Maritimes Area Wind Integration Study

August 2005

This study has been conducted by New Brunswick System Operator (NBSO) for the Atlantic Electricity Work Group (AEWG). Supporting data has been provided by Nova Scotia Power, New Brunswick Power, Prince Edward Island Energy Corporation and Vision Quest. The study has been jointly funded by Nova Scotia Power, New Brunswick Power, Maritime Electric Company and NBSO.

1.0 EXECUTIVE SUMMARY

The purpose of this study is to examine issues related to the integration of large amounts of wind-powered generation into the power systems of the Maritimes. These issues are not well known today, as the June 2005 total of all installed wind project capacity in the Maritimes is only 46 MW. The motivation for this study is that the provincial governments of the Maritimes intend to implement Renewable Portfolio Standards (RPS) requiring a certain percentage of the electricity sold in a province to be produced from renewable resources. Due to the current economic advantage that wind energy has versus other renewable generation alternatives, it is likely that these new policies will cause significant increases to the installed wind project capacity of the Maritimes.

There are four main areas where wind-powered generation can impact power system planning, operations, and associated costs. These are:

- Assigning a capacity value to wind projects that recognizes their contribution to system reliability,
- Managing hourly wind project output variation that increases the system load following requirement,
- Managing the minute-to-minute wind project output variation that increases the system regulating capacity requirement, and
- The need to accurately forecast wind project output on the day prior to operation so that unit commitment costs can be minimized

Due to data limitations, the latter two areas are not addressed in this report. Analysis of these issues in future studies may become possible as more data is gathered from new wind projects. The wind capacity integration issues that are analysed in this study in some detail are:

- Quantifying the reliability contribution (i.e. effective capacity) that new wind projects can make to the Maritimes,
- The impact of new wind projects on the variability of the load served by conventional generation, and
- The risk of increased costs associated with increased load variability during the spring run-off because the hydroelectric generation cannot be flexibly dispatched to respond to either load changes or wind generation changes.

This study measures the reliability contribution of eight simulated wind projects to the Maritimes power system (New Brunswick, Nova Scotia, PEI, and Northern Maine) using a standard Loss of Load Expectation (LOLE) analysis performed with a Monte Carlo simulation technique. The wind projects are simulated with wind speed and temperature data recorded at different sites. The result of this reliability measurement is the determination of an effective capacity for this intermittent wind resource.

The average effective capacity of simulated wind projects in the NB Area power system (NB, PEI, and Northern Maine) were calculated for different scenarios. The average effective capacities were:

- 66% - 2004 Maritimes with intra-area transfer limits

- 73% - 2004 Maritimes without intra-area transfer limits
- 60% - 2004 NB Area only
- 49% - 2003 Maritimes with intra-area transfer limits

It was seen in the study that the effective capacity results could vary year-to-year, and that the winter capacity factor was a good approximation of the effective capacity. Until additional years can be analysed, it is a recommendation of this study that wind projects connected to the NB Area power system be credited by capability period with a capacity equal to their expected capacity factor for that capability period.

The average effective capacity of simulated wind projects on the Nova Scotia power system was calculated for different scenarios. The average effective capacities were:

- 1% - 2004 Maritimes with intra-area transfer limits
- 62% - 2004 Maritimes without intra-area transfer limits
- 50% - 2004 Nova Scotia only

Similar to the NB Area, it is a recommendation of this study that wind projects connected to the Nova Scotia power system be credited with a capacity equal to their capacity factor by capability period.

The load variability of the NB Area, Nova Scotia Area, and Maritimes Area power systems was quantified by taking the standard deviation of the hourly load swing. The impact of wind generation on the load variability was calculated by subtracting simulated wind generation from the actual loads, and then recalculating the standard deviation of the hourly load swing of the remaining load. Using regulatory evidence filed by NB Power in 2002 regarding the cost of providing load following, it is estimated that a 1 MW increase in the standard deviation of the hourly load swing for the Maritime region results in an annual cost increase of $67,870.

The following table provides a summary of the load variability analysis.

Region	2004 Average System Load	2004 Load Swing Std. dev.	400 MW Wind Single Site Variability Increase		400 MW Wind Dispersed Sites Variability Increase		400 MW – NS, 600 MW – NB Composite Wind Impact	
	(MW)	(MW)	(MW)	$Millions	(MW)	$Millions	(MW)	$Millions
NS	1418	59	18.3	1.24	7.7	0.52	7.7	0.52
NB Area	2015	82	14.7	1.00	3.7	0.25	8.1	0.55
Maritimes	3433	123	10.2	0.69	1.8	0.12	10.3	0.70

The load variability analysis showed that the impact of wind generation on load variability is significantly reduced if the wind capacity is geographically dispersed amongst several sites as opposed to being all located at a single location. Thus, to integrate significant wind project capacity in the Maritimes, it is a recommendation of this study that the developed capacity be split up amongst several sites, and that these sites have a good geographic separation in order to minimize costs associated with increased load variability.

Another result of the load variability analysis was that the impact of wind generation on load variability is significantly reduced if load variability is managed on a Maritime basis versus a sub-area basis. This is demonstrated in the previous table where the additional load variability produced by 1000 MW of wind (600 MW NB Area, 400 MW Nova Scotia) is only 8.4%, or 10.3 MW more to the standard deviation of the hourly load swing at an estimated annual cost of $0.70 million. This compares to a 15.8 MW increase if the additional load variability is managed separately by the individual sub-areas at an estimated annual cost of $1.07 million. Note that these costs could be greater if the NS cost of load following is higher than the NBSO cost.

In the Nova Scotia and NB Area regions, the cost of load variability is distributed amongst the load in that region. Therefore, any load variability cost increase due to wind generation falls to the local customers, even if they are not the ones purchasing the wind energy. This may be seen as unfair in cases where a new wind project exports its power to a neighbouring system while producing higher load variability costs to customers in the local region. Should such scenarios develop, it is recommended that the Maritime regions may have to look at charging wind projects for increasing the local load variability.

At this time, it is difficult to say how much wind capacity is too much. The Maritimes only has 46 MW of wind generation as of June 2005, and that is not enough to properly judge the impacts of installing levels of wind capacity that are higher by an order of magnitude. Flexible hydroelectric generation is an important factor in terms of managing the variability of wind generation. Compared to other areas in Canada, this study shows that the Maritimes has relatively less flexible hydroelectric generation than any other area except Alberta. This may make it difficult to integrate as much wind capacity as some of those other areas, and policies such as the RPS for each Maritimes province may have to be more conservative because of this. It is a recommendation of this study that a conservative approach be taken with regard to the RPS design for the Maritimes to recognize that the Maritimes does not have the same quantity of flexible hydroelectric generation as do most other areas of Canada, with the exception of Alberta.

Spring run-off describes the April to May period where the snow melt and accompanying rainfall floods the rivers of the Maritimes and causes water to spill over at the hydroelectric stations. This study showed an example of how the 2004 spring run-off compromised the ability of the hydroelectric system to respond to load variability, and that the variability of the load served by thermal generation was increased by the simulated wind generation. It is recommendation of this study that the Maritimes take a gradual approach to integrating wind generation so that the costs associated with increased load variability during the spring run-off are better known. It is also a recommendation of this study that the Maritimes may be able to integrate more wind capacity if it finds opportunities to have the neighbouring power systems of Québec and New England assist with its load variability during the spring run-off.

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3.0 SYSTEM OVERVIEW

The objective of this study is to analyse the reliability issues regarding the integration of large amounts of wind generation capacity into the Maritimes Area. The Maritimes Area is consists of power systems in New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine. Within the Maritimes, Nova Scotia operates as a sub-area with a 350 MW transfer capacity limit to the New Brunswick. The NB Area (New Brunswick, PEI, and Northern Maine) operates as a single sub-area of the Maritimes with a 300 MW transfer limit to Nova Scotia.

Today, there is about 46 MW of wind generation in the Maritimes. Commercial wind projects have been developed in North Cape, PEI and Shelburne, Nova Scotia, plus there are a couple of individual test turbines. Monitoring of wind resources for the potential development of future wind projects has been conducted at several Maritimes Area sites. This study is based upon simulated wind project outputs from eight monitored wind resource sites in the Maritimes. Analysis in this study is mainly for 2004, with some supplemental analysis for 2003.

Wind energy simulations for 2004 were provided to the NBSO for three Maritime sites, and five additional wind energy sites were simulated by the NBSO using wind speed and temperature data recorded at 10-minute intervals. Wind data was converted to simulated wind power output levels using the power output characteristic curve for a Vestas V80 - 2.0 MW turbine at a 78-metre hub height. This particular output characteristic was chosen because it is typical of turbines being installed in current North American wind projects, and it was also chosen for its convenience, as this output characteristic can be found in the online database of NRCan's RETScreen® International wind energy project analysis software, available for free at NRCan's website.

The simulated wind projects for this study were for the following areas:

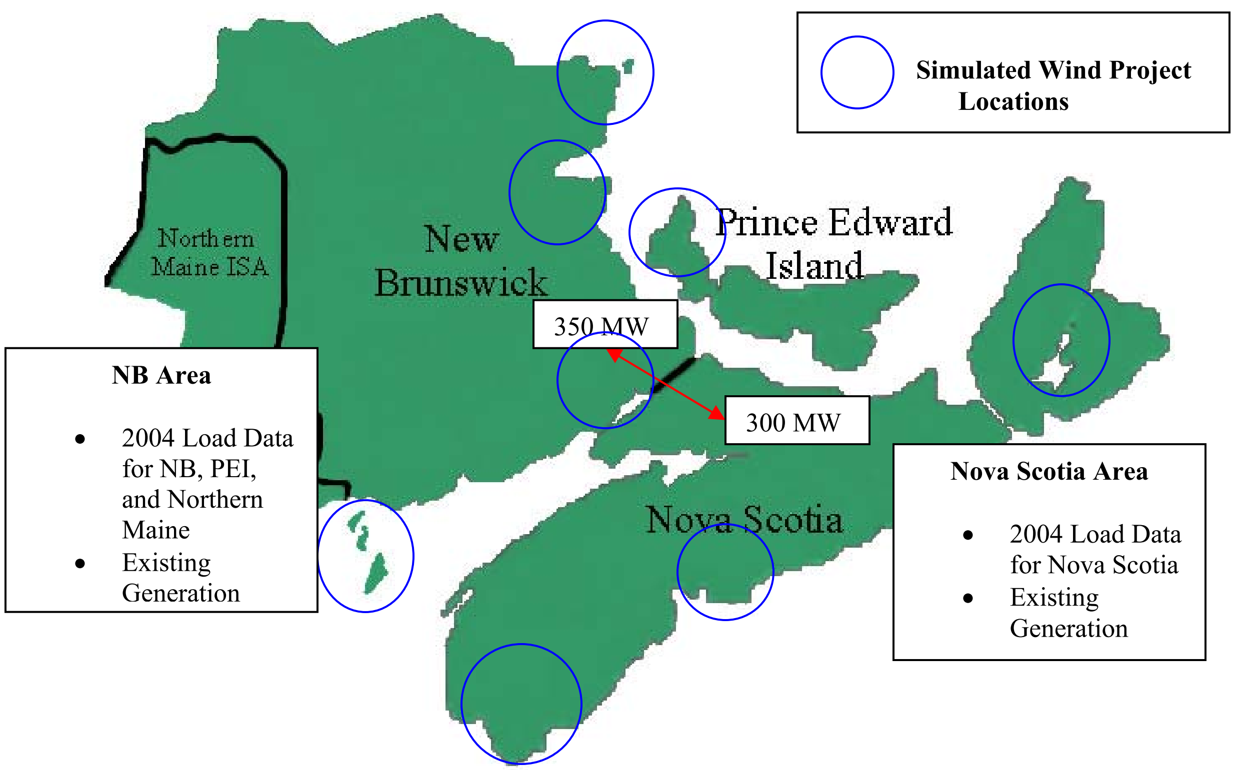
- North Cape / Tignish, PEI
- Cape Breton, NS
- Halifax / Dartmouth, NS
- Shelburne / Yarmouth, NS
- Dorchester / Tantramar, NB
- Miramichi, NB
- Grand Manan / Campabello, NB
- Lamèque / Miscou, NB

NBSO is cognizant that wind energy projections for individual sites have commercial value, and it was agreed to by the NBSO and all parties providing data for this study that wind energy calculations for individual sites would be kept confidential. As a result, no specific wind production performance of any one site is reported in this study. Where it was necessary in some areas of this study to report a result for a single site, the number reported is actually an average of the results at multiple sites.

No consideration of transmission limits other than those between New Brunswick and Nova Scotia is considered in any analysis. Also included are the actual hourly loads from 2004, plus the generation data utilized in the NPCC Maritimes Area Triennial Review of Resource Adequacy (December 2004). This review is available at https://www.npcc.org/publicFiles/documents/resourceAdequacyReviews/currentYear/Maritimes_Area_Triennial_Review_2004.pdf

A model of the system used for analysis is provided in Figure 1 below.

Figure 1
System Model



3.1 Limitations of this Wind Integration Study

This is the first wind integration study done by NBSO for the Maritimes Area and, because of its limited data, should be considered as preliminary.

There are four main areas where wind-powered generation can impact power system planning, operations, and associated costs. These are:

- Assigning a capacity value to wind projects that recognizes their contribution to system reliability,
- Managing hourly wind project output variation that increases the system load following requirement,
- Managing the minute-to-minute wind project output variation that increases the system regulating capacity requirement, and
- The need to accurately forecast wind project output on the day prior to operation so that unit commitment costs can be minimized

This study attempts to address only the first two areas. The impacts on regulation and unit commitment should be considered in future studies.

The regulation impact can be addressed with proper time synchronized data that should become more readily available as actual turbines are installed or greater effort is placed on data collection.

The unit commitment problem requires performing a day-ahead hourly load forecast and scheduling adequate conventional generation resources to meet that forecast. It is part of the normal practice for any power system. If the installed wind generation capacity in the Maritimes becomes significant, it will be necessary for the Maritime power systems to have day-ahead hourly wind energy forecasts incorporated into their scheduling. Failure to do so will likely cause an inefficient scheduling of resources, and may result in extra costs to ratepayers or degradation to system reliability. Neither is acceptable.

At this time, an analysis of the impact of day-ahead hourly wind energy forecasts on the costs associated with the scheduling of convention generation is unable to be performed by the NBSO. In order to perform such a study, the NBSO would need to acquire the following:

- A history of day-ahead hourly wind energy forecasts for the simulated wind projects used in this study,
- Software to perform a day-ahead security constrained unit commitment and energy dispatch for each sub-area of the Maritimes, and
- Conventional generation dispatch data for each sub-area of the Maritimes.

4.0 EFFECTIVE CAPACITY OF WIND GENERATION

4.1 Description

Electric utilities must own or contract for sufficient generation capacity in order to provide a reliable supply of electricity to their customers. Sufficient generation capacity ensures that adequate resources can be committed and scheduled for each hour, and that the electrical supply can always maintain a balance with the electrical load.

Unlike conventional power plants, wind projects cannot supply their capacity to the system on demand. This has caused some areas to discount wind projects from being a capacity resource. However, wind projects can contribute towards meeting area requirements for Loss of Load Expectation (LOLE). By comparing the contribution of a new wind project towards LOLE with the contribution of additional conventional capacity towards LOLE, an effective capacity for the new wind project can be determined.

The following analysis attempts to quantify the effective capacity for simulated wind projects by measuring their contribution towards meeting area LOLE requirements in terms of real capacity.

4.2 Loss of Load Expectation (LOLE) and Loss of Load Hours (LOLH)

Loss of Load Expectation (LOLE) is the probability of disconnecting firm load due to a deficiency of generation resources. The Northeast Power Coordinating Council (NPCC) criterion for LOLE is 0.1 days/year after accounting for emergency operating actions and interconnection support. This criterion can also be expressed as Loss of Load Hours (LOLH) of 2.4 hours/year.

In this study, LOLH was determined through a Monte Carlo random number probabilistic simulation of each generator's availability for each hour of the year. This process considered that the probability of a generator being unavailable for any hour is described by its Forced Outage Rate (FOR). FOR's are provided for each generator based upon operating experience, and are typically in the range of 1-10%. Random numbers between 0 and 1 produced each hour for each generator simulated that a generator was unavailable if the random number for that generator was less than its FOR, otherwise it was available. Planned maintenance was also factored into each generator's simulated availability by forcing generators to be unavailable during planned maintenance hours.

The Monte Carlo simulation also determined the reserve requirements for each hour, which are based upon the first and second generation contingency. As per Maritime system reserve requirements, the 10-minute reserve requirement was made equal to the size of the largest available generator, and the 30-minute reserve requirement was made equal to 50% of the size of the second largest available generator.

A loss of load hour occurred if the total simulated available capacity for an hour was insufficient to meet that hour's requirements for firm load and reserve. Firm load was calculated by subtracting the forecast monthly interruptible customer load from the actual hourly load. Surplus capacity in one sub-area of the Maritimes could assist another sub-area, but this assistance was limited by the intra-area transfer capabilities. No reliance on external interconnections, reduced 30-minute reserve, voltage reductions, other emergency actions, or better than average generator performance was considered in this LOLH determination. It is important to note that this level of load interruption did not actually occur in 2003 and 2004, but rather it is a simulation under the assumed conditions.

The results of this study, for each scenario, were produced from 1000 Monte Carlo simulations for each hour of the simulated year. The set of random numbers was kept constant for each scenario.

4.3 LOLH Simulation Model

The following inputs were incorporated into the LOLH simulation model:

- 2004 actual hourly load data for the Maritime Area (New Brunswick, Nova Scotia, PEI, and Northern Maine.)
- 2004 simulated hourly wind energy outputs for up to 8 sites.
- Intra-Area transfer capabilities
- 2004 Generator Capacities with corresponding Forced Outage Rates
- Planned Maintenance Schedule (typical, monthly)
- Interruptible Customer Load (monthly)

4.4 LOLH Simulation Scenarios

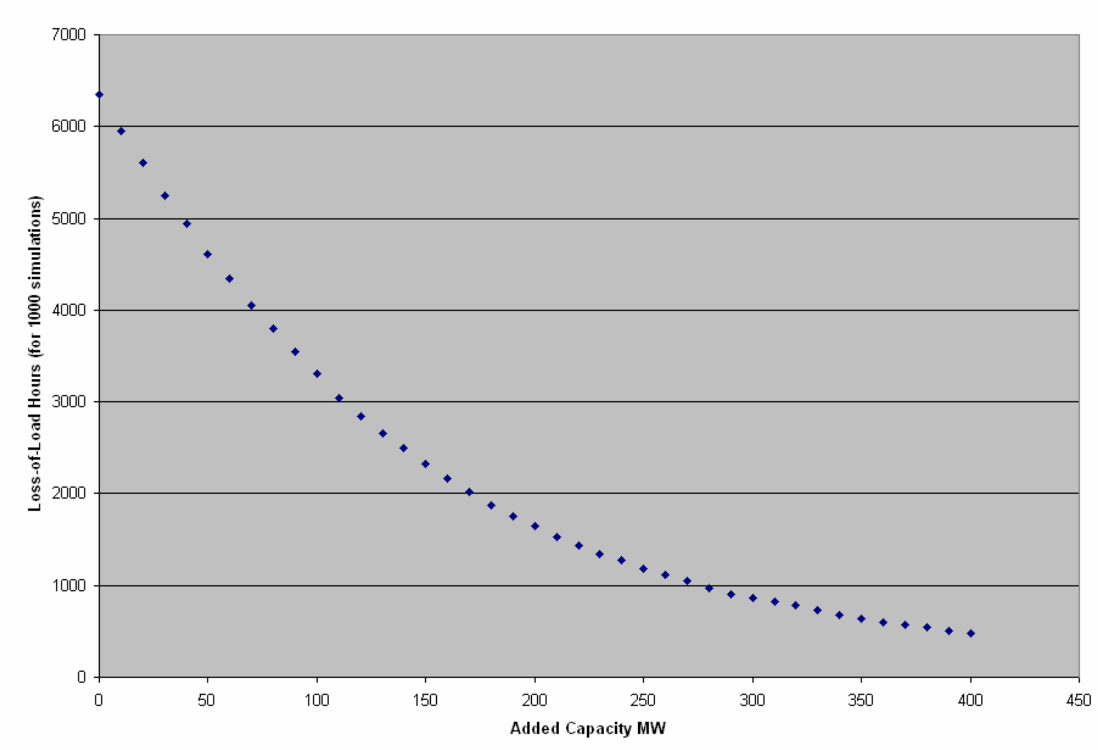
The following is a listing of the scenarios for which the LOLH was calculated:

- Scenario 1 - 2004 Maritime System with Intra-Area Transfer Limits
- Scenario 2 - 2004 Maritime System without Intra-Area Transfer Limits
- Scenario 3 - 2004 NB, PEI, and Northern Maine Areas Only
- Scenario 4 - 2004 NS System Only
- Scenario 5 - 2003 Maritime System with Intra-Area Transfer Limits

4.5 Scenario 1 - 2004 Maritime System with Intra-Area Transfer Limits

Figure 2 shows how the simulated 2004 Maritime System LOLH decreases with the addition of conventional capacity. In this scenario, the additional capacity was located in the New Brunswick sub-area, and intra-area transfer limits were enforced.

Figure 2
LOLH vs. Added Capacity – Scenario 1



This characteristic curve defines the relationship between LOLH and added capacity for this scenario. To determine the effective capacity of the simulated wind sites, the analysis was repeated with wind energy added to the system instead of conventional capacity. The impact of the wind energy on the LOLH determined a corresponding effective capacity value according to Figure 2.

4.6 Scenario 1 - Results

Table 1 shows how the initial LOLH (i.e. added capacity is zero) of 6346 hours from 1000 simulations (i.e. 6.346 hours/year) was distributed on a monthly basis.

Table 1
LOLH Distribution – Scenario 1

Month	LOLH	Percentage
Jan-04	5635	89%
Feb-04	385	6%
Mar-04	22	0%
Apr-04	109	2%
May-04	2	0%
Jun-04	0	0%
Jul-04	3	0%
Aug-04	1	0%
Sep-04	1	0%
Oct-04	1	0%
Nov-04	28	0%
Dec-04	159	3%
Totals	6346	100%

January 2004 was an exceptionally cold month with extreme wind chill as well, and these sustained cold temperatures caused the Maritime electric heating load to soar, resulting in all-time highs for hourly demand. The record demand levels for January 2004 give that month a huge 89% weighting on the LOLH simulation totals in Table 1.

The slight increase in LOLH seen in April 2004 is the result of some scheduled generator maintenance during the spring run-off. Overall, scheduled generator maintenance in the months of April through October does not have a significant impact on these LOLH numbers.

Based on Table 1, it is obvious that the calculation of effective Maritime capacity for the simulated wind projects is very dependent on the simulated January performance of these projects during the extreme load hours.

Table 2 represents the aggregated effective Maritime capacity calculations for the simulated wind projects.

Table 2
Effective Capacity – Scenario 1

Project Location	Simulated Wind Capacity (MW)	Effective Maritime Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	100	66	56	46	40
NS	100	1	48	40	33

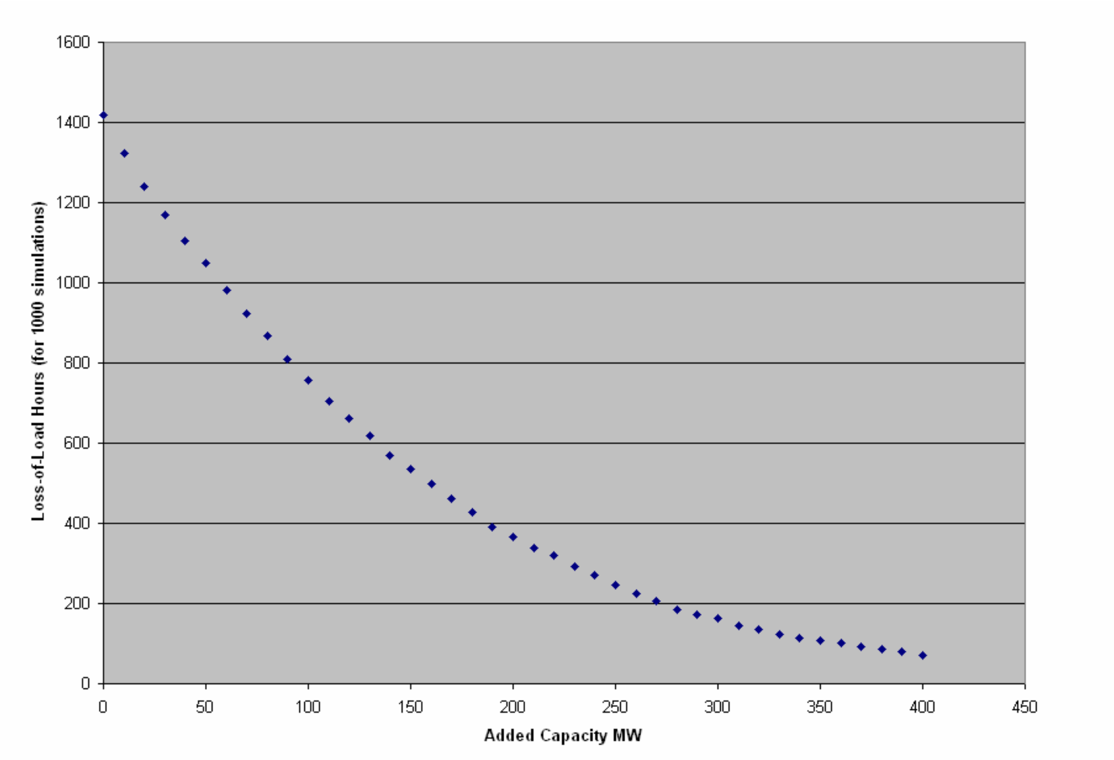
For the NB Area, a 100 MW wind project provided about 66 MW of effective Maritime capacity. This value is higher than the January, winter, or annual capacity factors, and thus demonstrates strong positive correlation between the simulated outputs of these wind projects and the highest loads experienced by the Maritimes in 2004. This is understandable because of the high correlation between high winds and low temperatures in January 2004, a correlation that was much higher than normal years according to meteorologists.

For Nova Scotia, the simulated wind projects provided negligible effective Maritime capacity, and this was entirely due to the 350 MW intra-area transfer limit between Nova Scotia and New Brunswick. Analysis of the LOLH showed that for the vast majority of simulated Maritime generation deficiencies, surplus available capacity in Nova Scotia was already assisting the rest of the sub-areas up to this 350 MW limit. Therefore, it was impossible for even additional conventional generation capacity in Nova Scotia to provide effective Maritime capacity in this scenario.

4.7 Scenario 2 - 2004 Maritime System without Intra-Area Transfer Limits

Figure 3 shows how the simulated 2004 Maritime System LOLH decreases with the addition of conventional capacity. In this scenario, the additional capacity was located in the New Brunswick sub-area, and intra-area transfer limits were not enforced.

Figure 3
LOLH vs. Added Capacity – Scenario 2



4.8 Scenario 2 - Results

Table 3 shows how the initial LOLH of 1417 hours over 1000 simulations was distributed on a monthly basis.

Table 3
LOLH Distribution – Scenario 2

Month	LOLH	Percentage
Jan-04	1362	96%
Feb-04	48	3%
Mar-04	0	0%
Apr-04	0	0%
May-04	0	0%
Jun-04	0	0%
Jul-04	0	0%
Aug-04	0	0%
Sep-04	0	0%
Oct-04	0	0%
Nov-04	0	0%
Dec-04	7	0%
Totals	1417	100%

As was seen in the previous scenario, the record demand levels for January 2004 give that month a huge 96% weighting on the LOLH simulation totals here.

As was the case in Scenario 1, the calculation of effective Maritime capacity for Scenario 2 is very dependent on the simulated January performance of these projects during the extreme load hours.

Table 4 represents the aggregated effective Maritime capacity calculations for the simulated wind projects.

Table 4
Effective Capacity – Scenario 2

Project Location	Simulated Wind Capacity (MW)	Effective Maritime Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	100	73	56	46	40
NS	100	62	48	40	33

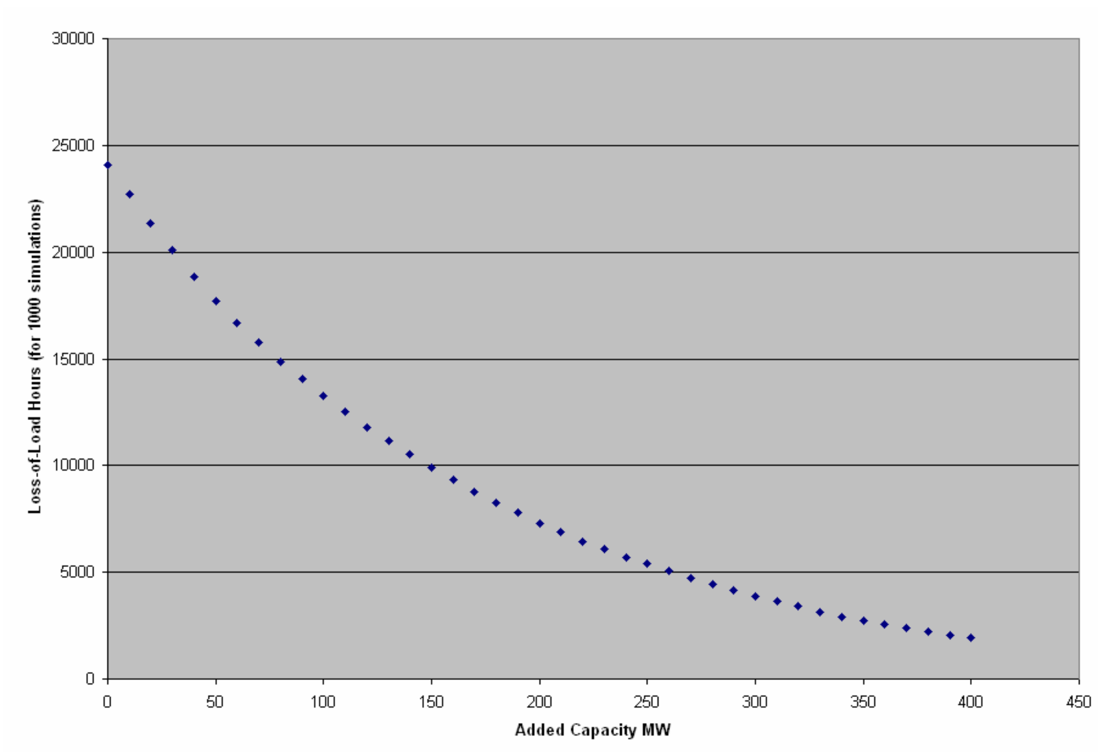
For the NB Area, a 100 MW wind project provided an average of 73 MW of effective Maritime capacity. As was the case in Scenario 1, the effective capacity value is higher than the January, winter, and annual capacity factor calculations, and thus demonstrates strong positive correlation between the simulated outputs of these wind projects and the highest loads experienced by the Maritimes in 2004.

For Nova Scotia, a 100 MW wind project provided an average of 62 MW of effective Maritime capacity. This too demonstrates strong positive correlation between the simulated outputs of these wind projects and the record high loads experienced by the Maritimes in 2004. It also proves that the intra-area transfer limit between Nova Scotia and New Brunswick was the cause of the negligible effective Maritime capacity values for the simulated Nova Scotia wind projects in Scenario 1.

4.9 Scenario 3 - 2004 NB Area Only

Figure 4 shows how the simulated 2004 NB Area LOLH decreases with the addition of conventional capacity. The Nova Scotia sub-area was excluded.

Figure 4
LOLH vs. Added Capacity – Scenario 3



4.10 Scenario 3 - Results

Table 5 shows how the initial LOLH of 24086 hours over 1000 simulations was distributed on a monthly basis.

Table 5
LOLH Distribution – Scenario 3

Month	LOLH	Percentage
Jan-04	19552	81%
Feb-04	1771	7%
Mar-04	185	1%
Apr-04	1236	5%
May-04	63	0%
Jun-04	12	0%
Jul-04	5	0%
Aug-04	1	0%
Sep-04	64	0%
Oct-04	69	0%
Nov-04	234	1%
Dec-04	894	4%
Totals	24086	100%

As was seen in the previous scenarios, the record demand levels for January 2004 give that month a huge 81% weighting on the LOLH simulation totals here.

Based on Table 5, it is obvious that the calculation of effective NB Area capacity for the simulated wind projects is very dependent on the January performance of these projects during the extreme load hours.

The slight increase in LOLH seen in April 2004 is the result of scheduled generator maintenance during the spring run-off. Overall, scheduled generator maintenance in the months of April through October does not have a significant impact on these LOLH numbers.

Table 6 represents the aggregated effective NB Area capacity calculations for the simulated wind projects.

Table 6
Effective Capacity – Scenario 3

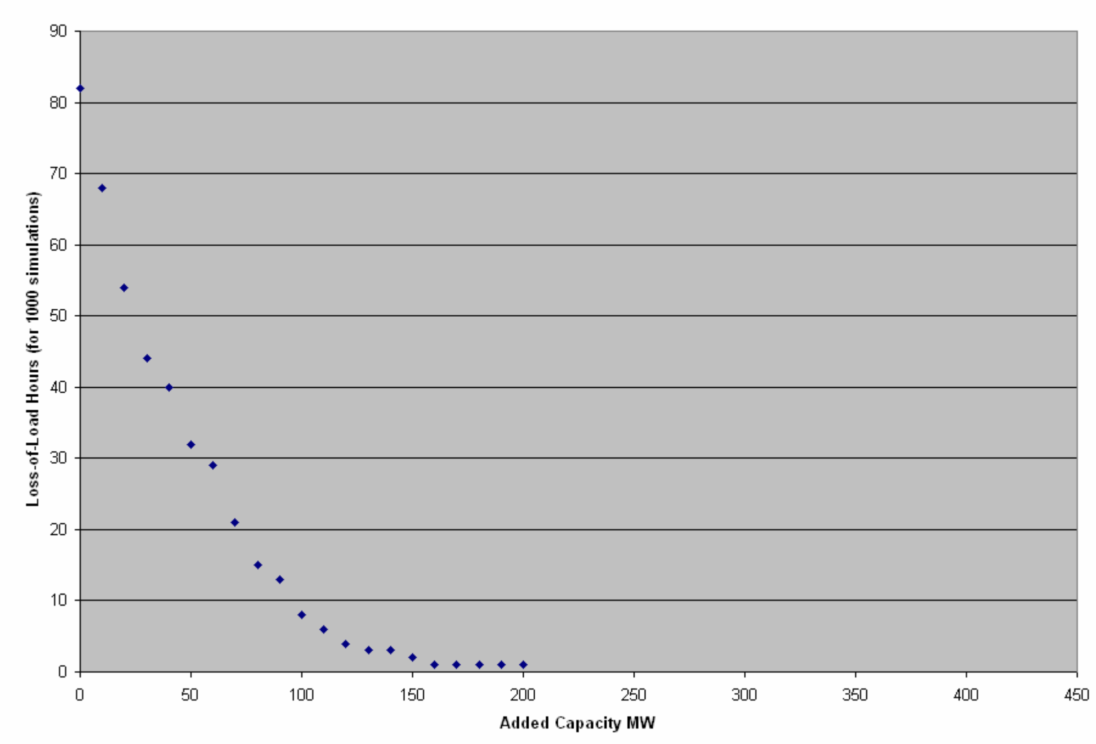
Project Location	Simulated Wind Capacity (MW)	Effective NB Area Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	100	60	56	46	40
NS	Not app.	Not app.	48	40	33

For the NB Area, a 100 MW wind project provided an average of 60 MW of effective NB Area capacity. This result is slightly higher than the January capacity factor, which indicates that there was some positive correlation between the simulated January wind energy and the highest January loads. As was the case in the previous scenarios, the effective capacity is much higher than the winter or annual capacity factors.

4.11 Scenario 4 - 2004 Nova Scotia Area Only

Figure 5 shows how the simulated 2004 Nova Scotia Area LOLH decreases with the addition of conventional capacity. The NB Area was excluded.

Figure 5
LOLH vs. Added Capacity – Scenario 4



4.12 Scenario 4 - Results

Table 7 shows how the initial LOLH of 82 hours over 1000 simulations was distributed on a monthly basis.

Table 7
LOLH Distribution – Scenario 4

Month	LOLH	Percentage
Jan-04	76	93%
Feb-04	4	5%
Mar-04	0	0%
Apr-04	0	0%
May-04	0	0%
Jun-04	0	0%
Jul-04	0	0%
Aug-04	0	0%
Sep-04	0	0%
Oct-04	0	0%
Nov-04	0	0%
Dec-04	2	2%
Totals	82	100%

As was seen in the previous scenarios, the record demand levels for January 2004 give that month a huge 93% weighting on the LOLH simulation totals here.

Based on Table 7, it is obvious that the calculation of effective Nova Scotia capacity for the simulated wind projects is very dependent on the January performance of these projects during the extreme load hours.

Table 8 represents the aggregated effective Nova Scotia capacity calculations for the simulated wind projects.

Table 8
Effective Capacity – Scenario 4

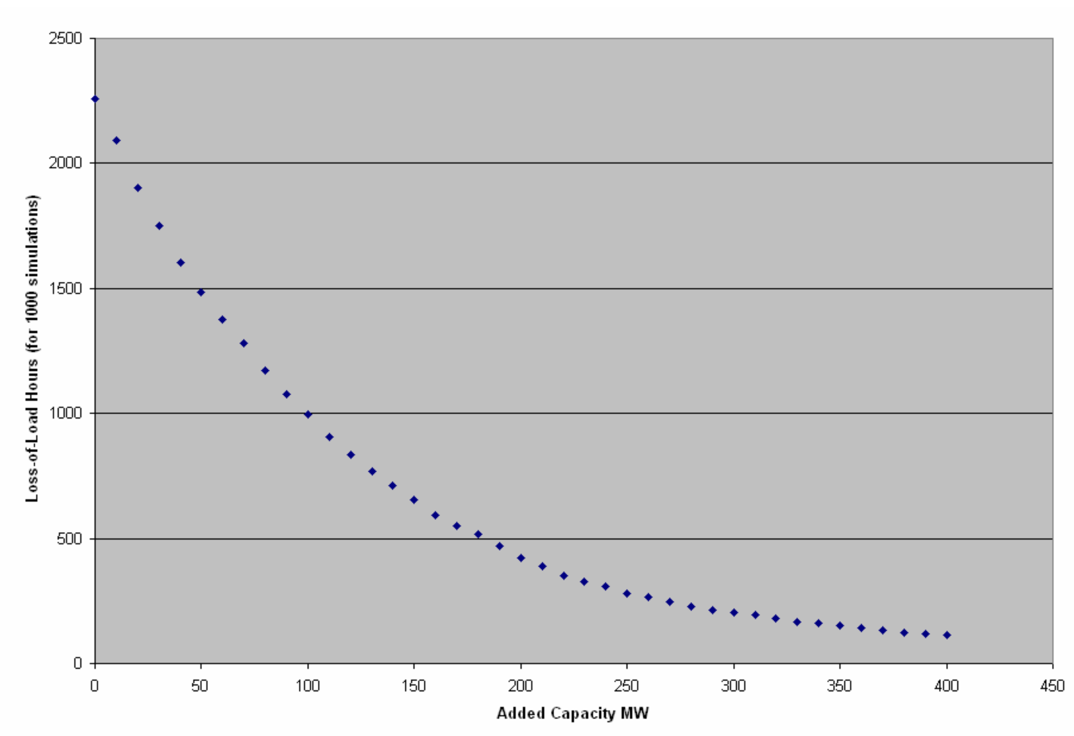
Project Location	Simulated Wind Capacity (MW)	Effective Nova Scotia Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	Not app.	Not app.	56	46	40
NS	100	50	48	40	33

For Nova Scotia, a 100 MW wind project provided an average of 50 MW of effective Nova Scotia capacity. This result is slightly higher than the January capacity factor, which indicates that there was some positive correlation between the simulated January wind energy and the highest January loads. As was the case in Scenario 2, the effective capacity is much higher than the winter or annual capacity factors.

4.13 Scenario 5 - 2003 Maritime System with Intra-Area Transfer Limits

Figure 6 shows how the simulated 2003 Maritime System LOLH decreases with the addition of conventional capacity. In this scenario, the additional capacity was located in the New Brunswick sub-area, and intra-area transfer limits were enforced.

Figure 6
LOLH vs. Added Capacity – Scenario 5



4.14 Scenario 5 - Results

Table 9 shows how the initial LOLH of 2258 hours over 1000 simulations was distributed on a monthly basis.

Table 9
LOLH Distribution – Scenario 5

Month	LOLH	Percentage
Jan-04	727	32%
Feb-04	852	38%
Mar-04	85	4%
Apr-04	448	20%
May-04	27	1%
Jun-04	1	0%
Jul-04	0	0%
Aug-04	4	0%
Sep-04	0	0%
Oct-04	4	0%
Nov-04	14	1%
Dec-04	96	4%
Totals	2258	100%

Unlike 2004, the 2003 year did not see record high demand occurring in the month of January. In this simulation, the months of January, February, and April comprise 90% of the LOLH. The high LOLH numbers for January and February can be explained by the typically colder temperatures causing the electric heating load to be at its highest during the year. The noticeable increase in LOLH seen in April 2003 is the result of scheduled generator maintenance during the spring run-off, combined with higher April loads than those seen in 2004.

Based on Table 9, it is obvious that the calculation of effective Maritime capacity for the simulated wind projects will be very dependent on the January, February, and April performance of these projects during the high load hours.

Table 10 represents the aggregated effective Maritime capacity calculations for the simulated wind projects. Unlike 2004, the 2003 simulation only had wind data for 2 out of the 8 wind sites, and both of these sites were located in the NB Area.

Table 10
Effective Capacity – Scenario 5

Project Location	Simulated Wind Capacity (MW)	Effective Maritime Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	100	49*	48*	47*	44*
NS	Not app.	Not app.	Not app.	Not app.	Not app.

* - This value represents a projection for all five NB Area wind sites, but it is only based upon two sites since there was no data available for the other three sites in 2003.

For the NB Area, a 100 MW wind project provided an average of 49 MW of effective Maritime capacity. This value is not much different than the winter or annual capacity factor values, and thus demonstrates that there was not a strong correlation between the simulated outputs of these wind projects and the highest loads experienced by the Maritimes in 2003.

4.15 Effective Capacity Results and Recommendations

The average effective capacity of simulated wind projects in the NB Area was calculated for different scenarios. The average effective capacities were:

- 66% - 2004 Maritimes with intra-area transfer limits
- 73% - 2004 Maritimes without intra-area transfer limits
- 60% - 2004 NB Area only
- 49% - 2003 Maritimes with intra-area transfer limits

These results show that the 2004 effective capacity of the simulated wind generation in the NB Area was much higher than its 46% winter capacity factor. A major contributing factor to this was that the extreme cold temperatures experienced in January 2004 were accompanied by high wind speeds at the simulated wind project locations. This weather event is considered unusual as wind speeds usually drop at extremely low temperatures. Supplementary analysis for 2003 produced an effective capacity that was very close to the 47% winter capacity factor.

The NBSO Market Rules require that the procedure to determine capacity credits from energy limited resources take into account the amount of energy production. The current Market Rules procedure for wind generation is to credit a wind project based upon the average capacity factor of its past three years of operation. This study provides evidence to support that position and suggests that projected generation using wind speeds could bridge the gap until three years of actual performance is achieved.

It is recommended at this time that wind projects in the NB Area be credited with a capacity equal to their winter capacity factor. Although the 2004 results produced effective capacity values that were much higher than the winter capacity factor for the wind generation, it was not established by this study as to whether extremely cold winter temperatures will always be accompanied by high wind speeds. Such a determination requires a broader study involving the simulation of many other winter periods.

The average effective capacity of simulated wind projects in Nova Scotia was calculated for different scenarios. The average effective capacities were:

- 1% - 2004 Maritimes with intra-area transfer limits
- 62% - 2004 Maritimes without intra-area transfer limits
- 50% - 2004 Nova Scotia only

This study showed that the transmission limit from Nova Scotia to New Brunswick prevented any additional Nova Scotia generation, including wind, from contributing effective capacity to the Maritimes. Once the transmission limit was removed, the 2004 effective capacities outperformed the 2004 Nova Scotia average winter capacity factor of 40%. As in the NB Area, a major contributing factor to this was that the extreme cold temperatures experienced in January 2004 were accompanied by high wind speeds at the simulated Nova Scotia wind project locations.

Similar to the NB Area, it is recommended at this time that wind projects in Nova Scotia be credited with a capacity equal to their winter capacity factor. Although the transmission limit from Nova Scotia to New Brunswick produced a negligible effective capacity value on a Maritimes basis, future wind projects in Nova Scotia can contribute effective capacity by replacing existing facilities, or by providing for additional load growth. As was the case in the NB Area, the 2004 results produced some effective capacity values for Nova Scotia wind generation that were much higher than the winter capacity factor, but it cannot be established that this will always be the case, and the study of additional years is required to make that determination.

5.0 IMPACT OF WIND GENERATION ON LOAD VARIABILITY

5.1 Description

Load variability is the fluctuation of electrical demand on the system for which dispatchable generation resources must balance with equivalent fluctuations of electrical supply. Adequate response to load variability is essential for maintaining both system frequency and scheduled interconnection flows. Since wind generation projects are non-dispatchable with fluctuating outputs, they can add to the load variability that the dispatchable generation resources must accommodate.

Higher load variability requires additional load following capability from generation resources, and a system operator's procurement of this additional capability ultimately results in additional costs to customers. Failure of a system to respond to load variability is likely to result in penalties from neighbouring areas due to variances between actual and scheduled interconnection flows. In a worst case scenario, the failure of systems to follow load may result in line trips or frequency deviations that could blackout customers.

The following analysis measures the load variability of the NB Area, NS Area and Maritimes Area systems as the standard deviation of the hourly load swing. The impact of wind capacity at single sites and wind capacity at multiple sites on this hourly load swing is also analysed.

5.2 Variability Measurement of the Hourly Load Swing

The ability to integrate significant wind generation capacity into the Maritimes depends very much upon the impact of these wind projects on the hourly load swing. Having some diversity amongst the wind project locations will generally produce a lesser increase to the hourly load swing than if the wind projects were close together, and thus will allow for more wind generation to be integrated into a system at a lower cost.

Diversity amongst the modeled wind sites for this study is quantified by calculating the correlation coefficients of the simulated wind project output levels between two projects. Perfect negative correlation between two wind projects results in a coefficient calculation of -1.0, perfect positive correlation results in a coefficient calculation of +1.0, and uncorrelated or zero correlation between projects results in a correlation coefficient of 0.

Table 11 provides a summary of the correlation coefficients between the hourly energy output levels of the modeled wind project sites in this study.

Table 11
Hourly Wind Energy Correlation Coefficients

	North Cape / Tignish, PEI	Cape Breton, NS	Halifax / Dartmouth, NS	Shelburne / Yarmouth, NS	Dorchester / Tantramar, NB	Miramichi, NB	Grand Manan / Campabello, NB	Lamèque / Miscou, NB
North Cape / Tignish, PEI	1.00							
Cape Breton, NS	0.50	1.00						
Halifax / Dartmouth, NS	0.37	0.45	1.00					
Shelburne / Yarmouth, NS	0.27	0.30	0.61	1.00				
Dorchester / Tantramar, NB	0.53	0.34	0.52	0.44	1.00			
Miramichi, NB	0.52	0.36	0.38	0.30	0.46	1.00		
Grand Manan / Campabello, NB	0.39	0.28	0.41	0.45	0.52	0.42	1.00	
Lamèque / Miscou, NB	0.63	0.42	0.29	0.29	0.42	0.54	0.38	1.00

In Table 11, the correlation coefficient between two sites is located at the intersection of the row and column corresponding to those sites. For example, the correlation coefficient between Lamèque / Miscou, NB and North Cape / Tignish, PEI is 0.63. This high coefficient reflects that these two sites are not very diverse, relative to one another, and that there is a strong connection between their hourly wind output levels. This is not surprising given that these two sites are relatively close to each other. This pattern is consistent throughout Table 11, where sites that are far apart from one another tend to have lower correlation coefficients (i.e. more relative diversity) than sites that are close together.

Table 12 is similar to Table 11 except that the correlation coefficients are calculated on a daily energy basis instead of hourly. As a whole, the correlation coefficients in Table 12 are higher than Table 11, indicating that the relative correlation of wind project output levels increases when longer timeframes such as days are considered, and decreases as shorter timeframes such as hours or minutes are considered.

Table 12
Daily Wind Energy Correlation Coefficients

	North Cape / Tignish, PEI	Cape Breton, NS	Halifax / Dartmouth, NS	Shelburne / Yarmouth, NS	Dorchester / Tantramar, NB	Miramichi, NB	Grand Manan / Campabello, NB	Lamèque / Miscou, NB
North Cape / Tignish, PEI	1.00							
Cape Breton, NS	0.67	1.00						
Halifax / Dartmouth, NS	0.52	0.61	1.00					
Shelburne / Yarmouth, NS	0.41	0.43	0.73	1.00				
Dorchester / Tantramar, NB	0.69	0.47	0.63	0.54	1.00			
Miramichi, NB	0.67	0.52	0.50	0.40	0.57	1.00		
Grand Manan / Campabello, NB	0.53	0.42	0.55	0.57	0.67	0.53	1.00	
Lamèque / Miscou, NB	0.75	0.56	0.37	0.39	0.55	0.63	0.53	1.00

While Table 11 and Table 12 show how the wind sites correlate with each other, it is necessary to simulate how each site, or group of sites, will impact the load variability of the system. For this study, an hourly time frame is used for measuring the impact of the simulated wind generation on load variability. Although wind data is available at smaller 10-minute intervals for each site, the clocks at these wind data collection towers were not synchronized together when the data was recorded. This compromises any attempts to study wind correlation at 10-minute intervals because such a study requires confidence that the 10-minute intervals being compared actually coincide amongst the sites, at least to a high degree. It is assumed that the hourly time frame chosen for this analysis allows the hourly intervals being compared to coincide to a high degree, even if the unsynchronized clocks differed from one another by a few minutes at the time that the wind data was recorded.

The hourly load swing is the change of a system's average load from one hour to the next. The variability of this hourly load swing can be calculated as the standard deviation of this change. Standard deviation is the most commonly used measure of statistical dispersion, and for this analysis represents how spread out the hourly load swing becomes as increased amounts of simulated wind energy are added to the system.

The cost of additional load variability in this study is approximated by using load following cost data submitted by NB Power in its 2002 evidence filing for its Open Access Transmission Tariff. This regulatory evidence filing is available at http://www.nbpower.com/en/transmission/regulatory/tar_july25_2002.html In Appendix B, p.46, Table 4-1 the charge rate for acquiring load following from generation for 2003/04 is $67.87 / kW-yr. While this charge rate applies to generation capacity, it can be shown for the New Brunswick system that the amount of generation capacity required for load following is approximately equal to the standard deviation of the hourly load swing. Therefore, additional load variability cost in this study is calculated as the $67.87 / kW-yr charge rate multiplied by the standard deviation MW increase of the hourly load swing.

5.3 Scenario 1 - Impact of Wind Energy on the NB Area Load Variability

For 2004, the NB Area's standard deviation of its combined hourly load swing was 82 MW. Table 11 shows the average impact of simulated wind generation in the NB Area on the load variability for 2004. The results show the impact of the wind capacity being located at a single site, and the impact of the wind capacity if it is evenly distributed amongst the five sites in the NB Area. Cost increases in this table were calculated as per the method described in Section 5.2.

Table 13
2004 Impact of Wind Projects on NB Area Load Variability

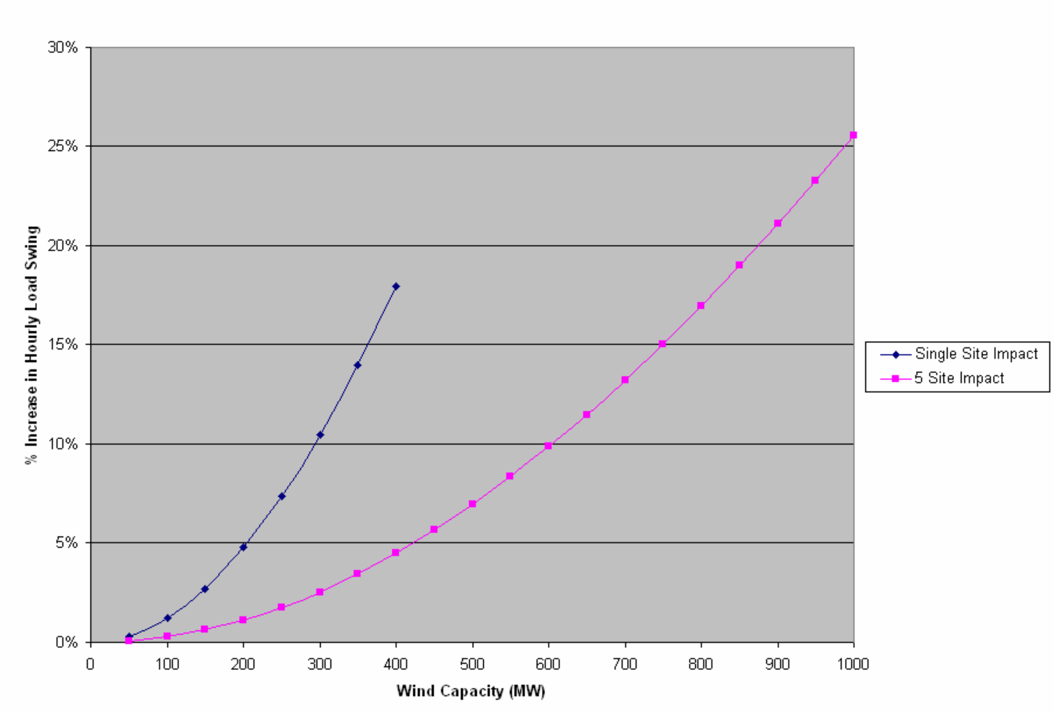
NB Area Wind Capacity MW	Increase on NB Area Load Variability (Single Site)	Single Site Annual Cost Increase ($Millions)	Increase on NB Area Load Variability (5 Sites)	5 Site Annual Cost Increase ($Millions)
100	1.2%	0.07	0.3%	0.02
200	4.8%	0.27	1.1%	0.06
300	10.5%	0.58	2.5%	0.14
400	17.9%	1.00	4.5%	0.25
500	-	-	6.9%	0.38
600	-	-	9.9%	0.55
700	-	-	13.2%	0.73
800	-	-	17.0%	0.95
900	-	-	21.1%	1.17
1000	-	-	25.5%	1.42

Adding 100 MW of wind at one site adds 1 MW (1.2% of 82) of load variability. From the data in Table 11, it can be seen that the impact on load variability by adding wind generation is not linear. The impact for 400 MW at one site is 14.7 MW (17.9% of 82). As wind capacity is added the impact on load variability appears to increase in proportion to the square of the capacity added. The load variability at one site is about four times that attained by the same amount of capacity added at diverse sites (note 17.9 % vs. 4.5% for 400 MW). Also if diverse sites are employed the amount of wind capacity that can be accommodated with the same degree of load variability is double (note17.9% and 17.0% at capacities of 400MW and 800MW respectively). From these results, we can state the following:

- Installing wind capacity amongst several sites versus a single site results in lower load variability, and thus any costs associated with increased load variability should also be lowered.
- Systems can accommodate more wind generation with less load variability problems if the wind projects are geographically dispersed.

Figure 7 displays the results of Table 11.

Figure 7
2004 Impact of Wind Projects on NB Area Load Variability



5.4 Scenario 2 - Impact of Wind Energy on Nova Scotia Load Variability

For 2004, Nova Scotia's standard deviation of its hourly load swing was 59 MW. Table 12 shows the average impact of simulated wind generation in Nova Scotia on the load variability for 2004. The results show the impact of the wind capacity being located at a single site, and the impact of the wind capacity if it is evenly distributed amongst the three sites in Nova Scotia. Cost increases in this table were calculated as per the method described in Section 5.2.

Table 14
2004 Impact of Wind Projects on Nova Scotia Load Variability

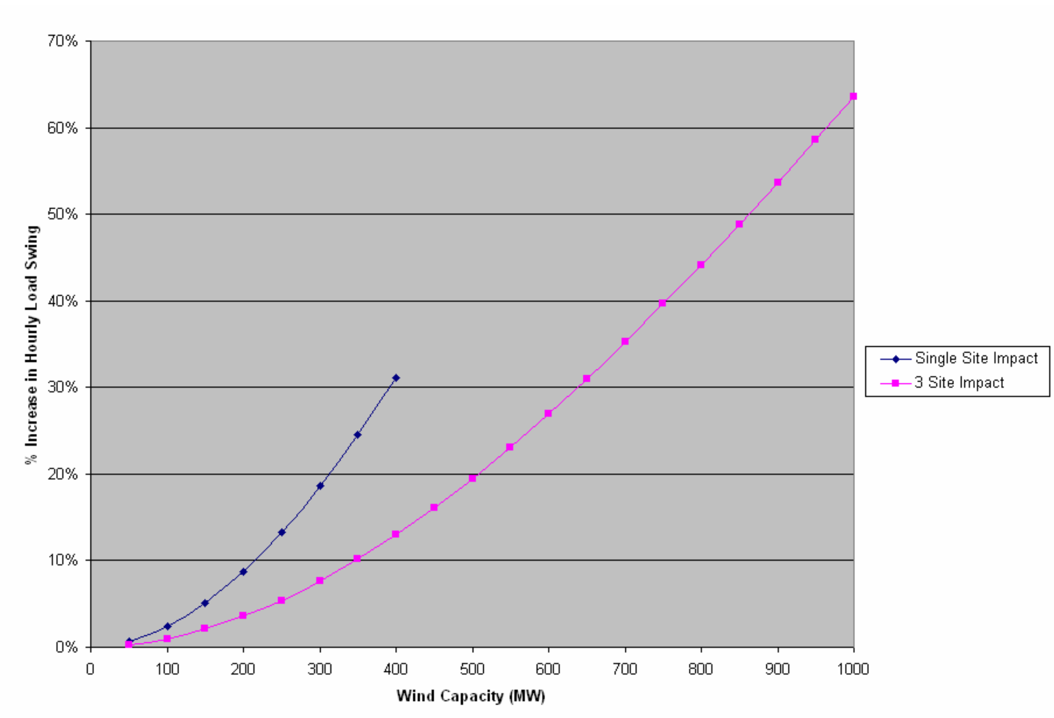
Nova Scotia Wind Capacity MW	Increase on Nova Scotia Load Variability (Single Site)	Single Site Annual Cost Increase ($Millions)	Increase on Nova Scotia Load Variability (3 Sites)	3 Site Annual Cost Increase ($Millions)
100	2.4%	0.10	1.0%	0.04
200	8.8%	0.35	3.6%	0.14
300	18.6%	0.75	7.6%	0.30
400	31.1%	1.25	13.0%	0.52
500	-	-	19.5%	0.78
600	-	-	27.0%	1.08
700	-	-	35.2%	1.41
800	-	-	44.2%	1.77
900	-	-	53.7%	2.15
1000	-	-	63.6%	2.55

From Table 12, it can be seen that the results are very similar in shape and proportion to the NB Area results but differ slightly in size. Let us compare. Adding 100 MW of wind at one site adds 1.4 MW (2.4% of 59) of load variability. The difference from the NB Area impact of 1 MW per 100 MW of wind can be attributed to system size. The load in Nova Scotia is about 67% of the load in the NB Area. This means that 100 MW of wind in Nova Scotia is a larger proportion of system load. If the impacts are normalized by system load, then it appears that there would be a 1 MW increase in load variability for about 70 MW of wind project.

To consider system size in the comparison of the NB Area results with the Nova Scotia results it may be more appropriate to compare the 300 MW Nova Scotia result of 18.6% against the 400 MW NB Area result of 17.9%. Another major consideration in viewing the Nova Scotia results is that there are only three diverse sites compared to five in the NB Area. The impact of this is that distribution of wind capacity resulted in a load variability impact of 41% of the average single site impact for Nova Scotia compared to 25% for the NB Area.

Figure 8 displays the results of Table 12.

Figure 8
2004 Impact of Wind Projects on Nova Scotia Load Variability



5.5 Scenario 3 - Impact of Wind Energy on Maritimes Load Variability

For 2004, the Maritimes Area's standard deviation of its combined hourly load swing was 123 MW. Table 13 shows the average impact of simulated wind generation in the Maritimes Area on the load variability for 2004. The results show the impact of the wind capacity being located at a single site, and the impact of the wind capacity if it is evenly distributed amongst the eight sites in the Maritimes. Cost increases in this table were calculated as per the method described in Section 5.2.

Table 15
2004 Impact of Wind Projects on Maritime Load Variability

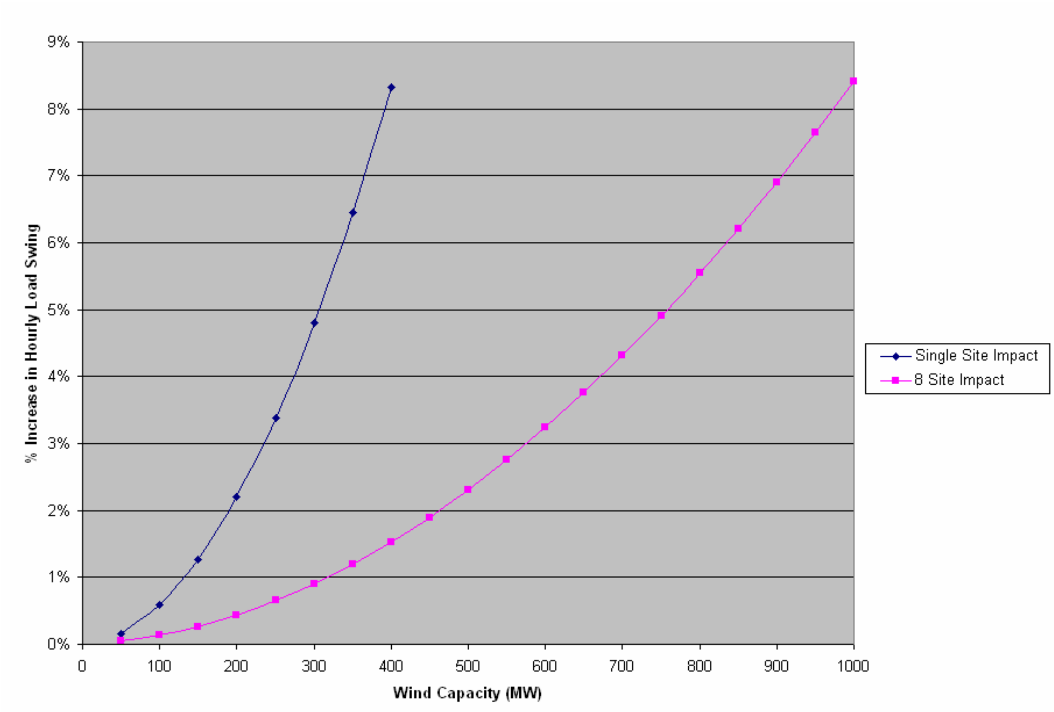
Maritime Wind Capacity MW	Increase on Maritime Load Variability (Single Site)	Single Site Annual Cost Increase ($Millions)	Increase on Maritime Load Variability (8 Sites)	8 Site Annual Cost Increase ($Millions)
100	0.6%	0.05	0.1%	0.01
200	2.2%	0.18	0.4%	0.03
300	4.8%	0.40	0.9%	0.08
400	8.3%	0.69	1.5%	0.13
500	-	-	2.3%	0.19
600	-	-	3.2%	0.27
700	-	-	4.3%	0.36
800	-	-	5.5%	0.46
900	-	-	6.9%	0.58
1000	-	-	8.4%	0.70

As expected following the comparison of Nova Scotia and NB Area results, the impact of 100 MW of wind is only 0.7 MW (0.6% of 123 MW). This result was expected to be lower because the impact of 100 MW is proportionately smaller. The impact of 400 MW at one site is also smaller and dispersion between eight sites also provides more moderation of the load variation impacts.

From Table 13, it can be seen that distributing the wind capacity amongst eight sites resulted in a load variability impact of only 18% of the average single site impact.

Figure 9 displays the results of Table 13.

Figure 9
2004 Impact of Wind Projects on Maritimes Area Load Variability



5.6 Wind Variability Results and Recommendations

The 2004 load variability of the Maritimes, as well as the sub-areas, was measured as the standard deviation of the hourly load swing. The standard deviation results were:

- NB Area - 82 MW
- Nova Scotia - 59 MW
- Maritimes - 123 MW

For 2004, it was shown that 400 MW of wind capacity at a single site increased the load variability significantly more than if it was distributed amongst several sites. These load variability increases for the Maritimes, as well as the sub-areas, were:

• NB Area	Single Site:	17.9%,	\$1.00 million per year
	Five Sites:	4.5%,	\$0.25 million per year
• Nova Scotia	Single Site:	31.1%	\$1.25 million per year
	Three Sites:	13.0%	\$0.52 million per year
• Maritimes	Single Site:	8.3%	\$0.69 million per year
	Eight Sites:	1.5%	\$0.13 million per year

In the Nova Scotia and NB Area regions, the cost of load variability is distributed amongst the load in that region. Therefore, any load variability cost increases due to wind generation falls to the local customers, even if they are not the ones purchasing the wind energy. This may be seen as unfair in cases where a new wind project exports its power to a neighbouring system while producing higher load variability costs to customers in the local region. Should such scenarios develop, the Maritime regions may have to look at charging wind projects for increasing the local load variability.

To integrate significant wind project capacity in the Maritimes, it is recommended that the developed capacity be split up amongst several sites, and that these sites have a good geographic separation in order to minimize costs associated with load variability.

The Maritime load was shown to be less variable than the sum of its sub-areas, and thus it is less impacted by the additional load variability from wind projects. It is recommended that efforts to develop significant wind project capacity in the Maritimes should include a plan to manage load variability on a Maritime basis versus having each sub-area manage its own. Such a strategy will result in less additional load following requirement for a given wind quantity or enable increased wind development for a given load following requirement.

6.0 HYDROELECTRIC CAPACITY AND SPRING RUN-OFF ISSUES

6.1 Hydroelectric Capacity in the Maritimes

In the Maritimes, much of the load variability is managed by the hydroelectric generators. They are the fastest responding generators on the system whenever there is a requirement to ramp up or down, and they can be brought on-line much quicker than a thermal or nuclear unit. This makes the amount of flexible hydroelectric generation on a power system an important factor in determining how much load variability that a system can handle. Since it was shown in Chapter 5 of this study that wind projects contribute increased load variability to the system, the amount of flexible hydroelectric generation on a power system is also an important factor in determining how much percent wind capacity that a system can handle.

The installed hydroelectric generation capacity in the Maritimes is around 20%. About a quarter of this is run-of-the-river with little flexibility in the way it is dispatched. The remainder or about 15% of Maritimes hydroelectric capacity has storage and dispatch flexibility for 10 to 11 months per year. For comparison, the provinces of Newfoundland and Labrador, Québec, Manitoba, and British Columbia all have installed hydroelectric generation capacity totals that exceed 90%, much of which has large storage with flexible dispatch capability. Other areas are Ontario with 25%, Saskatchewan with 24%, and Alberta with 7%. One can safely say that the areas where the installed hydroelectric generation capacity exceeds 90% can handle a lot more load variability, and thus a lot more percent wind capacity, than can areas that are 25% hydroelectric or less. Other factors, none of which are studied in this report, affecting the amount of load variability and wind generation that a system can accommodate, are:

- Thermal unit ramp rates
- Interconnection support
- Low voltage ride-through capability from wind projects, and
- Curtailment control systems for wind projects.

6.2 Spring Run-Off Issues Affecting Wind Project Development

Spring run-off describes the April to May period where the snow melt and accompanying rainfall floods the rivers of the Maritimes and causes water to spill over at the hydroelectric stations. During this period, hydroelectric plants must be operated at their full output levels to produce as much cheap energy as possible. Failure to do so would cause extra spilling at the stations, and the opportunity to use the extra spilled water for power generation would be forever lost.

It is during the spring run-off period that the ability of the hydroelectric generators to flexibly respond to load variability is compromised. Response to load variability requires a generator to ramp up or ramp down, yet the hydroelectric stations are unable to do this during the spring run-off without incurring the cost of allowing extra water to spill. Therefore, the spring run-off may create a cost barrier that inhibits the integration of a large amount of wind capacity if there is insufficient capability from the non-hydroelectric generation to respond to the increased load variability from the wind projects.

The length of the spring run-off can vary. In New Brunswick, the spring period of base loaded hydro typically lasts 2-4 weeks. In 2004, it lasted only 1.5 weeks, but more recently in 2005 it lasted for about five weeks.

Figure 10 illustrates how 400 MW of simulated wind capacity at five sites in New Brunswick and PEI would have impacted the sub-area of New Brunswick and PEI during the 2004 spring run-off:

Figure 10
NB + PEI Load, Hydro, and Wind
2004 Spring

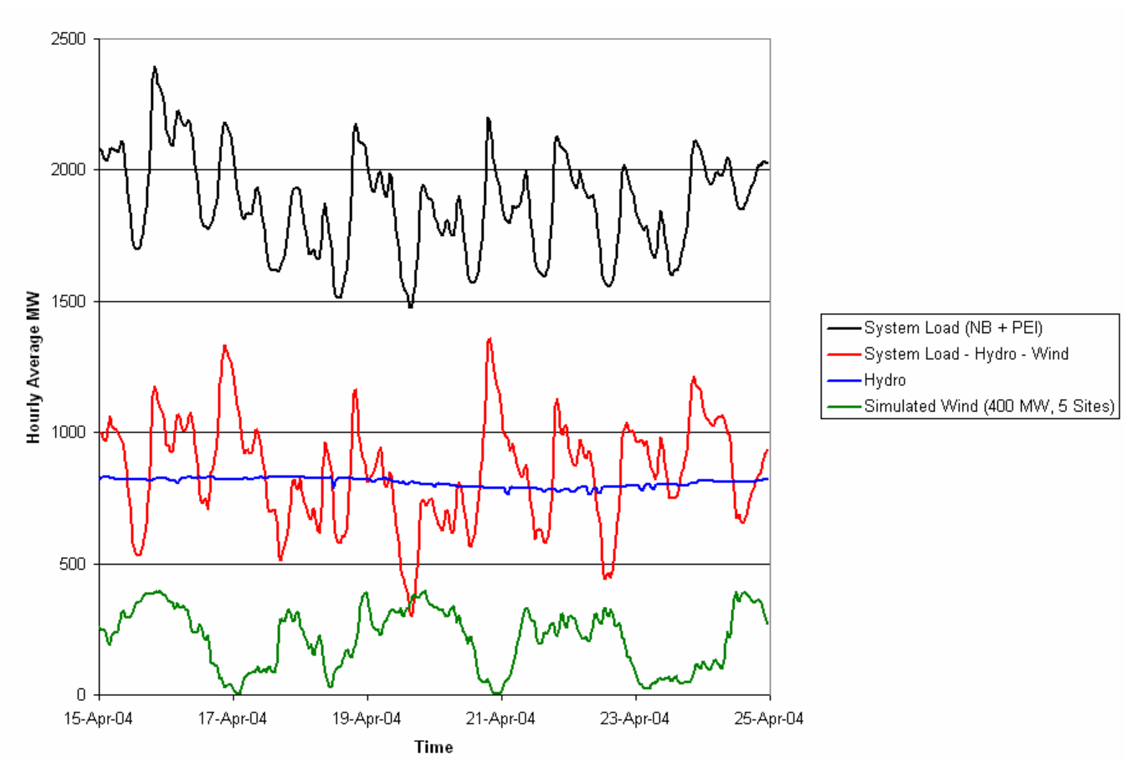


Figure 10 shows how the hydroelectric generation was base loaded over this 10-day period. The red waveform is the result of the hydroelectric and the 400 MW of simulated wind generation being subtracted from the initial load. The following comments can be made about the impact of the simulated wind generation during this period:

- Load variability has been increased by 8.1%. This increase must be responded to by the thermal generation on the system. As shown in the previous chapter, this variability increase would have been much higher if the wind generation had all been located at a single site rather than five sites.

- Average thermal load has been decreased by 809 MW by the base load hydro operation and an additional 215 MW from wind generation. The simulated wind generation was running at a 54% capacity factor during this period. This decrease in the load results in the commitment of less thermal generation.

With both a decrease in load to be served by thermal generation and an increase in the load variability, the variability impact of the wind generation puts increased strain on the capabilities of the thermal generators to follow the load. Less thermal units are necessary to serve the average load, but more will most likely be necessary to handle the ramping up and ramping down requirements.

To put this spring run-off challenge into perspective it should be compared to operation in the non run-off period. Load variability attributable to wind has roughly doubled (8.1% vs. 4.5% impact) while thermal load is about half (851 MW vs. typically 1500 MW). The combined impact is that the variability of the load supplied by thermal generation for this run-off period is about four times the average of the non run-off periods. This assumes that all load following would be supplied by thermal units even in the non run-off period. However, outside the run-off period there is also flexible hydro capacity in the order of 200 to 600 MW to assist the thermal units with load variability. Therefore, the simulated wind generation's impact on the variability of the load supplied by thermal generation during this run-off period is actually much greater than four times.

It is important to understand that the issue of wind hydro integration is primarily an issue of economics. NBSO and Nova Scotia Power Inc, as balancing authorities for their respective sub areas will ensure that there is sufficient load following capability to meet reliability standards. However the cost of acquiring that capability likely will be significantly increased in the run-off period. Not only will it impact the commitment of thermal units it may force the deliberate spilling of hydro energy in order to free up hydro capacity for load following. This is an area that requires more study and should be considered as a detailed portion of a unit commitment analysis with varying levels of wind penetration.

While outside the mandate of NBSO it is also a factor that should be considered by load serving entities in the economic evaluation of wind generation in comparison to conventional generation sources.

6.3 Hydroelectric Capacity and Spring Run-Off Results and Recommendations

At this time, it is difficult to say how much wind capacity is too much. The Maritimes only has 46 MW of wind generation today, and that is not enough to properly judge the impacts of installing levels of wind capacity that are higher by an order of magnitude. Compared to other areas in Canada, the Maritimes has relatively less hydroelectric generation than any other area except Alberta. This may make it difficult to integrate as much wind capacity as some of those other areas, and policies such as Renewable Portfolio Standards (RPS) for the Maritimes sub-areas may have to be more conservative because of this. Current indications are that RPS programs could target 1000 MW within the next ten years for the Maritimes Area. This would constitute about 20 to 25% of the area 12-month coincident peak load.

While the load variability analysis in Chapter 5 of this study indicates that this may be achievable for the non run-off period it is highly unlikely that it could be accommodated without difficulty in the run-off period. On this basis it is recommended that a conservative approach be taken with regard to the RPS design for the Maritimes and limit the total capacity in the long term to no more than 1000 MW.

The spring run-off compromises the ability of the hydroelectric system to respond to load variability increases caused by wind generation. It is recommended that in the short term the Maritimes take a conservative and gradual approach to integrating wind generation. It is recommended that RPS targets be much lower (likely half or 500 MW) until additional studies can be undertaken to quantify the cost and operational magnitude of wind variability during the spring run-off period.

Finally, it is also recommended that the Maritimes may be able to integrate more wind capacity if the Maritimes Area becomes one balancing area (as opposed the current two sub areas) and if the New Brunswick System Operator (NBSO) finds opportunities to have the neighbouring power systems of Québec and New England assist the Maritimes with its load variability. While such assistance would have value throughout the year it is especially important during the spring run-off period.

7.0 SUMMARY OF RESULTS

Effective Capacity

- The average effective capacity of simulated wind projects in the NB Area (NB, PEI, and Northern Maine) was calculated for different scenarios. The average effective capacities were:
    - 66% - 2004 Maritimes with intra-area transfer limits
    - 73% - 2004 Maritimes without intra-area transfer limits
    - 60% - 2004 NB Area only
    - 49% - 2003 Maritimes with intra-area transfer limits

- The average effective capacity of simulated wind projects in Nova Scotia was calculated for different scenarios. The average effective capacities were:
    - 1% - 2004 Maritimes with intra-area transfer limits
    - 62% - 2004 Maritimes without intra-area transfer limits
    - 50% - 2004 Nova Scotia only

Impact of Wind Projects on Load Variability

- The 2004 load variability of the Maritimes, as well as the sub-areas, was measured as the standard deviation of the hourly load swing. The standard deviation results were:
    - NB Area - 82 MW
    - Nova Scotia - 59 MW
    - Maritimes - 123 MW

- The annual cost for a 1 MW increase in load variability as measured in this study is estimated to be $67,870.

- For 2004, it was shown that 400 MW of wind capacity at a single site increased the load variability significantly more than if it was distributed amongst several sites. These load variability increases for the Maritimes, as well as the sub-areas, were:

o NB Area	Single Site:	17.9%,	$1.00 million per year
	Five Sites:	4.5%,	$0.25 million per year
o Nova Scotia	Single Site:	31.1%	$1.25 million per year
	Three Sites:	13.0%	$0.52 million per year
o Maritimes	Single Site:	8.3%	$0.69 million per year
	Eight Sites:	1.5%	$0.13 million per year

- Using the 2004 data it appears that 1000 MW of wind capacity could be accommodated in the Maritimes Area if it is geographically dispersed and spring run-off conditions are ignored. In this analysis, the increase to load variability was 8.4% or 10.3 MW to the standard deviation of the hourly load swing at an annual estimated cost of $0.70 million.

Hydroelectric Capacity and Spring Run-Off Issues

- The installed hydroelectric generation capacity in the Maritimes is about 20%. The provinces of Newfoundland and Labrador, Québec, Manitoba, and British Columbia all have installed hydroelectric generation capacity totals that exceed 90%. Other areas are Ontario with 25%, Saskatchewan with 24%, and Alberta with 7%. Since the amount of hydroelectric capacity is an important factor with respect to the handling of the increased load variability due to wind generation, the Maritimes may not be able to integrate as much wind capacity as the areas with more hydroelectric generation.

- The spring run-off compromises the ability of the hydroelectric system to respond to load variability increases caused by wind generation. During this period wind load variability doubles, no hydro resources are available for load following, and the amount of thermally supplied load is halved. This significantly increases the impact of wind generation on load following requirements.

- This is predominantly a cost issue. Not only will it impact the commitment of thermal units it may force the deliberate spilling of hydro energy in order to free up hydro capacity for load following. This is an area that requires more study and should be considered as a detailed portion of a unit commitment analysis with varying levels of wind penetration.

- At this time, it is difficult to say how much wind capacity is too much. The Maritimes only has 46 MW of wind generation today, and that is not enough to properly judge the impacts of installing levels of wind capacity that are higher by an order of magnitude. The spring run-off compromises the ability of the hydroelectric system to respond to load variability increases caused by wind generation. It is recommended that in the short term the Maritimes take a conservative and gradual approach to integrating wind generation. It is recommended that RPS targets be much lower (likely half of current projections or 500MW) until additional studies can be undertaken to quantify the cost and operational magnitude of wind variability during the spring run-off period.

8.0 SUMMARY OF RECOMMENDATIONS

Effective Capacity

- It is recommended that wind projects in the NB Area be credited with a capacity equal to their winter capacity factor.
- It is recommended that wind projects in Nova Scotia be credited with a capacity equal to their winter capacity factor.

Impact of Wind Projects on Load Variability

- To integrate significant wind project capacity in the Maritimes, it is recommended that the developed capacity be split up amongst several sites, and that these sites have a good geographic separation in order to minimize costs associated with increased load variability.
- It is recommended that the Maritimes may have to charge wind projects for increasing the local load variability should scenarios develop where the project's wind energy is being sold outside of the local area, but local area load customers are absorbing increased load variability cost due to the wind project.
- It is recommended that efforts to develop significant wind project capacity in the Maritimes should include a plan to manage load variability on a Maritime basis versus having each sub-area manage its own.

Hydroelectric Capacity and Spring Run-Off Issues

- It is recommended that a conservative approach be taken with regard to the RPS design for the Maritimes to recognize that the Maritimes does not have the same quantity of flexible hydroelectric generation as do most other areas of Canada, with the exception of Alberta.
- It is recommended that the Maritimes take a gradual approach to integrating wind generation so that the costs associated with load variability increases experienced during the spring run-off are better understood.
- It is recommended that the Maritimes may be able to integrate more wind capacity if the New Brunswick System Operator (NBSO) finds opportunities to have the neighbouring power systems of Québec and New England assist the Maritimes with its load variability during the spring run-off.