SUPPLEMENTARY EVIDENCE OF J.R. HAYNES
(REGULATED ACTIVITIES)
November 27, 2006

INTRODUCTION

This evidence is filed as Supplementary to the Regulated Activities Evidence provided to the Board with Hydro's General Rate Application in August 2006. It addresses the recommendation for an Integrated Resource Plan raised by two Intervenors and which requires clarification or a response from Hydro that has not otherwise been provided through the Request for Information (RFI) process.

LONG TERM GENERATION PLANNING/INTEGRATED RESOURCE PLAN

Mr. Douglas Bowman, on behalf of the Consumer Advocate, states that a comprehensive planning framework is necessary to increase confidence that customers are gaining maximum value from demand and supply procurement from both cost and socio-environmental perspectives (page 4 lines 15-18). At page 5 lines 16-17, he specifically recommends that Hydro submit to the Board, for review and approval, a detailed framework and schedule for undertaking a formal Integrated Resource Plan (IRP).

Similarly Mr. Patrick Bowman, on behalf of the Industrial Customers, on page 5 lines 29-31 of his report, states that a firm submission deadline should be established for Hydro to file a full comprehensive long-term Resource Plan and preferred development scenario for the Island Interconnected system. In response to NLH 34 IC lines 26-27, Mr. Bowman makes clear that the Resource Plan would include utility demand and supply side resources, that the process would be lead by Hydro (lines 17-18), and that external involvement would, for now, be focused on parties who make a material contribution to utility planning, such as Industrial Customers (line 28-30).

Generation Planning at Hydro

Historically, Hydro has made its investment decisions on generation expansion requirements in the absence of large-scale conservation investments or undertakings by focusing on minimizing revenue requirements solely on its expected, direct production costs.

Hydro views integrated resource planning as a natural extension to conventional least cost electricity supply planning once it is decided what demand side resources (and other considerations such as environmental risks) are to be included in the consideration of a utility’s portfolio of resource options for meeting future energy requirements.

As part of its ongoing responsibilities, Hydro prepares a long-term load forecast and a long-term least cost electricity supply plan to satisfy the forecasted electricity requirements each year. The generation expansion analysis compares hydroelectric and/or renewable indigenous resources with thermal alternatives and selects the resource sequence that minimizes the present value of costs while satisfying the established energy planning criteria and meeting environmental regulations.

An annual system planning report is prepared for Hydro's Leadership Team that reviews the latest generation expansion requirements, options and issues. Since this report is traditionally prepared in the last quarter, the latest report available is Hydro's 2005 Report[1] (attached as Schedule JRH - Supplementary 1).

For the 2005 report, in recognition of the uncertainty of Abitibi Consolidated Inc. operations in Stephenville, two scenarios were evaluated to ensure that Hydro's analysis and decision-making accounted for the possible loss of the newsprint mill load. In October 2005, Abitibi Consolidated Inc. did, in fact, permanently close the newsprint mill in Stephenville.

The 2006 Report is currently being prepared and will be filed with the Board next week. Thus, in Hydro's view, the most significant element of an IRP is already being undertaken by Hydro, as it has been done for many years.

Demand Side Management

Demand Side Management is another key element of an IRP and Hydro has made a further commitment to study conservation potential and implement applicable programs.

[1] On page 27 of this Schedule, Hydro has treated its direct costs for its indigenous and proprietary power projects as confidential due to the potential requirement for opening bidding in a request for proposals at a later date(s).

In 2007, Hydro intends to complete a study of the technical and economic potential for conservation in the Province from which will flow recommended conservation programs and applicable budgets.

This information will be evaluated in the context of Hydro's conventional system planning and an applicable conservation program bundle would be treated as a resource option for the purposes of generation expansion analysis. A suitable software module can be added to Hydro's existing system generation expansion program to accomplish this integrated planning.

Relevant Board Orders/Precedence

With respect to the suggestion that the Board should direct Hydro to submit a detailed framework and schedule for a full Integrated Resource Plan, Hydro notes that:

- In PU 14 (2004), the Board expressed its preference for a generic process to address issues and benefits associated with IRP owing to the complexity of issues involved;

- In response to NLH 33 IC, Patrick Bowman provided the BC Utilities Commission Resource Planning Guidelines (2003) as well as references to Resource Plans for the Yukon and Manitoba. Subsequently in NLH 42 IC, Mr. Bowman made reference to the website from which BC Hydro's 2006 Integrated Electricity Plan could be sourced. This Report is in excess of 2000 pages, took two years to prepare and while filed with the Commission in March 2006, is still in the pre-hearing process with oral hearing set to commence in January 2007. This demonstrates the scope of work and commitments for such an undertaking. A copy of the Index alone is attached as Schedule JRH - Supplementary 2.

Costs and Schedule for an IRP

While Hydro has requested that the Consumer Advocate and Industrial Customers' experts provide information regarding scheduling and costs of the IRP they suggest the Board model, neither has been able to do so. However, based on BC Hydro's experience, Hydro believes the costs of such a comprehensive and formal exercise would be enormous. No funds have been provided in the 2007 test year or beyond, for an IRP or the software module referenced previously.

Energy Plan

The Province's Energy Policy Plan, now due for release in 2007, represents a significant consideration with respect to an IRP since it can be expected to establish overall energy policy and objectives which may have a significant impact in future electricity supply sources. As examples only, there could be provincial policy directive to utilize stranded offshore natural gas for power generation, or there could be a directive to interconnect the Island and Labrador portions of the Province with a high voltage transmission link.

SUMMARY

Hydro believes that:

- Key aspects of electricity system planning are well in hand, and have been for years. Hydro regularly updates projections of system supply and demand to ensure adequate reliability. As energy costs have increased in recent years Hydro has re-examined cost-effective means to reduce its reliance on thermal power;
- Coupled with Hydro's pending review of conservation potential, these actions go a long way in addressing, at minimal cost, the more pertinent elements that integrated resource planning attempts to incorporate into conventional electricity resource planning;
- An IRP directive should flow from a generic process, as expressed by the Board in P.U. 14 (2004);
- The Board has not been provided, at this hearing, with a reliable estimate of the timing or costs associated with a comprehensive IRP; and
- An IRP directive in the absence on the Energy Plan directive is, in Hydro's opinion, premature.

Schedule JRH-Supplementary 1

Generation Planning Issues

2005 Update

System Planning

September 2005

Executive Summary

This report provides an overview of the Island's 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 insure that a decision on the preferred source can be made through an orderly process.

Based on an examination of the Island's existing plus committed capability, in light of the 2005 Planning Load Forecast and the generation planning criteria, the Island system can expect energy and capacity deficits starting in 2008. However, these deficits are not considered significant and additional supply would normally be planned for in-service in 2009. With the recent announcements by ACI of the scheduled closure of the Stephenville mill and #7 machine at Grand Falls, future generation requirements may be delayed until 2012. Assuming the likely development of at least 25 MW of wind power arising from Government's Wind Strategy review, the timing of future generation requirements could be delayed by an additional year.

However, the scenario in which the mill remains operational is contingent on the likely requirement that ACI proceed with the development of 66 MW of new hydroelectric capacity on the Exploits River. In such an event, Hydro would not be seeking additional generation beyond the new Exploits River developments until 2011.

Therefore, in any event, it is unlikely that there would be a requirement for Hydro to initiate an RFP to meet future power and energy requirements prior to at least the fall of 2006. Beyond seeking clarification on issues surrounding ACI's milling operations in Newfoundland, from a System Planning point of view, the following are the key issues that should be dealt with in the near term;

- Environment/Emissions Control Considerations - Considering the impact that environmental initiatives could have on future planning studies, it is necessary to remain current on activities elsewhere in this area;

- Wind Power - Hydro should continue to pursue and investigate the risks and opportunities associated with the integration of wind energy into the Island system; and

- Resource Inventory - Insure that Hydro maintains an inventory of resource options that have undergone sufficient study as to provide confidence in overall project concept and costs.

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1. Introduction

The purpose of this report is to provide an overview of the Island's generation requirements in light of the most recent load forecast and existing and committed capability. The intent is to provide an overview of the timing of the next requirement for additional generation supply, the resources available to meet that requirement, and to identify any issues that need to be addressed to insure an orderly decision on the preferred source can be made at a future date.

2. Load Forecast

This review uses the 2005 Planning Load Forecast as developed by Hydro's System Planning Department as the base case. This forecast is for the total Island Interconnected System and includes demand and energy met by our customers' generation resources. It assumes Voisey's Bay investments in Labrador as well as commercial refining operations on the Island starting in 2012. The forecast period is from 2005 to 2024 and, exclusive of the Voisey's Bay refinery, has an average annual compound growth rate of approximately 0.7%.

In addition, given the recent announcements by Abitibi Consolidated Inc. and the continuing uncertainty regarding the scheduled permanent closure of the Stephenville mill in October 2005, and the eventual closure of it's #7 paper machine in Grand Falls, a sensitivity load forecast incorporating this scenario is also considered.

The base case and sensitivity load forecasts are presented in Table A1.

3. System Capability

Table 3-1 provides a summary of the existing and committed capacity and energy capability of the Island System. Hydro is the prime supplier of electrical energy, accounting for 80% of the Island's net capacity. The remaining capacity is supplied by Newfoundland Power

Inc. Limited (8%), Corner Brook Pulp and Paper Limited (6%) and Abitibi Consolidated Inc. (3%). Hydro also has contracts with four Non-Utility Generators (3%) for the supply of energy.

Hydroelectric generating units account for 65% of the total existing Island net capacity and firm energy capability. The remaining net capacity comes from thermal resources on the Island and is made up of conventional steam, combustion turbine and diesel generating plants. Approximately 70% of the existing thermal capacity is located at the Holyrood Thermal Plant and is fired using heavy oil. The remaining capacity is located at sites throughout the Island.

Table 3-1

Island Capability	Net Capacity (MW)	Energy (GWh) Firm	Energy (GWh) Average
Newfoundland & Labrador Hydro			
Bay D'Espoir	592.0	2278	2596
Upper Salmon	84.0	489	550
Hinds Lake	75.0	283	340
Cat Arm	127.0	605	704
Granite Canal	40.0	224	224
Paradise River	8.0	27	37
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	7
TOTAL HYDRO	927.3	3911	4458
Holyrood	465.5	2996	2996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
TOTAL THERMAL	598.2	2996	2996
Newfoundland Power Inc.			
Hydro	94.6	323	426
Combustion Turbine	43.9	-	-
Diesel	7.0	-	-
TOTAL	145.5	323	426
Corner Brook Pulp and Paper Ltd.			
Hydro	122.4	790	870
Abitibi Consolidated Inc.			
Hydro	59.1	443	470
Non-Utility Generators			
Corner Brook Cogen	15.0	100	100
Exploits River Partnership	32.1	110	137
Rattle Brook	4.0	14	16
Star Lake	15.0	93	141
TOTAL	66.1	317	394
TOTAL EXISTING (DEC. 2004)	**1918.6**	**8780**	**9614**

4. Planning Criteria

Hydro has established criteria related to the appropriate reliability, at the generation level, for the total Island 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 insure an adequate supply for firm load:

Energy

The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm System capability.

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.

5. Identification of Need

Table 5-1 presents an examination of the base case load forecast (Table A1) with the planning criteria and shows energy and capacity deficits starting in 2008. Note that these identified deficits are not considered significant and additional supply would normally be planned for in 2009.

Table 5-1

Near Term Capability Requirements						
	Base Case Load Forecast		Existing System			
Year	Peak MW	Firm Energy GWh	Installed Net Capacity MW	Firm Capability GWh	LOLH hrs/yr	Energy Balance (GWh)
2005	1,612	8,573	1,919	8,780	1.4	207
2006	1,621	8,602	1,919	8,780	1.7	178
2007	1,637	8,744	1,919	8,780	2.4	36
2008	1,651	8,787	1,919	8,780	***2.8***	***(7)***
2009	1,660	8,864	1,919	8,780	3.5	(84)
2010	1,676	8,956	1,919	8,780	4.6	(176)
2011	1,693	8,995	1,919	8,780	5.7	(215)
2012	1,751	9,315	1,919	8,780	13.3	(535)
2013	1,761	9,400	1,919	8,780	82.4	(620)
2014	1,769	9,498	1,919	8,780	98.0	(718)
2015	1,774	9,513	1,919	8,780	103.7	(733)

A similar analysis of the sensitivity load forecast scenario in which the Stephenville mill and Grand Falls #7 paper machine are closed starting in 2006 is summarized in Table 5-2. Under this scenario, capacity and energy deficits are delayed until 2012 and 2013 respectively.

Figure A1 (Appendix A) presents a graphical comparison of historical and projected load and system capability for both the base case and sensitivity scenarios.

Table 5-2

Near Term Capability Requirements						
	ACI Sensitivity Load Forecast		Existing System			
Year	Peak MW	Firm Energy GWh	Installed Net Capacity MW	Firm Capability GWh	LOLH hrs/yr	Energy Balance (GWh)
2005	1,612	8,486	1,919	8,780	1.3	294
2006	1,541	7,938	1,919	8,780	0.3	842
2007	1,557	8,077	1,919	8,780	0.4	703
2008	1,587	8,247	1,919	8,780	0.7	533
2009	1,596	8,323	1,919	8,780	0.9	457
2010	1,612	8,415	1,919	8,780	1.2	365
2011	1,629	8,455	1,919	8,780	1.5	325
2012	1,687	8,774	1,919	8,780	***4.0***	6
2013	1,697	8,859	1,919	8,780	5.0	***(79)***
2014	1,705	8,958	1,919	8,780	6.0	(178)
2015	1,710	8,973	1,919	8,780	6.5	(193)

5.1. Impact of Wind Demonstration Project

The assessment of the feasibility of wind generation as a future alternative for the supply of electric power and energy on the Island of Newfoundland is ongoing. Pending the outcome of Government's wind strategy investigations, it is likely that a wind project(s) having a capacity of at least 25 MW could be sought for near term development and interconnection to the Island system. At current forecast rates of load growth, a 25 MW wind project could delay the requirement for a new generation source by one year.

6. Near Term Resource Options

This section presents a summary of options currently identified for near term generation expansion. Included is a brief project description as well as discussion surrounding project schedules, the current status of capital cost estimates, and any other issues related to generation expansion analysis and bringing an alternative into service.

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 the available head between the existing Meelpaeg Reservoir and the Upper Salmon Development to produce firm and average annual energy capability of 186 GWh and 203 GWh, respectively.

The development would include the construction of a 3 km long diversion canal between Meelpaeg Reservoir and Island Pond which would raise Island Pond to the Meelpaeg Reservoir level. As well, approximately 3.4 km of channel improvements would be constructed in the area. At the south end of Island Pond, a 750m long forebay would pass water to the dam, intake and powerhouse and discharge it into Crooked Lake via a 550 m long tailrace.

The facility would be interconnected with a nearby 230 kV transmission line connecting the Granite Canal development with the Upper Salmon Generating Station.

Schedule and Cost Estimate

The project had undergone a full environmental review in the late 80's and early 90's. Component studies and an Environmental Impact Statement were submitted in 1993 which was accepted by the Minister but could not go to Cabinet for final approval since the four year preparation period was exceeded. It was registered again in 1997 at which time an Environmental Preview Report (EPR) was required. The project will have to be registered yet again prior to project release. In the absence of any further work beyond that identified in 1997 the overall schedule would call for approximately 43 months from start to finish. If further field work is identified, the schedule may have to be extended.

The current capital cost estimate for Island Pond is based on the "Re-Optimization and Cost Update Study" which was prepared in 1997. To insure that Hydro is in a position to properly evaluate Island Pond, along with other competitive alternatives that may be submitted in a future RFP (see Section 8), a capital cost update proposal has been included in Hydro's 5-year capital plan to be completed prior to commencement of any future RFP.

Wind Project

The Island of Newfoundland has a world-class wind resource with many sites exhibiting excellent potential for wind power development. However, there are a number of operational constraints inherent to the Island System that limit the amount of additional non-dispatchable generation that can be accepted into the system. Pending further review and eventual operating experience, a maximum of 80 MW from wind is considered as economic and technically acceptable alternatives to meet a portion of future generation requirements for the Island System.

A 25 MW wind farm consists of a collection of 14 to 38 individual 660 kW to 1,800 kW wind turbines interconnected to a single delivery point to the Island System's transmission network and is estimated to produce firm and average annual energy capability of 91 GWh and 103 GWh, respectively.

Schedule and Cost Estimate

Wind projects typically require at least 12 months of site specific environmental monitoring to adequately define the resource. Project development and feasibility studies for attractive sites are typically carried out concurrent with the resource study and are often completed following the year long resource assessment. In anticipation of an eventual contract with either Hydro or Newfoundland Power, a number of proponents have already completed resource assessments for potential wind sites on the Island. The final design and construction for a 25 MW wind farm could be completed over an additional 12 to 18 months. Notwithstanding the speculative activity of some proponents, the overall project schedule calls for approximately 30 months from start to finish. However, additional time may be required to secure turbine delivery depending on market conditions at the time.

First year cost for wind energy is estimated to be 6 to 7 cents/kWh for projects completed in the near term. This cost does not include allowance for Government incentives such as the Wind Power Production Incentive (1.0 cents/kWh for the first 10 years of production), nor does it include value allowances for any environmental attributes.

Holyrood Combined Cycle Plant

Two alternatives have been identified and estimates prepared for a proposed Holyrood Combined Cycle Plant; a 125 MW and a 170 MW (net) combined cycle combustion turbine facility.

The combined cycle unit consists of a combustion turbine fired on light oil, a heat recovery steam generator, and a steam turbine generator. The plant would be located at the existing Holyrood Thermal Plant site to take advantage of the operational and capital cost savings associated with sharing existing facilities. The annual firm energy capability is estimated at 986 GWh for the 125 MW unit and 1,340 GWh for the 170 MW unit.

Schedule and Cost Estimate

It is expected that the Holyrood Combined Cycle Plant would require an EPR with the guidelines for its preparation similar to that of a 1997 review of the proposed project. The overall project schedule calls for approximately 36 months from start to finish.

The capital cost estimate for each option of the Holyrood Combined Cycle Plant is based on the "Combined Cycle Plant Study Update, Supplementary Report" which was completed in 2001.

Holyrood Unit IV

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

Schedule and Cost Estimate

It is expected that the Holyrood Unit IV project would require an EPR with the guidelines for its preparation similar to that of a 1997 review of the proposed project. The overall project schedule calls for approximately 51 months from start to finish.

In a March 2000 update of the capital cost estimate for the Holyrood Unit IV project the following concerns were raised surrounding the accuracy of the estimate:

- The basis for the estimate is eleven years old and does not reflect current market conditions;
- There are indications that manufacturers of conventional thermal plant equipment have reduced their prices to remain competitive with combined cycle power plants; and
- Some of the items included in the original capital cost estimate as general plant improvements have been implemented in the interim and should be removed from the cost estimate.

However, recent sensitivity analysis has demonstrated that the capital cost of the proposed Holyrood Unit IV project would have to drop by approximately 20% to be competitive with the combined cycle option. It is the opinion of Hydro's Generation Engineering Department that such a magnitude of decrease in cost is highly unlikely. Further, given anticipated stricter environmental regulations, the capital cost for the project could likely rise. Therefore, while Hydro will continue to include the proposed Holyrood Unit IV project in its portfolio of alternatives, at such time that appropriate sensitivity analysis identifies the project as a potential near term addition, the project feasibility and cost estimate should be reviewed in detail.

Hardwoods Unit 2 and Stephenville Unit 2 Combustion Turbine Units

These nominal 50 MW simple cycle combustion turbines would be located adjacent to similar existing units at Hydro's Hardwoods and Stephenville Terminal Stations. They are fired on light oil and are designed for peaking and voltage support functions.

Schedule and Cost Estimate

It is anticipated that both of these options will require an EPR. The overall project schedule calls for approximately 32 months from start to finish.

The capital cost estimate for these units were reviewed and updated in October 2000. Approximately 90% of the direct cost is for the gas turbine package and, with the sustained demand for gas turbines, prices can be expected to remain volatile for several years. Hydro should continue to monitor turbine prices to determine when further review of the capital cost estimates becomes necessary.

7. Preliminary Generation Expansion Analysis

To provide an indication of the timing and scale of future resource additions required over the load forecast period to 2024, the following presents the results of a preliminary generation expansion analysis for both the base case and ACI load forecast sensitivities. For this analysis, wind generation projects and projects in Hydro's own portfolio of resource options are made available to meet future load requirements. For this review it is assumed that a 25 MW wind project will be in service by 2007.

7.1. Study Economic Assumptions

This study uses an 8.4% discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2005. 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 generation expansion plans under base case and ACI load sensitivity cases are shown below in Table 7-1. Note that under the base case load growth scenario, two expansion plans are identified. The first shows a generation expansion plan in the absence of any further development of the Exploits River. However, the base case load scenario in which the Stephenville mill remains operational is contingent on the likely requirement that ACI proceed with the development of 66 MW of new hydroelectric capacity on the Exploits River (at Badger Chute and Red Indian Falls). The 2010 in-service date of this additional capacity is not related to system load requirements but to the time required to bring the projects into service and is a "given" in the second expansion plan around which other alternatives would be slotted to meet future load requirements.

Table 7-1

Preliminary Generation Expansion Analysis			
Year	Base Case Load Growth Scenario		ACI Load Sensitivity Scenario (less Stephenville Mill & #7 Machine at Grand Falls)
	Newfoundland Hydro Alternatives + Wind	ACI Development of Badger Chute and Red Indian Falls	
2005			
2006			
2007	25 MW Wind	25 MW Wind	25 MW Wind
2008			
2009	25 MW Wind		
2010	25 MW Wind	Badger C. + Red Indian	
2011	Island P. + Portland C.	25 MW Wind	
2012	Round Pond	25 MW Wind + Island P.	25 MW Wind
2013			25 MW Wind
2014	125 MW CCCT		
2015			Island Pond
2016		Portland Creek	
2017		Round Pond	
2018			Portland C. + Round P.
2019		125 MW CCCT	
2020			
2021			125 MW CCCT
2022			
2023			
2024	50 MW CT		

In a departure from past studies, generation from wind has replaced Island Pond as the preferred next source of generation from amongst Hydro's identified portfolio of resource options.

While these 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 and following a full review of Provincial resources, which likely would include a Request for Proposals. This, and other related issues are discussed further in the following section.

8. 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 7 months. This was accomplished only through having a high priority placed on the process by Management, 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 3 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 would likely 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.

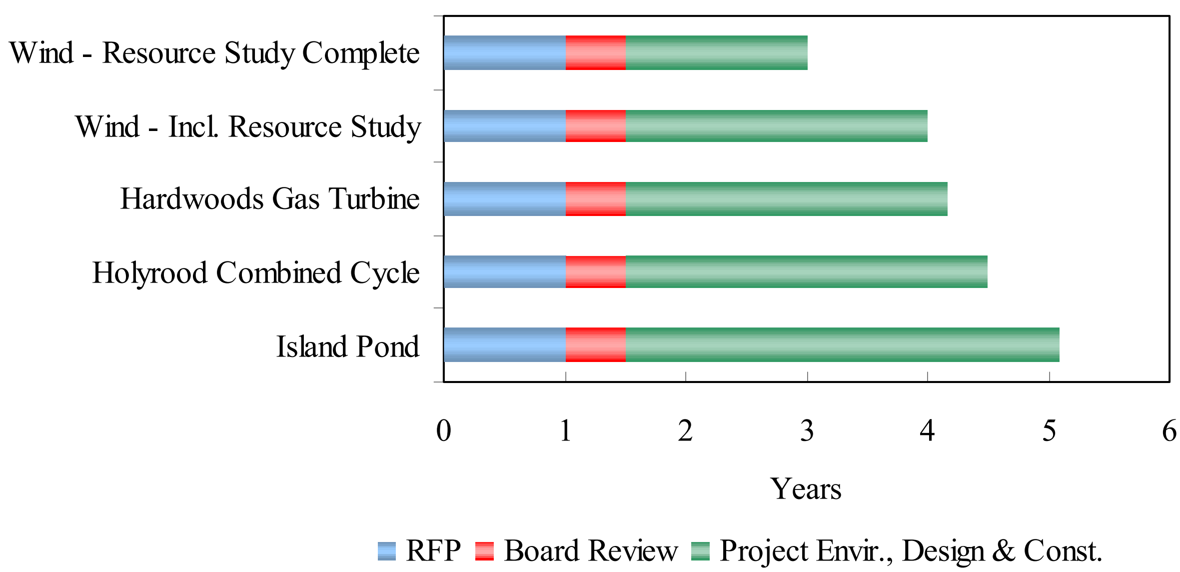
8.2. Public Utilities Board

Prior to 1996, Hydro was not required to seek approval from the Board of Commissioners of Public Utilities (Board) for its' capital program. However, with the 1996 amendments to the

Hydro Corporation Act, and in the absence of a Government exemption, Hydro 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 6 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.

The following bar charts illustrates the lead times, including that required for a Board review, for each of Hydro's near term alternatives.

Figure 8-1 - Project Lead Times



Under the base case forecast scenario that assumes a 25 MW wind project by 2007, but does not include any further development of the Exploits River as shown in Table 7-1, the next requirement for additional generation is in 2009. Based on the above lead times, the only project that could go through the full RFP and Board Review process and be developed to meet the 2009 in-service date would be Wind and a simple cycle gas turbine (Hardwoods Gas Turbine).

To meet the 2011 and 2012 in-service dates for new projects (beyond the initial 25 MW wind development in 2007 and ACI's Exploits River Developments) identified in the Table 7-1 expansion plans, Hydro would have to initiate an RFP process in late 2006 or 2007, respectively. This is due to the need to complete the RFP evaluation and subsequent Board review and have a final decision with sufficient lead time to protect the in-service date for the Island Pond alternative.

While these lead times are necessary for a full (open to all bidders and resource types) RFP and Board process, opportunities may be available to reduce the lead time necessary by limiting the scope of the RFP. For example, a "wind only" RFP would require less lead time as shown above.

9. Other Issues

9.1. Environmental Considerations

Known environmental costs, such as environmental mitigation and monitoring measures that may be identified under the Environmental Assessment Act, and the current 25,000 tonnes/year limitation on SO_2 emissions from Holyrood, have traditionally been included in generation planning studies. Hydro has also participated in recent studies to evaluate and communicate to Government, the potential impact of proposed changes in environmental regulations aimed at reducing further the amount of sulphur that Hydro will be permitted to emit. However, even beyond these latest considerations of Government, there remains considerable potential for other environmental initiatives (such as Kyoto) to impact utility decision-making. While it is impossible to predict the exact nature of future emissions control and other environmental programs, and their resulting costs, it is necessary to be aware of the issue and maintain a base of knowledge to, at the very least, be able to provide a qualitative level of analysis on the potential consequences of a resource decision. Considering that, in the absence of a transmission link to the North American grid, the future incremental energy supply for the

Island is very likely to be thermal based, this issue could have a significant impact on upcoming generation planning decisions.

9.2. Wind Power

While the requirements for additional generation resources to meet future load requirements may have been delayed to the 2013 timeframe due to the pending closure of the Stephenville mill and #7 paper machine in Grand Falls, it remains prudent for Hydro to proceed with an investigation of wind energy potential on the Island system. Recent estimates have identified wind energy as the likely least cost next source of generation for the Island Interconnected System. Further, once Federal Government incentives have been accounted for, wind may be cost competitive against the incremental cost of fuel at Holyrood.

Pending the outcome of Government's wind strategy investigations, it is likely that a wind project(s) having a capacity of at least 25 MW could be sought for near term development and interconnection to the Island system. This project, whether constructed by Hydro or through an independent power producer, would provide Hydro with the information necessary to more thoroughly investigate the risks and opportunities associated with the integration of wind energy into the Island system.

10. Summary

Based on an examination of the Island's existing plus committed capability, in light of the 2005 Planning Load Forecast and the generation planning criteria, the Island system can expect energy and capacity deficits starting in 2008. However, these deficits are not considered significant and additional supply would normally be planned for in-service in 2009. With the recent announcements by ACI of the scheduled closure of the Stephenville mill and #7 machine at Grand Falls, future generation requirements may be delayed until 2012. The addition of a wind project in the interim could delay these deficits even further, for example, a 25 MW wind project could delay the requirement for new capacity by an additional year.

Assuming that an initial 25 MW wind project will be in service by 2007, under the base case scenario in which the Stephenville mill remains in operation, there would be a requirement for additional capacity by the fall of 2010. However, the scenario in which the mill remains operational is contingent on the likely requirement that ACI proceed with the development of 66 MW of new hydroelectric capacity on the Exploits River. In such an event, Hydro would not be seeking additional generation beyond the new Exploits River developments until 2011.

Therefore, beyond the initial 25 MW wind project in 2007, it is unlikely that there would be a requirement for Hydro to initiate an RFP to meet future power and energy requirements prior to at least the fall of 2006. Beyond seeking clarification on issues surrounding ACI's milling operations in Newfoundland, from a System Planning point of view, the following are the key issues that should be dealt with in the near term;

- Environment/Emissions Control Considerations - Considering the impact that environmental initiatives could have on future planning studies, it is necessary to remain current on activities elsewhere in this area; and

- Wind Power - Hydro should continue to pursue and investigate the risks and opportunities associated with the integration of wind energy into the Island system; and

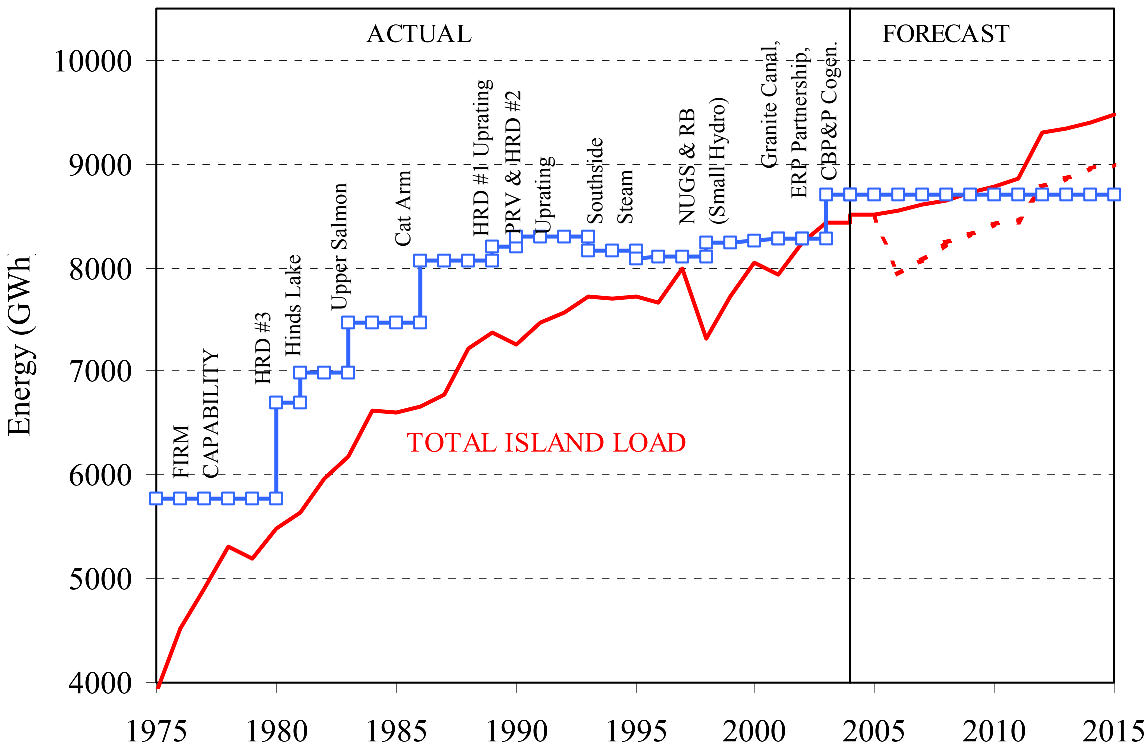
- Resource Inventory - Insure that Hydro maintains an inventory of resource options that have undergone sufficient study as to provide confidence in overall project concept and costs.

Appendix A

Table A1
2005 Planning Load Forecast and ACI Load Sensitivity Forecast

	2005 PLF – Base Case		ACI Load Sensitivity Forecast	
	Demand	Energy	Demand	Energy
Year	MW	GWh	MW	GWh
2005	1,612	8,573	1,612	8,486
2006	1,621	8,602	1,541	7,938
2007	1,637	8,744	1,557	8,077
2008	1,651	8,787	1,587	8,247
2009	1,660	8,864	1,596	8,323
2010	1,676	8,956	1,612	8,415
2011	1,693	8,995	1,629	8,455
2012	1,751	9,315	1,687	8,774
2013	1,761	9,400	1,697	8,859
2014	1,769	9,498	1,705	8,958
2015	1,774	9,513	1,710	8,973
2016	1,786	9,578	1,722	9,038
2017	1,798	9,644	1,734	9,103
2018	1,811	9,714	1,747	9,174
2019	1,824	9,781	1,760	9,240
2020	1,836	9,838	1,772	9,297
2021	1,847	9,888	1,783	9,348
2022	1,860	9,950	1,796	9,410
2023	1,872	10,017	1,808	9,476
2024	1,884	10,082	1,820	9,541

Figure A1 - Island Capability vs. Load



Appendix B

Table B-1
Fuel Forecast

Year	Residual 1.0%S (6.287 mBTU/BBL) $/BBL	Diesel (5.825 mBTU/BBL) $/litre
2005	42.70	0.560
2006	34.25	0.474
2007	35.50	0.432
2008	39.15	0.436
2009	40.95	0.442
2010	42.40	0.450
2011	44.80	0.467
2012	46.75	0.485
2013	48.75	0.503
2014	50.75	0.521
2015	52.70	0.539
2016	53.80	0.550
2017	54.90	0.561
2018	56.00	0.572
2019	57.15	0.584
2020	58.30	0.596
2021	59.50	0.608
2022	60.75	0.621
2023	62.00	0.634
2024	63.25	0.647

Source: NLH Economic Analysis Section, May 2005

Table B-2
Escalation Rates

Year	Hydraulic & Thermal Plant Construction	O&M	
		Materials ~ 75% Labour ~ 25%	Materials ~ 50% Labour ~ 50%
2006	2.0%	2.0%	2.2%
2007	1.9%	1.9%	2.0%
2008	1.9%	1.9%	2.0%
2009	2.0%	2.0%	2.2%
2010	2.0%	2.0%	2.2%
2011	2.0%	2.0%	2.2%
2012	2.0%	2.0%	2.3%
2013	1.9%	1.9%	2.2%
204	1.9%	1.9%	2.1%
2015-2020	2.1%	2.1%	2.3%
2020-2025	2.1%	2.1%	2.2%

Source: NLH Economic Analysis Section, March 2004

Table B-3
Future Resource Capital Cost Flow Estimates

Project	Direct Costs in January 2005$ (x 1,000)**					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Island Pond	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Round Pond	[redacted]	[redacted]	[redacted]			[redacted]
Portland Creek	[redacted]	[redacted]	[redacted]			[redacted]
Hardwoods CT	[redacted]	[redacted]	[redacted]			[redacted]
Stephenville CT	[redacted]	[redacted]	[redacted]			[redacted]
125MW Holyrood CCCT	[redacted]	[redacted]	[redacted]			[redacted]
170MW Holyrood CCCT	[redacted]	[redacted]	[redacted]			[redacted]

** Excludes Escalation and Interest During Construction

Schedule JRH-Supplementary 2

2006
Integrated Electricity Plan

Volume 1 of 2

reliable power,
at low cost,
for generations

BC hydro

BC hydro

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March 29, 2006

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

RE: British Columbia Hydro and Power Authority (BC Hydro) 2006 Integrated Electricity Plan (IEP) and Long-Term Acquisition Plan (LTAP)

Pursuant to section 45(6.1) of the *Utilities Commission Act* (*UCA*), BC Hydro is submitting the 2006 LTAP for the British Columbia Utilities Commission's (Commission) review. The 2006 LTAP is the last chapter of, and is backed up by, the enclosed 2006 IEP.

This letter sets out the Order sought and the requested process with respect to the 2006 LTAP. This letter also introduces BC Hydro's proposed approach with respect to the appropriate structure for the Commission's review of BC Hydro's long term and short term plans.

1. 2006 LTAP Application

Order Sought

In the 2006 LTAP application, BC Hydro seeks an Order which:

(a) States that the 2006 LTAP meets the requirements of section 45(6.1) of the *UCA*;

(b) Makes certain determinations pursuant to subsection 45(6.2)(b) of the *UCA* as specified in section 8.2 and section 8.4 of the 2006 LTAP; and

(c) Approves the submission of the transmission LTAP plan and contingencies plans for inclusion in BC Hydro's Network Integrated Transmission Service (NITS) application.

The evidence in the 2006 IEP supporting the 2006 LTAP will be subject to Commission review.

Requested Process

BC Hydro expects that the Commission will establish a process to review the 2006 LTAP under subsection 45(6.2)(a) of the *UCA*. BC Hydro respectfully submits that, if the Commission is prepared to do so, a first round of Commission Information Requests (IRs) be generated at as an early date as possible, and that BC Hydro respond to these IRs, and file its Revenue Requirement Application (RRA), prior to a Pre-Hearing Conference to assist with establishing a Regulatory Agenda or Agendas for both proceedings.

2. Long Term and Short Term Plan Review Processes

This submission is informed by the Commission's previous decisions and comments with respect to BC Hydro's planning process, and also its recent decision with respect to the capital planning process of other utilities within its jurisdiction.

BC Hydro begins by noting the Commission's observation that section 45(6.1) of the *UCA* is a flexible tool that should be tailored to particular circumstances of each individual utility. Accordingly, BC Hydro's submissions relate exclusively to the process it believes is appropriate for it in light of its particular structural, financial and regulatory circumstances. BC Hydro also notes the Commission's acceptance that there should be as much alignment between the management planning process employed by BC Hydro and the regulatory process as is practical.

Long-Term Plans

BC Hydro has for many years employed a 20-year long-term planning horizon to identify the range of projects that may be considered to serve customers' future needs. BC Hydro prepares its IEP, describing how BC Hydro could address its customers' electricity needs over a 20 year planning horizon, and its LTAP, itemizing the actions BC Hydro intends to take over a ten-year period to meet those needs, as part of BC Hydro's overall planning and resource acquisition processes.

BC Hydro proposes to file with the Commission, every two years, its LTAP that identifies the then current ten-year outlook. Thus, every two years, BC Hydro will identify those acquisitions or projects that have shifted from planned to acquired, built or undertaken, and those new potential means of meeting long-term needs that have been added to the last years of the plan. Each LTAP will also identify adjustments to the plan required in light of changing circumstances.

The LTAP will provide the resource acquisition plan and the basis upon which BC Hydro will make its NITS application with British Columbia Transmission Corporation. The LTAP will comply with section 45(6.1) of the *UCA*. The question of whether there is a need for reviews pursuant to subsection 45(6.2)(a) of future LTAPs likely can best be determined after experience is gained from the review of the initial 2006 LTAP.

BC Hydro will prepare and file with the Commission subsequent IEPs as necessary to support the LTAP. BC Hydro does not propose that the 2006 IEP or subsequent IEPs be part of the section 45(6.1) filing requirement, as much of the IEP does not lend itself to regulatory approval because it can only give a broad indication of what options are likely to be available to BC Hydro in the future. Under this approach, there would not be a separate resource options report and there would be no need for a regulatory process in association therewith.

Short-Term Plans

Pursuant to the negotiated settlement of BC Hydro's 2005 Resource Expenditure and Acquisition Plan, BC Hydro made a number of commitments regarding the review of its short-term capital plans. In particular, BC Hydro agreed to seek a Commission determination pursuant to section 45(6.2)(b) of the entirety of its F2007 capital plan, and agreed to seek Commission determinations under section 45(6.2)(b) in respect of the entirety of its capital plans at its Mica, GM Shrum, John Hart and Ruskin facilities. Further, it agreed to seek those determinations in its F2007 RRA filing.

It is apparent that there is considerable potential overlap between the subject of this IEP and LTAP filing, and what will be the subject of the RRA filing. In light of the potential for overlap, and the obvious benefit of not having the same plans reviewed in two concurrent proceedings, BC Hydro has been working to formulate a proposed review process that puts the right plans in the right hearing. Generally speaking, BC Hydro believes that its short-term plans are best reviewed in a RRA proceeding. Thus, it is in that application that BC Hydro will elaborate more fully on the processes it believes are best suited for review of its short term capital, DSM and resource acquisition plans.

BC Hydro will be providing to the Commission, within the next two weeks, further details on its proposed approach to bringing forward its short term plans for review, and the relationship of the short term planning process to the LTAP.

Yours sincerely,

JSofield

Joanna Sofield
Chief Regulatory Officer

Enclosure

c. Intervenors as set out in Attachment A

ATTACHMENT A

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BC hydro

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