Q. With respect to Granite Canal, please provide a copy of the business case analysis supporting construction of the facility, showing year by year projections for the life of the plant of

(a) load or generation,
(b) avoided diesel quantities (barrels),
(c) avoided diesel expense,
(d) annual operating costs, and
(e) depreciation, interest and return under each of the four approaches to depreciation used, previously proposed or proposed by Hydro; that is i) the sinking fund method, ii) the Gannett Fleming 2005 Study approach, iii) the Gannett Fleming 2009 Study approach and iv) the approach proposed by the present Application.

A. Please refer to IC-NLH-8 Attachment 1. The detailed annual projections are not readily available as the analysis was completed in an integrated strategic planning computer program. The available data is contained in IC-NLH-8 Attachment 1 as follows:

(a) Appendix A, Table A-1
(b) Not applicable. The justification was based upon a comparison of alternatives, rather than avoided fuel.
(c) Not applicable – The justification was based upon a comparison of alternatives, rather than avoided fuel.
(d) Not available – each option used varying operation and maintenance costs.
(e) Hydro does not have available data for the depreciation estimates for all options. However, the three options under discussion are the existing methodology - sinking fund, the proposed methodology – Average Service Life

(ASL) and the methodology proposed in previous Gannett Fleming recommendations - Equal life Group (ELG) are shown in the table below.

GRANITE	CANAL	Sinking Fund	ASL	ELG
		Depreciation Expense	Depreciation Expense	Depreciation Expense
	Y2003	72,865		
	Y2004	154,512		
	Y2005	187,444		
	Y2006	214,021		
	Y2007	224,166		
	Y2008	279,057		
	Y2009	270,029		
	Y2010	291,190		
	Y2011	314,010	2,610,238	2,886,641
	Y2012	338,618	2,610,238	2,886,641
	Y2013	365,154	2,610,238	2,886,641
	Y2014	393,770	2,610,238	2,886,641
	Y2015	424,629	2,610,238	2,886,641
	Y2016	457,905	2,610,238	2,886,641
	Y2017	493,790	2,610,238	2,886,641
	Y2018	524,552	2,610,229	2,886,631
	Y2019	557,420	2,603,944	2,879,681
	Y2020	601,103	2,599,528	2,874,797
	Y2021	648,209	2,599,528	2,874,797
	Y2022	699,007	2,577,412	2,850,339
	Y2023	639,782	2,555,605	2,826,223
	Y2024	571,531	2,555,604	2,826,222
	Y2025	616,316	2,555,604	2,826,222
	Y2026	664,602	2,549,343	2,819,298
	Y2027	716,588	2,480,466	2,743,127
	Y2028	731,839	2,468,378	2,729,759
	Y2029	746,711	2,451,454	2,711,043
	Y2030	805,222	2,378,859	2,630,761
	Y2031	868,317	2,364,836	2,615,253
	Y2032	936,357	2,354,870	2,604,232
	Y2033	993,660	2,354,870	2,604,232
	Y2034	1,054,836	2,354,870	2,604,232
	Y2035	1,137,490	2,350,763	2,599,690

	Y2036	1,226,621	2,330,226	2,576,978
	Y2037	1,319,152	2,306,819	2,551,093
	Y2038	1,415,094	2,302,138	2,545,916
	Y2039	1,526,012	1,955,514	2,162,587
	Y2040	1,645,625	1,883,721	2,083,192
	Y2041	1,774,613	1,872,793	2,071,107
	Y2042	1,913,712	1,872,249	2,070,505
	Y2043	1,907,315	1,872,249	2,070,505
	Y2044	1,894,402	1,872,249	2,070,505
	Y2045	2,042,890	1,865,286	2,062,805
	Y2046	2,203,017	1,481,590	1,638,478
	Y2047	2,375,695	1,121,809	1,240,600
	Y2048	2,561,907	1,113,492	1,231,402
	Y2049	2,762,716	1,103,413	1,220,256
	Y2050	2,979,265	1,103,413	1,220,256
	Y2051	3,212,787	1,103,413	1,220,256
	Y2052	3,464,613	1,097,346	1,213,546
	Y2053	2,046,736	976,074	1,079,432
	Y2054	452,759	911,118	1,007,598
	Y2055	488,248	911,118	1,007,598
	Y2056	526,518	906,844	1,002,872
	Y2057	567,787	901,925	997,432
	Y2058	612,292	897,834	992,907
	Y2059	660,285	868,067	959,988
	Y2060	712,040	868,067	959,988
	Y2061	767,851	868,067	959,988
	Y2062	828,037	699,428	773,492
	Y2063	892,941	463,335	512,398
	Y2064	n/a	463,335	512,398
	Y2065	n/a	463,335	512,398
	Y2066	n/a	463,335	512,398
	Y2067	n/a	463,335	512,398
	Y2068	n/a	463,334	512,397
	Y2069	n/a	463,334	512,397
	Y2070	n/a	463,334	512,397

The discount rate and cost of capital rates are specified in Section 2.6.1 of IC-NLH-8 Attachment 1.

NEWFOUNDLAND AND LABRADOR HYDRO

GENERATION EXPANSION STUDY
OF
NEAR TERM OPTIONS
FOR
MEETING NEWFOUNDLAND'S LOAD GROWTH

November 1999

Prepared by:

System Planning Department

EXECUTIVE SUMMARY

This report documents an evaluation undertaken by Newfoundland and Labrador Hydro (NLH) to identify the least cost next source of power and energy for the Island Interconnected System from amongst those options which could be developed by NLH. These include the most competitive hydroelectric and thermal options available as determined from a 1997 request for proposals (RFP). The RFP was terminated due to uncertainty surrounding the development of the Voisey's Bay Nickel smelter/refinery.

Continuing uncertainty with respect to the load forecast in combination with long term supply uncertainty surrounding the potential Labrador Infeed has caused NLH to postpone a decision on the next source for as long as possible. In light of projected requirements in the 2002 timeframe, NLH has proceeded with an evaluation of its own options. This evaluation will identify the most cost effective option which could be developed (without resorting to an RFP and its inherent lengthy process).

For the near term (up to 2007), NLH has assessed the current capability of the Island System in light of forecasted load. NLH has identified the need for approximately 125 MW and 440 GWh of additional generation capacity and capability in the period prior to the proposed January, 2007 in service date of the Labrador Infeed. NLH options available to meet the near term requirements for additional supply consist of a mix of small hydro developments, an oil fired conventional steam unit, a combined cycle combustion turbine, and simple cycle combustion turbines.

This analysis compares the cost of meeting the near term energy requirements of the Island electrical system under both the Isolated Island and the Labrador Infeed long term alternatives. Based on the economic parameters used, and technically feasible NLH options available, the combination of Granite Canal in 2002 followed by Island Pond in 2003 represents the most cost effective means to meet the Island's near term energy requirements under both long term alternatives. The preference for this hydroelectric option over the next best option, in cumulative present worth terms, is estimated at $39 million (1999$) under the Isolated Island alternative, and $47 million (1999$) under the Labrador Infeed alternative with the majority of these benefits realized in the near term. Furthermore, this conclusion remains unchanged throughout all sensitivity analyses performed.

Based on these conclusions and the results of the 1997 RFP which also identified Granite Canal as the most cost effective option for Island generation expansion, it is recommended that NLH take actions necessary to proceed with the construction of Granite Canal and insure its fall 2002 in-service date. To address requirements beyond those met by Granite Canal, it is recommended that NLH proceed to issue a new request for generation proposals in the spring of 2000 with a targeted in-service date of successful option(s) in the 2003/2004 timeframe.

TABLE OF CONTENTS

1. INTRODUCTION

This report presents the evaluation carried out by Newfoundland and Labrador Hydro (NLH) to determine the least cost next source of power and energy for the Island Interconnected System.

Continuing uncertainty with respect to the load forecast (nickel smelter/refinery) in combination with long term supply uncertainty surrounding the potential Labrador Infeed has caused NLH to postpone a decision on the next source for as long as possible. In light of projected requirements in the 2002 timeframe, NLH has proceeded with an evaluation of its own options. This evaluation will identify the most cost effective option which could be developed (without resorting to an RFP and its inherent lengthy process).

Options available to meet the near term requirements for additional supply consist of a mix of small hydro developments, an oil fired conventional steam unit, a combined cycle combustion turbine, and simple cycle combustion turbines.

To address the long term supply uncertainty, the analysis examines the cost effectiveness of several near term supply options followed by either of two long term alternatives for meeting future load growth. For the long term, under the Isolated Island alternative, requirements for additional generation will be met by a mix of conventional heavy oil fired steam and light oil fired combined cycle and simple cycle combustion turbines. Long term requirements under the Labrador Infeed alternative will be met by the HVDC Infeed and peaking plant as required.

The methodology and results of the evaluation to identify the most cost effective near term options for the Island Interconnected system are discussed in this report.

2. EVALUATION METHODOLOGY and ASSUMPTIONS

The method used to examine the cost effectiveness of each generation expansion plan is to compare, on a cumulative present worth basis, its incremental investment and system operating costs with alternate system expansions. This technique of comparing system expansion plans permits an examination of the effect of a proposed project on the plant that currently exists and the plant that will likely follow. This study involves a comparison of alternate generation plans within each of the longer term Labrador Infeed and Isolated Island alternatives. The main economic criterion used to compare the plans is the discounted value of all system costs at the current discount rate.

It is important to note that because of certain assumptions, which were made to simplify the analysis and focus on the near term, comparisons should not be made between the Labrador Infeed and Isolated Island alternatives.

In order to develop the cumulative present worth costs used in the economic evaluation, the following information is required:

- A study time horizon and load forecast;
- A description of the existing system;
- Planning criteria;
- The identification of the need and timing of new generation source(s);
- The identification of alternative technically feasible power and energy sources for both the near and the long term; and
- The definition of all other relevant study assumptions.

Once this information is available, the evaluation proceeds with the economic analysis. Each of the above items is discussed in further detail in the following sections.

2.1 Study Time Horizon and Load Forecast

2.1.1 Study Time Horizon

The detailed simulation, or planning period, for this analysis covers the period from 1999 through 2037. This period is long enough to simulate, over the full economic life, the operation of any thermal option constructed in the period prior to the proposed 2007 in-service date of the Labrador Infeed. In addition, an end effects period is included to extend the full study period to 2063, long enough to evaluate the life cycle operation of a hydroelectric source constructed in the period to 2003. The end effects period is used to analyze differences between plans beyond the simulation period's horizon. This includes replacement-in-kind of all plant added in the simulation period as well as long run production costs based on costs experienced in the final years of simulation.

2.1.2 Load Forecast

This study uses for the base case the 1999 Official Load Forecast as developed by NLH's Economic Analysis Department. This forecast is for the total Island Interconnected System and includes demand and energy met by our customers' generation resources. The addition of a new 100 MW industrial load in 2007 is included in the forecast. Exclusive of this new industrial load, the forecast has an average annual compound growth rate of approximately 1.0% in the period to 2006, and dropping to approximately 0.7% in the period beyond 2007. The load forecast and the associated seasonal profile are presented in Tables A1 and A2 respectively.

2.2 Description of the Existing System

The current electric energy requirements of the Island System are supplied mainly by hydroelectric plants, and supplemented by conventional oil fired thermal plants, combustion turbines and diesel engines. This section presents the capability and operating parameters of these existing facilities.

2.2.1 Island Capability

Table 2-1 provides a summary of the existing capacity and energy capability of the Island System. NLH is the prime supplier of electrical energy, accounting for 81% of the Island's net capacity. The remaining capacity is supplied by Newfoundland Light and Power Co. Limited (8%), Deer Lake Power Co. Ltd. (6%) and Abitibi Price Inc. (3%). NLH also has contracts with two small hydro non-utility generators (1%) for the supply of energy.

2.2.2 Existing Hydroelectric Resources

Hydroelectric generating units account for 64% of the total existing Island net capacity and firm energy capability. Table A5 shows the data used to model the existing hydroelectric units. In this study fixed operating costs for these units are excluded from all analysis since it is common to all generation expansion sequences examined.

2.2.3 Existing Thermal Resources

The existing thermal resources on the Island are made up of conventional thermal 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 and are fired on light oil.

For planning purposes, a 75% annual capacity factor is assumed in determining the firm energy capability for the Holyrood Thermal Plant. All other existing thermal capacity normally performs a peaking or voltage support function, and as such, are not assigned any firm energy capability. However, they serve as a means of addressing unforseen energy requirements resulting from higher than expected load growth in the period prior to the planned in service date of a new facility or from a delay in bringing a new facility into service. Table A6 shows the data used to model the existing thermal units. In this study, with the exception of the Holyrood units, fixed operation and maintenance costs for existing thermal resources are not considered since it is common to all generation expansion sequences examined.

Table 2-1

Island Capability	Net Capacity (MW)	Energy (GWh)	
		Firm	Average
Newfoundland & Labrador Hydro			
Bay D'Espoir	592.0	2234	2587
Upper Salmon	84.0	476	549
Hinds Lake	75.0	283	339
Cat Arm	127.0	605	736
Paradise River	8.0	27	39
Snook's, Venam's & Mini Hydro	1.4	5	7
TOTAL HYDRO	887.4	3630	4257
Holyrood	465.5	2996	2996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Woodchip	4.6	-	-
TOTAL THERMAL	602.8	2996	2996
Newfoundland Light & Power Co. Ltd.			
Hydro	93.3	323	440
Combustion Turbine	47.2	-	1
Diesel	6.5	-	-
TOTAL	147.0	323	441
Deer Lake Power Co. Ltd.			
Hydro	118.9	757	834
Abitibi Price Inc.			
Hydro	58.5	419	460
Non-Utility Generators			
Hydro	19.0	107	136
TOTAL EXISTING (DEC. 1998)	**1833.6**	**8232**	**9124**

2.3 Planning Criteria

NLH has established criteria related to the appropriate reliability, at the generation level, for the total Island System which 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 Expectation (LOLE) target of not more than 2.8 hours per year.

2.4 Identification of Need

Based on an examination of the Island's existing capability (Table 2-1), the load forecast (Table A1), and the planning criteria, the Island system has energy and capacity deficits starting in 2000 and 2001 respectively. Table 2-2 presents a summary of these near term capacity and energy requirements and a discussion of the impact of these deficits follows.

Table 2-2

Near Term Capability Requirements						
	Load Forecast		Existing plus Committed System			
Year	Peak MW	Firm Energy GWh	Installed Net Capacity MW	Firm Capability GWh	LOLE hrs/yr	Energy Balance (GWh)
1999	1,553	8,124	1,834	8,232	1.80	108
2000	1,573	8,241	1,834	8,232	2.19	*(9)*
2001	1,582	8,284	1,834	8,232	***3.03***	(52)
2002	1,603	8,358	1,834	8,232	4.10	(126)
2003	1,627	8,462	1,834	8,232	5.91	(230)
2004	1,647	8,548	1,834	8,232	6.80	(316)
2005	1,665	8,627	1,834	8,232	10.19	(395)
2006	1,679	8,703	1,834	8,232	12.68	(471)

2.4.1 Load Forecast Risk Analysis

In addition to the base load forecast, NLH's Economic Analysis Department carried out an analysis designed to address load forecast risk in the short term as it relates to the timing of new generation additions to the System. The 1999 Official Load Forecast Risk Analysis Summary report is included in Appendix D. The following Table 2-3 summarizes the LOLH indices and energy balances resulting from the application of the low and high forecast cases to the generation timing analysis.

The risk analysis demonstrates that in the high load case, while deficits in both energy and capacity are slightly higher than in the base 1999 OLF, they occur in the same years, 2000 and 2001 respectively. In the low load case deficits in energy and capacity are delayed one year to 2001 and 2002 respectively.

Table 2-3

Year	Low Case		1999 OLF		High Case	
	LOLH Index (Hours/yr)	Energy Balance (GWh)	LOLH Index (Hours/yr)	Energy Balance (GWh)	LOLH Index (Hours/yr)	Energy Balance (GWh)
1999	1.52	136	1.80	108	1.85	105
2000	1.83	21	2.19	***(9)***	2.38	***(26)***
2001	2.44	***(3)***	***3.03***	(52)	***3.74***	(91)
2002	***3.02***	(60)	4.10	(126)	5.22	(170)
2003	4.02	(138)	5.91	(230)	7.24	(270)

This analysis indicates that criteria violations in 2000 and 2001 are marginal in both the base case and the low load sensitivity case. Further, in the high load sensitivity case, deficits in 2001 are not felt to be excessive. Also, from the 1999 Load Forecast Risk Analysis Summary report it can be concluded that variations in load from the expected values are more likely to be lower rather than higher than the base case. This, combined with project lead times of approximately three years (see Section 2.5.1), has focused the following analysis on the identification of options to meet deficits starting in 2002.

2.5 Identification of Future Resource Options

The following sections describe the resources available to meet the future capacity and energy requirements for the Island System. The data used to model these resources is presented in Appendix B.

2.5.1 Near Term NLH Options

NLH has identified the following options as potential resources for near term system expansion. Each of these near term resources has been brought to a final feasibility level of study. This level of study provides a high level of confidence in both the cost estimates and operating characteristics associated with the resources. In addition, a brief overview of each projects' environmental status is provided.

Before scheduling new resources to meet near term deficits in power and energy, it is important to allow sufficient lead time to bring the source into service. In addition to the normal engineering and construction activities, time to clear environmental hurdles must be allowed. Table 2-4 provides the earliest in-service date for each of the near term NLH options assuming a decision to proceed by the fall of 1999.

Table 2-4

Option	Earliest In-Service
Granite Canal	Fall 2002
Island Pond	Fall 2003
Holyrood CCCT	Fall 2002
Holyrood IV	Fall 2003
Hardwoods CT	Fall 2001
Stephenville CT	Fall 2001

Granite Canal

Granite Canal is a proposed 42 MW hydroelectric project located within the watershed of the existing Bay D'Espoir development. The project would utilize the available head between Granite Lake and Meelpaeg Reservoir to produce firm and average annual energy capability of 216 GWh and 224 GWh, respectively. An Environmental Preview Report (EPR) on the project has been submitted to the Department of Environment and Labour. The EPR concludes that the environmental impact of the project will be insignificant with all potential negative impacts mitigated and monitored with existing technology. The estimated capital cost of the Granite Canal option includes approximately $1.4 million (1999$) for environmental related costs.

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. An earlier Environmental Impact Statement was approved but has since expired. The project now requires an EPR. The estimated capital cost of the Island Pond option includes approximately $1.2 million (1999$) for environmental related costs.

Holyrood Combined Cycle Plant

The proposed Holyrood Combined Cycle Plant is a 170 MW (net) combined cycle combustion turbine facility. The combined cycle unit consists of a 116 MW combustion turbine fired on light oil, a heat recovery steam generator, and a 60 MW 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 the sharing of existing facilities. The annual firm energy capability is estimated at 1,340 GWh. The Holyrood Combined Cycle plant requires an EPR with the guidelines for its preparation based on a 1997 review of the proposed project. The capital cost estimate includes approximately $300,000 for environment studies.

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. The Holyrood Unit IV project requires an EPR with the guidelines for its preparation based on a 1997 review of the proposed project. The capital cost estimate includes approximately $500,000 for environment studies.

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 NLH's Hardwoods and Stephenville Terminal Stations. They are fired on light oil and are designed for peaking and voltage support functions. It is anticipated that both of these options will require an EPR.

2.5.2 Long Term Expansion Options

In addition to the near term options identified above, NLH has identified options as potential resources for the longer term system expansion. NLH has carried out previous analysis of long term alternatives which included oil fired, coal fired and nuclear plants and an HVDC Infeed to the Island from Labrador. The most recent analysis (1990) concluded that, in the absence of an Infeed, the relative ranking from lowest to highest cost of the isolated options was oil fired followed by coal fired and nuclear generation. Since the basic parameters governing the relative attractiveness of these longer term options have not changed, it is not expected that the relative ranking will change. In addition, the Province enacted legislation several years ago eliminating nuclear generation from consideration as an option for the Island. Therefore, for this study, coal and nuclear have not been considered as long term expansion options for the Island.

Since the discovery of oil and natural gas on the Grand Banks, the potential of using gas for energy production has been recognized. However, the technical or economic feasibility of delivering and using natural gas on the Island has not been established. Therefore, for this study, natural gas resources also have not been considered as expansion options for the Island.

Of the following long term options, the Labrador Infeed resource option has been brought to the final feasibility level of study. The greenfield thermal resource estimates are based on the final feasibility estimates of similar plant.

Labrador Infeed

The Labrador Infeed consists of a high voltage direct current (HVDC) interconnection between new terminal stations at Gull Island in Labrador and Soldier's Pond on the Island of Newfoundland. The Infeed has approximately 1088 km of bi-polar HVDC line with approximately 38 km of submarine cable across the Strait of Belle Isle. Rated at ± 400 kV the Infeed is capable of delivering 845 MW and 5943 GWh of annual firm energy capability at the receiving end.

Greenfield Conventional Steam Unit

Similar to the existing Holyrood units, the Greenfield Conventional Steam Units are 142.5 MW (net) conventional steam units fired on heavy oil. The units would be located at a greenfield site designed to accommodate four such units in a single plant. The firm annual energy capability for each unit is estimated at 936 GWh.

Greenfield Combined Cycle Unit

Similar to the proposed Holyrood Combined Cycle unit, the Greenfield Combined Cycle Units are 170 MW (net) combined cycle combustion turbine facilities. The combined cycle unit consists of a 116 MW combustion turbine fired on light oil, a heat recovery steam generator, and a 60 MW steam turbine generator. The units would be located at greenfield sites designed to accommodate two such units in a single plant. The annual firm energy capability for each unit is estimated at 1,340 GWh.

Greenfield Combustion Turbine

The Greenfield Combustion Turbine is a nominal 50 MW simple cycle combustion turbine similar to NLH's existing Hardwoods and Stephenville combustion turbines. The unit is fired on light oil and designed for peaking and voltage support purposes. The units would be located at greenfield sites designed to accommodate two such units in a single plant.

2.6 Study Assumptions

The following are the economic and technical parameters necessary to quantify the long term costs of each generation expansion plan.

2.6.1 Discount Rate and Cost of Capital

This study uses an 8.5% current discount rate, with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 1999. The weighted average cost of capital is also assumed to be 8.5% for all capital projects constructed within the simulation period.

2.6.2 Capital Costs

This section presents a summary of the capital cost estimates for all generation projects considered in this study. The capital costs and cash flows in January-1999 dollars excluding interest during construction are shown in Table B4. The direct capital cost per unit of net capacity ($/kW) in January-1999 dollars for each project is summarized in Table 2-5.

2.6.2.1 Labrador Infeed Capital Costs

Since the Labrador Infeed capital costs are common to all Labrador Infeed alternative plans, they have been excluded from the base analysis.

Table 2-5

Project Capital Costs		
Project	**Unit Size (MW)**	**Direct Capital Cost ($/kW) (Jan. 1999 $)**
Granite Canal	42	$2,608
Island Pond	36	$3,601
Hardwoods CT	50	$797
Stephenville CT	50	$814
Greenfield CT	50	$861
Holyrood CCCT	170	$773
Greenfield CCCT (Unit 1)	170	$1,042
Greenfield CCCT (Unit 2)	170	$773
Holyrood IV Steam	142.5	$1,433
Greenfield Conventional Steam (Unit 1)	142.5	$2,857
Greenfield Conventional Steam (Unit 2)	142.5	$1,484
Greenfield Conventional Steam (Unit 3)	142.5	$1,991
Greenfield Conventional Steam (Unit 4)	142.5	$1,512

2.6.3 Escalation Rates and Fuel Price Forecast

A general inflation rate of approximately 2% per year is assumed for the forecast period. In this context, a forecast of escalation rates for the capital cost of various generation technologies and operations and maintenance costs were developed by NLH's Economic Analysis Department. These escalation rates are presented in Table A3. Forecasts of prices for heavy oil (No. 6 Residual Fuel) and light oil (No. 2 Diesel Fuel) were also developed by NLH's Economic Analysis Department. Long term fuel costs (2007 and beyond) assume a real 1999 dollar crude oil price of US$21/BBL for Arab light crude oil delivered to the Caribbean from which product prices for the Avalon Peninsula are derived. The fuel forecasts are presented in Table A4.

In addition to the base fuel price forecast for heavy oil, NLH has committed that no more than 25,000 tonnes of SO_2 emissions would be released from NLH's thermal generation at Holyrood based on an average hydraulic year. For this study, the emission limit was maintained by using lower sulphur content fuels blended with base fuel to stay within the commitment. The base heavy fuel price forecast is based on 2.2% sulphur content fuel. The price premiums for 1.6% and 1.0% sulphur content fuel are 10% and 20% respectively.

2.6.4 Maintenance and Forced Outage Rates

To carry out an assessment of the reliability or load carrying capability of the generation system, it is necessary to model each unit's capability, maintenance requirement, and forced outage rate (FOR). FORs for existing resources are presented in Tables A5 and A6. FORs for future resources are presented in Tables B1, B2 and B3. The FORs used in this study are based on the Canadian Electrical Association's (CEA) 1997 Annual Report on Generation Equipment Status.

2.6.5 Thermal Unit Heat Rates

The heat rate of a thermal unit defines the efficiency at which its fuel energy is converted into electrical energy. That efficiency rate in combination with the heat content of the fuel and the fuel cost defines a unit's variable fuel cost in \$/MWh. For all of NLH's existing thermal units, the heat rates and heat contents have been established based on past operating experience. For new thermal units the heat rates are based on manufacturers' specifications with adjustments for degradation of unit performance over time. The heat rates assumed in this analysis are presented in Tables A6 and B2. Heat content values are indicated in Table A4.

2.6.6 Operation and Maintenance Costs

Operating costs, excluding fuel, for existing generation are shown in Table A6. For those resources that normally perform a peaking or voltage support function (combustion turbine and diesel generators), Hydro's experience has shown that O&M costs are not heavily dependent on production levels and therefore all O&M costs have been treated as fixed. Further, all existing generation fixed O&M costs (with the exception of Holyrood) have been excluded from the analysis since they are common to all scenarios. For future generation options, the O&M costs (fixed and variable) are included in the analysis and are shown in Tables B1, B2 and B3.

2.6.7 Plant Economic Life

For new generation units the following plant economic lives are used:

Table 2-6

Unit Type	Economic Life (Years)
Hydroelectric	60
Conventional Steam	30
Simple Cycle CT	30
Combined Cycle CT	30
Labrador Infeed	50

2.6.8 Standby Costs of Holyrood Units

Once in service, the Labrador Infeed will displace the present on-Island thermal generation. In the first year following the in-service date of the Labrador Infeed, it is assumed that the Holyrood plant would be placed in a standby mode of operation. The cost of preparing Holyrood for standby operation and maintaining sufficient oil reserve is estimated at $10.9 million (1999$).

In addition to the above capital costs, there are annual standby operation and maintenance costs estimated at $5.4 million commencing in 2008. These costs include the staff and general maintenance costs plus annual exercising of the units to keep both the units and staff in a state of readiness.

Future reactivation of the Holyrood units to an active mode of operation is based on an economic (least cost) decision considering total incremental system operating costs.

2.6.9 Cost of Infeed Energy

After the Labrador Infeed is in service, Island load requirements are expected to be met first by on-Island hydroelectric energy followed by Labrador hydroelectric energy via the Infeed. For purposes of this study it is assumed that Infeed energy will be available at the sending end (in Labrador) at a fixed annual rate of $25.24/MWh over the full study time frame.

3. ECONOMIC EVALUATION: ANALYSIS and RESULTS

Two levels of economic analysis are performed to evaluate the relative attractiveness of the near term options. The first level utilizes a simple spreadsheet analysis to perform a static screening of options which compares the options based solely on their individual costs at various production levels.

The second level is the detailed economic evaluation portion of this study and is based on a comparison of alternate plans within each of the Isolated Island and Labrador Infeed long term alternatives. The model which NLH used to establish the least cost and alternate plans is the PROSCREEN II Integrated Strategic Planning System, a comprehensive utility planning computer simulation model.

Each of these methods is described in more detail, along with the associated results of each method, in the following sections.

3.1 Static Screening Analysis

The first evaluation performed is a static screening curve analysis. In this analysis the levelized unit energy cost (LUEC) is calculated over the life of the options with the results expressed in 1999$. The LUEC of a resource is a single cost ($/MWh) which represents the present value of a resource's component costs (capital, fuel and O&M) over the lifetime of the option at a selected annual capacity factor.

The LUEC is defined as:

$$LUEC_{2002} = \frac{\sum_{n=2002}^{N} (All\ cost\ components)_n / (1+d)^{(n-2002)}}{\sum_{n=2002}^{N} (Energy)_n / (1+r)^{(n-2002)}}$$

Where: d = current/nominal discount rate, and
r = real discount rate.

This resource cost is then de-escalated to 1999 using a forecast of CPI by the following formula:

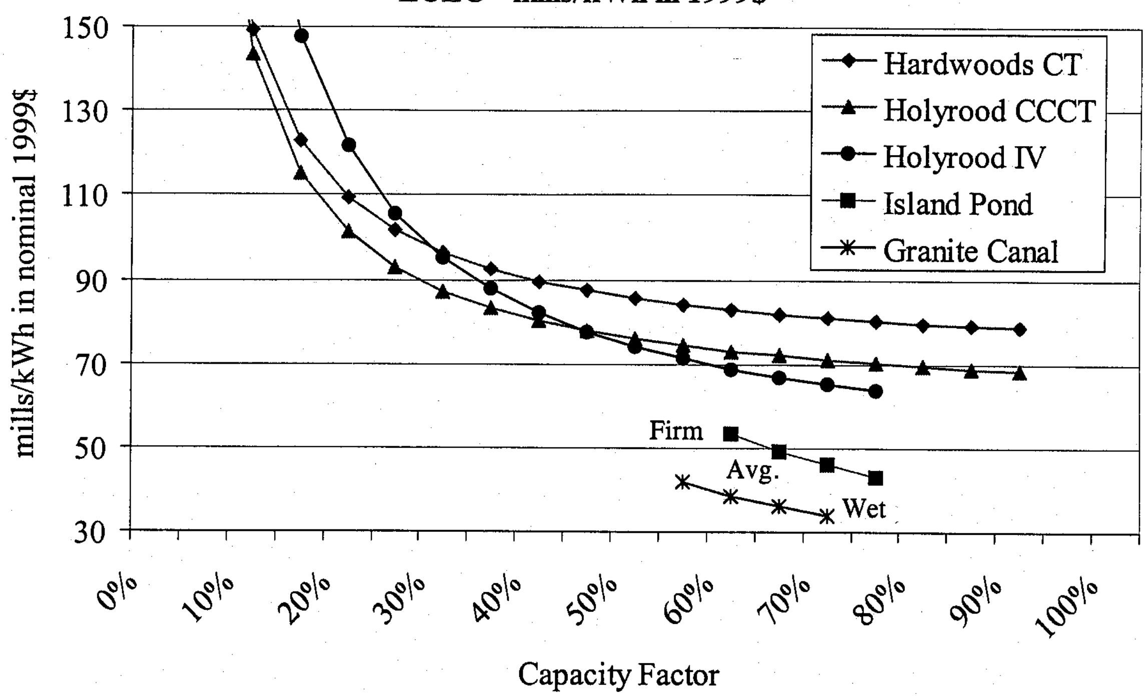
$$LUEC_{1999} = LUEC_{2002}\ x\ CPI_{1999} / CPI_{2002}$$

To perform the static screening curve analysis, costs are calculated over a range of capacity factors for thermal based options. For hydroelectric options, costs are calculated at the options' firm, average and high water annual capabilities (see Figure 3-1).

A static screening analysis is a quick and straightforward method for developing insight into the relative merits of the options. It provides an initial indication of the relative value of options over a range of annual capacity factors based on project costs alone. This analysis demonstrates that the Granite Canal and Island Pond hydroelectric options are lower cost options when compared to the thermal based options, regardless of capacity factor. Further, the Holyrood IV conventional steam option is preferred over the combined cycle option for capacity factors in excess of 45%. However, these results must be viewed with caution in regard to the assumptions used to perform the analysis since:

- The options are compared only on the basis of project costs alone;
- There is no regard for the capacity and relative reliability offered by the various options;
- There is no regard for the firm energy contribution to the system (see Energy criteria in Section 2.3);
- Differing maintenance requirements for the options are not considered; and
- There is no regard for system dispatch. Therefore the amount of energy expected to be produced by each option and the impact of each option on the operation of the existing system is not known.

Figure 3-1
Static Screening Analysis
LUEC - mills/kWh in 1999$



The following economic evaluation will add the levels of detail required to take the above factors into account to arrive at a final conclusion and recommendation.

3.2 Detailed Economic Analysis

The computer model used to perform the detailed economic analysis is the PROSCREEN II Integrated Strategic Planning System. A major component of this model is PROVIEW™, an automatic expansion planning optimization tool which can determine the least-cost resource plan for a utility system under a prescribed set of constraints and assumptions.

This study utilizes PROVIEW's dynamic programming logic. Dynamic programming evaluates all feasible combinations of expansion plans throughout the planning horizon. It selects the best expansion plan as that which results in the lowest cumulative present worth of utility costs which reflects the incremental system revenue requirements.

The dynamic programming algorithm used by PROVIEW to analyze the generation expansion problem is described as follows. In each year of the study all numeric combinations of the available options are considered. Each combination is evaluated subject to timing and reliability constraints set by the planner. Only those plans that meet all of these constraints are retained for consideration in future years. Once all possible combinations have been evaluated for all years during the planning period, the plan with the combination of resources that results in the lowest cumulative present worth of utility costs is considered the optimal plan. The model also produces a specified number of sub-optimal plans allowing the comparison of plans which contain different types of resources.

These results are then used to compute the cumulative present worth benefits of the preferred near term option(s) as compared to the alternatives. In this evaluation the following economic indicators are calculated:

- Net Benefits; and
- Benefit/Cost Ratio.

3.2.1 Net Benefits

Net benefits is the present worth preference of one plan over another and are defined as:

Net Benefits = *CPW Costs Plan A - CPW Costs Plan B*

where: *Plan A* is the least cost, or base case, plan; and
Plan B is the alternate sub-optimal plan.

3.2.2 Benefit/Cost Ratio

The Benefit/Cost Ratio is defined as:

$$\frac{\textit{Benefit}}{\textit{Cost}} = \frac{\textit{Benefit Due to Project}}{\textit{Cost of Project}} = \frac{\textit{Net Benefits + CPW Cost of Project}}{\textit{CPW Cost of Project}}$$

Where:

CPW Cost of Project = Cumulative present worth of the costs (investment and operating) associated with a chosen project.

3.3 Environmental Considerations

Environmental considerations are addressed in this study through the internalization of known environmental costs into the analysis plus a qualitative analysis of the relative impacts of various plans.

With regard to the known environmental considerations, the following provides a brief description of the environmental costs that have been included in all analyses included in this study.

- As described earlier in Section 2.6.3, NLH has committed that no more than 25,000 tonnes of SO_2 emissions would be released from NLH's thermal generation at Holyrood based on an average hydraulic year. The cost of maintaining this emissions limit has been included in all plans evaluated in this study through blending with premium lower sulphur fuels as necessary to stay within the limit.

- Also described earlier in Section 2.5.1, the capital cost estimates for all near term options include costs to implement environmental mitigation and monitoring measures as may be identified under the Environmental Assessment Act.

In addition to these internalized environmental considerations/costs, there are other factors that have the potential to impact on utility decision-making. At the present time, much interest has been directed toward controlling emissions from fossil fuels. While it is impossible to predict the exact nature of future emissions control programs, and their resulting costs, a comparison of the quantity of emissions expected to be released under the least cost and the alternate expansion plans provides insight into the relative environmental impact of the various plans. For this study the quantity of expected CO_2 and NO_x emissions under each plan is calculated to provide the basis for this qualitative comparison.

3.4 Detailed Analysis Results - Isolated Island Alternative

Based on the study assumptions outlined previously, the least cost Isolated Island expansion plan is shown in Table 3-1 (Plan A). Near term requirements (prior to 2006) are met by Granite Canal and Island Pond in 2002 and 2003 respectively. In the long term, Island requirements are met through a combination of simple and combined cycle combustion turbines (CCCTs). Also shown in Table 3-1 are alternate (sub-optimal) near term plans in which the Holyrood CCCT is brought into service before Island Pond and before Granite Canal. These alternate plans are shown to demonstrate the magnitude of the preference for the hydroelectric options over the best thermal option.

Table 3-1

Alternate Generation Expansion Plans – Isolated Island Alternative			
Year	Plan A Base Case	Plan B	Plan C
1999			
2000	-		
2001			
2002	Granite Canal	Granite Canal	HRD CCCT
2003	Island Pond	HRD CCCT	
2004			
2005			
2006	HRD CCCT		Granite Canal
2007			
2008		Island Pond	Island Pond
2009			
2010	CT	CT	CT
2011			
2012			
2013			
2014	CCCT	CCCT	CCCT
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026	CT	CT	CT
2027			
2028			
2029	CCCT	CT	CCCT
2030			
2031			
2032			CCCT
2033		CCCT & HRD IV	
2034			
2035			
2036	CCCT		
2037		CT	
CPW to 2037 (1999$ x 10^6)	$2,677.9	$2,696.0	$2,717.2
CPW to 2063 (1999$ x 10^6)	$3,073.0	$3,092.4	$3,109.7

CT – Combustion Turbine CCCT – Combined Cycle Combustion Turbine HRD IV – Holyrood IV

Based on these results, Table 3-2 presents a summary of economic indicators calculated to gauge the relative value of the preferred plan versus the alternatives.

Table 3-2

Base Case Economic Analysis of NLH Near Term Options Evaluation of Preferred Granite Canal & Island Pond Near Term Plan (millions 1999$)		
Economic Indicator	**Isolated Island Alternative**	
	to 2037	**to 2063**
CPW Incremental Costs Optimal Plan A:	$2,677.9	$3,073.0
Alternate Plan B:	$2,696.0	$3,092.4
Alternate Plan C:	$2,717.2	$3,109.7
Net Benefits of Plan A Versus Plan B:	$18.1	$19.4
Versus Plan C:	$39.3	$36.7
Benefit/Cost Ratio:	1.19	1.17

As shown in the above table, the cumulative present worth preference, in 1999$, for the least cost Plan A as compared to the alternate Plans B and C is $18.1 million and $39.3 million respectively for the simulation period to 2037. Similarly, for the full study period the CPW preference for Plan A is $19.4 million and $36.7 million versus Plans B and C respectively. When comparing the hydroelectric option (Plan A) to the best thermal option (Plan C) these net benefits translate into a benefit/cost ratio of 1.19 out to 2037 and 1.17 to 2063.

To identify when the benefits of the least cost Plan A over the alternate plans are realized, the cumulative present worth costs of each of the plans are plotted in Figure C1 (see Page 56 in

Appendix C). This figure shows that the benefits of the least cost plan are realized in the near term and then maintained throughout the simulation period.

The following Table 3-3 presents a comparison of the quantity of thermal emissions expected to be released under each plan.

Table 3-3

Isolated Island Alternative Comparison of Thermal Emissions			
Year	Plan A Base Case	Plan B	Plan C
Tonnes CO_2 to 2037	104.8×10^6	106.1×10^6	106.0×10^6
Tonnes NO_x to 2037	449.9	454.5	455.1

As would be expected, the quantity of thermal emissions released is lower in the least cost expansion plan with the hydroelectric options as the near term sources. 104.8 million tonnes CO_2 for the least cost expansion plan versus 106.1 and 106.0 million tonnes CO_2 in the alternate plans, and 449.9 tonnes NO_x versus 454.5 and 455.1 tonnes NO_x in the alternate plans. Therefore, in cases where there is some future economic cost placed on thermal emissions, the cost effectiveness of the hydroelectric resources would be enhanced.

3.5 Detailed Analysis Results - Labrador Infeed Alternative

The least cost Labrador Infeed expansion plan is shown in Table 3-5. As with the Isolated Island alternative, near term requirements prior to the 2007 infeed in the optimal Plan A are met by Granite Canal and Island Pond in 2002 and 2003 respectively. In the long term, additional Island requirements are met by the Labrador Infeed. Also shown in Table 3-5 is an alternate (sub-optimal) near term plan in which the Holyrood CCCT is brought into service instead of Granite Canal and Island Pond. Unlike in the Isolated Island alternative where the near term plan is essentially a decision regarding the timing/order of the top three options (Granite Canal, Island Pond and Holyrood CCCT), alternate plans in the Labrador Infeed alternative are either Granite Canal and Island Pond, or the Holyrood CCCT. Were the CCCT to be constructed in the near term, then it is sufficient to meet the Island requirements until 2007 when the Labrador Infeed comes into service thereby eliminating the need for additional near term generation. This alternate plan is shown to demonstrate the magnitude of the preference for the hydroelectric options over the best thermal option

As indicated earlier, the Infeed will displace the present on-Island thermal generation. In 2008 the existing Holyrood facility will be converted to a standby mode of operation. Capital modifications will be made to insure a state of readiness in the unlikely event of a long term outage on the Infeed. In addition, sufficient operation and maintenance staff will be retained to operate the plant should the need arise. As stated earlier, the reactivation of Holyrood is based on an economic (least cost) decision where the system costs associated with the continued standby operation are compared against those associated with the normal operation of the plant.

3.5.1 Cost of a Firm Water Year

Table 3-4

Year	Load Forecast	Installed Capability	Energy Balance
1999	8,124	8,232	108
2000	8,241	8,232	(9)
2001	8,284	8,232	(52)
2002	8,358	8,269	(89)
2003	8,462	8,480	18
2004	8,548	8,634	86
2005	8,627	8,634	7
2006	8,703	8,634	(69)

In the generation plan with Granite Canal and Island Pond added prior to the Labrador Infeed, an energy deficit of 69 GWh occurs in 2006 (see Table 3-4); the year immediately before the in-service date of the infeed. With the large amount of energy capability being added in 2007, NLH would not commit to the construction of a new energy resource to meet the small 2006 deficit. Rather, NLH would run the risk of a firm water year occurring in 2006 and having to run combustion turbines for energy. This plan therefore, should include additional costs associated with the probability of a firm water year (estimated at approximately 7%) occurring in 2006.

Since costs for an average water year are included in the existing analysis, only the incremental costs of a firm water year over an average water year are included in the calculation of the present value costs of running an energy deficit in 2006. This cost is estimated by multiplying the probability of occurrence of a firm water year by the difference in the incremental operating costs associated with the firm water year and an average water year and present worthing the result to 1999$. The detailed calculation of the cost penalty for the 2006 energy deficit (which is then added to the least cost case CPW cost) is as follows:

Incremental system costs under firm water conditions:	$201.8 million
Incremental system costs under average water conditions:	$133.4 million
Difference in system costs:	$ 68.4 million
Multiply by probability of firm water year	x 0.07
Cost of running an energy deficit in 2006 (in 2006$)	$ 4.8 million
Present worth to 1999$ (at 8.5% discount rate)	**$ 2.7 million**

Similar calculations are performed when this situation arises in other cases studied in this report.

Table 3-5

Alternate Generation Expansion Plans – Labrador Infeed Alternative		
Year	Plan A Base Case	Plan B
1999		
2000		
2001		
2002	Granite Canal	HRD CCCT
2003	Island Pond	
2004		
2005		
2006		
2007	Labrador Infeed	Labrador Infeed
2008	Existing HRD in Standby	Existing HRD in Standby
2009		
2010		
2011		
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031	HRD Reactivated	
2032		
2033		HRD Reactivated
2034		
2035		
2036		
2037		
CPW to 2037 (1999$ x 10^6)	$1,504.8	$1,551.9
CPW to 2063 (1999$ x 10^6)	$1615.4	$1662.3

CT – Combustion Turbine CCCT – Combined Cycle Combustion Turbine HRD IV – Holyrood IV

Based on these results, Table 3-6 presents a summary of the economic indicators calculated to gauge the relative value of the least cost plan versus the alternative.

Table 3-6

Base Case Economic Analysis of NLH Near Term Options Evaluation of Preferred Granite Canal & Island Pond Near Term Plan (millions 1999$)		
Economic Indicator	**Labrador Infeed Alternative**	
	to 2037	**to 2063**
CPW Incremental Costs Optimal Plan A:	$1,504.8	$1,615.4
Alternate Plan B:	$1,551.9	$1,662.3
Net Benefits of Plan A Versus Plan B:	$47.1	$46.9
Benefit/Cost Ratio:	1.22	1.21

As shown in the above table, the cumulative present worth preference, in 1999$, for the least cost plan as compared to the alternate plan is $47.1 million and $46.9 million over the periods to 2037 and 2063 respectively. These net benefits translate into benefit/cost ratios of 1.22 to 2037 and 1.21 to 2063. As with the Isolated Island alternative, the plot of cumulative present worth costs of the plans (see Figure C2, Page 57) shows that, compared to the CCCT based plan, the benefits of the least cost plan are realized in the near term and maintained throughout the simulation period.

The following Table 3-7 presents a comparison of the quantity of thermal emissions expected to be released under each plan.

Table 3-7

Labrador Infeed Alternative Comparison of Thermal Emissions		
Year	Plan A Base Case	Plan B
Tonnes CO_2 to 2037	15.4×10^6	17.5×10^6
Tonnes NO_x to 2037	65.6	74.5

Also similar to the Isolated Island alternative, the quantity of thermal emissions released is lower in the least cost expansion plan with the hydroelectric options as the near term sources. 15.4 million tonnes CO_2 for the least cost expansion plan versus 17.5 million tonnes in the alternate plan, and 65.6 tonnes NO_x versus 74.5 tonnes NO_x in the alternate plan. Therefore, in cases where there is some future economic cost placed on thermal emissions, the cost effectiveness of the hydroelectric resources would be enhanced.

4. SENSITIVITY ANALYSIS

The economic viability of a project may be significantly affected by changes in certain study assumptions. For this study, sensitivity analyses are performed on the following parameters as applicable to each of the Labrador Infeed and Isolated Island long term alternatives:

- Load Forecast;
- Fuel Price Forecast;
- Granite Canal and Island Pond Capital Cost;
- Labrador Infeed Energy Rate; and
- Holyrood Retirement Assumptions.

For each of the sensitivity analyses, the Net Benefits, Benefit/Cost Ratio and Payback Period economic indicators are calculated in the same manner as for the base case and are summarized in Appendix C. A description of each of the sensitivity cases and the corresponding results is given in the following sections.

4.1 Load Forecast

Changes in the load forecast have the potential to affect not only the timing of near term resources (as was examined in Section 2.4 of this report) but may also impact on which option is considered optimal. To evaluate the sensitivity of the near term decision to longer term changes in the load forecast, three load forecast sensitivity cases are evaluated. The first two are based on extensions of the low and high series originating from the OLF risk analysis. In the period beyond the 2003 horizon for the risk analysis, the base load forecast has an average compound annual load growth of approximately 0.8% exclusive of the 100 MW industrial load. For the same period, assumed compound annual growth rates of 0.9% and 0.6% are used for the high and low load forecasts respectively. For the third load forecast sensitivity, the 100MW industrial load starting in 2007 in the base analysis is removed from the forecast. Note that these long term forecast sensitivities are based on arbitrary assumptions of load growth and do not reflect any detailed analysis of alternate provincial economic forecasts. Table C1 (Page 58, Appendix C) presents a summary of the results of this sensitivity analysis. As can be seen from the table, the preference for Granite Canal and Island Pond as compared to the Holyrood CCCT is maintained with little variation in net benefits. Under the Isolated Island alternative, over the simulation period to 2037, net benefits range from a low of $31.7 to a high of $50.3 depending on the forecast sensitivity case. Similarly, under the Labrador Infeed alternative, net benefits to 2037 range from $42.1 million to $47.1 million.

4.2 Fuel Price Forecast

The sensitivity to both a high and low fuel price series was examined. NLH's Economic Analysis section developed a high and low fuel price series applied to both light and heavy fuels. The resulting series (see Table A4) represent an approximate +/-25% change in the underlying crude oil price assumptions. Table C2 (Page 59, Appendix C) presents a summary of the results of the sensitivity analysis to fuel price forecast. In all fuel sensitivity cases, Granite Canal and Island Pond remain the preferred near term options. As would be expected, the preference for the hydraulic options increases with an increase in fuel prices and vice versa. When compared to the alternate plan with the CCCT as the near term source, for the high fuel price sensitivity the net benefits (to 2037) of Granite and Island increase to $57.3 million under the Labrador Infeed alternative and $48.5 million under the Isolated Island alternative. Similarly, for the low fuel price sensitivity the net benefits (to 2037) of Granite and Island decrease to $35.8 million under the Labrador Infeed alternative and $25.1 million under the Isolated Island alternative.

4.3 Granite Canal and Island Pond Capital Cost

The sensitivity to the capital cost of Granite Canal and Island Pond has been examined on the basis of the degree of confidence contained in the projects' engineering feasibility reports. Therefore, cases with a 10% increase in the capital cost of the Granite Canal and Island Pond options have been analyzed.

While the cost effectiveness for Granite Canal and Island Pond as the least cost near term options is reduced from the base case, they remain the preferred options for the near term with the least cost and sub-optimal expansion plans unchanged from the base case analysis. Over the simulation period to 2037, under the Labrador Infeed alternative the net benefits of the least cost plan are reduced from $47.1 million in the base case analysis to $27.2 million. Similarly, under the Isolated Island alternative, net benefits are reduced from $39.3 million in the base case to $34.0 million under the increased capital cost sensitivity. The results of this sensitivity analysis are summarized in Table C3 (Page 60, Appendix C).

4.4 Labrador Infeed Energy Rate

Sensitivity to a +10% and -10% change in the base infeed energy rate was performed for the Labrador Infeed alternative. As would be expected, the preference for the hydraulic options increases with an increase in the infeed energy rate and vice versa. For the +10% case, the net benefits increase from $47.1 million in the base case to $53.3 million over the simulation period to 2037. Similarly, for the –10% case, net benefits decrease from $47.1 million to $41.0 million. In both cases, Granite Canal and Island Pond remain the preferred near term options. Table C-4 (Page 61, Appendix C) presents a summary of the results of the sensitivity to infeed energy rate analysis.

4.5 Existing Holyrood Retirement

Table 4-1

Unit	Commission Year
Holyrood Unit 1	1971
Holyrood Unit 2	1971
Holyrood Unit 3	1980

The base case analysis assumes that, since existing on-Island plant is common between plans, the replacement of these units due to obsolescence would also be common between plans. However, since the near term operation of the existing Holyrood units would differ between a hydraulic based and a thermal based near term expansion plan, the impact of this operating difference could affect the expected retirement dates of the units. The commissioning dates for each of these existing units is shown in Table 4-1.

Following the strict application of the 30 year economic life assumption would see the retirement of Holyrood Units 1 and 2 in 2001, and Unit 3 in 2010. However, during the initial years of operation, these units were used infrequently and at low capacity factors and their economic lives have therefore been extended to reflect an equivalent life of 30 *operating* years in this analysis. One operating year is assumed equivalent to production at an annual 75% capacity factor. Since the existing Holyrood units are placed in a standby mode of operation for an extended period in the Labrador Infeed alternative, this sensitivity was performed on the Isolated Island alternative only.

Changing the Holyrood retirement assumptions as described above, results in slightly different longer term expansion plans (the expansion plans are the same as in the base case analysis out to 2017; see Table 3-1) and higher overall plan costs. However, this has little affect on the net benefits associated with the least cost plan. The net benefits under this sensitivity are reduced to $39.1 million from $39.3 million for the base case analysis over the simulation period to 2037. These results indicate that the retirement assumptions for the existing Holyrood units do not affect the preference for Granite Canal and Island Pond in the near term. The results of this analysis are summarized in Table C5 (Page 62, Appendix C).

5. CONCLUSIONS

This analysis compares the cost of meeting the near term energy requirements of the Island electrical system under both the Isolated Island and the Labrador Infeed long term alternatives. Based on the economic parameters used, and technically feasible NLH options available, the combination of Granite Canal in 2002 followed by Island Pond in 2003 represents the most cost effective means to meet the Island's near term energy requirements under both long term alternatives. The preference for this hydroelectric option, in cumulative present worth terms under base assumptions, is estimated at $39 million (1999$) with a benefit/cost ratio of 1.19 under the Isolated Island alternative, and $47 million (1999$) with a benefit/cost ratio of 1.22 under the Labrador Infeed alternative. Furthermore, the majority of these benefits are realized in the first 5 years of operation of the options. Sensitivity analysis confirms that the cost effectiveness of the Granite Canal/Island Pond options is maintained over a range of variation in significant parameters.

6. RECOMMENDATIONS

This report has concluded that, of NLH's available options, the development of Granite Canal is the most cost effective means to meet the Island's near term energy requirements in 2002. Further, of all options (both utility and non-utility) evaluated in the 1997 RFP, Granite Canal was identified as the most cost effective option available.

Therefore, based on the conclusions of this analysis, and the results of the 1997 RFP, it is recommended that NLH take actions necessary to proceed with the construction of Granite Canal and insure its fall 2002 in-service date. To address requirements beyond those met by Granite Canal, it is recommended that NLH proceed to issue a new request for generation proposals in the spring of 2000 with a targeted in-service date of successful option(s) in the 2003/2004 timeframe.

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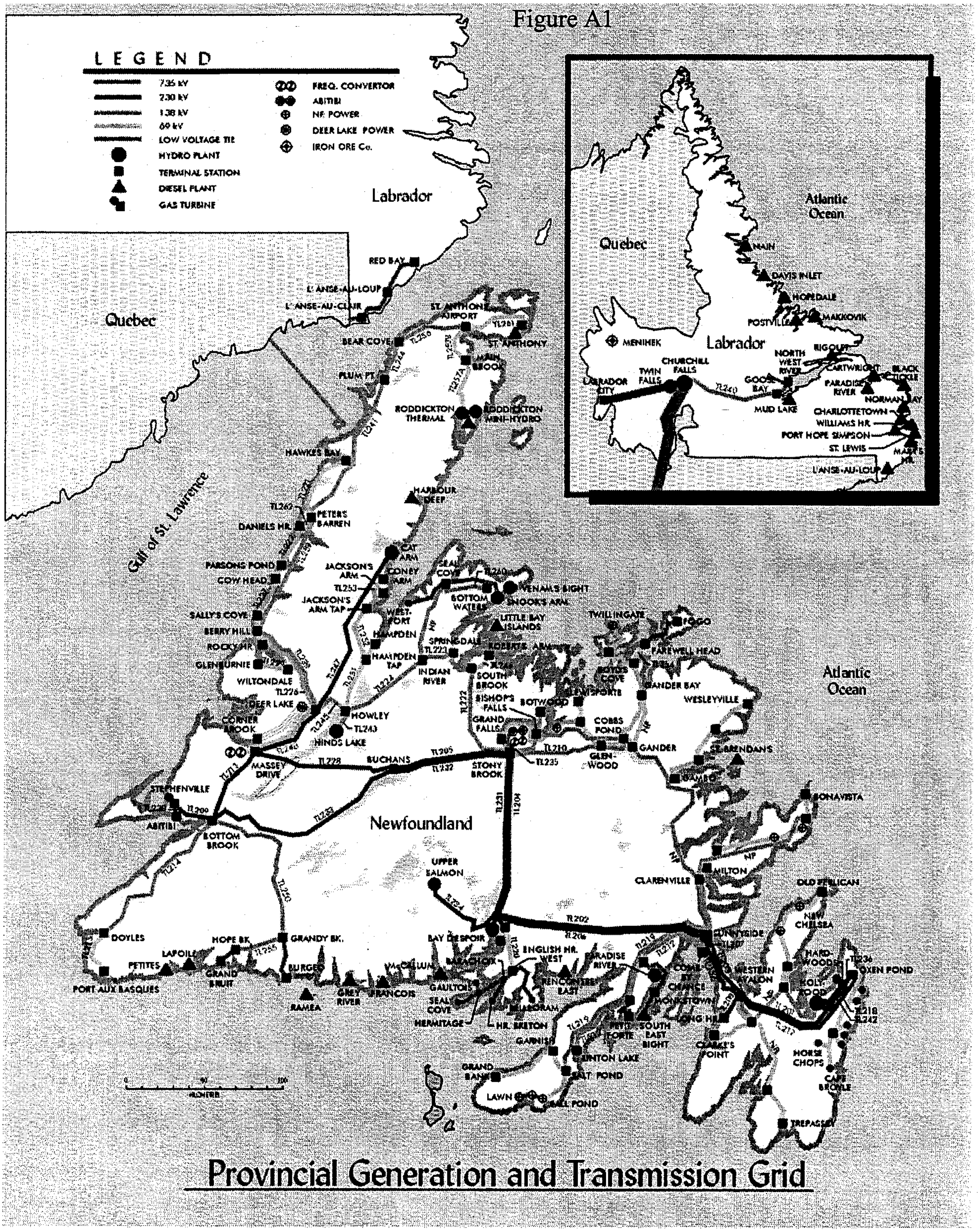
APPENDIX A

General Assumptions and Existing System Data

Figure A1



Provincial Generation and Transmission Grid

Table A1

Island Load Forecast		
Year	Peak (MW)	Energy (GWh)
1999	1,553	8,124
2000	1,573	8,241
2001	1,582	8,284
2002	1,603	8,358
2003	1,627	8,462
2004	1,647	8,548
2005	1,665	8,627
2006	1,679	8,703
2007	1,775	9,430
2008	1,785	9,484
2009	1,803	9,575
2010	1,821	9,660
2011	1,839	9,744
2012	1,852	9,815
2013	1,868	9,889
2014	1,882	9,936
2015	1,896	10,005
2016	1,912	10,082
2017	1,927	10,146
2018	1,936	10,187
2019	1,959	10,288
2020	1,973	10,365
2021	1,989	10,437
2022	2,004	10,509
2023	2,019	10,581
2024	2,034	10,653
2025	2,049	10,725
2026	2,064	10,797
2027	2,079	10,869
2028	2,094	10,941
2029	2,109	11,013
2030	2,124	11,085
2031	2,139	11,157
2032	2,154	11,229
2033	2,169	11,301
2034	2,184	11,373
2035	2,199	11,445
2036	2,214	11,517
2037	2,229	11,589

Source: NLH Economic Analysis Department

Table A2

ISLAND MONTHLY LOAD SHAPE		
Month	**Per Unit Peak**	**Per Unit Annual Energy**
January	0.963	0.107
February	1.000	0.102
March	0.909	0.100
April	0.810	0.088
May	0.753	0.081
June	0.679	0.071
July	0.598	0.066
August	0.554	0.063
September	0.574	0.060
October	0.717	0.076
November	0.856	0.087
December	0.935	0.099

Table A3

Escalation Rates (%)					
Year	Capital Escalation				O&M
	Hydro-Electric	Steam-Electric	Combustion Turbine		
2000	2.2%	2.1%	2.1%		2.3%
2001	2.0%	2.1%	2.0%		2.1%
2002	2.1%	1.9%	1.9%		2.0%
2003	2.3%	2.3%	2.1%		2.2%
2004	2.1%	2.4%	2.2%		2.4%
2005	2.1%	1.9%	2.1%		2.2%
2006	1.8%	1.8%	1.8%		1.9%
2007	1.9%	1.9%	1.9%		2.0%
2008	2.2%	2.2%	2.2%		2.3%
2009	2.0%	2.0%	2.0%		2.1%
2010	2.0%	2.0%	2.0%		2.2%
2011	1.9%	1.9%	2.0%		2.0%
2012-2037	2.1%	2.1%	2.2%		2.3%

Source: NLH Economic Analysis Department

Table A4

Fuel Forecast (Current CDN$/BBL)						
Year	Residual (6.287 mBTU/BBL)			Diesel (5.825 mBTU/BBL)		
	Low	Base	High	Low	Base	High
1999	13.80	19.0	22.10	25.80	32.7	36.10
2000	14.60	20.2	23.40	27.70	34.7	38.80
2001	15.70	21.6	25.20	29.60	37.0	41.50
2002	16.80	23.2	27.10	32.10	40.1	45.00
2003	17.90	24.7	29.00	35.30	43.7	49.10
2004	19.20	26.4	31.10	38.00	46.9	52.80
2005	20.60	28.2	33.40	39.90	49.4	55.80
2006	22.00	28.8	35.70	42.00	50.4	59.00
2007	22.40	29.4	36.40	42.80	51.5	60.20
2008	22.90	30.0	37.10	43.60	52.5	61.40
2009	23.30	30.6	37.80	44.50	53.6	62.60
2010	23.80	31.2	38.60	45.30	54.7	63.90
2011	24.30	31.8	39.40	46.30	55.6	65.20
2012	24.70	32.4	40.10	47.20	56.8	66.40
2013	25.20	33.1	41.00	48.20	58.0	67.70
2014	25.70	33.8	41.80	49.10	59.1	69.20
2015	26.30	34.4	42.60	50.10	60.2	70.60
2016	26.80	35.1	43.50	51.00	61.5	71.90
2017	27.30	35.8	44.30	52.10	62.8	73.30
2018	27.90	36.5	45.20	53.10	64.1	74.90
2019	28.40	37.3	46.10	54.20	65.3	76.30
2020	29.00	38.0	47.00	55.30	66.6	77.90
2021	29.60	38.8	48.00	56.40	67.9	79.50
2022	30.20	39.6	48.90	57.50	69.3	81.10
2023	30.80	40.3	49.90	58.70	70.6	82.70
2024	31.40	41.2	50.90	59.90	72.0	84.30
2025	32.00	42.0	51.90	61.00	73.4	86.00
2026	32.70	42.8	53.00	62.30	75.0	87.80
2027	33.30	43.7	54.00	63.60	76.5	89.50
2028	34.00	44.5	55.10	64.90	78.1	91.20
2029	34.70	45.4	56.20	66.20	79.7	93.00
2030	35.40	46.3	57.30	67.50	81.3	94.90
2031	36.10	47.2	58.40	68.90	82.9	96.80
2032	36.80	48.1	59.60	70.30	84.6	98.70
2033	37.50	49.1	60.80	71.70	86.3	100.70
2034	38.30	50.1	62.00	73.10	88.0	102.70
2035	39.10	51.1	63.20	74.60	89.8	104.80
2036	39.90	52.1	64.50	76.10	91.6	106.90
2037	40.70	53.1	65.80	77.60	93.4	109.00

Source: NLH Economic Analysis Department

Table A5

Existing Hydro Units - Modeling Data						
Plant Name	Owner	# of Units	Total Net Capacity	Annual Energy (GWH)**		FOR (%)
				Firm	Average	
Bay D'Espoir	NLH	7	592.0	2234	2587	0.80
Hinds Lake	NLH	1	75.0	283	339	0.80
Upper Salmon	NLH	1	84.0	476	549	0.80
Cat Arm	NLH	2	127.0	605	736	0.80
Paradise River	NLH	1	8.0	27	39	0.80
Snook's Arm	NLH	1	0.6	3	3	0.80
Venam's Bight	NLH	1	0.4	2	3	0.80
Roddickton	NLH	1	0.4	0	1	0.80
Cape Broyle	NLP	1	6.4			2.49
Fall Pond	NLP	1	0.3			2.49
Hearts Content	NLP	1	2.7			2.49
Horse Chops	NLP	1	7.6			2.49
Lawn	NLP	1	0.6			2.49
Lockston	NLP	2	3.0			2.49
Lookout Brook	NLP	2	5.5			2.49
Mobile	NLP	1	12.0			2.49
Morris	NLP	1	1.1			2.49
New Chelsea	NLP	1	3.7			2.49
Petty Harbour	NLP	3	5.2	323	440	2.49
Pierres Brook	NLP	1	4.0			2.49
Pitman's Pond	NLP	1	0.6			2.49
Port Union	NLP	2	0.5			2.49
Rattling Brook	NLP	2	11.5			2.49
Rocky Pond	NLP	1	3.1			2.49
Sandy Brook	NLP	1	5.7			2.49
Seal Cove	NLP	2	3.2			2.49
Topsail	NLP	1	2.4			2.49
Tors Cove	NLP	3	6.8			2.49
Victoria	NLP	1	0.5			2.49
West Brook	NLP	1	0.8			2.49
Rose Blanche	NLP	1	6.1			2.49
Watsons Brook	DLP	2	4.0	757	834	2.49
Bishop Falls	AP	9	14.0			2.49
Grand Falls	AP	5	42.7	419	460	2.49
Buchans	AP	1	1.8			2.49

** Periodically reviewed and updated

Table A6

Existing Thermal Units - Modeling Data									
Plant Name	Owner	Type	# of Units	Net Capacity MW	Firm Energy GWh	FOR %	Heat Rate BTU/kWh	O&M	
								Fixed $/kW	Variable $/MWh
Holyrood	NLH	OF	3	465.5	2,996	11.2	10,006	19.08	3.94
Roddickton	NLH	OF	1	4.6	-	10.0	18,886	-	-
Holyrood	NLH	CT	1	10.0	-	9.4	12,263	-	-
Hardwoods	NLH	CT	1	54.0	-	9.4	12,263	-	-
Stephenville	NLH	CT	1	54.0	-	9.4	12,263	-	-
Greenhill	NLP	CT	1	25.0	-	9.4	12,263	-	-
Salt Pond	NLP	CT	1	15.0	-	9.4	12,263	-	-
Mobile GT	NLP	CT	1	7.2	-	9.4	12,263	-	-
Hawkes Bay	NLH	DL	1	5.0	-	1.2	10,970	-	-
St. Anthony/ Roddickton	NLH	DL	8	9.7	-	1.2	10,970	-	-
Port Aux Basques	NLP	DL	2	4.2	-	1.2	10,970	-	-
St. John's	NLP	DL	1	2.7	-	1.2	10,970	-	-
Port Union	NLP	DL	1	0.5	-	1.2	10,970	-	-

OF - Oil Fired

CT - Combustion Turbine

DL - Diesel

Q. Please confirm that the primary economic benefit or justification for construction of Granite Canal is avoidance of Holyrood or other thermal generation.

A. The primary justification for the construction of Granite Canal was the least cost solution to a system energy deficit forecast to begin in 2000, and a capacity deficit forecast to begin in 2001. Please refer to IC-NLH-8 Attachment 1, Section 2.4. At the time of the evaluation, the near term options which were considered were:

- Granite Canal Hydroelectric
- Island Pond Hydroelectric
- Holyrood Combined Cycle Plant
- Holyrood Unit IV
- Hardwoods Combustion Turbine
- Stephenville Combustion Turbine

Q. With reference to the Gannett Fleming 2011 Study (page I-4), please confirm Hydro is in agreement with the statement that: "Use of the ASL procedure represents a change from the sinking fund method which will not result in an appropriate matching of depreciation expense with **the estimated consumption of service value** of electric property" (emphasis added). Please provide a detailed definition and explanation of the concept of the "estimated consumption of service value", as referred to in Gannett Fleming 2011 Study.

A. Hydro confirms that it is in agreement with the quoted statement. Service value as used in the Gannett Fleming report is based on the definition as provided by the Federal Energy Regulatory Commission (FERC) in part 101 of its Uniform System of Accounts which states that “Depreciation, as applied to utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption of prospective retirement of utility plant in the course of public service from causes which are known to be in current operation and against which the utility is not protected by insurance”. Further, FERC states that service value is equal to the difference between original cost and net salvage value of plant.

Q. Please indicate whether Gannett Fleming has determined that the peer Canadian utilities referred to in Schedule 2 (Part III of the 2011 Study) are considered comparable utilities to Hydro.

A. Gannett Fleming chose the utilities as indicated in Schedule 2 of the Gannett Fleming report on the basis that they did represent comparable utilities. Each of the utilities in the peer group is a regulated Canadian Electric utility. In developing the peer group, Gannett Fleming gave recognition to the need to incorporate utilities from the electric generation, transmission and distribution lines of business. Additionally, Gannett Fleming sought to use peers that have recently filed depreciation studies before their regulatory body. Lastly, Gannett Fleming selected utilities for which Gannett Fleming had completed the most recent depreciation study in order to provide an understanding of the comparability of the utilities.