Q. Table 1 on page 1 of the Executive Summary to the Report entitled *"Supply and Install 100 MW (Nominal) of Combustion Turbine Generation",* April 10, 2014, shows that the LOLH criteria of 2.8 hours per year is anticipated to be exceeded in 2015. When was this capacity shortage first forecast by Hydro?

A. In 2009, in the *Generation Planning Issues 2009 October Update* in Table 5-1, page 10 (see GT-V-NLH-004 Attachment 1), a capacity deficit was forecasted to occur in 2015. The most recent analysis in 2012 also shows the capacity deficit occurring in 2015 (See Appendix C of the Report – *Generation Planning Issues – November 2012*, Table 5-1, page 11).

GENERATION PLANNING ISSUES
2009 OCTOBER UPDATE

System Planning Department
October 2009

newfoundland labrador hydro
a nalcor energy company

Executive Summary

This report provides an overview of the Island Interconnected System (the System) generation capability, the timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly and thus cost-effective process.

The Province's Energy Plan outlines specific measures to address environmental concerns related to the Holyrood Thermal Generating Station (HTGS). The long-term plan is to replace the energy provided by the plant with electricity from the lower Churchill development through a High Voltage Direct Current (HVdc) transmission link from Labrador to the island. In the event the Lower Churchill Project does not proceed, scrubbers and precipitators will be installed at the plant. This requires Newfoundland and Labrador Hydro (Hydro) to maintain two planning load forecasts and two preliminary generation expansion plans; one for the HVdc link and one for the Isolated Island scenario. The load forecasts presented reflect the supply costs associated with the Isolated Island scenario given that options exist to mitigate any effects of up-front costs associated with the HVdc link option. Based on an examination of the System's existing plus committed capability, in light of the 2009 Planning Load Forecasts (PLF) and the generation planning criteria, under both scenarios, capacity (Loss of Load Hours (LOLH)) deficits start in 2015. There are no energy deficits in either case until post-2018. If a third wind project is brought in-service in 2013, generation additions for the Isolated Island scenario could be postponed until 2016.

In order to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio, under an Isolated Island scenario, the addition of an RFP process necessitates a decision to proceed in late 2011 to meet an in-service date of fall 2016. This is due to the need to complete the RFP evaluation

and subsequent Board of Commissioners of Public Utilities (Board) review and have a final decision by mid-2013

It should be noted that while Hydro is closely monitoring potential emissions reductions regulations, the analysis presented does not model potential costs or credits under an environmental mitigation strategy such as a cap-and-trade system.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVdc Transmission Link – Hydro must be prepared for events that may delay the proposed Lower Churchill Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both a HVdc link future and an Isolated Island future. For the latter case, other future generation sources should be considered;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.

Table of Contents

1.0 Introduction

This report provides an overview of the Island Interconnected System (the System) generation capability, the timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly process.

In September 2007, the Provincial Government released its Energy Plan. The Energy Plan directed Hydro to evaluate two options to deal with environmental concerns at the Holyrood Thermal Generating Station (HTGS). Option A was to replace HTGS produced electricity with electricity from the Lower Churchill River development via a High Voltage Direct Current (HVdc) transmission link to the Island. Option B was to install scrubbers and electrostatic precipitators to control emissions at the HTGS and maximize the use of wind, small hydro and energy efficiency programs to reduce the reliance on HTGS produced electricity. These two options require significantly different strategies to effectively implement and require the development of two separate, preliminary, generation expansion plans to manage the near-term until a decision can be made on which option will be pursued for future development.

This report addresses the timing of the next requirement, in light of the most recent load forecast, for additional generation supply under both options and the resources available to meet that requirement. The report also identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly process.

2.0 Load Forecast

This review utilizes the 2009 Planning Load Forecast (PLF) as prepared in the spring of 2009. Long-term load forecasts for the Province are derived using Hydro's own electricity demand models and are driven by corresponding Provincial economic forecasts that are regularly prepared for Hydro by the Department of Finance, Government of Newfoundland and Labrador. For this analysis, Hydro has included the lower Churchill River generation and transmission investments as an alternative to the isolated Island future while recognizing that these developments have yet to be technically committed through project sanction. The load forecasts presented reflect the supply costs associated with the Isolated Island scenario given that options exist to mitigate any effects of up-front costs associated with the HVdc link option. Some key assumptions respecting incremental economic activity for both generation supply futures are:

- Single Island newsprint operation at Corner Brook;
- Single Island oil refining operation at Come by Chance producing at 115,000 barrels per day;
- Commercial production at the Vale Inco NL nickel processing facility on the Island in 2013[1];
- Teck Resources Limited mining operations at Duck Pond continuing through 2013[2].

In terms of high-level economic indicators, growth rate summaries for the HVdc link and Isolated Island scenarios are presented in Table 2-1. As indicated in the table, there are modest longer-term economic differences associated with the two generation supply alternatives.

[1] Amended 2002 Development Agreement, Vale Inco and the Government of Newfoundland and Labrador
[2] Teck Cominco 2007 Annual Report.

Table 2-1

Provincial Economic Indicators – 2009 PLF				
		2008-2013	**2008-2018**	**2008-2028**
Adjusted Real GDP at Market Prices* (% Per Year)	HVdc Link	2.1%	1.0%	0.8%
	Isolated Island	1.3%	0.9%	0.8%
Real Disposable Income (% Per Year)	HVdc Link	2.7%	1.5%	1.2%
	Isolated Island	2.1%	1.4%	1.2%
Average Housing Starts (Number Per Year)	HVdc Link	2,710	2,525	2,170
	Isolated Island	2,700	2,510	2,160
End of Period Population ('000s)	HVdc Link	518	516	509
	Isolated Island	515	511	507

*Adjusted GDP excludes income that will be earned by the non-resident owners of Provincial resource developments to better reflect growth in economic activity that generates income for local residents.

Hydro carries out generation planning for the total system and that includes the power and energy supplied by Hydro's customer-owned-generation resources in addition to Hydro's bulk and retail electricity supply, including power purchases. The projected electricity growth rates for the System under both the HVdc Link and Isolated Island cases are presented in Table 2-2. An important source of load growth for the utility sector on the Island continues to be the unwavering preference for electric water heating systems space and ever-increasing preference for electric space heating across residential and commercial customers. For Hydro's industrial customers, single newsprint mill and oil refinery operations are maintained, the Teck Resources mine is expected to operate through 2013 and the Vale Inco NL nickel processing facility is now scheduled to be in commercial production in 2013.

Table 2-2

Electricity Load Growth Summary – 2009 PLF				
		2008-2013	**2008-2018**	**2008-2028**
Utility[1]	HVdc link	1.9%	1.3%	1.1%
	Isolated Island	1.8%	1.3%	1.1%
Industrial[2]	HVdc link	0.0%	0.1%	0.1%
	Isolated Island	0.0%	0.1%	0.1%
Total	HVdc link	1.4%	1.0%	0.9%
	Isolated Island	1.3%	1.0%	0.9%

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. Industrial load is the summation of Corner Brook Pulp and Paper, AbitibiBowater[3], North Atlantic Refining, Teck Resources and Vale Inco NL.

Table 2-3 provides a summary of the 2009 PLF projections for electric power and energy for the System for the period 2009 to 2018. Similar long-term projections are also prepared for the Labrador Interconnected System and for Hydro's Isolated Diesel Systems to derive a Provincial electricity load forecast. Appendix A contains the longer term PLF that was used to complete the generation expansion analysis.

[3] AbitibiBowater ceased production at its Grand Falls newsprint mill in February 2009.

Table 2-3

Electricity Load Summary – 2009 PLF						
HVdc Link	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand[3] (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2009	1,326	5,985	286	1,603	1,592	7,781
2010	1,351	6,100	196	1,435	1,534	7,727
2011	1,376	6,210	236	1,456	1,568	7,858
2012	1,400	6,348	274	1,679	1,604	8,223
2013	1,417	6,417	282	1,984	1,673	8,601
2014	1,437	6,501	275	2,009	1,686	8,710
2015	1,450	6,588	275	2,009	1,699	8,798
2016	1,469	6,660	275	2,009	1,718	8,871
2017	1,485	6,669	275	2,009	1,733	8,881
2018	1,488	6,613	275	2,009	1,737	8,824
Isolated Island	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2009	1,326	5,985	286	1,603	1,592	7,781
2010	1,351	6,100	196	1,435	1,534	7,727
2011	1,376	6,210	236	1,456	1,568	7,858
2012	1,399	6,300	274	1,679	1,603	8,174
2013	1,416	6,366	282	1,984	1,672	8,550
2014	1,431	6,431	275	2,009	1,680	8,640
2015	1,443	6,481	275	2,009	1,691	8,691
2016	1,453	6,562	275	2,009	1,702	8,772
2017	1,471	6,574	275	2,009	1,719	8,784
2018	1,477	6,613	275	2,009	1,726	8,824

Note: 1. Utility and Industrial demands are non-coincident peak demands.
2. Total System is the total Island Interconnected System and includes losses. Demands are coincident peak demands.
3. Maximum demand in 2009 includes AbitibiBowater paper mill.

3.0 System Capability

Hydro is the primary supplier of system capability to the Island Interconnected System, accounting for 78 percent of its net capacity and 77 percent of its firm energy. Capability is also supplied by customer generation from Newfoundland Power Inc., and Corner Brook Pulp and Paper Limited (Kruger Inc.) Hydro also has contracts with two Non-Utility Generators (NUGs) for the supply of power and energy as well as contracts with two wind power projects that became operational in late 2008 and early 2009. Hydro also receives energy from the expropriated assets at Star Lake and on the Exploits River.

Hydroelectric generation accounts for 64 percent of the System's existing net capacity and firm energy capability. The remaining net capacity comes from wind farms and thermal resources. The thermal resources are made up of conventional steam, combustion turbine and diesel generation plants. Of the existing thermal capacity, approximately 71 percent is located at the HTGS and is fired using No. 6 fuel oil. The remaining capacity is located at sites throughout the Island. A complete breakdown of the System's existing capability is provided in Table 3-1.

Table 3-1

Island Interconnected System Capability – As of June 2009			
	Net Capacity [MW]	Energy [GWh]	
		Firm	Average
<u>Newfoundland & Labrador Hydro</u>			
Bay d'Espoir	592.0	2,272	2,648
Upper Salmon	84.0	492	567
Hinds Lake	75.0	290[4]	339[5]
Cat Arm	127.0	678	682
Granite Canal	40.0	191[4]	220[5]
Paradise River	8.0	33	36
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	7
Total Hydraulic	927.3	3,961	4,499
Holyrood	465.5	2,996	2,996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	598.2	2,996	2,996
Total NL Hydro	**1,525.5**	**6,957**	**7,495**
<u>Newfoundland Power Inc.</u>			
Hydraulic	96.6	324	428
Combustion Turbine	36.5	-	-
Diesel	7.0	-	-
Total	140.1	324	428
<u>Corner Brook Pulp and Paper Ltd.</u>			
Hydraulic	121.4	793	864
<u>Star Lake and Exploits Generation</u>			
Hydraulic	105.8	634	749
<u>Non-Utility Generators</u>			
Corner Brook Cogen	15.0	100	100
Rattle Brook	4.0	13	16
St. Lawrence Wind	27.0	92	104
Fermeuse Wind	27.0	75	84
Total	73.0	280	304
Total Island Interconnected System	**1,965.8**	**8,988**	**9,840**

[4] Firm Energy numbers for Hinds Lake and Granite Canal were reversed in the previous report.

4.0 Planning Criteria

Hydro has established criteria related to the appropriate reliability, at the generation level, for the System that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more that 2.8 hours per year[6].

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[7].

5.0 Identification of Need

Table 5-1 presents an examination of the HVdc link and Isolated Island load forecasts compared to the planning criteria. It does not incorporate Hydro's preliminary expansion plan to show uncommitted generation additions. In 2006, firm system capability was updated to reflect a 115 GWh increase in Hydro's hydroelectric-plant capability. This change was the result

[5] Average Energy numbers for Hinds Lake and Granite Canal were reversed in the previous report.
[6] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.
[7] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (HTGS) is based on energy capability adjusted for maintenance and forced outages.

of a hydrology adjustment and the use of an integrated system model which determines a more realistic firm system capability. Previously, firm system capability was calculated using the summation of individual firm values provided by the design consultants of each facility.

Table 5-1 illustrates when supply capacity and firm capability will be outpaced by forecasted electricity demand under the two different expansion scenarios being considered. The table shows that under both the HVdc link and Isolated Island scenarios, capacity (LOLH) deficits start in 2015 but that there are no energy deficits in either case until post-2018. Since the closure of the pulp and paper mills in Stephenville and Grand Falls, capacity deficits now precede energy deficits indicating that the system is now capacity, rather than energy, constrained.

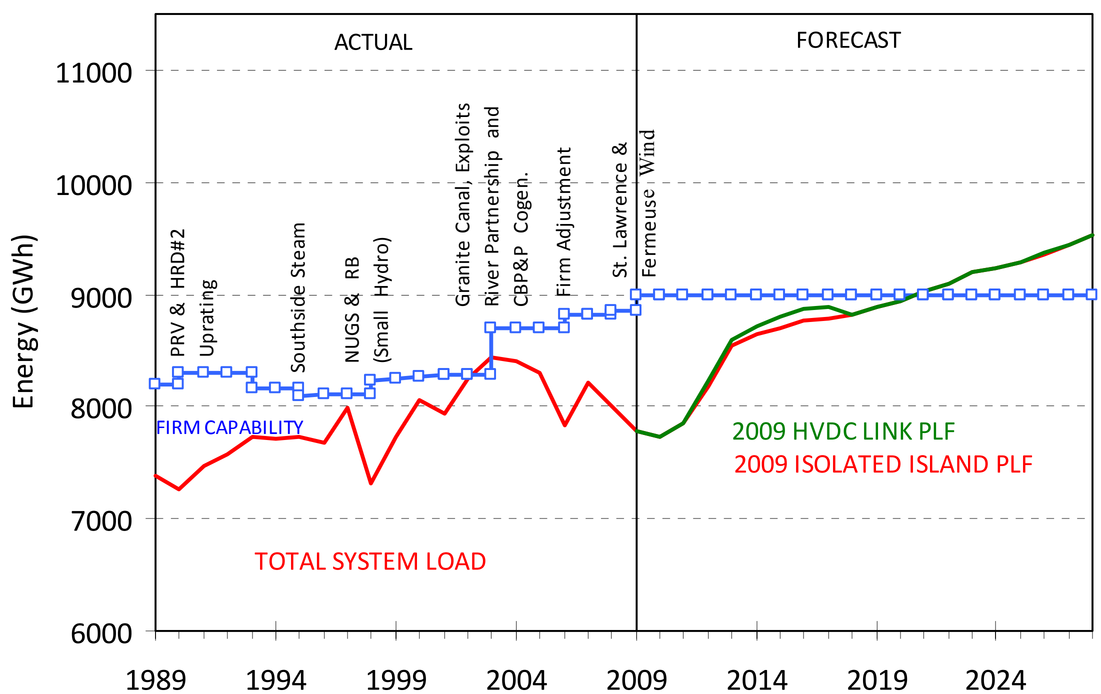
It should be noted that the capacity deficits trigger the need for the next generation source by 2015 under the current planning criteria. Under the expansion scenario ultimately pursued, this need may be met by different sources as explained in the Preliminary Generation Expansion Analysis section (Section 7).

Table 5-1 – Load Forecasts Compared to Planning Criteria

Year	Load Forecasts				Existing System		LOLH [hr/yr]		Energy Balance [GWh]	
	Maximum Demand [MW]		Firm Energy [GWh]							
	HVdc Link	Isolated Island	HVdc Link	Isolated Island	Installed Net Capacity [MW]	Firm Capability [GWh]	HVdc Link	Isolated Island	HVdc Link	Isolated Island
2009	1,592	1,592	7,781	7,781	1,966	8,849	0.40	0.40	1,068	1,068
2010	1,534	1,534	7,727	7,727	1,966	8,988	0.12	0.12	1261	1261
2011	1,568	1,568	7,858	7,858	1,966	8,988	0.25	0.25	1130	1130
2012	1,604	1,603	8,223	8,174	1,966	8,988	0.57	0.54	765	814
2013	1,673	1,672	8,601	8,550	1,966	8,988	2.02	1.91	387	438
2014	1,686	1,680	8,710	8,640	1,966	8,988	2.62	2.40	278	348
2015	1,699	1,691	8,798	8,691	1,966	8,988	3.32	3.09	190	297
2016	1,718	1,702	8,871	8,772	1,966	8,988	4.34	3.71	117	216
2017	1,733	1,719	8,881	8,784	1,966	8,988	5.24	4.65	107	204
2018	1,737	1,726	8,824	8,824	1,966	8,988	5.18	5.18	164	164

Figure 5-1 presents a graphical representation of historical and forecasted load and system capability for the HVdc link and Isolated Island scenarios. It is a visual representation of the energy balance shown in Table 5-1.

Figure 5-1
Island Interconnected System Capability vs. Load Forecast



6.0 Near-Term Resource Options

This section presents a summary of identified near-term generation expansion options. It represents Hydro's current portfolio of alternatives that may be considered to fulfill future generation expansion requirements. Included is a brief project description as well as discussion surrounding project schedules; the basis for capital cost estimates; issues of bringing an alternative into service; and other issues related to generation expansion analysis.

6.1 Island Pond

Island Pond is a proposed 36 MW hydroelectric project located on the North Salmon River, within the watershed of the existing Bay d'Espoir development. The project would utilize approximately 25 metres of net head between the existing Meelpaeg Reservoir and Crooked Lake to produce an annual firm and average energy capability of 172 GWh and 186 GWh, respectively.

The development would include the construction of a three kilometre diversion canal between Meelpaeg Reservoir and Island Pond, which would raise the water level in Island Pond to that of the Meelpaeg Reservoir. Also, approximately 3.4 kilometres of channel improvements would be constructed in the area. At the south end of Island Pond, a 750 metre long forebay would pass water to the 23 metre high earth dam, and then onto the intake and powerhouse finally discharging it into Crooked Lake via a 550 metre long tailrace. The electricity would be produced by one 36 MW Kaplan turbine and generator assembly.

The facility would be connected to TL263, a nearby 230 kV transmission line connecting the Granite Canal Generating Station with the Upper Salmon Generating Station.

Schedule and Cost Estimate Basis

To ensure that Hydro is in a position to properly evaluate Island Pond, an outside consultant was commissioned to prepare a final-feasibility level study and estimate. The final report, *Studies for Island Pond Hydroelectric Project*, was presented to Hydro in December 2006. The report prepared a construction ready update report including an updated capital cost estimate and construction schedule. In the absence of any further work beyond what was identified, the overall schedule is estimated to be approximately 42 months from the project release date to the in-service date.

6.2 Portland Creek

Portland Creek is a proposed 23 MW hydroelectric project located on Main Port Brook, near Daniel's Harbour, on the Northern Peninsula. The project would utilize approximately 395 metres of net head between the head pond and outlet of Main Port Brook to produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively.

The project requires: a 320 metre long diversion canal; three concrete dams; a 2,900 metre penstock; a 27 kilometre 66 kV transmission line from the project site to Peter's Barren Terminal Station; and the construction of access roads. The electricity would be produced by two 11.5 MW Pelton turbine and generator assemblies.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Portland Creek is based on a January 2007 feasibility study, *Feasibility Study for: Portland Creek Hydroelectric Project*, prepared for Hydro by outside consultants. The proposed construction schedule indicates a construction period of 32 months from the project release date to the in-service date. The main activities that dictate the schedule are the construction of access roads and the procurement of the turbine and generator units.

6.3 Round Pond

Round Pond is a proposed 18 MW hydroelectric project located within the watershed of the existing Bay d'Espoir development. The project would utilize the available net head between the existing Godaleich Pond and Long Pond Reservoir to produce an annual firm and average energy capability of 108 GWh and 139 GWh, respectively.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Round Pond is based on the 1988 feasibility study, *Round Pond Hydroelectric Development*, prepared for Hydro by outside consultants, and the associated 1989 Summary Report based on the same. In the absence of any further work beyond what was identified in this study, the overall program for the Round Pond development is estimated to be completed in 33 months, including detailed engineering design. The period for site works includes two winter seasons during which construction activities can be expected to be curtailed. Work on transmission line, telecontrol and terminal equipment would be incorporated in this schedule.

6.4 Wind Generation Projects

The Island of Newfoundland has a world-class wind resource with many sites exhibiting excellent potential for wind-power development. Despite this, there are a number of operational constraints that limit the amount of additional non-dispatchable generation that can be accepted into the System. In January 2007, Hydro signed its first power purchase agreement (PPA) for 27 MW of wind power located at St. Lawrence and in December 2007 it signed a second PPA for another 27 MW of wind power located at Fermeuse. These projects have both begun to generate power into the Island grid. Pending further review and eventual operating experience and with the loss of the load associated with the shutdown of the Grand Falls Pulp and Paper Mill in late 2008, it was decided to postpone a RFP for a third wind farm, as the potential for spill, due to the additional non-dispatchable generation, makes the project economically unattractive (see Section 9.1 Intermittent and Non-Dispatchable Resources).

Any future wind farm would potentially consist of a number of interconnected wind turbines, each ranging in size from 1.8 to 3.0 MW (or larger, as the technology becomes available), tied to a single delivery point on the System's transmission network. For example, a 25 MW wind farm could consist of eight turbines and, depending on the location's wind resource, produce an estimated annual firm and average energy capability of approximately 70 and 110 GWh, respectfully.

Hydro would not develop wind-based projects strictly to address capacity deficits due to the inability to selectively dispatch turbines during periods of high demand. However, these projects do carry some inherent capacity value based on their positive influence on the LOLH calculation and could possibly defer the need for other new generation sources.

Schedule and Cost Estimate Basis

Wind projects typically require at least six to eight months of site-specific environmental monitoring to adequately define the resource. Project development, environmental review and feasibility studies for attractive sites are typically initiated concurrent with the resource study and are finalized shortly after completing the resource assessment. The final design and construction for a wind farm could be completed over an additional 12 to 18 months. The overall project schedule is approximately 30 months from the project release date to the in-service date. Additional time may be required, depending on market conditions, to secure turbine delivery.

6.5 Combined Cycle Plant

The combined cycle facility, also known as a combined-cycle combustion turbine (CCCT) facility, consists of a combustion turbine fired on light oil, a heat recovery steam generator, and a steam turbine generator.

Two alternative sites are being considered and estimates have been prepared based on two different power ratings at each site. One alternative calls for a proposed combined-cycle plant to be located at the existing HTGS to take advantage of the operational and capital cost savings associated with sharing existing facilities. The other alternative is to develop a greenfield site at a location that has yet to be determined. The greenfield alternative may be preferred due to environmental constraints that may be placed on any new developments at Holyrood and reduce the risk of loss of multiple generation sources in the event of major events.

In either alternative, the power ratings being considered are either a 125 MW or a 170 MW (net) CCCT facility. The annual firm energy capability is estimated at 986 GWh for the 125 MW option and 1,340 GWh for the 170 MW option.

Schedule and Cost Estimate Basis

It is expected that a combined-cycle plant would require an Environmental Preview Report (EPR) with the guidelines for its preparation similar to the 1997 review of the proposed Holyrood Combined Cycle Plant. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for each power rating of the Holyrood Combined Cycle Plant is based on the *Combined Cycle Plant Study Update, Supplementary Report* which was completed in 2001, with a review by Hydro's Mechanical Engineering Department in 2009.

6.6 Holyrood Thermal Generating Station Unit IV

HTGS Unit IV is a 142.5 MW (net) conventional steam unit fired on heavy oil and is based on similar technology as the three existing HTGS units. The unit would be located at the HTGS adjacent to the existing units. The annual firm energy capability is estimated at 936 GWh.

Schedule and Cost Estimate Basis

It is expected that the HTGS Unit IV project would require, at a minimum, an EPR with the guidelines for its preparation similar to that of a 1997 review of the proposed project. The overall project schedule is estimated to be approximately 51 months from the project release date to the in-service date.

Sensitivity analysis has demonstrated that the capital cost of the proposed HTGS Unit IV project would have to drop considerably compared with the combined-cycle option given that environmental mitigation requirements, which would be required for this facility, will increase the cost of such a facility. It is highly unlikely that this option would be competitive with a combined-cycle option. Therefore, Hydro will continue to include the proposed HTGS Unit IV project in its portfolio of alternatives but the cost estimate should be updated, in detail, when the appropriate sensitivity analysis identifies the project as a potential near-term addition.

6.7 Combustion Turbine Units

These nominal 50 MW (net), simple-cycle combustion turbines (CT) would be located either adjacent to similar existing units at Hydro's Hardwoods and Stephenville Terminal Stations or at greenfield locations. They are fired on light oil and due to their modest efficiency relative to a CCCT plant, they are primarily deployed for peaking and voltage support functions but, if required, can be utilized provide an annual firm energy capability of 394 GWh each.

Schedule and Cost Estimate Basis

It is anticipated an EPR would be required for each proposed CT project. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for these units was reviewed and updated in 2009, by Hydro's Mechanical Engineering Department. Approximately 90 percent of the direct cost is for the gas turbine package and due to recent fluctuations in demand for gas turbines; prices remain volatile. Hydro should continue to monitor turbine prices to determine when a further in-depth review of the capital cost estimates becomes necessary.

6.8 High Voltage Direct Current (HVdc) Link

As part of the potential development of the lower Churchill River (Lower Churchill Project), a HVdc link would be constructed to the Island to replace power and energy required from the HTGS and to help meet the future energy requirements of the Island. The schedule and capital cost estimate for this project is currently under development.

7.0 Preliminary Generation Expansion Analysis

To provide an indication of the timing and scale of future resource additions required over the load forecast horizon, Hydro uses *Ventyx Strategist®* software to analyse and plan the generation requirements of the System for a given load forecast. *Strategist®* is an integrated, strategic planning computer model that performs, amongst other functions, generation system reliability analysis, projection of costs simulation and generation expansion planning analysis.

The expansion scenarios presented are considered preliminary and they have not been submitted for approval by the Board. In the Province's Energy Plan, Hydro has been directed to pursue one of two options for dealing with environmental concerns related to the HTGS. The first option is based on replacing the HTGS with energy from the Lower Churchill River development via a HVdc link to the Island. The second option is based on an isolated System and is similar to present day operations but the HTGS environmental concerns of sulphur dioxide (SO_2) and particulate emissions will be addressed via the addition of scrubbers and electrostatic precipitators. The scrubbers and electrostatic precipitators will not address greenhouse gas issues. These two options have been named for the purposes of this report as the HVdc link scenario and the Isolated Island scenario.

These expansion plan scenarios represent Hydro's preferred path, utilizing resources from the identified portfolio.

The generation expansion analysis uses an 8.00 percent discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2009. Other key economic parameters necessary to quantify the long-term costs of alternate generation expansion plans are summarized in Appendix B.

Based on the study assumptions outlined previously, the least-cost[8] generation expansion plan, under the two scenarios, is shown below in Table 7-1 and graphically in Figures 7-1 and 7-2.

7.1 High-Voltage Direct Current Link Scenario

Under the HVdc link scenario, no additional generation sources are required until the HVdc link is put in-service. The HVdc link would be put in-service in 2015 and this would provide

[8] For Hydro, the term "least-cost" refers to the lowest Cumulative Present Worth (CPW) of all capital and operating costs associated with a particular incremental supply source (or portfolio of resources) over its useful economic life, versus competing alternatives or portfolios. CPW concerns itself only with the expenditure side of the financial equation. The lower the CPW, the lower the revenue requirement for the utility and hence, the lower the electricity rates will be. By contrast, the term Net Present Value (NPV) typically refers to a present value taking into account both the expenditure and revenue side of the financial equation, where capital and operating expenditures are negative and revenue is positive. The alternative with the higher NPV has the greater return for the investor.

Hydro's system capability requirements well beyond the horizon of this expansion analysis. However, the existing 50 MW CTs at Hardwoods and Stephenville would be retired in 2022, and a new 50 MW CT would be constructed in that year, to replace them.

7.2 Isolated Island Scenario

Under the Isolated Island scenario, the third wind project is planned for 2013, at the same time the additional load from the Vale Inco NL facility is forecast to come on to the grid, enabling the grid to absorb more non-dispatchable generation. Wind is considered due to the benefits of fuel displacement and emissions reductions at the HTGS. The final decision on whether or not to proceed with a wind project will require some deeper analysis to determine the optimal timing, and size of a potential project.

The next supply options in the least-cost generation expansion scenario are the indigenous hydroelectric plants of Island Pond in 2016, Portland Creek in 2019, and Round Pond in 2021 followed by a 170 MW CCCT plant in 2023 and a 50 MW CT in 2026. The CCCT plant is indicative of the most economic thermal plant for supplying base load, which the Island would require in the long-term for firm capability as an isolated system.

For the Isolated Island scenario, further additions of thermal-electric plants can be expected post 2027. Many of Hydro's assets are nearing their expected end-of-life and it is important to point out that under both expansion plans, the 54 MW combustion turbines located at Hardwoods and Stephenville are scheduled to retire during the study period.

While the expansion plans are indicative of the scale of future requirements, any final decision on resource additions will be made at an appropriate time in the future following a full review. These, and other issues, are discussed further in the following section.

Table 7-1

2009 Generation Expansion Plans (Preliminary)		
Year	HVdc Link Scenario Hydro's Alternatives (Capacity/Firm Capability)	Isolated Island Scenario Hydro's Alternatives (Capacity/Firm Capability)
2009		
2010		
2011		
2012		
2013		Wind Farm (25 MW/77 GWh)
2014		
2015	HVdc link (800 MW)	
2016		Island Pond (36MW/172 GWh)
2017		
2018		
2019		Portland Creek (23 MW/99 GWh)
2020		
2021		Round Pond (18 MW/108 GWh)
2022	CT (50 MW/394.2 GWh) HWD CT & SVL CT Retired	
2023		CCCT (170 MW/1,340 GWh) SVL CT Retired
2024		HWD CT Retired
2025		
2026		CT (50 MW/394.2 GWh)
2027		
2028		

Note: The HVdc link expansion plan satisfies Hydro's generation planning criteria well beyond the 2028 planning horizon. However, the Isolated Island expansion plan will require further additions as HTGS units are retired beginning in 2032 (estimated).

Figure 7-1
Preliminary HVDC Link Expansion Plan vs. Load Forecast

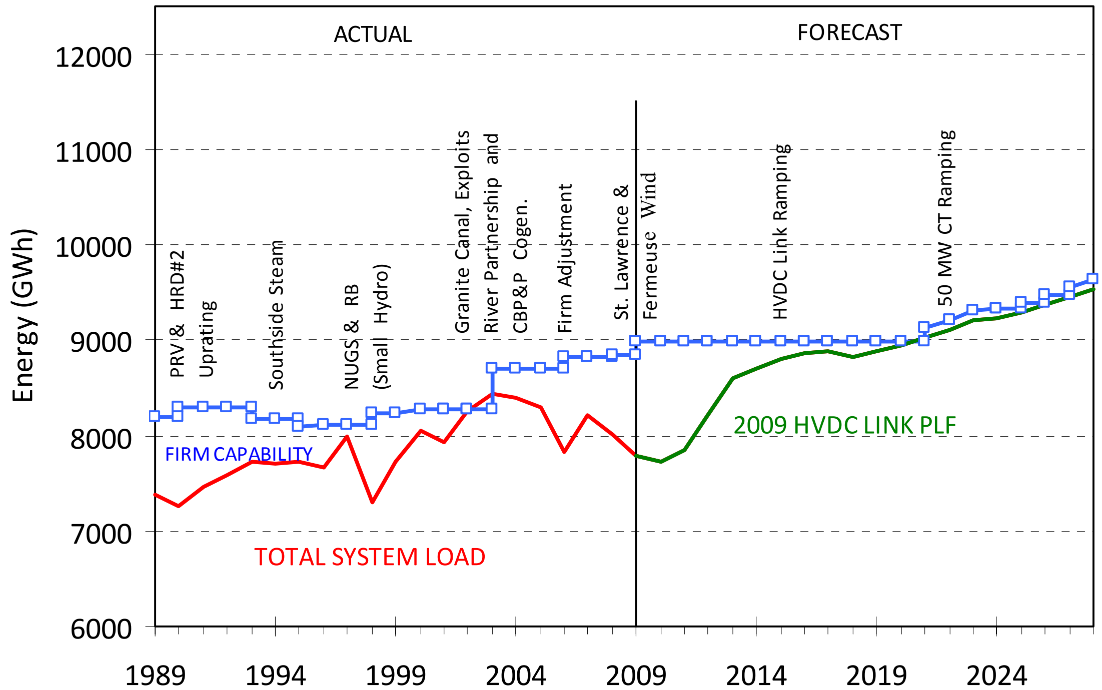
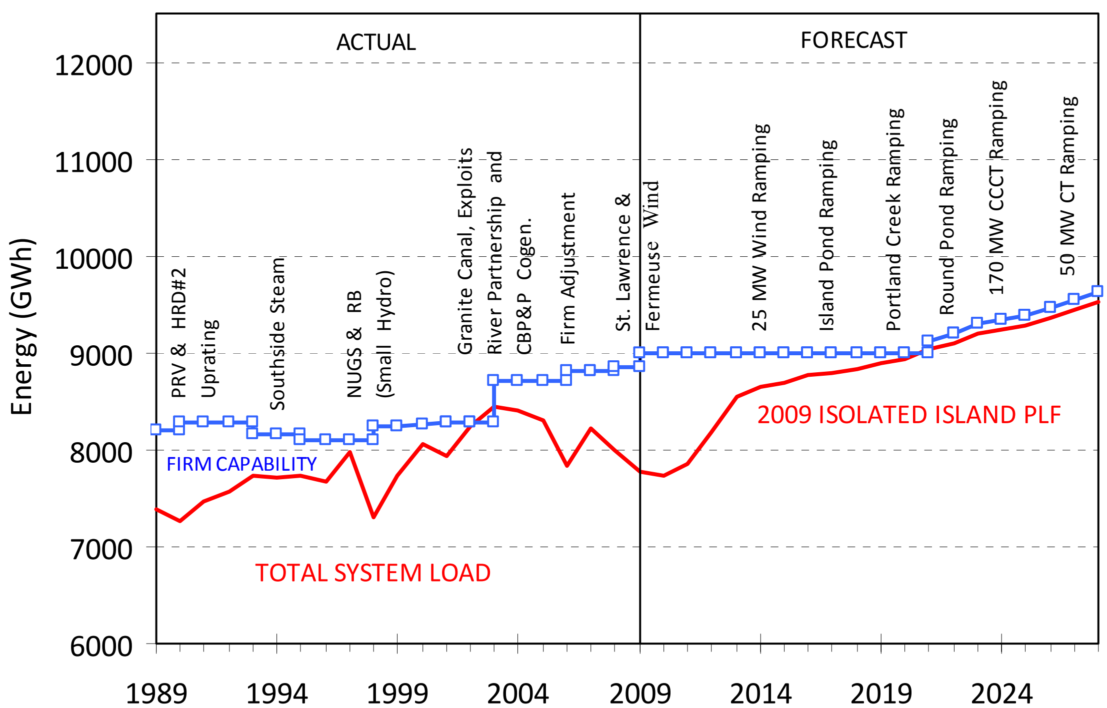


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



8.0 Timing of Next Decision

8.1 Request for Proposals

In addition to those resources included in Hydro's own portfolio of near term alternatives, any number of alternatives may be brought forward under a general request for generation proposals (RFP). As with the 1997 RFP, alternatives submitted under a general RFP can range from various forms of conventional technologies to alternate technologies such as wind power.

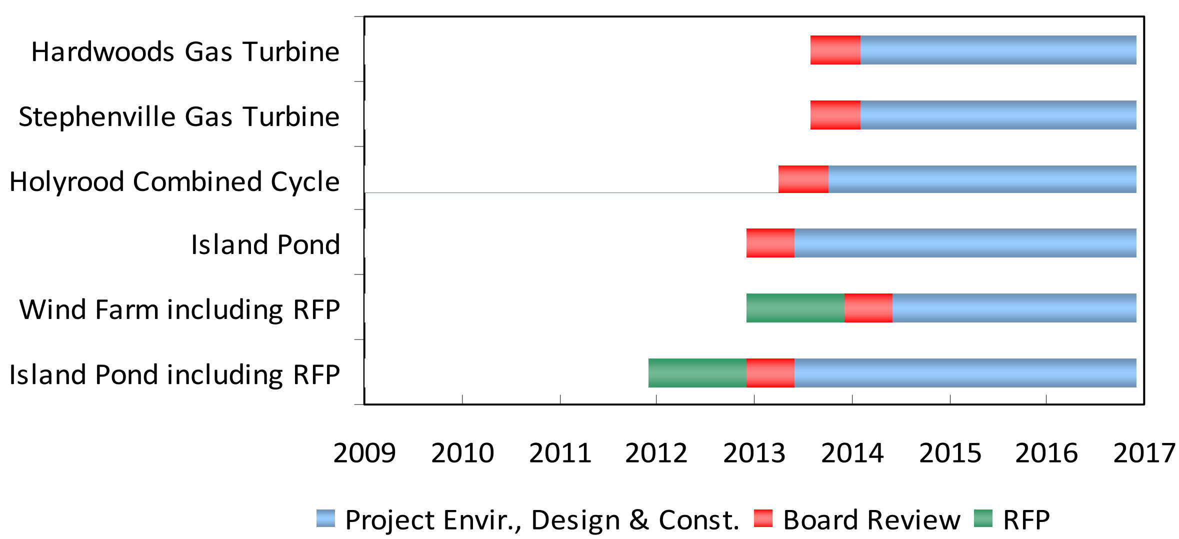
In addition to the time required to bring a project through the normal environmental and construction schedules, additional lead time is required to implement an RFP process. Based on Hydro's 1997 experience, the minimum amount of time required to issue and evaluate proposals through an RFP process is approximately seven months. This was accomplished only through having a high priority placed on the process by the Leadership Team, the commitment of key personnel from various departments and the assistance of consultants from outside Hydro. Due to the urgency to have a final report on generation expansion alternatives ready by mid-June 1997, the RFP, issued in mid-January, gave proponents only approximately three months to submit proposals. Many proponents expressed concern about the short time allotted to prepare proposals and it was evident that if more time had been provided, there may have been more submissions. Ideally, the RFP process requires approximately 15 months to complete, as was the case for Hydro's first RFP for small hydro non-utility generators in 1992. An RFP process with a 12 month schedule from issue through to completion of the project evaluations is a reasonable compromise between the accelerated schedule of the 1997 RFP and the much longer 1992 RFP schedule.

8.2 Newfoundland and Labrador Board of Commissioners of Public Utilities

Prior to 1996, Hydro was not required to seek approval from the Board for its capital program. However, with the 1996 amendments to the Hydro Corporation Act, Hydro, in the absence of a Government exemption, must seek Board approval before committing to a new generation project whether owned or contracted. Given that this process has yet to be tried, approval is estimated to take as long as six months depending on the level of interest shown and the number of interveners requesting standing at the hearings. Based on the level of interest shown at recent Board hearings and as expressed in the 1997 RFP, it is expected that there would be significant interest in a hearing for a new generation source.

Assuming an additional 25 MW wind project is brought in-service by 2013, for fuel displacement at Holyrood, additional generation will be required by the fall of 2016. Based on the requirement for additional generation by the fall of 2016 under an Isolated Island scenario, the following bar chart illustrates the lead times, including that required for a Board review, for each of the near term alternatives to achieve in-service by that time.

Figure 8-1 - Project Lead Times



The addition of an RFP process necessitates a decision to proceed in late 2011 to meet an in-service date of fall 2016. This is due to the need to complete the RFP evaluation and subsequent Board review and have a final decision by mid-2013 to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio.

9.0 Other Issues

9.1 Intermittent and Non-Dispatchable Resources

Based on the Island's existing plus committed generating capacity, approximately 397 MW, or 20 percent of net capacity can be characterized as non-dispatchable generation. While energy production from these resources is predictable over the long term, the generation may not be available when needed. The concern with this type of generation comes on two fronts; first in the availability of the generation to meet higher loads; and second on occasions of light load when the non-dispatchable capacity can no longer be absorbed into the system without adverse technical and economic impacts.

From a generation planning point of view, when assessing the adequacy of system resources to meet peak demands, the characteristics of non-dispatchable generation are incorporated into the unit models. Therefore, on a go-forward basis, new non-dispatchable resources are appropriately evaluated in generation capacity planning analyses.

However, long-term generation planning may not necessarily capture the short-term operational constraints of intermittent and non-dispatchable resources, particularly those related to the ability of the system to absorb the capacity under light load periods. As more and more intermittent and non-dispatchable capacity is added to the system, there comes a point at which the ability to maintain stability and acceptable voltages throughout the system is compromised. As well, there is an increased risk of spilling during high inflow periods as hydraulic production is reduced to accept non-dispatchable production.

In advance of any future RFP that would likely feature non-dispatchable resources such as small hydro and wind energy, it is necessary to determine what limitations on non-dispatchable resources are appropriate. While this has been studied a number of times, changes in available generation and load, such as the Grand Falls paper mill ceasing operations, necessitates a revisting of the analysis. In this light it is recommended that System Planning, in cooperation with Generation Operations, continue to conduct studies to identify the amount of non-dispatchable capacity that may be added without adversely affecting the operation of the system. Changes in these areas may affect proposals in an RFP process in the context of the type of proposal and price.

9.2 Environmental Considerations

Known environmental costs, such as environmental mitigation and monitoring measures that may be identified under the Environmental Assessment Act, and the current Provincial Government 25,000 tonnes per year limitation on SO_2 emissions from the HTGS, have traditionally been included in generation planning studies. In 2007, the Provincial Energy Plan communicated that Hydro would deal with environmental emissions concerns at the HTGS either by pursuing the development of the lower Churchill River and a HVdc link to the Island, or install capital intensive environmental mitigation technologies in the form of scrubbers and electrostatic precipitators to control emissions at the HTGS.

In 2006, Hydro began burning 1 percent sulphur No. 6 fuel oil for the HTGS. While there can be additional purchase costs for 1 percent sulphur over 2 percent sulphur fuel oil, this improvement in fuel grade has reduced SO_2 and other emissions by about 50 percent. In early 2009, Hydro further switched to 0.7 percent sulphur fuel, which may reduce SO_2 emissions by a further 30 percent.

There remains considerable potential for other Government-led environmental initiatives (such as the Clean Air Act, cap-and-trade systems, carbon taxes, etc.) that can impact utility decision-making. While it is impossible to predict the exact nature of future emissions controls or other environmental programs, and their resulting costs, it is necessary to be aware of the issue.

The most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon dioxide (CO_2) is the primary greenhouse gas and Hydro, by virtue of its Holyrood thermal operations, is a principal emitter in the Province at an average of 0.97 million tonnes per year[9]. In the absence of a transmission link from Labrador to the Island, the long-term incremental energy supply for the Island is very likely to be thermal-based and thus this issue could have a significant impact on production costing and future generation planning decisions.

For example, under a cap-and-trade system, the amount of effluent, such as CO_2, Hydro could be permitted to emit could potentially be capped by a regulator at a certain level. To exceed this level, credits could perhaps be purchased from a market-based system at a price set by the market. Conversely, surplus credits for effluent not emitted under the cap level might be traded on the market to generate revenue. This type of system could have significant impacts on Hydro's production costing and the cost of electricity, especially under the Isolated Island scenario.

Other emissions that may come under further regulation include nitrogen oxides (NO_x) and particulate.

Hydro maintains a base of knowledge to be able to provide a qualitative level of analysis on the potential consequences of environmental initiatives such as this on resource decisions. As well, Hydro is closely monitoring national and international activity in this area.

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[9] Based on the 5-year average of 970,459 tonnes per year of CO_2 from 2004 through 2008.

9.3 Holyrood Thermal Generating Station End-of-Life

Units 1 and 2 of the HTGS were commissioned in 1971 and Unit 3 was commissioned in 1979. Under an Isolated Island future, the energy these units will be required to produce will be approaching their firm capability. Under a HVdc link future, these units will be required, as a minimum, to function as synchronous condensers to provide System voltage support as well as to provide a backup supply for some period after the HVdc link comes inservice. Due to the age of these assets, significant capital investments may be required to ensure that they are capable of operating reliably until their anticipated end of life. Typically, as thermal plants age they are derated to account for their decreasing reliability caused by increasing failure rates of aging components. Under an Isolated Island scenario, Hydro cannot derate these units without adding additional generation sources. Hydro must determine what is required for the HTGS to function until its anticipated end of life under both expansion scenarios and to facilitate this, the Board has approved a Condition Assessment of the facility, which will begin during 2009.

9.4 Energy Conservation

In November 2008, Hydro filed a request to defer costs incurred in 2009 associated with the new programs outlined in the Five Year Conservation and Demand Management (CDM) Plan submitted to the Board in June 2008. This request provided updated program concept information and energy savings were estimated at 70 GWh per year in 2013. Also in November, Hydro and Newfoundland Power launched the takeCHARGE program, a joint utility energy conservation program providing tips and information as well as rebates and community programming to help consumers save. The launch of the program brand and website was the first step in bringing the programs outlined in the Five Year CDM Plan to market. In early June 2009, the residential rebate programs were launched addressing home heating savings. A commercial lighting rebate program was also launched at the end of June and a large Industrial program is scheduled in the fall. This collaborative approach is ensuring positive steps towards the creation of a culture of conservation. In all likelihood, the energy conserved will not delay the need for additional generation; however, Hydro should continue to assess its impact on the PLF and expansion plans.

10.0 Conclusion

Based on an examination of the System's existing plus committed capability, in light of the 2009 PLF and the generation planning criteria, the Island system can expect capacity deficits starting in 2015 under both the HVdc link and Isolated Island scenarios but no energy deficits until post-2018. If a third wind project is brought in-service in 2013, generation additions for the Isolated Island scenario could be postponed until 2016.

Due to the direction given to Hydro under the Provincial Government's Energy Plan, two generation expansion plans are to be maintained until a sanction decision on the Lower Churchill Project can be reached. These two expansion plans differ based on the inclusion of a HVdc link as an available alternative to meet the System's energy requirements. The decision for sanctioning for the Lower Churchill Project is scheduled for 2010 and at that time, the expansion scenario that Hydro will ultimately pursue will be known. Until that time, it would be desirable to avoid committing to one generation expansion plan over another; however, Hydro must be prepared to react to protect the reliability of energy supply for the Provincial market. If a revised forecast indicates that a decision is required prior to the Lower Churchill Project sanctioning, a detailed study on how best to proceed will have to be prepared to ensure that the most appropriate decision can be undertaken in an orderly process.

In order to meet the deficits noted in 2015/2016, Hydro has identified two possible sources. The preferred source depends whether or not the Lower Churchill Project and the HVdc link are sanctioned. Assuming that the Project and link are sanctioned, the HVdc link will meet the capacity and energy requirements of the Island for many years to come and nothing is required before the HVdc link. However, if the Project and link are not sanctioned, Hydro will likely require the construction of the 36 MW Island Pond hydroelectric plant to meet its capacity requirements. It is likely that the remaining hydroelectric facilities of Portland Creek and Round Pond would also be constructed for their capacity and energy benefits along with their economic and environmental benefits associated with the displacement of fuel required to produce energy at the HTGS. In order to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio, the addition of an RFP process for other supplies necessitates a decision to proceed in late 2011 to meet an in-service date of fall 2016. This is due to the need to complete the RFP evaluation and subsequent Board review and have a final decision by mid-2013

The impact of energy conservation measures resulting from the *Five-Year Energy Conservation Plan* will need to be evaluated to determine what, if any impact, it has on the decision for the next source. At this time, it is expected that the principal benefits will be the economic and environmental benefits of the reduced reliance on HTGS produced electricity and that the timing for the next decision will be unaffected.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVdc Transmission Link – Hydro must be prepared for events that may delay the proposed Lower Churchill Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both a HVdc link future and an Isolated Island future. For the latter case, other future generation sources should be considered;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;

- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.

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Appendix A

Table A-1
2009 Planning Load Forecasts

	2009 PLF HVdc Link Case		2009 PLF Isolated Island Case	
Year	Maximum Demand [MW]	Firm Energy [GWh]	Maximum Demand [MW]	Firm Energy [GWh]
2009	1,592	7,781	1,592	7,781
2010	1,534	7,727	1,534	7,727
2011	1,568	7,858	1,568	7,858
2012	1,604	8,223	1,603	8,174
2013	1,673	8,601	1,672	8,550
2014	1,686	8,710	1,680	8,640
2015	1,699	8,798	1,691	8,691
2016	1,718	8,871	1,702	8,772
2017	1,733	8,881	1,719	8,784
2018	1,737	8,824	1,726	8,824
2019	1,734	8,887	1,734	8,887
2020	1,745	8,936	1,745	8,936
2021	1,756	9,028	1,756	9,027
2022	1,773	9,102	1,773	9,100
2023	1,785	9,202	1,785	9,199
2024	1,801	9,237	1,801	9,233
2025	1,809	9,294	1,809	9,290
2026	1,819	9,367	1,819	9,362
2027	1,831	9,449	1,831	9,444
2028	1,844	9,531	1,844	9,525

Appendix B

Table B-1

Fuel Forecast

Year	Residual 0.7%S (6.287 MBTU/BBL) [$/BBL]	Diesel (5.825 MBTU/BBL) [$/litre]
2009	60.50	0.530
2010	73.30	0.620
2011	88.10	0.725
2012	87.90	0.720
2013	90.60	0.740
2014	93.50	0.770
2015	95.40	0.815
2016	101.50	0.860
2017	107.00	0.900
2018	111.80	0.940
2019	119.20	1.000
2020	126.10	1.060
2021	128.60	1.080
2022	131.10	1.100
2023	133.80	1.125
2024	136.40	1.145
2025	139.20	1.170
2026	141.90	1.190
2027	144.80	1.215
2028	147.70	1.240

Source: Investment Evaluation, Nalcor and Market Analysis Section, System Planning, Hydro, June 2009

Table B-2

Escalation Rates

Year	General Inflation		Construction			Operation & Maintenance	
	GDP	Canadian CPI	Hydro & Thermal Plant	Transmission Line	Transformer Station	More Materials Less Labour	More Labour Less Materials
2009	1.0%	1.8%	1.4%	-0.2%	0.9%	2.2%	2.8%
2010	1.9%	1.9%	0.5%	2.3%	1.3%	2.2%	2.8%
2011	1.9%	1.9%	1.7%	2.0%	1.0%	2.2%	2.8%
2012	1.9%	1.9%	2.3%	3.4%	2.0%	2.2%	2.8%
2013	2.0%	2.0%	3.0%	3.5%	2.8%	2.2%	2.8%
2014	2.0%	2.0%	3.1%	3.5%	3.1%	2.2%	2.8%
2015	2.0%	2.0%	2.0%	1.9%	2.4%	2.2%	2.8%
2016	2.0%	2.0%	1.5%	1.7%	1.7%	2.2%	2.8%
2017	2.0%	2.0%	2.7%	2.6%	2.0%	2.2%	2.8%
Post 2018	2.0%	2.0%	2.7%	2.8%	2.2%	2.2%	2.8%

Source: Investment Evaluation, Nalcor and Market Analysis Section, System Planning, Hydro, January 2009