Atlantic Energy Gateway (AEG) Balancing Study Report

A Study of Potential Savings in the Case of a Common Unit Commitment and Dispatch Function for Atlantic Canada

FINAL REPORT
June 15, 2012

Table of Contents

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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.

The New Brunswick System Operator (NBSO) has studied the potential savings of a common unit commitment and dispatch function for balancing electricity supply and demand in Atlantic Canada. This work was undertaken at the request of the AEG Steering Committee and performed with direction from the AEG System Operations Technical Committee and an AEG Balancing Study subgroup. Funding for third-party expenses was provided by the government of Canada in accordance with a contribution agreement.

The fundamental hypothesis behind the study is that savings can be achieved by balancing electric power system resource demand and supply in Atlantic Canada on a common basis rather than separately as is done today. Currently New Brunswick, Northern Maine and Prince Edward Island are balanced as one balancing area. Nova Scotia and Newfoundland are each balanced on their own as indicated in Figure 1.

Fig. 1 Separate Balancing

NBSO has no knowledge of a contemporary study of this nature having been undertaken by others. It is, however, a commonly accepted belief that balancing supply and demand would be less expensive under a regional dispatch. Diversity of both supply and demand is one driver of savings. The ability to select supply from a broader portfolio of resources is another driver.

The introduction of intermittent renewable supplies (e.g. wind power, in-stream tidal, and solar) to the power system accentuates the benefits of a common regional dispatch because of the corresponding increase in the need for balancing. A common regional dispatch can also ease the integration of more conventional but inflexible generation such as nuclear and some co-generation.

Figure 2 explains the sources of expected savings from using a single unit commitment and dispatch function to balance the regional power system in Atlantic Canada.

Fig. 2: Nature of Expected Cost Savings with Regional Balancing

Cost =	**Quantity x Price**
Quantity	Lower balancing needs due to: - diverse consumption (lifestyle, time, season, weather, etc.) - diverse inflexible generation (nuclear, wind, tidal, cogeneration, etc.) - diverse timing of loss of supply
Price	Less expensive to perform balancing due to: - size selection (start a small generator rather than a large generator) - flexibility (fast hydro vs. slow thermal units) - timing of generation outages and derates - timing of hydro conditions (run-off, dry spell, etc.) - removal of transmission tariff charges within region

This project created a model, database, and skill-set that could be used for future study work including:
- an update of this balancing study with forecast errors included;
- analyzing the impact of various quantities and types of renewable generation;
- assessing the value of various dispatchable generation, load control, and storage options;
- identifying the savings of other collaborative balancing options; and
- quantifying the impact of various provincial and regional emissions policy options.

The opportunity to use this model and database for future regional studies is dependent on utility agreement to allow the confidential portions to persist and be used appropriately.

It is important to note that the results are specific to the timeframes indicated. Additionally, the results are a function of the assumptions that were made regarding consumption characteristics, supply availability, and the characteristics of the supply. The study was performed for two test years. The 2010/11 test year was studied in order to validate the simulation model using actual historical data, and to quantify the potential savings of a common Maritime Provinces dispatch for the current power system. The 2020 year was studied in order to quantify the potential savings of a common Atlantic Canada dispatch for a single year in which the system would include the Muskrat Falls hydro generation development and interprovincial transmission projects. The supply resources for that test year would also include generation builds and retirements identified in the AEG Resource Development Technical Committee's least cost combined integrated resource planning scenario.

The key results of the balancing study are summarized in Table 1. The table shows savings in two timeframes. The savings in the 2010/11 year estimate what could have been achieved had the balancing for the Maritime Provinces and northern Maine been performed collaboratively rather than having each of the New Brunswick/PEI/northern Maine system and the Nova Scotia system balanced on its own. The simulation of the 2020 year estimates the savings of balancing the Atlantic Provinces and Northern Maine as one area rather than as three, given the anticipated expansion of the region's intermittent renewable energy resources by 2020. Further details and explanations of the cases are contained within this report. All dollar figures in this report are in 2015 Canadian dollars unless otherwise indicated and were converted from then-current dollars based on 2% annual inflation.

Unit Commitment and Dispatch Savings

The study indicates a one-year savings in unit commitment and dispatch costs from combining balancing areas of approximately $25.1 million in the 2010/11 test year. For the 2020 test year the savings indicated by the study are $7.9 million.

Ancillary Services Capacity Savings

Regulation and Load Following are services that are ancillary to electric demand and energy commodities and are used to perform the balancing function. Regulation service involves adjusting the output of generators within seconds to match short term fluctuations in generation requirements. Load Following service involves adjusting the output of generators over minutes up to an hour to match increasing or decreasing generator requirements.

Given the reduced requirements for capacity for regulation and load following the savings in the incremental capacity cost associated with these services (based on an assumed cost of $10/MW-h for Regulation, $8/MW-h for Load Following, and $7/MWh for 10-minute spinning reserve) is $0.4 million in 2010/11 and $0.7 million in 2020.

Table 1 Results Summary ($m in 2015 dollars)

	2010/11			2020		
	2010/11 Three Areas	**2010/11 Two Areas**	**Impact of Sharing (i.e. Savings)**	**2020 Three Areas**	**2020 One Area**	**Impact of Sharing (i.e. Savings)**
Transmission	Current	Current	_	Upgraded	Upgraded	_
Supply mix	Current	Current	_	Combined Plan	Combined Plan	_
Generation costs	$840.8	$815.7	$25.1	$706.9	$644.8	$62.1
Cost of imports	_	_	_	$6.3	$5.2	$1.1
Revenue from exports	_	_	_	$196.8	$141.5	$55.3
Ancillary services costs	$1.7	$1.3	$0.4	$2.4	$1.7	$0.7
Total	$842.5	$817	$25.5	$518.8	$510.2	$8.6

Due to changes in the inputs, such as fuel costs, that occur over time, it is not valid to simply extrapolate these results out to multiple years. However, these results do provide an indication of the order of magnitude of the potential savings.

The model that has been built and validated can be used to study additional system configurations and time periods. That work would require the assembly of the appropriate additional data, and permission from utilities to re-use the confidential data that was used in this study. This study has also set a precedent for regional collaboration that could be extended beyond study work to greater collaboration in actual system operations.

This balancing study addresses some of the limitations of the study work that was performed in the AEG resource development study with respect to variability of energy needs, generator characteristics, and ancillary services. Like all production cost studies, this balancing study complements, but is not a replacement for more technical reliability studies.

The production cost savings assessed in this study are not entirely incremental to those in the resource development study. They are another view of the same type of costs, but with a more accurate reflection of how the power system operates. The tradeoff for the operational accuracy is that it was only feasible to study relatively short periods of time (one year in each case) within the scope of the project. Building and using a model to simulate multiple years of operation would take longer and be more costly. This balancing study does isolate the reduction in production costs achievable by operating with combined balancing areas rather than separate ones given the assumed transmission and generation plan. To follow that transmission and generation plan without implementing regional dispatch would mean that the region would forego these potential savings.

The purpose of this study is to provide indicative quantification of the potential savings. The results are intended to inform policy makers and help them evaluate the appropriateness of pursuing a common system balancing function. These estimates of savings do not take into account the costs of implementing the common dispatch or the administrative savings of performing this activity on a regional basis. Furthermore, this study does not consider the potential costs or economies of scale associated with performing other system operations functions on a regional basis. The impact of performing any system operator function, such as balancing, on a regional basis must account for impacts on various stakeholders including the allocation of the savings.

The savings identified in this report should be considered in conjunction with other AEG work product including those related to how a common regional dispatch might be achieved. That being said, it is important to note that there are various models that have been suggested as a means to implement a common regional dispatch. These include a regional system operator, contracting of services to one system operator, coordination agreements between utilities, and a regional system administrator.

The initial objectives of this study have largely been achieved. A model has been built that addresses some of the limitations of other production cost models in how the power system is balanced operationally. The potential savings of a common unit commitment and dispatch function for balancing electricity supply and demand in Atlantic Canada for the years 2010 and 2020 have been estimated as planned. A robust and detailed set of wind power and consumption data has been created. A set of simulated forecasts for both of these data sets has also been created. The region has increased its knowledge and skill set with respect to modelling the regional power system.

The study results and the non-confidential data are available for other analysis and study work related to regional system operations. While the original objective of being able to sustain the model and portions of the associated database has not been achieved, future study work in the region can benefit from the non-confidential data, knowledge, and skill set produced by this exercise.

Background

A resource development optimization study was undertaken as one of the key components of the AEG project. During the course of defining that study, that project's workgroup expressed concern that the exercise would not accurately represent 5-minute variability of consumption and wind power production, generator characteristics, and operating reserve requirements.

Subsequently, the AEG System Operations Technical Committee asked NBSO for a study to be scoped out for an update to the NBSO's 2007 Maritimes Area Wind Integration Study based on its work on that study and the NBSO's procurement of more advanced modeling capability. A scoping document for a "balancing study" was submitted to that committee on May 5, 2011 for consideration and comments. The scoping document and the need for such a study were discussed by that committee during a conference call on May 16, 2011. The comments were generally favourable. That earlier scoping document suggested an analysis of a variety of scenarios including one considering the sensitivity of greater development of wind power and one for load control. The tentative schedule called for the work to be completed by March 1, 2012.

On May 24 & 25 the AEG Steering Committee also discussed the need for a study of this nature. It was noted that the AEG work was to be completed by the end of 2011, but that there was an interest in having a study of that nature performed. NBSO suggested a reduced scope that would focus on the benefits of collaboration including with respect to balancing and operating reserves. The AEG Steering Committee then asked NBSO to submit a proposal by June 9, 2011 to undertake a balancing study of a reduced scope that would be completed by the end of 2011. Accordingly, NBSO proposed a balancing study for consideration by the AEG Steering Committee. That proposal was reviewed and accepted by the AEG Steering Committee at a meeting on June 9, 2011.

The key deliverable is an estimate of unit commitment and dispatch savings arising from regional collaboration in balancing and operating reserves. The primary goal of the study is to provide analysis with respect to system balancing and operating reserves in Atlantic Canada in support of the overall AEG objective of supporting renewables development through regional cooperation.

The 2007 Maritimes Wind Integration Study confirmed that commercial scale integration of wind power would increase the cost of system balancing including load following. The diversity benefits of pooling the loads and wind generation of the Maritime Provinces were examined based on simulated wind power production. The 2007 study was based on integrating up to 1000 MW of wind power into the Maritime Provinces. Since then the amount of wind power being considered for installation has increased to in excess of 2000 MW. At this level the incremental requirements for balancing including load following are still expected to be material compared to the quantities needed to manage variations in load.

In the Maritimes Wind Integration Study various suggestions were made as to how the Maritime Provinces could adapt to the introduction of wind power as indicated in the following extraction from that report.

> *The project work has identified a number of areas in which the cost of integration might be reduced. The following are suggested to somewhat mitigate these issues:*
>
> - *improved production forecasting methods to be developed by both the market participants for wind facilities, and system operators,*
> - *development within each balancing area to be spread around geographically so as to take advantage of the diverse wind speeds,*
>
> *In addition there are a number of things that should be explored to try and ease the accommodation of the variability and uncertainty such as the following:*
>
> *(1) Pursue less onerous deadlines for schedule changes by Market Participants with ISO-New England,*

(2) NBSO pursue use of 15 minute schedules with ISO-New England and Quebec,
(3) Explore the possibility of dynamic scheduling with ISO-New England and Quebec,
(4) Demand response capability be developed including bid-based demand response,
(5) Market rules and connection agreements must provide the right for production from generation facilities, including wind, to be curtailed as necessary to maintain system reliability,
(6) Market participants in the NB/PEI/NMe Balancing Area selling or buying output from wind facilities should structure contracts so that they can balance schedules hourly (or perhaps even every 15 minutes in the case of transactions with other Areas) to accommodate fluctuations in forecasted production,
(7) A regional joint RFP for capacity based ancillary services be implemented to encourage use of more resources for the provision of these services,
(8) Nova Scotia and the NB/PEI/NMe Balancing Area could form a Maritimes Balancing Area so as to take greater advantage of diversity of wind speeds, system peaks, and generation capabilities (one approach that should be considered is to implement a joint dispatch of regulation and load following as a precursor to forming some form of regional market).
(9) Policies should accommodate storage facilities (pumped hydro, compressed air, etc.).

One of the benefits of a regional approach to balancing is that it would take advantage of the significant diversity that exists across the region in wind regimes. The 2007 study examined a hypothetical 1000 MW of wind power in the Maritimes Provinces. The standard deviation (a measure of variability) for hourly swings in wind power dropped from 69.6 MW (i.e. 38.5 + 31.1) under the current arrangement of two balancing areas to 51.5 MW for a single Maritime Provinces balancing area.

Wind and Load Variability
(Data from Table 4 of 2007 Maritimes Wind Integration Study)

	One Balancing Area			Separate Balancing Areas					
	Maritimes (1000 MW of Wind)			NB/PEI/NME (600 MW Wind)			NS (400 MW Wind)		
Standard Deviation (MW)	Load	Wind	Net	Load	Wind	Net	Load	Wind	Net
	127	51.5	137	83.7	38.5	92.2	60.1	31.1	67.8

There is now more historical wind power production data available and more sophisticated means to simulate future production - thereby providing an opportunity to update the analysis of 2007. Rather than examining the standard deviation of wind power the balancing study analyses the impact of combining balancing areas on the overall load following requirements. The AEG project has, however, created data sets of wind power production that could be used to examine standard deviation for swings in wind power production in various resolutions as fine as 5 minutes.

In addition to the specific studies requested, the AEG Steering Committee also wanted a regional model that could be used for future studies. The project was therefore proposed and started on the understanding that the inputs could be agreed upon by the project's participants, would not be confidential, and would produce a regional model for future use.

During the course of the project some of the utilities requested that the study use confidential data for some of the utility-specific inputs. Therefore additional lead time was required to establish non-disclosure agreements. In addition, the setting up and refining of the model required more time than what was originally expected. The additional time that was required is somewhat attributable to the complexities of the system that was modelled. Furthermore, the use of confidential data means that at the end of the project the confidential data is to be removed from the model. Therefore the enduring regional model will be incomplete and would need to be repopulated for any future regional study work.

Study Approach

The study examines the unit commitment and system dispatch costs for two scenarios. The first scenario assumes that the obligations for intra-hour balancing and operating reserves rest with the respective Balancing Area and that there are three Balancing Areas (Nova Scotia, Newfoundland, and the current New Brunswick Balancing Area which is comprised of New Brunswick, Prince Edward Island, and Northern Maine). The second scenario assumes that there is a single Balancing Area in Atlantic Canada and Northern Maine with a common obligation for intra-hour balancing and operating reserves.

Due to the data preparation and computer processing time that would be required, the scenarios were modelled for individual test years, not a multi-year period. Also, the results are dependent upon a number of input assumptions. For example, emission constraints were modelled to reflect various requirements, but those requirements may very well change over time. Therefore the results are indicative of the potential unit commitment and dispatch savings in a given year. These numbers cannot be considered as typical or representing an average for an extended number of years.

The removal of incremental transmission charges in the study for flows between provinces contributes to the efficiency of the single balancing area. The following table indicates other sources of potential savings of a single balancing area, whether or not those savings are realized today, and whether or not they were modelled in the balancing study.

Source of Benefits	**Done Today?**	**In AEG Study?**
Efficient day-ahead unit commitment	Very Limited	Yes
Efficient procurement of ancillary services	Limited	Yes
Efficient intra-day unit commitment (e.g. use of combustion turbines)	Limited	Yes
Efficient intra-hour dispatch of energy	No	Yes
“Pooling” of load following requirements	No	Yes
“Pooling” of regulation requirements	No	Yes
“Pooling” of forecast error	No	Future Study

Difficulties were encountered with the Hour-Ahead simulations at 5-minute resolution which were intended to more closely simulate actual system dispatch that occurs within the day. The lengthy solution times, large data set, and significant number of modelling options proved challenging. As a consequence, reasonable results for the Hour-Ahead simulations were not produced in time for inclusion in this report.

Scenarios to be Studied Under AEG

The following scenarios were studied to provide information that policy-makers can use when considering policy options related to regional collaboration in operations including in support of renewables integration.

2010/11 Base Case
The purpose of this case is to assess the validity of the model by comparing it against the actual unit commitment and dispatch that occurred in 2010/11.

The characteristics of this case include:

- Existing generation including wind farms
- Current balancing areas (NS, NB/PEI/NME and NL)
- Actual load with actual or simulated 5-minute resolution
- No load control
- Daily hydro energy limits per facility
- Existing transmission and inter-area transfer capabilities
- Hourly zonal economic optimization of unit commitment and dispatch for each Balancing Area
- Balancing via Automatic Generation Control (AGC) intra-hour
- Hourly schedules on transfers between Balancing Areas
- Reserve sharing as per the existing arrangement between NB and NS
- Assume perfect wind power production forecasts for simplicity
- Assume perfect load forecasts for simplicity

2010/11 Two Balancing Areas
The purpose of this case is to assess the unit commitment and dispatch savings that could have resulted from operating the Maritimes as a single Balancing Area. Operating Atlantic Canada as a single Balancing Area in 2010/11 was not studied because without an electrical connection such as the Maritime Link, that scenario was not feasible.

The characteristics of this case include:

- Variation to 2010/11 Base Case
- Merging from 3 to 2 balancing areas (NS/NB/PEI/NME and NL)

2020 Base Case

The purpose of this case is to assess the operation of the system that is identified by the resource development analysis to be least cost. This case can then be used as the comparison for other cases that are purposefully selected to quantify the consequences (including the costs and benefits) of various policy decisions.

The characteristics of this case include:

- Expected generation including wind farms
- Size of uncommitted wind farms at 100 MW each, with location to be set by NBSO with assistance of local utility
- Current Balancing Areas (Nova Scotia, Newfoundland, and the current New Brunswick Balancing Area which is comprised of New Brunswick, Prince Edward Island, and Northern Maine)
- The obligations for intra-hour balancing and operating reserves rest with the respective Balancing Area and there are three Balancing Areas (but with Reserve sharing in the Maritimes as per the existing arrangement between NB and NS)
- Operating Reserves in accordance with NPCC Directory 5 (Dec 5, 2010)
- Hourly zonal economic optimization of unit commitment and dispatch for each Balancing Area
- Balancing via Automatic Generation Control (AGC) intra-hour
- Hourly schedules on transfers between Balancing Areas
- Simulated wind power production with 5-minute resolution
- Expected load with 5-minute resolution (addressing correlation between load and wind)
- Assume perfect wind power production forecasts for simplicity
- Assume perfect load forecasts for simplicity
- Daily hydro energy limits per facility
- No load control is assumed for simplicity
- Expected transmission (to be defined here but follow the lead of the Resource Development group) is the existing transmission plus the Maritime Link (500 MW from Newfoundland to Nova Scotia and 250 MW in the opposite direction), the upgraded connection between Prince Edward Island and New Brunswick (at 350 MW in both directions), and the upgraded connection between New Brunswick and Nova Scotia (at 800 MW in both directions).

2020 Single Balancing Area

The purpose of this case is to quantify the costs of operating the system that is identified by the resource development analysis to be least cost, but under the assumption that the regional system is operated as a single Balancing Area with a common centralized economic dispatch and operating reserve regime. These costs will then be compared against the costs of the 2020 Base Case which has three Balancing Areas each with its own economic dispatch and operating reserve regime.

The characteristics of this case include:

- Variation to 2020 Base Case
- Collapse into a single economic dispatch and a single balancing area for the Maritimes Area and Newfoundland and Labrador.
- Assume perfect wind power production forecasts for simplicity
- Assume perfect load forecasts for simplicity
- The obligations for intra-hour balancing and operating reserves rest with the single Balancing Area
- Operating Reserves in accordance with NPCC Directory 5

While likely of interest to the AEG, the examination of sensitivities of unit commitment and dispatch costs to other factors was not to be done within the scope of this study. Nonetheless, future study work may very well take place through other forums. The future work should consider variations on resource development, forecast errors, transmission expansion, emissions constraints, and hybrid operations models. The initial balancing study will also result in a model and a regional skill set that can be leveraged to undertake other needs in the future. Some of the data was provided by a utility subject to a non-disclosure agreement which is specific to this exercise. Therefore future studies would require additional permission for the use the confidential data, or the use of other data.

One sensitivity of particular interest for future study is the impact of assuming lower transfer capability for simultaneous flows from New Brunswick to Prince Edward Island and Nova Scotia in the 2010/11 cases than what was used in the initial analysis. Also, the inter-provincial flow values that are charted in this report can be used to determine the frequency with which the model made use of interprovincial connections in excess of a given MW threshold in each of the cases that were studied.

The analysis and information provided by the initial balancing study and the capability for future studies provide value to Canada, the utilities and provinces of Atlantic Canada, NBSO and other stakeholders. Most significantly the value arises from a quantification of possible savings of regional collaboration on intra-hour balancing and operating reserves.

The presentation of the output of the simulation must not compromise any non-disclosure agreement either through direct release of confidential information or through the release of information that can be reverse-engineered to obtain confidential information.

Simulation and Analysis Tools and Inputs

NBSO populated and ran an operational unit commitment and dispatch model in order to perform the analysis described herein on behalf of the AEG. The model accounts for intra-hour variations in balancing needs, regulation, load following and operating reserves much more realistically than can other production cost models that are used within the Atlantic Provinces.

The exercise benefitted greatly from the provision of expertise and data from the utilities. To the extent required, in lieu of utility and facility specific data, NBSO used a combination of publicly available information and engineering judgement to populate the model.

NBSO used Plexos software to perform the analysis. NBSO owns a user license for the software and owns and maintains the model and other modeling parameters. Some of the data provided by utilities is confidential, commercially sensitive, and subject to non-disclosure agreements. Plexos Solutions LLC. was contracted by NBSO to assist with setting up, populating, and using the model based on their skill set, knowledge of the software, and experience with similar exercises.

AWS Truepower was contracted by NBSO to simulate wind power production because of their past work on similar exercises in other areas and their experience in forecasting wind power production in the region. AWS produced the following datasets for use in the modeling of the 2020 year:

- Simulated wind power production at 5-minute resolution for existing and prospective sites throughout Atlantic Canada.
- Synthesized day ahead and hour ahead wind power production forecasts
- Synthesized day ahead and hour ahead consumption forecasts for each of the four Atlantic Canadian provinces

The wind power production dataset was based on 2005 as an historical test year. In order to account for weather related effects, the shape of the simulated 2020 consumption used in the modeling was based on the load shape of that same test year. The utility of the synchronized datasets produced by AWS Truepower for analyzing consumption and wind power patterns is significant. Having a good understanding of trends and correlations in the actual and forecast values of both of these parameters can lead to better choices in how the power system is planned and operated.

Potential Future Studies

One of the secondary benefits of the proposed project is that the model can be used for additional analysis that would be beneficial to a variety of stakeholders (e.g. Canada, the Atlantic Provinces, utilities). That analysis could examine the impact on unit commitment and dispatch costs of various policies, operational practices, generation investments, and transmission system changes. The following have been identified for the purpose of illustrating scenarios that could be studied in the future after the completion of the AEG work.

- 2020 with separate balancing areas but 15-minute scheduling (versus 60-minute today)
- 2020 with load forecast error and wind power production forecast error
- 2020 with load control
- 2020 with storage
- 2020 with more wind power (and quantification of incremental integration costs)
- 2020 with in-stream tidal power
- 2020 with various transmission & generation options
- 2040 with power system predicted by AEG
- 2010 but with Lepreau in service and price based dispatch of Quebec and New England interfaces.
- 2020 with various environmental constraint scenarios
- Analysis of value of adding flexible generation (eg combined cycle gas turbine)
- Any of previous but with no confidential data

Use of the full AEG model for other purposes would require new or renewed non-disclosure agreements with New Brunswick, Nova Scotia and Newfoundland and Labrador utilities.

Like all production cost studies, this balancing study complements, but is not a replacement for more technical reliability studies. Those studies would examine issues such as local voltage and transmission constraints, security of fuel supply, contingency analysis, and dynamic system performance.

Simulation Results

The following table contains some of the more relevant outputs of the simulation cases. The "Impact of Sharing" column is the difference between the respective common dispatch cases ("Two Areas" in 2010/11 and "One Area" in 2020) and the respective "Base" case as a percentage of the respective "Base" case.

Table 2 Simulation Results

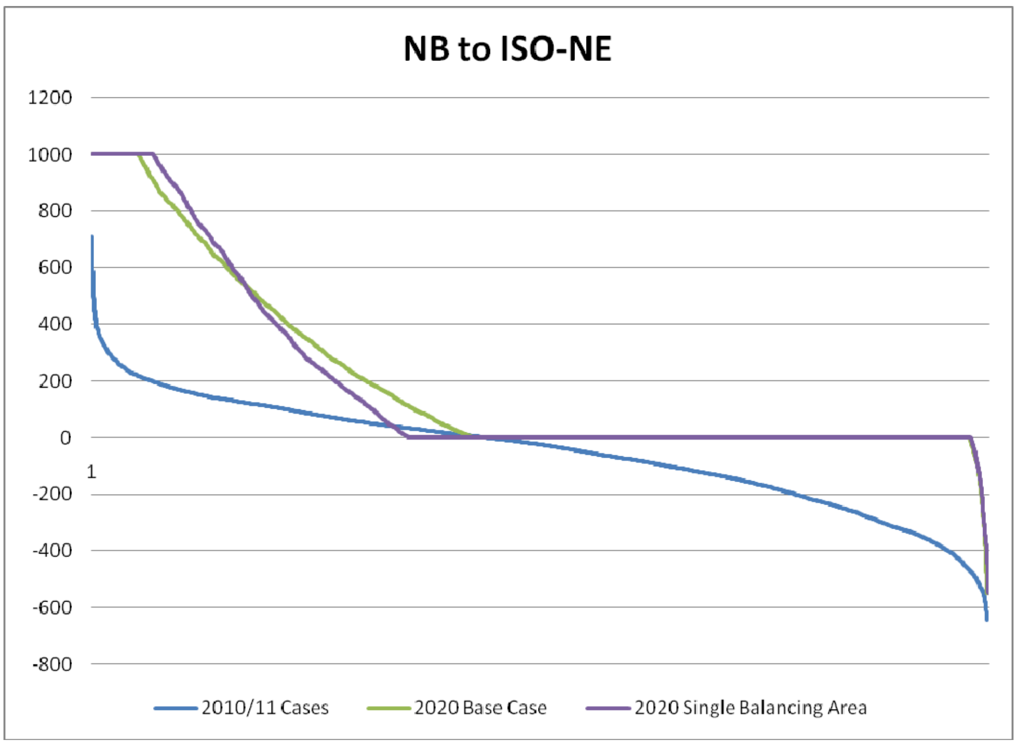
Measure	2010/11				2020			
	2010/11 Base (Three Areas)	2010/11 Two Areas	Impact of Sharing #	Impact of Sharing %	2020 Base (Three Areas)	2020 One Area	Impact of Sharing #	Impact of Sharing %
Costs $m	$840.8	$815.7	-$25.1	-3.0	$516.4	$508.5	-$7.9	-1.5
Start-up	$4.5	$3.8	$-0.7	-15.6	$1.8	$1.4	$-0.4	-22.2
Production	$836.3	$811.9	$-24.4	-2.9	$705.1	$643.4	$-61.7	-8.7
Imports	N/A	N/A	N/A	N/A	$6.3	$5.2	$-1.1	-17.4
Exports	N/A	N/A	N/A	N/A	$196.8	$141.5	$-55.3	-28.1
Start-ups #	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Nuclear	N/A	N/A	N/A	N/A	8	8	0	0
Coal	31	49	18	58	44	29	-15	-34.1
Oil	96	80	-16	-16.6	2	0	-2	-100
Natural gas	115	90	-25	-21.7	52	58	6	11.5
CT/Diesels	569	596	27	4.7	343	41	-302	-88
Production GWh	29,341	29,341	0	0	41,104	40,123	-980	-2.4
Nuclear	N/A	N/A	N/A	N/A	4,713	4,713	0	0
Coal	11,172	10,628	-544	-4.9	8,264	8,167	-97	-1.2
Oil	1,249	1,072	-177	-14.2	2	0	-2	-100
Natural gas	3,697	4,424	727	19.7	9,283	8,402	-881	-9.5
CT/Diesels	18	11	-7	-38.9	0.6	0.2	-0.4	-66.6
Hydro	9,261	9,262	1	0	13,449	13,449	0	0
Wind	2,048	2,048	0	0	3,484	3,484	0	0
Other	1,896	1,896	0	0	1,908	1,908	0	0
Net import GWh	4,332	4,332	0	0	-3,263	-2,283	980	N/A
Imports	4,891	4,891	0	0	88	81	-7	-8
Exports	559	559	0	0	3,351	2,364	-987	-29.5
Ancillaries Avg	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Regulation MW	48	34.3	-13.7	-28.6	58.2	35.7	-22.5	-38.7
Load Follow. MW	54.8	49.8	-5	-9.1	101	94.7	-6.3	-6.2

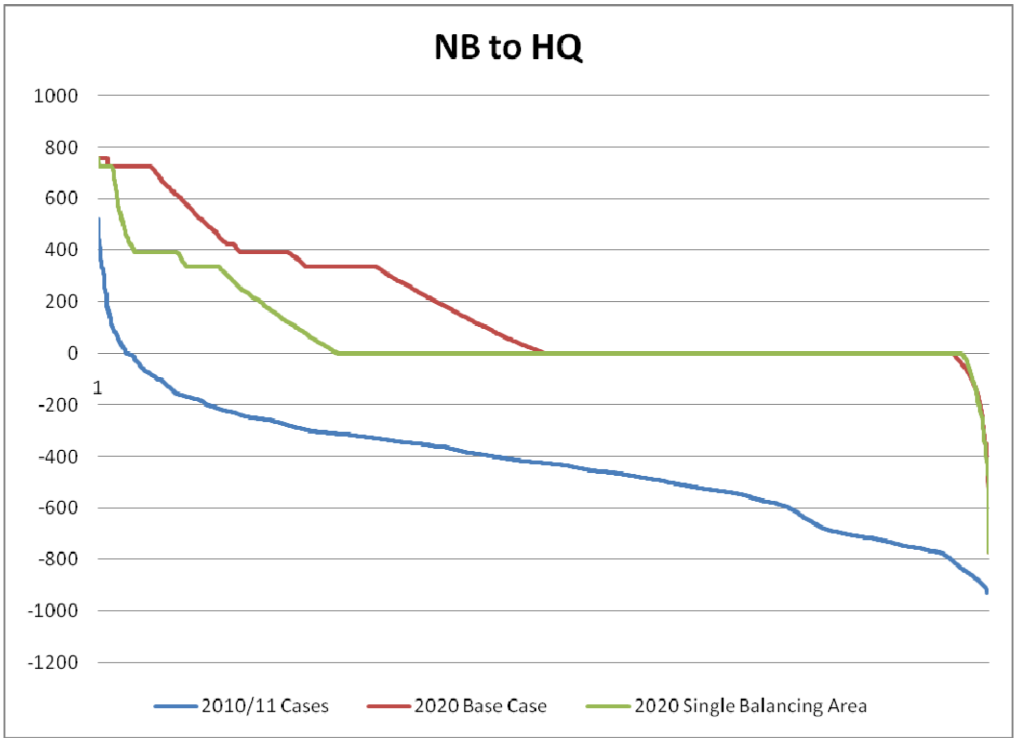
N/A = Not applicable

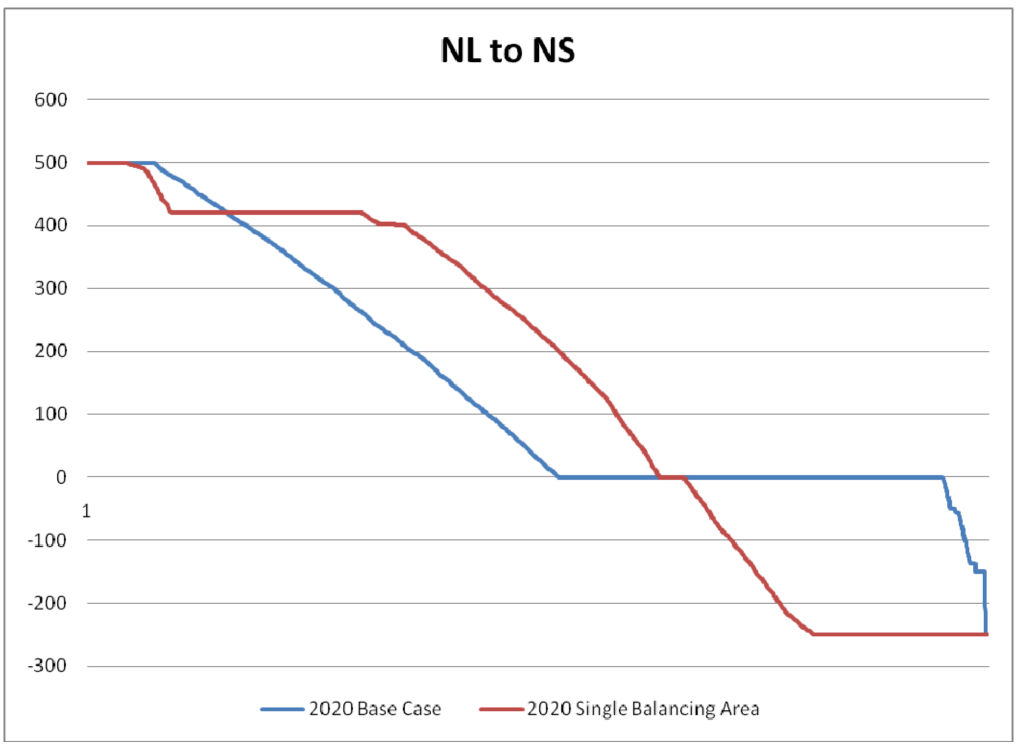
The following flow duration charts indicate the physical energy flows to and from external markets and between provinces in Atlantic Canada. The curves on each chart represent flows for the four cases studied as follows:

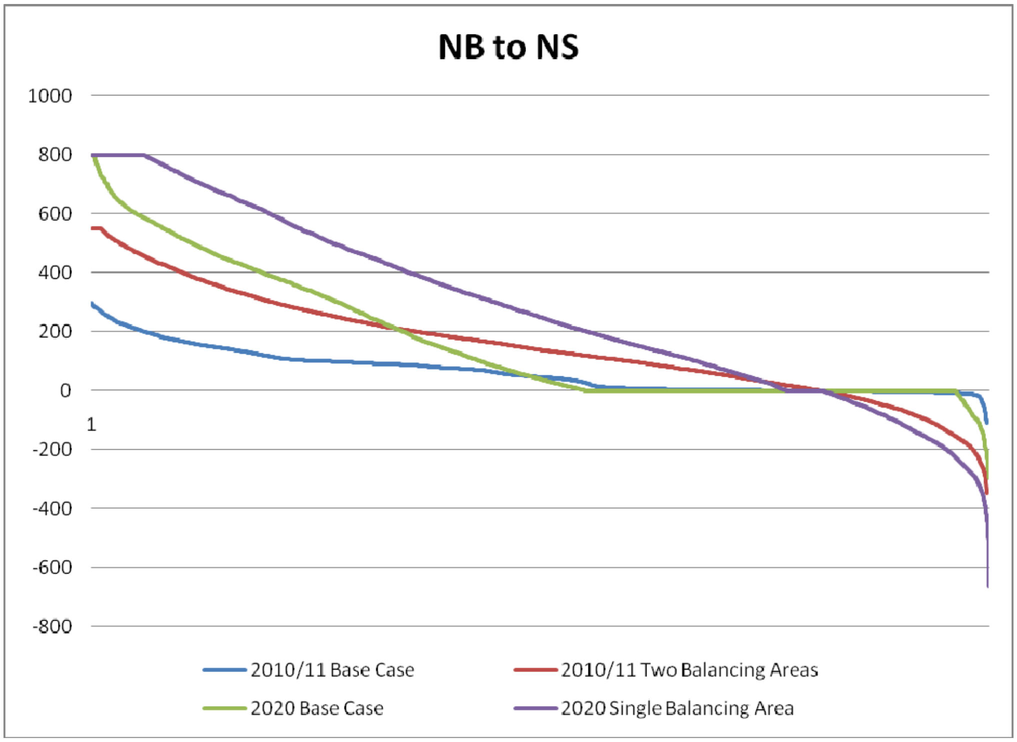
1. 2010/11 Base Case (separate dispatch and existing transmission)
2. 2010/11 Two Balancing Areas (common dispatch and existing transmission)
3. 2020 Base Case (separate dispatch and expanded transmission)
4. 2020 Single Balancing Area (common dispatch and expanded transmission)

The horizontal axis is “number of hours” with the total number of hours in a non leap year being 8760. The vertical axis is “MW of flow” in the direction implied by the title of the chart. Each point on the curve indicates the number of hours in the year in which flows exceed the indicated MW value. The area under the curve but above the horizontal axis is the total flow in the direction implied by the chart title. The area above the curve but below the horizontal axis is the total flow in the opposite direction.

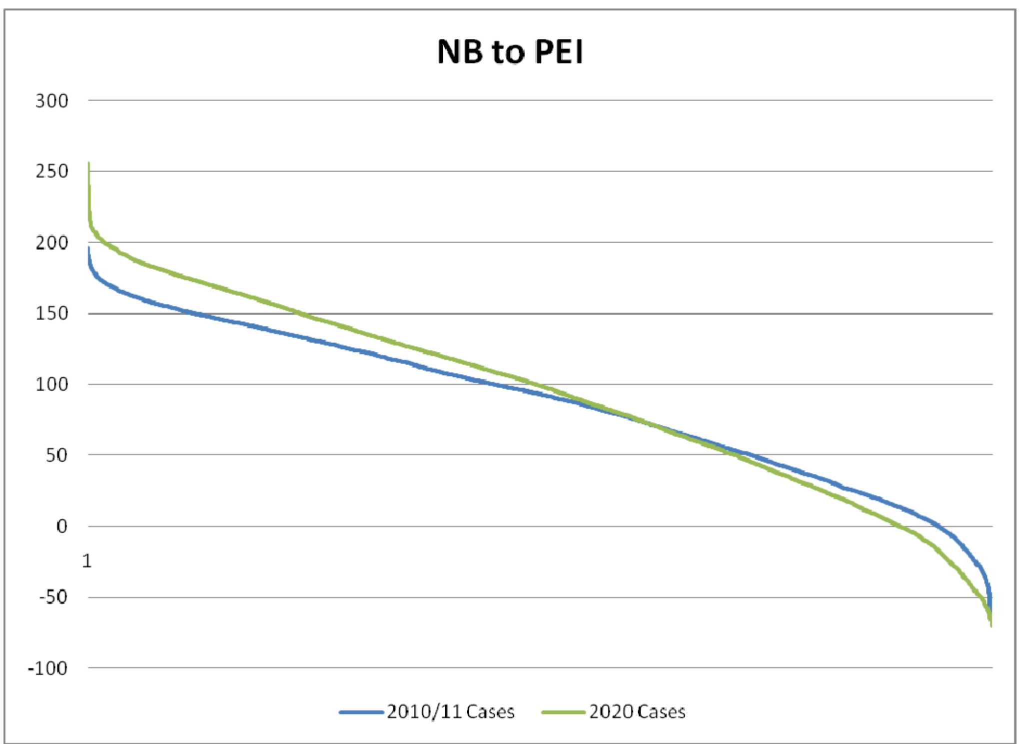



NB to HQ
1000
800
600
400
200
0
1
-200
-400
-600
-800
-1000
-1200
2010/11 Cases
2020 Base Case
2020 Single Balancing Area


NL to NS
600
500
400
300
200
100
0
1
-100
-200
-300
2020 Base Case
2020 Single Balancing Area



NB to NS
1000
800
600
400
200
0
1
-200
-400
-600
-800
2010/11 Base Case
2010/11 Two Balancing Areas
2020 Base Case
2020 Single Balancing Area



NB to PEI
300
250
200
150
100
50
0
1
-50
-100
2010/11 Cases
2020 Cases

Discussion of the Results

The simulation takes into account important factors such as significant transmission constraints, generation characteristics, and inter-area cost savings achieved through market-to-market transactions. The transmission constraints which were modelled are identified in Appendix 1. Generation characteristics are largely as provided by the respective utility and in many cases are confidential so are not included in this report. The impact of market-to-market transactions were taken into account so as to reduce the likelihood of overstating the potential savings of a common balancing function. The means by which this goal was achieved is described in Appendix 1 of this report.

Given the limited time available to complete the project and the additional complexities of doing so, uncertainties of generation contingencies, load forecast error, and wind power production forecast errors were not taken into account in the study. Such uncertainties increase the cost of unit commitment and dispatch because no unit commitment and dispatch algorithm can optimize to conditions that are not forecast. Nonetheless, the costs caused by these uncertainties would be less under a common balancing function due to diversity of the forecast errors and the availability of a broader portfolio with which to respond to contingencies and forecast error. Therefore, in this respect the actual savings in unit commitment and dispatch from a common balancing function would be even greater than shown in the results of this study.

It is also important to note that while this study looks at balancing supply and demand at a five-minute resolution, it does not consider reactive supply and voltage support, system stability, or contingency analysis. These would typically be considered in more detailed technical system impact and operational studies. Additionally, transmission losses and the optimization of losses and voltage levels are not taken into account in this study. A more comprehensive regional dispatch would take these factors into account and result in an additional source of savings. Savings arising from economies of scale are not part of this study either.

There are many additional factors that impact the level of the costs and therefore presumably also affect the savings of a common balancing function. Some significant factors are:

- Point Lepreau availability
- Hydro flows
- Wind power production
- Load characteristics (loss of load, changes in consumption patterns, etc.)
- Availability of additional balancing services (load control, more flexible imports, etc.)
- Flexibility of new generation
- Generation retirements

Due to the time and funding constraints, the sensitivities of the results to these and other factors were not studied. That being said, the model could be used to examine the impact of these factors in future study work.

As expected, the total cost of unit commitment and dispatch was less in the cases in which there was a common balancing function. The savings in the 2010/11 case was $25.1 million for the 12 month period. The savings in the 2020 case was $7.9 million. These represent savings of 3.0% and 1.5% respectively. As noted herein, these are merely order of magnitude values and are not necessarily representative for other years.

Similarly, the total requirement for regulation and load following was also less. Additional benefits of a common balancing function are expected to include less hydro and wind power being curtailed due to a short term energy surplus.

The reduced requirements for regulation and load following contribute to the reduction in the unit commitment and dispatch costs, but they also mean lower cost of having capacity that can provide these services. These capacity savings are estimated for each of 2010/11 and 2020 based nominally on the average of the unit costs that were used in deriving the New Brunswick, Prince Edward Island, and Nova Scotia tariff rates for these services.

Table 3 Regulation and Load Following

	2010/11	2020
Regulation		
Average Reduction in Requirements (MW)	13.7	22.5
Incremental Unit Cost ($/MW-h)	$3	$3
Total Savings ($million/year)	$0.36	$0.60
Load Following		
Average Reduction in Requirements (MW)	5	6.3
Incremental Unit Cost ($/MW-h)	$1	$1
Total Savings ($million/year)	$0.04	$0.06

The total savings of $25.5 million in the 2010/11 case and $8.6 million in the 2020 case are considered material given the total dollars involved and the margin of error in the inputs to the simulation and the nature of the simulation. This study analyzes savings, but it is also expected that higher levels of variable renewable resources (e.g. wind, solar, tidal) could be reliably integrated at less cost under a common dispatch model. Similarly, relatively inflexible cogeneration technologies (e.g. biomass or natural gas generation associated with industrial processes) could also be integrated at lower cost under regional balancing.

There are additional potential benefits of regional balancing that have not been quantified in this study. These include:

- Greater reliability due to diversity benefits and pooling of resources
- Fewer curtailments of zero cost zero emission energy (e.g. wind, hydro)
- Fewer interruptions of non-firm customers due to diversity benefits and pooling of resources
- Implementation savings arising from economies of scale

Appendix 1: Modeling Information and Data Assumptions

The following document captures some key assumptions used in the modeling, the modeling approach, and aspects of the data requirements.

Section 1:
Model Design Overview

The model is being built in Plexos modeling software. Any utility data provided in confidence is not to be used for other purposes or shared with other utilities without appropriate permissions. The model itself (excluding confidential data) will be the property of NBSO in accordance with the NBSO-NRCan Contribution Agreement. Any non-AEG use of the model must not be attributed to or otherwise associated with the AEG project.

The following design decisions have been assumed pending AEG review:

- Hourly unit commitment and dispatch to be done on a 5 minute resolution (for more details see Section 3)
- In the “Separate Balancing Area” cases there is a need to accurately represent market activities between the balancing areas
- Each province is represented as a *Region* (NB, NS, PEI, NL, QC, ME, NME, NE)
- Within each *Region* can be *Nodes* where:
  - *Nodes* are assumed to be a single bus where loads and generation are connected
  - *Nodes* are areas defined by transmission constraints
  - The following nodes are assumed:

Region	Node(s)
New Brunswick	New Brunswick
Nova Scotia	Nova Scotia
PEI	PEI
Newfoundland	Avalon Newfoundland West
Quebec	Hydro Quebec – Eel River (HQ-Eel River) Hydro Quebec – Madawaska (HQ-Madawaska)
Northern Maine	Northern Maine
New England	New England

- Northern Maine will be modelled on a simplified basis in 2010/11 and 2020 as:
  - Mars Hill wind farm (actual 2010/11, forecast 2020)
  - An aggregate load equal to exports (actual 2010/11, forecast 2020) from NB minus Mars Hill generation profile
  - An aggregate generator equal to imports (actual 2010/11, forecast 2020) to NB minus Mars Hill generation profile
- New England and Quebec will each be modelled on a simplified basis in 2010/11 as:
  - An aggregate load equal to exports from NB
  - An aggregate generator equal to imports to NB

- Interprovincial tie constraints are based on TTC since this is an energy dispatch analysis. These values were to be used unless the AEG determined more appropriate values. It was intended that the values used by the resource development group be adopted. Alternatively the study group could have established other values.
  - For the case of the NB to NS consideration was given to setting the value at the transfer capability that exists for x % of the hours, but this approach was not adopted.
  - The following constraints were assumed for 2010/11 (but are not applied in the cases in which actual flows are used):

Node From	Node To	Summer TTC	Winter TTC
New Brunswick	Northern Maine	No Constraint	No Constraint
Northern Maine	New Brunswick	No Constraint	No Constraint
New Brunswick	HQ – Eel River	335 MW	335 MW
HQ – Eel River	New Brunswick	350 MW	350 MW
New Brunswick	HQ – Madawaska	400 MW	435 MW
HQ – Madawaska	New Brunswick	391 MW	423 MW
New Brunswick	New England	1000 MW	1000 MW
New England	New Brunswick	550 MW	550 MW
New Brunswick	Onslow	550 MW	480 MW
Onslow	New Brunswick	350 MW	350 MW
New Brunswick	PEI	195 MW	200 MW
PEI	New Brunswick	200 MW	200 MW

- The following changes were assumed for 2020:

Node From	Node To	Summer TTC	Winter TTC
New Brunswick	Nova Scotia	800 MW	800 MW
Nova Scotia	New Brunswick	800 MW	800 MW
New Brunswick	PEI	350 MW	350 MW
PEI	New Brunswick	350 MW	350 MW
Newfoundland	Nova Scotia	500 MW	500 MW
Nova Scotia	Newfoundland	250 MW	250 MW

- Tie flows are to be treated:
  - As actual flows for 2010/11 case
  - As a combination of: predicted schedule, economic energy sales and tie drift (if practical in the modeling) for 2020 case
- Tie drift was to be modelled as a heavily constrained storage device
- New England and Quebec will each be modelled as a combination of a priced generator and a priced load (both hourly dispatchable) for the 2020 case
  - Pricing may contain “on peak” and “off peak” variations
  - A hurdle rate of $3/MWh is applied leaving Atlantic Canada and a hurdle rate of $16/MWh is applied entering Atlantic Canada in order to simulate the transactional costs (tariff, losses, administration, etc)
  - To be scheduled day ahead for 2010/11 and 2020 cases
- Nova Scotia and New Brunswick interface to be scheduled Day Ahead and allowed to float +/- 20MW for the Hour Ahead unit commitment
- Operating reserve capacity requirements on tie connections are respected
- AWS simulation of 2020 wind power production was conducted on a timely basis, so interim use of NBP and NSPI resource assumptions and scaling of historical production (on the assumption that the current wind regimes are relatively diverse and additional sites will not substantially increase diversity) was not required.
- The “2010/11” Study horizon is Aug, 1 2010 – July 31, 2011
- The “2020” Study horizon is Jan, 1 2020 – Dec 31, 2020

<u>Group Data Requirement:</u>

- Discussion was required to determine:
  - Hydro energy is represented as:
    - Daily limits for NB in 2010
    - Monthly limits for NL and NS in 2010
  - Monthly limits for NB, NL and NS in 2020

- o The 2020 load profile was based on an extrapolated 2005 load profile. The 2005 load was selected to correlate with the ASW wind profiles
- o Fuel Costs were provided by the individual utilities for 2010/11 and were provided by the resource development study for 2020.
- o Emission constraints (Provincial caps and limits for NB/NS/NL/PEI)
    - CO_2, NO_x, SO_x, mercury

Utility Specific Data Requirement:

- Generation in each *Region*
    - o Generator data as per a spreadsheet template.
    - o Connection *Node*
    - o Generation data for new facilities existing in 2020
    - o Generation retirements before 2020
- Load for each *Node* at 5 minute resolution (2010/11)
    - o If load for particular *Nodes* is unavailable, a percentage of total *Region* load
- Generation profile at 5 minute resolution (2010/11):
    - o Wind generators
    - o Self scheduled generation
- Hydro energy limits as identified in group discussion (2010/11)
- Generation outage and de-rate information for 2010/11
- Predicted forced outage rates and maintenance outages for 2020
- Tie capabilities between *Nodes* within *Region* as applicable(2010/11 & 2020)
- Flexibility of the DC ties
    - o Maritime Link
    - o Island Link
- Recommended location for future wind farms (2020)
    - o Quantity of wind to be determined by resource development group
- Grouping of generation
    - o Combining individual units to be dispatched as a single plant
- Ancillary service(s) requirements (see Section 2)
    - o Services required
    - o MW Quantity and/or formula used to define requirement
- Creation of a single ramp rate per facility in the case of facilities that have different ramp rates in different ranges in order to keep complexity of the optimization reasonable (avoiding impractically long solution times).
- Identification of “Non-firm” load quantities including specifics of ability to provide ancillary services. Note that the modeling tool has an “unserved load feature” that can be turned on or off. The initial assumption is that this feature is turned off.

If the above information was not provided/available assumptions were made based on generic data. Submission and use of confidential data is subject to appropriate NDAs and adequate time to complete the work within the AEG schedule.

Baselining of 2010/11 Against Actuals:
The following metrics will be used to assess how well the model simulates the actual dispatch that occurred in 2010/11.

- Number and timing of thermal generator start-ups
- Monthly fuel burn
- Annual unit capacity factor

Report Information:

- Explain assumptions for each case
- Caveats regarding limitations of assumptions, inputs and modelling approach

- Results to provide the following information:
  - Savings in unit hours of dispatch
  - Quantify number of starts and stops
  - Unit commitment and dispatch cost saving in orders of magnitude
  - Total regulation requirement
  - Total load following requirement
  - Capacity cost savings from reduced ancillary service provision (based on an assumed unit cost of the respective services)
- Results are to be reported for the region, as opposed to specific facilities, nodes or provinces
- Caveats regarding the “snap-shot” nature of the results and the hazards of extrapolation of the results
- Information on the use of the interfaces
  - Load duration curves for the interfaces between markets?
  - % of hours each interface is loaded beyond 95%
  - Average loading on each interface (defined for each direction)

Section 2: Capacity-Based Ancillary Service (CBAS) Requirements for AEG Balancing Study

CBAS Requirement Types:
1. AGC/Regulation
2. Load Following
3. Spinning Reserve
4. Supplemental Reserve
5. 30-min Reserve

The following table defines the CBAS regimes under each of the cases that are to be simulated.

	2010/11 Base (Three BAs)	**2010/11 Two BAs**	**2020 Base (Three BAs)**	**2020 One BA**
AGC (Regulation)	Each BA	Each BA	Each BA	The one BA
Load Following	Each BA	Each BA	Each BA	The one BA
10-Minute Spinning Reserve	Each BA but with reserve sharing between NS and NB/PEI/NMe BAs as described below.	Each BA	Each BA but with reserve sharing between NS and NB/PEI/NMe BAs as described below.	The one BA
10-Minute Supplemental Reserve	“	Each BA	“	The one BA
30 Minute Supplemental Reserve	“	Each BA	“	The one BA

1. AGC (Regulation) Requirement

AGC Requirement = Requirement for Loads + Incremental Requirement for Wind.

For the purpose of unit commitment and dispatch these two values are to be constants based on analysis of historical load and wind data and projections of future requirements. Each Balancing Area has its own requirement and must meet it from internal resources.

	2010/11 Base	**2010/11 Two BAs**	**2020 Base**	**2020 One BA**
NB/PEI/NMe	20.6 first 4 months, then 21.2	calculated	21.2	dna
NS	27	calculated	27	dna
NL	dna	dna	10	dna
NS/NB/PEI/NMe	dna	calculated	dna	dna
NL/ NS/NB/PEI/NMe	dna	dna	dna	calculated

The regulation requirements for combined BAs is to be equal to the square root of the sum of the individual BA requirements squared. This approach is based on the assumption that the regulation requirements are not correlated.

For example, the Regulation Requirement for NS/NB/PEI/NMe can be calculated as:

SQRT[(Regulation Requirement for NS)^^{2} + (Regulation Requirement for NB/PEI/NMe)^^{2}]

A generator's AGC (Regulation) capability is defined as its up or down 10-minute ramp capability constrained by its AGC range.

2. Load Following

LF Req. = Maximum of (5 Minute Load – Wind Power Production in Same Interval) - (Hourly Average Load - Hourly Average Wind Power Production) + Load Following Requirement for Schedule Changes on Regulated Interfaces

Each Balancing Area has its own requirement and must meet it from internal resources.

A generator's LF capability is defined as its ability to ramp up or down over 30 minutes.

The load following requirement for schedule changes was not modelled due to uncertainty of whether or not this component would be applied consistently in the region.

3. Spinning Reserve

General
Spinning Req. = MAX (0, ¼ * Largest Contingency – AGC Req – LF Req – Shared Spinning Reserve)

Largest Contingency = MAX (Largest Generator Contingency, Largest Intertie Contingency)

Largest Generator Contingency = MAX (The Largest Net MW Output of a Nuclear Generator or Thermal Generator Scheduled by MOD) and Dalhousie is treated as a single contingency, and 30 MW is added to Point Lepreau to account for no-load station service.

Shared Spinning Reserve = reduction to account for reserve sharing arrangement with at least one other BA.

4. 10-Minute Supplemental Reserve

Supplemental Req. (without exports) = MAX (0, 3/4 * Largest Contingency –AGC Req Not Used for Spin –LF Req Not Used for Spin – Shared 10 Minute Supplemental Reserve)

5. 30-Min Supplemental Reserve

30-min Supplemental Req = MAX (0, ½ * 2^{nd} Contingency – AGC Req Not Used for Spin or 10 Min Supplemental – LF Req Not Used for Spin or 10 Min Supplemental - Shared 30-min Reserve)

6. Reserve Sharing

In the base cases the following reserve sharing approach is to be assumed. This approach is a reasonable simplified version of the current arrangement.

<u>10-Minute Spinning</u>

- NS carries 25 MW.
- The NB/PEI/NMe Balancing Area meets its reserve requirements for 10-minute spinning reserve in accordance with the generic formula above (but counts the full amount of the NS 10-minute spinning reserve as Reserve Sharing).
- NL has no reserve sharing.

<u>10-Minute Supplemental</u>

- NS carries 100 MW.
- The NB/PEI/NMe Balancing Area meets its reserve requirements for 10-minute supplemental reserve in accordance with the generic formula above (but counts the full amount of the NS 10-minute supplemental reserve as Reserve Sharing).

<u>30-Minute Supplemental</u>

- NS carries 50 MW.
- The NB/PEI/NMe Balancing Area meets its reserve requirements for 30-minute supplemental reserve in accordance with the generic formula above (but counts the full amount of the NS 30-minute supplemental reserve as Reserve Sharing).

<u>Notes:</u>

- No modelling of recallable export sales as those were no longer permissible in New England as of Dec 2010. Also, sales of this type were minimal in the months prior to this given the Point Lepreau outage.
- No modelling of imports or exports of CBAS (or reserve sharing outside of the Maritimes) as these were not occurring in the 2010/11 year and will not necessarily be feasible in future years.
- It is assumed that no ancillary services are provided by load in New Brunswick, Northern Maine, or Prince Edward Island. Provision of ancillary services by load in Nova Scotia were modelled at NSPI's direction.

AEG Balancing Study Ancillary Service Assumptions for 2020 Cases

The following ancillary service regime is assumed for the 2020 case.

2020 Base

- Each Balancing Area carries enough of each ancillary service (regulation, load following, 10 minute spinning, 10 minute supplemental, and 30 minute supplemental) to meets its own needs.
- The reserve requirements are based on each Balancing Area's respective source contingencies in accordance with the current NPCC Directory 5.*
- Assume existing reserve sharing between NB and NS continues. The following approach was considered but rejected based on as assumption of continuity. No reserve sharing agreement is assumed as (i) there is no guarantee that one will exist in 2020, (ii) if a reserve sharing agreement did exist in 2020 any assumptions on specifics would be entirely speculative, and (iii) benefits arising from reserve sharing would be a consequence of regional collaboration and therefore are within the scope of what we want to capture in this study.

2020 One Area

- The one Atlantic Canada Balancing Area carries enough of each ancillary service (regulation, load following, 10 minute spinning, 10 minute supplemental, and 30 minute supplemental) to meets its needs.
- The reserve requirements are based on the Balancing Area's respective source contingencies in accordance with the current NPCC Directory 5.*
- Tie usage will be reported and assessed with respect to how often ancillary services are constrained zonally. Studies taking into account zonal requirements are to be noted for possible future study. This approach may exaggerate the savings.

** Directory 5 requires:*

- *Spinning reserve equal to 25% of the largest source contingency in Balancing Area*
- *10 Minute Supplemental Reserve equal to 75% of the largest source contingency in Balancing Area*
- *30 Minute Supplemental Reserve equal to 50% of the second largest source contingency in Balancing Area*
- *Reserve associated with transactions across HVDC are the responsibility of the sinking Balancing Area for the transaction.*

New HVDC Contingencies: The Maritime link's two poles are each single contingencies so use 50% of the respective energy flow to take into account the possibility of operating mono-pole following the loss of the other pole. The Island Link contingency size is to take into account the nominal rating is 450MW/pole or 900MW total. In the event of the loss of a pole the remaining pole is capable of delivering 200% of its rating for 10 Minutes (900MW). In addition that pole will be capable of delivering 150% of its capability continuously (675MW).

Section 3: Market Operations Assumptions to Be Used for the AEG Balancing Study Modeling

	2010/11 Base (Three Areas)		2010/11 Two Areas		2020 Base (Three Areas)		2020 One Area	
	Day-Ahead Commitment	**Hour-Ahead Commitment & Dispatch**	**Day-Ahead Commitment**	**Hour-Ahead Commitment & Dispatch**	**Day-Ahead Commitment**	**Hour-Ahead Commitment & Dispatch**	**Day-Ahead Commitment**	**Hour-Ahead Commitment & Dispatch**
Dispatch Horizon	Upcoming 24 hours	Upcoming 1 hour	Upcoming 24 hours	Upcoming 1 hours	Upcoming 24 hours	Upcoming 1 hours	Upcoming 24 hours	Upcoming 1 hours
Look Ahead Horizon	Subsequent 24 Hours	Subsequent 3 hours	Subsequent 24 Hours	Subsequent 3 hours	Subsequent 24 Hours	Subsequent 3 hours	Subsequent 24 Hours	Subsequent 3 hours
Resolution	Hourly	5-minute for hour 1 and hourly for hours 2-4	Hourly	5-minute for hour 1 and hourly for hours 2-4	Hourly	5-minute for hour 1 and hourly for hours 2-4	Hourly	5-minute for hour 1 and hourly for hours 2-4
Areas	1. NB/PEI/NME 2. NS 3. NL	1. NB/PEI/NME 2. NS 3. NL	1. NB/PEI/NME/NS 2. NL	1. NB/PEI/NME/NS 2. NL	1. NB/PEI/NME 2. NS 3. NL	1. NB/PEI/NME 2. NS 3. NL	NB/PEI/NME/NS/NL	NB/PEI/NME/NS/NL
NB/Quebec Interface	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.	Commit on economics subject to transmission constraint.*	Dispatch on economics subject to transmission constraint.*
NB/NE Interface	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.+	Commit on economics subject to transmission constraint.*+	Dispatch on economics subject to transmission constraint.*+
NB/NS Interface	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.+	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.
NL/NS Interface	Does not exist in this timeframe.	Does not exist in this timeframe.	Does not exist in this timeframe.	Does not exist in this timeframe.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.

Notes:

+ Allow deadband (of +/- 50 MW for NB/NE interface and +/- 20 MW for NB/NS interface) around the nominal hourly tie flow.

Modeling approach taken with the Plexos tools in order to simulate the assumptions noted above:

- Sequential solving of (i) Day-ahead commitment taking inter-market actuals into account as noted above, and (ii) Hour-ahead commitment and dispatch taking inter-market actuals into account as noted above.
- The Day Ahead commitment looks at the upcoming 24 hour calendar day at an hourly resolution, and with an additional 24 hours considered as a look-ahead (also at hourly resolution).
- The unit commitment for certain generation from the Day-Ahead will be locked in for the Hour-ahead commitments. That is, the output of the Day-head run will define which generators are committed. The Hour-ahead run will, in the case of generators that are set-up to inherit the Day-ahead commitment, get the commitment status from that Day-ahead output file.
- The Hour-ahead run optimizes the upcoming hour at a 5-minute resolution and also looks ahead another 3 hours with an hourly resolution. The purpose of the four hour view is to make a better decision on additional unit commitments and on dispatch given the existence of slow-moving generators. The next hour's run will then overwrite the values from hours 2, 3 and 4. The Hour ahead optimization will be done in two passes, with the first one establishing the nominal hourly flows when appropriate (in accordance with the table above).