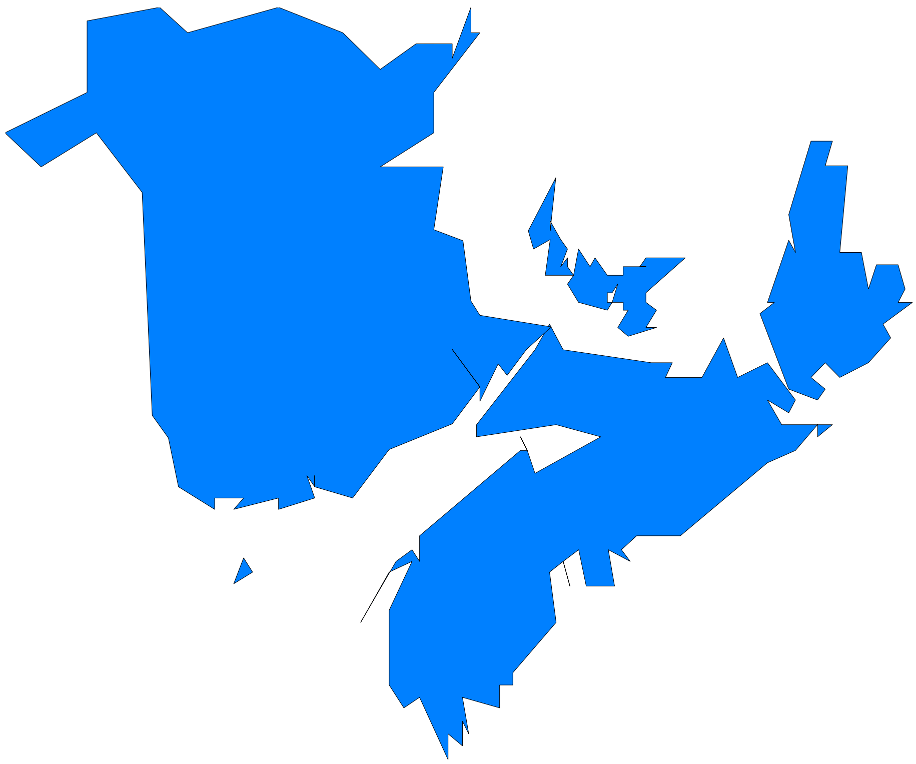
NPCC
MARITIME AREA
TRIENNIAL REVIEW OF RESOURCE ADEQUACY



NS POWER INC.
NB POWER CORPORATION
MARITIME ELECTRIC COMPANY LIMITED

December 1998

1.0 EXECUTIVE SUMMARY

1.1 This report is the fourth submission of the Maritime Area electrical system to the NPCC Triennial Review of Resource Adequacy and covers the period January 1998 to December 2007 inclusive. The previous Triennial Review, completed by NB Power, was submitted in July 1994. The Maritime Area includes NB Power, NS Power, and Maritime Electric Company Limited (MECL). MECL supplies the province of Prince Edward Island.

The Maritime Area's combined load forecast consists of the 1997 NS Power and MECL forecasts and the NB Power February 1998 update of the 1997 Business Plan load forecast. The forecast peak for 1998 is 4884 MW, which is 192 MW less than the forecasted peak for 1998 used in the 1994 review. Growth in demand over the study period is 1.9% for both the 1998 and the 1994 review.

A reserve criterion for the Maritime 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 1998 through 2007 varies from a low of 0.0022 and a high of 0.0515 days/year. This results in a requirement of 0 MW of interconnection support for the Maritime Area for the entire study period. Further, assuming load forecast uncertainty (LFU), the expected number of firm load disconnections from 1998 through 2006 varies from a low of 0.0077 and a high of 0.0845 days/year resulting in 0 MW of interconnection support. In 2007, with LFU, the expected number of firm load disconnections increases to 0.1304 days/year. In 2007 the Maritime Area requires approximately 55 MW of interconnection support to maintain the 0.1 days/year reliability criterion.

1.2 Summary of Major Assumptions and Results

TABLE 1

MAJOR ASSUMPTIONS		
Load Forecast	NB Power 1998 NS Power 1997 MECL 1997	
Resource Adequacy Criterion	0.1 days/year	
Maritime Required Reserve	20 %	
Maritime Unit Data	Appendix A - Table A-2	
RESULTS		
Year	**Expected Number of Firm Load Disconnections days/year**	**Required Interconnection Support MW**
Base Load Forecast 1998 - 2007	0.0022 - 0.0515	0
Base Load Forecast including LFU 1998 - 2006 2007	0.0077 - 0.0845 0.1304	0 55

Note: NB Power forecast is the February 1998 update of the 1997 Business Plan load forecast.

2.0 TABLE OF CONTENTS

2.1 List of Tables

2.2 List of Figures

3.0 INTRODUCTION

3.1 This report covers the period January 1998 to December 2007 inclusive and is the fourth submission of the Maritime Area electrical system to the NPCC Triennial Review of Resource Adequacy. The previous Triennial Review, completed by NB Power, was submitted in July 1994. The Maritime Area includes NB Power, NS Power, and Maritime Electric Company Limited (MECL). MECL supplies the province of Prince Edward Island. Since the Eastern Maine Electric Coop (EMEC) is essentially regarded by NP Power as a wholesale customer, their load is included in the analysis.

3.2 The load forecast data in the 1994 review was based on the 1993 NS Power and NB Power load forecasts and the 1994 MECL load forecast. In the current review, the Maritime Area combined load forecast consists of the 1997 NS Power and MECL forecasts and the NB Power February 1998 update of the 1997 Business Plan load forecast. For the present review, the forecast peak of 4884 MW for 1998 is 192 MW less than the forecasted peak for 1998 used in the 1994 review. The difference is due to reduced load forecasts for NB Power (103 MW lower in 1998) and NS Power (203 MW lower in 1998) and utility peak coincidence difference of 114 MW. The MECL forecast is essentially the same as the 1994 review for the year 1998. As shown in Table 2, growth in demand over the study period is 1.9% for both the 1998 and the 1994 review. With the lower forecast load and the expected availability of natural gas in the Maritime Area, the size, timing and type of unit additions have changed with respect to the 1994 review.

3.3 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	1998 Review MW	1994 Review MW
1998	4884	5076
1999	5157	5170
2000	5235	5268
2001	5308	5362
2002	5388	5450
2003	5461	5533
2004	5535	5617
2005	5610	
2006	5691	
2007	5770	
Average Annual Compound Growth Rate		
Ten Year Period	1998 - 2007	1995 - 2004
Growth Rate	1.9 %	1.9 %

4.0 RESOURCE ADEQUACY CRITERION

4.1 Statement of Resource Adequacy Criterion

The three utilities comprising the Maritime 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; Maritime Electric requires a reserve equal to 15% of the firm system load. The Maritime 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 Maritime 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 which 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 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. (20 MW)
11. Load up thermal units to emergency ratings. (60 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 Maritime 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 Maritime 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 Maritime 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 Maritime Area, isolated from all other systems, a reserve of 20% corresponds to an expected number of firm load disconnections of approximately 0.17 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 Maritime Area has a reserve of 20% with the interruptible load removed, approximately 100 MW of interconnection assistance is required in order to meet the NPCC criterion. This represents approximately 5% 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 provided through the availability of the Millbank combustion turbine 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. As a result of the preceding, it is concluded that the reserve criterion of the Maritime Area meets the NPCC Resource Adequacy Criterion.

4.5 Recent Reliability Studies

NB Power, NS Power, and MECL individually conduct an annual review 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 first quarter of 1998.

Table 3 and Figure 1 illustrate the expected number of firm load disconnections which would result for the planned system if the benefits arising from the interconnections were ignored. The expected number of disconnections varies from 0.0022 days/year in 1999 to approximately 0.0515 days/year in 2007.

TABLE 3

EXPECTED NUMBER OF FIRM LOAD DISCONNECTIONS
BASE LOAD FORECAST

Calendar Year	Expected Number of Disconnections days/year	Required Interconnection Support MW
1998	0.0071	0
1999	0.0022	0
2000	0.0035	0
2001	0.0030	0
2002	0.0176	0
2003	0.0165	0
2004	0.0095	0
2005	0.0227	0
2006	0.0317	0
2007	0.0515	0

Table 3 illustrates the total level of assistance required from neighbouring utilities in order for the Maritime Area system to achieve the NPCC criterion. For the period 1998 through 2007 inclusive, no interconnection assistance is required.

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 load forecasts of the Maritime Area utilities has shown that the standard deviation of the load forecast errors is approximately 5% 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 five and ten 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, five percent increased and ten percent increased load models respectively.

The results of the LFU evaluation are tabulated in Table 4 and are illustrated in Figure 1. With LFU, no interconnection assistance is required by the Maritime Area for the period 1998 through 2006. In 2007, approximately 55 MW of interconnection assistance may be required for the Maritime Area to maintain the NPCC criterion.

The results of the LFU analysis are intended as a sensitivity analysis. If higher than forecast loads occur, then the Maritime Area has contingency plans (see Section 5.3) it could implement.

TABLE 4

EXPECTED NUMBER OF FIRM LOAD DISCONNECTIONS LOAD FORECAST UNCERTAINTY		
Calendar Year	Expected Number of Disconnections days/year	Required Interconnection Support MW
1998	0.0193	0
1999	0.0077	0
2000	0.0115	0
2001	0.0108	0
2002	0.0476	0
2003	0.0462	0
2004	0.0291	0
2005	0.0623	0
2006	0.0845	0
2007	0.1304	55

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 criteria of the Maritime Area. The planned reserve is the actual reserve which will occur for the load forecast and resource plan used in this study. Note that since the Eastern Maine Electric Coop (EMEC) is essentially regarded by NB Power as a wholesale customer, their load is included in the analysis.

Table 5 presents the results of the comparison.

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	%
1998	6072	4884	418	1606	36.0	893	20.0
1999	6472	5157	507	1822	39.2	930	20.0
2000	6471	5235	509	1745	36.9	945	20.0
2001	6643	5308	517	1852	38.7	958	20.0
2002	6368	5388	522	1502	30.9	973	20.0
2003	6468	5461	524	1531	31.0	987	20.0
2004	6638	5535	525	1628	32.5	1002	20.0
2005	6581	5610	525	1496	29.4	1017	20.0
2006	6606	5691	526	1441	27.9	1033	20.0
2007	6606	5770	527	1363	26.0	1049	20.0

Note: Interruptible load includes curtailable load. Increase in interruptible from the 1994 review are due to existing and forecasted increases in interruptible/curtailable customer load.

5.2 Comparison of Planned and Required Reserve - High Load Growth

Table 6 illustrates the changes in planned and required reserve if the annual growth rate is 1% higher than forecast (i.e. 2.9% per year versus 1.9% per year). The results show that the resource plan of the Maritime Area is sufficient to maintain a reserve of 20% or greater until 2006. This provides sufficient lead time to permit the Maritime Area to initiate appropriate actions as described in the following section.

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	%
1998	6072	4884	418	1606	36.0	893	20.0
1999	6472	5206	507	1773	37.7	940	20.0
2000	6471	5337	509	1643	34.0	966	20.0
2001	6643	5464	517	1696	34.3	989	20.0
2002	6368	5601	522	1289	25.4	1016	20.0
2003	6468	5733	524	1259	24.2	1042	20.0
2004	6638	5868	525	1295	24.2	1069	20.0
2005	6581	6000	525	1106	20.2	1095	20.0
2006	6606	6153	526	979	17.4	1125	20.0
2007	6606	6300	527	833	14.4	1155	20.0

5.3 Contingency Plans

The Maritime 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. The 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 2 illustrate the planned resource capacity mix for the Maritime Area.

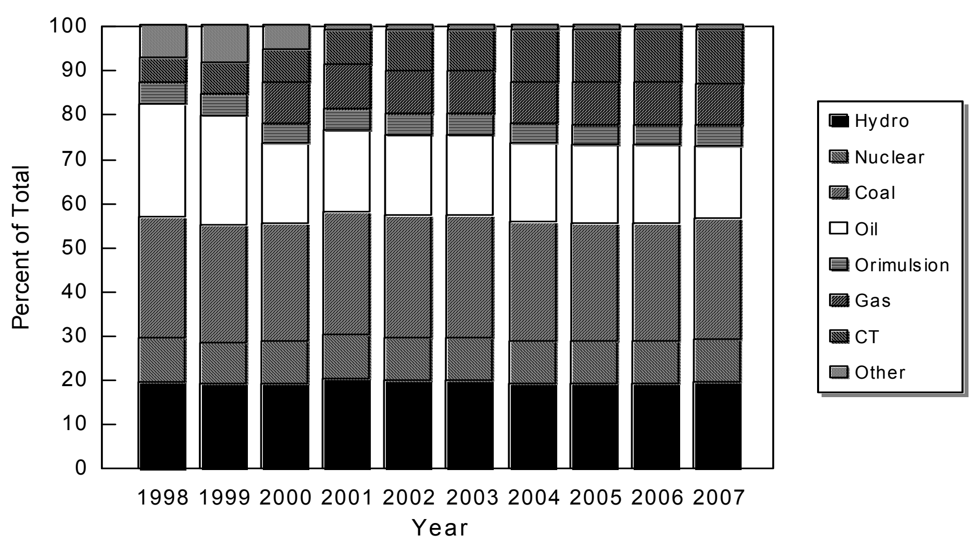
TABLE 7

PLANNED RESOURCE CAPACITY MIX

Month of January	Hydro %	Nuclear %	Coal %	Oil %	Gas %	Orimulsion %	C.T. %	Other %
1998	20	10	27	26	0	5	6	6
1999	19	9	26	25	0	5	7	9
2000	19	10	27	18	9	5	7	5
2001	20	10	28	18	10	5	8	1
2002	20	10	27	18	10	5	9	1
2003	20	10	27	18	10	5	9	1
2004	19	10	27	18	9	5	11	1
2005	19	10	27	18	9	5	11	1
2006	19	10	27	18	9	5	11	1
2007	20	10	27	16	9	5	12	1

Note: Other includes NUGs, Lepreau Diesel, and Purchases

FIGURE 2
PLANNED RESOURCE CAPACITY MIX



6.2 Planned Resource Energy Mix

Table 8 and Figure 3 illustrate the planned resource energy mix for the Maritime Area.

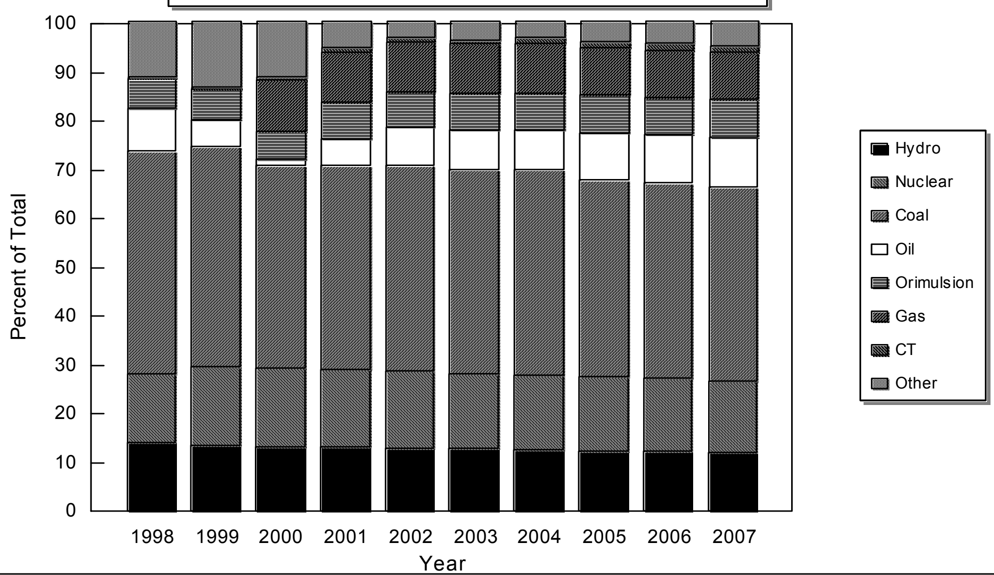
TABLE 8

PLANNED RESOURCE ENERGY MIX

Month of January	Hydro %	Nuclear %	Coal %	Oil %	Gas %	Orimulsion %	C.T. %	Other %
1998	14	14	46	9	0	6	0	11
1999	14	16	45	5	0	6	0	14
2000	13	16	41	1	11	6	1	11
2001	13	16	42	5	10	7	1	6
2002	13	16	42	8	10	7	1	3
2003	13	15	42	8	10	7	1	4
2004	13	15	42	8	10	7	1	4
2005	12	15	40	10	10	8	1	4
2006	12	15	40	10	10	8	1	4
2007	12	15	40	10	10	8	1	4

Note: Other includes NUGs, Lepreau Diesel and Purchase

FIGURE 3
PLANNED RESOURCE ENERGY MIX



6.3 Fuel Mix Strategy

The following discussion reviews the potential generating resources available to the Maritime utilities which would not only reduce dependence on fossil fuels but also help to control emissions.

6.3.1 Conventional Hydro

One option available to NB Power for additional hydro capacity is the Grand Falls - Morrell Integrated Development. This integrated approach to increasing and enhancing the hydro-electric potential in the Upper Saint John River incorporates a pumped storage scheme at Grand Falls. A new power station would be built adjacent to the existing plant and would house three 100 MW reversible pump-turbines. A conventional 140 MW hydro project located 29 km downstream at Morrell would provide the reservoir for the pump mode at Grand Falls. The total project would provide 440 MW of new capacity and add some 1,000 GWh of new conventional hydro energy. Half of this energy would be generated in the high-flow April-June period, with the pump storage capability providing reliable operation for peaking needs over the remainder of the year.

Another option available to NB Power to achieve more efficient water utilization at the Mactaquac Plant is the installation of a new 21 MW conventional hydro unit. Designed to operate at maximum efficiency at a water flow rate of 2300 cfs, this unit would be utilized during the off-peak load periods. Current practice is to operate one of the large units at low load, discharging a flow of approximately 2300 cfs but at a very low efficiency of generation. The net energy benefit achieved by this option would be approximately 60 GWh.

There are also other potential small hydro developments as well as redevelopment of existing hydro sites such as Tobique and Green River.

In Nova Scotia, there are no major hydro projects left to be developed. MECL has no plans for hydro power development.

6.3.2 Tidal

There are two tidal projects in the Bay of Fundy which continue to exhibit some potential of becoming economically viable. Site B9, across the mouth of Cobequid Bay and located entirely in Nova Scotia, has a potential capacity of 5000 MW. Site A8, across the Cumberland Basin between New Brunswick and Nova Scotia, has a potential capacity of 1400 MW. Both sites are economically dependent on substantial export sales and have a minimum ten year engineering and construction lead time.

6.3.3 Nuclear

Nuclear power remains a potentially economically acceptable base load option. However, there is at present, no plan to construct additional nuclear generation.

6.3.4 Natural Gas

Natural gas is not currently available to the region. However, natural gas from the Sable Island Project is expected to be available to the Maritime Area by late 1999. It could be used for new gas fired combined cycle units and/or to fuel present oil fired units such as Coleson Cove, Courtenay Bay or Tufts Cove. Subject to regulatory approval, NS Power plans to convert existing oil fired generation at Tufts Cove to direct fired gas. NB Power plans to repower Courtenay Bay with natural gas.

6.3.5 Coal

Coal power is an economic and financially attractive alternative. Both NB Power and NS Power continue to examine the potential of future units. With the large reserves of coal resources available, both utilities will continue to investigate the feasibility of burning coal more economically and cleanly through the use of technologies such as coal washing, coal water mixtures, fluidized bed combustion, flue gas desulphurization, and integrated coal gasification combined cycle.

6.3.6 Combustion Turbine / Combined Cycle

NB Power, NS Power and MECL are evaluating the addition of combustion turbine and combined cycle units for capacity reserve. With the availability of natural gas, new combined cycle gas units may become an attractive option to meet load.

6.3.7 Orimulsion™

Conversion of both units at the Dalhousie Plant to utilize Orimulsion™, a water emulsified bitumen, was completed in late 1994.

6.3.8 Demand Side Management

The load forecast used in this review includes the impact of DSM capacity and energy and efficiency programs which are expected to be achieved over the study period.

6.3.9 Non-Utility Generation

The Maritime Area continues to evaluate potential NUG capacity, particularly projects which utilize cogeneration or renewable resources.

6.3.10 Other

Alternate energy sources such as wood, biomass, solar, wind, fuel cells, etc., continue to be investigated as generation sources but, to date, have not been shown to be economically attractive from a utility perspective.

APPENDIX A

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 1995 system load data provided a typical Maritime Area load shape. Demand and energy forecasts for 1998 to 2007 inclusive were prepared by each utility. The combined load forecast for the Maritime Area is shown in Table A-1.

TABLE A-1

MARITIME AREA LOAD FORCAST

COINCIDENT DEMAND MW

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Peak
1998	4884	4657	4147	4111	3546	3125	3209	3099	3163	3669	4211	4575	4884
1999	5157	4985	4431	4254	3684	3255	3249	3144	3216	3715	4270	4661	5157
2000	5235	5024	4518	4333	3753	3323	3323	3208	3283	3785	4352	4749	5235
2001	5308	5153	4577	4395	3806	3372	3374	3254	3330	3937	4414	4818	5308
2002	5388	5223	4640	4454	3859	3420	3422	3302	3377	3891	4474	4883	5388
2003	5461	5294	4702	4518	3914	3467	3469	3349	3424	3944	4539	4950	5461
2004	5535	5302	4768	4581	3969	3516	3519	3397	3471	3999	4607	5014	5535
2005	5610	5441	4833	4645	4025	3564	3570	3445	3519	4056	4673	5088	5610
2006	5691	5517	4900	4709	4082	3616	3622	3495	3570	4112	4741	5156	5691
2007	5770	5593	4966	4776	4139	3664	3671	3545	3620	4170	4809	5231	5770

ENERGY GWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	oct	Nov	Dec	Total
1998	2765	2439	2487	2184	2031	1806	1820	1845	1858	2053	2252	2629	26169
1999	2862	2557	2583	2244	2087	1857	1871	1896	1910	2128	2313	2700	27009
2000	2919	2607	2636	2291	2130	1896	1904	1930	1943	2168	2356	2748	27530
2001	2957	2642	2669	2314	2151	1915	1936	1963	1975	2203	2394	2792	27911
2002	2999	2681	2709	2336	2171	1932	1967	1993	2005	2236	2430	2833	28292
2003	3042	2720	2750	2357	2190	1949	1997	2023	2035	2268	2467	2875	28673
2004	3085	2761	2792	2379	2211	1967	2029	2055	2068	2303	2505	2916	29070
2005	3129	2802	2835	2401	2231	1984	2060	2087	2100	2338	2543	2961	29470
2006	3174	2843	2877	2423	2251	2003	2093	2120	2133	2373	2582	3003	29876
2007	3219	2884	2920	2446	2272	2022	2126	2152	2166	2409	2621	3047	30285

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

1.1.3 Some entities within the Maritime Area supply a portion of their own electricity demand and energy requirements. These entities are interconnected within the Maritime Area and are not members of the Area. Only that portion of electricity demand and energy projections that is supplied by the Maritime 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 Maritime Area are presented in Table A-2. Table A-3 presents a summary of changes in resource data for the period 1998-2007 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) 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
MARITIME AREA RESOURCES

NB Power Resources						
Plant	**Unit**	**Type**	**Capacity MW**	**Maintenance**		**Notes**
				Weeks	**Period**	
Point Lepreau	1	Nuclear	635	6	May	
Lepreau Diesel		Diesel	5	6	May	
Coleson Cove	1	Oil	335	8	May-Jun	
	2	Oil	335	8	Jul-Aug	
	3	Oil	335	8	Sep-Oct	
Belledune	2	Coal	458	4	Apr	
Dalhousie	1	Orimulsion	97	4	Oct	
	2	Orimulsion	203	4	Sep	
Courtenay Bay	1	Oil	45			Deactivated, Retired in Nov 2001
	2	Oil	12	4	Apr	Planned retirement in Jun 2000
	3	Oil	99	8	Sep-Oct	Planned retirement in Jun 2000
	4	Oil	98	8	Jul-Aug	Retired in Nov 2007
	C.Cycle	Natural Gas	283	4	Jun	Planned in-service Jun 2000
Grand Lake	8	Coal	57	6	Sep-Oct	Retired in Nov 2004
Ste. Rose	1	CT	100	1	Jul	
Grand Manan	3	CT	28	1	Sep	
Millbank	1	CT	100	1	Jul	Tied to sale contract until Nov 1998
	2	CT	100	1	Jul	Tied to sale contract until Nov 2002
	3	CT	100	1	Jul	Tied to sale contract until Nov 2011
	4	CT	100	1	Jul	Tied to sale contract until Nov 2011
NUG Purchase	All	NUG	49			
Mactaquac	1	Hydro	110	2	Jun	
	2	Hydro	110	2	Jun	
	3	Hydro	110	2	Jul	
	4	Hydro	116	2	Jul	
	5	Hydro	113	2	Aug	
	6	Hydro	113	2	Aug	
Bechwood	1	Hydro	36	1	Feb	
	2	Hydro	36	1	Feb	
	3	Hydro	41	1	Feb	
Grand Falls	1	Hydro	17	1	Mar	
	2	Hydro	17	1	Mar	
	3	Hydro	17	1	Mar	
	4	Hydro	17	1	Mar	
Tobique	1	Hydro	10	1	Jul	
	2	Hydro	10	1	Jul	
Sisson	1	Hydro	9	1	Aug	
Milltown	All	Hydro	4	1	Aug	
Purchase Contract		NBP-HQ	300			Term: Mar 1998 to Feb 2000

TABLE A-2 Cont'd

NS Power Resources						
Plant	**Unit**	**Type**	**Capacity MW**	**Maintenance**		**Notes**
				Weeks	**Period**	
Tufts Cove	1	Oil	80	4	Aug	Capacity Increases to 93 Jan 2000
	2	Oil	99	4	Sep	Capacity reduces to 94 Jan 2000
	3	Oil	154	4	May	Capacity reduces to 144 Jan 2000
Lingan	1	Coal	156	4	Apr	
	2	Coal	156	4	May	
	3	Coal	156	4	Aug	
	4	Coal	156	4	Sep	
Pt. Tupper	2	Coal	154	4	Jun	
Trenton	5	Coal	156	4	Jun	
	6	Coal	156	4	Oct	
Pt. Aconi	1	Coal	166	4	Jul	
Burnside	1	CT	33	4	Jul	
	2	CT	33	4	Aug	
	3	CT	33	4	Sep	
	4	CT	33	4	Oct	
Victoria Junction	1	CT	33	4	Jul	
	2	CT	33	4	Aug	
Tusket	1	CT	24	4	Sep	
New CT	1	CT	170	4	Jul	In-service Jan 2004
Wreck Cove	1	Hydro	115	1	Jul	
	2	Hydro	115	1	Jul	
		Hydro	4	1	Jul	
Annapolis		Hydro	8	1	Jul	
Avon		Hydro	21	1	Aug	
Black River		Hydro	7	1	Aug	
Nictaux		Hydro	13	1	Aug	
Lequille		Hydro	6	1	Sep	
Paradise		Hydro	44	1	Sep	
Mersey		Hydro	25	1	Sep	
Sissiboo		Hydro	11	1	Jun	
Bear River		Hydro	3	1	Jun	
Tusket		Hydro	1	1	Jun	
Roseway		Hydro	10	1	Jul	
St. Margrets		Hydro	11	1	Jul	
Sheet Harbour		Hydro	3	1	Aug	
Dickie Brook		Hydro	1	1	Aug	
Fall River						
IPP	All	NUG	25			

TABLE A-2 Cont'd

MECL Resources						
Plant	**Unit**	**Type**	**Capacity MW**	**Maintenance**		**Notes**
				Weeks	**Period**	
Charlottetown	5	Oil	3	3	Jun	
	6	Oil	7	3	Jun	
	7	Oil	7	3	Aug	
	8	Oil	10	3	Oct	
	9	Oil	19	3	Aug	
	10	Oil	19	3	Jun	
Borden	1	CT	15	3	Jul	
	2	CT	27	3	Sep	
Chtown GT/HRSG	1	CT	25	3	Aug	In-service Aug 2001
	2	CT	25	3	Oct	In-service Aug 2005

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

TABLE A-3

SUMMARY OF CHANGES IN CAPACITY				
Year	**January Capacity**	**December Capacity**	**Capacity Change**	**Explanation**
1998	6072	6472	400	HQ Purchase (+300), Millbank 1 (+100)
1999	6472	6472	0	
2000	6471	6643	172	Tufts Cove (-1), Courtenay Bay (+172)
2001	6643	6368	-275	HQ Purchase (-300), Chtown GT/HRSG 1 (+25)
2002	6368	6468	100	Millbank 2 (+100)
2003	6468	6468	0	
2004	6638	6581	113	Grand Lake 8 (-57), Combustion Turbine (+170)
2005	6581	6606	25	Chtown GT/HRSG 2 (+25)
2006	6606	6606	0	
2007	6606	6508	-98	Courtenay Bay (-98)

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 included forced outages, unplanned maintenance outages, deferrable forced outages and planned outages. All except the last 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 Electrical Association (CEA).

FORs for new units are based upon the utilities' experience with similar units in conjunction with averages compiled by the Canadian Electrical 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.

TABLE A-4

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

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 Maritime 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 of Demand Side Management programs on each utilitiy is included in the Maritime Area forecast in Table A-1.

1.6 Modelling of Non-Utility Generation

NB Power and NS Power each represent non-utility capacity as a single unit with operating characteristics and FORs equivalent to other Maritime Area units of similar size. These are tabulated in Table A-2 and are identified by type NUG.

1.7 Other Assumptions

It was determined that there were no internal transmission limitations. It is assumed that there are no unit slippages or or unit deratings due to environmental constraints.

APPENDIX B

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 January, 1994.

The program is a single area program which 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.