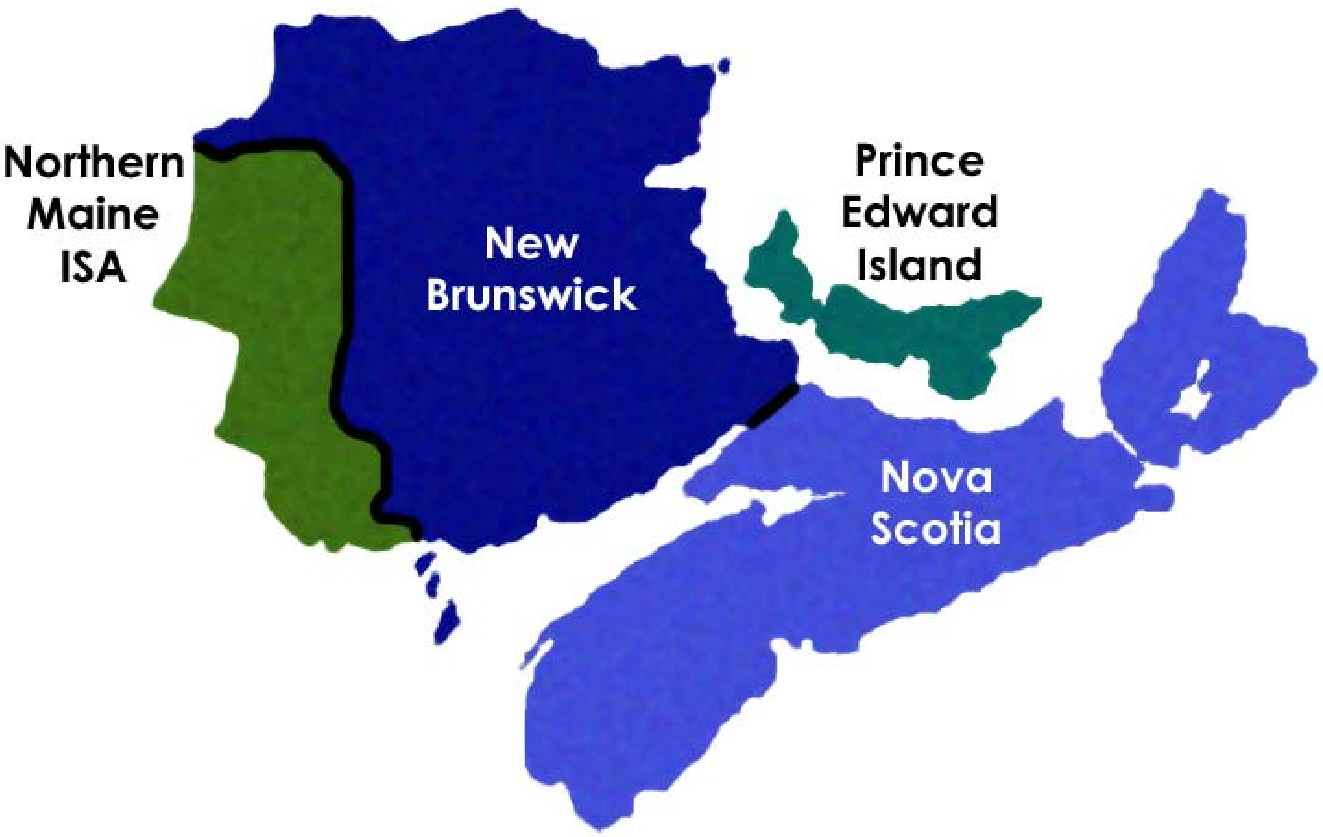
Approved by the RCC
March 5, 2008

NPCC
2007 MARITIMES AREA
COMPREHENSIVE REVIEW OF RESOURCE ADEQUACY



NEW BRUNSWICK SYSTEM OPERATOR
NOVA SCOTIA POWER INCORPORATED
MARITIME ELECTRIC COMPANY LIMITED
NORTHERN MAINE ISA, INC.

December 2007

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1.0 EXECUTIVE SUMMARY

The 2007 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2008 through December 2012, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for the review are specified in the NPCC Document B-8 entitled, "*Guidelines for Area Review of Resource Adequacy*" (Revised: November 29, 2005). This review supplants the previous Comprehensive Review that was performed in 2004 and approved by the RCC on March 9, 2005.

Table 1 provides a summary of the Major Assumptions and Results of this review.

Table 1: Summary of Major Assumptions and Results

MAJOR ASSUMPTIONS			
Load Forecast	NBSO 2007 NS Power 2007 MECL 2007 NMISA 2007		
Load Shape (all years)	2006/07		
Resource Adequacy Criterion	Loss of Load Expectation less than or equal to 0.1 days/year		
Maritimes Required Reserve	20% of peak firm load		
Inter-Area Transmission Capacity Limits	Path	Export Limit (MW)	Import Limit (MW)
	NBSO to NS Power	300	350
	NBSO to MECL	222	124
	NBSO to NMISA	100	90
Maritimes Unit Data	Appendix A – Table A-2 (by system operator)		

RESULTS		
Year	**Expected Number of Firm Load Disconnections Days/year**	**Interconnection Support to meet Criterion (0.1 Days/year) MW**
2008	0.019	0
2009	0.086	0
2010	0.015	0
2011	0.003	0
2012	0.001	0

The Maritimes Area is a winter peaking area that includes the New Brunswick System Operator (NBSO), Nova Scotia Power Inc. (NS Power), Maritime Electric Company Ltd. (MECL), and the Northern Maine Independent System Administrator, Inc (NMISA). MECL supplies the province of Prince Edward Island.

The Maritimes Area's combined load forecast for this review consists of the NBSO, NS Power, MECL, and NMISA 2007 forecasts. The coincident peak forecast for 2008 is 5524 MW, which is 304 MW below the 5828 MW forecast in the 2004 review. This reduced load forecast reflects significant load decreases in the forestry industry and pulp and paper industry due to mill closures, slower customer load growth in reaction to higher charges for electricity, and government sponsored energy efficiency programs. The average annual demand growth over the 2008-12 study period of this review is 0.88%, which is lower than the 1.49% annual demand growth forecast in the 2004 review.

The reserve criterion for the Maritimes Area is 20%, and adherence to this criterion is demonstrated to comply with the NPCC reliability criterion. The NPCC reliability criterion of less than 0.1 days of firm load disconnections per year is not exceeded by the Maritimes Area for all years in the 2008-12 study period, and varies between 0.001 to 0.086 days/yr for the base load forecast with load forecast uncertainty. The Maritimes Area requires no support from its interconnections to meet the NPCC reliability criterion for all years of the study period. The Maritimes Area is also shown to adhere to its own 20% reserve planning criterion in all years for the base load forecast, with reserve levels varying between 22% and 40%.

For the high load forecast sensitivity, the Maritimes Area exceeds its 20% reserve criterion for all years, varying between 21% and 35%.

An additional sensitivity was performed in which the credit for wind project capacity in the Maritimes Area was set to zero. This still resulted in the Maritimes Area exceeding its 20% reserve criterion in all years except 2009 where its reserve margin was 19%, 35 MW short of the 20% criterion. This shortfall represents only 2.1% of the Maritimes Area tie benefits capability. The results of this sensitivity demonstrate that the Maritimes Area is not overly reliant on wind capacity in order to meet its 20% reserve planning criterion.

A second 345 kV tie between New Brunswick and New England has been commissioned as of Dec. 5, 2007. This second tie increases the import capability of the Maritimes Area from 1100 MW to 1650 MW. The export capability from the Maritimes Area to New England also increases from 700 MW to 1000 MW.

Wind project capacity was modeled in this interim review based upon results from the Sept. 21, 2005 NBSO report "Maritimes Wind Integration Study". (

http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf) This report showed that the effective capacity from wind projects, and their contribution to Loss of Load Expectation, was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production.

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3.0 INTRODUCTION

The 2007 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2008 through December 2012, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for the review are specified in the NPCC Document B-8 entitled, "*Guidelines for Area Review of Resource Adequacy*" (Revised: November 29, 2005). This review supplants the previous Comprehensive Review that was performed in 2004 and approved by the RCC on March 9, 2005.

The Maritimes Area is a winter peaking area that includes the New Brunswick System Operator (NBSO), Nova Scotia Power Inc. (NS Power), Maritime Electric Company Ltd. (MECL), and the Northern Maine Independent System Administrator, Inc (NMISA). MECL supplies the province of Prince Edward Island.

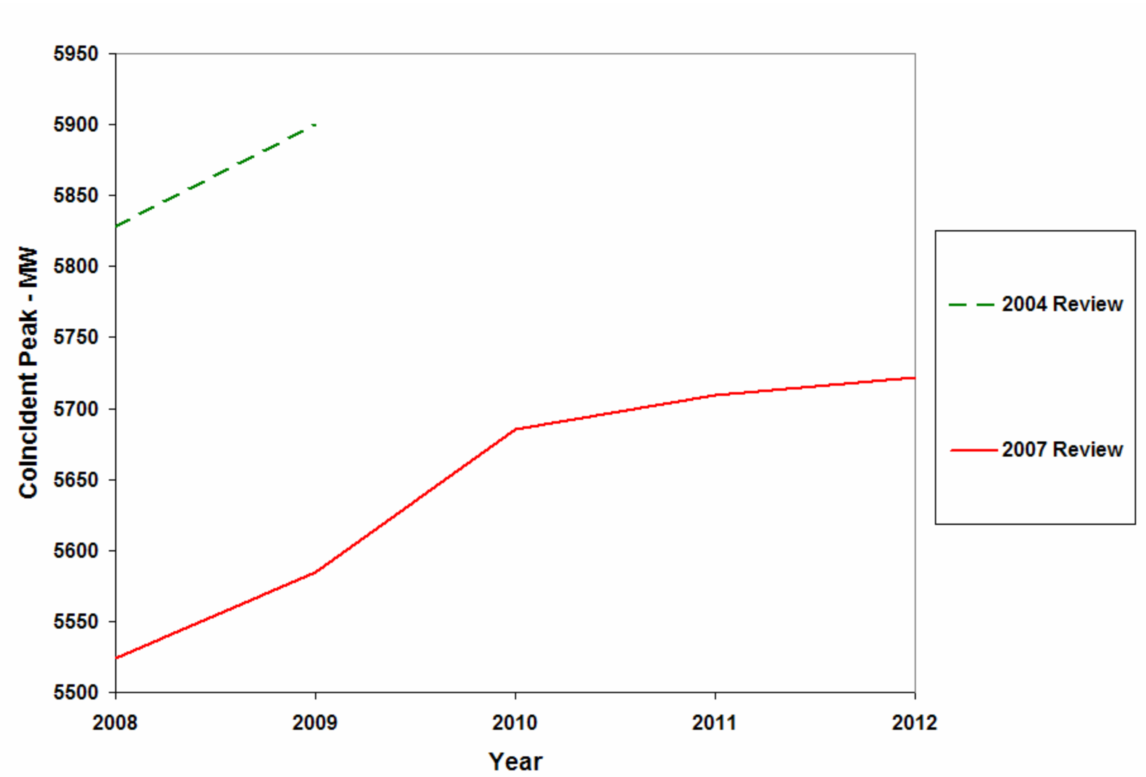
Table 2 and Figure 1 provide a comparison of the load forecasts in the 2004 and 2007 reviews. The coincident peak forecast for 2008 is 5524 MW, which is 304 MW below the 5828 MW forecast in the 2004 Comprehensive Review. This reduced load forecast reflects significant load decreases in the forestry industry and the pulp and paper industry due to mill closures, slower customer load growth in reaction to higher charges for electricity, and government sponsored energy efficiency programs. The average annual growth in demand over the study period of this review is 0.88%, which is lower than the 1.49% annual demand growth forecast in the 2004 review.

A capacity reserve criterion for the Maritimes Area is described in 4.3 and adherence to this criterion is demonstrated in 5.1 for both base case and high load forecasts. Further, this reserve capacity criterion is shown to comply with the NPCC reliability criterion in 4.4.

Table 2: Comparison of Load Forecasts

Winter Peak (Month of February)	**2007 Review MW**	**2004 Review MW**
2008	5524	5828
2009	5585	5900
2010	5685	N/A
2011	5709	N/A
2012	5722	N/A
Five Year Period	**2008 - 2012**	**2005 - 2009**
Growth Rate	0.88%	1.49%

Figure 1: Comparison of Load Forecasts



4.0 RESOURCE ADEQUACY CRITERION

4.1 Statement of Resource Adequacy Criterion

NBSO, NS Power, and MECL individually apply a capacity based criterion in determining their required reserve. NMISA does not apply a capacity based criterion beyond the NPCC reliability criterion.

NBSO and NS Power each require a reserve equal to the largest unit or 20% of the firm load, and MECL requires a reserve equal to 15% of the firm system load. As a simplification, the Maritimes Area as a whole was assumed to have the same criterion as NBSO and NS Power because of the relatively small sizes of MECL and NMISA relative to NBSO and NS Power combined. Thermal and hydro generators are considered available at the Demonstrated Maximum Net Capability (DMNC) in the determination of the reserve margin.

The NPCC Generation Reliability criterion states (from *NPCC Document A-2, Basic Criteria for Design and Operation of Interconnected Power Systems, May 6, 2004*):

Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

In effect, this criterion is applied as less than 0.1 days of firm load disconnections per year.

4.2 Emergency Operating Procedures

Although this document presents a review of resource adequacy for the interconnected Maritimes Area, each separate system remains under the exclusive control of its system operator for purposes of economic dispatch. For reliability purposes, however, reserve sharing agreements do exist and the systems operate as an Area in accordance with NPCC criteria and guidelines.

The particular actions taken by the Energy Coordinator/Dispatcher when faced with a developing or sudden capacity shortage are based upon the assessment of which of a number of possible actions are best suited to the prevailing system conditions. The actions initiated are based upon previous experience in dealing with similar situations and, if the situation permits, usually after consultation with other System Operations personnel similarly experienced in this regard. In practice, the corrective actions that are taken are one or more of the following Emergency Operation Procedures (EOP):

1. Synchronize and load all available hydro units.

2. Bring on-line units up to their DMNC.

3. Cancel economy and other external interruptible sales.

4. Begin start-up procedures for "cold-standby" thermal units.

5. Synchronize and load combustion turbines.

6. Purchase capacity from Hydro-Quebec.

7. Purchase capacity from New England.

8. Cut interruptible sales to industrial customers.

9. Maximize MVAR support (capacitor banks, synchronous condensers) if capacity shortage is causing a low voltage condition in a particular area.

10. Implement a 5% voltage reduction at selected substations within Nova Scotia (1-5 MW)

11. Load up thermal units to emergency ratings. (40 MW)

12. Appeal to the public for voluntary customer load reduction.

13. Disconnect customer loads as necessary to correct either a local or widespread problem.

Some or all of the above steps may be used in varying sequence to meet a capacity shortage depending on the generation pattern in effect at the time and whether or not the shortage results in localized internal system problems.

Although steps 10 through 12 are valid, the level of assistance available from these procedures is not modeled in this study.

4.3 Maritimes Area Required Reserve

The Area employs a reserve criterion of 20% of firm load with the understanding that the interconnection assistance is potentially available if required. The required installed reserve is shown in Section 5.0.

4.4 Relationship of Reserve Criterion to NPCC Reliability Criterion

In order to relate the Maritimes Area reserve criterion to the NPCC resource adequacy criterion as stated in Section 4.1, it is necessary to evaluate the system at a time when it just meets the reserve criterion.

The evaluation shows that for the Maritimes Area, isolated from all other systems, a reserve of 20% corresponds to an expected number of firm load disconnections of approximately 0.142 days/year. The NPCC criterion of 0.1 days/year expected number of customer disconnections as stated in Section 4.1 allows for the inclusion of the effects of interconnections.

When the Maritimes Area has a reserve of 20% with the interruptible load removed, approximately 50 MW of interconnection assistance is required in order to meet the NPCC criterion. This represents only 3.0% of the normal import capabilities with Quebec (1100 MW) and New England (550 MW*). In addition, NB Power is supplying 200 MW of system peaking capacity to Hydro Quebec tied to the availability of the Millbank combustion turbine (CT) units. Between January 2008 and November 2011, two of the Millbank CT's have not been included in this study to account for this capacity export. However, this arrangement has the effect of increasing the total interconnection capability between Hydro Quebec and New Brunswick by an additional 200 MW. The 2005 NPCC report "Review of Interconnection Assistance Reliability Benefits – 2nd Tie Addendum" confirmed that the Maritimes Area has a Maximum Tie Benefit Potential equal to its import capability.

As a result of the preceding, it is concluded that the reserve criterion of the Maritimes Area meets the NPCC Resource Adequacy Criterion.

* The 550 MW import capability from New England into New Brunswick is conditionally firm depending on the generating status of units in Maine. The unconditional firm import capability from New England to New Brunswick is 300 MW.

4.5 Recent Reliability Studies

NBSO, NS Power, MECL, and NMISA individually conduct internal reviews of their capacity requirements by comparison of generation sources with forecast loads according to the reserve criterion described previously.

The results presented in this review are based upon an evaluation conducted during the fourth quarter of 2007 for the period 2008 through 2012.

To determine load forecast uncertainty (LFU) an analysis of the historical load forecast of the Maritimes Area utilities has shown that the standard deviation of the load forecast errors is approximately 4.6% based upon the four year lead time required to add new resources. To incorporate LFU, two additional load models were created from the base load forecast by increasing it by 4.6 and 9.2 percent respectively. The reliability analysis was repeated for these two load models.

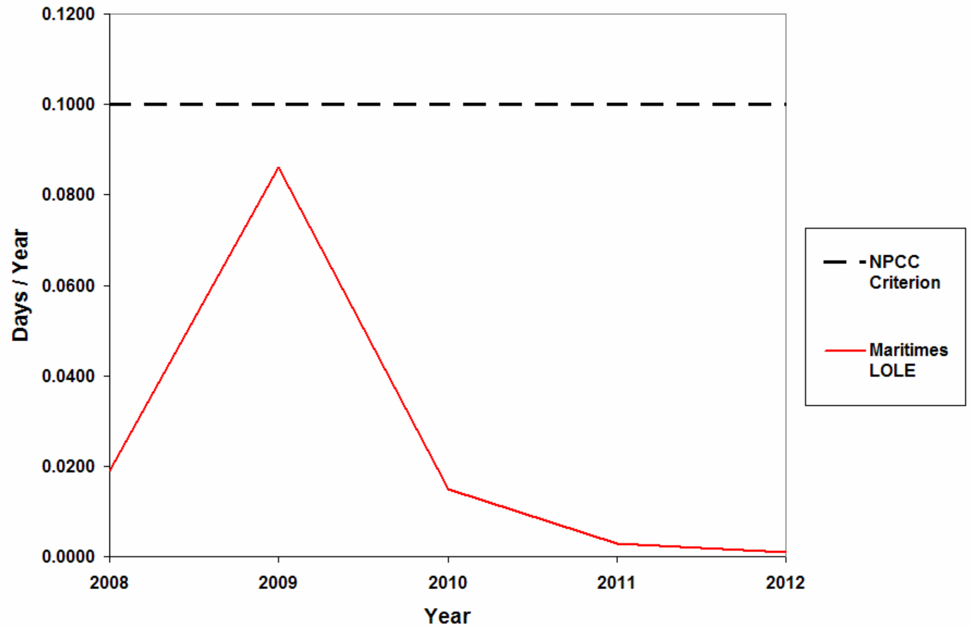
It is assumed that the forecast error is approximately normally distributed around the forecast value, and that the contribution to system LOLE is negligible when loads are less than the forecast value by more than ½ standard deviation. This results in weighting factors of 0.383, 0.242, and 0.067 for the three results obtained using the base, 4.6 percent increased, and 9.2 percent increased load models respectively.

The results of the LFU evaluation as indicated in Table 3 and Figure 2 demonstrate that the Maritimes Area system meets the NPCC criterion of 0.1 days/year without interconnection assistance for all years of the 2008-12 study period.

Table 3: Expected Number of Firm Load Disconnections – Base Case with Load Forecast Uncertainty

Calendar Year	Expected Number Of Firm Load Disconnections days/year	Interconnection Support to meet Criterion (0.1 days/year) MW
2008	0.019	0
2009	0.086	0
2010	0.015	0
2011	0.003	0
2012	0.001	0

Figure 2: Expected Number of Firm Load Disconnections



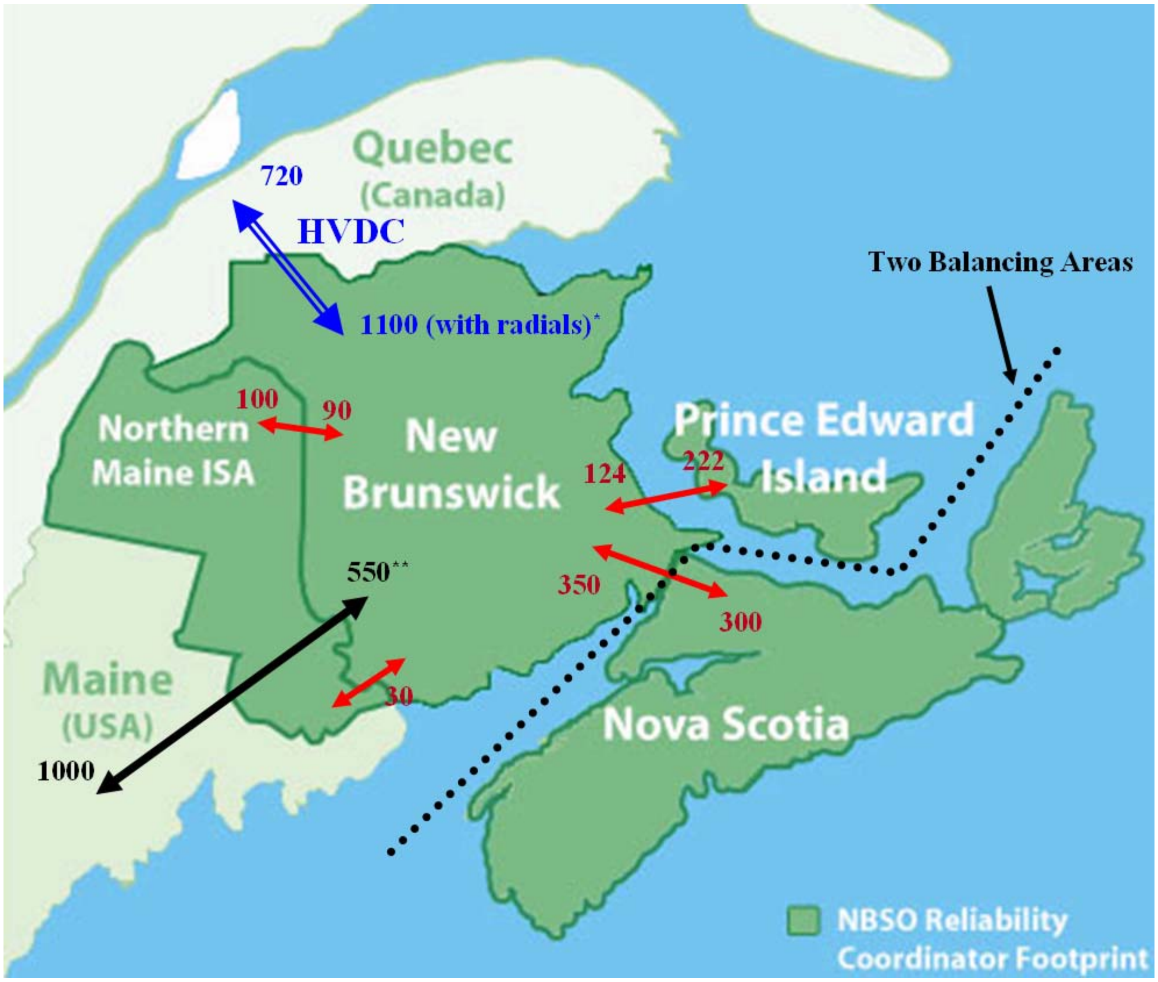
4.6 Intra-Area Transmission Capacity Limits

Within the Maritimes Area, the areas of Nova Scotia, PEI, and Northern Maine are radially connected only to New Brunswick as per Figure 3. Of these three interconnections, only between New Brunswick and Nova Scotia is there a transmission congestion issue.

PEI does not have enough installed generation above its minimum load to exceed the transfer rating to New Brunswick. The PEI firm peak load is also lower than the transfer rating from New Brunswick.

Northern Maine does not have enough installed capacity (158 MW in 2008) to generate an amount greater than the sum of the local load and the interconnection export rating (at least 160 MW). The Northern Maine peak load is also much lower than the thermal limits of the four lines (two 138 kV and two 69 kV) connecting Northern Maine to New Brunswick. The 100 MW transfer limit into Northern Maine is set to guard against a transmission contingency during high imports, but this limit could be exceeded if it were necessary to prevent a loss of load event. Therefore, the 100 MW limit on flows from New Brunswick to Northern Maine was not enforced in the analysis conducted in this review.

Figure 3: Intra-Area Transmission Capacity Limits



* The radial load that can be supplied from Québec includes a paper mill in Dalhousie, NB whose load is about 100 MW. The owner of this mill, AbitibiBowater Inc. announced in November 2007 that this mill will be shut down soon, resulting in a 100 MW load decrease for New Brunswick as well as a reduction of import capability from Québec (from 1100 MW to 1000 MW).

** The 550 MW import capability from New England into New Brunswick is conditionally firm depending on the generating status of units in Maine. The unconditional firm import capability from New England to New Brunswick is 300 MW.

5.0 RESOURCE ADEQUACY ASSESSMENT

5.1 Comparison of Planned and Required Reserve – Base Case

In the comparison of the planned and required reserve, the following definitions apply. The required reserve of 20% is the reserve criterion of the Maritimes Area. The planned reserve is the actual reserve that will occur for the load forecast and resource plan used in this study.

Table 4 and Figure 4 represent the results of the reserve comparison for the base load forecast. In each year of the analysis, the planned reserve is greater than the required reserve.

Table 4: Comparison of Planned and Required Reserve - Base Load Forecast

Month Of February	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2008	6662	5524	521	1659	33%	1001	20%
2009	6171	5585	523	1109	22%	1012	20%
2010	6924	5685	556	1795	35%	1026	20%
2011	7013	5709	561	1865	36%	1030	20%
2012	7245	5722	565	2088	40%	1031	20%

5.2 Comparison of Planned and Required Reserve – High Load Growth

Table 5 and Figure 4 illustrate the changes in planned and required reserve if the annual growth rate is 1% higher than forecast (i.e. 1.88% per year versus 0.88% per year). The results show that the resource plan of the Maritimes Area is sufficient to maintain a reserve of 20% or greater for all years of the study period.

Table 5: Comparison of Planned and Required Reserve - High Load Growth

Month Of February	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2008	6662	5524	521	1659	33%	1001	20%
2009	6171	5628	523	1066	21%	1021	20%
2010	6924	5734	556	1746	34%	1036	20%
2011	7013	5841	561	1733	33%	1056	20%
2012	7245	5951	565	1859	35%	1077	20%

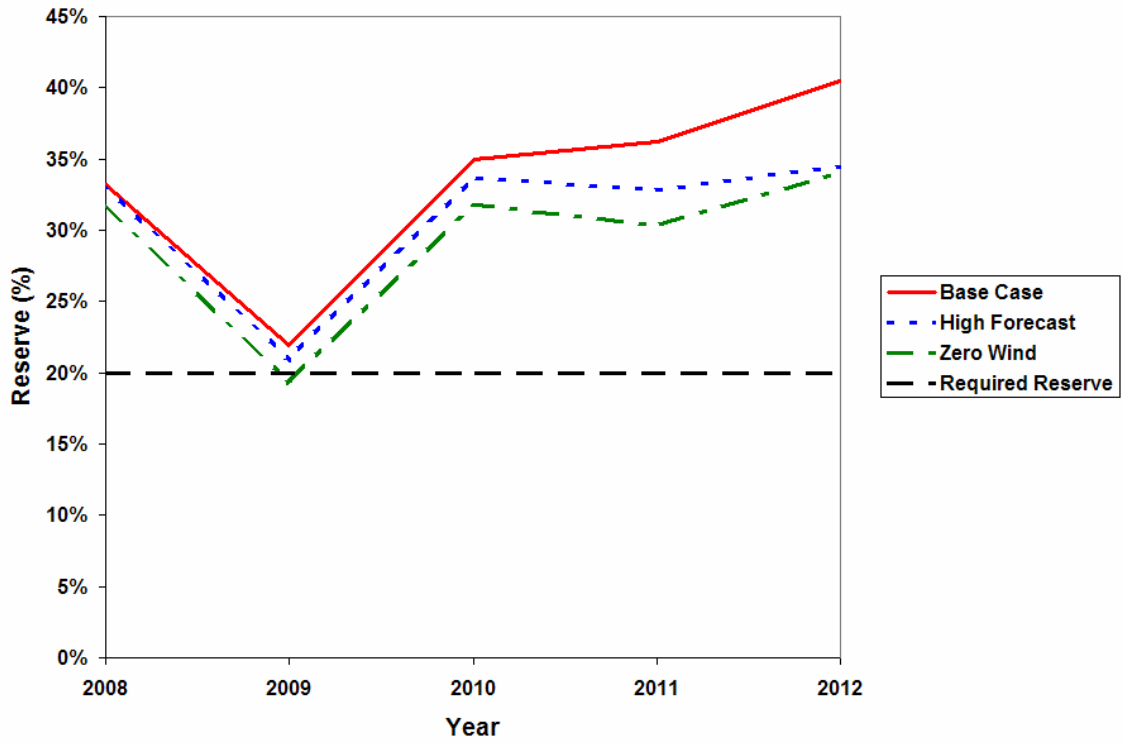
5.3 Comparison of Planned and Required Reserve – Zero Wind

In order to determine the impact of wind capacity in allowing the Maritimes Area to achieve its required reserve, a sensitivity was performed whereby the wind capacity on the system was given a zero capacity credit. Table 6 and Figure 4 illustrate the planned and required reserve for the zero wind capacity credit scenario. The results show that Maritimes Area exceeds its 20% reserve criterion in all years except 2009 where its reserve margin is 19%, 35 MW short of the 20% criterion. This shortfall represents only 2.1% of the Maritimes Area total tie benefits capability. The conclusion from this sensitivity is that the Maritimes Area is not overly reliant on wind capacity in order to achieve its 20% reserve criterion.

Table 6: Comparison of Planned and Required Reserve - Zero Wind

Month Of February	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2008	6597	5524	521	1594	32%	1001	20%
2009	6039	5585	523	977	19%	1012	20%
2010	6764	5685	556	1635	32%	1026	20%
2011	6712	5709	561	1564	30%	1030	20%
2012	6915	5722	565	1758	34%	1031	20%

Figure 4: Planned Versus Required Reserve



5.4 Contingency Plans

The Maritimes Area utilities forecast high and low load growth scenarios, and the impact of these forecasts on the system operator generation scenarios are continually being evaluated in order to address load and resource uncertainties. In the event of a higher than expected growth in load, a number of options would be considered. These options include the purchases of capacity and/or energy, the advancement of base load generation additions, and the installation of combustion turbines.

6.0 PLANNED RESOURCE CAPACITY MIX

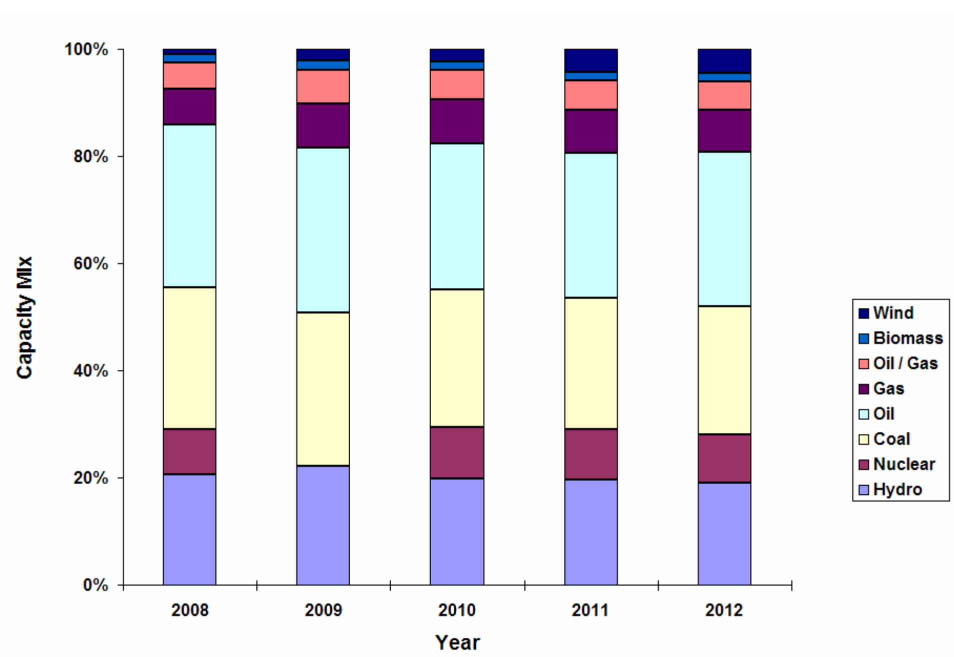
6.1 Planned Resource Capacity Mix

Table 7 and Figure 5 illustrate the planned resource capacity mix for the Maritimes Area. Appendix A, Section 1.2, Table A-2 presents a detailed list of all capacity resources for the Maritimes Area.

Table 7: Planned Resource Capacity Mix

Month Of February	Hydro %	Nuclear %	Coal %	Oil %	Gas %	Oil / Gas %	Biomass %	Wind %
2008	20.6	8.4	26.5	30.4	6.8	4.8	1.6	1.0
2009	22.2	0.0	28.6	30.7	8.4	6.3	1.7	2.1
2010	19.9	9.5	25.6	27.3	8.2	5.6	1.5	2.3
2011	19.6	9.4	24.6	27.0	8.1	5.5	1.5	4.3
2012	19.0	9.1	23.9	28.8	7.9	5.3	1.4	4.6

Figure 5: Planned Resource Capacity Mix



6.2 Reliability Impact of Resource Diversification Strategy

As can be seen from Table 7 and the associated Figure 5, the Maritimes Area has a diversified mix of resources such that there is not a high degree of reliance upon any one type or source of fuel. As a result of this level of fuel type and resource diversification, there are no adverse reliability impacts resulting from this resource capacity mix, nor are there any environmental restrictions.

The Maritimes Area continues to see an increase in wind energy projects. PEI currently has 73 MW of wind capacity. Northern Maine has 42 MW of wind capacity, and is studying the possibility of adding another 500 MW. NS Power has 60 MW of wind capacity, and has launched a call for an additional 130 MW. New Brunswick has contracted for 96 MW of wind capacity by December 2008, and has launched a call for an additional 300 MW by November 2010.

As a result of the second 345 kV interconnection between New Brunswick and New England, the Maritimes Area has increased its import capability by 550 MW, and its export capability by 300 MW. It is also of benefit to both the Maritimes Area and New England that this increased transfer capability is between systems that have peak loads occurring at different times of the year, with the Maritimes Area being a winter peaking area, and New England being a summer peaking area.

APPENDIX A DESCRIPTION OF RESOURCE RELIABILITY MODEL

DESCRIPTION OF RESOURCE RELIABILITY MODEL

1.0 Load Model

1.1 After reviewing historical hourly system load data of the Maritime utilities, it was determined that the 1999 system load data provided a typical Maritimes Area load shape. Demand and energy forecasts for 2005 to 2009 inclusive were prepared by each system operator. The combined load forecast for the Maritimes Area is shown in Table A-1.

Table A - 1: Maritimes Area Load Forecast

COINCIDENT DEMAND MW													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Peak**
2008	5386	5524	5087	4399	3807	3507	3606	3538	3611	4173	4675	5363	5524
2009	5479	5585	5076	4479	3980	3675	3684	3641	3648	4234	4722	5406	5585
2010	5622	5685	5213	4585	4084	3755	3791	3749	3755	4350	4852	5530	5685
2011	5653	5709	5242	4607	4104	3774	3814	3772	3778	4376	4878	5557	5709
2012	5673	5722	5261	4619	4115	3785	3829	3787	3792	4392	4896	5575	5722
ENERGY GWh													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2008	3124	2855	2869	2491	2321	2112	2146	2181	2191	2423	2643	3075	30432
2009	3196	2937	2940	2564	2394	2201	2218	2252	2217	2458	2660	3089	31124
2010	3232	2972	2975	2595	2424	2229	2247	2281	2245	2487	2692	3124	31503
2011	3243	2982	2985	2605	2433	2238	2257	2290	2254	2498	2701	3135	31621
2012	3248	2987	2990	2608	2437	2241	2262	2295	2257	2502	2705	3139	31670
INTERRUPTIBLE DEMAND MW													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**On Peak**
2008	500	521	494	516	535	520	540	548	542	538	520	522	521
2009	483	523	499	504	529	518	541	547	527	539	525	522	523
2010	515	556	531	536	561	551	574	580	561	572	557	554	556
2011	520	561	536	541	566	556	579	586	566	577	562	559	561
2012	524	565	539	545	570	560	583	590	571	581	567	563	565

Note: The forecast coincident demand is higher in February than January due to the impact of historical curtailments of interruptible customers in January. These historical curtailments are also reflected in the interruptible demand forecast, where January interruptible demand is shown to have the lowest value for each year.

Load forecast uncertainty (LFU) was considered in the analysis as described in Section 4.5

1.3 Some entities within the Maritimes Area supply a portion of their own electricity demand and energy requirements. These entities are interconnected within the Maritimes Area and are not members of the Area. Only that portion of electricity demand and energy projections that is supplied by the Maritimes Area utilities is included in the area forecast.

1.4 The load forecast in Table A-1 includes the impact of DSM and efficiency programs.

2.0 Resource Unit Representation

Generating unit data for the four members of the Maritimes Area are presented in Table A-2. Table A-3 presents a summary of changes in resource data for the period 2005 - 2009 inclusive. The following sections document the tabulated data.

2.1 Unit Ratings

2.1.1 Definition

The generating unit capacity ratings represented in Table A-2 are the Demonstrated Maximum Net Capability (DMNC) winter ratings. These are evaluated periodically to establish each unit's sustained maximum net output over a two consecutive hour period.

2.1.2 Procedure for Verifying Ratings

Ratings of NBSO units are reviewed annually by the Generation Efficiency Section of the NB Power Generation (Conventional) Plant Operations Engineering Division in conjunction with System Operations. Data obtained from unit testing and from the generation reliability system is used in conducting these reviews. The Thermal Production Department at NS Power review unit capability ratings on an as-needed basis. As unit conditions change the impact on unit capability is assessed and, if required, a 2-hour test with the unit at full load is performed.

Table A - 2: Maritimes Area Resources

NBSO Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Point Lepreau	1	Nuclear	558	Planned 18-month Refurbishment in April 2008
		Diesel	5	
Belledune	2	Coal	457	
Coleson Cove	1	Oil	324	
	2	Oil	324	
	3	Oil	324	
Dalhousie	1	Oil	96	
	2	Oil	203	
Bayside	6	Natural Gas	263	Capacity includes Combined Cycle Operation
Grand Lake	8	Coal	57	
Grand Manan	3	Diesel	29	
Millbank	1	Diesel	99	Summer Capacity = 85 MW
	2	Diesel	99	Summer Capacity = 85 MW
	3	Diesel	see note	Modeled as Tied to Sale Contract Until Nov 2011
	4	Diesel	see note	Modeled as Tied to Sale Contract Until Nov 2011
Ste Rose	1	Diesel	99	Summer Capacity = 85 MW
Grandview	1	Natural Gas	45	
	2	Natural Gas	45	
NUG Purchases		Biomass/Hydro	59	
Mactaquac	1	Hydro	109	
	2	Hydro	109	
	3	Hydro	109	
	4	Hydro	116	
	5	Hydro	113	
	6	Hydro	113	
Beechwood	1	Hydro	36	
	2	Hydro	36	
	3	Hydro	41	
Grand Falls	1	Hydro	16	
	2	Hydro	16	
	3	Hydro	16	
	4	Hydro	16	
Tobique	1	Hydro	10	
	2	Hydro	10	
Sisson	1	Hydro	9	
Milltown	1	Hydro	4	
TOTAL CAPACITY			**3976**	Total Capacity as of January 2008

Table A – 2: Maritimes Area Resources (cont'd)

NS Power Resources				
Plant	**Unit**	**Type**	**Capacity (MW)**	**Notes**
Tufts Cove	1	Gas/Oil	81	
	2	Gas/Oil	93	
	3	Gas/Oil	147	
	4	Natural Gas	49	Summer Capacity = 47 MW
	5	Natural Gas	49	Summer capacity = 47 MW
Lingan	1	Coal	155	
	2	Coal	155	
	3	Coal	155	
	4	Coal	155	
Pt. Tupper	2	Coal	154	
Trenton	5	Coal	150	Summer Capacity = 135 MW
	6	Coal	157	
Pt. Aconi	1	Coal	171	
Burnside	1	Lt Oil	33	Summer Capacity = 25 MW
	2	Lt Oil	33	Summer Capacity = 25 MW
	3	Lt Oil	33	Summer Capacity = 25 MW
	4	Lt Oil	33	Summer Capacity = 25 MW
Victoria Junction	1	Lt. Oil	33	Summer Capacity = 25 MW
	2	Lt. Oil	33	Summer Capacity = 25 MW
Tusket	1	Lt. Oil	24	Summer Capacity = 21 MW
Wreck Cove	1	Hydro	115	
	2	Hydro	115	
Annapolis		Hydro	4	
Avon		Hydro	7	
Black River		Hydro	23	
Nictuax		Hydro	7	
Lequille		Hydro	11	
Paradise		Hydro	5	
Mersey		Hydro	43	
Sissiboo		Hydro	24	
Bear River		Hydro	13	
Tusket		Hydro	2	
Roseway		Hydro	2	
St. Margrets		Hydro	11	
Sheet Harbour		Hydro	11	
Dickie Brook		Hydro	4	
Fall River		Hydro	1	
NUG Purchases	All	Biomass/Hydro	26	
NS Wind Projects	All	Wind	23	66 MW Nominal Rating, Winter Firm Capacity = 23 MW, Summer Firm Capacity = 12 MW
TOTAL CAPACITY			**2340**	Total Capacity as of January 2008

Table A – 2 Maritimes Area Resources (cont'd)

MECL Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Charlottetown	6	Oil	5	
	7	Oil	7	
	8	Oil	10	
	9	Oil	19	
	10	Oil	19	
	11	Diesel	49	
Borden	1	Diesel	15	Summer Capacity = 12 MW
	2	Diesel	25	Summer Capacity = 20 MW
Summerside Diesel		Diesel	10	Owned by the city of Summerside
PEI Wind	All	Wind	29	73 MW Nominal Rating, Winter Firm Capacity = 29 MW, Summer Firm Capacity = 26 MW
TOTAL CAPACITY			**188**	Total Capacity as of January 2008

Note: MECL Resources include a 20 MW ownership in the Dalhousie Plant and a 30 MW participation in Point Lepreau. These units are NBSO units and are shown in the NBSO resources.

Table A – 2 Maritimes Area Resources (cont'd)

NMISA Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Tinker		Hydro Diesel	35 1	
Caribou Oil		Oil	23	
Caribou		Diesel Hydro	7 1	
Boralex – Ashland (FF)		Wood	30	
Boralex – Ashland (AEI)		Wood	37	
Squa Pan		Hydro	1	
Flo's Inn		Diesel	4	
Loring		Diesel	6	
NMISA Wind	All	Wind	13	42 MW Nominal Rating, Winter Firm Capacity = 13 MW, Summer Firm Capacity = 8 MW
TOTAL CAPACITY			158	Total Capacity as of January 2008

Table A - 3: Summary of Changes in Capacity

Year	January Capacity MW	December Capacity MW	Capacity Change MW	Explanation
2008	6662	6104	-558	Point Lepreau Refurbishment begins April 2008 (-558)
2009	6104	6829	+725	Point Lepreau Refurbishment ends October 2009 (+658), NB Wind (+38 firm), NS Wind (+29 firm)
2010	6829	6924	+95	Lingan 2 (+5), Lingan 4 (+5), Tuft's Cove 6 (+150), Tuft's Cove 4 (-49), Tuft's Cove 5 (-49), NS Hydro (+5), NS Wind (+28 firm)
2011	6924	7211	+287	Millbank Capacity Contract to HQ expires (+198), Grand Lake retired (-57), NB Wind (+122 firm), Lingan 3 (+5), NS Wind (+19 firm)
2012	7211	7245	+34	Lingan 1 (+5), NS Wind (+29 firm)

2.2 Unit Unavailability Factors

2.2.1 Types of Unavailability Factors Represented

The types of unavailability factors represented in this reliability assessment are forced outages and planned outages. Forced outages include unplanned maintenance outages, deferrable forced outages, starting failure outages and unit deration adjustments. All except planned outages are included in the Forced Outage Rates (FORs) presented in Table A-4. Planned outages are scheduled manually for the reliability program based upon projected maintenance schedules.

New Brunswick forced outage rates are calculated as per MP-12-A – Criteria and Considerations in the Determination and Certification of Eligible Installed Capacity and Eligible Unforced Capacity (http://www.nbso.ca/Public/_private/MP-12-A.pdf). The calculation in this Market Procedure is consistent with the DAFOR (derating adjusted forced outage rate) calculation in IEEE Standard 762-2006, Section 8.17.4.

Nova Scotia Power Inc. (NSPI) uses the DAFOR (derating adjusted forced outage rate) calculation for forced outage rates as in IEEE Standard 762-2006, Section 8.17.4. NSPI maintains a database of combustion turbine and fossil unit reliability and performance data and is a contributing utility to the Canadian Electricity Association Equipment Reliability Information System (CEA-ERIS). The CEA-ERIS also calculates DAFOR using the industry standard definition as per IEEE 762-2006.

The forced outage rates for the smaller PEI and Northern Maine systems are modeled using forced outage rates for units of similar size and fuel type in New Brunswick and Nova Scotia. Most of the small diesel and oil units in these systems operate less than 100 hours per year, and statistics necessary for calculating their DAFOR values are not available. The modeled FOR values for generators in these systems are between 5 – 7 %.

2.2.2 Source of Unavailability Factors

Forced Outage Rates for existing units are based on actual outage data as well as on data of similar sized units as compiled by the Canadian Electricity Association (CEA).

FORs for new units are based upon the utilities' experience with similar units in conjunction with averages compiled by the Canadian Electricity Association (CEA).

2.2.3 Maturity Considerations

Immature FORs were not used in this evaluation.

2.2.4 Tabulation of Forced Outage Rates

The ranges of FORs used in the assessment are tabulated in Table A-4. These values are consistent with those used in the business plans of the Maritimes Area utilities and reflect the results of maintenance and operational strategies.

Table A - 4: Maritimes Area Forced Outage Rates

Unit Type	Forced Outage Rate %	
	2007 Review	**2004 Review**
Hydro	1 - 5	1 - 8
Nuclear	4	5
Coal	2 – 28*	2 - 8
Oil	4 - 10	5 - 10
Natural Gas	3 - 4	3 - 10
Oil / Gas	2**	2 - 10
Biomass	3	3 - 5
Wind (after deration)	1	N/A

* Only one coal generator had a forced outage rate as high as 28%. All other coal generators had forced outage rates at 4% or less.

** Some of the oil/gas generation in the 2004 review appears as just oil in the 2007 review. This reclassification accounts for the forced outage rate improvement for this category.

2.3 Purchase and Sale Representation

Purchases and sales are represented as an adjustment to the capacity or load as appropriate.

2.4 Retirements

Retirements were considered by removing the units from the model at their retirement date.

3.0 Representation of Interconnected Systems

Interconnections were not explicitly modeled. The approach used in this evaluation was to determine the level of interconnection assistance required in order for the Maritimes Area to meet the NPCC criterion.

4.0 Modeling of Limited Energy Sources

Under normal operating conditions, the hydro system is operated considerably below its DMNC rating due to economics. However, if required to maintain customer load, it would be operating at full capacity by utilizing the headponds and other existing storage reservoirs. This is one of the options documented in the Emergency Operating Procedures (Section 4.2). Therefore, in the evaluation, hydro units are considered available for all hours during which the unit is not on forced outage or maintenance. There are no seasonal adjustments to the DMNC ratings of the hydro units.

5.0 Modeling of Demand Side Management

The expected monthly demand and energy reduction due to Demand Side Management programs for each system operator is included in their respective forecasts and in the combined Maritimes Area forecast in Table A-1.

6.0 Modeling of Non-Utility Generation

NBSO and NS Power each aggregate small non-utility generating capacity into a single unit with operating characteristics and FORs equivalent to other Maritimes Area units of similar size. These are tabulated in Table A-2 and are identified by type NUG. The Bayside 6 unit is modeled separately because its size is comparable to the larger units on the system.

7.0 Other Assumptions

The study assumed that there would be no unit slippages or unit deratings due to environmental constraints.

APPENDIX B: DESCRIPTION OF RELIABILITY PROGRAM

DESCRIPTION OF RELIABILITY PROGRAM

The program used for this assessment, LOLP, was originally developed at NB Power in 1984 in order to complete the Triennial Review of Resource Adequacy. Since that time the program has been improved, and its capabilities expanded, with the most recent modifications being completed in Fall 2007.

The original program was a single area program that performed the classical LOLP analysis based upon the weekday peak hour load, as well as an LOLH and EENS analysis which is based upon all of the hourly loads. The results of the program were benchmarked against the results of the IEEE reliability test system, as well as against the results of the PICES program used by NS Power for the 1991 Triennial Review. The program was further benchmarked by evaluating its results against those documented in the 1992 CIGRE Task Force 38-03-10 report "Composite Power System Reliability Analysis Application to the New Brunswick Power Corporation System"". In all cases, excellent agreement of results was observed.

In the Fall of 2007, modifications to the original program allowed it to perform a Monte Carlo analysis of a multi-area system with intra-area tie limits. This Monte Carlo simulation was written using MATLAB® software for programming and random number generation, and it performs as follows:

- For each daily coincident peak load, generation is simulated in each jurisdiction of the Maritimes. This simulation uses random numbers against a generator's Forced Outage Rate to determine the status of each unit. Planned generator maintenance is also enforced.
- Generation surpluses or deficits are determined for each jurisdiction. Because each jurisdiction other than New Brunswick (NB) is only connected to NB, these surpluses and deficits can be transferred to New Brunswick.
- Surpluses transferred to NB from another jurisdiction are limited by the intra-area export limit of the jurisdiction.
- Deficits in a jurisdiction other than NB that exceed the import capability from NB results in a loss of load event. Otherwise, the deficit is transferred to NB.
- With all transfer-limited surpluses and deficits transferred to NB, it is determined whether or not the simulated generation in NB plus transferred surpluses is adequate to supply both the NB load and any transferred deficits. If not, then a loss of load event occurs.
- The Monte Carlo simulation is performed for each daily peak hour of the year, and the yearly simulation is repeated 100,000 times in order to calculate the average LOLE in days/year.

The base load shape for the program is system hourly net loads for each jurisdiction comprising the Area. Monthly load shapes for the individual jurisdictions are created by scaling the hourly loads to match the load forecast values of both demand and energy. This method preserves the effects of load chronology as well as load coincidence between the jurisdictions. This method is also identical between the new program and the old program. A separate monthly load shape comprising only the peak load of each day is created for the LOLE analysis.

To test the recent modifications, the Monte Carlo simulation was successfully tested for single areas by comparing its results with the previously benchmarked LOLP program. The multi-area performance of the new program was tested on simplified systems whereby the LOLE results could be calculated by hand and compared with the program calculations.