10 Year System Outlook
2010-2019
Draft Report

June 30, 2010

NOVA SCOTIA
POWER
An Emera Company

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1.0 INTRODUCTION

Nova Scotia Power Inc.'s (NSPI, the Company) filing of June 30, 2008 provided the initial 10 Year System Outlook. Following NSPI's second annual 10 Year System Outlook filing on June 30, 2009, the Nova Scotia Utility and Review Board (UARB, Board), in its letter dated January 11, 2010 provided the following:

> Recognizing the direct relationship among the Outlook, the IRP, and the ACE Plan, the Board anticipates that any significant recommendations resulting from these briefings will be incorporated by NSPI into its 2010 Outlook report.

Consistent with the 3.4.2.1[1] Market Rule requirements and the subsequent Board direction, the 2010 Outlook contains the following:

1. A summary of the NSPI load forecast employed in the Outlook;
2. An update on the DSM program undertaken by the Company;
3. A summary of generation expansion anticipated for facilities owned by NSPI and others;
4. A discussion of transmission planning issues, including comment on related issues raised in the Board's letter;
5. Identification of transmission-related capital projects currently in the Transmission Expansion Plan;
6. An overview of potential transmission development scenarios pending the outcome of generation development, inside and outside of Nova Scotia.

The basis for the 2010 Outlook is the assumptions employed in the 2009 Integrated Resource Plan (IRP) Update. The assumptions have been developed by NSPI and the Board's consultants, with input from IRP stakeholders.

1 The NSPSO system plan will address: a) transmission investment planning; b) DSM programs operated by NSPI Customer Service division or others; c) NSPI generation planning for existing Facilities, including retirements as well as investments in upgrades, refurbishment or life extension; d) new Generating Facilities committed in accordance with previous approved NSPSO system plans; e) new Generating Facilities planned by Market Participants or Connection Applicants other than NSPI, and f) requirements for additional DSM programs and / or generating capability (for energy or ancillary services).

2.0 LOAD FORECAST

The NSPI load forecast provides an outlook on the energy and peak demand requirements of in-province customers. The forecast provides the basis for the financial planning and overall operating activities of the Company.

The forecast is based on analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market and the price and availability of other energy sources. Weather conditions, in particular temperature, affect electrical energy and peak demand. The forecast is based on the 10-year average temperatures measured in the Halifax area of the Province. The values presented in the tables below reflect the effects of current and proposed Conservation and Demand Side Management programs.

Table 1 shows historical and forecast total annual energy requirements. The highest months of energy consumption in Nova Scotia are December through February due to the electric heating load in the Province. The Net System Requirement (NSR) for the province had grown at an average of 0.9 percent per year in the five year period from 2003-2008 and declined by 3.7 percent in 2009 due to the economic recession. With the exception of 2010 when the NSR is expected to increase by 2.7% due to economic recovery, NSR is forecast to decline an average of 0.8 percent annually over the next 10 years with the effects of Conservation and Demand Side Management programs. Without the effects of these programs, the NSR is forecast to grow an average of 1.1 percent annually.

NSPI is also cognizant in its planning of the potential for new load which could emerge from shifts away from fossil fuels for transport and other economic uses of electricity which could increase in time.

NSPI also forecasts the peak hourly demand for future years. This process uses forecast energy requirements and expected load shapes (hourly consumption files) for the various customer classes. Load shapes are derived from historical analysis, adjusted for expected changes (e.g. customer plans to add major equipment). Table 2 shows the historical and forecast net system peak.

Table 1 – Total Energy Requirement with Future DSM Program Effects (Source: 2010 NSPI Load Forecast)

Year	Net System Requirement (GWh)	Growth Rate (%)
2001	11,303	0.6
2002	11,501	1.8
2003	12,009	4.4
2004	12,388	3.2
2005	12,338	-0.4
2006	10,946	-11.3
2007	12,640	15.5
2008[2]	12,539	-0.8
2009[3]	12,073	-3.7
2010F	12,397	2.7*
2011F	12,444	0.4
2012F	12,471	0.2
2013F	12,382	-0.7
2014F	12,255	-1.0
2015F	12,138	-1.0
2016F	11,994	-1.2
2017F	11,844	-1.3
2018F	11,704	-1.2
2019F	11,560	-1.2
2020F	11,394	-1.4

Note:
Actual growth rates for 2006 and 2007 were -11.3 percent and 15.5 percent respectively, which reflects one of NSPI's largest customers having a temporary shutdown and remaining closed for nine months in 2006. In 2007 the plant returned to normal full load operations.
*Increase is the result of forecasted economic recovery.

[2]Actual results include the effects of 2008 DSM programs on 2008 load estimated at 4.6 GWh
[3] Actual results include the effects of 2008 and 2009 DSM programs on 2009 load estimated at 41.2 GWh

Table 2 – Coincident Peak Demand with Future DSM Program Effects

(Source: 2010 NSPI Load Forecast)

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1	369	-10.4	1,619	1.4
2002	2,078	4.5	348	-5.7	1,730	6.9
2003	2,074	-0.2	291	-16.4	1,783	3.1
2004	2,238	7.9	377	29.6	1,861	4.4
2005	2,143	-4.2	392	4.0	1,751	-5.9
2006	2,029	-5.3	386	-1.5	1,644	-6.1
2007	2,145	5.7	381	-1.3	1,764	7.3
2008	2,192	2.2	352	-7.5	1,840	4.3
2009	2,092	-4.5	268	-23.9	1,824	-0.8
2010F	2,290	9.5*	324	21.0*	1,966	7.8
2011F	2,301	0.5	326	0.7	1,975	0.4
2012F	2,302	0.0	325	-0.4	1,977	0.1
2013F	2,282	-0.9	318	-2.1	1,964	-0.7
2014F	2,254	-1.2	310	-2.7	1,945	-1.0
2015F	2,229	-1.1	302	-2.5	1,927	-0.9
2016F	2,197	-1.4	294	-2.6	1,903	-1.2
2017F	2,165	-1.5	286	-2.6	1,879	-1.3
2018F	2,134	-1.4	279	-2.5	1,855	-1.2
2019F	2,103	-1.5	272	-2.4	1,831	-1.3
2020F	2,066	-1.7	266	-2.3	1,800	-1.7

*Increase is the result of forecasted economic recovery.

3.0 DEMAND SIDE MANAGEMENT FORECAST

The table below summarizes annual projected demand and energy savings included in the Load Forecast in Section 2.0. The trajectory is consistent with the DSM profile from the 2009 IRP Update adjusted for early year changes.

Table 3 – Demand Side Management Forecast *

Year	Cumulative Demand Savings (MW)	Cumulative Energy Savings (GWh)
2010	12	66
2011	33	179
2012	73	354
2013	126	610
2014	187	900
2015	245	1176
2016	302	1452
2017	358	1724
2018	414	1989
2019	467	2247
2020	520	2499

Note: Cumulative Demand Savings include interruptible customers

*The DSM Forecast values represent the difference between the “With DSM” and “Without DSM” load forecast values of the April 2010 Load Forecast.

On June 7, 2010, the Board approved the $41.9 million overall expenditure associated with NSPI’s application for the 2011 DSM Plan. Going forward the new DSM Administrator, Efficiency Nova Scotia Corporation, will manage this function. This process is expected to be in operation by February 2011.

4.0 GENERATION RESOURCES

4.1 Existing Generation Resources

Nova Scotia's generation portfolio is comprised of a mix of fuel types that includes coal, petroleum coke, light and heavy oil, natural gas, wind and hydro. In addition NSPI purchases energy from independent power producers located in the province and imports power across the NSPI/NB Power inter-tie. Table 4 lists NSPI's generating stations/ systems along with their fuel types and net operating capacities based on the assumptions used in the 2009 IRP Update. It has been updated to include changes and new additions effective January 2010.

Table 4 – 2010 Generating Resources

(Data sourced from 2009 IRP Update Assumptions)

Plant/System	Fuel Type	Winter Net Capacity
Avon	Hydro	7.6
Black River	Hydro	23
Lequille System	Hydro	26
Bear River System	Hydro	39.5
Roseway	Hydro	1.6
Tusket	Hydro	2.7
Mersey System	Hydro	42
St. Margaret's Bay	Hydro	10
Sheet Harbour	Hydro	10
Dickie Brook	Hydro	2.5
Wreck Cove	Hydro	212
Annapolis Tidal*	Hydro	3.7
Fall River	Hydro	0.5
Total Hydro		**381.1**
Tufts Cove	Heavy Fuel Oil/Natural Gas	321.0
Trenton	Coal/Pet Coke/Heavy Fuel Oil	307.0
Point Tupper	Coal/Pet Coke/Heavy Fuel Oil	152.0
Lingan	Coal/Pet Coke/Heavy Fuel Oil	617.0
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	171.0
Total Steam		**1568.0**
Tufts Cove	Natural Gas	98.0
Burnside**	Light Fuel Oil	132.0

Plant/System	Fuel Type	Winter Net Capacity
Tusket	Light Fuel Oil	24.0
Victoria Junction	Light Fuel Oil	66.0
Total Combustion Turbine		**320.0**
Contracts (pre-2001)	Independent Power Producers	25.8
Renewables(firm) (post 2001)***	Independent Power Producers	42.3
NSPI wind (firm)***	Wind	0.3
Total IPPs & Renewables		**68.4**
Total Capacity		**2337.5**

*Capacity of Annapolis Tidal Unit is based on an average performance level at peak time. Nameplate capacity (achieved at low tide) is 19.4 MW.
**Burnside unit #4 (winter capacity of 33 MW) is presently unavailable but can be returned to service in a relatively short time period. It continues to be included as a resource; however, it has not been returned to service yet as asset management plans for the Burnside fleet are being re-assessed.
*** The assumed firm capacity value of wind reflects the assumed firm capacity contribution based on a three year average of actual capacity factor during peak hours and the annual forecasted value (as per formula agreed on by NSPI and the Renewable Energy Industry Association of Nova Scotia and as employed in NSPI 2009 IRP Update modeling). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

4.2 Changes in Capacity

Table 5 provides the firm Supply and Demand Side Management capacity additions per the Port Hawkesbury (PH) Biomass Project Base Case Plan (as filed with UARB in P-128.10 April 9, 2010) over the 2010-2020 time period. This Plan is based on the 2009 IRP Update assumptions and analysis, modified to include the PH Biomass Project. For DSM, the amounts shown are reductions in forecast firm demand for the period. Amounts shown as Hydro include relatively small capacity additions to NSPI's existing generation fleet. The PH Biomass Project is configured as an Energy Resource Interconnection Service (ERIS) (refer to Section 5.1) and is not included in the Table.

Table 5 – Capacity Additions & DSM

New Resources 2010-2020	MW
DSM firm*	434
Tufts Cove 6	48.9
Hydro**	4.2
Firm Contracted Wind***	51.0
Nuttby Wind Project***	15.8
Firm RES (2015)****	40
Total Firm Supply & Demand MW Projected Over Planning Period	**593.9**

Notes:
* DSM Firm does not include interruptible customers
** Hydro shown is Marshall at 4.2 MW as per the 2009 Update assumptions.
*** Firm Contracted wind and Nuttby wind reflects the assumed firm capacity contribution based on a combined three year average of actual capacity factor during peak hours and the annual forecasted value (as per formula agreed on by NSPI and the Renewable Energy Industry Association of Nova Scotia and as employed in NSPI 2009 IRP Update modeling).
**** Firm RES (2015) represents an addition of renewable energy to comply with the 2015 RES recently announced in the Province's Renewable Electricity Plan in April 2010. The value in the table reflects an assumed firm capacity value of intermittent wind generation of approximately 40 percent based on the winter capacity factor for long-term planning purpose (generator capacity multiplied by the winter capacity factor of 40 percent). An annual capacity factor of 32 percent was assumed for determining annual energy from the wind installation. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

5.0 NEW GENERATING FACILITIES

5.1 Potential New Facilities

As of late June 2010, NSPI's interconnection request queue includes 1,382 MW of proposed generation projects at various stages of interconnection study. Sponsors of these projects have requested either Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS). NRIS refers to a firm capacity request with the potential for transmission reinforcement upon completion of the System Impact Study (SIS). ERIS refers to a requested capacity but only to the point where transmission reinforcement will not be required. The effect of this on installed firm capacity will continue to be monitored. Results of the various interconnection studies will be incorporated into future transmission plans. Table 6 provides NSPI's interconnection request queue as of June 23, 2010.

Table 6 – Generation Interconnection Queue

Nova Scotia Power - Interconnection Request Queue

NOVA SCOTIA POWER
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Publish Date: *Wednesday, June 23, 2010*

Queue Order	IR #	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date DD-MMM-YY	Status	Service Type	Studies Available
1	45	19-Jan-05	Cumberland	30	30	L-6535	Wind	01-Oct-12	Unexecuted GIA Filed	N/A	
2	82	15-Nov-06	Colchester	45	45	L-5040	wind	01-Dec-10	GIA Executed	ERIS	
3	114	23-Mar-07	Pictou	60	60	L-6511	wind	30-Oct-10	Unexecuted GIA Filed	ERIS	
4	141	20-Apr-07	Digby	30	30	77V	wind	31-Aug-10	GIA Executed	NRIS	
5	8	14-Oct-03	Guysborough	13.8	13.8	L-5527B	Wind	20-Sep-12	GIA in Progress	N/A	
6	56	19-Aug-05	Cumberland	34	34	L-5058	Wind	30-Nov-08	Facilities Study in Progress	ERIS	
7	151	22-Aug-07	Halifax	50	50	91H	steam turbine	30-Jun-10	Impact Study in Progress	NRIS	
8	67	27-Apr-06	Annapolis	40	40	L-5026	Wind	31-Oct-10	Impact Study Agrmnt Complete	ERIS	
9	68	27-Apr-06	Digby	35	35	L-5533	Wind	31-Oct-10	Impact Study Agrmnt Complete	ERIS	
10	86	09-Jan-07	Pictou	50	50	L-7003	wind	01-Jan-09	Impact Study Agrmnt Complete	NRIS	
11	115	23-Mar-07	Pictou	120	120	L-7003	wind	30-Nov-09	Impact Study Agrmnt Complete	NRIS	

Nova Scotia Power - Interconnection Request Queue: Page 1 of 3

ERIS - Energy Resource Interconnection Service
NRIS - Network Resource Interconnection Service
N/A - Not Applicable

Queue Order	IR #	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date DD-MMM-YY	Status	Service Type	Studies Available
12	117	13-Apr-07	Shelburne	10	10	L-5027	wind	01-Sep-09	Impact Study Agrmnt Complete	ERIS	
13	126	16-Apr-07	Cumberland	70	70	L-6513	wind	31-Dec-09	Impact Study Agrmnt Complete	ERIS	
14	128	17-Apr-07	Cumberland	40.5	40.5	L-6535	wind	20-Nov-09	Impact Study Agrmnt Complete	ERIS	
15	130	17-Apr-07	Cape Breton	200	200	L-7012	wind/water	31-Dec-09	Impact Study Agrmnt Complete	NRIS	
16	131	17-Apr-07	Cape Breton	11.5	11.5	L-5580	wind	30-Nov-09	Impact Study Agrmnt Complete	ERIS	
17	140	20-Apr-07	Antigonish	30	30	L-7004	wind	01-Nov-09	Impact Study Agrmnt Complete	NRIS	
18	149	05-Jul-07	Cumberland	70	70	L-6536	wind	20-Nov-09	Impact Study Agrmnt Complete	ERIS	
19	156	16-May-08	Antigonish	49.5	49.5	L-6511	Wind	31-Dec-10	Impact Study Agrmnt Complete	NRIS	
20	157	16-May-08	Guysborough	49.5	49.5	L-6515	Wind	31-Dec-10	Impact Study Agrmnt Complete	NRIS	
21	163	28-Jan-09	Richmond	60	60	47C	Steam	30-Apr-11	Impact Study Agrmnt Complete	NRIS	
22	213	29-Jul-09	Cumberland	15	15	37N	Tidal	31-Dec-10	Impact Study Agrmnt Complete	ERIS	
23	219	08-Apr-10	Richmond	64	64	47C	Steam	31-Dec-12	Feasibility Study In Progress	ERIS	
24	222	26-Apr-10	Pictou	48	48	L-5508	Steam	31-Aug-12	Feasibility Study In Progress	NRIS	
25	223	30-Apr-10	Cape Breton	16	16	L-6540	Biomass	15-Dec-12	Feasibility Study In Progress	NRIS	

Nova Scotia Power - Interconnection Request Queue: Page 2 of 3

ERIS - Energy Resource Interconnection Service
NRIS - Network Resource Interconnection Service
N/A - Not Applicable

Queue Order	IR #	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date DD-MMM-YY	Status	Service Type	Studies Available
26	225	03-May-10	Pictou	70	70	L-7004	Wind	31-Dec-12	Feasibility Study In Progress	NRIS	
27	226	03-May-10	Kings	70	70	L-6013	Wind	31-Dec-12	Feasibility Study In Progress	NRIS	
		Totals:		1381.8	1381.8						

Nova Scotia Power - Interconnection Request Queue: Page 3 of 3

ERIS - Energy Resource Interconnection Service
NRIS - Network Resource Interconnection Service
N/A - Not Applicable

Included in this interconnection queue is 165 MW of wind energy projects which are part of NSPI's Renewable Energy Standards (RES) commitment for 2011. In addition to these wind projects, the queue contains a 50 MW, NSPI-owned steam project (NSUARB Approved), a 60 MW Biomass Project, a 15 MW wind project that is at the GIA negotiation stage and a 34 MW wind project that is at the Facilities Study stage. All remaining projects in the queue are considered to be at the initial queue stage as they have not yet proceeded to the System Impact Study stage of the Revised Generator Interconnection Procedures. Table 7 indicates the location and size of the planned generating facilities.

Table 7 – RES-committed Renewable Generation Projects

Company/Location	**Nameplate Capacity MW**
Acciona Wind Energy Canada at Amherst	30
Shear Wind Inc. at Brown's Mountain Range in Pictou and Antigonish Counties	60
NSPI at Nuttby Mountain in Colchester County	45
NSPI/Emera at Gulliver's Cove in the Municipality of Digby	30
NSPI at Tuft's Cove, Dartmouth	50
Total New Facilities Nameplate Capacity	**215**

NSPI also has an application before the Board for approval of a 60 MW biomass generation project located in the Port Hawkesbury area. A draft of the System Impact Study required to determine the transmission effects of this project has been completed.

5.2 Renewable Electricity Plan

In April, 2010, the Nova Scotia Department of Energy (DOE) released its Renewable Electricity Plan, which sets out the Province's commitment to renewable electrical energy supply. This plan includes a legislated renewable energy target of 25 percent by 2015, as well as a goal of 40 percent by 2020.

In addition to these targets, the plan includes revised processes for procurement of large and medium-sized renewable projects, implements a Community-Based Feed-in-Tariff (COMFIT) for up to 100MW of community-owned projects connected to the distribution system and provides for enhanced net-metering for renewable projects up to 1 MW in capacity.

Implementation timelines and uptake rates for the programs remain to be determined and will be monitored.

5.3 Province's Wind Integration Study

The 2008, Hatch Ltd. Wind Integration Study identified and assessed the effects of integrating large scale wind power generation into Nova Scotia's electric power system. This study confirmed that "more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure."[4]

NSPI has begun monitoring the effects of variable energy sources of an intermittent nature, such as wind, to be better prepared to forecast and schedule production loads and hence determine possible implications to system stability and availability.

5.4 Other Opportunities

In addition to the above, potential developments outside of Nova Scotia (e.g. Lower Churchill and Point Lepreau II), if implemented, would influence the Company's long-term resource plan in general and transmission system development, in particular. These developments continue to be monitored.

[4] Final Report, Nova Scotia Wind Integration Study, 2008, Hatch Ltd., p.11-13.

6.0 RESOURCE ADEQUACY

6.1 Operating Reserve Criteria

As a member of the Maritimes Area of the Northeast Power Coordinating Council (NPCC), NSPI meets the operating reserve requirements as outlined in *NPCC Document A-6, Operating Reserve Criteria*. This criteria is reviewed and adjusted periodically by NPCC. The criteria note that:

> The ten-minute reserve available to each Area shall at least equal its first contingency loss…and,
>
> The thirty-minute reserve available to each Area shall at least equal one half its second contingency loss.

In the *Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO)*, NSPI and the NBSO have agreed to share the reserve requirement for the Maritimes Area on the following basis:

> The Ten-Minute Reserve Responsibility, for contingencies within the Maritimes Area, will be shared between the two Parties based on a 12CP [coincident peak] Load-Ratio Share…. Notwithstanding the Load-Ratio Share the maximum that either Party will be responsible for is 100 percent of its greatest, on-line, net single contingency, and,
>
> NSPI shall be responsible for 50 MW of Thirty-Minute Reserve.

NSPI maintains a ten minute operating reserve of 171 MW, of which approximately 36 MW is held as spinning reserve. Additional regulating reserve is maintained to manage the variability of customer load and generation. It is anticipated that regulating reserve requirements will increase with the addition of wind generation resources due to the added variability that will be introduced.

NSPI performs an assessment of operational resource adequacy covering an 18 month period two times a year (in April and October preceding the summer and winter capacity periods). These reports of system capacity and adequacy are posted on the NSPI OASIS site in the Forecast and Assessments section.

6.2 Planning Reserve Criteria

NSPI is required to comply with the NPCC reliability criteria. These criteria are outlined in *NPCC Reliability Reference Directory #1 – Design and Operation of the Bulk Power System*[5] and states that:

> The probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than once in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. 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 Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

NSPI maintains a capacity based planning reserve margin equal to 20 percent of its firm system load in order to comply with the NPCC criteria. To assess the resource adequacy of the system, the New Brunswick System Operator, as Reliability Coordinator, submits a resource adequacy review to NPCC on behalf of the Maritimes Area. This review is completed every three years with interim reviews completed annually. In the most recent comprehensive review, the *2007 Maritimes Area Comprehensive Review of Resource Adequacy*,[6] it was found that the NPCC criteria would be met with a 20 percent reserve margin for the Maritimes area along with 50 MW of additional capacity provided by interconnection assistance. This confirms that the 20 percent planning reserve margin applied by NSPI is acceptable under the NPCC reliability criteria.

[5] http://www.npcc.org/viewDoc.aspx?name=A-02.pdf&cat=regStandCriteria
[6] http://www.npcc.org/viewDoc.aspx?name=2007 Maritimes Area Comprehensive Review.pdf&cat=revResource

6.3 Load and Resources Review

The ten year load forecast and resources additions in Table 8 below are based on the capacity additions and DSM forecast in Table 5. Table 8 indicates that a planning reserve margin equal to 20 percent of the firm peak load is maintained.

Table 8 – NSPI 10 Year Load and Resources Outlook

Load and Resources Outlook for NSPI - Winter 2010/2011 to 2019/2020 (All values in MW except as noted)											
		2010/2011	**2011/2012**	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**
A	Firm Peak Load Forecast	2,000	2,039	2,071	2,102	2,132	2,156	2,178	2,200	2,220	2,234
B	DSM Firm	26	62	107	157	205	252	299	345	390	434
C	Peak Firm Less DSM (A - B)	1,975	1,977	1,964	1,945	1,927	1,903	1,879	1,855	1,831	1,800
D	Required Reserve (C * 20%)	395	395	393	389	385	381	376	371	366	360
E	Required Capacity (C + D)	2,370	2,372	2,356	2,334	2,313	2,284	2,254	2,226	2,197	2,160
F	Existing Resources	2338	2338	2338	2338	2338	2338	2338	2338	2338	2338
	Total Cumulative Additions:										
G	Thermal	49	49	49	49	49	49	49	49	49	49
H	Hydro	0	4	4	4	4	4	4	4	4	4
I	Firm Contracted Wind*	43	51	51	51	51	51	51	51	51	51
J	Nuttby Wind Project (firm)*	16	16	16	16	16	16	16	16	16	16
K	Firm RES (2015)**	0	0	0	0	40	40	40	40	40	40
L	Total Firm Supply Resources (F + G + H + I + J + K)	2445	2458	2458	2458	2498	2498	2498	2498	2498	2498
	+ Surplus / - Deficit (L - E)	75	85	101	124	185	213	243	271	301	337
	Reserve Margin % (L/C -1)	24%	24%	25%	26%	30%	31%	33%	35%	36%	39%

*Firm Contracted wind and Nuttby Wind reflects the assumed firm capacity contribution based on a combined three year average of actual capacity factor during peak hours and the annual forecasted value (as per formula agreed on by NSPI and the Renewable Energy Industry Association of Nova Scotia and as employed in NSPI 2009 IRP Update modeling).

**Firm RES (2015) represents an addition of renewable energy to comply with the 2015 RES recently announced in the Province's Renewable Electricity Plan in April 2010. The value in the table reflects an assumed firm capacity value of intermittent wind generation of approximately 40 percent based on the winter capacity factor for long-term planning purposes (generator capacity multiplied by the winter capacity factor of 40 percent). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

7.0 TRANSMISSION PLANNING

7.1 System Description

The existing transmission system has over 5,200 kilometres of transmission lines at voltages at the 69 kV, 138 kV, 230 kV and 345 kV levels.

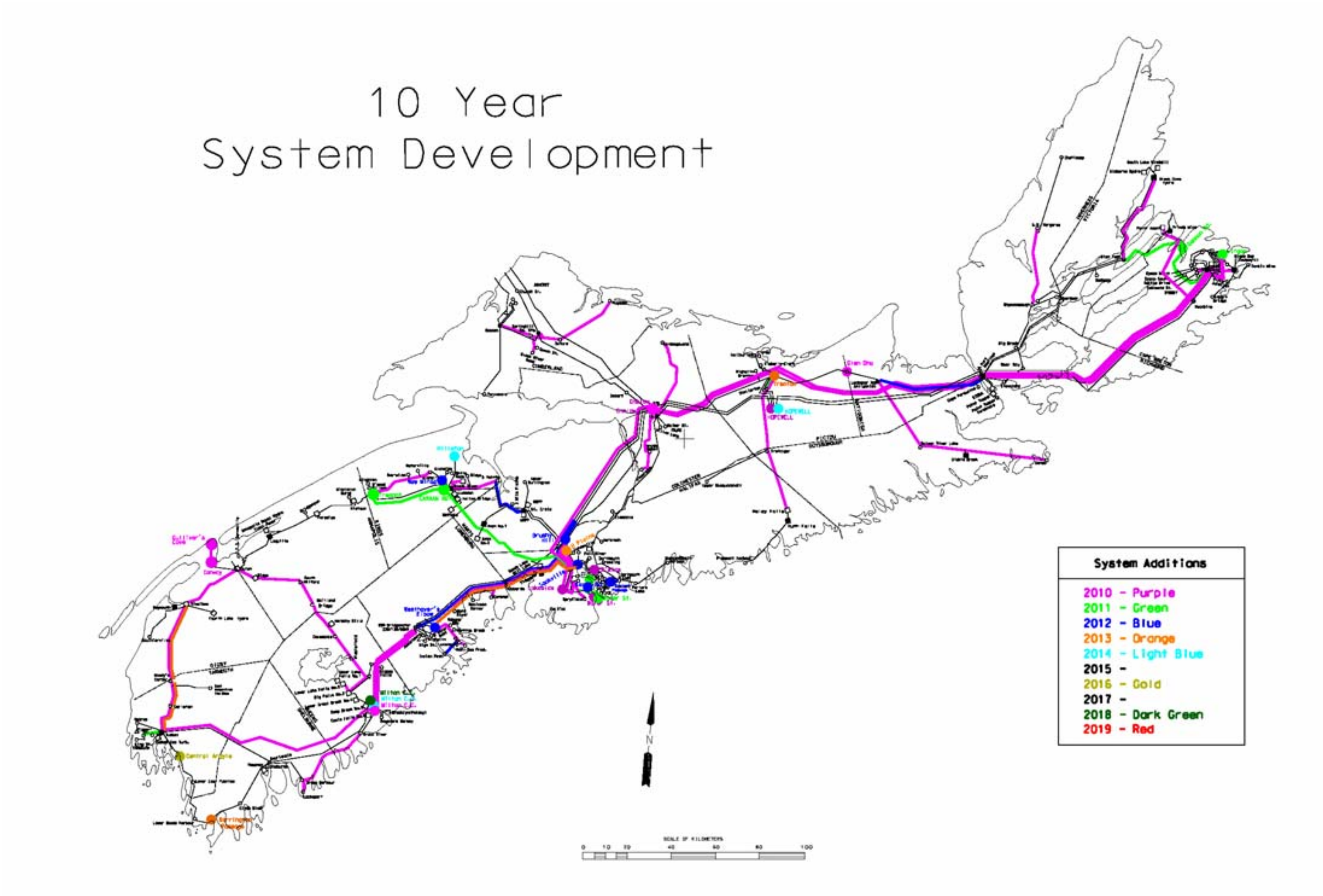
- The 345 kV transmission system is approximately 468 kilometres in length and is comprised of 372 kilometres of steel tower lines and 96 kilometres of wood pole lines.

- The 230 kV transmission system is approximately 1253 kilometres in length and is comprised of 47 kilometres of steel/laminated structures and 1206 kilometres of wood pole lines.

- The 138 kV transmission system is approximately 1786 kilometres in length and is comprised of 303 kilometres of steel structures and 1483 kilometres of wood pole lines.

- The 69 kV transmission system is approximately 1627 kilometres in length and is comprised of 12 kilometres of steel/concrete structures and 1615 kilometres km of wood pole lines.

Nova Scotia is interconnected with the New Brunswick electric system through one 345 kV and two 138 kV lines providing up to 350 MW of transfer capability to New Brunswick and up to 300 MW of transfer capability from New Brunswick, depending on system conditions. As the New Brunswick system is interconnected with the province of Quebec and the state of Maine in USA, Nova Scotia is integrated into the NPCC power system.



7.2 Transmission Design Criteria

NSPI, consistent with good utility practice, utilizes a set of deterministic criteria for its interconnected transmission system that combines protection performance specifications with system dynamics and steady state performance requirements.

The approach used has involved the subdivision of the transmission system into various classifications each of which is governed by distinct design criteria (see Appendix A). In general, the criteria require the overall adequacy and security of the interconnected power system to be maintained following a fault on and disconnection of any single system component.

The NSPI bulk transmission system is planned, designed and operated in accordance with single contingency criteria. NSPI is a member of the Northeast Power Coordinating

Council (NPCC). Those portions of Nova Scotia Power's bulk transmission network wherein single contingencies can potentially adversely affect the interconnected NPCC system are designed and operated in accordance with the NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems*.

NSPI makes extensive use of Special Protection Systems (SPS) within SCADA to maximize the utilization of transmission assets. These systems act to maintain system stability and remove equipment overloads, post contingency, by rejecting generation and/or shedding load. The NSPI system has several transmission corridors that are regularly operated at limits without incident due to these SPS's.

7.3 Transmission Life Extension

NSPI has in place a comprehensive maintenance program on the transmission system aimed at maintaining reliability and extending the useful life of transmission plant. The program is centered on detailed transmission plant inspections and associated prioritization of plant replacement (i.e., poles, crossarms, guywires, and hardware replacement).

The table below lists the lines within the NSPI transmission system which have undergone maintenance over the past two years along with proposed planned maintenance for 2010:

2008	2009	2010
L5003 (Farrell St.-Sackville)	L5003(Farrell St.-Sackville)	L5017(5 Points-Canaan)
L5014 (St. Croix-Burlington)	L5004(Sackville-Geizer Hill)	L5029(Maccan-Springhill)
L5015 (St. Croix-Avon #1)	L5017(Canaan-Five Points)	L5030(Aberdeen-Black River)
L5019 (CanaanRd.-Hollow Bridge)	L5039(Spryfield-Geizer Hill)	L5035(Hells Gate-Canaan)
L5020 (Hollow Bridge-Methals)	L5500(Trenton-Stellarton)	L5037(East River-Canexel)
L5023 (Waterville Tap-Waterville)	L5510(Stellarton-Malay Falls)	L5039(Lakeside-Spryfield)
L5029 (Maccan-Springhill)	L5511(Trafalgar-Malay Falls)	L5040(Onslow-Tatamagouche)

2008	2009	2010
L5031 (Mill Lake-Robinson's Corner)	L5512(Malay Falls-Ruth Falls)	L5048(Green Harbour-Lockport)
L5033 (Canaan Rd.-Hillaton)	L5521(Onslow-Truro)	L5058(Springhill-Pugwash)
L5040 (Onslow-Tatamagouche)	L5573(VJ-Lingan Mine)	L5527(Antigonish-Canso)
L5055 (Tap to Rio Algom)	L6003(Tufts Cove-Sackville)	L5532(Gulch-Big Falls)
L5506 (Abercrombie-Pictou)	L6004(Sackville-Canaan Road)	L5535(Sissiboo-Tusket)
L5534 (Tusket-Hebron)	L6006(Bridgewater-Milton)	L5544(Big Falls-Upper Lake Falls)
L5537 (Tusket-Gas Turbine)	L6013(Canaan Road-Tremont)	L5547(Westhavers Elbow-Lunenburg)
L5538 (Sissiboo-Weymouth)	L6014(Kempt Road-Tufts Cove)	L5559(Whycocomagh-SW Margaree)
L5550 (Maccan-Parrsboro)	L6035(Water St.-Kempt Road)	L5560(VJ-Townsend St.)
L5551 (Lunenburg-Riverport)	L6038(Lakeside-Kearney Lake)	L5561(VJ-Seaboard)
L5561 (VJ-Seaboard)	L6515(Lochaber Road-Hastings)	L5569(Terrace-Townsend)
L5563 (VJ-Townsend St.)	L6516(Hastings-VJ)	L6006(Bridgewater-Milton)
L5564 (VJ-Keltic Drive)	L6517(Hastings-Tupper)	L6010(Brushy Hill-Sackville)
L5565 (Seaboard-Albert Bridge)	L6518(Hastings-NewPage)	L6016(Brushy Hill-Lakeside)
L5572 (VJ-Seaboard)	L6523(Tupper-NewPage)	L6024(Milton-Tusket)
L5579 (Cheticamp-S.W. Margaree)	L6540(VJ-Sysco)	L6025(Bridgewater-Milton)
L6004 (Sackville-Canaan Rd.)	L6545(Wreck Cove-Glen Tosh)	L6516(Hastings-VJ)
L6008 (Sackville-Lakeside)	L6549(Wreck Cove-Glen Tosh)	L6531(Milton-Bridgewater)
L6013 (Canaan Rd.-Tremont)	L7001(Onslow-Brushy Hill)	L6545(Glentosh-Wreck Cove)
L6024 (Milton-Tusket)	L7002(Onslow-Brushy Hill)	L7012(Hastings-Lingan)
L6518 (Pt. Hastings-Stora)	L7011(Hastings-Lingan)	L7015(Pt. Aconi-Woodbine)
L6527 (Onslow Tie Line)	L8001(Onslow-NB Border)	L5530B(Broad River-East Green Harbour)
L6533 (VJ-Lingan)	L6005A(Brushy Hill-Sackville)	L5547A(Mahone Bay Tap-Mahone Bay)
L6536 (Springhill-NB Border)	L6005B(Brushy Hill-Sackville)	L5564A(Terrace St. Tap)
L6538 (Glen Tosh-Gannon Rd.)	L5560(VJ-Townsend Street)	L7003(Onslow-Hastings)
L5032(Rockingham-Rockingham Tap)		L7011(Lingan-Hastings)

2008	2009	2010
L6515(Antigonish-Lochaber Road)		L6002(Sackville-Gold River)
L5004(Sackville-Geizer Hill)		Various Insulator Replacements
L5011(Farrell St.-Imperial Oil)		
L7009 (Brushy Hill-Bridgewater)		
L5024B (Tremont-Greenwood)		
L5031A (Mill Lake-Middle River)		
L5536A (Tusket-Pleasant St.)		
L5536B (Pleasant St.-Hebron)		
L6012B (St. Croix-Canaan Rd.)		
L5539 (Milton-Liverpool)		
L5541 (Milton-Big Falls)		
L6003 (Tuft's Cove-Sackville)		
L6503 (Onslow-Trenton)		
L7002 (Onslow-Brushy Hill)		
L7008 (Brushy Hill-Bridgewater)		
L8002 (Lakeside-Onslow)		
L5579 (Cheticamp-SW Margaree)		
L5027 (Tusket-Souriquois)		
L6002 (Sackville-Bridgewater)		
L6020 (Milton-Souriquois)		
L7005 (Onslow-Pt. Hastings)		
L7014 (Lingan-Woodbine)		
L5535 (Sissiboo-Tusket)		
L5576 (Gannon RD-Keltic Drive)		
L7011 Pt. Hastings-Lingan)		
L5004 (Sackville-Geizer Hill)		
L5573 (VJ-Lingan Mine)		
L6035 (Water St.-Kempt Rd.)		
L6537 (Hastings-Glen Tosh)		
L8004 (Hopewell-Woodbine)		
L5532 Gulch-Big Falls)		
L7003(Onslow-Hastings)		
L7004(Onslow-Hastings)		

2008	2009	2010
L8003(Onslow-Hopewell)		

Nova Scotia Power also has in place a pole retreatment program that enables the useful life of plant to be extended.

The table below lists the lines within the NSPI transmission system which have undergone pole retreatment over the past two years along with proposed pole retreatment for 2010.

2008	2009	2010
L5031(MillLake-Robinsons Corner)	L5036(Berwick Tap-Berwick)	L5014(St. Croix-Burlington)
L5033(Canaan Rd.-Hillaton)	L5037(East River-Louisiana Pacific)	L5015(St. Croix-Avon)
L5053(Michelin-Tremont)	L5046(5017 Tap-Wolfville Ridge)	L5020(Hollow Bridge-Methals)
L5540(Milton-Deep Brook)	L5047(5026 Tap-Bridgetown)	L5021(Canaan Rd.-Klondike)
L5544(Big Falls-Upper Lake Falls)	L5056(5026 Tap-Annapolis)	L5506(Abercrombie-Pictou)
L5545(Bridgewater-High St.)	L5521(Onslow-Willow Lane)	L5510(Stellarton-Malay Falls)
L5555(Gannon Rd.-Prince)	L5536(Tusket-Hebron)	L5511(Trafalgar-Upper Musquodoboit)
L5560(VJ-Townsend St.)	L6005(Brushy Hill-Sackville)	L5512(Malay Falls-Ruth Falls)
L5563(VJ-Townsend St.)	L6024(Milton-Tusket)	L5531(Gulch-Sissiboo)
L5564(VJ-Keltic Dr.)	L6025(Bridgewater-Milton)	L5535(Sissiboo-Tusket)
L5565(Seaboard-Albert Br.)	L6047(Milton-Bowater)	L5546(Bridgewater-Westhavers Elbow)
L5571(VJ-Whitney Pier)	L6048(Milton-Bowater)	L5547(Westhavers Elbow-Lunenburg)
L5572(VJ-Seaboard)	L6515(Lochaber Road-Hastings)	L5548(Maccan-Amherst)
L5573(VJ-Lingan Mine)	L6539(Gannon Road-VJ)	L5561(Victoria Junction-Seaboard)
L6002(Sackville-Bridgewater)	L6548(Hastings-Sub Tie Line)	L6009(Sackville-Burnside)
L6006(Bridgewater-Milton)	L7014(Lingan-Woodbine)	L6020(Milton-Souriquois)
L6012(Brushy Hill-St. Croix)		L6536(Springhill-NB Border)
L6050(Aerotech Park)		L6538(Glentosh-Gannon Rd.)
L6503(Onslow-Trenton)		

7.4 Transmission Project Approval

The transmission plan presented in this document provides a summary of the planned reinforcement of the NSPI power system. The proposed investments are required to maintain system reliability and security and comply with System Design Criteria. NSPI has sought to upgrade existing transmission lines and utilize existing plant capacity, system configurations, and existing rights-of-way and substation sites where economic.

Major projects included in the plan have been included on the basis of a preliminary assessment of need. The projects will be subjected to further technical studies, internal approval by NSPI, and final funding approval by the Nova Scotia Utility and Review Board. Projects listed in this plan may change because of final technical studies, changes in the load forecast, changes in customer requirements or other matters determined by the Company or the UARB.

In 2008 a Maritimes Area Technical Planning Committee was established to review intra-area plans for Maritimes Area resource adequacy and transmission reliability. This Committee will also project congestion levels in regards to the total transfer capabilities on the utility interfaces. This information will be used as part of assessments of potential upgrades or expansions of the inter-ties, including any potential new inter-tie between Nova Scotia and New Brunswick. The Technical Planning Committee has transmission planning representation from Nova Scotia Power, New Brunswick System Operator, Maritime Electric Company Ltd., Northern Maine Independent System Administrator and NB Power Transmission.

7.5 NSPI/NB Interconnection Overview

The power systems of Nova Scotia and New Brunswick are interconnected via three overhead transmission lines; one 345kV line from Onslow, Nova Scotia to Memramcook, New Brunswick, and two 138kV lines from Springhill, Nova Scotia to Memramcook, New Brunswick. The primary function of the interconnection is to support system reliability.

Electricity is imported or exported over the inter-tie in proportion to the electrical characteristics of the lines. The 345kV line carries approximately 80 percent of the total power transmitted.

Power systems are designed to accommodate a single contingency loss (i.e. loss of the largest element) and since the 345kV line carries the majority of the flow, loss of the 345kV line becomes the limiting factor. Flow on the 138kV lines is also influenced by the loads in Prince Edward Island; Sackville, New Brunswick; and Amherst, Nova Scotia.

Import and export limits on the inter-tie have been established to ensure the Nova Scotia system can withstand a single contingency loss. The limits are up to 350MW export and up to 300MW import. These figures represent limits under pre-defined system conditions. Conditions which determine the actual limit of the interconnection are:

Export	**Import**
Number of thermal units armed for generation rejection (maximum two)	NS system load level (Import less than 22% of total system load)
Reactive Power Support level in the Halifax Regional Municipality	Percentage of dispatchable generation
Arming of Special Protection Systems	NB export level to PEI and/or New England
Real time line ratings (climatological conditions in northern NS)	Real time line ratings (climatological conditions in northern NS)
NS System load level	Load level in Moncton area
Largest single load contingency in NS	Largest single generation contingency in NS

If the NSPI system is separated from New Brunswick during export (i.e. the inter-tie trips), system frequency (cycles/second) will rise, risking unstable plant operation and possible damage. To address this NSPI uses fast-acting Special Protection Systems to reject generation and stabilize the system.

If the NSPI system is separated during import, system frequency will drop. Depending on the system characteristics at the time of disruption and the magnitude of the import electricity flow that was lost, the system will respond and re-balance. It does this by rejecting load through under-frequency load shedding (UFLS) protection systems as required.

The loss of the 345kV line between Onslow, NS and Memramcook, NB is not the only contingency that can result in Nova Scotia becoming separated from the New Brunswick Power system while importing power. All power imported to Nova Scotia flows through the Moncton/Salisbury area of New Brunswick. Since there is no generation in the Moncton/Salisbury area, and only a limited amount of generation in Prince Edward Island, power flowing into Nova Scotia is added and shares transmission capacity with the entire load of Moncton, Memramcook, and PEI.

The New Brunswick System Operator restricts export to Nova Scotia to a level such that any single contingency does not cause adverse impacts on NB or PEI load. Any transmission reinforcement proposed to improve reliability, increase import and export capacity or prevent the activation of UFLS in Nova Scotia must also consider the reinforcement of the southeast area of the New Brunswick transmission system. As noted earlier, NS and NB are working together to evaluate transmission needs in the areas noted.

NSPI Capital Item CI# 29009 Right of Way Purchase Northern NS

In jurisdictions across North America it is becoming more difficult to obtain access to the land and the rights of way necessary to undertake transmission projects. It is estimated that the addition of a second inter-tie will cost approximately $200 million and require at least 5 years to procure the required permits and complete construction.

The timing and configuration of an expansion to the provincial inter-tie has yet to be determined. However, given the dynamic nature of the provincial and regional electricity markets it is likely that an upgrade may be required over the next decade. Similarly it is possible to identify the preferred route of the new line.

To this end, NSPI has identified a future capital item in the 2010 Annual Capital Expenditure (ACE) Plan to commence the planning and acquisition of land right of way for a second 345kV line to New Brunswick. The project cost and scope will be submitted to the Board for approval by June 30, 2010.

8.0 TRANSMISSION DEVELOPMENT 2010 TO 2018

Transmission development plans are summarized below. As discussed earlier, these projects are subject to change. For 2010, the majority of the projects listed are included in the 2010 Annual Capital Expenditure Plan. For 2010 onward, the projects are noted in the projected year of completion.

1. 2010

- Work will begin on the construction of additional transmission to the Western Valley area. This will include the construction of a 138 kV circuit between Canaan Road and Tremont, a 138 kV termination at Canaan Road and the addition of a 138-69 kV, 33.6/44.8/56 MVA transformer at Tremont along with the establishment of a 138 kV bus. This project is necessary to mitigate various contingencies that could result in transformer overload scenarios, line overload conditions and low voltage conditions.

- The insulator replacement program will continue with the reinsulation of 5 circuits due to cement growth issues. Insulator cement growth has been identified on certain types of insulators that will result in the circuit experiencing an unplanned outage. This results in either customer outages or an outage to a circuit on the transmission system that could result in an uneconomic generation dispatch until the issue is rectified.

- The transmission reliability investment program will continue targeting transmission switches and circuit breakers. This program is intended to replace equipment that has encountered operational issues or those in which spare parts are no longer available.

- A program will commence to replace porcelain cutouts and some insulators at various transmission substations. NSPI has encountered issues with porcelain cutouts on the distribution system. These cutouts are similar to those used on certain equipment in substations. A failure of a cutout in a transmission substation could result in an outage to all customers supplied from that substation.

- Work will take place on a 230 kV circuit between Onslow and Port Hastings for the purpose of increasing ground clearances. A recent transmission line survey indicated that certain spans of this transmission line required that the conductor be raised to comply with operating temperature ground clearances.

- In accordance with the NPCC *Classification of Bulk Power System Elements* (Document A-10), dual high-speed protection systems are required at 138 kV substations at Hopewell, Tufts Cove, and Burnside.

- Work will commence on acquiring a right of way for a second 345 kV tie to New Brunswick.

- Work will continue on the uprating of a 345 kV circuit between Onslow and Lakeside for the purpose of increasing the operating temperature of the line.

- Work will begin to acquire a spare generator transformer that will be utilized to prevent a prolonged outage resulting from a failure of certain generator transformers.

- Work will begin on right of way acquirement between Dartmouth East and Eastern Passage for the purpose of accommodating a 138 kV circuit to a proposed new 138 kV substation in the Eastern Passage area.

- Work will begin on right of way acquirement from the existing 138 kV Canaan Road substation to a new substation site in the New Minas area for the purpose of accommodating a 138 kV circuit to a new 138 kV substation in the New Minas area.

- The 69 kV transmission interconnection to the Nuttby mountain wind farm will be placed in service.

- The Digby wind farm will be placed in service. This will include at 69-34.5 kV substation at the wind farm, a 17.5 km 69 kV circuit from the wind farm to an existing substation in Digby (Conway), and a 69 kV circuit breaker at Conway Substation along with various system upgrades.

- Work will commence on replacing the 138 kV Gas Insulated Switchgear at the existing Water St. substation.

- The Glen Dhu wind farm is scheduled to go in service. This will include the establishment of a 138 kV ring bus on an existing 138 kV circuit between Trenton and Antigonish.

2. 2011

- The insulator replacement program will continue with the reinsulation of three circuits due to cement growth issues.

- The transmission reliability investment program will continue targeting transmission switches and circuit breakers.

- In accordance with the NPCC *Classification of Bulk Power System Elements* (Document A-10), dual high-speed protection systems are required at 138 kV substations at Onslow, Brushy Hill, and Lakeside. In addition breaker backup will be added at the Tufts Cove 69 kV substation.

- The program to replace porcelain cutouts and some insulators at various transmission substations will continue.

- The Canaan Road to Tremont transmission upgrade is scheduled to be placed in service.

- The project to replace the 138 kV Gas Insulated Switchgear at Water St. will be completed.

- Work will continue on acquiring a right of way for a second 345 kV tie to New Brunswick.

- An existing 69 kV circuit between Trenton and Bridge Avenue is planned to be rebuilt to provide additional capacity. This project is being undertaken to avoid an overload condition for the contingency loss of a parallel 69 kV circuit during high load conditions.

- An existing 69 kV circuit between Tusket and Pleasant Street, Yarmouth is planned to be reconductored to provide additional capacity.

3. 2012

- The insulator replacement program will continue with the reinsulation of 2 circuits due to cement growth issues.

- The transmission reliability investment program will continue targeting transmission switches and circuit breakers.

- The program to replace porcelain cutouts and some insulation at various transmission substations will continue.

- In accordance with the NPCC *Classification of Bulk Power System Elements* (A-10), dual high speed protection systems are required at 138 kV substations at Sackville, Kempt Road, and New Page (Port Hawkesbury).

- The existing 138-69 kV, 20/26.7 MVA transformer at Westhaver's Elbow is planned to be changed out for a unit rated 22.5/33.3 MVA for the purpose of addressing voltage regulation in the area.

- A new 138-12 kV, 15/20/25 MVA substation is proposed to be constructed in New Minas for the purpose of supplying additional load growth.

- A new 138-25 kV substation is planned to be constructed at a new site in the Eastern Passage area. This substation would be served by the construction of a new 138 kV circuit from an existing Dartmouth East substation to the new site. This station is required to prevent equipment overloads during contingency conditions and address load growth in the Eastern Passage area.

- The double-circuit towers that carry L-7008 and L-7009 for 5.5 km out of the Brushy Hill 230 kV substation will be re-configured to accommodate the normal contingency loss of both towers.

- A 69 kV circuit between St. Croix and Five Points substations will be rebuilt.

4. 2013

- The insulator replacement program will continue with the reinsulation of one circuit due to cement growth issues.

- The transmission reliability investment program will continue targeting transmission switches and circuit breakers.

- The program to replace porcelain cutouts and some insulation at various transmission substations will continue.

- An existing 69-12 kV, 7.5/10/12.5 MVA transformer at Barrington Passage is planned to be changed out for a unit rated 15/20/25 MVA to address area load growth.

- Load will be transferred from the 2 x 138-69 kV autotransformers at Trenton. This will be accomplished by changing out an existing 69-25 kV transformer at Trenton with a 138-25 kV unit.

- A second 138-25 kV, 25/33/42 MVA transformer will be added at the existing Hammonds Plains Road substation.

5. 2014

- An existing 69-12 kV transformer at Hillaton will be changed out for a unit rated 15/20/25 MVA.

- The 138 kV bus at Milton will be rearranged to avoid loss of the bus due to a bus tie breaker failure.

- The program to replace porcelain cutouts and some insulators at various transmission substations will be completed.

- The 345 kV bus at Hopewell will be developed into a ring bus configuration.

6. 2016

- An existing 69-12 kV transformer at Central Argyle will be changed out for a unit rated 7.5/10/12.5 MVA.

7. 2018

- An existing 69-25 kV transformer at Milton will be changed out for a unit rated 15/20/25 MVA.

- There is a possibility of an additional supply to the Halifax downtown area. This could take the form of a 138 kV underwater cable from Dartmouth to Water St. or another route that has not as yet been determined. This evaluation will commence in the near future.

9.0 UNCERTAINTY

The Nova Scotia Power system is dynamic, complex to plan and operate, and influenced by developments inside and outside of our Province. Much remains unknown with respect to the form, location and scope of future generation, as emission regulations and Renewable Energy Standards evolve and projects required to maintain compliance are studied including the implications of large amounts of intermittent generation such as wind.

Once determined, development and implementation of the appropriate transmission plan to address these challenges will require a timely and effective response from NSPI and stakeholders. Recognizing this, NSPI has begun initial work to project the transmission system reinforcement required to support various generation scenarios, inside and outside of the Province. This work is summarized in Appendix B.

It should be reinforced that this work remains preliminary and is included in this report to provide insight to the potential nature of transmission reinforcement across the Province over the next decade (beyond that described earlier in this report). Whether the scenarios unfold as projected will be determined by a host of factors unknown today including:

- The location, size and configuration of generation developments across Nova Scotia;
- The emergence of new generation sources and markets outside of Nova Scotia;
- Ongoing change to power system industry engineering and operating standards;
- Changes in customer demand or emergent technologies dependant on electricity.

What can be drawn from the information presented in Appendix B is that:

- Transmission system reinforcement will be required to accommodate the addition of renewable generation across Nova Scotia;
- The design of the transmission system reinforcement will be determined by the location and scope of the generation development;

- Transmission plans should be robust to accommodate changes in area and provincial load and generation;
- Transmission system plans will be subject to change in response to opportunities, inside and outside of Nova Scotia; and
- Further work on this is required.

10.0 CONCLUSION

It is likely that the NSPI transmission system will require reinforcement in the coming decade and that this reinforcement will occur across the province and at the provincial inter-tie. The specific form of this reinforcement is not understood in detail today. Work to understand this is proceeding in accordance with the underlying market drivers.

On June 30, 2010, NSPI will apply to the UARB for approval of the purchase of right of way to accommodate a second provincial inter-tie. Additional transmission applications will be forthcoming once the design, cost and business cases necessary to support these investments are complete.

It is NSPI's objective to develop and implement a timely, effective and robust transmission expansion plan. This process will require the Board's support and the participation of stakeholders. NSPI will continue to keep the Board and stakeholders apprised as this work moves forward.

11.0 REFERENCES

1. *2004 Maritimes Area Triennial Review of Resource Adequacy*, Report approved by NPCC Reliability Coordinating Council March 9, 2005.

2. *Basic Criteria for Design and Operation of Interconnected Power Systems*, Northeast Power Coordinating Council Document A-2, May 6, 2004.

3. *Final Report, Nova Scotia Wind Integration Study*, Hatch, Ltd., 2008.

4. *Integrated Resource Plan Report*, Nova Scotia Power Inc., November 30, 2009.

5. *Nova Scotia Wholesale Electricity Market Rules,* February 1, 2007.

6. Regulations Respecting Renewable Energy Standards made under Section 5 of Chapter 25 of the Act of 2004, the *Electricity Act.*

APPENDIX A

SYSTEM DESIGN CRITERIA

Nova Scotia Power's interconnected system is divided into several classifications, each of which is governed by different design criteria.

These classifications are as follows:

1. Primary Transmission
2. Secondary Transmission
3. Electrically Remote Transmission
4. Sub-transmission
5. Transformation

The System Design criteria combine protection performance specifications with system dynamics and steady state performance requirements. Within any classification, system studies assume specified protection performance to determine the required number, characteristics and type of system elements, while protection design incorporates only that equipment necessary to achieve the assumed performance, assuming a single coincident protection element failure.

DEFINITIONS

1. **Primary Transmission** is defined as the 345 kV transmission system interconnecting Lakeside-Onslow-Hopewell-Woodbine, and Salisbury, New Brunswick, the 230 kV transmission system interconnecting Brushy Hill-Onslow-Lingan-and Pt. Aconi, Nova Scotia and the interconnecting 345/230 kV transformation between them.

2. **Secondary Transmission System** is defined to be that part of the system which serves mainly to interconnect miscellaneous generation and Primary Transmission with Sub transmission at major load centres.

The lesser importance of secondary transmission relative to the Primary Transmission permits a relaxation of the design criteria from that required for the primary transmission system. This definition then governs most of the 138 kV developments plus certain 69 kV and 230 kV, other than on the Primary Transmission system.

3. **Electrically Remote Transmission** is defined by those buses at which ultimate fault levels are projected to not exceed 1500 MV.A three phase.

4. **Sub transmission System** is defined to be that part of the system which primarily serves as a source for transformation to the distribution level. This type of system is primarily characterized by radial feeds although looped sub transmission exists.

5. **Interconnected Transmission System** is defined as the combined Primary, Secondary, and Electrically Remote Transmission systems including connected generation.

6. **Normal system** conditions are defined to include all of the following:

   a) Any load condition (this includes the full range of annually forecasted loads).

   b) All transmission facilities in service (no line or transformer maintenance).

   c) Economically scheduled and dispatched generation allowing for planned generator maintenance outages (non-firm generation is not included as economically dispatched generation).

   d) Stable steady-state operation of the Interconnected Transmission System.

   e) All system voltages within 95 percent to 105 percent of nominal, unless otherwise noted.

   f) All system elements operating within their continuous thermal ratings, unless otherwise noted.

7. **A system element** is defined to be any one generator, transmission line, transformer or bus section.

8. **Local back-up clearance** is defined to be the time to clear an in-zone fault.

9. **Remote back-up clearance** is defined to be the time to clear an out-of-zone fault.

10. **Breaker back-up** is defined to be protection against local breaker failure to trip for any reason. Breaker back-up will be applied to all Primary Transmission and most of the Secondary Transmission systems.

I. PRIMARY TRANSMISSION SYSTEM

Prime clearance times are defined to be 4.5 cycles first zone and 6 cycles second zone with permissive signal for both three-phase and line-to-ground faults.

Back-up clearance times are defined to be 15 to 18 cycles for both three-phase and line-to-ground faults.

The Design Criteria[7] are:

1. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent three-phase fault on any one system element except a generator or bus section, cleared in prime time. No cascade tripping shall occur.

2. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively damped following a permanent line-to-ground fault on any one system element cleared in prime time. No cascade tripping shall occur.

[7] Note: The Primary Transmission System Design Criteria may be superseded by the NPCC Basic Criteria for the Design and Operation of Interconnected Power Systems.

3. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one system element except a bus section or generator, cleared in back-up time. No cascade tripping beyond elements cleared by the operative back-up protection shall occur.

4. From normal system conditions following loss of any one system element with or without fault, all system elements shall be within their long-term thermally limited ratings.

5. From normal system conditions, for the loss of any one system element with or without fault, steady state post-contingency Interconnected Transmission System bus voltage shall not be less than 90 percent or greater than 110 percent of nominal following correction by automatic tap-changers. In addition, no bus shall experience a voltage change from pre-fault to post-fault condition greater than 10 percent before movement of tap changers.

6. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

II. SECONDARY TRANSMISSION SYSTEM

Prime time clearance is defined to be 6 to 9 cycles for both three-phase and line-to-ground faults. (No additional expenditure may be made to reduce clearing times from 9 to 6 cycles without authorization from System Design.)

Local back-up clearance is defined to be less than 30 cycles (a figure of 20 cycles is desirable but where coordination so dictates, a 30 cycle figure is acceptable).

Remote back-up clearance is defined to be less than 30 cycles which in certain instances implies reduced margins of coordination.

The Design Criteria are:

1. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent three-phase fault on any one system element except a generator or bus section cleared in prime time. No cascade tripping shall occur.

2. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one system element cleared in prime time. No cascade tripping shall occur.

3. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one system element except a generator or bus section, cleared in back-up time. No cascade tripping beyond elements cleared by the operative back-up protection shall occur.

4. From normal system conditions following loss of any one system element with or without fault, all system elements shall be within their thermally limited ratings in the steady state.

5. From normal system conditions, for the loss of any one system element with or without fault, steady-state post-contingency Interconnected Transmission System bus voltages shall be less than 90 percent or greater than 110 percent of nominal following correction by automatic tap-changers. In addition no bus shall experience a voltage change from pre-fault to post-fault condition greater than 10 percent before movement of tap-changers.

6. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

III. ELECTRICALLY REMOTE TRANSMISSION

Prime time clearance is defined to be 9 cycles for both three-phase and line-to-ground faults. Note 1 and Note 2.

The Design Criteria are:

1. The Interconnected Transmission System dynamic response shall be stable and positively-damped following a fault on any one Electrically Remote system element.

2. From normal system conditions following loss of any one element with or without fault, all remaining elements shall be within their thermally limited ratings.

3. From normal system conditions, for the loss of any one Electrically Remote system element with or without fault, no Interconnected transmission system bus voltage shall be less than 90 percent or greater than 110 percent of nominal following a steady state settling out of the system nor shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10 percent before tap-changer correction.

4. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

NOTES:

1. No expenditure may be made to reduce clearing times to reference values without authorization from System Design.

2. Permissive tripping between an electrically remote bus and a transmission bus (or between 2 electrically remote buses) is not required, i.e., local back-up clearances are acceptable.

3. Application of the above criteria does not preclude the possibility that for loss of certain remote system elements there will be a designed loss of load. This load would be restored after operator action.

IV. SUB-TRANSMISSION SYSTEM

The Design Criteria are:

1. Sub transmission system loading shall be within the thermally limited ratings.

2. The sub transmission system voltages shall not be less than 97.5 percent or greater than 105 percent of nominal.

3. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

4. From normal system conditions, following the loss of any one sub transmission system element with or without a fault, any sub transmission system bus which remains connected to the system, shall maintain sufficient voltage following automatic tap-changer correction to permit operation of any affected distribution bulk supply bus at 105 percent of nominal following a steady state settling out of the system. In no case shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10 percent before tap-changer correction.

5. The application of the above criteria does not guarantee a continuity of supply for any single contingency. In the case of a line, since a lengthy outage is considered to have a low probability time to repair is considered adequate for restoration of service; however, in the case of transformation, since an outage is generally a prolonged one, either the use of a mobile transformer for a short-term replacement or the installation of a spare transformer and interconnections with adjacent substations at the distribution level, are considered in decisions concerning the guaranteeing, after outage, of an alternative supply.

V. TRANSFORMATION

Design Criteria

1. Capacity for any individual transformation point shall, under nominal system conditions, be sufficient to meet the daily load requirements after due consideration is given to the following:

   a) Economic dispatch or outage of generation.

   b) Loading of transformer(s) to their (or their associated equipment) thermally-limited ratings as per Note 4.

2. Reinforcement is required in all cases when, for a single contingency, there will result either, thermal damage to equipment in attempting to continue to supply the load, or, inability to meet the daily load requirements in whole or in part after due consideration is given to the following:

   a) The capacity of the underlying interconnection(s) with another supply point(s) when applicable.

   b) Out-of-merit running of generation when applicable.

   c) Loading of remaining station(s) transformer(s) to their (or their associated equipment) thermally-limited ratings as per Note 4. (This is in conjunction with (a) and (b) above as applicable.)

   d) Largest available suitable mobile transformer loaded to its nameplate rating. (This is in conjunction with (a) and (b) above as applicable.)

NOTES:

1. Reinforcement may be the economic choice even if (a), (b) and (c) or (d) result in satisfaction of the load supply criteria because estimated out-of-merit costs may significantly exceed the costs of capital advancement.

2. The Primary Transmission system may require additional transformation in certain instances when, although the above (a), (b) and (c) may result in satisfaction of this particular criteria, any other of several possible contingencies (transmission lines, generators or transformer(s)) could result in either frequent or prolonged outages to a widespread part of the system.

3. The result of application of these criteria may not be installation of additional transformation.

APPENDIX B

TRANSMISSION ADDITIONS FOR GENERATION DEVELOPMENT SCENARIOS

Distributed large-scale renewable generation, large-scale imports and exports and new in-province thermal generation all have a potential role in serving Nova Scotia's future electricity needs. Each will likely require reinforcement of the current transmission system. However the form of this reinforcement cannot be known in advance of a determination of the location and scope of generation sources.

In lieu of this certainty, NSPI has undertaken preliminary transmission scenario planning regarding alternative generation sources. This exercise provides insight to the constraints which currently exist on the provincial transmission system and provides perspective as to the investments that will be required to realize various generation opportunities.

The information remains largely conceptual. It is not intended to describe the future plans of the utility but rather the nature of decisions facing the Company with respect to transmission system expansion where network resource interconnection service is required. The scenarios are helpful in highlighting transmission projects that appear under numerous scenarios, and as such, may form the foundation for a robust long-term transmission expansion plan. These expansion plans could help to enable a higher degree of renewable energy in Nova Scotia, which NSPI supports.

Renewable Generation Additions

1) Wind Development Scenarios (2013 - 2019)

a) Mainland (Metro) wind generation (100MW-150MW) development scenario

Establish a new 138kV substation in the Dartmouth area along with rebuilding/re-conductoring two existing circuits and building a new 138 kV circuit between Fall River and Sackville.

b) Mainland (South Nova) wind generation (100MW-150MW) development scenario

Re-conductor an existing 138 kV circuit between Milton and Tusket along with an existing 69 kV circuit between Tremont and Michelin. A 138 kV substation would be established in the Tusket area along with substation bus modifications at Canaan Road, Milton and Bridgewater. Two 230 kV circuits currently occupying double circuit towers towards the Bridgewater area would be separated.

c) Mainland (Lower Annapolis Valley) wind generation (100-150MW) development scenario

This scenario requires the completion of a 138kV line L-6617 from Tremont to Canaan Rd currently scheduled for construction along with a new ring bus configuration at Tremont, including a second 138-69 kV transformer, and substation modifications at Canaan Road. An existing 69 kV circuit between Tremont and Gulch would be uprated to 138 kV and the 69 kV substations currently connected to this circuit would be converted to 138 kV. This would include the development of a 138 kV ring bus configuration at Paradise. In addition new 138 kV circuits would be constructed from Gulch to Tremont and Tusket substations. Two 230 kV circuits currently occupying double circuit towers towards the Bridgewater area would be separated.

d) Mainland (Upper Annapolis Valley) wind generation (100-150MW) development scenario

An existing 69 kV circuit between Sissiboo and Tusket would be rebuilt to a higher capacity. Substation modifications would be required at Canaan Road and Milton along with changing out two 138-69 kV autotransformers at Canaan Road for higher capacity units. Two 230 kV circuits currently occupying double circuit towers towards the Bridgewater area would be separated.

e) Mainland (Northern Nova Scotia) wind generation (100-150MW) development scenario

Construct a new 138kV line from Onslow to Springhill and install a 100 MVAR static compensator on the Onslow 230 kV bus along with increasing reactive power compensation at Brushy Hill. An existing 230 kV circuit would be uprated to 345 kV to provide a 345 kV transmission connection between Onslow and Brushy Hill.

f) Cape Breton Wind generation (150MW -250MW) development scenario

An existing 230 kV circuit would be uprated to 345 kV to provide a 345 kV transmission connection between Onslow and Brushy Hill and reactive power compensation would be increased at Brushy Hill. A 345 kV substation would be established at Port Hastings and 345 kV circuits would be constructed from Port Hastings to both Woodbine and Spider Lake including a new Canso crossing. A new 345 – 138 kV substation would be established at Spider Lake that would terminate 3 x 138 kV circuits in the Dartmouth area. In addition 100 MVAR of reactive compensation would be established in the Dartmouth area.

2) Port Hawkesbury 60MW Biomass- Cape Breton Strait Area Scenario

An additional line crossing the Strait of Canso would be constructed to eliminate the double circuit contingency limit. A bus reconfiguration at NSPI's Onslow 345kV EHV substation, an upgrade of a 138kV line terminal at NSPI's Trenton substation, and the addition of switched capacitors at NSPI's Brushy hill substation would also be required.

Large External Imports (300MW) or Export development scenario

a) To facilitate a large import or export via NB interconnect

To enable import, a new 345 kV transmission circuit would be required between Onslow to the New Brunswick system. An existing 230 kV circuit would be uprated to 345 kV to provide a 345 kV transmission interconnection between Onslow and Brushy Hill along with increased reactive compensation at Brushy Hill. In addition a 345 kV ring bus would be established at Hopewell and a 345 kV circuit would be constructed from Hopewell to the Metro area. Joint planning studies are required with New Brunswick to determine upgrades to the New Brunswick system that would be required to support a firm import of this magnitude.

For additional firm export from NS to NB, added further study may also be required.

b) Newfoundland Submarine Cable Import (300MW) or Export development scenario

A 300 MW DC to AC terminal would be required at Onslow or Brushy Hill along with a DC submarine cable from Newfoundland to Cape Breton along with overhead DC transmission from Cape Breton to Onslow or Brushy Hill. An existing 230 kV circuit would be converted to 345 kV to provide a 345 kV transmission connection between Onslow and Brushy Hill. A 345 kV ring bus would be established at Hopewell and a new 345 kV transmission circuit would be constructed between Hopewell and the Metro Halifax area.

Additional export of energy from Newfoundland through Nova Scotia would require further study in order to determine the additional transmission investment required.

Large Natural Gas Generator (250MW – 350MW) expansion scenario

For contingency loss of a large generator scenario the NS-NB inter-tie may require reinforcement depending on potential unit size.

a) Eastern Shore/Point Tupper Natural Gas Generator Scenario

Substation expansions would take place at Point Tupper and Port Hastings including the addition of a 345/230 kV transformer at Port Hastings. A 345/138 kV substation would be established at Spider Lake. A new 230 kV circuit would be required from Point Tupper to Port Hastings and a 345 kV circuit would be required between Port Hastings and Spider Lake.

b) Metro Large Natural Gas Generator Scenario

Development of a 138 kV substation at Spider Lake to terminate two existing Dartmouth 138 kV circuits along with increasing the conductor size on two existing Dartmouth circuits. A new 138 kV circuit will be required from Spider Lake to Sackville as well as a high capacity line from Tufts Cove to Brushy Hill. In addition substation modifications will take place at Tufts Cove and Brushy Hill.