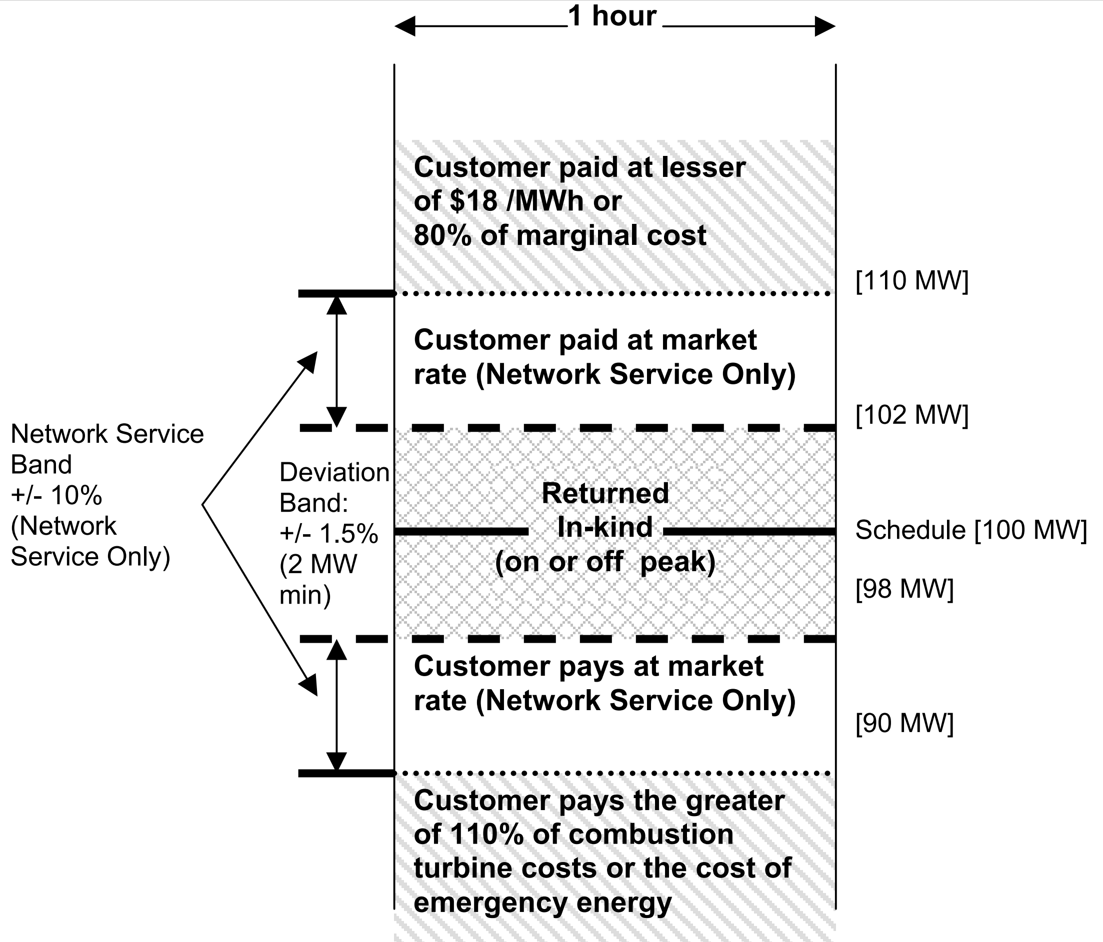
> *constraints. The energy imbalance service shall be priced at a proxy value recognizing cost and could move towards market-based pricing. The purpose is to encourage development of an efficient and effective service".*[45]

> *"The MDC recommends that balancing energy service be initially provided as an ancillary service through the transmission tariff and that its provision be based on the following principles:*
> - *It should efficiently provide economic signals that will drive behaviors appropriate for reliable operation of the system*
> - *Pricing of the service should be market-based where possible through:*
>   - *Offers for increments and decrements*
>   - *A proxy market price*
>   - *Ceilings and floors as necessary to protect participants".*[46]

Based on these considerations the energy imbalance service has been priced to encourage transmission customers to balance their supply to their load while permitting a reasonable degree of flexibility.

[45] Market Design Committee, Final Report (April 2002) Recommendation 3-29.
[46] Market Design Committee, Final Report (April 2002) Recommendation 3-30, p26.

Figure 4-1: Energy Imbalance Schematic



Note: Cumulative energy imbalance is limited to no more than +/- 20% of the average scheduled energy. Energy imbalances that occur while cumulative energy imbalance is in excess of +/- 20% of the average scheduled energy will be treated as being outside of the deviation bands.

The transmission provider settles hourly imbalances between the energy supplied and the energy consumed as illustrated in Figure 4-1. The energy imbalance service is structured to allow hourly imbalance within a clearly defined deviation band (+/- 1.5%, 2 MW minimum) to be settled through intentional scheduling of correcting imbalances. Energy imbalance for point-to-point service outside of the deviation band is priced to discourage excessive imbalances. Energy imbalance for network service outside of the deviation band within the larger network service band is priced at market based prices. Outside these two bands, energy imbalance is priced to motivate the transmission customer to avoid excessive imbalances. To prevent a build-up of imbalances, there is also a limit of +/- 20% of the average scheduled energy on the cumulative imbalance within the respective deviation band. The intention is to minimize the cost shifting that would occur if the value of energy at the time that the correction is made is different than what it was when the initial imbalance occurred.

5.0 SUMMARY

A summary of the rates for all services determined in this report is provided in Table 5-1. For ease of comparison the rates for all services are provided in the common units of $/kW-month.

Table 5-1
Rates For Services in NB Power's Open Access Transmission Tariff

Services	Schedule in Tariff	$/kW-month
Scheduling, System Control, and Dispatch Service	Schedule 1	
Point-to-Point		0.11921
Network		0.10
Reactive Supply and Voltage Control	Schedule 2	
Point-to-Point		0.15
Network		0.12
Regulation	Schedule 3	0.04
Load Following	Schedule 3	0.10
Energy Imbalance Service	Schedule 4	N/A
Contingency Reserve – Spinning	Schedule 5	0.17
Contingency Reserve – Supplemental (10-minute)	Schedule 6	0.45
Contingency Reserve – Supplemental (30-minute)	Schedule 6	0.29
Point-to-Point Service	Schedule 7	2.25363
Network Integration Service	Attachment H	1.84

Attachments

A. Transmission Services Cost Allocation and Rate Design Analysis

B. Ancillary Services Cost of Service and Rate Design Analysis

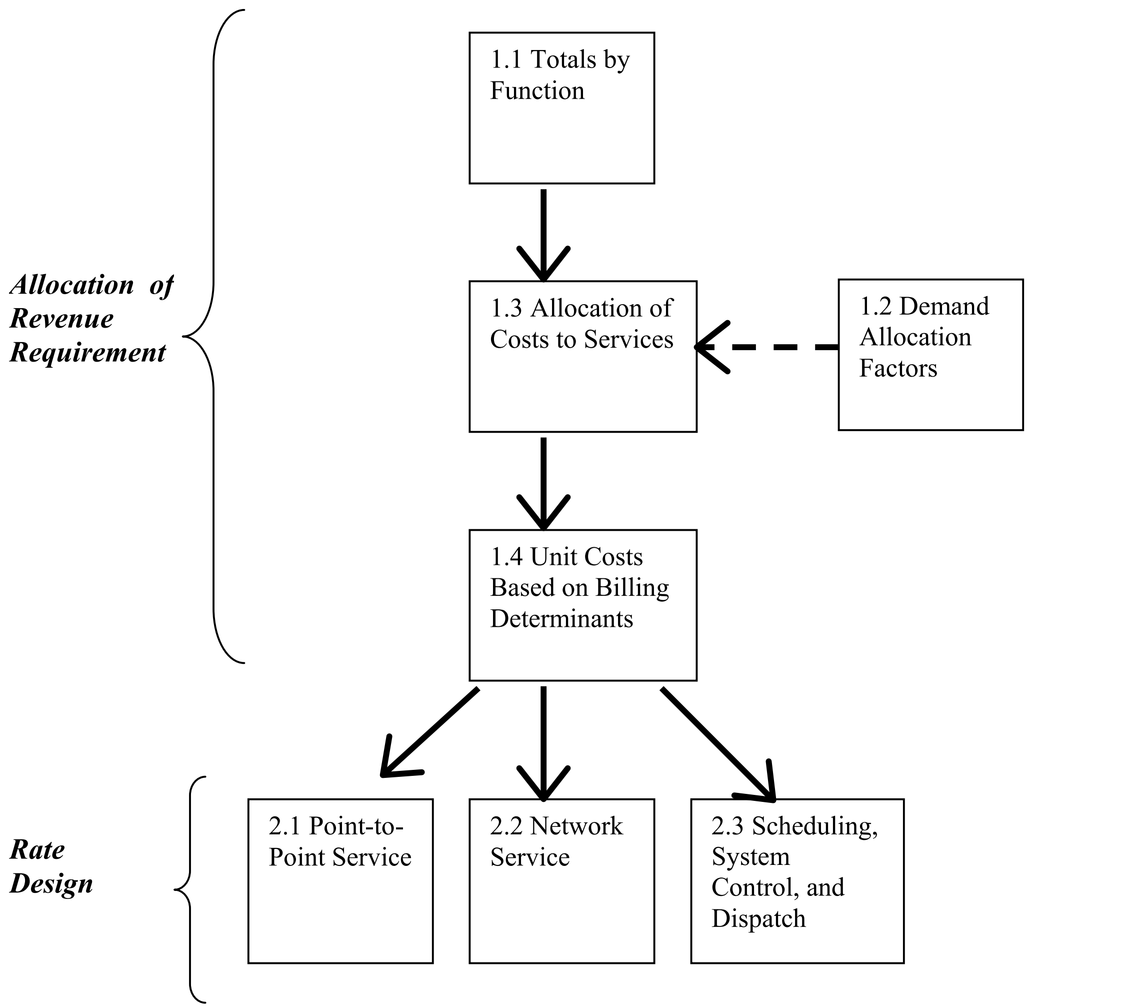
ATTACHMENT A: TRANSMISSION SERVICES COST ALLOCATION AND RATE DESIGN ANALYSIS

The Open Access Transmission Tariff Cost Allocation and Rate Design identifies and allocates the appropriate revenue requirement to the services provided under the tariff. The end-products are rate schedules for Point-to-Point Service, Network Service, and Scheduling, System Control, and Dispatch. This document outlines the contents and purpose of each of the seven schedules. The interrelationship between schedules is highlighted in Figure 1. The seven schedules are:

- Schedule 1.1 Demand Allocation Factors
- Schedule 1.2 Totals by Function
- Schedule 1.3 Allocation of Costs to Service Category
- Schedule 1.4 Unit Costs (Based on billing determinants)
- Schedule 2.1 Rates for Point-to-Point Service
- Schedule 2.2 Rate for Network Service
- Schedule 2.3 Rate for Scheduling, System Control, and Dispatch

In Schedule 1.1 (Demand Allocation Factors), the load ratio share of demand is calculated for each service. This is used as the basis for allocations. Schedule 1.2 (Totals by Function) summarizes the costs associated with each asset category. Schedule 1.4 (Unit Costs) calculates the cost per unit of each service. The rates for each of the services provided directly by the transmission provider under the Open Access Transmission Tariff are presented in Schedules 2.1, 2.2, and 2.3.

Figure 1: Diagram of the Key Relationships between Schedules



Schedule 1.1

NB POWER Transmission Business Unit
COST ALLOCATION
Totals by Function – Fiscal Year Ending March, 2004
($1000's)

	1	2	3a	3b	4	5	6	7	8
Asset Category	Average Gross Plant	Average Net Plant	Amortization Expense Total	Allocated Amortization Expense Total	OM&A Expense Total	Finance, Taxes & Return on Equity Total	Total Cost by Function	Credits by Function	Net Cost by Function
Generation Related Transmission Assets	**65,375**	**38,872**	**2,101**	**2,524**	**1,577**	**5,518**	**9,619**	**0**	**9,619**
Unit Transformers	40,796	25,067	1,325	1,589	-	3,547	5,137	0	5,137
Terminals	10,340	4,609	300	367	713	675	1,755	0	1,755
Transmission Lines	14,239	9,197	476	568	864	1,296	2,728	0	2,728
Bulk Network	**469,060**	**233,536**	**11,477**	**14,403**	**29,956**	**33,749**	**78,109**	**7,522**	**70,587**
Interconnections									
Terminals	6,540	2,239	186	199	451	340	990	456	534
Transmission Lines	19,540	9,025	376	471	1,186	1,315	2,972	272	2,699
HVDC	32,735	5,928	261	473	1,784	1,021	3,278	300	2,978
In-Province									
Terminals	198,152	97,252	6,448	7,717	13,664	14,077	35,458	3,249	32,209
Transmission Lines	212,094	119,092	4,206	5,543	12,871	16,997	35,411	3,245	32,166
Local Service	**41,393**	**17,829**	**1,024**	**1,266**	**2,376**	**2,620**	**6,262**	**574**	**5,689**
Terminals	0	0	0	0	0	0	0	0	0
Metering	2,234	957	65	80	128	141	349	32	317
Transmission Lines	27,148	11,755	663	820	1,559	1,727	4,105	376	3,729
Specific Transmission Lines									
Industrial Customers	11,900	5,052	292	362	683	744	1,789	164	1,626
Wholesale Customers	111	65	3	4	6	9	20	2	18
Energy Control Centre (Transmission)	**11,254**	**3,294**	**152**	**225**	**3,634**	**512**	**4,371**	**337**	**4,035**
General Transmission Assets	**62,271**	**35,877**	**3,664**						
Total NB Power Transmission Business Unit	**649,352**	**329,408**	**18,418**	**18,418**	**37,544**	**42,400**	**98,362**	**8,432**	**89,930**
Basis of Allocation				Gross Plant	Assigned & Gross Plant	Net Plant	Col 3b + Col 4 + Col 5	Assigned & Col 6	Col 6 - Col 7

Notes:

General Transmission Assets consist of Telecom, Motor Vehicles, Work in Progress, and Other (including an allocation of Corporate)

Schedule 1.2

COST ALLOCATION

Demand Allocation Factors
Average of 12 Monthly Peaks

	1	2	3	4
Service	**Long-Term Firm Res'ns**	**Trans -mission System 12 CP**	**Allocation Factors (%)**	**Billing Determinants Substation 12 NCP Served at Distribution Transformer**
Point to Point[1]	**720**	**-**	**25.53%**	**0**
Network In-Province	**-**	**2,100**	**74.47%**	**2,571**
TOTAL MW	720	**2,100**	**100.00%**	

Basis of Allocation	Col 1&2/ Total

Notes:

1 - Long-term firm reservations are reservation of at least one year in duration
2 - The allocation factors and billing determinants above are used in subsequent schedules

NB POWER Transmission Business Unit

COST ALLOCATION

Allocation of Costs to Services

($1,000's)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Services	Amortization Expense				OM&A Expense				Finance Charges				Credits	Total
	Bulk Network	Local Service	Generation Related Assets	Total	Bulk Network	Local Service	Generation Related Assets	Total	Bulk Network	Local Service	Generation Related Assets	Total	Total	
Point-to-Point Service	3,677	323	0	4,000	7,647	607	0	8,254	8,615	669	0	9,284	2,067	19,471
Network Service [(2)]	10,726	942	0	11,669	22,309	1,770	0	24,079	25,134	1,952	0	27,085	6,029	56,804
Generation Connection Service	0	0	2,524	2,524	0	0	1,577	1,577	0	0	5,518	5,518	0	9,619
Scheduling, System Control, and Dispatch				225				3,634				512	337	4,035
Total NB Power Transmission Business Unit	14,403	1,266	2,524	18,418	29,956	2,376	1,577	37,544	33,749	2,620	5,518	42,400	8,432	89,930
Basis of Allocation	Sch 1.2 Col 3	Sch 1.2 Col 3	Assigned	Col 1 + Col 2 + Col 3	Sch 1.2 Col 3	Sch 1.2 Col 3	Assigned	Col 5 + Col 6 + Col 7	Sch 1.2 Col 3	Sch 1.2 Col 3	Assigned	Col 9 + Col 10 + Col 11	Assigned	Col 4 + Col 8 + Col 12 - Col 13

Notes:

1. The total expense associated with each function (bulk network, local service, generation related transmission assets) comes from Column 8 of Schedule 1.1 Cost Allocation
2. The allocation of the revenue requirement associated with each function is identified above.

Schedule 1.4

NB POWER Transmission Business Unit

COST ALLOCATION

Unit Costs

	1	2	3	4
Services	**Total Cost By Service ($1000)**	**Total Usage By Service (MW)**	**$/kW-yr**	**Monthly $/kW-m**
Point-to-Point Service[1]	**19,471**	**720**	**27.04**	**2.25**
Network Service [2]	**56,804**	**2,100**	**27.04**	**2.25**
Sub-Total Point-to-Point and Network Service	**76,276**	**2,820**	**27.04**	**2.25**
Generation Connection Service	**9,619**	**N/A**	**N/A**	**N/A**
Scheduling, System Control, and Dispatch	**4,035**	**2,820**	**1.43**	**0.12**
Total NB Power Transmission Business Unit	**89,930**	**N/A**	**N/A**	**N/A**
Basis of Allocation	Sch 1.3 Col 14	Sch 1.2 Cols 1&2	Col 1 / Col 2	Col 3 / 12

Notes:

1 - Usage based on firm reservations
2 - Usage based on substation 12NCP for 2003/2004
3 - Cost of service = cost by service / usage by service

1

Schedule 2.1

NB POWER Transmission Business Unit

RATE DESIGN

Rates for Point-to-Point Services

Service Category	1 Total Cost By Class ($1000)	2 Total Usage By Class (MW)	3 $/kW-yr	4 $/kW-m
Point-to-Point Service(1)	19,471	720	27.04351	2.25363

			Rates $/MW-yr	Rates $/MW-m
Yearly(2)		Monthly Cost * 1000	27,043.56	2,253.63
Monthly(3)	($/MW-m)	Yearly/12		2,253.63
Weekly(3)	($/MW-w)	Yearly/52		520.07
On-Peak Daily(3)	($/MW-d)	Weekly/5		104.01
Off-Peak Daily(3)	($/MW-d)	Yearly/365		74.09
On-Peak Hourly(4)	($/MW-h)	Daily/16		6.50
Off-Peak Hourly(4)	($/MW-h)	Yearly/8760		3.09

Notes:

1 - Usage based on long term firm reservations
2 - Firm only
3 - Firm or non-firm
4 - Non-firm only

Schedule 2.2

NB POWER Transmission Business Unit

RATE DESIGN

Rate for Network Service

	1	2	3	4
Service Category	**Cost of Service $/kW-yr**	**Cost of Service Monthly $/kW-m**	**Coincidence Factor**	**Monthly $/kW-m Billing Rate**
Network Service	**27.04**	**2.25**	**81.7%**	**1.84**
Basis of allocation	Sch 1.4, Col 3	Col 1/12	See Note Below	Col 2 * Col 3

Notes:

Calculation of coincidence factor for network service loads

a 12 coincident peak load	2,100	MW	(Sch 1.2, Col 2)
b 12 non-coincident peak load	2,571	MW	(Sch 1.2, Col 4)
Coincidence factor = **a/b**	81.7%		

Schedule 2.3

NB POWER Transmission Business Unit

RATE DESIGN
Scheduling, System Control, and Dispatch (Schedule 1 of the Tariff)

	1	2	3	4
Service	**Total Cost of Service ($1000)**	**Total Usage (MW)**	**Yearly Cost $/kW-yr**	**Monthly Cost $/kW-m**
Sched, Sys. Ctrl. & Disp	**4,035**	**2,820**	**1.43048**	**0.11921**

Sched, Sys Ctrl. & Disp for Point-to-Point(1)		**Rate for Services Billed Monthly** **Services**	**$/MW-yr**	**$/MW-m**
Yearly(2)		Monthly Cost * 1000	**1,430.52**	**119.21**
Monthly(3)	($/MW-m)	Yearly/12		**119.21**
Weekly(3)	($/MW-w)	Yearly/52		**27.51**
On-Peak Daily(3)	($/MW-d)	Weekly/5		**5.50**
Off-Peak Daily(3)	($/MW-d)	Yearly/365		**3.92**
On-Peak Hourly(4)	($/MW-h)	On-Peak Daily/16		**0.34**
Off-Peak Hourly(4)	($/MW-h)	Yearly/8760		**0.16**

	Cost of Service			**Rate**
	$/kW-yr	**$/kW-m**	**Coincidence Factor**	**Monthly $/kW-m**
Sched, Sys. Ctrl. & Disp. for Network Service	**1.43**	**0.12**	**81.7%**	**0.10**

Notes:

1 - Usage based on long term firm reservations
2 - Firm only
3 - Firm or non-firm
4 - Non-firm only

1

ATTACHMENT B: ANCILLARY SERVICES COST OF SERVICE AND RATE DESIGN ANALYSIS

Schedule.1.0

Capacity Based Ancillary Services
Cost Data for Proxy Units

Parameters		Greenfield Combined Cycle Gas Unit	Simple Cycle Gas Unit
Variable OM&A Cost	($M)	2.1	0.2
Fixed OM&A Cost	($M)	11.8	0.5
Capital Additions	($M)	0.4	0.2
	($/kW-Yr)	1.0	1.6
Capital Cost	($M)	428	60
	($/kW)	1070	600
Project Life	(Years)	25	25
Capacity	(MW)	400	100
Year Dollars	2006		
Escalation Rate	1.80%		
Interest Rate	7.15%		
Levelized Lifecycle Costs			
Variable OM&A Cost	($/MWh)	0.88	0.88
Fixed OM&A Cost	($/kW-Yr)	34.63	5.87
Capital Additions	($/kW-Yr)	1.17	1.88
Capital Cost	($/kW-Yr)	93.06	52.18

Notes:
1. The combined cycle unit is used as the proxy for on-line services
2. The simple cycle unit is used as the proxy for off-line services

Schedule 1.1

Capacity Based Ancillary Services
Cost of Providing Services

Ancillary Service	Proxy Source	1 Capacity (MW)	2 Capital Cost 2004$ ($/kW)	3 Exp'd Life (y)	4 Escallating Capital Charge ($/kW-yr)	5 O&M ($/kW-yr)	6 Payments in Lieu of Taxes ($/kW-yr)	7 Total Fixed Costs ($/kW-yr)	8 Contribution Reactive Supply ($/kW-yr)	9 Installed Capacity ($/kW-yr)	10 Energy Prod'n[3,4] ($/kW-yr)	11 Rate for Ancill. Service ($/kW-yr)
Regulation and Frequency Response												
Regulation	Combined Cycle - Greenfield (Fast AGC)	400	$1,032	25	$101.42	$31.39	$22.36	$ 155.17	$1.21	$17.31	$54.66	$81.99
Load Following	Combined Cycle - Greenfield (Slow AGC)	400	$1,032	25	$101.42	$30.48	$22.36	$ 154.26	$1.21	$17.31	$67.87	$67.87
Operating Reserves												
Spinning (10 Minute)	Combined Cycle - Greenfield	400	$1,032	25	$101.42	$30.18	$22.36	$ 153.96	$1.21	$17.31	$74.50	$60.95
Supplemental (10 Minute)	Combustion Turbine - Simple Cycle (quickstart)	100	$ 589	25	$57.85	$5.11	$12.75	$ 75.72	$0.60	$17.31	$0.00	$57.81
Supplemental (30 Minute)	Combustion Turbine - Simple Cycle	100	$ 579	25	$56.87	$5.11	$12.54	$ 74.52	$0.60	$17.31	$0.00	$56.61
		Sch 1.0	Sch 1.0 in 2004$	Sch 1.0	Sch 1.0	Sch 1.0		Col (4+5+6)	MVAR/MW *React Cost Note 5 *React Cost $/kVAR/yr	Assign		Col 7 - Col 6 -Col 9 - Col 10

Notes:

1. ICAP value based on Natsource 12 month quotes for 2003 escallated to 2004 — Discount rate 10.3%
2. MVAR/MW 48.4% (90% lagging power factor requirement) — Escallation 1.8%
3. Capacity factor for regulation 40%
4. Capacity factor for load following 50%
5. Capacity factor for spinning reserve 55%
6. Capacity factor for supplemental 10 minute reserve 0%
7. Capacity factor for supplemental 30 minute reserve 0%

Schedule 1.2

Capacity Based Ancillary Services
MW Requirements

	1	2	3	4	5	6
	Maritimes Control Area	**Nova Scotia**	**NB/N.Me./ PEI**	**PEI**	**Northern Maine**	**New Brunswick**
Peak Load (using 2001/2002 12CP)	3926	1598	-	156	119	2053
Maritimes Control Area Load Share Ratio	100.00%			3.97%	3.03%	52.29%
Without Nova Scotia			100.00%	6.70%	5.11%	88.19%
Regulation and Frequency Response						
Regulation			19	1.27	0.97	16.76
Load Following			53	3.55	2.71	46.74
Operating Reserves (Contingency Reserves)						
Spinning (10 Minute)	125.0	25.0	-	6.7	5.1	88.2
Supplemental (10 Minute)	375.0	100	-	18.4	14.1	242.5
Supplemental (30 Minute)	229.1	50	-	12.0	9.2	157.9
Nominal first contingency relative to Maritimes Control Area 1CP load			5000	MW	10%	500
Actual first contingency						660
Nominal second contingency relative to Maritimes Control Area load					10%	500
Actual second contingency						458.1

Notes:
1. The smaller of the nominal and actual contingencies will be the tariff obligation
2. The spinning reserve requirement is typically 25% of the total 10 minute reserve
3. The 10 minute reserve requirement is 100% of the largest contingency
4. The 30 minute reserve is 50% of the second largest contingency

Capacity Based Ancillary Services
New Brunswick Usage

	1	2	3	4	5
		Network Service Billing Determinants			
	Usage by Point-to-Point MW	Total MW	Loads That Self Supply MW	Loads That Purchase From Third Party MW	Net Usage in Tariff MW
Regulation and Frequency Response					
Regulation	0	2571	0	0	2571
Load Following	0	2571	0	0	2571
Operating Reserves (Contingency Reserves)					
Spinning (10 Minute)	0	2571	0	0	2571
Supplemental (10 Minute)	0	2571	0	0	2571
Supplemental (30 Minute)	0	2571	0	0	2571
					Col (1+2-3-4)

Notes:
1. Customers also have the option to self-supply or purchase these services from a third party

Capacity Based Ancillary Services
Rate Design
Revised Version

	1	2	3	4	5	6	6'	7	8
	Revenue Req't ($/kW-yr)	**Service Req'd** (MW)	**Revenue Req't** ($1000/yr)	**Usage** (MW)	**Rate for Pt-Pt** ($/kW-yr)	**Rate for Pt-Pt** ($/MW-m)	**Rate for Network** ($/kW-m)	**Rate for Pt-Pt** ($/MW-w)	**Rate for Pt-Pt** ($/MW-d)
Regulation and Frequency Response									
Regulation	$ 81.99	16.76	$ 1,373.82	2571	$ 0.534	$ 44.50	$ 0.04	$ 10.27	$ 2.05
Load Following	$ 67.87	46.74	$ 3,172.38	2571	$ 1.234	$ 102.83	$ 0.10	$ 23.73	$ 4.75
Operating Reserves (Contingency Reserves)									
Spinning (10 Min.)	$ 60.95	88.2	$ 5,375.08	2571	$ 2.090	$ 174.17	$ 0.17	$ 40.19	$ 8.04
Supp. (10 Min.)	$ 57.81	242.5	$14,020.66	2571	$ 5.450	$ 454.17	$ 0.45	$ 104.81	$ 20.96
Supp. (30 Min.)	$ 56.61	157.9	$ 8,939.43	2571	$ 3.480	$ 290.00	$ 0.29	$ 66.92	$ 13.38
Totals		552.1	$32,881.37		$12.790	$1,065.67	$ 1.05	$ 245.96	$ 49.19
	Sch 2.1	Sch 2.2	Col 1 * Col 2	Sch 2.3	Col 3/Col 4	Col 5/12 *1000	Col 6' Rounded /1000	Col 5/52	Col 7/5

Capacity Based Ancillary Services
External Revenues
Revised Version

	1	2	3	4
	Rate ($/kW-yr)	**PEI (MW)**	**N. Maine (MW)**	**Total**
12NCP (12CP, Schedule 1.2 * Coincidence factor)		191	146	337
Regulation and Frequency Response				
Regulation	$ 0.53	$ 102	$ 78	$ 180
Load Following	$ 1.23	$ 236	$ 180	$ 415
Operating Reserves (Contingency Reserves)				
Spinning (10 Minute)	$ 2.09	$ 399	$ 304	$ 703
Supplemental (10 Minute)	$ 5.45	$ 1,041	$ 794	$ 1,834
Supplemental (30 Minute)	$ 3.48	$ 664	$ 507	$ 1,171
Total ($1000/yr)				$ 4,304

Notes:
1. These services are itemized separately on the Transmission income statement
2. The coincidence factor is assumed to be 81.7% (12NCP data not available)
3. The actual revenues will depend upon the extent to which the external parties choose to either self-supply or purchase from a third party. The estimate of these external revenues for the test year is $300,000.

Schedule 2.1

Reactive Supply and Voltage Control
Service Cost

Ancillary Service	Proxy Source	1	2	3	4	5	6	7
		Capacity (MVAr)	**Capital Cost 2003$ ($)**	**Expected Life (y)**	**Escallating Capital Charge ($/yr)**	**O&M ($/yr)**	**Payments in Lieu of Taxes ($/kW-yr)**	**Total Fixed Costs ($/yr)**
Reactive Supply and Voltage Control								
	Synchronous Condensors[(1)]	330	$26.5	30	$2.48	$0.08	$0.90	$3.46
Adjustment to account for the fact that a synchronous generator is more economical because of the dual purposes served by the generator (energy production and reactive supply and voltage control)						50.0%		$ 1.73
Revenue requirement per VAR of capability				$/kVAR/yr				$5.25
Estimated peak VAR requirement				MVAR	246			
Additional VAR requirement for dynamic system security				MVAR	800			
	Total VAR requirement			MVAR	1046			1046
Revenue requirement total				$1000/yr				$ 5,488

Notes:

1. Based on historical costs escallated to 2003 dollars
2. Discount rate 10.3%
3. Escallation 1.8%
4. Note that the total nameplate capability of generation currently on the system is 2200 MVAR
5. The requirement divided by the nameplate capability is 1046 divided by 2360 47.5%

Schedule 2.2

Reactive Supply and Voltage Control
Rate Design

	1	2	3	4	5	6	7	8	9
	Revenue Requirement ($1000/yr)	**Billing Determinants (MW)**	**Yearly ($/kW-yr)**	**Monthly ($/kW-m)**	**Weekly ($/MW-w)**	**On-Peak Daily ($/MW-d)**	**Off-Peak Daily ($/MW-d)**	**On-Peak Hourly ($/MW-h)**	**Off-Peak Hourly ($/MW-h)**
Reactive Supply and Voltage Control									
Total	$ 5,488.1								
less Credits	$ 408.5								
Net	$ 5,079.5								
Point-to-Point	$ 1,296.9	720	$ 1.801	$ 0.150	$ 34.63	$ 6.93	$ 4.93	$ 0.43	$ 0.21
Network	$ 3,782.6	2571	$ 1.471	$ 0.123					
		3291							
Calculation of credits (short term firm and non-firm revenues from this service)									
2003/2004 in MW			n/a	2,425	-	3,930	-	40,949	-
Revenue ($1000/yr)			n/a	363.70	-	27.23	-	17.61	-
	Allocated on 12CP			Col 3/12	Col 3/52	Col 5/5	Col 3/365	Col 6/16	Col 3/8760

Notes:
1. The transmission customer (Point-to-Point or Network) must purchase this service from the transmission provider
2. Credits are revenue from Reactive Supply and Voltage Control associated with short term firm and non-firm point-to-point service
3. 12CP usages are 720 MW and 2100 MW respectively

Énergie NB Power

Application for an Open Access Transmission Tariff

Panel C Presentation to the Public Utilities Board

Panel C: Revenue Requirement and Rate Design

Bill Marshall
George Porter

Sharon MacFarlane
David Lavigne

Énergie NB Power

Presentation Outline

- Transmission Rate Design by Step
- Generation Ancillaries Rate Design
- Summary

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Steps of the Rate Design Process

1 Define Principles

2 Determine Transmission Assets

3 Calculate Revenue Requirement

4 Define Services Offered

5 Allocate Revenue Requirement to Services

6 Define Billing Determinants

7 Design Rates

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Step 1 - Define Principles

- Ensure recovery of revenue requirement
- Develop rates that are “just and reasonable”, without “undue discrimination”
- Support the New Brunswick electricity market
- Ensure compatibility with industry standard FERC Order 888 as recommended by Market Design Committee

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Step 2 - Determine Transmission Assets

- **Defined as system between Generation and Distribution**
- **Includes some generation connection assets**
  - Generator step up transformers
  - Radial transmission lines
  - Generation synchronizing breakers

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Step 3 - Calculate Revenue Requirement

- **Operations, maintenance and administration**
  - *includes an allocation of corporate OM&A and is net of services provided between business units*
- **Amortization**
  - *as booked (straight-line, various asset lives)*
- **Finance charges**
  - *based on NB Power's total existing debt and new debt*
- **Return on equity (ROE)**
  - *11%*
- **Payments in lieu of taxes**
  - *equivalent to taxes of a for-profit company*

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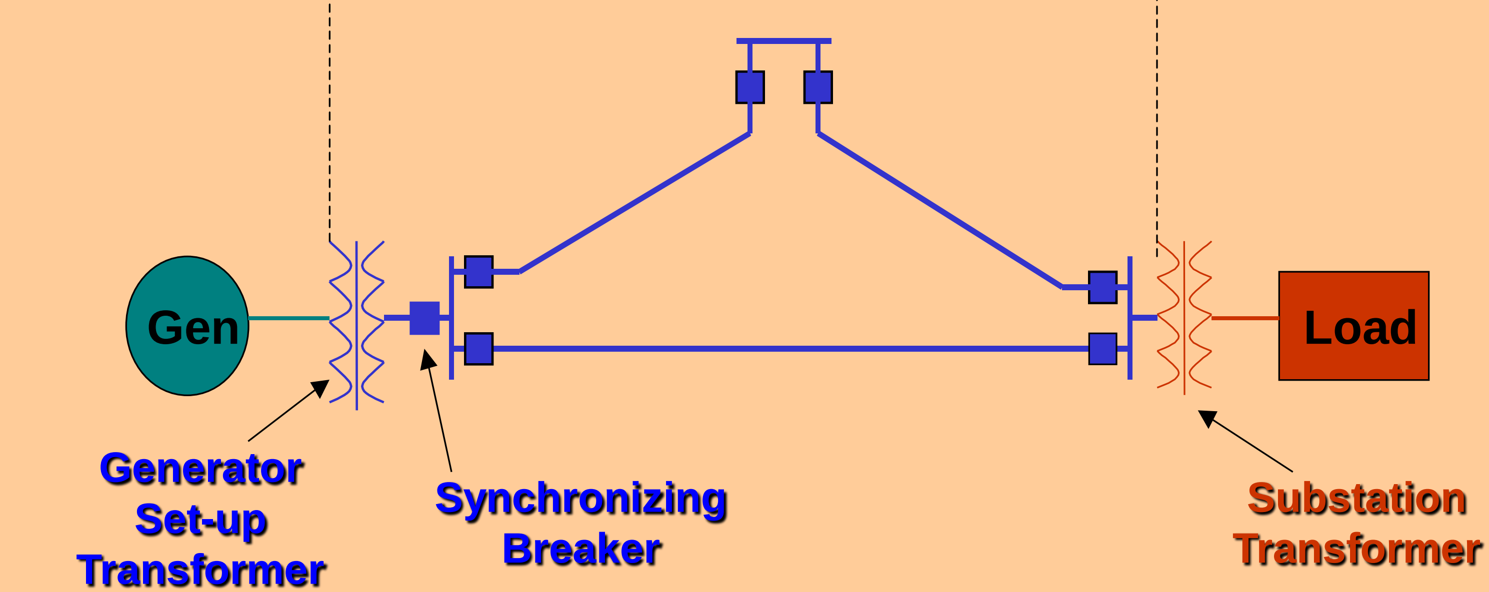
Step 2 - Determine Transmission Assets



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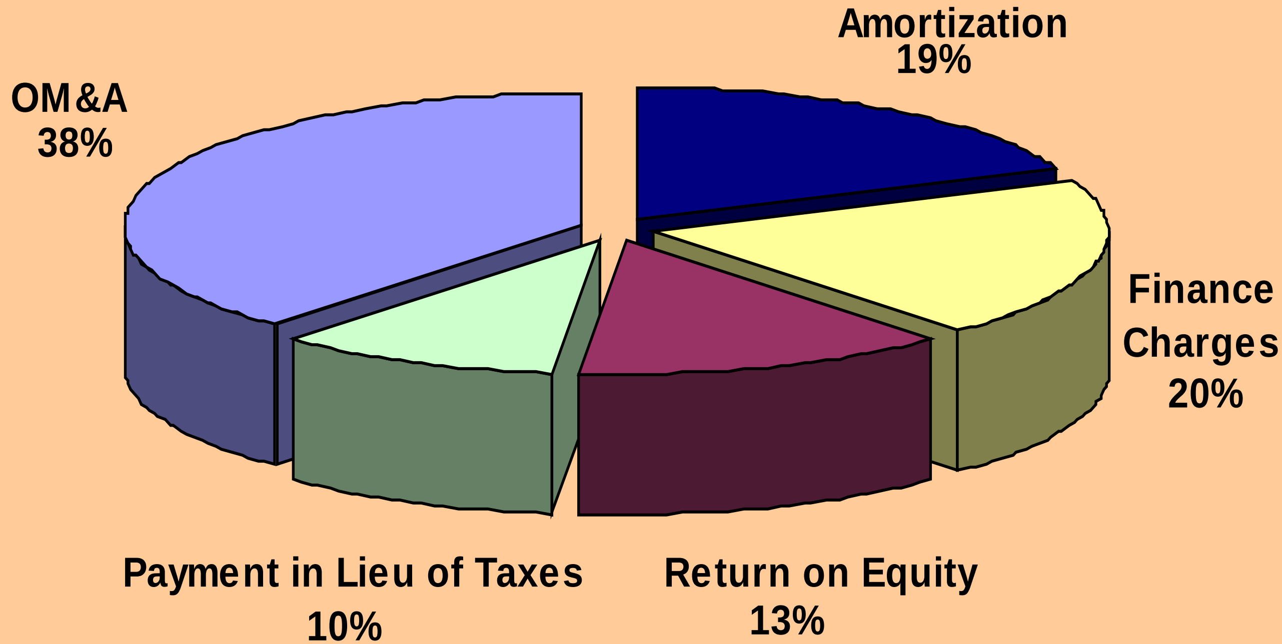
Step 3 - Calculate Revenue Requirement

Total transmission requirement is $98.4 million



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Step 4 - Define Services Offered

The services provided

- Generation Connection
- Point-to-Point
- Network Integration
- Scheduling, System Control, and Dispatch
- Ancillary Services from Generation Sources

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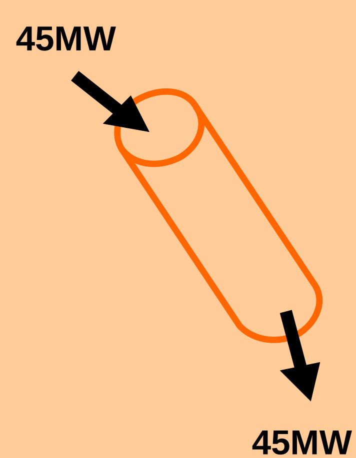
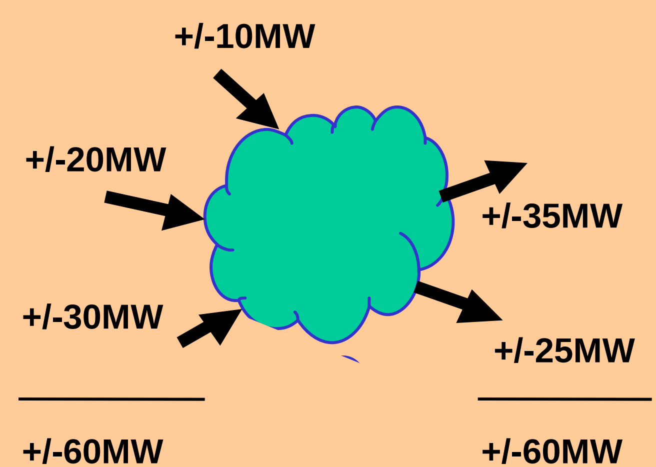
Step 4 - Define Services Offered

Point-to-Point Service



Network Integration Service



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Step 5 - Allocate Revenue Requirement to Services

- **Identify revenue requirement for physical asset categories**
  - Amortization is known
  - OM&A based on gross book value
  - Finance charges and ROE based on net book value
- **Energy Control Centre is directly assigned to "Scheduling, System Control, and Dispatch"**

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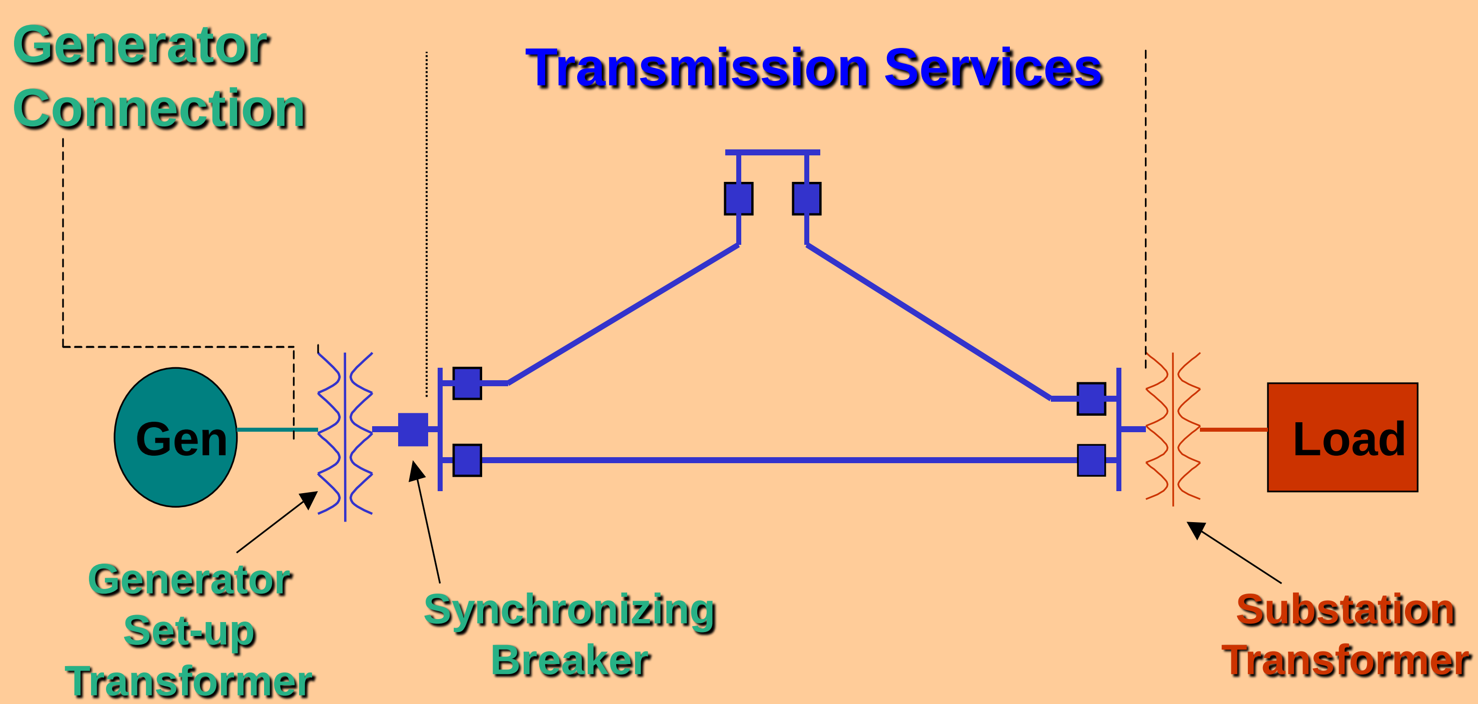
Step 5 - Allocate Revenue Requirement to Services



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Step 5 - Allocate Revenue Requirement to Services

- Net out revenue from short-term and miscellaneous services
- Determine Point-to-Point and Network usage
- Allocate between Point-to-Point and Network based on usage ratio

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Step 5 - Allocate Revenue Requirement to Services

$98.4

$9.6
Generation Connection

$84.4

Energy Control Centre
$4.4
Scheduling, System Control & Dispatch

$8.1
(miscellaneous revenue)

$76.3

Transmission Services
- **Long-term Firm Point-to-Point**
- **Network Integration**

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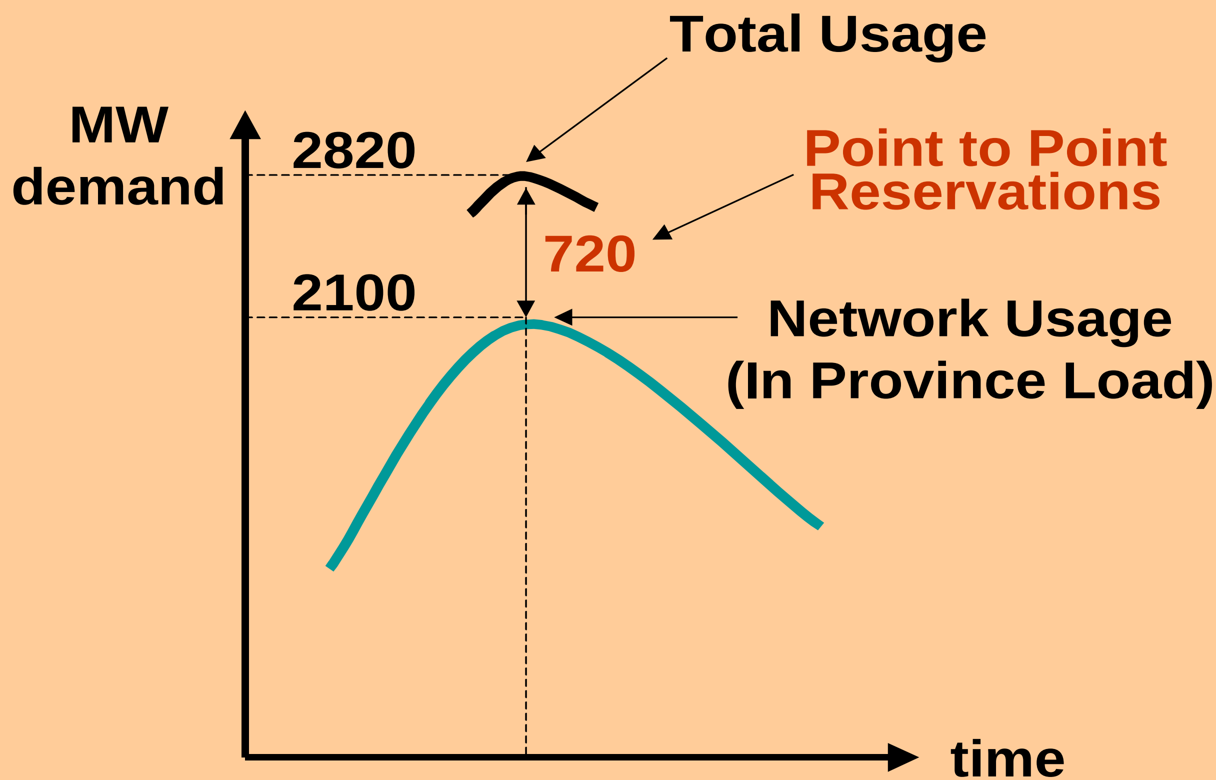
Step 5 - Allocate Revenue Requirement to Services

Usage Determination



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Step 5 - Allocate Revenue Requirement to Services

Transmission Services

$76.3

720MW ÷ 2820MW

2100MW ÷ 2820MW

Long-term Firm Point-to-Point	Network Integration
$19.5	$56.8

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Step 6 - Define Billing Determinants

Service	Definition	MW
Point-to-Point	Long-Term Firm Reservations	720
Network	Monthly Net Non-coincident Peak Demand	2571

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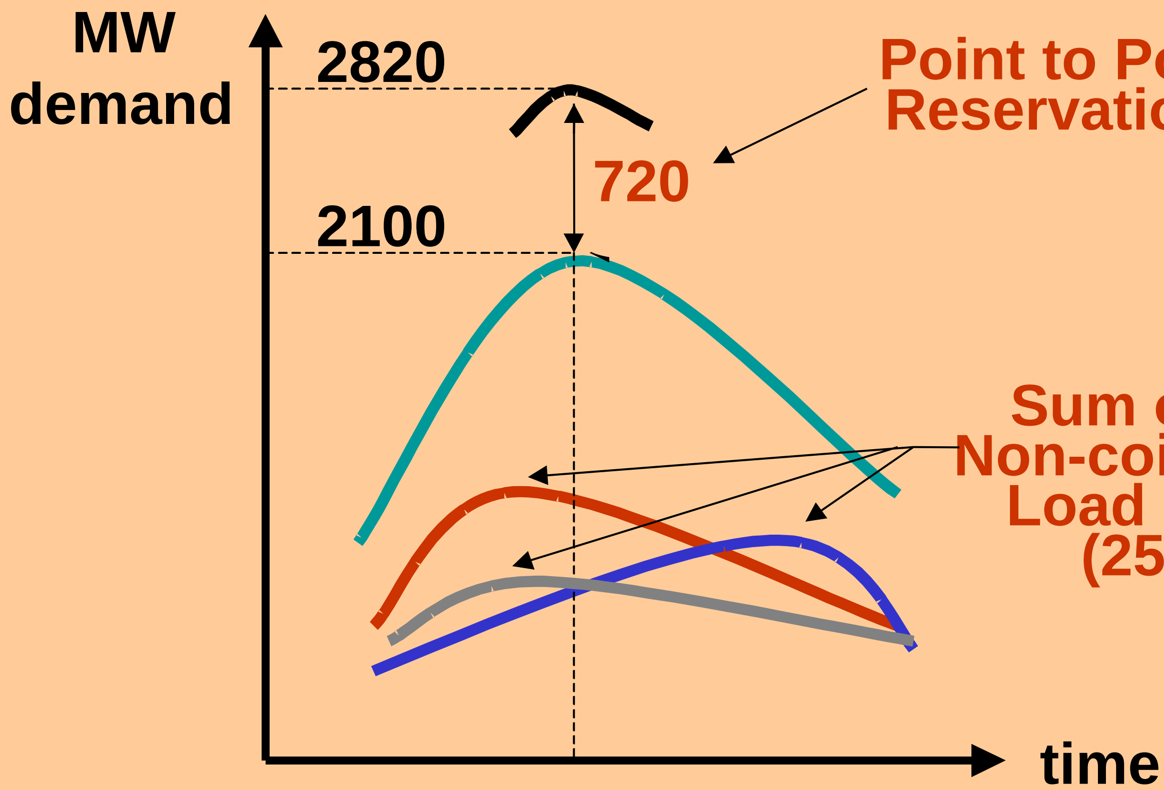
Step 6 - Define Billing Determinants



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Step 7 - Design Rates

Postage stamp rates calculated as follows

$$\text{rate} = \frac{\text{revenue requirement}}{\text{billing determinant}}$$

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Step 7 - Design Rates

Long-Term Firm Point-to-Point

$$\text{rate} = \frac{\text{revenue requirement}}{\text{billing determinant}}$$

$$= \frac{\$19.5 \text{ million}}{720 \text{ MW}}$$

= $27.04/kW-year

= $2.25/kW-month

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Step 7 - Design Rates

Network Integration

$$\text{rate} = \frac{\text{revenue requirement}}{\text{billing determinant}}$$

$$= \frac{\$56.8\text{ million}}{2571\text{ MW}}$$

$$= \$22.08/\text{kW-year}$$

$$= \$1.84/\text{kW-month}$$

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Step 7 - Design Rates

Short Term Point to Point Rates

- **Monthly and Weekly prorated from Annual**
- **Daily and Hourly include a premium**
  - reflect the value of on-peak usage
  - discourage "cherry picking"
  - use FERC approved "Appalachian" approach

Daily On-Peak = Weekly ÷ 5
Hourly On-Peak = Daily ÷ 16

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Step 7 - Design Rates

Rate comparisons

	$/kW-yr
NB Power	*27.04*
Hydro-Quebec	71.09
Manitoba Hydro	35.77
SaskPower	32.14
BC Hydro	51.12
Bangor Hydro*	41.48
Central Maine Power*	23.03
Maine Public Service*	42.87

**US$0.64/Cdn$1*

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Generation Ancillaries - Method

Process repeated for generation ancillaries

- **Reactive Supply and Voltage Control**
- **Regulation**
- **Load Following**
- **Operating Reserve - Spinning**
- **Operating Reserve Supplemental - 10 min**
- **Operating Reserve Supplemental - 30 min**

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Generation Ancillaries - Method

Four pricing methods were considered

- **embedded costs**
  (may over or undervalue the resource, requires confidential data of commercial value)
- **short-run marginal costs**
  (difficult to measure, highly variable, and provide inadequate incentives)
- **bid based**
  (market power problems due to thin market)
- **long-run marginal costs (proxy units)**

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Generation Ancillaries - Method

Long-run marginal cost pricing (proxy units)

- **provides adequate compensation to supplier**
- **mitigates market power**
- **transparent**
- **not site or system specific**
- **predictable**

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Generation Ancillaries - Method

Service	Proxy Unit
Reactive Supply/Voltage	Synchronous condenser
Regulation	Combined cycle gas turbine
Load Following	"
Reserve - Spinning	"
Reserve Supplemental (10 minute and 30 minute)	Simple cycle gas turbine

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Generation Ancillaries - Method

Proxy unit costs are discounted by contributions from the following

- **reactive supply and voltage control**
- **installed capacity credits**
- **energy production potential**

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Generation Ancillaries - Rates

Ancillary Services rates calculated as follows

$$\text{ancillary rate} = \frac{\text{revenue requirement}}{\text{billing determinant}}$$

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Generation Ancillaries - Rates

Service	$/kW-m
Scheduling, System Control, and Dispatch	0.10
Reactive Supply and Voltage Control	0.12
Regulation and Load Following	0.14
Contingency Reserve – Spinning	0.17
Contingency Reserve – Supplemental (10 & 30 min)	0.74
Total	1.27

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NB Power's Tariff

- Recovers revenue requirement
- Produces "just and reasonable" rates without "undue discrimination"
- Supports implementation of market
- Compatible with industry standard

Point-to-Point Service	$27.04/kW-year
Network Service	$1.84/kW-month
Network Service & Ancillaries	$3.11/kW-month

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Request IR-263:

With reference to Appendix 6.05, page 20, in the Data Assumptions column of Appendix A to the WKM Report it is noted that "Capital upgrade costs of supply alternatives are taken from Figure 3." However Figure 3 of the report just shows a map of potential transmission upgrades without any capital upgrade costs. Please provide the referenced capital upgrade costs.

Response IR-263:

Due to an oversight, the reference in the Appendix did not get updated. The capital upgrade costs are provided in Figure 4 which is repeated here.

Figure 4
Transmission Costs and Capabilities

		Cost NPV 2015 ($M)	ATC (MW)	Firm Capability (MW)	Available for NS Power (MW)
NB-NS Interface Options					
#1	Onslow-Coleson Coveplus voltage support	$ 450	800	600	500
#2	NB Status Quo (Voltage support)	$ 30	400	80	0
NB-HQ Interface Options					
#1	Eel River Status Quo (2015)	$ 100	310		
	Madawaska Status Quo (3031)	$ 94.8	430		
	Total HQ#1	$ 195	740	690	0
#2	Eel River Status Quo	$ 100	310		
	Madawaska Minor Upgrade	$ 250	600		
	Total HQ#2	$ 350	910	860	165
#3	Eel River Status Quo	$ 100	310		
	Madawaska Major Upgrade	$ 400	940		
	319 kV Line to Riviere-du-Loup (90 km)	$ 100			
	Total HQ#3	$ 600	1250	1200	500

Madawaska Status Quo NPV Cost is $150M escalated at 3% to 2031 and discounted at 6.0% to 2015

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Request IR-264:

With reference to Appendix 6.06:

(a) Please prepare similar tables for all scenarios and sensitivity runs and provide all calculations, spreadsheets, reports, other work papers, Strategist inputs and outputs, and any other materials used for those tables.

(b) Please extend all of the tables for all alternatives, scenarios and sensitivity runs to 2050 or demonstrate how the present values for the 35-year contract period were otherwise obtained.

Response IR-264:

(a) Please refer to Synapse IR-11.

(b) Please refer to SBA IR-30 (b).

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Request IR-265:

With reference to Appendix 6.06, page 1, please provide all calculations, spreadsheets, reports, work papers, Strategist inputs and outputs, and any other materials showing all the data and calculations used to obtain the Study Period NPVs for the three alternatives against the base load forecast.

Response IR-265:

Please refer to Synapse IR-11 and SBA IR-30 (b).

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Request IR-266:

With reference to Appendix 6.06, page 2. Please provide all calculations, spreadsheets, reports, work papers, Strategist inputs and outputs, and any other materials showing all the data and calculations used to obtain the Planning Period annual operating costs and capital costs for the Maritime Link and Other Import comparison against the base load forecast.

Response IR-266:

Please refer to Synapse IR-11.

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Request IR-267:

With reference to Appendix 6.06, page 3. Please provide all calculations, spreadsheets, reports, work papers, Strategist inputs and outputs, and any other materials showing all the data and calculations used to obtain the Planning Period annual operating costs and capital costs for the Maritime Link and Indigenous Wind comparison against the base load forecast.

Response IR-267:

Please refer to Synapse IR-11.

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Request IR-268:

With reference to Appendix 6.06, page 4. Please provide all calculations, spreadsheets, reports, work papers, Strategist inputs and outputs, and any other materials showing all the data and calculations used to obtain the Study Period NPVs for the three alternatives against the low load forecast.

Response IR-268:

Please refer to Synapse IR-11.

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Request IR-269:

With reference to Appendix 6.06, page 5. Please provide all calculations, spreadsheets, reports, work papers, Strategist inputs and outputs, and any other materials showing all the data and calculations used to obtain the Planning Period annual operating costs and capital costs for the Maritime Link and Other Import comparison against the low load forecast.

Response IR-269**:**

Please refer to Synapse IR-11.

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Request IR-270:

With reference to Appendix 6.06, page 6. Please provide all calculations, spreadsheets, reports, work papers, Strategist inputs and outputs, and any other materials showing all the data and calculations used to obtain the Planning Period annual operating costs and capital costs for the Maritime Link and Indigenous Wind comparison against the low load forecast.

Response IR-270:

Please refer to Synapse IR-11.

Request IR-271:

With reference to Appendix 8.01:

a) Please provide details on the scope of the "Woodbine Upgrades" as defined in Section 3.4 of the Agency and Service Agreement.

b) Is there any relationship between the "Woodbine Upgrades" and the Nova Scotia Power Network Upgrades presented in Figure 8-1 in the Application?

Response IR-271:

(a) The scope of the Woodbine Upgrades includes:

- 5 new 345 kV breakers. One of these new breakers will replace the existing 101S- 801 345 kV breaker, which will become a spare breaker due to construction reasons. The new replacement breaker will be numbered as 101S-811.

- 7 new 230 kV breakers. The two existing 230 kV breakers will remain in place.

- A new 101S-T82 transformer rated 345kV/230kV/26.4kV, GrdWye/GrdWye/Delta, 340/453.3/566.7 MVA. The existing 101S-T81 transformer will remain in place.

- Two new 345 kV nodes for terminations of the two HVdc poles.

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- Four new 230 kV nodes for terminations of L-7011 and L-7012. L-7011 and L-7012 are presently connected between 88S-Lingan and 3C-Port Hastings. The lines will be renumbered such that the two lines between 101S-Woodbine and 3C-Port Hastings will retain the line number L-7011 and L-7012, but the two lines between 101S-Woodbine and 88S-Lingan will have the new designation as L-7021 and L-7022.

- One new 345 kV node and one new 230 kV node for the new 101S-T82 transformer.

- The two new reactors, each rated 26.4 kV and 50 MVAR 3 phase, associated with the new 101S-T82 transformer are not included in this preliminary spec. Depending upon the final selection of the HVdc converters, these two new reactors may not be needed. The existing two reactors on 101S-T81 transformer will remain in service.

- New 345 kV and 230 kV bus and line disconnects as required.

- New surge arresters as required.

- New revenue metering as required.

- Re-arrangement of the existing station layout and expansion of the substation to a breaker and a half bus configuration to accommodate the above expansion.

(b) The NS Power Network Upgrades presented in Figure 8-1 are in addition to the Woodbine Upgrades. Pending further detailed study the extent of the upgrades in Figure 8-1 may vary but it is not anticipated that any changes will be significant.