NPCC
MARITIMES AREA
TRIENNIAL REVIEW OF RESOURCE ADEQUACY

NOVA SCOTIA POWER INCORPORATED
NEW BRUNSWICK POWER CORPORATION
MARITIME ELECTRIC COMPANY LIMITED

December 2001

1.0 EXECUTIVE SUMMARY

1.1 The Maritimes Area Triennial Review of Resource Adequacy, covering the period January 2002 through December 2006, is the fifth such submission to the Northeast Power Coordinating Council (NPCC). The previous Triennial Review was approved in December 1998. The Maritimes Area is a winter peaking area that includes Nova Scotia Power Incorporated (NS Power), New Brunswick Power Corporation (NB Power), and Maritime Electric Company Limited (MECL). MECL supplies the province of Prince Edward Island.

The Maritimes Area's combined load forecast consists of the NS Power and MECL 2000 forecasts and the NB Power February 2001 forecast. The forecast peak for 2002 is 5134 MW, which is 254 MW less than the forecasted peak for 2002 used in the 1998 review. The average annual growth in demand over the study period is 1.13% (before the effects of industrial self-generation in 2006 are included) for the 2001 review as compared to 1.37% for the 1998 review.

The reserve criterion for the Maritimes Area is 20% and adherence to this criterion is demonstrated to comply with the NPCC reliability criterion. For the base load forecast, the expected number of firm load disconnections for the period 2002 through 2006 varies from a low of 0.0048 to a high of 0.0185 days/year. Further, assuming load forecast uncertainty (LFU), the expected number of firm load disconnections from 2002 through 2006 varies from a low of 0.0150 to a high of 0.0427 days/year. These levels meet the NPCC criterion. Support from interconnections, although available, is not necessary in order to achieve these levels.

1.2 Summary of Major Assumptions and Results

TABLE 1

MAJOR ASSUMPTIONS

Load Forecast	NB Power 2001 NS Power 2000 MECL 2000
Resource Adequacy Criterion	0.1 days/year
Maritimes Required Reserve	20 %
Maritimes Unit Data	Appendix A - Table A-2 (by utility)

RESULTS

Year	Expected Number of Firm Load Disconnections days/year	Required Interconnection Support MW
Base Load Forecast		
2002	0.0048	0
2003	0.0046	0
2004	0.0082	0
2005	0.0185	0
2006	0.0115	0
Base Load Forecast including LFU		
2002	0.0150	0
2003	0.0148	0
2004	0.0234	0
2005	0.0418	0
2006	0.0427	0

Note: The expected number of firm load disconnections for the Base Load Forecast including LFU is based on the procedure described in Section 4.5.

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3.0 INTRODUCTION

The Maritimes Area Triennial Review of Resource Adequacy, covering the period January 2002 through December 2006, is the fifth such submission to the Northeast Power Coordinating Council (NPCC). The previous Triennial Review was approved in December 1998. The Maritimes Area is a winter peaking area that includes Nova Scotia Power Incorporated (NS Power), New Brunswick Power Corporation (NB Power), and Maritime Electric Company Limited (MECL). MECL supplies the province of Prince Edward Island. As well, a projection of firm sales external to the Maritimes Area is included in the analysis.

The load forecast data in the 1998 review was based on the 1997 NS Power and MECL load forecasts and the NB Power February 1998 update of the 1997 Business Plan load forecast. In the current review, the Maritimes Area combined load forecast consists of the NS Power and MECL 2000 forecasts and the NB Power 2001 load forecast. For the present review, the forecast peak of 5134 MW for 2002 is 254 MW less than the forecasted peak for 2002 used in the 1998 review. The difference is due to adjusted load forecasts for NB Power (54 MW lower in 2002), NS Power (198 MW lower in 2002), MECL (4 MW higher in 2002) and utility peak coincidence difference of 6 MW. As shown in Table 2, average annual growth in demand over the study period is 1.13% and 1.37% for the 2001 and the 1998 review, respectively. With the lower forecast load and the availability of natural gas in the Maritimes Area, the size, timing and type of unit additions have changed with respect to the 1998 review. In 2006 the availability of natural gas to end use consumers in the Maritimes Area results in a negative increase in load, primarily due to industrial self-generation.

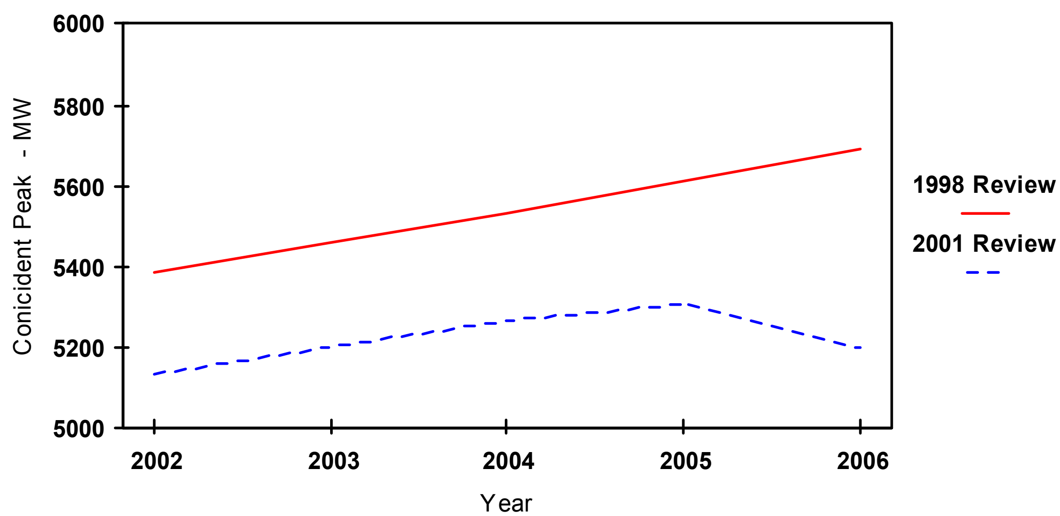
A reserve criterion for this combined system is described and adherence to this criterion is demonstrated. Further, this reserve criterion is shown to comply with the NPCC reliability criterion.

TABLE 2

COMPARISON OF LOAD FORECASTS		
	Load Forecast	
Month of January	2001 Review MW	1998 Review MW
2002 2003 2004 2005 2006	5134 5205 5266 5310 5205	5388 5461 5535 5610 5691
Average Annual Compound Growth Rate		
Five Year Period	2002 - 2006	2002 – 2006
Growth Rate	1.13 %*	1.37%

* Before effects of industrial self-generation are included in 2006.

FIGURE 1
Comparison of Load Forecasts



4.0 RESOURCE ADEQUACY CRITERION

4.1 Statement of Resource Adequacy Criterion

The three utilities comprising the Maritimes Area individually apply a capacity based criterion in determining their required reserve.

NB Power and NS Power each require a reserve equal to the largest unit or 20% of the firm system load and MECL requires a reserve equal to 15% of the firm system load. The Maritimes Area as a whole was assumed to have the same criterion as NB Power and NS Power. This simplification has negligible effect on the results because of the size of MECL relative to NB Power and NS Power combined. Thermal and hydro generation are considered available at the Demonstrated Maximum Net Capacity (DMNC) in the determination of the reserve margin.

The NPCC Generation Reliability criterion states:

Each area's resources will be planned in such a manner that, after due allowance for scheduled maintenance, forced and partial outages, interconnections with neighbouring areas, and available operating procedures, the probability of disconnecting non-interruptible customers due to a resource deficiency, on the average, will be no more than once in ten years.

In effect, this criterion is applied as 0.1 days per year.

4.2 Emergency Operating Procedures

Although this document presents a review of resource adequacy for the interconnected Maritimes Area system, each separate system remains under the exclusive control of its utility 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 on 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 Operating 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. (20-60 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 modelled in this study.

4.3 Maritimes Area Required Reserve

The Area employs a reserve criterion of 20% of firm load with the understanding that 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 2.1, it is necessary to evaluate the system at a time when it just meets the reserve criterion. The Maritimes Area is projected to have a reserve margin greater than 20% for every year of the study period. It was therefore necessary to scale the load upwards in order to achieve a reserve margin of 20% for a comparison evaluation.

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 0.135 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 less than 3% of the normal maximum ratings of the interconnections with Quebec (1100 MW) and New England (700 MW). In addition, NB Power is supplying system peaking capacity to Hydro Quebec tied to the availability of the Millbank combustion turbine (CT) units. Therefore, the Millbank CT's are only included in the study calculations as Area resources when they are no longer a part of the sale. This arrangement has the effect of increasing the total interconnection capability between Hydro Quebec and New Brunswick by the contract amount (300 MW until Nov. 1, 2002; 200 MW thereafter). The May, 1999 NPCC CP-5 Working Group report "Review of Interconnection Assistance Reliability Benefits" concluded that the amount of interconnection assistance available to the Maritimes Area ranged from 1175 MW to 1875 MW.

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

4.5 Recent Reliability Studies

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

The results presented in this review are based upon an evaluation conducted during the second quarter of 2001 for the period 2002 through 2006.

Table 3 and Figure 2 illustrate that the Maritimes Area system can achieve the NPCC criterion for expected number of customer disconnections of 0.1 days/year without the benefits arising from interconnection support from neighbouring utilities.

TABLE 3

EXPECTED NUMBER OF FIRM LOAD DISCONNECTIONS BASE LOAD FORECAST		
Calendar Year	Expected Number of Firm Load Disconnections days/year	Required Interconnection Support MW
2002	0.0048	0
2003	0.0046	0
2004	0.0082	0
2005	0.0185	0
2006	0.0115	0

The effect of load forecast uncertainty (LFU) was evaluated using a method similar to that described in the NPCC CP-5 report "Review of Interconnection Assistance Reliability Benefits" (June, 1994). An analysis of the historical load forecasts 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. This results in weighting factors of 0.384, 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.

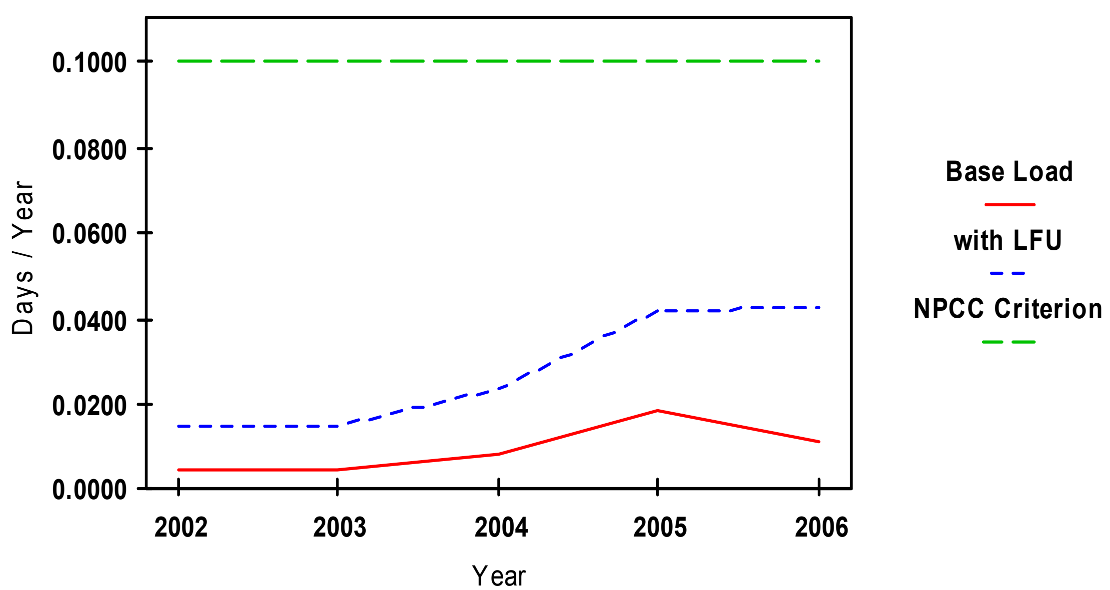
The results of the LFU evaluation as indicated in Table 4 and Figure 2 demonstrate that the Maritimes Area system can still achieve the NPCC criterion of 0.1 days/year without interconnection assistance in the period 2002 through 2006.

The results of the LFU analysis are intended as a sensitivity analysis. If higher than forecast loads occur, then the Maritimes Area has contingency plans (see Section 5.3) that may be implemented.

TABLE 4

EXPECTED NUMBER OF FIRM LOAD DISCONNECTIONS LOAD FORECAST UNCERTAINTY		
Calendar Year	Expected Number of Disconnections days/year	Required Interconnection Support MW
2002	0.0150	0
2003	0.0148	0
2004	0.0234	0
2005	0.0418	0
2006	0.0427	0

FIGURE 2
Expected Number of Firm Load Disconnections



5.0 RESOURCE ADEQUACY ASSESSMENT

5.1 Comparison of Planned and Required Reserve

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 which will occur for the load forecast and resource plan used in this study. Projected firm sales external to the Maritimes Area are also included in the load for this analysis.

Table 5 and Figure 3 present the results of the reserve comparison for the base load forecast. In each year of the analysis, the planned reserve varies from 479 to 656 MW greater than the required reserve.

TABLE 5

COMPARISON OF PLANNED AND REQUIRED RESERVE BASE LOAD FORECAST

Month of January	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2002	6171	5134	533	1570	34.1	920	20.0
2003	6259	5205	536	1590	34.1	934	20.0
2004	6282	5266	540	1556	32.9	945	20.0
2005	6198	5310	544	1432	30.0	953	20.0
2006	6171	5205	547	1513	32.5	932	20.0

5.2 Comparison of Planned and Required Reserve - High Load Growth

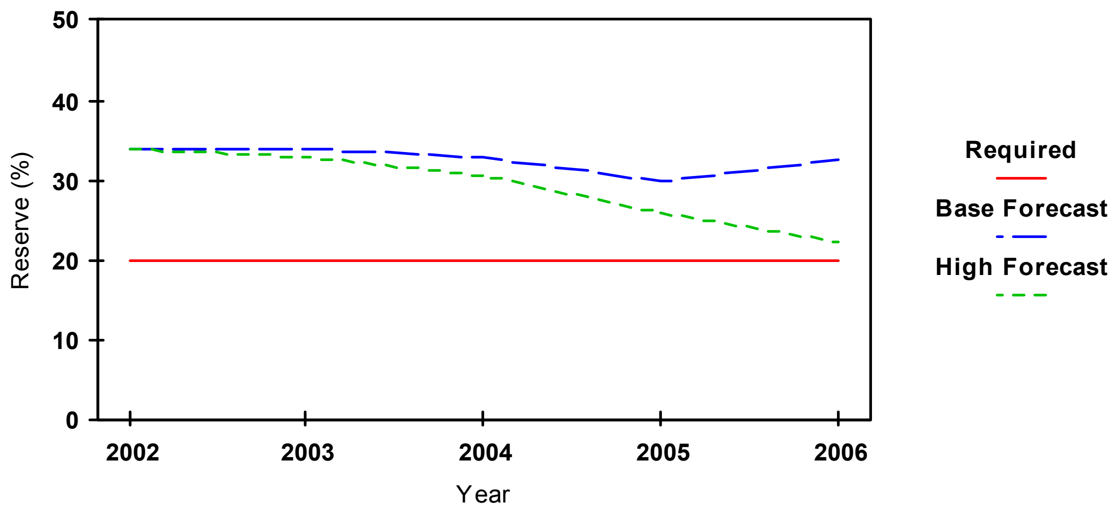
Table 6 and Figure 3 illustrate the changes in planned and required reserve if the annual growth rate is 1% higher than forecast (i.e. 2.13% per year versus 1.13% per year) and the effects of industrial self-generation are ignored. The results show that the resource plan of the Maritimes Area is sufficient to maintain a reserve of 20% or greater through 2006. This provides sufficient lead time to permit the Maritimes Area to initiate appropriate actions as described in the following section. The planned reserve varies annually from 125 to 650 MW greater than the required reserve.

TABLE 6

COMPARISON OF PLANNED AND REQUIRED RESERVE
HIGH LOAD FORECAST

Month of January	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2002	6171	5134	533	1570	34.1	920	20.0
2003	6259	5242	536	1553	33.0	941	20.0
2004	6282	5354	540	1468	30.5	963	20.0
2005	6198	5469	544	1273	25.9	985	20.0
2006	6171	5585	547	1133	22.5	1008	20.0

FIGURE 3
Planned Versus Required Reserve



5.3 Contingency Plans

The Maritimes Area utilities forecast high and low load growth scenarios and the impact of these forecasts on the utility 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 4 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.

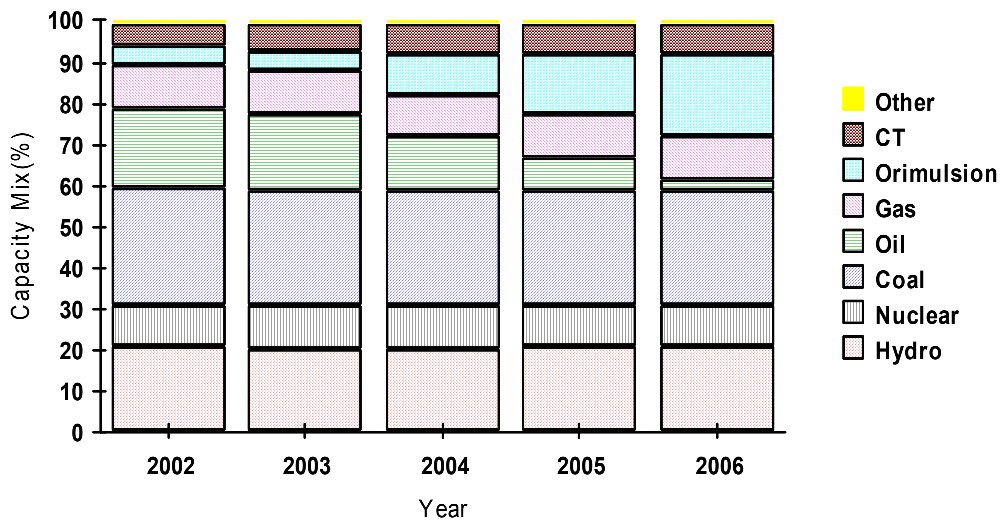
TABLE 7

PLANNED RESOURCE CAPACITY MIX

Month of January	Hydro %	Nuclear %	Coal %	Oil %	Gas %	Orimulsion %	C.T. %	Other %
2002	21	10	28	19	11	5	5	1
2003	20	10	28	19	11	5	6	1
2004	20	10	28	13	11	10	7	1
2005	21	10	27	8	11	15	7	1
2006	21	10	27	3	11	20	7	1

Note: Other includes NUGs, Lepreau Diesel, and Purchases

FIGURE 4
Planned Resource Capacity Mix



Note: Other includes NUGs, Lepreau Diesel, and Purchases

6.2 Reliability Impact of Resource Diversification Strategy

As can be seen from Table 7 and the associated Figure 4, the Maritimes Area has a diversified mix of resources such that there is not a high degree of reliance on any one type or source of fuel. As a result of this level of fuel type and source diversification, there are no reliability impacts resulting from this resource capacity mix, nor are there any environmental restrictions.

This level of diversification has been achieved by conversion of existing resources to utilise a different fuel (Dalhousie 1 and 2 from oil and coal, respectively, to Orimulsion^{tm}) or an additional fuel (Tufts Cove 1, 2, & 3 to natural gas while retaining oil-fired capability). Further, Bayside 6 is a natural gas fired combined cycle unit utilising a new CT in conjunction with the existing Courtenay Bay 3 unit which was an oil fired unit. In addition, a proposed new unit in Nova Scotia is a natural gas CT.

The Maritimes Area is continuing its policy of fuel diversification during the study period with the planned conversion of the 3 oil-fired units at Coleson Cove to Orimulsion^{tm} (2003-2005) as well as the proposed life extension of the Point Lepreau nuclear unit (refurbishment starting in April, 2006).

An option available to the Maritimes Area is increased purchase capability resulting from a second interconnection with New England (undergoing regulatory and environmental hearing processes) as well as through the proposed Neptune HVDC project. This project involves an undersea cable connection between New Brunswick and New York City (Phase 2 in 2004) and between Nova Scotia and Boston (Phase 3 in 2005).

Other potential options include additional natural gas fired units (utility-owned as well as NUG), wind energy (Nova Scotia has RFP for 50 MW), hydro redevelopment and tidal.

APPENDIX A

DESCRIPTION OF RESOURCE RELIABILITY MODEL

DESCRIPTION OF RESOURCE RELIABILITY MODEL

1.1 Load Model

1.1.1 After reviewing historical hourly system load data of the three utilities, it was determined that the 1999 system load data provided a typical Maritimes Area load shape. Demand and energy forecasts for 2002 to 2006 inclusive were prepared by each utility. 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
2002	5134	5078	4547	4059	3713	3442	3357	3395	3418	3975	4330	4827	5134
2003	5205	5149	4608	4115	3759	3499	3408	3447	3473	4028	4389	4893	5205
2004	5266	5211	4658	4159	3797	3548	3453	3490	3523	4066	4434	4941	5266
2005	5310	5254	4693	4194	3823	3586	3489	3522	3493	3958	4338	4844	5310
2006	5205	5144	4580	4064	3692	3465	3366	3405	3402	3968	4327	4825	5205
ENERGY GWh													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2002	3003	2706	2738	2368	2186	2007	2029	2051	2053	2258	2458	2879	28736
2003	3053	2751	2814	2412	2225	2047	2069	2090	2094	2298	2500	2926	29279
2004	3099	2800	2859	2443	2260	2085	2105	2128	2131	2335	2535	2962	29742
2005	3130	2825	2893	2423	2240	2072	2096	2118	2119	2314	2506	2919	29656
2006	3087	2786	2855	2386	2210	2051	2074	2094	2096	2283	2465	2868	29254
INTERRUPTIBLE DEMAND MW													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	On Peak
2002	533	546	551	525	538	568	576	559	544	549	540	538	533
2003	536	550	555	528	542	572	580	562	548	553	543	542	536
2004	540	553	559	532	545	575	584	566	551	557	547	545	540
2005	544	557	562	535	549	579	587	570	555	560	550	549	544
2006	547	560	566	539	552	582	591	573	558	564	554	552	547

1.1.2 Load forecast uncertainty was considered in the analysis as described in Section 4.5.

1.1.3 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.

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

1.2 Resource Unit Representation

Generating unit data for the three utilities of the Maritimes Area are presented in Table A-2. Table A-3 presents a summary of changes in resource data for the period 2002-2006 inclusive. The following sections document the tabulated data.

1.2.1 Unit Ratings

1.2.1.1 Definition

The generating unit capacity ratings presented 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.

1.2.1.2 Procedure for Verifying Ratings

Ratings of N.B. Power units are reviewed annually by the Generation Efficiency Section of the N.B. Power 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 Nova Scotia 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

NB Power Resources

Plant	Unit	Type	Capacity MW	Notes
Point Lepreau	1	Nuclear	635	
		Diesel	5	
Coleson Cove	1	Oil	335	
	2	Oil	335	
	3	Oil	335	
Belledune	2	Coal	458	
Dalhousie	1	Orimulsion™	97	
	2	Orimulsion™	203	
Courtenay Bay	2	Oil	12	Planned retirement in November 2002
	4	Oil	98	
Bayside	6	Natural Gas NUG	273	Capacity Includes Combined Cycle Operation with Courtenay Bay 3
Grand Lake	8	Coal	57	Planned retirement in November 2004
Ste. Rose	1	CT	100	Modeled as Tied to Sale Contract Until November 2002
Grand Manan	3	CT	29	
Millbank	1	CT	100	Tied to Sale Contract until November 2011
	2	CT	100	Tied to Sale Contract until November 2011
NUG Purchase	All	NUG	47	
Mactaquac	1	Hydro	110	
	2	Hydro	110	
	3	Hydro	110	
	4	Hydro	116	
	5	Hydro	113	
	6	Hydro	113	
Bechwood	1	Hydro	36	
	2	Hydro	36	
	3	Hydro	41	
Grand Falls	1	Hydro	17	
	2	Hydro	17	
	3	Hydro	17	
	4	Hydro	17	
Tobique	1	Hydro	10	
	2	Hydro	10	
Sisson	1	Hydro	9	
Milltown	All	Hydro	4	
TOTAL CAPACITY			**3805**	Total capacity only includes units in service as of Jan. 2002

TABLE A-2 Cont'd

NS Power Resources

Plant	Unit	Type	Capacity MW	Notes
Tufts Cove	1	Gas / Oil	80	
	2	Gas / Oil	99	
	3	Gas / Oil	153	
Lingan	1	Coal	155	Summer Capacity = 140 MW
	2	Coal	155	Summer Capacity = 140 MW
	3	Coal	155	Summer Capacity = 145 MW
	4	Coal	155	Summer Capacity = 145 MW
Pt. Tupper	2	Coal	148	
Trenton	5	Coal	150	Summer Capacity = 135 MW
	6	Coal	156	
Pt. Aconi	1	Coal	165	
Burnside	1	CT (Lt Oil)	33	Summer Capacity = 25 MW
	2	CT (Lt Oil)	33	Summer Capacity = 25 MW
	3	CT (Lt Oil)	33	Summer Capacity = 25 MW
	4	CT (Lt Oil)	33	Summer Capacity = 25 MW
Victoria Junction	1	CT (Lt Oil)	33	Summer Capacity = 25 MW
	2	CT (Lt Oil)	33	Summer Capacity = 25 MW
Tusket	1	CT (Lt Oil)	24	Summer Capacity = 21 MW
New CT	1	CT (Gas)	50	In-service Jan 2002
Wreck Cove	1	Hydro	115	
	2	Hydro	115	
Annapolis		Hydro	4	
Avon		Hydro	7	
Black River		Hydro	23	
Nictaux		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	
IPP	All	NUG	25	
TOTAL CAPACITY			**2264**	Total capacity only includes units in service as of Jan. 2002

TABLE A-2 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	
Borden	1	CT	15	
	2	CT	27	
Ch'town GT/HRSG	1	CT	50	In Service October 2003
TOTAL CAPACITY			**102**	Total capacity only includes units in service as of Jan. 2002

Note: MECL resources include a 20 MW ownership in the Dalhousie Plant and 30 MW participation in Pt. Lepreau. These units are NB Power units and are shown in the NB Power resources.

TABLE A-3

SUMMARY OF CHANGES IN CAPACITY				
Year	**January Capacity**	**December Capacity**	**Capacity Change**	**Explanation**
2002	6171	6259	88	Millbank Contract (+100); Courtenay Bay 2 retired (-12)
2003	6259	6282	23	Charlottetown HRSG (+50); Coleson Cove 3 conversion (-27)
2004	6282	6198	-84	Gr. Lake 8 retired (-57); Coleson Cove 2 conversion (-27)
2005	6198	6171	-27	Coleson Cove 1 conversion (-27)
2006	6171	6171	0	

1.2.2 Unit Unavailability Factors

1.2.2.1 Type 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.

1.2.2.2 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).

1.2.2.3 Maturity Considerations

Immature FORs were not used in this evaluation.

1.2.2.4 Tabulation of Typical Unavailability Factors

The range of typical FORs used in the assessment are tabulated in Table A-4. These values are consistent with those used in the business plans of the 3 utilities and reflect the results of maintenance and operational strategies.

TABLE A-4

MARITIMES AREA TYPICAL FORCED OUTAGE RATES	
Unit Type	**Forced Outage Rate %**
Nuclear	8 - 12
Coal	2 - 14
Oil	2 - 10
Orimulsion	6 - 12
Natural Gas (Combined Cycle)	5 - 10
Combustion Turbine	8 - 12
Hydro	1 - 5
NUG	2- 6

1.2.3 Purchase and Sale Representation

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

1.2.4 Retirements

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

1.3 Representation of Interconnected Systems

Interconnections were not explicitly modelled. 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.

1.4 Modelling 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 operated 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 2.2). Therefore, in the evaluation, hydro units are considered available for all hours during which the unit is not on forced outage or maintenance.

1.5 Modelling of Demand Side Management

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

1.6 Modelling of Non-Utility Generation

NB Power 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 as a separate unit because its size is comparable to the larger units on the system.

1.7 Other Assumptions

Internal transmission limitations were not modeled. The results of isolated pool modelling for the NPCC Summer 2001 Multi-Area Probabilistic Reliability Assessment have shown that the ability of the Maritimes Area to meet the NPCC resource adequacy criterion is not affected by any internal transmission limitations.

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

APPENDIX B

DESCRIPTION OF RELIABILITY PROGRAM

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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 May, 2001.

The program is a single area program that performs 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 have been 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.

The base load shape for the program is input in the form of EEI format system hourly net loads for each utility (maximum of 5) comprising the Area. Monthly load shapes for the individual utilities are created by scaling the hourly loads to match load forecast values of both demand and energy. A monthly load shape for the Area is then obtained by combining the monthly load shapes of the individual utilities. This method preserves the effects of load chronology as well as load coincidence between the utilities. A separate monthly load shape comprising only the peak load of each weekday is created for the classical LOLP analysis.

The program utilizes a two state capacity model from which it constructs a table of the cumulative probability of all of the capacity outage states having a probability greater than a user set threshold (1.OE-08 for this analysis). The table is modified, if necessary, on a monthly basis to account for capacity additions, unit retirements, or units going on, or coming off of, maintenance. Note that the maintenance schedule is input by the user.