Nova Scotia
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energy everywhere.

June 30, 2011

Ms. Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
PO Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: Nova Scotia Power Inc. 10 Year System Outlook

Dear Ms. McNeil,

Section 3.4.5.1 of the Wholesale Market Rules Regulations provides:

> Subject to any contrary order of the Board, the NSPSO shall submit the draft NSPSO system plan to the Board for the Board's public comment process and for any Board review, and shall publish the draft plan each year by the end of June.

On behalf of the NSPSO, the 2011 10 Year System Outlook is attached for the Board's review. Concurrent with this filing, NSPI will post this report on the NSPSO OASIS site at:

http://oasis.nspower.ca/en/home/default/forecastsandassessments.aspx

Please provide any direction or questions on this filing to the undersigned.

Yours truly,

J. René Gallant
Vice President Regulatory Affairs

10 Year System Outlook
2011-2020
Draft Report

June 30, 2011

NOVA SCOTIA
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1.0 INTRODUCTION

Nova Scotia Power Inc. (NSPI, the Company) submitted the first 10 Year System Outlook report on June 30, 2008. 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 2011 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 2011 Outlook is the assumptions employed in the 2009 Integrated Resource Plan (IRP) Update. The assumptions were 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 informs the basis for the investment 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 efficiency and Demand Side Management programs.

Table 1 shows historical and forecast net annual energy requirements. NSPI remains a winter peaking utility and accordingly, the highest period of energy consumption in Nova Scotia is 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 primarily due to the economic recession. Warmer than average weather kept load growth to 0.7 percent in 2010 but 2011 is forecast to grow at 4.4 percent growth with some expected economic rebound and the expected return to more typical temperatures. NSR is forecast to decline an average of 1.3 percent annually over the next 10 years with the effects of Demand Side Management (DSM) programs. Without the effects of these DSM programs, the NSR is forecast to grow an average of 0.8 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 transportation 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 data) 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[2]

Year	Net System Requirement (GWh)	Annual Change (%)
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*	12,539	-0.8
2009*	12,073	-3.7
2010*	12,158	0.7
2011F	12,688	4.4
2012F	12,647	-0.3
2013F	12,507	-1.1
2014F	12,339	-1.3
2015F	12,180	-1.3
2016F	12,008	-1.4
2017F	11,832	-1.5
2018F	11,651	-1.5
2019F	11,492	-1.4
2020F	11,333	-1.4
2021F	11,173	-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.

*Results for the years 2008 to 2010 contain the effects of DSM programs.

[2] Data sourced from the 2011 NS Power Load Forecast, filed with the UARB on April 28, 2011.

Table 2 – Coincident Peak Demand with Future DSM Program Effects[3]

Year	Net System Peak MW	Annual Change %	Non-Firm Peak MW	Annual Change %	Firm Peak MW	Annual Change %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1.0	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[4]	1,824	-0.8
2010*	2,114	1.0	295	10.0	1,820	-0.3
2011F	2,310	9.3	316	7.3	1,994	9.6
2012F	2,308	-0.1	309	-2.4	2,000	0.3
2013F	2,277	-1.4	308	-0.3	1,970	-1.5
2014F	2,242	-1.6	304	-1.3	1,938	-1.6
2015F	2,208	-1.5	298	-1.9	1,910	-1.4
2016F	2,173	-1.6	292	-1.9	1,880	-1.5
2017F	2,135	-1.7	287	-2.0	1,849	-1.7
2018F	2,096	-1.9	281	-1.9	1,815	-1.8
2019F	2,061	-1.7	276	-1.8	1,785	-1.6
2020F	2,026	-1.7	271	-1.7	1,755	-1.7
2021F	1,991	-1.7	267	-1.7	1,725	-1.7

*Results for the years 2008 to 2010 contain the effects of DSM programs.

[3] Data sourced from the 2011 NS Power Load Forecast, filed with the UARB on April 28, 2011.
[4] Decrease due to economic recession affecting primarily industrial customers.

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)
2011	33	115
2012	60	306
2013	113	570
2014	173	869
2015	231	1,154
2016	288	1,439
2017	345	1,715
2018	400	1,980
2019	454	2,238
2020	506	2,490
2021	557	2,736

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 2011 Load Forecast.

In 2010, the responsibility for energy efficiency and conservation programs was transferred from NSPI to the new DSM Administrator, Efficiency Nova Scotia Corporation (ENSC). In early 2011, ENSC filed an application with the Board seeking approval for an overall expenditure of $43.7 million associated with the 2012 DSM Plan. A decision from the UARB was issued June 30, 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 2011.

Table 4 – 2011 Generating Resources[5]

Plant/System	Fuel Type	Winter Net Capacity (MW)
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**

[5] Data sourced from 2009 IRP Update Assumptions

Plant/System	Fuel Type	Winter Net Capacity (MW)
Tufts Cove	Natural Gas	98.0
Burnside**	Light Fuel Oil	99.0
Tusket	Light Fuel Oil	24.0
Victoria Junction	Light Fuel Oil	66.0
Total Combustion Turbine		**287.0**
Contracts (pre-2001)	Independent Power Producers	25.8
Renewables(firm) (post 2001)***	Independent Power Producers	72.2
NSPI wind (firm)***	Wind	28.5
Total IPPs & Renewables		**126.5**
Total Capacity		**2362.6**

*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 it is assumed to be returned to service in the future. Asset management plans for the Burnside fleet are currently 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 the 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. Capacity additions have been further updated to reflect renewable energy requirements set forth in the province’s renewable electricity plan in April 2010. For DSM, the amounts shown are reductions in forecast firm demand for the period which makes additional capacity available. 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 2011-2021	MW
DSM firm*	495
Tufts Cove 6	48.9
Hydro**	4.2
Firm Contracted Wind***	5.7
Firm RES (2015)****	50.6
Community Feed-in-Tariff*****	20.0
Total Firm Supply & Demand MW Projected Over Planning Period	**624.4**

Notes:

* DSM Firm does not include interruptible customers.

** Hydro shown is Marshall Falls at 4.2 MW as per the 2009 IRP Update assumptions.

*** Firm Contracted 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 announced in the Province's Renewable Electricity Plan in April 2010. The value in the table includes the firm contribution of dispatchable generation as well as an assumed firm capacity value of intermittent wind generation. For long-term planning purposes the firm capacity value of wind is based on the winter capacity factor (generator capacity multiplied by the winter capacity factor). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. Legislation has recently received Royal Assent for RES (2020) with a target of 40%. NSPI is currently determining the capacity additions associated with this.

*****The Community Feed-in-Tariff represents distribution-connected renewable energy projects as outlined in the Province's Renewable Electricity Plan in April 2010. The value in the table is the assumed firm capacity value of intermittent generation for small-scale projects. For long-term planning purposes the firm capacity value is based on an assumed 20% capacity factor. 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 June 27, 2011, NSPI's interconnection request queue includes 1461 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 transmission 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 27, 2011.

Table 6 – Generation Interconnection Queue

Nova Scotia Power - Interconnection Request Queue

Publish Date: *Monday, June 27, 2011*

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Queue Order	IR #	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date DD-MMM-YY	Revised Inservice date	Status	Service Type	IC Identity
1	45	19-Jan-05	Cumberland	31.5	31.5	L-6535	Wind	15-Jan-12		GIA Executed	N/A	N/A
2	8	14-Oct-03	Guysborough	13.8	13.8	L-5527B	Wind	20-Sep-12		GIA Executed	N/A	N/A
3	56	19-Aug-05	Cumberland	34	34	L-5058	Wind	01-Nov-14		GIA Executed	ERIS	N/A
4	151	22-Aug-07	Halifax	50	50	91H	Steam	30-Jun-10		GIA Tendered	NRIS	N/A
5	219	08-Apr-10	Richmond	64	64	47C	Steam	31-Dec-12		FAC in Progress	ERIS	N/A
6	227	26-Aug-10	Hants	10.2	10.2	L-4048	Steam	01-Jul-12		FAC in Progress	NRIS	N/A
7	225	03-May-10	Pictou	60	60	L-6503	Wind	31-Dec-12		FAC in Progress	ERIS	N/A
8	233	14-Jan-11	Colchester	50.6	50.6	L-5040	Wind	31-Dec-14		SIS in Progress	ERIS	N/A
9	234	14-Jan-11	Pictou	41.4	41.4	L-6503	Wind	31-Dec-14		SIS in Progress	ERIS	N/A
10	67	27-Apr-06	Annapolis	40	40	L-5026	Wind	31-Oct-10		SIS Agrmnt Complete	ERIS	N/A

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	Revised Inservice date	Status	Service Type	IC Identity
11	68	27-Apr-06	Digby	35	35	L-5533	Wind	31-Oct-10		SIS Agrmnt Complete	ERIS	N/A
12	86	09-Jan-07	Pictou	50	50	L-7003	wind	01-Jan-09		SIS Agrmnt Complete	NRIS	N/A
13	115	23-Mar-07	Pictou	120	120	L-7003	wind	30-Nov-09		SIS Agrmnt Complete	NRIS	N/A
14	117	13-Apr-07	Shelburne	10	10	L-5027	wind	01-Sep-09		SIS Agrmnt Complete	ERIS	N/A
15	126	16-Apr-07	Cumberland	70	70	L-6513	wind	31-Dec-09		SIS Agrmnt Complete	ERIS	N/A
16	128	17-Apr-07	Cumberland	40.5	40.5	L-6535	wind	20-Nov-09		SIS Agrmnt Complete	ERIS	N/A
17	130	17-Apr-07	Cape Breton	200	200	L-7012	wind/water	31-Dec-09		SIS Agrmnt Complete	NRIS	N/A
18	131	17-Apr-07	Cape Breton	11.5	11.5	L-5580	wind	30-Nov-09		SIS Agrmnt Complete	ERIS	N/A
19	149	05-Jul-07	Cumberland	70	70	L-6536	wind	20-Nov-09		SIS Agrmnt Complete	ERIS	N/A
20	163	28-Jan-09	Richmond	60	60	47C	Steam	30-Apr-11		SIS Agrmnt Complete	NRIS	N/A
21	213	29-Jul-09	Cumberland	15	15	37N	Tidal	31-Dec-10		SIS Agrmnt Complete	ERIS	N/A
22	222	26-Apr-10	Pictou	48	48	L-5508	Steam	31-Aug-12		SIS Agrmnt Complete	NRIS	N/A

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	Revised Inservice date	Status	Service Type	IC Identity
23	232	14-Jan-11	Antigonish	50.6	50.6	L-6511	Wind	31-Dec-14		SIS Agrmnt tendered	ERIS	N/A
24	235	19-Jan-11	Halifax	50	50	L-6043	Wind	1-Jul-14		SIS Agrmnt tendered	ERIS	N/A
25	238	28-Jan-11	Yarmouth	50	50	9W	Wind	01-Jul-14		FEAS In Progress	NRIS	N/A
26	241	14-Feb-11	Colchester	1	1	L-5040	Wind	30-Mar-11		IR Valid	NRIS	N/A
27	242	24-Nov-11	Cumberland	49.6	49.6	L-5550	Wind	31-Dec-12		FEAS In Progress	ERIS	N/A
28	244	14-Mar-11	Cumberland	34.5	34.5	30N	Wind	31-Dec-14		SIS Agrmnt tendered	ERIS	N/A
29	273	27-May-11	Cumberland	100	100	L-5550	Wind	31-Dec-12		IR Valid	NRIS	N/A
		Totals:		1461.2	1461.2							

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:

- a 31.5 MW wind project that has completed the GIP process and is at the design stage;

- 47.8 MW of wind projects that have completed the GIP process but have yet to secure a PPA;
- a 50 MW, NSPI-owned steam project (UARB approved) with GIA tendered;
- 60 MW of wind and 74.2 MW of biomass projects at the Facilities Study stage which are part of NSPI's Renewable Energy Standards (RES) commitment for 2013; and
- 92 MW of wind projects that are at the System Impact 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 Generator Interconnection Procedures. Table 7 indicates the location and size of the committed generating facilities.

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Table 7 – Committed Renewable Generation Projects

Company/Location	**Nameplate Capacity MW**
SP Amherst Wind Power LP in Cumberland County	31.5
Canso Wind Energy Centre ULC in Guysborough County	13.8
Pugwash Wind Farm Inc. in Cumberland County	34
NSPI Biomass at NewPage Port Hawkesbury in Richmond County	64
IR #227 Biomass in Hants County	10.2
IR #225 Wind in Pictou County	60
IR #233 Wind in Colchester County	50.6
IR #234 Wind in Pictou County	41.4
Total New Facilities Nameplate Capacity	**305.5**

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 requirement of 25 percent of net energy sales by 2015, as well as a goal of 40 percent by 2020. The legislation for the 2020 target received Royal Assent in May 2011. The 2015 renewable energy requirement will be met through equal participation by independent power producers (IPPs) and Nova Scotia Power. IPPs will compete for 300 GWh in a bidding process managed by the Renewable Electricity Administrator, who will oversee the competition by calling for bids, evaluating bid submissions and selecting winning projects.

In addition to these targets, the plan includes 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.

The Enhanced Net Metering program is expected to be initiated in July of this year. Implementation of the COMFIT program is also anticipated to occur in 2011, although uptake rates for this program 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."[6]

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

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

hence determine possible implications to system stability and availability. In 2011 a wind integration study will be commenced.

5.4 Other Opportunities

In addition to the above, potential developments outside of Nova Scotia (e.g. Lower Churchill), 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. Table 8 shows NSPI's OATT Transmission Service Queue as of April 7, 2011.

Table 8 – OATT Transmission Service Queue

OATT Transmission Service
Queued System Impact Studies
Revised April 7, 2011

Number	Project	Date & Time of Service Request	Project Type	Project Location	Project size (MW)	Status
1	TSR 100	June 4, 2010 10:50 AM	Point to Point	NB/NS border to Lingan, NS	320	SIS Study initiated
2	TSR 200	November 16, 2010 2:44 PM	Point to Point	Lingan, NS to NS/NB border	500	SIS Study initiated
3	TSR 300	February 14, 2011 11:15 AM	Point to Point	Wreck Cove, NS to NS/NB border	300	Withdrawn

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 Regional Reliability Reference Directory #5, Reserve.* This Criteria is reviewed and adjusted periodically by NPCC. The Criteria require that:

> Each Balancing Authority shall have ten-minute reserve available that is at least equal to its first contingency loss…and,
>
> Each Balancing Authority shall have thirty-minute reserve available that is at least equal to 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 twice 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 Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System*[7] 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 *2010 Maritimes Area Comprehensive Review of Resource Adequacy*,[8] it was confirmed that the NPCC criteria would be met with a 20 percent reserve margin for the Maritimes area along with 70 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.

[7] http://www.npcc.org/viewDoc.aspx?name=A-02.pdf&cat=regStandCriteria
[8] http://www.npcc.org/viewDoc.aspx?name=2010_Maritimes_Area_Comprehensive_Review_of_Resource_Adequacy_RCC.pdf&cat=revResource

6.3 Load and Resources Review

The ten year load forecast and resources additions in Table 9 below are based on the capacity additions and DSM forecast in Table 5. Table 9 indicates that a planning reserve margin equal to 20 percent of the firm peak load is maintained.

Table 9 – NSPI 10 Year Load and Resources Outlook

Load and Resources Outlook for NSPI - Winter 2011/2012 to 2020/2021
(All values in MW except as noted)

		2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021
A	Firm Peak Load Forecast	2,058	2,076	2,099	2,120	2,141	2,159	2,172	2,190	2,205	2,220
B	DSM Firm	58	107	161	210	260	310	358	404	450	495
C	Firm Peak Less DSM (A - B)	2,000	1,970	1,938	1,910	1,880	1,849	1,815	1,785	1,755	1,725
D	Required Reserve (C x 20%)	400	394	388	382	376	370	363	357	351	345
E	Required Capacity (C + D)	2,400	2,364	2,325	2,292	2,256	2,219	2,178	2,142	2,106	2,070
F	Existing Resources	2363	2363	2363	2363	2363	2363	2363	2363	2363	2363
	Total Cumulative Additions:										
G	Thermal*	49	82	82	82	82	82	82	82	82	82
H	Hydro	0	0	4	4	4	4	4	4	4	4
I	Firm Contracted Wind**	0	6	6	6	6	6	6	6	6	6
J	Firm RES (2015)***	0	10	10	51	51	51	51	51	51	51
K	Community Feed-in-Tariff****	0	0	2	4	10	16	20	20	20	20
L	Total Firm Supply Resources (F + G + H + I + J + K)	2412	2460	2466	2509	2515	2521	2525	2525	2525	2525
	+ Surplus - Deficit (L - E)	12	97	141	217	259	302	347	383	419	455
	Reserve Margin % (L/C -1)	21%	25%	27%	31%	34%	36%	39%	41%	44%	46%

*Thermal includes Burnside #4 (winter capacity 33 MW) assumed to be returned to service in 2013.

**Firm Contracted 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 announced in the Province's Renewable Electricity Plan in April 2010. The value in the table includes the firm contribution of dispatchable generation as well as an assumed firm capacity value of intermittent wind generation. For long-term planning purposes the firm capacity value of wind is based on the winter capacity factor (generator capacity multiplied by the winter capacity factor). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. Legislation has recently received Royal Assent for RES (2020) with a target of 40%. NSPI is currently determining the capacity additions associated with this.

****The Community Feed-in-Tariff represents distribution-connected renewable energy projects as outlined in the Province's Renewable Electricity Plan in April 2010. The value in the table is the assumed firm capacity value of intermittent generation for small-scale projects. For long-term planning purposes the firm capacity value is based on an assumed 20% capacity factor. 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 approximately 5,150 kilometres of transmission lines at voltages at the 69 kV, 138 kV, 230 kV and 345 kV levels.

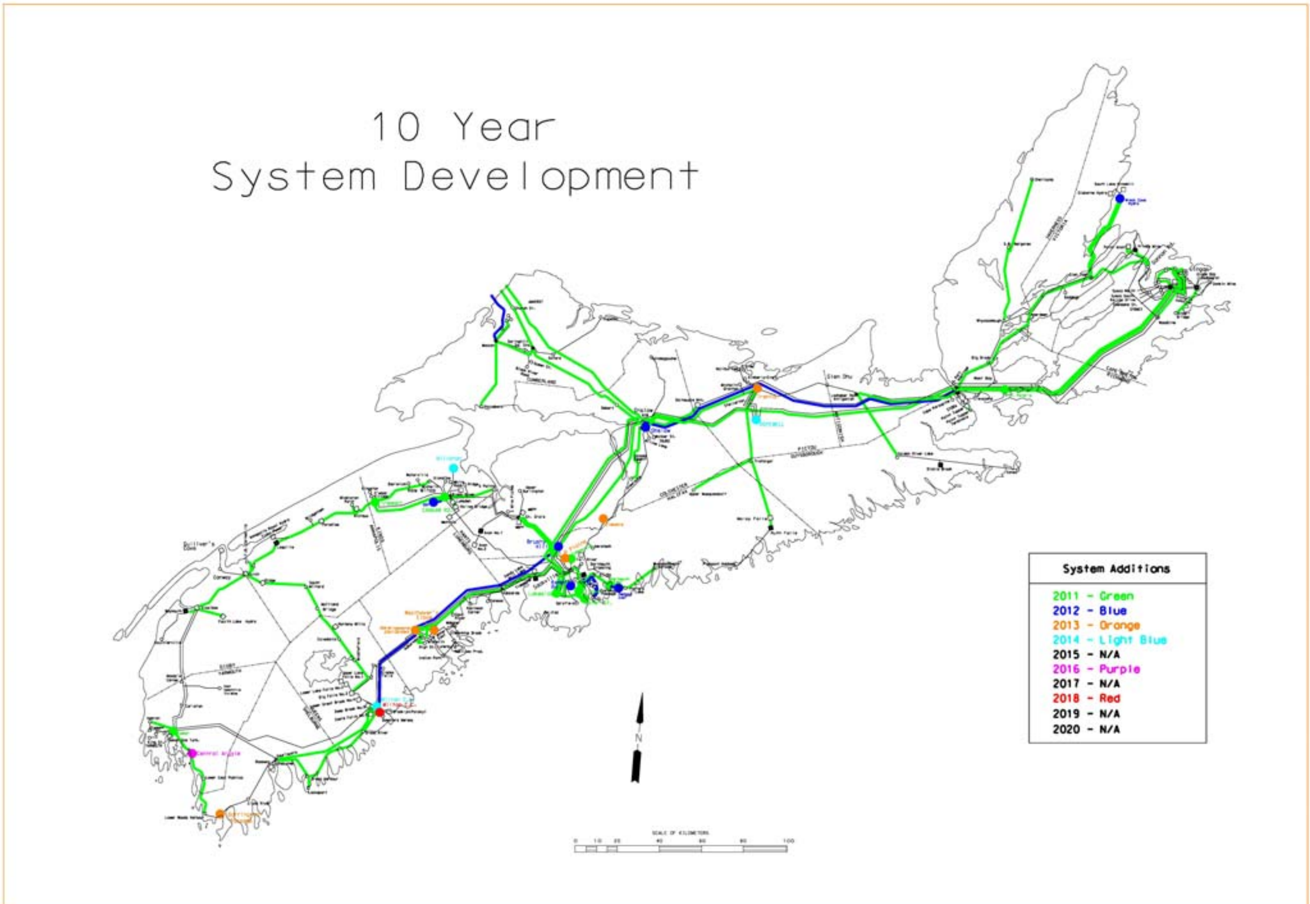
- The 345 kV transmission system is approximately 468 kilometres in length and is comprised of 372 kilometres of steel tower lines and 96 kilometres of wood pole lines.

- 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 1668 kilometres in length and is comprised of 12 kilometres of steel/concrete structures and 1656 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, Nova Scotia is integrated into the NPCC bulk 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. 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 the Supervisory Control and Data Acquisition (SCADA) system to enhance 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 Special Protection Systems.

7.3 Transmission Life Extension

NSPI has in place a comprehensive maintenance program on the transmission system focused on maintaining reliability and extending the useful life of transmission assets. The program is centered on detailed transmission asset inspections and associated prioritization of asset 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 2011:

2009	2010	2011
L5003(Farrell St.-Sackville)	L5017(5 Points-Canaan)	L5003(Sackville-Akerley)
L5004(Sackville-Geizer Hill)	L5029(Maccan-Springhill)	L5004(Sackville-Rockingham)
L5017(Canaan-Five Points)	L5030(Aberdeen-Black River)	L5011(Farrell-Imperial)
L5039(Spryfield-Geizer Hill)	L6002(Sackville-Gold River)	L5019(Canaan-Hollow Bridge)
L5500(Trenton-Stellarton)	L5037(East River-Canexel)	L5028(Onslow-Stewiacke)
L5510(Stellarton-Malay Falls)	L5039(Lakeside-Spryfield)	L5044(Tap-Middleton)
L5511(Trafalgar-Malay Falls)	L5040(Onslow-Tatamagouche)	L5053(Tremont-Michelin)

2009	2010	2011
L5512(Malay Falls-Ruth Falls)	L5048(Green Harbour-Lockport)	L5510(Bridge Ave.-Malay Falls)
L5521(Onslow-Truro)	L5058(Springhill-Pugwash)	L5511(Trafalgar-Upper Musquodoboit)
L5573(VJ-Lingan Mine)	L7011(Lingan-Hastings)	L5512(Malay Falls-Ruth Falls)
L6003(Tufts Cove-Sackville)	L5532(Gulch-Big Falls)	L5524(Antigonish-Salmon River)
L6004(Sackville-Canaan Road)	L5535(Sissiboo-Tusket)	L5531(Gulch-Sissiboo)
L6006(Bridgewater-Milton)	L5544(Big Falls-Upper Lake Falls)	L5532(Big Falls-Gulch)
L6013(Canaan Road-Tremont)	L7003(Onslow-Hastings)	L5534(Tusket-Hebron)
L6014(Kempt Road-Tufts Cove)	L5559(Whycocomagh-SW Margaree)	L5538(Sissiboo-Weymouth)
L6035(Water St.-Kempt Road)	L5560 (VJ-Townsend St.)	L5546(Bridgewater-Westhavers)
L6038(Lakeside-Kearney Lake)	L5561(VJ-Seaboard)	L5549(Maccan-Hickman)
L6515(Lochaber Road-Hastings)	L5569(Terrace-Townsend)	L5550(Maccan-Parrsboro)
L6516(Hastings-VJ)	L6006(Bridgewater-Milton)	L5555(Gannon Road-Aconi)
L6517(Hastings-Tupper)	L6010(Brushy Hill-Sackville)	L5559(Whycocomaugh-SW Margaree)
L6518(Hastings-NewPage)	L6016(Brushy Hill-Lakeside)	L5565(Seaboard-Albert Bridge)
L6523(Tupper-NewPage)	L6024(Milton-Tusket)	L5571(VJ-Whitney Pier)
L6540(VJ-Sysco)	L6025(Bridgewater-Milton)	L5575(Whitney Pier-Lingan)
L6545(Wreck Cove-Glen Tosh)	L6516(Hastings-VJ)	L5579(SW Margaree-Cheticamp)
L6549(Wreck Cove-Glen Tosh)	L6531(Milton-Bridgewater)	L6008(Sackville-Lakeside)
L7001(Onslow-Brushy Hill)	L6545(Glentosh-Wreck Cove)	L6011(Brushy Hill-St. Croix)
L7002(Onslow-Brushy Hill)	L7012(Hastings-Lingan)	L6020(Milton-Sourquois)
L7011(Hastings-Lingan)	L7015(Pt. Aconi-Woodbine)	L6033 (Lakeside-Water St.)
L8001(Onslow-NB Border)	L5530B(Broad River-East Green Harbour)	L6042(Tufts Cove-Dartmouth East)
L6005A(Brushy Hill-Sackville)	L5564A(Terrace St. Tap)	L6043(Dartmouth-Musquodoboit)
L6005B(Brushy Hill-Sackville)	Various Insulator Replacements	L6051(Brushy Hill-St. Croix)
L5560(VJ-Townsend Street)		L6503(Onslow-Trenton)
		L6513(Onslow-Springhill)
		L6514(Maccan-Springhill)

2009	2010	2011
		L6515(Antigonish-Port Hastings)
		L6527(Onslow Substation Tie)
		L6533(Victoria Junction-Lingan)
		L6536(Springhill-NB Border)
		L6537(Port Hastings-Glen Tosh)
		L6538(Glen Tosh-Gannon-Road)
		L6545(Glen Tosh-Wreck Cove)
		L6549(Glen Tosh-Wreck Cove)
		L7002(Onslow-Brushy Hill)
		L7005(Onslow-Port Hastings)
		L7014(Lingan-Woodbine)
		L7019(Onslow-Dalhousie Mountain)
		L5027A(Tusket-Lower Woods Harbour)
		L5540A(Tap-Deep Brook Hydro)
		L5545A/5545B (Bridgewater-Auburndale/High St.)
		L8001(Onslow-New Brunswick)
		Various

Nova Scotia Power also has in place a wooden pole retreatment program that enables the useful lives of these assets to be extended.

The table below lists the lines within the NSPI transmission system which have undergone wooden pole retreatment over the past two years along with proposed wooden pole retreatment for 2011.

2009	2010	2011
L5036(Berwick Tap-Berwick)	L5014(St. Croix-Burlington)	L5017 (Five Points-Canaan Rd.)
L50179	L5015(St. Croix-Avon)	L5025(Paradise-Tremont)
L5046(5017 Tap-Wolfville Ridge)	L5020(Hollow Bridge-Methals)	L5026(Gulch-Paradise)
L5047(5026 Tap-Bridgetown)	L5021(Canaan Rd.-Klondike)	L5035 (Hells Gate-Canaan Rd.)
L5056(5026 Tap-Annapolis)	L5506(Abercrombie-Pictou)	L5042(Farrell-Albro Lake)
L5521(Onslow-Willow Lane)	L5510(Stellarton-Malay Falls)	L5048(East Green Harbour-Lockport)
L5536(Tusket-Hebron)	L5511(Trafalgar-Upper Musquodoboit)	L5050(Sissiboo-Fourth Lake)
L6005(Brushy Hill-Sackville)	L5512(Malay Falls-Ruth Falls)	L5057(Tap-Cornwallis)
L6024(Milton-Tusket)	L5531(Gulch-Sissiboo)	L5500 (Trenton-Bridge Ave.)
L6025(Bridgewater-Milton)	L5535(Sissiboo-Tusket)	L5530(Milton-Souriquois)
L6047(Milton-Bowater)	L5546(Bridgewater-Westhavers Elbow)	L5538(Sissiboo-Weymouth)
L6048(Milton-Bowater)	L5547(Westhavers Elbow-Lunenburg)	L6516(Hastings-Victoria Junction)
L6515(Lochaber Road-Hastings)	L5548(Maccan-Amherst)	L6521(Point Tupper-Point Tupper Terminal)
L6539(Gannon Road-VJ)	L5561(Victoria Junction-Seaboard)	L6543(Hastings 138kV-230kV)
L6548(Hastings-Sub Tie Line)	L6009(Sackville-Burnside)	L7011(Hastings-Lingan)
L7014(Lingan-Woodbine)	L6020(Milton-Souriquois)	
	L6536(Springhill-NB Border)	
	L6538 (Glentosh-Gannon Rd.)	

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, NPCC/NERC Reliability Standards 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 estimate 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 345 kV line from Onslow, Nova Scotia to Memramcook, New Brunswick, and two 138 kV 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 transmission lines. The 345 kV 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 345 kV line carries the majority of the power flow, loss of the 345 kV line becomes the limiting factor. Power flow on the 138 kV 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 allow the Nova Scotia and the New Brunswick system to withstand a single contingency loss. The limits are up to 350 MW export and up to 300 MW 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 must be 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 the New Brunswick system during export (i.e. the inter-tie trips), system frequency (cycles/second) will rise, risking unstable plant operation and possible equipment 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 configuration at the time of separation and the magnitude of the import electricity flow that was interrupted, the system will respond and re-balance. The system does this by automatically rejecting load through under-frequency load shedding (UFLS) protection systems as required.

The loss of the 345 kV 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 power 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 power 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 collaborating to evaluate transmission needs in the areas previously noted.

In jurisdictions across North America it is becoming increasingly difficult to obtain access to the land and the right-of-ways necessary to undertake transmission projects. It is estimated that the addition of a second inter-tie will require at least 5 years to secure the required permits and completing 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 been granted approval by the Nova Scotia Utility and Review Board to proceed with the acquisition of a right-of-way to accommodate a second 345 kV circuit between Nova Scotia and New Brunswick.

8.0 TRANSMISSION DEVELOPMENT 2011 TO 2020

Transmission development plans are summarized below. As highlighted earlier, these projects are subject to change. For 2011, the majority of the projects listed are included in the 2011 Annual Capital Expenditure Plan. For 2011 onward, the projects are noted in the projected year of completion.

1. 2011

- Work will be completed 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 was necessary to mitigate various contingencies that could result in transformer overload scenarios, line overload conditions and low voltage conditions.

- The transmission insulator replacement program will continue with the reinsulation of 3 circuits (L-6002 from Gold River to Bridgewater, L-5532 from Big Falls to Gulch, and L-5524 from Antigonish to Salmon River Lake) due to identified 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 resolved.

- 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, those in which spare parts are no longer available or have reached the end of life.

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

- The structures on a water crossing on a 230 kV transmission circuit between Lingan and Port Hastings will be replaced with steel towers.

- In accordance with NSPI's implementation plan for requirements of the NPCC *Classification of Bulk Power System Elements* (Document A-10), dual high-speed protection systems are required at 138 kV substations at Tufts Cove and Lakeside. In addition, breaker control backup will be added at the Tufts Cove 69 kV substation.

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

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

- Work will continue on acquiring 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 acquisition 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 transmission circuit to a new 138 kV substation in the New Minas area.

- The project to replace the 138 kV Gas Insulated Switchgear at the existing Water St. substation will be completed in 2011.

- A third 138-25 kV transformer is proposed for Water St. along with the refurbishment/replacement of a portion of the 25 kV switchgear.

- Work will be completed in 2011 on system modifications required to accommodate the Digby wind farm.

- Work will continue on the removal and replacement of transmission substation devices with 500 mg/kg or more of PCBs, to be in compliance with Federal Environmental PCB Regulations.

- A 138 kV transmission circuit between Sackville and Bridgewater will undergo some structure replacements to meet ground clearance requirements.

- Work will be completed to upgrade steel transmission towers on two 138 kV transmission circuits on the Halifax Peninsula that terminate in the Water St. 138 kV substation.

- Work will commence on a multi-year re-furbishment program to prevent metal deterioration on transmission line steel towers. The 2011 program scope will focus on four steel towers associated with the 138 kV Halifax Harbour Crossing circuit.

- Work will be completed to upgrade conductor and replace deteriorated structures on a 69 kV circuit between Trenton and Bridge Avenue for the purpose of increasing circuit 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.

- A project will be initiated to install a 138-25 kV transformer for each of Kempt Road and Dartmouth East substations for reliability purposes in the event of transformer failures at these substations.

2. 2012

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

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

- Transformer installations at Kempt Road and Dartmouth East substations, initiated in 2011, will be completed.

- 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 and Brushy Hill.

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

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

- Network upgrades are required on the transmission system to accommodate a new wind farm in the Amherst area.

- Work will continue on right-of-way acquisition between Dartmouth East and the Harbour East area for the purpose of accommodating a 138 kV circuit to a proposed new 138 kV substation in the Harbour East area.

- In the Dartmouth area two 69 kV circuits (L-5011 and L-5012) will be uprated to ensure proper ground clearances are met.

- It is planned to purchase a 69 – 25/12 kV transformer and a 138 – 25 kV transformer as system spares.

- Work will continue on the removal and replacement of transmission substation devices with 500 mg/kg or more of PCBs, to be in compliance with Federal Environmental PCB Regulations.

- 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. This project will also include a 138 kV line terminal at Canaan Road and a 138 kV transmission circuit between Canaan Road and the new substation.

- The construction of a new 138-25 kV substation is planned to be started at a new site in the Harbour East area. This project will also include a new 138 kV circuit from an existing Dartmouth East substation and the 138 kV line terminal at Dartmouth East.

- An existing 138 – 25 kV transformer at the Kempt Road substation is proposed to be rewound due to suspected damage as the result of repeated through faults.

- The spar arms on a 138 kV circuit between Bridgewater and Milton will be reinforced.

- Work will take place on a 230 kV circuit between Onslow and Port Hastings, a 230 kV circuit between Brushy Hill and Bridgewater, and a 138 kV circuit between Maccan and the New Brunswick border 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.

- Work will continue to prevent metal deterioration on transmission steel towers.

- The 138 kV cables at the Wreck Cove Hydro site are proposed to be replaced.

- A project will be initiated to install a 138-25 kV transformer for each of Lucasville and Lochaber Road substations for reliability purposes in the event of transformer failures at these substations.

3. 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.

- Transformer installations at Lucasville Road and Lochaber Road substations, initiated in 2012, will be completed.

- The 138-25 kV substation in the Harbour East area and associated transmission line to the existing Dartmouth East substation along with the 138 kV line terminal at Dartmouth East substation will be completed.

- 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.

- 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.

- An existing 138 – 25 kV transformer at Elmsdale is proposed to be rewound due to suspected damage as the result of repeated through faults.

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

- At Bridgewater, a second 36 MVAR capacitor bank is proposed to be added on the 138 kV bus.

4. 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.

5. 2016

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

6. 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.

There are no additions indicated in 2015, 2017, 2019 and 2020. This will most likely change as those time periods draw closer and local planning studies could indicate system modifications or additions.

9.0 UNCERTAINTY

The Nova Scotia Power power system is dynamic, complex to plan and operate, and influenced by developments inside and outside of our Province. Much uncertainty remains 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, Generation Development Scenarios.

It should be reinforced that transmission studies remain preliminary and are 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 materialize 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 evolution of power system industry engineering, operating standards and NPCC/NERC reliability 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 system expansion plans should be robust to accommodate changes in area and provincial load and generation;

- Transmission system expansion plans will be subject to change in response to opportunities, inside and outside of Nova Scotia; and

- Transmission system planning remains an ongoing evolution as evidenced by other jurisdictions.

10.0 CONCLUSION

It is likely that the NSPI transmission system will continue to require reinforcement in the coming decade and that this reinforcement will occur across congested corridors and at the provincial inter-tie. Studies to understand the reinforcement scope is proceeding in accordance with the underlying market drivers, primarily RES requirements and other provincial and federal legislation.

In 2010 the UARB approved NSPI's application for 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 maintain 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

PURPOSE

The purpose of this document is to establish the Nova Scotia Power Inc. (NSPI) planning and development criteria to be applied to new additions to NSPI transmission system planned or constructed after the effective date of this document. NSPI's transmission system is divided into four classifications, each of which is governed by different design criteria. Where and when applicable, NSPI criteria will be superseded by the Northeast Power Coordinating Council (NPCC) criteria.

The NSPI classifications are as follows:

1. Primary Transmission
2. Secondary Transmission
3. Electrically Remote Transmission
4. Transformation

The NSPI System Design Criteria combine protection performance specifications with system dynamics and steady state performance requirements. When system expansions are undertaken, facilities are to be constructed such that the criteria are met. The specified speed of protection systems must be achieved unless faster speeds are specified or slower speeds are accepted based on system studies. System studies to determine adequacy and investment requirements must be conducted using the actual characteristics (setting and operating time) of existing protection systems.

DEFINITIONS

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

   a. Expected load conditions.
   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% to 105% of nominal, unless otherwise noted.

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

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

3. *Breaker back-up* is defined to be protection against a local breaker's failure (mechanical or electrical) to trip when initiated by an associated protection operation.

4. *Single contingency* is defined as loss of one *system element* with or without a fault.

1. PRIMARY TRANSMISSION SYSTEM

Primary Transmission is defined as 230 kV and above.

The protection system must be designed with redundancy to cater to any single element failure, in keeping with good utility practice and conform to industry standards.

Unless otherwise specified, and determined appropriate by transient stability studies, the goal for fault clearing times will be 4 cycles or less for near end fault and 6 cycles or less for remote end fault with permissive signal for both three-phase and line-to-ground faults (or less).

a. Fault clearance for a near end fault with a breaker failure (fault cleared by breakers local to the line terminal) will be *12* cycles or less.

b. Fault clearance for a near end fault with a breaker failure (for lines that will also require breaker operation at the remote bus on the non-faulted line to clear the fault) will be *13* cycles or less.

c. Fault clearance for a remote end fault with a breaker failure (fault cleared by breakers local to the line terminal) will be *14* cycles or less.

d. Fault clearance for a remote end fault with a breaker failure (for lines that will also require breaker operation at the remote bus on the non-faulted line to clear the fault) will be *15* cycles or less.

e. *Breaker back-up* will be applied to all Primary Transmission.

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 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 cleared in breaker 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 110% of their thermally limited ratings under the condition that the System Operator can take action within a 10 minute period to reduce load on the element.

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 not less than 90% or greater than 110% 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% 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.

7. The maximum net generation that may be rejected by a Special Protection Scheme (SPS) for normal contingency is 310 MW.

2. SECONDARY TRANSMISSION SYSTEM

This category includes all other loop transmission facilities, operating higher than 100 kV, which are not included in the Primary Transmission nor the Electrically Remote Transmission categories.

The protection system must be designed with sufficient redundancy to cater to any single element failure, in keeping with good utility practice and conform to industry standards. The clearing time will be 6 cycles or less (near end) and 8 cycles or less (remote end) for both three-phase and line-to-ground faults.

a. Fault clearance for a near end fault with a breaker failure (fault cleared by breakers local to the line terminal) will be **14** cycles or less.

b. Fault clearance for a near end fault with a breaker failure (for lines that will also require breaker operation at the remote bus on the non-faulted line to clear the fault) will be **15** cycles or less.

c. Fault clearance for a remote end fault with a breaker failure (fault cleared by breakers local to the line terminal) will be **16** cycles or less.

d. Fault clearance for a remote end fault with a breaker failure (for lines that will also require breaker operation at the remote bus on the non-faulted line to clear the fault) will be **17** cycles or less.

e. *Breaker back-up* will be applied to Secondary Transmission if system studies determine the requirement.

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* 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* cleared in *breaker 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 110% of their thermally limited ratings in steady state, under the condition that the System Operator can take action within a 10 minute period to reduce load on the element.

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 not less than 90% or greater than 110% 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% 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.

3. ELECTRICALLY REMOTE TRANSMISSION SYSTEM

This category is defined by the buses at which the ultimate fault levels will not exceed 1,500 MVA three-phase.

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

2. From *normal system conditions* following any *single contingency* with or without a fault, all system elements shall be within their thermally limited ratings in the steady state.

3. From *normal system conditions*, for any *single contingency* with or without a fault, steady-state post-contingency system bus voltages shall not be less than 90% and not be greater than 110% 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% before movement of tap changers.

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

5. *Breaker back-up* will be applied to Electrically Remote Transmission if system studies determine the requirement.

4. TRANSFORMATION

Capacity for any individual transformation point shall, under *normal 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.

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 the Notes below. (This in conjunction with (a) and (b) above as applicable.)

d. Largest available *suitable* mobile transformer loaded to its nameplate rating. (This 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 criterion because estimated out-of-merit costs may significantly exceed the costs of capital advancement.

2. In accordance with methods accepted within North America, and particularly with reference to "C57.91-1995 IEEE Guide for Loading Mineral-Oil-Immersed Transformers", it is NSPI practice to permit the loading of transformers to exceed the nominal or nameplate value.

3. For distribution load serving transformers to exceed the nominal or nameplate value, where calculations are not specifically conducted, overload capability assumptions based on normal cyclic daily loading may be made, but shall not exceed 133% of top nameplate rating. In any case the maximum overload capability is not to exceed the current NSPI SCADA Alarm limits. In special circumstances, such as *single contingency* situations where some means of reducing the overload exists, a thermal rating based on a loss of life of 2 1/2% may be applied to distribution load serving transformers, in accordance with the above and engineering judgment. The loss of life permitted is measured over the time required to reduce the loading on the transformers. This may be done by switching low voltage circuits or relieving load by use of a mobile transformer.

4. System power transformers (not distribution load serving transformers) with a nameplate rating of less than 200MVA are rated at 100% of the 65^{o}C manufacturer nameplate MVA for summer and 110% of the 65^{o}C manufacturer nameplate MVA for winter under

normal operating conditions. For winter conditions, under contingency, transformers are limited to 120% of the 65^{o}C manufacturer nameplate MVA.

5. Where calculations are not specifically conducted, overload capability assumptions for system transformers greater than 200 MVA (65 deg C nameplate rating) will be based on 100% for both summer and winter under system normal.

6. When no means of reducing the overload exists, a 0% loss of life is used.

APPENDIX B

GENERATION DEVELOPMENT SCENARIOS

Dispersed 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 defined 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.

This 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 (100 MW-150 MW) development scenario

      Establish a new 138 kV substation in the Dartmouth area along with rebuilding/reconductoring 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 138 kV line from Tremont to Canaan Road currently in 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 replacing two 138-69 kV autotransformers at Canaan Road with 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 138 kV 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) NewPage 60MW Biomass- Cape Breton Strait Area Scenario

The NewPage 60 MW Biomass project has been approved. This generation has been assigned a capacity factor of zero and is meant to displace some existing Cape Breton generation. No transmission upgrades are required for this project as this is ERIS service.

Large External Imports (300MW) or Export development scenario

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

To enable import, a new 345 kV transmission circuit would be required between Onslow and the New Brunswick system. Additional studies would be required, taking into consideration the potential for new generation sources, to determine transmission modifications or additions required on the Nova Scotia System. 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, further study would also be required.

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

System studies are currently underway to determine the transmission required across Nova Scotia to accommodate a 300 MW or higher import from Newfoundland. The import from Newfoundland will be via a DC submarine cable from Newfoundland to Cape Breton.

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 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.