Q. (Rates and Regulation Evidence page 4.7, lines 5 to 12)
Please provide updated marginal costs based on the methodology outlined in NERA's May 2006 marginal cost study documented in the report entitled *Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission* and the July 2006 report entitled *Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design*. Please identify marginal costs for the two scenarios with and without the Labrador Interconnection/Muskrat Falls project. Please file copies of the NERA reports for the record.

A. The marginal costs below are based on the 2006 NERA Economic Consulting marginal cost approach for the Island Interconnected System. Copies of the two referenced reports are attached. The two scenarios requested are contained in Tables 1 and 2 below. Using the 2006 NERA approach, Table 1 outlines the marginal costs assuming a Labrador interconnection while Table 2 outlines the marginal costs assuming no Labrador interconnection.

The marginal cost of demand and energy should reflect the commercial arrangements between Nalcor and Hydro for the costs of electricity from Muskrat Falls and for the costs of the new transmission infrastructure. After those arrangements have been finalized, a marginal cost study would be required to determine Hydro's future marginal costs of demand and energy.

Table 1 Scenario: Labrador Interconnection		
Marginal Cost Estimates at August 2013 Isolated Island Interconnected System		
	Energy $/MWh	Capacity $/KW - Yr
2013	$176	$64
2014	$163	$176
2015	$155	$270
2016	$160	$165
2017	$164	$217
2018	$54	$54
2019	$59	$59
2020	$66	$64
2021	$69	$68
2022	$72	$72

Notes:
1. Modelled as Per NERA Economic Consulting marginal cost approach (2006).
2. Fuel costs for 2013 as per test year, beyond 2014 per NLH corporate assumptions, August 2013.
3. Excludes transmission marginal costs.
4. Marginal cost projection is at customer meter.
5. Prices beyond 2017 reflect opportunity cost as per NERA approach.

Table 2 Scenario: No Labrador Interconnection Marginal Cost Estimates at August 2013 Isolated Island Interconnected System		
	Energy $/MWh	Capacity $/KW - Yr
2013	$176	$64
2014	$163	$176
2015	$155	$251
2016	$160	$111
2017	$164	$135
2018	$167	$91
2019	$171	$91
2020	$176	$64
2021	$186	$53
2022	$193	$59

Notes:
1. Modelled as Per NERA Economic Consulting marginal cost approach (2006).
2. Fuel costs for 2013 as per test year, beyond 2014 per NLH corporate assumptions, August 2013.
3. Excludes transmission marginal costs.
4. Marginal cost projection is at customer meter.

May 2006

FINAL REPORT

Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission

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I. Introduction

Newfoundland and Labrador Hydro (NLH) retained NERA Economic Consulting (NERA) to prepare estimates of its marginal costs of providing electricity generation and transmission service on the Island Interconnected System.[1] This report describes the methods used and summarizes the results of the analysis.

Why estimate marginal costs? There are several reasons. First, economic theory indicates that prices that reflect marginal costs lead to the most efficient allocation of society's scarce resources. Many economists believe that efficient resource allocation should be one of the goals of price setting in a regulated industry. In consideration of this issue, in its Order No. P.U.14 (2004), the Board of Commissioners of Public Utilities of Newfoundland and Labrador (the Board) directed NLH to undertake a marginal cost study. Second, in the increasingly competitive electric utility environment, it is very important to know the marginal costs of providing a wide range of services so a utility can ensure that its own promotional efforts and strategic plans are prudent. Finally, accurate estimates of marginal costs are essential for determining the benefits of load management, distributed generation and conservation programs, for the design of special contracts for individual customers, and for engineering studies such as acceptable loss levels in transformer specifications.

Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of electricity service one must ask and answer the question: What are *all* the additional generation and transmission costs that would be incurred with changes in kilowatt-hours of energy, and kilowatts of demand? Given the characteristics of electricity supply and demand, the cost of additional consumption may differ depending upon the time of the change in output. As a result, it is important to estimate time-differentiated marginal costs of electricity service.

NERA determines the marginal cost of electricity by examining the system planners' and operators' response to load changes at different times of the day and year. The method is not a formula, but a series of guidelines outlining what should be measured and how the measurement can be made.

A utility's marginal costs (particularly generation costs) may not be the same every year, even in the absence of inflation. Because load forecasting is an imperfect science and capacity must often be added in discrete chunks rather than smoothly as load grows, utilities and regions often

[1] NLH owns generation in Labrador, but is not able to serve load on Newfoundland with those resources. NLH also serves some remote areas of the Island and Labrador that are not connected to the grid. This study covers only the Island interconnected system.

have more or less capacity than is optimal. NERA estimated generation costs for the period 2007 to 2025 using output from NLH's system planning analysis. The transmission element of marginal cost was developed based on NLH's budget for growth-related transmission projects. The yearly marginal costs developed in this study can be combined as needed for any marginal cost application. For example, five years' worth of costs would be used to estimate the benefits of a load management program expected to be effective for five years. A single year's costs might be used to set a special economic development rate that is revised every year. The costs developed for this report are expressed in 2007 dollars.

In this study NERA considers two scenarios for generation marginal costs. Scenario One assumes that NLH's Island interconnected system will remain isolated from Labrador and the rest of the northeastern North American region. Scenario Two assumes that a high voltage transmission interconnection to Labrador will go into service in 2014, providing NLH with the opportunity to become an active participant in the regional market for energy and generation capacity. This approach assumes that NLH will respond to incremental load either by purchasing more at market prices or by selling less at market prices. (See Section III.)

Estimates of NLH's marginal costs depend on a number of key factors. The addition or loss of a large block of power demand and energy consumption will change NLH's generation expansion planning and operation, and therefore change marginal costs. Higher- or lower-than-expected fuel costs will change marginal energy costs and may change the generation expansion plan and the net cost of capacity additions. The addition of new supply resources (e.g. natural gas) will alter marginal system costs, as will financial factors such as the cost of debt and/or the allowed rate of return on equity. For theses reasons, it is appropriate that the utility's marginal costs be re-visited when there are fundamental changes to the key underlying assumptions.

II. Selection of Costing/Pricing Periods

NERA developed hourly marginal cost estimates for each time-varying component of marginal cost covered by this study (generation capacity, energy and transmission). These hourly estimates can be aggregated to meet the requirements of any marginal cost application. However, for purposes of providing summary tables for this report and as recommendations for improving the cost-reflectiveness of NLH's rates, NERA developed two sets of costing/pricing periods that are efficient (grouping hours of similar cost), administratively feasible, and likely to be appropriate for a significant number of years. The first set of periods is based on the patterns of costs of the Island interconnected system (Scenario One) over the next five years. The second set of periods is based on the cost patterns after the construction of the Labrador interconnection (Scenario Two).

The process used to develop the recommended costing/pricing periods was to sum all the time-varying marginal costs (generation capacity and energy, and transmission) for each hour, and use regression analysis to determine a set of seasons and periods within seasons that minimizes the squared differences between the individual hourly costs and the average for the period, while taking into consideration historical weather patterns, administrative feasibility and the need for the periods to be reasonably easy for customers to remember.

For Scenario One NERA limited the potential number of periods to two seasons and two (peak/off-peak) diurnal periods in the Winter season. NERA found no need for time-differentiation in the Non-Winter Season. The pattern of hourly marginal costs of generation and transmission in Scenario Two warrants three seasonal periods and three (peak/shoulder/off-peak) diurnal periods within each season (except for the Spring & Fall months, which only have peak and off-peak periods). The half-hour period definitions are the result of the pattern of expected market prices of generation capacity and energy in the Eastern time zone, which is one and a half hours behind Newfoundland time.

The costing periods under each Scenario are illustrated below:

Figure 1: Scenario One Periods (Isolated System)

Winter: January – March and December

Peak: Weekdays, 7:00 am to noon & 4:00 pm to 8:00 pm. [Newfoundland time]

Off-Peak: All remaining hours.

Non-Winter: April - November

No time-of-day differentiation.

Figure 2: Scenario Two Periods (Interconnection)

Summer: June – August

Peak: Weekdays, 1:30 to 7:30 pm.

Shoulder: Weekdays, 8:30 am to 1:30 pm and 7:30 to 11:30 pm; Weekends, 10:30 am to 12:30 pm.

Off-Peak: All remaining hours.

Winter: January – February and November – December

Peak: Weekdays, from 5:30 to 9:30 pm.

Shoulder: Weekdays, from 8:30 am to 5:30 pm, and 9:30 to 11:30 pm. Weekends: 5:30 to 9:30 pm.

Off-Peak: All remaining hours.

Spring & Fall: March – May and September – October

Peak: Weekdays, from 8:30 am to 11:30 pm. Weekends: 10:30 am to 11:30 pm.

Off-Peak: All remaining hours.

Note: All hours refer to Newfoundland time.

III. Marginal Generation Costs

NERA analyzed NLH's generation costs for two scenarios. In Scenario One, NLH's Island interconnected system remains isolated from the rest of the region and NLH serves marginal kWh and kW with its own Island resources (including local purchases). In Scenario Two, with the new transmission interconnection to Labrador in service in 2014,[2] NLH's marginal cost of generation is determined by regional market prices, which depend upon regional supply and demand and transmission constraints. This approach assumes that NLH is an active participant in the regional market and responds to marginal load by either purchasing more or selling less energy and capacity at market prices.

The Scenario One analysis recognizes that an isolated system often has excess capacity for some period of years after a capacity addition. Thus the generation capacity costs can be low in a number of years. When marginal costs are determined by market conditions, as in Scenario Two, there is more likelihood that capacity and load will stay in relative balance. As a result, Scenario Two assumes that the market price of capacity will reflect the full annualized cost of a peaking unit in each year.

A. Scenario One – Isolated Island System

The Island interconnected system is planned and operated to minimize costs and provide reliable service under a full range of hydrological conditions. Marginal energy cost is a function of the utility's dispatch of its generating resources. In years when additional load triggers a capacity addition, the annualized cost of adding capacity, net of any fuel savings the added capacity would provide in other hours by displacing resources with higher operating costs, represents the marginal generation capacity cost. As a result, the marginal cost estimates for Scenario One depend upon NLH's generation expansion plans, and the forecast of system reliability that results from that plan.

While NLH develops its plans using a range of assumptions about hydrological conditions, NERA has used the results based on expected water availability. The marginal cost study is a forward-looking exercise intended to provide cost estimates many years into the future. Obviously in real time, hydrological conditions might be better or worse than average, and total short-run marginal costs correspondingly lower or higher.

NLH utilizes Strategist system planning software to plan generation for the Island interconnected grid for any given load forecast. Strategist is an integrated strategic planning computer model that performs, among other things, generation system reliability analysis, production cost simulation and generation expansion planning analysis. NLH's modeling takes into account the expected variation in hydrological conditions. NLH's assessment of the timing for new investment for the Island's power supply and associated facilities is based on previously

[2] Scenario Two begins with 2015, the first full year of operation of the proposed Labrador Interconnection.

established generation planning criteria. These criteria set the minimum level for reserve capacity and firm energy to ensure an adequate power supply to meet the grid's firm load requirements. These criteria are:

- 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 than 2.8 hours per year.

The power and energy load forecast used in the Scenario One analysis is NLH's 2006 planning load forecast covering the period 2006 to 2025. The underlying projected annual growth rate for electricity requirements on the Island grid is approximately one percent and includes provision for a hydromet nickel processing facility to be in operation on the Island grid by 2012.

NLH has run Strategist assuming no new generation resources in order to see the timing of new generation requirements from a firm energy and LOLH perspective.[3] The results, in Table 1, indicate that if NLH adheres only to a firm energy criterion, the next generation source would be required in 2014. However, the LOLH target of 2.80 is exceeded prior to that date, in 2012. This primacy of the LOLH criterion on the Island grid represents a shift from the energy criterion, which has historically been the driver behind generation additions.[4] Factors contributing to this shift include the recent closure of the high load factor newsprint mill at Stephenville and the utilization of wind power, with its relatively low capacity contribution

.

[3] However, this Strategist run does include NLH's committed request for proposals for 25 MW of wind power scheduled to be in service in 2008.

[4] Using Strategist, NLH has determined that peak load would have to be 50-60 MW lower to reduce LOLH to the target level of 2.8 in 2014, the year in which the energy criterion requires a capacity addition.

Table 1: Firm Energy and LOLH Results with No New Generation Additions

Isolated Island Base Case Generation Requirements		
Year	Energy Criterion With No New Resources GWh	Capacity Criterion With No New Resources LOLH
2006	701	0.44
2007	630	0.51
2008	600	0.61
2009	549	0.64
2010	445	0.93
2011	370	1.31
2012	96	**3.04**
2013	14	3.94
2014	**(85)**	4.71
2015	(98)	5.01
2016	(169)	5.93
2017	(239)	7.43
2018	(315)	9.06
2019	(388)	11.02
2020	(455)	12.77
2021	(515)	15.45
2022	(587)	18.46
2023	(658)	24.74
2024	(726)	30.21
2025	(792)	38.51

The Base Case isolated island generation expansion plan used in the development of Scenario One marginal costs is provided in Table 2, along with the resulting firm energy balances and LOLH. Through 2019, as generation expansion is required, NLH has scheduled additional indigenous electricity resources in the form of wind and hydroelectric plants. For 2020 and beyond, NLH has tentatively identified a combined cycle combustion turbine (CCCT) as indicative of a large base load thermal plant that could be appropriate to build and operate at that time. This far out in the system planning horizon, resource options are subject to more uncertainties than local indigenous resources being scheduled in the medium term.

Table 2: Isolated Island Generation Expansion Plan Used for Scenario One Analysis

Year	Resource	Energy Balance GWh	LOLH Hours per Year
2006		701	0.44
2007		630	0.51
2008	Wind Farm (91 GWh)	600	0.61
2009		549	0.64
2010		445	0.93
2011		370	1.31
2012	Wind Farm (91 GWh)	111	2.88
2013	Wind Farm (91 GWh)	121	2.86
2014		97	2.77
2015	Island Pond (186 GWh)	115	2.61
2016		199	1.87
2017		129	2.36
2018	Round Pond (128 GWh)	74	2.79
2019	Portland Creek (77 GWh)	121	2.68
2020	CCCT (986 GWh)	283	2.28
2021		1,044	0.47
2022		973	0.61
2023		901	0.89
2024		833	1.26
2025		768	1.57

1. Scenario One Marginal Energy Costs

NLH dispatches its hydro resources in order to:

- Obtain the most energy from hydro production across the year (by minimizing the probability of spill and the need to operate thermal units, while maintaining the firm energy target);
- Keep thermal units as close to their efficient operating levels as possible; and
- Assist with system frequency and voltage control.

An additional kWh of energy consumed in a given hour generally leads to an additional kWh of hydro production in that hour (plus marginal energy losses), which is then replaced by thermal generation at Holyrood at a later time. As a consequence, NLH marginal energy costs exhibit no daily, weekly or seasonal variation. Under most hydrological conditions, this replacement energy is produced at times when the thermal units are operating at high levels (when heat rates are the most efficient).

In a predominantly hydro system with no binding intra-year storage constraints, hydro can be dispatched so that the thermal units operating at the margin have virtually the same operating costs (a combination of heat rate and fuel price) in every hour of the year. NLH attempts to keep its thermal units operating in the most efficient rate by varying hydro production and by taking one or more thermal units off line. However, system reserve and load restrictions do cause some variation in the heat rates of the thermal units within seasons.

For the purposes of this marginal cost study, NLH estimates that the replacement of a marginal hydro-generated kWh typically occurs when Holyrood itself is marginal and operating at 688 net kWh per barrel of fuel. Such replacement energy is generally produced in the Spring or Fall. In Winter, capacity limitations would argue against replacement, and for about two months in the Summer the thermal units are normally shut down.[5] However, because of NLH's fuel procurement and storage practices, it is difficult to predict when the replacement fuel would be purchased. As a result NERA has used NLH's forecast of annual fuel prices to compute the cost of producing the replacement thermal energy and thus the fuel component of the marginal energy costs is the same for all hours of the year.

Table 3 shows the derivation of 2007 marginal energy costs at the generator for each costing period. These figures include fuel, variable O&M, expense-related overheads (administrative and general or "A&G" expenses), revenue requirement for fuel stock and cash working capital, and marginal energy losses. Heavy fuel oil accounts for over 90 percent of the marginal energy cost. The development of the non-fuel marginal cost factors is explained later in Section V. The marginal fuel costs for the Holyrood thermal plant are based on NLH's corporate fuel price forecast for No. 6 heavy fuel oil (1-percent sulfur) as of the Spring 2006. There are a number of inputs making up the fuel price forecast, including world oil market outlooks as regularly prepared by the PIRA Energy Group.

[5] Except in dry years or when required to accommodate system maintenance.

Table 3: Scenario One—Development of 2007 Marginal Energy Costs by Period

		Winter		Non-Winter
		Peak	Off-Peak	All Hours
		(2007 Dollars per kWh)		
(1)	Marginal Fuel Cost	0.0806	0.0806	0.0806
(2)	Variable O&M	0.0012	0.0012	0.0012
(3)	A&G on Variable O&M (2) x 50.76%	0.0006	0.0006	0.0006
(4)	Total Marginal Running Cost (1)+(2)+(3)	0.0825	0.0825	0.0825
	<u>Working Capital</u>			
(5)	Fuel Stock Working Capital (1) x 14.11%	0.0114	0.0114	0.0114
(6)	Cash Working Capital (2) x 3.84%	0.0000	0.0000	0.0000
(7)	Total Working Capital (5)+(6)	0.0114	0.0114	0.0114
(8)	Revenue Requirement for Working Capital (7) x 8.40%	0.0010	0.0010	0.0010
(9)	Marginal Energy Cost at Generator (4)+(8)	0.0834	0.0834	0.0834
	<u>Marginal Energy Loss Factors</u>			
(10)	Transmission Level	1.047	1.047	1.047
	<u>Marginal Energy Cost at Meter</u>			
(11)	Transmission Level (9)*(10)	0.0873	0.0873	0.0873

The results for the entire study period (2007-2025) are shown on Table 4A. These marginal energy costs are very sensitive to assumptions about fuel costs. Table 4B compares the base case results (by groups of years) to results from three alternative fuel price scenarios.

Table 4A: Scenario One—2007-2025 Base Case Marginal Energy Costs

	Marginal Energy Costs (2007 Dollars per kWh)
2007	$0.0873
2008	$0.0862
2009	$0.0848
2010	$0.0810
2011	$0.0843
2012	$0.0860
2013	$0.0853
2014	$0.0846
2015	$0.0854
2016	$0.0856
2017	$0.0859
2018	$0.0862
2019	$0.0864
2020	$0.0866
2021	$0.0868
2022	$0.0871
2023	$0.0873
2024	$0.0875
2025	$0.0878

Table 4B: Scenario One—Average Marginal Energy Costs under Alternative Fuel Price

	Base Case	Test 1 (Fuel = 50% of base case)	Test 2 (Fuel = 75% of base case)	Test 3 (Fuel = 150% of base case)
	(2007 Dollars/kWh)			
2007-2011	$0.0847	$0.0434	$0.0640	$0.1261
2012-2020	$0.0858	$0.0439	$0.0648	$0.1276
2021-2025	$0.0873	$0.0447	$0.0660	$0.1299

2. Scenario One Marginal Generation Capacity Costs

If load grows in hours when capacity is tight, there is a reduction in reliability, which is a marginal shortage cost imposed on consumers. When the shortage cost is sufficiently high, it is cost-effective to add capacity to restore reliability to the acceptable level. In years when an increment of load would not trigger a capacity addition, there is still a marginal capacity cost – the cost to consumers of the reduced reliability that results when load grows but capacity remains the same.

The type of capacity added solely to restore reserves to the required level in response to load growth is generally a peaking unit, such as a combustion turbine. Generating units designed to run more often than peakers have higher fixed costs, which are only justified when their variable costs are low enough to warrant their dispatch in many hours, not just in peak hours. The fixed costs of baseload or intermediate units are thus incurred for both capacity and energy reasons.

As shown above in Table 2, NLH's current base case expansion plan includes three 25-MW wind purchase contracts, construction of three small hydro projects, and a combined cycle combustion turbine (CCCT) unit. Because of the intermittent nature of wind generation and its non-dispatchability, NLH does not count on these wind projects to provide capacity in particular hours. As a result, NERA has not considered these wind projects as a marginal source of capacity in calculating NLH's marginal generation capacity cost.

Tables 5A and 5B show the development of the annualized cost of each non-wind resource in the base case expansion plan. The per-kW investment costs of the hydro units and CCCT are adjusted for general plant, and annualized using an economic carrying charge that includes an allowance for plant-related A&G. Fixed O&M, including non-plant-related A&G, and an allowance for working capital are added. The working capital factor includes cash, materials and supplies. Each of the major factors used to convert the investment cost of the hydro projects and CCCT to an annual value is discussed later in this report.

Line (16) on Tables 5A and 5B divides the annual cost by one minus the effective forced outage rate (EFOR) of the resource. This adjustment recognizes that these resources will not always be available to provide an additional kW of capacity when needed, and grosses up the investment to represent a "perfect" kW that is available in all hours when it can be economically dispatched.

To yield a pure capacity cost, the annual costs per kW must be reduced by the annual average operating cost savings expected to be provided by a marginal kW of these non-peaking resources over their lives. The annual operating cost savings were computed, for each resource, by multiplying the expected hours of operation in each full year of operation, by the difference between the expected Holyrood marginal running costs per kWh[6] and the running cost per kWh of the capacity addition in that year.[7] These annual operating cost savings were then averaged over the expected service life of the unit.[8] This crediting of the annual fixed costs of the marginal kW for the average annual operating cost savings recognizes that the last kW added to the system is required to meet marginal load only in a single (or very few) hours of the year.[9] If the unit runs in other hours, that is because it displaces a resource with higher running costs.

6 NLH estimates that the Holyrood efficiency in these particular hours is between the average value of 630 kWh/BBL and the marginal value of 688 kWh/BBL. The marginal fuel cost is then fuel cost per BBL divided by efficiency. Variable O&M and working capital were also included in the operating cost savings calculations.

7 The running costs of the hydro units are assumed be to zero.

8 When necessary the 2036 fuel price forecasts and hours run were used in subsequent years.

9 The annual fixed cost is calculated on a real-levelized basis and all calculations are done in 2007 Canadian dollars.

As an estimate of the net capacity of cost of a generic hydro unit, NERA averaged the results for the three hydro additions, weighting them by installed capacity. In the case of the CCCT, the unit is expected to operate at the margin (in the years included in the study) and thus generates no fuel savings. The final adjustments on Tables 5A and 5B incorporate marginal demand losses.

Table 5A: Scenario One—Annual Cost of Planned Hydro Capacity Additions Net of Fuel Savings

		Island Pond 2016	Round Pond 2019	Portland Creek 2020
		(2007 Dollars)		
		(1)	(2)	(3)
(1)	Marginal Investment per kW of Capacity	$4,701	$7,421	$4,740
(2)	With General Plant Loading (1) x 1.2470	$5,862	$9,254	$5,911
(3)	Annual Economic Charge Related to Capital Investment	6.67%	6.67%	6.67%
(4)	A&G Loading	0.17%	0.17%	0.17%
(5)	Total Annual Carrying Charge (3)+(4)	6.83%	6.83%	6.83%
(6)	Annualized Costs (2) x (5)	$400.65	$632.42	$403.94
(7)	Fixed O&M Expenses	$14.59	$19.09	$16.47
(8)	With A&G Loading (7) x 1.5076	$22.00	$28.79	$24.82
(9)	Sub-Total (6)+(8)	$422.64	$661.21	$428.77
	Working Capital			
(10)	Material and Supplies (2) x 1.06%	$62.14	$98.09	$62.65
(11)	Prepayments (2) x 0.00%	$0.00	$0.00	$0.00
(12)	Cash Working Capital (8) x 3.84%	$0.84	$1.11	$0.95
(13)	Total Working Capital (10)+(11)+(12)	$62.99	$99.19	$63.61
(14)	Revenue Requirement for Working Capital (13) x 8.40%	$5.29	$8.33	$5.34
(15)	Total Annual Costs (9)+(14)	$427.94	$669.54	$434.11
(16)	Total AnnualCosts Adjusted For Effective Forced Outage Rate (15) / (1-0.0091)	$431.87	$675.69	$438.10
(17)	Projected Annual Fuel Savings	$496.71	$652.60	$572.47
(18)	Cost of Hydro Net of Fuel Savings (16)-(17) but not less than zero	$0.00	$23.09	$0.00
(19)	Capacity (MW)	36	18	14
(20)	Capacity Weighted Average Cost of Hydro Net of Fuel Savings (per kW)		$6.11	
(21)	Capacity Weighted Average Cost of Hydro Adjusted for Losses (per kW)		$6.41	

For the Island system, fuel costs have an enormous impact on the net cost of generation capacity. High expected fuel costs offset all or most of the fixed cost of the hydro and wind units in NLH's resource plan. The marginal cost analysis confirms a key rule for NLH's system planning—subject to transmission constraints, when fuel costs are high and expected to remain so, it may be cost-effective to pre-build indigenous capacity and displace fuel at Holyrood.

Table 5B: Scenario One—Annual Cost of Planned Combined Cycle Combustion Turbine Capacity Addition Net of Fuel Savings

		CCCT 2021 (2007 Dollars) (1)
(1)	Marginal Investment per kW of Capacity	$1,346.00
(2)	With General Plant Loading (1) x 1.2470	$1,678.46
(3)	Annual Economic Charge Related to Capital Investment	7.82%
(4)	A&G Loading	2.32%
(5)	Total Annual Carrying Charge (3)+(4)	10.15%
(6)	Annualized Costs (2) x (5)	$170.29
(7)	Fixed O&M Expenses	$11.58
(8)	With A&G Loading (7) x 1.5076	17.46
(9)	Sub-Total (6)+(8)	$187.74
	Working Capital	
(10)	Material and Supplies (2) x 1.06%	$17.79
(11)	Prepayments (2) x 0.00%	$0.00
(12)	Cash Working Capital (8) x 3.84%	$0.67
(13)	Total Working Capital (10)+(11)+(12)	$18.46
(14)	Revenue Requirement for Working Capital (13) x 8.40%	$1.55
(15)	Total Annual Costs (9)+(14)	$189.29
	Total Annual Costs Adjusted	
(16)	For Effective Forced Outage Rate (15) /(1-0.05)	$199.26
(17)	Projected Annual Average Fuel Savings	$0.00
(18)	Cost of CCCT Net of Fuel Savings (16)-(17)	$199.26
(19)	Cost of CCCT Adjusted for Losses (per kW)	$209.02

Tables 5A and 5B show annual net capacity costs for the types of units in the expansion plan. In any given year, marginal load growth will not necessarily trigger a capacity addition; however, it will reduce the reliability of service for customers in general. The marginal cost of generation capacity can be computed for each year by adjusting the net annual cost of the next capacity addition by the ratio of expected LOLH to target LOLH, as shown on Table 6. When this ratio is less than one, the marginal cost reflects the reduced value of capacity because of higher than target reserves. When the ratio is above one, capacity is particularly valuable because reliability is below the target level.[10]

Table 6A: Scenario One—Annual Marginal Generation Capacity Costs, 2007-2025

	Annualized Cost of Generation	Forecast LOLH	Marginal Generation Capacity Cost
	(2007 Dollars/kW)		(2007 Dollars/kW)
	(1)	(2)	(3)
			(1)*(2)/2.80
2007	$6.41	0.51	$1.17
2008	6.41	0.61	1.39
2009	6.41	0.64	1.47
2010	6.41	0.93	2.14
2011	6.41	1.31	2.99
2012	6.41	2.88	6.58
2013	6.41	2.86	6.54
2014	6.41	2.77	6.33
2015	6.41	2.61	5.99
2016	6.41	1.87	4.28
2017	6.41	2.36	5.41
2018	6.41	2.79	6.38
2019	6.41	2.68	6.13
2020	6.41	2.28	5.22
2021	209.02	0.47	35.36
2022	209.02	0.61	45.37
2023	209.02	0.89	66.24
2024	209.02	1.26	94.34
2025	209.02	1.57	117.48
Note: Target LOLH is		2.80	

To illustrate the effect of the fuel price forecast on the annual marginal generation capacity cost, NERA computed the cost of the hydro units in the resource plan net of fuel savings using the same three fuel price scenarios employed in the sensitivity analysis of marginal energy costs. Table 4B shows the results, summarized by groups of years. In the first two periods, prior to the addition of the CCGT, which is not expected to generate fuel savings, marginal generation capacity costs are much higher than the base case when fuel costs are assumed to be lower. Note that these calculations assume no change in the resource plan. In fact, particularly in Test 1, some or all of the planned hydro additions would probably be replaced with a CCCT or some other resource with lower fixed costs.

[10] The rationale for this adjustment is described in more detail in Appendix A.

Table 6B: Scenario One—Annual Marginal Generation Capacity Costs Using Alternative Fuel Cost Assumptions

	Average Annual Marginal Generation Capacity Cost			
	Base Case	Test 1 (Fuel=50% of base case)	Test 2 (Fuel=75% of base case)	Test 3 (Fuel=150% of base case)
	---(2007 Dollars/kW)---			
	(1)	(2)	(3)	(4)
2007-2011	$1.83	$64.49	$24.88	$0.00
2012-2020	$5.87	$206.77	$79.76	$0.00
2021-2025	$71.76	$71.76	$71.76	$71.76

The annual costs must then be time-differentiated. NLH's system planning model produces estimates of LOLH for each month. NERA used the relative LOLH in each month, aggregated to seasons and averaged over the period 2007-2011, to compute generation capacity costs by the seasonal costing periods.[11]

Within a month, capacity costs were assigned to hours based on each hour type's relative probability of being the peak hour of the month.[12] These results were also aggregated over the months in a season. Table 7 shows the resulting generation capacity cost time-differentiation factors, summarized by costing period.

Table 7: Scenario One—Time-Differentiation Factors for Generation Capacity Costs

		Assignment Factor
		(1)
Winter		
	Peak	83%
	Off-Peak	16%
	Subtotal	99%
Non-Winter		1%
	Subtotal	1%
TOTAL		100%

[11] The seasonal relative LOLH values are essentially unchanged for the entire period, 2007-2025.

[12] The hour types are the 24 hours in weekdays, Saturdays, and Sundays.

Table 8 shows the resulting monthly marginal generation capacity costs per kW at transmission voltage, by costing period. The annual costs are assigned to costing periods using the time-differentiation factors in Table 7 and divided by the number of months in the season to produce monthly costs per kW.

Table 8: Scenario One—Monthly Marginal Generation Capacity Costs at Transmission Voltage (2007-2025)

	Winter		Non-Winter
	Peak	Off-Peak	
	(2007$ per kW-mo)		
	(1)	(2)	(3)
2007	0.24	0.05	0.00
2008	0.29	0.06	0.00
2009	0.31	0.06	0.00
2010	0.45	0.09	0.00
2011	0.62	0.12	0.00
2012	1.37	0.26	0.01
2013	1.36	0.26	0.01
2014	1.32	0.25	0.01
2015	1.25	0.24	0.01
2016	0.89	0.17	0.00
2017	1.13	0.22	0.01
2018	1.33	0.25	0.01
2019	1.28	0.24	0.01
2020	1.09	0.21	0.01
2021	7.35	1.41	0.04
2022	9.44	1.81	0.05
2023	13.78	2.64	0.07
2024	19.62	3.76	0.10
2025	24.44	4.68	0.13

B. Scenario Two – Labrador Infeed: Market-Based Marginal Generation Costs

The second scenario for the long term supply of power and energy to the Island of Newfoundland involves a high voltage direct current transmission interconnection from Labrador to the Island. This transmission line would interconnect the Island grid to hydroelectric plant(s) on the Churchill River in Labrador and to the transmission networks of eastern North American via Hydro Quebec. The capacity of this interconnection would be 800 MW, capable of delivering about 7,000 GWh annually. It would be capable of displacing the Island's existing thermal generation and delivering the Island's incremental power and energy requirements for many years to come.

If the Labrador Interconnection is built, it is expected to be completed by 2014 and Holyrood will be mothballed. Once the interconnection is operational, in any given hour NLH will generally be either buying or selling energy (and in some hours capacity) in the regional market. Thus, NLH's dispatchers will respond to a customer's additional electricity consumption either by purchasing more energy (in the unlikely event that NLH is a net buyer at the time) or selling less energy (if, as is likely, NLH is a net seller at the time). NLH's marginal cost of generation will be the market price of electricity in the region – an opportunity cost.

The Labrador Interconnection will give NLH access to the transmission network of Hydro Quebec, which is in turn connected to Ontario, New York, New England and New Brunswick. Market prices of energy and capacity in Quebec will reflect supply and demand conditions in this entire area, unless transmission constraints are binding. In that case, market prices will reflect more localized supply and demand conditions. Thus, estimates of market prices in Quebec are a reasonable representation of NLH's opportunity costs of generation under this scenario. This study assumes there are no transmission constraints in Labrador, but that constraints similar to those that created differences in market prices between Quebec and the US Northeast electricity market in the period 2001-2005 will continue. In the absence of regional transmission constraints, prices (apart from differentials due to varying losses) are the same across regional Canadian and US Northeast electricity markets, and these broader markets determine NLH's opportunity cost in many hours.

Detailed simulations of these market prices for future years were not available for this study. NLH provided, as a reasonable starting point, a long-term forecast of market prices (2007 – 2025) prepared by the US Department of Energy (DOE).[13] These are US national annual average prices. Information on recent spot energy hourly prices as recorded by the NY ISO for the Hydro Quebec region were used to time-differentiate the DOE forecasts, giving market prices that vary by month and time of day.

The DOE forecast of per-kWh market prices used as the basis for market price estimates includes both energy and capacity components. However, the historical NY-ISO's hourly market prices for the Hydro-Quebec region that were used for time-differentiation do not fully reflect the market value of capacity. In both New York and New England there is a separate capacity market. In Ontario, there is centralized long-term procurement for capacity.
Consequently, generators have historically obtained revenues for capacity outside the spot energy market. For this reason NERA estimated hourly market prices of energy and capacity separately, as described below.

1. Scenario Two—Market-Based Marginal Generation Capacity Costs

In the long term, the regional market value of capacity tends toward the cost of adding new peaking capacity, because the market is large enough for supply and demand for capacity to remain relatively balanced. NERA assumed that in the post-2014 period when the interconnection is in operation, the regional annual market value of capacity will be equal to the annualized cost of a combustion turbine (CT).

[13] Annual Energy Outlook 2006. Early Release. Table A8.

Table 9 shows the derivation of this annual cost. The marginal investment per kW of capacity, adjusted by general plant loading, is annualized using an economic carrying charge that includes a loader for plant-related A&G expenses. The fixed O&M cost per kW of capacity is adjusted by an expense-related A&G loader and added to this capital cost. A revenue requirement component for working capital is also added. Each of these components of the calculation uses NLH's costs, because the regional capacity price is likely to reflect the costs of publicly-owned utilities in Eastern Canada.

For purposes of estimating the marginal generation capacity cost to NLH, the annual cost of a kW of CT capacity is multiplied by 1 plus a reserve margin of 16 percent.[14] This adjustment, on Line (16) of Table 9, reflects the fact that, in response to a one-kW growth in load in a peak hour, NLH will need to reduce its sales of capacity (or increase its purchases of capacity) by more than one kW to maintain its target level of reserves. The loss adjustment on the last line takes into account losses within Labrador, losses on the Labrador interconnection, and losses within the Island. The losses within Labrador reduce NLH's opportunity cost of capacity to an amount below the market price in the Hydro Quebec zone.

[14] NLH indicates that it needs a capacity reserve of 16% of annual peak load to maintain its 2.8 LOLH/year target.

Table 9: Annualized Cost of a Combustion Turbine

		CT Cost (2007 Dollars) (1)
(1)	Marginal Investment per kW of Capacity	$492.39
(2)	With General Plant Loading (1) x 1.2470	614.02
(3)	Annual Economic Charge Related to Capital Investment	7.82%
(4)	A&G Loading	2.32%
(5)	Total Annual Carrying Charge (3)+(4)	10.15%
(6)	Annualized Costs (2) x (5)	$62.29
(7)	Fixed O&M Expenses	$13.36
(8)	With A&G Loading (7) x 1.5076	$20.15
(9)	Sub-Total (6)+(8)	$82.44
	Working Capital	
(10)	Material and Supplies (2) x 1.06%	6.51
(11)	Prepayments (2) x 0.00%	
(12)	Cash Working Capital (8) x 3.84%	0.77
(13)	Total Working Capital (10)+(11)+(12)	7.28
(14)	Revenue Requirement for Working Capital (13) x 8.40%	0.61
(15)	Total Annual Costs (9)+(14)	$83.05
(16)	Total Annual Costs Adjusted For Reserve Margin (15) x 1.16	$96.34
(17)	Annual Cost per kW Adj for Losses	$103.64

Generation capacity will have value in the region only in "critical hours" when demand is high enough to trigger the probability of market participants' not meeting their reserve requirements. NERA assumed that these critical hours can be approximated by the hours when spot energy prices are likely to exceed the operating cost of a combustion turbine, and thereby include a shortage component. To identify these hours, NERA analyzed the spot prices recorded by the New York ISO for the Hydro Quebec zone in the period 2000-2005. Table 10 shows the time-differentiation factors for generation capacity developed by analyzing these critical hours.

Table 10: Scenario Two—Time-differentiation Factors for Regional Market Price of Generation Capacity

		Total Critical Hours	Assignment Factor
		(1)	(2)
Winter			(1)/total hrs
	Peak	168	50%
	Shoulder	40	12%
	Off-Peak	0	0%
	Subtotal	208	62%
Summer			
	Peak	126	38%
	Shoulder	0	0%
	Off-Peak	0	0%
	Subtotal	126	38%
Spring/Fall			
	Peak	0	0%
	Off-Peak	0	0%
	Subtotal	0	0%

Table 11 shows the time-differentiated monthly marginal generation capacity costs by costing period under Scenario Two for years 2015-2025.[15] The values are calculated by applying the time-differentiation factors in Table 10 to the annual capacity cost in Table 9 and converting to monthly costs by dividing seasonal values by the number of months in the season.

[15] Under our assumption that the market price of capacity will follow the annualized cost of a peaker, Scenario Two marginal generation capacity costs for all subsequent years will be the same in real terms.

Table 11: Scenario Two—Marginal Monthly Generation Capacity Costs, Years 2015-2025

	Monthly Capacity Cost (2007$ per kW-mo)
Winter	
Peak	$13.03
Shoulder	$3.10
Off-Peak	$0.00
Total	$16.14
Summer	
Peak	$13.03
Shoulder	$0.00
Off-Peak	$0.00
Total	$13.03
Spring/Fall	
Peak	$0.00
Off-Peak	$0.00
Total	$0.00

2. Scenario Two—Market-Based Marginal Energy Costs

The DOE forecast of annual prices per kWh reflect combined energy and capacity values. The capacity element in the DOE forecast price must be removed to avoid double-counting. For each forecast year (2007-2025) NERA multiplied the DOE average spot price forecast by 8760 hours to convert it to an annual revenue amount, and then subtracted the annualized cost of a CT, before the reserve margin adjustment, in Table 9 above. The remaining value represents the annual energy market revenue for one kW dispatched in every hour of the year.

To convert this annual energy revenue into specific prices for each hour, NERA used the same 2000-2005 spot prices for the Hydro Quebec region that were used to identify the critical hours. NERA capped these hourly prices at the variable cost of a CT[16] in that year; averaged the resulting patterns of hourly spot prices over the six years for typical weekdays, Saturdays and Sundays of each month; and applied these patterns to the annual energy revenue for each forecast year. Table 12 shows the average market price estimates for 2015, converted to marginal energy costs by period. The only adjustments to the market prices needed to convert them to marginal energy costs at NLH's transmission system are an allowance for cash working capital and adjustments for losses. The loss factors used in this adjustment reflect losses within Labrador, losses on the interconnection and losses within NLH's network. Table 13 shows marginal energy costs for the entire period, 2015-2025.

[16] Gas cost, variable O&M, and A&G loading on the variable O&M.

Table 12: Scenario Two—Development of Marginal Energy Costs by Period (2015)

		Winter			Spring/Fall		Summer		
		Peak	Sh	Offpeak	Peak	Offpeak	Peak	Sh	Offpeak
		(2007 Dollars per kWh)							
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(1)	Regional Market Energy Price per kWh	$0.0629	$0.0540	$0.0417	$0.0525	$0.0364	$0.0611	$0.0511	$0.0349
	<u>Working Capital</u>								
(2)	Cash Working Capital (1) x 3.84%	$0.0024	$0.0021	$0.0016	$0.0020	$0.0014	$0.0023	$0.0020	$0.0013
(3)	Revenue Requirement for Working Capital (2) x 8.40%	$0.0002	$0.0002	$0.0001	$0.0002	$0.0001	$0.0002	$0.0002	$0.0001
(4)	Marginal Energy Cost at Generator (1)+(3)	$0.0631	$0.0542	$0.0419	$0.0526	$0.0365	$0.0613	$0.0512	$0.0350
	<u>Marginal Energy Loss Factors</u>								
(5)	Transmission Level	1.0758	1.0758	1.0758	1.0758	1.0758	1.0758	1.0758	1.0758
	<u>Marginal Energy Cost at Meter</u>								
(6)	Transmission Level (4)*(5)	$0.0679	$0.0583	$0.0451	$0.0566	$0.0393	$0.0659	$0.0551	$0.0377

Table 13: Scenario Two—Marginal Energy Costs by Period (2015-2025)

	Winter			Spring/Fall		Summer		
	Peak	Sh	Offpeak	Peak	Offpeak	Peak	Sh	Offpeak
	(2007 Dollars per kWh)							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
2015	$0.0679	$0.0583	$0.0451	$0.0566	$0.0393	$0.0659	$0.0551	$0.0377
2016	$0.0680	$0.0584	$0.0451	$0.0567	$0.0394	$0.0660	$0.0552	$0.0377
2017	$0.0680	$0.0584	$0.0451	$0.0567	$0.0394	$0.0661	$0.0552	$0.0378
2018	$0.0698	$0.0600	$0.0463	$0.0583	$0.0404	$0.0678	$0.0567	$0.0388
2019	$0.0717	$0.0616	$0.0476	$0.0598	$0.0415	$0.0697	$0.0582	$0.0398
2020	$0.0718	$0.0617	$0.0477	$0.0599	$0.0416	$0.0698	$0.0583	$0.0399
2021	$0.0718	$0.0618	$0.0477	$0.0600	$0.0416	$0.0698	$0.0584	$0.0399
2022	$0.0719	$0.0618	$0.0478	$0.0600	$0.0417	$0.0699	$0.0584	$0.0399
2023	$0.0666	$0.0618	$0.0467	$0.0585	$0.0412	$0.0682	$0.0559	$0.0406
2024	$0.0740	$0.0636	$0.0492	$0.0618	$0.0429	$0.0720	$0.0601	$0.0411
2025	$0.0759	$0.0652	$0.0504	$0.0633	$0.0440	$0.0738	$0.0616	$0.0422

IV. Marginal Transmission Costs

For most utilities the long-term marginal cost of transmission can be estimated from the typical investment per kW of transmission added to meet load growth. Transmission investment is somewhat lumpy, so the addition of capacity in a given year does not necessarily reflect load growth in that year. NERA normally relies on the cost of budgeted growth-related transmission projects over the budget period as the basis for our marginal cost estimates.

Projects considered to be growth-related include the following categories:

- Projects related to growth in system or area loads; and
- Projects related to increased interconnection capability to provide for added reliability.

Transmission expenditures that replace existing facilities without adding capacity would be undertaken even in the absence of load growth and, therefore, are not marginal. Projects that connect generation to the network are generation-related and not functionally transmission. Transmission projects that facilitate economy purchases or economy interchange, but do not add significantly to system reliability, are energy-related, rather than transmission-related. Projects that bring the system to a new target level of reliability (rather than returning the system to an unchanged target in response to load growth) are also not marginal.

NLH provided its capital budget for the period 2006-2009. There is only one growth-related transmission project during that period. Therefore, the load-related transmission investment per kW of load growth in the budget period may not be representative. Using only forecast information is a more strictly marginal approach, but in this case may be misleading because of the short budget period and the lumpiness of transmission investment in an isolated system. Using a combination of historical and budget information may better align expenditures with load growth causing them.

NERA reviewed projects during the historical period as well (2001-2005) and found that growth-related investment was made in 2002 and 2003. The bulk of the projects were not growth-related.[17] Table 14 shows the investment in growth-related transmission per kW of load growth over the period 2002-2009. NERA assumed that this value is representative of marginal transmission investment over the full forecast period, 2006-2025. There are no differences in planned transmission network investment between the Scenario One and the Scenario Two.

[17] On the interconnected Island grid, growth-related projects are very limited because work on the 230 kV bulk system, which was constructed in the late 1960s, is now typically driven by issues other than load growth.

Table 14: Marginal Transmission Investment

(1)	Total Investment in Demand-Related Transmission Facilities, 2002-2009 (Thousands of 2007 Dollars)	$3,646
(2)	Estimated Additions to Peak Load 2002-2009 (Megawatts)	98
(3)	Total Marginal Investment in Growth-Related Transmission Facilities per Kilowatt (2007 Dollars) (1) / (2)	$37.21

When load growth requires transmission investment, marginal transmission O&M expenses are also incurred. Because the growth-related projects involve substations rather than lines, NERA began with an analysis of NLH's average level of transmission substation O&M expenses in the recent past as a guide for estimating marginal O&M costs. O&M expenses for 2000 to 2004 were first converted into 2007 dollars. These constant dollar values were then divided by kilowatts of weather-normalized peak load at the transmission level. The expenses per kW have declined significantly in recent years, so NERA used the 2003-2004 average as the estimate of marginal transmission O&M expenses.

Table 15: Marginal Transmission O&M

	Year	Transmission Station O&M Expenses	Weather Normalized System Peak Demand	Expense Per KW of System Peak Loads	Weighted Labor & Material Cost Index	Expense Per KW of System Peak Load
		(Thousand Dollars)	(MW)	(Dollars)	(2007=1.00)	(2007 Dollars)
				(1) / (2)		(3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2000	$3,235	1460	$2.22	0.86	$2.58
(2)	2001	$3,063	1562	$1.96	0.89	$2.21
(3)	2002	$3,615	1601	$2.26	0.92	$2.47
(4)	2003	$2,823	1601	$1.76	0.94	$1.87
(5)	2004	$2,561	1612	$1.59	0.97	$1.65
(6)	Estimated Annual Transmission O&M Expenses for the Planning Period (Average 2003-2004)					$1.76

Table 16 shows the development of annualized marginal transmission cost, which follows the same procedure used for the annualized CCCT cost on Table 5B above.

Table 16: Annual Marginal Transmission Cost

		2007 Dollars per kW
(1)	Marginal Investment per kW of System Peak	$37.21
(2)	With Plant Loading (1) x 1.2470	46.40
(3)	Annual Economic Carrying Charge Related to Capital Investment	6.87%
(4)	A&G Loading (plant related)	0.82%
(5)	Total Annual Carrying Charge (3) + (4)	7.69%
(6)	Annualized Costs (2) x (5)	3.57
(7)	O&M Expenses	1.76
(8)	With A&G Loading (7) x 1.5076 (Non-plant Related)	2.66
(9)	Sub-total (6)+(8)	6.23
	Working Capital	
(10)	Material and Supplies (2) x 1.06%	0.49
(11)	Prepayments (2) x 0.00%	0.00
(12)	Cash Working Capital Allowance (8) x 2.43%	0.06
(13)	Total Working Capital (10) + (11) + (12)	0.56
(14)	Revenue Requirement for Working Capital (13) x 8.40%	0.05
(15)	Total Transmission Costs (9) + (14)	6.27
(16)	Loss-adjusted Transmission Cost	$6.58

Transmission capacity is sized to handle annual peak demands on the transmission system. NERA used the estimated relative probability of annual transmission system peak, based on five years of historical hourly transmission loads,[18] to time-differentiate transmission marginal costs. The reduced carrying capability of transmission facilities in periods of high ambient temperature is taken into account in these calculations.

Tables 17 A and B show the time-differentiation factors for marginal transmission costs, by period. There are two sets of factors – one for Scenario One periods and a second for Scenario Two periods.

[18] From years 2000 to 2004.

Table 17 A: Scenario One—Time-Differentiation Factors for Marginal Transmission Costs

			Relative Probability of System Peak
			(1)
(1)	Winter		
		Peak	78%
		Off-Peak	22%
		Subtotal	100%
(2)	Non-Winter		0%
(3)	TOTAL		100%

Table 17 B: Scenario Two—Time-Differentiation Factors for Marginal Transmission Costs

		Relative Probability of System Peak
Winter		
	Peak	36%
	Shoulder	43%
	Off-Peak	19%
	Subtotal	98%
Summer		
	Peak	0%
	Shoulder	0%
	Off-Peak	0%
	Subtotal	0%
Spring/Fall		
	Peak	2%
	Off-Peak	0%
	Subtotal	2%
	TOTAL	100%

Tables 18 A and B show the monthly time-differentiated marginal transmission costs, using the annual costs developed on Table 16 and the two sets of time-differentiation factors for marginal transmission costs. The seasonal costs have been divided by number of months in the season to convert to monthly costs.

Table 18 A: Scenario One—Monthly Marginal Transmission Costs 2007-2025

	Monthly Transmission Cost (2007$ per kW-mo)
Winter	
Peak	$1.29
Off-Peak	$0.35
Non-Winter	$0.00

Table 18 B: Scenario Two—Monthly Marginal Transmission Costs 2007-2025

	Monthly Transmission Cost (2007$ per kW-mo)
Winter	
Peak	$0.59
Shoulder	0.72
Off-Peak	0.32
Summer	
Peak	0.00
Shoulder	0.00
Off-Peak	0.00
Spring/Fall	
Peak	0.02
Off-Peak	0.01

V. Other Marginal Costs

A. Administrative and General Expenses and General Plant

When a utility adds plant and incurs additional O&M expenses, it typically incurs additional overhead costs as well. A given element of administrative and generation (A&G) expense can grow with plant or with O&M expenses, or remain constant. General plant typically grows with other types of plant. NERA's marginal cost study includes A&G and general plant loaders for expenses and plant to capture these elements of marginal cost.

1. Administrative and General Expenses

Based on NLH's categories of overheads, these expenses were divided into two categories: (1) those associated with plant, and (2) those "non-plant-related" overheads associated with O&M expenses. The sum of A&G accounts related to the level of O&M were divided by O&M expenses (which exclude fuel and purchased power costs) less A&G. NERA used the average of this ratio over 2003 and 2004 as the A&G loader on O&M expenses.

For A&G expenses associated with plant, NERA divided the identified plant-related overhead expenses by plant in service, and averaged over the period 2003-2004. To this NERA added the ratio of property insurance cost to gross plant. The results are shown in Table 19.

Table 19: Loading Factors for Administrative and General Expenses

		Estimate of Loading Factor
Applicable to Non-Plant-Related Expenses :		50.76%
Applicable to Plant-Related Expenses:		
	Hydro	0.169%
	Thermal	2.325%
	Transmission	0.824%

2. General Plant

General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. When a utility adds generation, transmission and distribution equipment, the need for general plant grows as well. To account for the marginal cost of general plant NERA estimated a general plant-loading factor applicable to other marginal plant. NERA developed a regression model that explains cumulative additions to general plant in service as a linear function of cumulative additions to total electric plant (less general plant) in service over the period 1991 to 2004. The result, shown in Table 20, was a highly significant coefficient for total plant additions, which NERA adopted as the general plant loader.

Table 20: Loading Factor for General Plant

	Estimate of Loading Factor
General Plant	24.70%

The result of the regression analysis is given below:

ADDGEN =	-9643273 +	0.2470 ADDTOLES	
t-Statistic	(-2.6)	(14.05)	
Standard Error	3683057	0.018	

$R^2 = 0.9427$ N = 14 DF=13

B. Fuel Stock and Working Capital

When NLH generates a marginal kWh using a fuel that requires a stockpile, it incurs additional costs related to financing the additional stockpile. The fuel stock factor added to marginal energy costs takes into account the average time that fuel used by NLH resides in its storage facilities.

The fuel stock factor was calculated from the ratio of total No. 6 fuel inventory to total No. 6 fuel expenses for the years 2002, 2003, and 2004. The ratios for these years were relatively close, so NERA averaged the ratios for the three years. This average ratio, 0.14, indicates that NHL maintained a fuel stock of about 1.5 month's fuel use (when Holyrood fuel data is averaged across a full 12 months.) This reflects NLH's normal fuel management practices, including a seasonal inventory build in late winter and early spring to mitigate the risk of navigational restrictions for tankers to its Holyrood plant because of ice.

Each non-fuel expense element of marginal cost is adjusted for cash working capital. NLH sees a longer lag in receipts from its customers than in payments to its suppliers. NERA based its cash working capital adjustment on average customer days of lag versus the average days of payments lag.[19] The factor, 3.84 percent, also incorporates a pro-rata share of the HST adjustment. In the

[19] Lags in fuel cost payments were excluded from this calculation because cash working capital for fuel is included in NLH's fuel adjustment mechanism. Lags in payments for purchased power were also excluded because purchased power is not marginal.

case of Scenario Two market transactions, NERA assumed a net lag of 14 days, which also results in a 3.84-percent cash working capital factor.

Materials and supplies kept in inventory are another element of working capital. NERA based its estimate of the requirement for marginal materials and supplies on the average ratio of materials and supplies to gross electric plant over the period 2002-2004. The tables calculating annual costs of elements of the system also include a line for a prepayment element of working capital; however, this element is zero for NLH.

The revenue requirement for working capital is the dollar amount of working capital multiplied by the after-tax weighted average cost of capital. Because NLH does not pay income taxes, the after-tax cost of capital is the same as the weighted average cost of capital.

Table 21: Working Capital Factors

Materials & Supplies	1.06%
Non-Fuel Cash Working Capital	3.84%
Scenario Two Market Transactions	3.84%

C. Marginal Losses

Two types of net marginal losses are used in the study. Demand losses are applied to marginal generation capacity and transmission costs. Marginal energy losses are applied to marginal energy costs. Different loss factors were developed for Scenarios One and Two.

1. Marginal Demand Losses

Marginal demand loss factors related to the expansion of the physical system are based on total losses at system peak. Total losses include both fixed losses associated predominantly with transformer cores, and variable losses associated with conductors.

To supply an added kW at a meter point, NLH must provide sufficient generation and transmission capacity to accommodate that kW plus transmission losses.[20] The demand loss factors used in this study were estimated using a regression analysis of energy losses developed by NLH for long term forecasting and an estimate of no-load (fixed) losses.[21] The regression analysis estimates the impact of hydro and thermal generation on annual system energy losses.[22]

Because most of the marginal generation capacity in NLH's expansion plan are hydro units located in relatively remote areas (similar to the current hydro units), NERA calculated the

[20] The marginal demand loss factor for an individual component is the ratio of the input to the output from that component at time of peak. The capacity adjustment for a component up-stream of a customer meter is the product of all the loss factors including that of component itself.

[21] E-mail from NLH, dated March 03, 2006.

[22] E-mail from NLH, dated March 02, 2006.

demand loss factor for Scenario One as the sum of the hydro regression coefficient[23] and no-load losses. Given the relatively high loading of the transmission lines connecting hydro units to the NLH system the hydro regression coefficient provides a useful proxy for variable losses at peak.

Scenario Two applies the same demand loss factor to marginal transmission costs as used in Scenario One. However, the market-based generation capacity cost estimate in Scenario Two requires a marginal energy loss factor adjustment because it is based on an estimate of hourly prices. For this purpose NERA used the sum of the hydro regression coefficient and the estimated energy losses on the Labrador interconnection itself. The market prices also include an adjustment for losses within Labrador, which reduce the revenue NLH can expect to earn on its energy and capacity sales to somewhat less than market prices for transactions in Hydro Quebec.

2. Marginal Energy Losses

Marginal energy losses are incurred in moving an additional kWh through the fixed system. Fixed losses are, by definition, not affected by supplying an additional kWh. Only variable losses come into these calculations.

The Holyrood units typically do not follow load and existing CTs and diesel units are used sparingly and primarily for area protection. The immediate source of a marginal kWh is typically a hydro unit. Consequently NERA used variable hydro losses (from the regression analysis) as our estimate of Scenario One marginal energy losses on NLH's transmission system.

For Scenario Two, NERA applied to the market-based marginal energy cost estimates the sum of the hydro regression coefficient (representing marginal energy losses on the Island) and estimated marginal energy losses on the Labrador interconnection itself. As explained above, a further adjustment accounts for the losses within Labrador, which reduce the revenue from (or the opportunity cost of) marginal sales to the market to below the market price quoted in Hydro Quebec.

[23] The regression coefficient for hydro gives the fraction of a hydro-generated kWh that is lost in transmission.

Table 22: Marginal Demand and Energy Losses

		Demand	Energy
Base Case Scenario		1.0490	1.0470
Infeed Case Scenario			
	2015	1.0758	1.0758
	2016	1.0775	1.0775
	2017	1.0791	1.0791
	2018	1.0809	1.0809
	2019	1.0825	1.0825
	2020	1.0841	1.0841
	2021	1.0855	1.0855
	2022	1.0872	1.0872
	2023	1.0910	1.0910
	2024	1.0929	1.0929
	2025	1.0944	1.0944

VI. Computation of Carrying Charges

To be useful in ratemaking and other marginal cost applications, the marginal investment in new plant must be converted into annual costs using an economic carrying charge. These annual charges reflect the ownership costs of NLH's incremental plant: return to "stockholders" (in this case the Province) and bondholders, and depreciation.

For use in a marginal cost study, the appropriate stream of annual charge is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all ownership costs over the life of the investment. It is helpful to think of this stream as a series of rental charges that an entrepreneur in a competitive industry would charge for the use of utility equipment. The rental charges would rise as inflation made the equipment more valuable, but tend to decline as technological improvements made newer equipment more attractive to renters. The present value of the entire stream would have to be sufficient to cover the entrepreneur's ownership costs, or the investment would never take place. On the other hand, competition would keep the entrepreneur from charging more than the cost of ownership (including a fair return on the investment). In such a stream of rental charges, the first year's charge represents the cost in today's dollars of making the plant or equipment available for a year. These first-year charges are shown on Table 23. Appendix B illustrates the calculation of the annual ownership costs for a CCCT and the calculation of the first year's economic carrying charge from that stream of annual costs. It also provides the specific assumptions used for each type of plant.

Table 23: Economic Carrying Charges

		CCCT & CT	Hydro	Transmission
		(1)	(2)	(3)
(1)	Present Value of Revenue Requirements Related to Incremental $1,000 Investment	$1,000	$1,000	$1,000
(2)	Present Value Cost of Replacing Dispersed Retirements Related to Incremental $1,000 Investment	$22	$10	$26
(3)	Total Present Value Cost Related to Incremental $1,000 Investment (1)+(2)	$1,022	$1,010	$1,026
(4)	First-Year Annual Economic Charge Related to Incremental $1,000 Investment	$78	$67	$69
(5)	First-Year Annual Economic Charge Related to Incremental Investment [(4)/$1,000]	7.82%	6.67%	6.87%

One major element of the ownership cost of utility equipment is the incremental cost of capital. NLH has two sources of capital—debt and retained earnings. The retained earnings are revenues in excess of expenses and represent the Province's investment in the utility, which entails an opportunity cost. For the incremental cost of debt NERA used 8.6 percent, which is NLH's projected cost of long-term debt, including a one-percent debt guarantee fee. In 2004 the Board ordered NLH to use as its cost of equity the long-term incremental cost of new debt, excluding the debt guarantee fee (i.e. 7.6 percent). NERA weighted the equity and debt portions, 80/20, which is consistent with NLH's current capital structure. The result is a weighted average cost of capital of 8.4 percent.

A required assumption for the economic carrying charge calculation is the expected rate of inflation net of technical progress applicable over the life of the investment. NERA has used NLH's long-term inflation estimates of 1.97% for generation plant and 2.17% for transmission plant. The rate of technological progress is assumed to be incorporated in the inflation rate because of lack of a basis on which to estimate future technological progress.

Another component of the economic carrying charge is an adjustment for the fact that not all plant and equipment will last its estimated service life. Some components will require early replacement, causing added costs, while some will last longer than expected and produce savings. Line 2 of Table 23 above shows the adjustment for this dispersed pattern of replacements.[24]

[24] Appendix B describes the calculation of the dispersed retirements adjustment.

VII. Summary Schedules for Two Scenarios

Tables 24 A and B summarize, respectively, the 2007 – 2025 time-differentiated marginal costs for Scenario One and the 2015 – 2025 time-differentiated marginal costs for Scenario Two, both stated on a per kWh basis. The per-kW costs were converted to per-kWh costs by dividing by the number of hours in the period.

Table 24 A: Scenario One—Summary of 2007-2025 Marginal Costs (per kWh)

		Winter		
		Peak	Off-Peak	Non-Winter
		---------- (2007 Dollars) ---------		
		(1)	(2)	(3)
	2007			
(1)	Energy	$0.0873	$0.0873	$0.0873
(2)	Generation Capacity	$0.0012	$0.0001	$0.0000
(3)	Transmission	$0.0066	$0.0007	$0.0000
(4)	Total per kWh	$0.0952	$0.0881	$0.0873
	Total per kWh			
	2008	$0.0943	$0.0870	$0.0862
	2009	$0.0930	$0.0856	$0.0848
	2010	$0.0899	$0.0819	$0.0810
	2011	$0.0941	$0.0852	$0.0843
	Average 2007-2011	**$0.0933**	**$0.0855**	**$0.0847**
	2012	$0.0997	$0.0872	$0.0860
	2013	$0.0989	$0.0864	$0.0853
	2014	$0.0980	$0.0857	$0.0846
	2015	$0.0984	$0.0865	$0.0854
	2016	$0.0968	$0.0866	$0.0856
	2017	$0.0983	$0.0870	$0.0859
	2018	$0.0996	$0.0873	$0.0862
	2019	$0.0996	$0.0875	$0.0864
	2020	$0.0988	$0.0877	$0.0866
	Average 2012-2020	**$0.0987**	**$0.0869**	**$0.0858**
	2021	$0.1313	$0.0901	$0.0869
	2022	$0.1422	$0.0911	$0.0871
	2023	$0.1648	$0.0929	$0.0874
	2024	$0.1951	$0.0952	$0.0876
	2025	$0.2201	$0.0972	$0.0879
	Average 2021-2025	**$0.1707**	**$0.0933**	**$0.0874**
Note: Hours per month used to convert costs per kW to per kWh:		194	532	734

Table 24 B: Scenario Two—Summary of 2015 - 2025 Marginal Costs (per kWh)

	Winter			Spring/Fall		Summer		
	Peak	Sh	Offpeak	Peak	Offpeak	Peak	Sh	Offpeak
	------------------------------- (2007 Dollars per kWh) -----------------------------							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
2015								
Energy	$0.0679	$0.0583	$0.0451	$0.0566	$0.0393	$0.0659	$0.0551	$0.0377
Generation Capacity	$0.1508	$0.0114	$0.0000	$0.0000	$0.0000	$0.0992	$0.0000	$0.0000
Transmission	$0.0068	$0.0026	$0.0009	$0.0000	$0.0000	$0.0002	$0.0000	$0.0000
Total per kWh	$0.2255	$0.0723	$0.0459	$0.0566	$0.0393	$0.1653	$0.0551	$0.0377
Total per kWh								
2016	$0.2258	$0.0724	$0.0460	$0.0567	$0.0394	$0.1655	$0.0552	$0.0377
2017	$0.2261	$0.0725	$0.0460	$0.0567	$0.0394	$0.1657	$0.0552	$0.0378
2018	$0.2281	$0.0741	$0.0472	$0.0583	$0.0404	$0.1676	$0.0567	$0.0388
2019	$0.2303	$0.0757	$0.0485	$0.0598	$0.0415	$0.1015	$0.0582	$0.0398
2020	$0.2306	$0.0758	$0.0485	$0.0599	$0.0416	$0.1017	$0.0584	$0.0399
2021	$0.2308	$0.0759	$0.0486	$0.0600	$0.0416	$0.1701	$0.0584	$0.0399
2022	$0.2311	$0.0760	$0.0486	$0.0600	$0.0417	$0.1703	$0.0584	$0.0399
2023	$0.2264	$0.0759	$0.0476	$0.0585	$0.0412	$0.1689	$0.0560	$0.0406
2024	$0.2341	$0.0778	$0.0500	$0.0618	$0.0429	$0.1729	$0.0602	$0.0411
2025	$0.2361	$0.0794	$0.0512	$0.0633	$0.0440	$0.1748	$0.0617	$0.0422
Note: Hours per Month used to conver costs per kW to per kWh:	86	272	367	441	293	131	311	294

Tables 25A and B restate the Scenario One 2007-2025 marginal costs and Scenario Two 2015 - 2025 marginal costs, with the marginal generation capacity and transmission costs stated on a per kW-month basis.

Table 25 A: Scenario One—Summary of 2007-2025 Marginal Costs (per kWh and per kW)

	ENERGY	GENERATION & TRANSMISSION CAPACITY		
		Winter		
	All Periods	Peak	Off-Peak	Non-Winter
	(2007 Dollars per kWh)	--------- (2007 Dollars per kW-mo.) -------		
	(1)	(2)	(3)	(4)
2007	$0.0873	$1.53	$0.40	$0.00
2008	$0.0862	$1.58	$0.41	$0.00
2009	$0.0848	$1.60	$0.41	$0.00
2010	$0.0810	$1.73	$0.44	$0.00
2011	$0.0843	$1.91	$0.47	$0.00
Avg. 2007-11	**$0.0847**	**$1.67**	**$0.43**	**$0.00**
2012	$0.0860	$2.66	$0.62	$0.01
2013	$0.0853	$2.65	$0.61	$0.01
2014	$0.0846	$2.61	$0.61	$0.01
2015	$0.0854	$2.53	$0.59	$0.01
2016	$0.0856	$2.18	$0.53	$0.01
2017	$0.0859	$2.41	$0.57	$0.01
2018	$0.0862	$2.61	$0.61	$0.01
2019	$0.0864	$2.56	$0.60	$0.01
2020	$0.0866	$2.37	$0.56	$0.01
Avg. 2012-20	**$0.0858**	**$2.51**	**$0.59**	**$0.01**
2021	$0.0868	$8.64	$1.76	$0.04
2022	$0.0871	$10.73	$2.16	$0.05
2023	$0.0873	$15.07	$2.99	$0.07
2024	$0.0875	$20.91	$4.11	$0.10
2025	$0.0878	$25.72	$5.03	$0.13
Avg. 2021-25	**$0.0873**	**$16.21**	**$3.21**	**$0.08**

Table 25 B: Scenario Two—Summary of 2015-2025 Marginal Costs (per kWh and per kW)

		Winter			Spring/Fall		Summer		
		Peak	Sh	Offpeak	Peak	Offpeak	Peak	Sh	Offpeak
		(2007 Dollars)							
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
2015	Energy (per kWh)	$0.0679	$0.0583	$0.0451 #	$0.0566	$0.0393	$0.0659	$0.0551	$0.0377
	Gen. & Trans. Capacity (per kW-mo)	$13.62	$3.81	$0.32	$0.00	$0.00	$13.05	$0.01	$0.00
2016	Energy (per kWh)	$0.0680	$0.0584	$0.0451	$0.0567	$0.0394	$0.0660	$0.0552	$0.0377
	Gen. & Trans. Capacity (per kW-mo)	$13.64	$3.82	$0.32	$0.00	$0.00	$13.07	$0.01	$0.00
2017	Energy (per kWh)	$0.0680	$0.0584	$0.0451	$0.0567	$0.0394	$0.0661	$0.0552	$0.0378
	Gen. & Trans. Capacity (per kW-mo)	$13.66	$3.82	$0.32	$0.00	$0.00	$13.09	$0.01	$0.00
2018	Energy (per kWh)	$0.0698	$0.0600	$0.0463	$0.0583	$0.0404	$0.0678	$0.0567	$0.0388
	Gen. & Trans. Capacity (per kW-mo)	$13.68	$3.83	$0.32	$0.00	$0.00	$13.12	$0.01	$0.00
2019	Energy (per kWh)	$0.0717	$0.0616	$0.0476	$0.0598	$0.0415	$0.0697	$0.0582	$0.0398
	Gen. & Trans. Capacity (per kW-mo)	$13.70	$3.83	$0.32	$0.00	$0.00	$4.19	$0.01	$0.00
2020	Energy (per kWh)	$0.0718	$0.0617	$0.0477	$0.0599	$0.0416	$0.0698	$0.0583	$0.0399
	Gen. & Trans. Capacity (per kW-mo)	$13.72	$3.84	$0.32	$0.00	$0.00	$4.19	$0.01	$0.00
2021	Energy (per kWh)	$0.0718	$0.0618	$0.0477	$0.0600	$0.0416	$0.0698	$0.0584	$0.0399
	Gen. & Trans. Capacity (per kW-mo)	$13.74	$3.84	$0.32	$0.00	$0.00	$13.17	$0.01	$0.00
2022	Energy (per kWh)	$0.0719	$0.0618	$0.0478	$0.0600	$0.0417	$0.0699	$0.0584	$0.0399
	Gen. & Trans. Capacity (per kW-mo)	$13.76	$3.85	$0.32	$0.00	$0.00	$13.19	$0.01	$0.00
2023	Energy (per kWh)	$0.0666	$0.0618	$0.0467	$0.0585	$0.0412	$0.0682	$0.0559	$0.0406
	Gen. & Trans. Capacity (per kW-mo)	$13.80	$3.86	$0.32	$0.00	$0.00	$13.24	$0.01	$0.00
2024	Energy (per kWh)	$0.0740	$0.0636	$0.0492	$0.0618	$0.0429	$0.0720	$0.0601	$0.0411
	Gen. & Trans. Capacity (per kW-mo)	$13.82	$3.86	$0.32	$0.00	$0.00	$13.26	$0.01	$0.00
2025	Energy (per kWh)	$0.0759	$0.0652	$0.0504	$0.0633	$0.0440	$0.0738	$0.0616	$0.0422
	Gen. & Trans. Capacity (per kW-mo)	13.84	3.87	0.32	0.00	0.00	13.28	0.01	0.00

Appendix A

Rationale for EFOR Adjustment to Annual Cost of New Capacity

Prudent planning for generation capacity expansion involves a trade-off between cost and reliability. Customers want reliable service, but are not willing to pay prices that guarantee no generation-related outages. Utilities set reliability standards that reflect consumers' willingness to pay for reliability. NLH standard is 2.8 loss-of-load hours (LOLH) per year. NLH adds capacity as needed to meet this standard. However, given the isolation of the system and the lumpiness of capacity additions, reliability is typically greater than the target level for a few years after each new generation addition. In those years, marginal load does not trigger another generation addition, but does affect reliability of the system to some degree, by increasing LOLH above what otherwise would have occurred.

The cost of the added LOLH depends upon the cost to consumers of unserved energy. Although it is difficult to measure the cost of unserved energy (CUE), it is easy to back into the CUE that is implicit in the utility's reliability target.

If we assume that the reliability target (LOLH*) is set based on an accurate assessment of the CUE, then it must be true that in a year when actual LOLH = LOLH*, the system is optimal and the benefits of the last (or next) kW of capacity are just equal to the cost of the last (or next) kW of capacity. These benefits are the outage costs avoided because of the presence of the last kW of capacity – CUE times LOLH*, multiplied by one minus the effective forced outage rate of the marginal kW of capacity, because there is probability that it will be forced out in some of the hours when it is needed to supply load. The cost of that marginal kW of capacity is the annual cost of a kW of peaking capacity (ACC), or of another type of capacity less the fuel savings it will provide in other hours.

Benefit of marginal kW = Cost of marginal kW

$$(1\text{-EFOR}) \times CUE \times LOLH^* = ACC$$

Solving for CUE gives the value of CUE implicit in the reliability target.

$$CUE = [ACC / (1\text{-EFOR})]/LOLH^*$$

In any given year, when LOLH may not be equal to LOLH*, the annual marginal cost of capacity is:

$$LOLH * CUE = [ACC / (1\text{-EFOR})] \times [LOLH / LOLH^*].$$

Thus, the annual marginal cost of generation in any year is the annual cost of the least-cost capacity option, adjusted for its effective forced outage, times the ratio of expected to target LOLH.

Appendix B

Calculation of Economic Carrying Charges

The inputs and resulting first year economic carrying charges for hydro generation, gas turbine generation (both combined cycle and simple cycle) and transmission are shown in Table A below. In the case of transmission, the carrying charge used is a weighted average of carrying charges for five categories of transmission plant. The weights are the net plant in these categories.

Table A: Economic Carrying Charges and Corresponding Inputs

				CCGT /GT	Hydro Generation	Aggregate Trans-mission	Towers	Trans-Formers	Poles	Pole Structures & Conductors	Compress-ed Air Sys, Insulators
(1)	Type of Plant										
(2)	Book Life			30	60		65	45	35	50	30
(3)	Iowa Curve			S3	R4		R2.5	R3	R2	R3	S2.5
(4)	Tax Life			0	0		0	0	0	0	0
(5)	Income Tax Rate			0	0		0	0	0	0	0
(6)	Property Tax			0	0		0	0	0	0	0
(7)	Tax Basis			0	0		0	0	0	0	0
	Composite Incremental Cost of Capital	Share	Cost								
(8)	Debt	80%	8.60%								
(9)	Preferred Stock	0%	0.00%								
(10)	Common Equity	20%	7.60%								
(11)	Total Weighted Cost of Capital		8.40%								
(12)	Discount Rate (After-tax Cost of Capital)		8.40%								
(13)	Inflation			1.97%	1.97%		2.17%	2.17%	2.17%	2.17%	2.17%
(14)	Share of Transmission Costs					100%	10%	42%	7%	22%	18%
	First Year Carrying Charge			7.82%	6.67%	6.87%	7.69%	6.73%	7.45%	6.87%	6.50%

The tables below show the calculation of the first year's economic carrying charge for a CCGT. The purpose of the calculation is to find the first of a stream of annual charges (escalating at the rate of inflation net of technical progress for that type of plant) whose present value just equals the present value of the revenue requirements over the asset's lifetime. Table B shows the inputs for the calculation. Table C (two pages) shows the year-by-year revenue requirements associated with a $1000 investment.

There is an adjustment for assets that manifest dispersed retirements, rather than lasting exactly their average service lives. In that case, some of the plant is retired and needs to be replaced in every year of the service life (for portions that fail early), and beyond (for portions that last longer than the average service life). Iowa curves characterize the pattern of surviving plant over its life. In the example below, the curve is 30S3. The differences in survivors from one year to the next are the retirements (and the needed replacements).

The replacements prior to the average service life add to the present value of the revenue requirement, and those afterwards decrease it. Columns (16) and (17) shown below on the second page of Table C are used to calculate the increased present value of the revenue requirement resulting from dispersed retirement. The entries in column (16), labeled multiplier, represent the real discount factors for N years beyond the in-service date.[25] The cells in column (17) link to the dollars of the asset to be replaced in that year and multiply them by the difference in the present value of replacement in that year and a replacement at 30 years (the average service life). Summing column (17) yields the net increase in the present values of dispersed replacements. This value is converted to the equivalent present value of revenue requirement on line (2) of the first year carrying charge sheet (Table D), by multiplying it by the ratio of present value of revenue requirements (before adjustment for dispersed retirements) for a $1000 investment to the original $1000 investment. In this case that ratio is one.

Table B: Economic Carrying Charge Inputs – CCCT

ASSUMPTIONS

(1)	Type of Plant	CCGT							
(2)	Book Life		30	Years					
(3)	Iowa Curve		S3						
(4)	Tax Life		0	Years					
(5)	Income Tax Rate		0	Percent (Incremental combined state and federal rate)					
(6)	Property Tax		0	Percent (Based on gross plant)					
(7)	Tax Basis		0	Percent (Proportion of investment that is tax depreciable)					
	Composite Incremental Cost of Capital								
(8)	Debt		80		@	8.6	=	6.88	Percent
(9)	Preferred Stock		0		@	0	=	0.00	
(10)	Common Equity		20		@	7.6	=	1.52	
(11)	Total Weighted Cost of Capital							8.40	Percent
(12)	Discount Rate (After-tax Cost of Capital)							8.40	Percent
	Total return and calculations reflect:								
	The normalization of the difference between book and recovery-period depreciations.								
(13)	Inflation		1.9700	Percent (Inflation net of technical progress.)					

[25] Equal to 1 plus the discount rate divided by 1 plus the inflation rate applicable to the asset, all divided by the number of years from the in-service date.

Table C: First Page of Plant Lifetime Revenue Requirement Calculation - CCGT

Year	Mean Annual Survi- vors	Book Depreci- ation	Retire- ments	Book Depreci- ation Reserve	Net Book Invest- ment	Mean Tax Depreci- ation	Deferred Income Tax	Deferred Tax Reserve
		(1) / 30		(2) - (3) ^1	(1)-(4)		0.00% x [(6)-(2)]	Sum of (7) ^1
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	1000.000	33.333	0.000	0.000	1000.000	0.000	0.000	0.000
2	1000.000	33.333	0.000	33.333	966.667	0.000	0.000	0.000
3	1000.000	33.333	0.000	66.667	933.333	0.000	0.000	0.000
4	1000.000	33.333	0.000	100.000	900.000	0.000	0.000	0.000
5	1000.000	33.333	0.000	133.333	866.667	0.000	0.000	0.000
6	1000.000	33.333	0.100	166.667	833.333	0.000	0.000	0.000
7	999.900	33.330	0.100	199.900	800.000	0.000	0.000	0.000
8	999.800	33.327	0.200	233.130	766.670	0.000	0.000	0.000
9	999.600	33.320	0.500	266.257	733.343	0.000	0.000	0.000
10	999.100	33.303	1.000	299.077	700.023	0.000	0.000	0.000
11	998.100	33.270	1.500	331.380	666.720	0.000	0.000	0.000
12	996.600	33.220	2.400	363.150	633.450	0.000	0.000	0.000
13	994.200	33.140	3.600	393.970	600.230	0.000	0.000	0.000
14	990.600	33.020	5.200	423.510	567.090	0.000	0.000	0.000
15	985.400	32.847	7.100	451.330	534.070	0.000	0.000	0.000
16	978.300	32.610	9.600	477.077	501.223	0.000	0.000	0.000
17	968.700	32.290	12.400	500.087	468.613	0.000	0.000	0.000
18	956.300	31.877	15.600	519.977	436.323	0.000	0.000	0.000
19	940.700	31.357	19.300	536.253	404.447	0.000	0.000	0.000
20	921.400	30.713	23.100	548.310	373.090	0.000	0.000	0.000
21	898.300	29.943	27.100	555.923	342.377	0.000	0.000	0.000
22	871.200	29.040	31.300	558.767	312.433	0.000	0.000	0.000
23	839.900	27.997	35.300	556.507	283.393	0.000	0.000	0.000
24	804.600	26.820	39.300	549.203	255.397	0.000	0.000	0.000
25	765.300	25.510	42.800	536.723	228.577	0.000	0.000	0.000
26	722.500	24.083	94.500	519.433	203.067	0.000	0.000	0.000
27	628.000	20.933	50.400	449.017	178.983	0.000	0.000	0.000
28	577.600	19.253	51.600	419.550	158.050	0.000	0.000	0.000
29	526.000	17.533	52.000	387.203	138.797	0.000	0.000	0.000
30	474.000	15.800	51.600	352.737	121.263	0.000	0.000	0.000
31	422.400	14.080	50.400	316.937	105.463	0.000	0.000	0.000
32	372.000	12.400	48.600	280.617	91.383	0.000	0.000	0.000
33	323.400	10.780	45.900	244.417	78.983	0.000	0.000	0.000
34	277.500	9.250	42.800	209.297	68.203	0.000	0.000	0.000
35	234.700	7.823	39.300	175.747	58.953	0.000	0.000	0.000
36	195.400	6.513	35.300	144.270	51.130	0.000	0.000	0.000
37	160.100	5.337	31.300	115.483	44.617	0.000	0.000	0.000
38	128.800	4.293	27.100	89.520	39.280	0.000	0.000	0.000
39	101.700	3.390	23.100	66.713	34.987	0.000	0.000	0.000
40	78.600	2.620	19.300	47.003	31.597	0.000	0.000	0.000
41	59.300	1.977	15.600	30.323	28.977	0.000	0.000	0.000
42	43.700	1.457	12.400	16.700	27.000	0.000	0.000	0.000
43	31.300	1.043	9.600	5.757	25.543	0.000	0.000	0.000
44	21.700	0.723	7.100	-2.800	24.500	0.000	0.000	0.000
45	14.600	0.487	5.200	-9.177	23.777	0.000	0.000	0.000
46	9.400	0.313	3.600	-13.890	23.290	0.000	0.000	0.000
47	5.800	0.193	2.400	-17.177	22.977	0.000	0.000	0.000
48	3.400	0.113	1.500	-19.383	22.783	0.000	0.000	0.000
49	1.900	0.063	1.000	-20.770	22.670	0.000	0.000	0.000
50	0.900	0.030	0.500	-21.707	22.607	0.000	0.000	0.000
51	0.400	0.013	0.200	-22.177	22.577	0.000	0.000	0.000
52	0.200	0.007	0.100	-22.363	22.563	0.000	0.000	0.000
53	0.100	0.003	0.100	-22.457	22.557	0.000	0.000	0.000
54	0.000	0.000	0.000	-22.553	22.553	0.000	0.000	0.000

Table C: Second Page of Plant Lifetime Revenue Requirement Calculation

Year	Mean Net Invest- ment	Equity	Interest	Taxable Income	Income Tax	Property Tax	Revenue Require- ment	Multiplier ^2	Yearly Value of Dispersed Retirements ^3
	(1)-(4) -(8)	1.52% x (9)	6.88% x (9)	[(2)-(6)+ (7) + (10)] / (1-0.00%)	0.00% x (12)	0.00% x (1)	(2)+(7)+ (10)+(11)+ (13)+(14)		[(3)x(16)]- -[(3) x 0.159696] ^4
	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
1	1000.000	15.200	68.800	48.533	0.000	0.000	117.333	0.941	0.000
2	966.667	14.693	66.507	48.027	0.000	0.000	114.533	0.885	0.000
3	933.333	14.187	64.213	47.520	0.000	0.000	111.733	0.832	0.000
4	900.000	13.680	61.920	47.013	0.000	0.000	108.933	0.783	0.000
5	866.667	13.173	59.627	46.507	0.000	0.000	106.133	0.737	0.000
6	833.333	12.667	57.333	46.000	0.000	0.000	103.333	0.693	0.053
7	800.000	12.160	55.040	45.490	0.000	0.000	100.530	0.652	0.049
8	766.670	11.653	52.747	44.980	0.000	0.000	97.727	0.613	0.091
9	733.343	11.147	50.454	44.467	0.000	0.000	94.921	0.577	0.209
10	700.023	10.640	48.162	43.944	0.000	0.000	92.105	0.543	0.383
11	666.720	10.134	45.870	43.404	0.000	0.000	89.274	0.510	0.526
12	633.450	9.628	43.581	42.848	0.000	0.000	86.430	0.480	0.769
13	600.230	9.123	41.296	42.263	0.000	0.000	83.559	0.452	1.051
14	567.090	8.620	39.016	41.640	0.000	0.000	80.656	0.425	1.379
15	534.070	8.118	36.744	40.965	0.000	0.000	77.709	0.400	1.703
16	501.223	7.619	34.484	40.229	0.000	0.000	74.713	0.376	2.076
17	468.613	7.123	32.241	39.413	0.000	0.000	71.654	0.354	2.405
18	436.323	6.632	30.019	38.509	0.000	0.000	68.528	0.333	2.698
19	404.447	6.148	27.826	37.504	0.000	0.000	65.330	0.313	2.957
20	373.090	5.671	25.669	36.384	0.000	0.000	62.053	0.294	3.110
21	342.377	5.204	23.556	35.147	0.000	0.000	58.703	0.277	3.176
22	312.433	4.749	21.495	33.789	0.000	0.000	55.284	0.260	3.154
23	283.393	4.308	19.497	32.304	0.000	0.000	51.802	0.245	3.012
24	255.397	3.882	17.571	30.702	0.000	0.000	48.273	0.230	2.782
25	228.577	3.474	15.726	28.984	0.000	0.000	44.710	0.217	2.444
26	203.067	3.087	13.971	27.170	0.000	0.000	41.141	0.204	4.182
27	178.983	2.721	12.314	23.654	0.000	0.000	35.968	0.192	1.621
28	158.050	2.402	10.874	21.656	0.000	0.000	32.530	0.180	1.072
29	138.797	2.110	9.549	19.643	0.000	0.000	29.192	0.170	0.524
30	121.263	1.843	8.343	17.643	0.000	0.000	25.986	0.160	0.000
31	105.463	1.603	7.256	15.683	0.000	0.000	22.939	0.150	-0.477
32	91.383	1.389	6.287	13.789	0.000	0.000	20.076	0.141	-0.893
33	78.983	1.201	5.434	11.981	0.000	0.000	17.415	0.133	-1.229
34	68.203	1.037	4.692	10.287	0.000	0.000	14.979	0.125	-1.483
35	58.953	0.896	4.056	8.719	0.000	0.000	12.775	0.118	-1.653
36	51.130	0.777	3.518	7.291	0.000	0.000	10.808	0.111	-1.731
37	44.617	0.678	3.070	6.015	0.000	0.000	9.084	0.104	-1.741
38	39.280	0.597	2.702	4.890	0.000	0.000	7.593	0.098	-1.674
39	34.987	0.532	2.407	3.922	0.000	0.000	6.329	0.092	-1.561
40	31.597	0.480	2.174	3.100	0.000	0.000	5.274	0.087	-1.410
41	28.977	0.440	1.994	2.417	0.000	0.000	4.411	0.082	-1.220
42	27.000	0.410	1.858	1.867	0.000	0.000	3.725	0.077	-1.030
43	25.543	0.388	1.757	1.432	0.000	0.000	3.189	0.072	-0.841
44	24.500	0.372	1.686	1.096	0.000	0.000	2.781	0.068	-0.652
45	23.777	0.361	1.636	0.848	0.000	0.000	2.484	0.064	-0.499
46	23.290	0.354	1.602	0.667	0.000	0.000	2.270	0.060	-0.359
47	22.977	0.349	1.581	0.543	0.000	0.000	2.123	0.056	-0.248
48	22.783	0.346	1.567	0.460	0.000	0.000	2.027	0.053	-0.160
49	22.670	0.345	1.560	0.408	0.000	0.000	1.968	0.050	-0.110
50	22.607	0.344	1.555	0.374	0.000	0.000	1.929	0.047	-0.056
51	22.577	0.343	1.553	0.356	0.000	0.000	1.910	0.044	-0.023
52	22.563	0.343	1.552	0.350	0.000	0.000	1.902	0.042	-0.012
53	22.557	0.343	1.552	0.346	0.000	0.000	1.898	0.039	-0.012
54	22.553	0.343	1.552	0.343	0.000	0.000	1.894	0.037	0.000
	Present Value of Revenue Requirement at After-tax Average Cost of Capital						$1,000		
	Sum of Dispersed Retirements								$22.35

Table D: First Year Economic Carrying Charge - CCCT

(1)	Present Value of Revenue Requirements Related to Incremental $1,000 Investment	$1,000
(2)	Present Value Cost of Replacing Dispersed Retirements Related to Incremental $1,000 Investment ^5	$22.35
(3)	Total Present Value Cost Related to Incremental $1,000 Investment (1)+(2)	$1,022.35
(4)	Annual Economic Charge in Constant Dollars Related to Incremental $1,000 Investment ^6	$78.23
(5)	Annual Economic Charge Related to Incremental Investment [(4) / $1,000]	7.82%

^1 Off-set one year

^2 Multiplier = $\frac{\text{(1+Inflation)\^{}Year}}{\text{(1 + Discount Rate)\^{}Year}}$

^3 Yearly Value of Dispersed Retirements =

$$\left((3) \times \frac{\text{(1 + Inflation)\^{}Year}}{\text{(1 + Discount Rate)\^{}Year}} \right) \text{ minus } \left((3) \times \frac{\text{(1 + Inflation)\^{}Book Life}}{\text{(1 + Discount Rate)\^{}Book Life}} \right)$$

^4 $0.159696 = \frac{\text{(1 + Inflation)\^{}Book Life}}{\text{(1 + Discount Rate)\^{}Book Life}}$

^5 $22.35 = \frac{\text{Sum of Dispersed Retirements x PV of Revenue Requirements}}{1{,}000}$

^6 The appropriate charge is the first year's charge which rises annually at the rate of inflation net of technological progress. The first year charge is calculated using the following formula:

$$\boxed{AC^T = K \times (R-J) \times (1+J)^{(T-1)} \times [\,1 / [1 - [(1 + J)/(1 + R)]^N\,]\,]}$$

Where:
AC^T = Annual Charge in Year T
T = Year (For first year = 1)
K = Total PV of Original Investment ($1022.35)
R = Discount Rate (8.4000%)
J = Inflation Rate Net of Technical Progress (1.97%)
N = Book Life (30 years)

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July 26, 2006

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road
P.O. Box 21040
St. John's, Newfoundland & Labrador
A1A 5B2

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Order No. P.U. 14 (2004)

The Board in Order No. P.U. 14(2004) page 166, item 11, ii, ordered that Hydro file on or before June 30, 2006 a system-wide marginal cost study, which Hydro filed on June 21, 2006. Enclosed please find fifteen (15) copies of a follow-up report entitled "Implications of Marginal Cost Results for Rate Class Allocation and Rate Design", and a memo from National Economic Research Associates Inc. updating results from the original report.

Yours truly,

Geoffrey P. Young
Legal Counsel

GPY/jc
Enclosures

cc: Mr. Peter Alteen, Newfoundland Power Inc.
Mr. Thomas J. Johnson, Consumer Advocate
Mr. Joseph S. Hutchings, Q.C., Poole Althouse

July 2006

Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design

Prepared for

Newfoundland and Labrador Hydro

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Executive Summary

The efficiency of electric rates in Newfoundland has been discussed in several recent rate cases. During Newfoundland and Labrador Hydro's (NLH) last hearing, time-of-day (TOD) and seasonal rates were identified as issues. NERA was engaged to conduct a marginal cost study of generation and transmission service on NLH's island integrated system,[1] and to discuss the implications of the results for NLH's rates for Newfoundland Power (NP) and industrial customers. This report describes the implications of the marginal cost results for NLH's class revenue allocation and rate structures, and summarizes NERA's recommendations.

Rates that are going to be in effect for several years should take into consideration the likely levels of marginal costs over that entire period. Marginal costs levels over an even longer period are sometimes used in the rate design process to give consumers longer-term price signals and to avoid the disruptive effects of rate designs that change substantially from rate case to rate case. The marginal cost structure and levels (in 2007 dollars) based on current load forecasts and expansion plans, expected fuel prices, and normal water conditions are quite stable over the period 2007-2020. This report primarily uses the average marginal costs over the period 2007-2011 as the basis for the rate design evaluations.

The marginal cost analysis indicates that there is no seasonal, weekly or daily variation in NLH's marginal energy costs because of the operation of the hydro resources. An additional kWh of energy consumed in a give hour generally leads to an additional kWh of hydro production in that hour (plus marginal energy losses), which is then replaced by thermal generation at Holyrood at a later time. Under most hydrological conditions, this replacement energy is produced at times when the thermal units are operating at high levels (when heat rates are the most efficient). Thus, the cost of fuel for Holyrood, its heat rate, and marginal energy losses define marginal energy costs in each year. As a result, there is no marginal cost basis for seasonal or TOD energy charges.

Generation capacity marginal costs vary by month due to differences in loss-of-load probability, and within a month based on differences in hourly probability of peak. However, because of expected high fuel costs, the net cost of adding generation capacity is quite low after accounting for energy savings the capacity will produce in hours other than peak hours. Similarly, marginal transmission costs vary across seasonal and hours with transmission system probability of peak; however, NLH's mature transmission system requires little expansion to accommodate forecast growth. As a result, the marginal generation and transmission capacity costs would support only small time-differentiated winter demand charges (and no demand charges in non-winter months).

Under NLH's current planning assumptions, marginal generation capacity costs will start to rise significantly after 2012. Even before that date, if fuel prices fall significantly below current forecast levels, net marginal generation capacity costs will be higher than the base case, and

[1] *Final Report: Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission* (May 2006).

marginal energy costs will be comparably lower.[2] These situations would call for larger winter demand charges with greater TOD differentiation.

A comparison of the base case marginal cost estimates (averaged for 2007-2011) to current rates (forecast 2007 rates at current rate structures) reveals that:

- The two-block energy charge for NP, with the tail block set near marginal cost, is nearly optimal; however the demand charge is well above marginal capacity cost and should ideally be time-differentiated and applied only in winter months.

- The rate structure for Industrial firm customers does not give efficient price signals; the energy charge is significantly below marginal cost and the demand charge significantly above marginal cost and applied to all months. Smaller, time-differentiated, winter-only demand charges would give more efficient price signals.

- The Non-firm Industrial (energy-only) rate set at approximately marginal energy cost is reasonable; however, if firm demand charges are significantly reduced, there will be little incentive to participate in this optional program. Interruptibility does not have much planning value as long as capacity costs remain low, but curtailable loads can provide important operational benefits and new interruptible programs that pay/credit for actual interruptions by both industrial customers and NP may be warranted.

If NLH were to allocate its total generation and transmission revenue requirement to classes based on an equal percentage of marginal cost revenues, industrial customers would receive a 13.5-percent increase and NP a 2.1-percent reduction. It might be appropriate to temper this cost shift by using information about the relative demand elasticities of the two classes.[3]

NERA recommends that NLH consider adopting a rate structure for both NP and Industrial customers that reflects the marginal cost structure. Each rate would have a two-block energy charge, with the tail block set at marginal cost. The low first block would be used to reconcile marginal costs to the class revenue requirement, since charging marginal energy cost for all kWh would produce too much revenue. The first block size for Industrial customers could be set on a customer-specific basis to control bill impacts. Both rates would have winter on-peak and off-peak demand charges. Although small, the demand charges would establish the correct structure, and demand charges would rise in future years with marginal capacity costs.

NERA also recommends that NLH explore new interruptible options that would reward curtailable loads for operational savings provided when curtailments are called, and reflect the fact that controlled loads are valuable on an operational basis (such as in poor hydro years, and during severe weather or unit outages) although they currently have little value on a planning basis.

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[2] This situation is evaluated in a separate memo to NLH dated June 28, 2006.

[3] NERA did not have such elasticity information. Although industrial customers are generally considered to be fairly elastic, NP has quickly responded to the current rate structure (introduced in January 2005) with its two-block energy charges and demand charges.

Finally, any proposal for rate structures should only be made after a careful analysis of impacts such as utility revenue adequacy, customer load changes, implementation and administrative costs, and bill impacts.

I. Introduction

In jurisdictions where economic efficiency is considered to be an important objective of electricity rates, estimates of the marginal cost of service are typically used, along with other information, to set class revenue requirements, rate structure, and the level of each charge. In Order No. P.U.14 (2004), the Board of Commissioners of Public Utilities of Newfoundland and Labrador (the Board) directed Newfoundland and Labrador Hydro (NLH) to file a marginal cost study. The results of that study, undertaken by NERA Economic consulting (NERA), are summarized in a separate report. This report describes the implications of the marginal cost results for NLH's class revenue allocation and rate structures, and summarizes NERA's recommendations. Because the marginal cost study was limited to an analysis of generation and transmission costs of the Island interconnected system, this report's scope is limited to NLH's rates for Newfoundland Power (NP) and the industrial class.

NLH's marginal costs of generation vary from year to year, as the Island system adjusts its resources to meet growth in energy requirements and peak demand. Because NLH does not have access to support from neighboring utilities in emergencies and cannot sell off-system energy and capacity that is temporarily in excess of local requirements after the addition of a new resource, marginal generation costs fluctuate in cycles. Rates that are going to be in effect for several years should take into consideration the likely levels of marginal costs over that entire period. Marginal costs levels over an even longer period are sometimes used in the rate design process to give consumers longer-term price signals and to avoid the disruptive effects of rate designs that change substantially from rate case to rate case.[4]

To estimate NLH's long-term marginal costs[5] requires making assumptions about several critical factors, including future fuel prices, load growth, availability of natural gas, hydrological conditions, construction of a Labrador Interconnect, the availability of indigenous resources such as wind and hydro, and future generation technology. The NERA marginal cost study looked in depth at the effects of the Labrador Interconnect and alternative fuel price scenarios. However, this report is based on the results of the Scenario One case, without the Labrador Interconnect

[4] The view that rates should reflect very long-term marginal costs is not universally held; in fact, the move to market-based prices and other forms of real-time prices is designed to provide customers with up-to-date signals about the current marginal costs of supplying their electricity needs.

[5] The expression "long-term marginal cost" refers to an analysis that looks out over many years and reflects changes in loads, capacity, resource mix and fuel prices over time. The expression "long-run marginal cost" technically refers to the marginal costs of an optimally-configured system in demand/supply equilibrium, rather than to costs estimated for a period of years.

and with base case fuel prices.[6] The marginal cost structure and levels (in 2007 dollars) are quite stable over the period 2007-2020. This report primarily uses the average marginal costs over the period 2007-2011 as the basis for the rate design evaluations.

The marginal cost estimates are based on current load forecasts and expansion plans, expected fuel prices and normal water conditions. In any given year, conditions might be significantly different, resulting in short-run marginal costs (including shortage costs) that deviate from expected long-term marginal costs. For example, reliability (short-run generation capacity cost) is very sensitive to water availability. Furthermore, in any given hour, system emergencies might result in short-lived capacity shortages that make short-run marginal costs (including shortage costs) significantly higher than long-term marginal costs. Other than implementing real-time pricing (or some variant), utilities typically base rate design on the patterns of expected costs over the period the rates are expected to be in effect, or for some longer period. The recommendations in this report take that approach, with discussion of possible interruptible options that might help deal with short-term deviations from long-term marginal costs.

In developing rate recommendations for NLH, the NERA team began by looking at what a pure marginal cost revenue allocation and rate design would look like. Such rates would produce more revenue than needed to meet NLH's revenue requirement, so the team then analyzed how to efficiently close the gap between marginal cost revenues and revenue requirement (defined as revenues for 2007 based on current rates adjusted for historical and current fuel riders). The team then analyzed several efficient rate structure options, taking into consideration other factors likely to be important in the Newfoundland context.

II. Marginal Cost Revenues and the Marginal Cost Revenue Gap

The first step in the development of marginal cost-based rates is to calculate marginal cost revenues – the revenue that would be produced by charging each class marginal costs as rates. Marginal cost revenues can then be compared to forecast revenues at current rate structures to determine the total gap between marginal cost revenues and this measure of revenue requirement, as well as the share of marginal cost of service being paid by each class. Because marginal generation capacity costs (in 2007 dollars) vary over the 23-year period covered by the marginal cost study, this comparison was computed for three periods: 2007-2011, 2012-2000, and 2021-2025. For each period the annual marginal costs were averaged.

Table 1 shows average marginal cost revenues for the three periods compared to forecast 2007 revenues at current rates for NLH's wholesale utility and industrial customer classes. In order to make the revenues comparable, the current rate revenue forecast for NLH customers excludes historic and current fuel riders, assuming instead that NLH customers have the expected 2007 fuel costs incorporated into their rates. In addition, all revenues collected from NP to cover the NLH rural distribution subsidy are excluded from the current rate revenue forecast.

[6] The current expectation is that the Interconnect would be operational no earlier than 2014. Rate structures could be redesigned (and customers prepared for the changes) well before then.

Current rates, defined this way, cover about two-thirds of NLH's marginal costs for these two classes in total, with NP paying a somewhat higher percentage of its marginal cost of service than the industrial class. Ideally each class should pay revenues sufficient to cover its marginal cost revenues.[7] However, in the case of a utility such as NLH with significant low embedded cost hydraulic capacity (holding down revenue requirements) and high-cost energy at the margin (raising marginal cost revenues), this is not feasible. Economic theory suggests that deviations from marginal cost pricing necessary to close the gap should take into account the relative elasticity of demand of the various classes (in the case of rates charged to NP, this includes both NP's responsiveness to prices the company pays for wholesale purchases and the price elasticity of NP's retail customers), with larger adjustments made for classes with lower price elasticities of demand. In the absence of a study of the relative elasticity of demand by class, a standard approach is to set target class revenue at the same percent of marginal cost revenues (the so-called "Equi-Proportional Marginal Cost" or "EPMC" approach). This suggests that, in a revenue neutral rate case and without information suggesting that industrial customers are more price elastic than NP and its customers, the industrial class should see a significant increase in revenue requirement, and NP a decrease.

[7] Actually, because customers, not classes, make electricity consumption decisions, it is customers who should pay at least their marginal cost of service. But since most customers are making consumption decisions at the margin (rather that deciding whether to use electricity at all or whether to relocate to someplace with lower electricity prices), it is most important that prices for *marginal consumption* cover marginal costs.

Table 1: Scenario One—Average Marginal Cost Revenues for Three Periods Compared to Forecast (Adjusted) Revenues at Current Rate Structures

		Industrial	Newfoundland Power	Total
			(2007 $)	
				(1)+(2)
		(1)	(2)	(3)
(A)	Forecast 2007 Revenues at Current Rate Structures	45,425,834	292,129,343	337,555,177
(B)	Average Marginal Cost Revenues			
	2007-2011	78,850,145	437,414,470	516,264,615
	2012-2020	80,228,548	445,846,169	526,074,717
	2021-2025	88,868,566	496,964,967	585,833,533
(C)	Revenue Gap (B)-(A)			
	2007-2011	33,424,311	145,285,127	178,709,438
	2012-2020	34,802,714	153,716,826	188,519,540
	2021-2025	43,442,732	204,835,624	248,278,356
(D)	2007 Revenues at Current Rate Structures as Percent of Marginal Cost Revenues			
	2007-2011	58%	67%	65%
	2012-2020	57%	66%	64%
	2021-2025	51%	59%	58%

In the remainder of this report, we focus on the marginal cost revenues in the period 2007-2011 as the basis for illustrative revenue requirements and rate structures. Marginal cost revenues for the 2012-2020 period are within five percent of those for 2007-2011, and 2021-2025 is too distant a period (and the marginal costs for that period too uncertain) to form a reasonable basis for near-term rates.

Table 2 shows the effects of class revenue requirements set so that the total covers the forecast 2007 revenue requirement and each class pays 65 percent of its marginal cost revenues. The increases implied for the industrial class might lead to loss of some of these loads.

Table 2: Class Revenue Changes Using EPMC (Based on 2007-2011 Marginal Costs)

		Industrial	Newfoundland Power	Total
			(2007 $)	
		(1)	(2)	(3)
(A)	Forecast 2007 Revenues at Current Rate Structures	$45,425,834	$292,129,343	$337,555,177
(B)	EPMC Revenues using 2007-2011 Marginal Costs	$51,555,489	$285,999,688	$337,555,177
(C)	Required Increase	$6,129,655	-$6,129,655	$0
(D)	Percentage Increase	13.5%	-2.1%	0.0%

III. Marginal Cost Rate Structures

Even more important for economic efficiency than class revenue allocation is rate structure. Most electricity consumers are not making electricity-related consumption and investment decisions based on their total bill (which reflects revenue allocation), but rather on the price of marginal consumption (which depends on rate structure):

- What will I save if I reduce my peak monthly (or annual) demand?
- What will I save if I reduce my over all energy use?
- What will I save if I shift load from peak to off-peak hours?

Table 3 shows Scenario One average marginal energy and capacity costs over the period 2007-2011 compared to current energy and demand charges (adjusted as described above) for the three classes of large customers.

Table 3: Comparison of Forecast Current 2007 Rate Structures and Average 2007-2011 Marginal Costs

		Energy 2007$/kWh	Demand 2007$/kW-mo.		
			Winter		Non-Winter
			Peak	Off-Peak	
Marginal Costs		$0.0847	$ 1.67	$ 0.43	$0.00
			All months (12-month ratchet)		
NP Rates	1st Block	$0.0054	$6.97		
	2nd Block	$0.0877			
Industrial Rates (Firm)		$0.0384	$6.38		
Non-Firm Industrial Rate		$0.0877	(Not applicable)		

Period Definitions (Newfoundland time)
Winter: Jan – Mar and Dec
Peak: Weekdays, 7:00 am to noon & 4:00 pm to 8:00 pm.
Off-Peak: All remaining hours.

Non-Winter: April – November
No time-of-day differentiation.

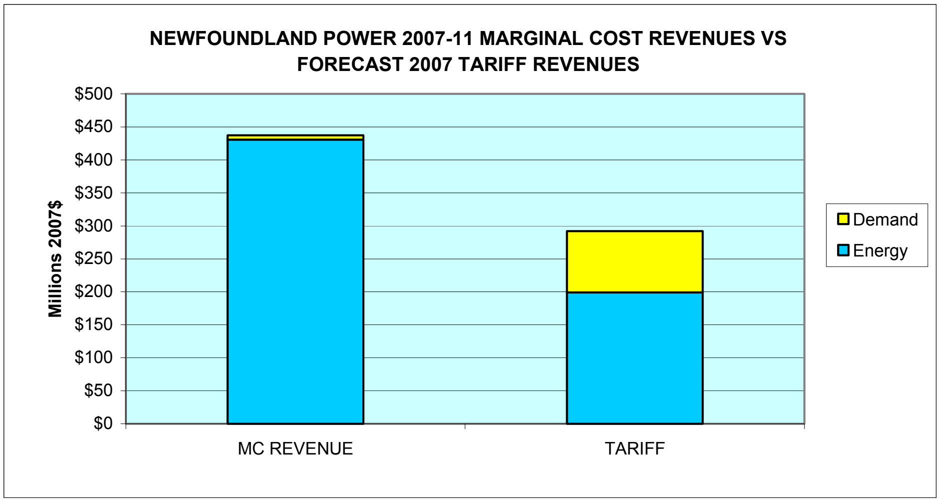
Looking just at the marginal cost relationships (but ignoring the need to close the marginal cost revenue gap) suggests that rate structures should change in the following ways:

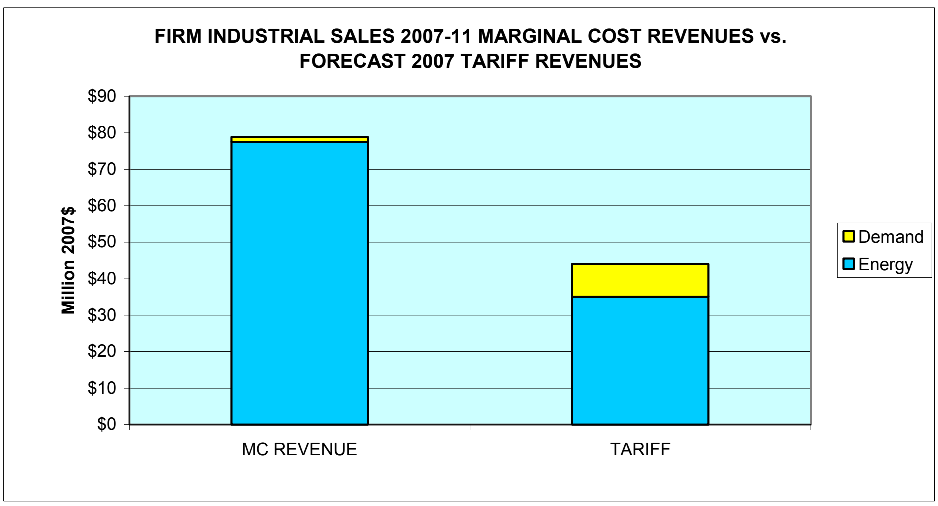
- The NP tail-block energy charge should be slightly lower and the demand charge much lower.[8]
- Firm industrial rates should have much higher energy charges and much lower demand charges.
- Interruptible rates should have slightly lower energy charges.

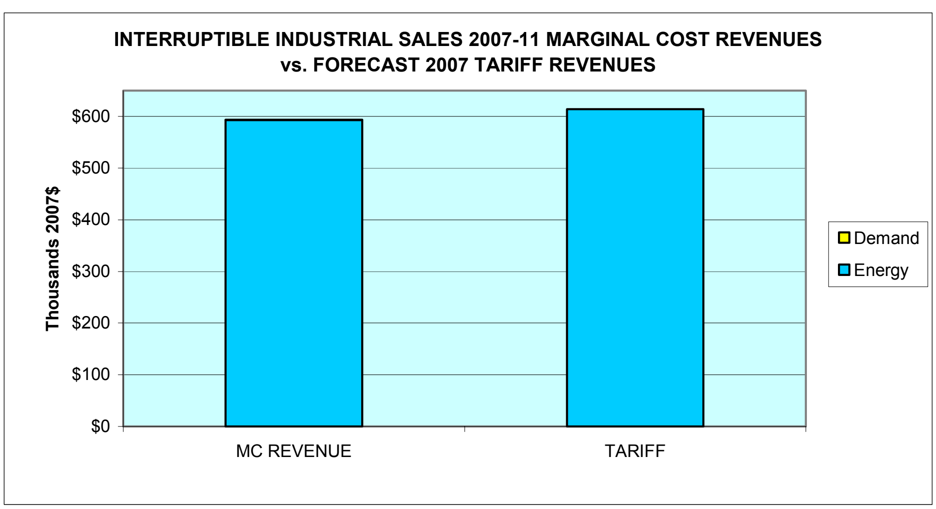
Figure 1 compares current rates and marginal costs from the perspective of revenues, and highlights the different shares of energy and demand elements.

[8] The size of the first block should remain sufficiently small so that NP's monthly energy use does not fall below that amount. This keeps the marginal price at the level of the tail block.

Figure 1: Comparison of Components of Marginal Cost Revenues and Forecast 2007 Rate Revenues







IV. Illustrative Marginal Cost-Based Rates

Table 1 above shows that charging full marginal costs for all units sold would produce too much revenue. Some components of rates must be reduced to ensure that each class generates revenues equal to its allocated revenues. For efficiency, the downward adjustments should be made to the elements of the rate to which customers are least price-responsive. In retail rates for small customers, this often means setting fixed charges (customer charges and charges assessed on the basis of contract capacity) below marginal cost. In the case of NLH's industrial customers and NP, the options include (1) use of blocked charges that discount early blocks but keep the tail block at or close to marginal cost (as in the current NP rate), and (2) differential reductions in demand and/or energy rates based on assumed differences in price responsiveness to these charges.[9]

A. Options for NP Rates

The current rate structure for NP includes a two-block inverted energy charge and a newly-implemented demand charge assessed on the highest monthly demand (less credits for NP's generation) in the winter season (November – March).[10] The energy charge is lower for the first 250,000 MWh per month, and higher for all additional energy. The actual first- and second-block charges vary with application of the Rate Stabilization Plan (RSP), which provides for annual adjustments for variations in hydraulic production, fuel costs, load and rural rates.

Implementation of the demand charge in this rate in January 2005 has triggered response by NP. The company has signed up approximately an additional 6 MW of curtailable load that can switch to the customers' backup generation, experimented with voltage reductions, and ensured better timing of their own hydro generation availability in and around peak days. NP has also undertaken a number of measures to improve customer awareness of conservation opportunities.[11]

Clearly NP is responsive to the new demand charge. However, since the size of the current demand charge is significantly above marginal generation and transmission capacity costs, NP may well be over-investing in demand-reducing measures.[12] As Figure 1 shows, the vast majority of the marginal cost of serving NP is marginal energy costs. Each additional kWh supplied adds nearly 8.5 cents in costs, and each kWh conserved saves about 8.5 cents. NLH does incur transmission and generation capacity costs when peak load grows, but the cost of the generation capacity added is nearly offset by the energy savings the new capacity creates. Thus the critical price signal that NP needs to see in developing its retail rates and its demand management programs is the high marginal energy cost.

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[9] Quantitative information on the relative elasticity of NP and industrial customers with respect to energy and demand charges is not available.

[10] The actual calculation of billing demand includes weather adjustments and incorporates a minimum billing demand based on test-year assumptions.

[11] Information provided by NP on June 6, 2006.

[12] These measures also potentially save distribution costs on the NP system itself, but this effect is beyond the scope of NERA's assignment.

Because marginal capacity costs are so low, an obvious choice for the NP rate is a structure consisting entirely of energy charges, with the tail block set at expected marginal energy cost (as the NP rate did until 2005).[13] The two-block feature is a convenient way to reconcile marginal costs to the class revenue requirement. The price of the first block could be adjusted to eliminate the excess revenue that would result if all kWh were charged at the full marginal cost level.

Table 4 shows illustrative energy-only rates under two revenue requirement scenarios – forecast 2007 revenues at current rate structures and a lower revenue requirement that would result from an EPMC allocation of the total forecast 2007 revenue requirement. This rate structure has the advantage of extreme simplicity, and should be easily implementable, since it is basically a return to the pre-2005 rate structure. The shading indicates charges equal to marginal cost.

Table 4: Illustrative NP Energy-Only Tariffs

	Energy-Only Rates	
	First Block Price (2007$ per kWh)	Second Block Price (2007$ per kWh)
With Class Revenue Equal to:		
Forecast 2007 Revenue	$0.0386	$0.0847
EPMC Revenue using 2007-2011 Average Marginal Costs	$0.0366	$0.0847

Notes:
The first block is 250,000 MWh per month.
Indicates price equal to marginal cost.

An alternative would be to keep the energy tail-block price at marginal cost, introduce a time-differentiated demand charge at full marginal cost and, again, reconcile to the class revenue requirement by adjusting the price of the first energy block. The resulting demand charges are quite small, but their presence in the rate structure would preserve this element for future years when marginal capacity costs may be higher. The implementation of the time-differentiated demand charges would require only minor changes to the billing system. An appropriate definition of billing demand in this rate structure would be the highest 15-minute demand in the winter season (November – March), with separate calculations for peak and off-peak billing demand. There would be no demand charges applicable in the non-winter months.[14]

[13] Prior to 2005, the NP rate was an energy-only rate, but without blocking.

[14] Non-winter capacity costs are negligible for the foreseeable future.

Standard marginal-cost based demand charges are applied to billing demand defined by metered demand in the billing month. However, given the isolation of the NLH system and the dominance of NP's load, it makes sense to charge NP on the basis of its peak winter demand. Unlike the current demand charge, there would be no demand charges assessed in the non-winter months. This makes the demand charges more transparent to both NP and its customers (to the extent the wholesale rate structure is reflected in retail rates) and emphasizes the importance of winter peak load reductions relative to load reductions in other months.

This energy/demand structure, although with a much smaller demand charge than current rates, has the advantage of preserving a demand charge in the rate structure in preparation for the likely structure of marginal costs in the future, when marginal capacity costs are likely to be larger.[15] The energy/demand rate structure would give full, efficient marginal cost signals for marginal consumption in both the energy and demand components.

Table 5 shows what the charges would be with this demand/energy structure, again for both forecast 2007 and EPMC class revenue requirements.

Table 5: Illustrative NP Energy/Demand Tariffs

	Energy/Demand Rates			
	First Block Price	Second Block Price	Winter Peak Demand Charge	Winter Off-Peak Demand Charge
	(2007$ per kWh)		(2007$ per kW/mo)	
With Class Revenue Equal to:				
Forecast 2007 Revenue	$0.0355	$0.0847	$1.67	$0.43
EPMC Revenue using 2007-2011 Average Marginal Costs	$0.0334	$0.0847	$1.67	$0.43

Notes:

The first block is 250,000 MWh per month.

Billing demand would be highest 15-minute demand in the current winter season (Dec.-Mar.), with the December calculation taking into account the previous Jan. - Mar.

Indicates price equal to marginal cost.

[15] Scenario One marginal capacity costs are expected to be nearly ten times higher in the post-2020 period than in 2007-2011. If the Labrador Interconnect is constructed (possibly as early as 2014), the market-based marginal capacity cost will also be higher than near-term Scenario One estimates for 2007-2011.

B. Options for Industrial Rates

The current industrial rate structure consists of a substantial demand charge applied to billing demand (defined by complex formulae in the individual industrial customer contracts[16]) and a flat energy charge that is subject to the RSP adjustment. As Table 3 shows, the energy charge is significantly below marginal cost and the demand charge is significantly higher than marginal cost.

The same two options discussed for the NP rate also make sense for NLH's industrial customers. Given the critical importance of marginal energy costs, a two-block energy-only structure could be developed, with the tail block set at marginal cost and the first block set sufficiently below marginal cost to reconcile to the class revenue requirement. The first block should be defined at a size small enough that all industrial customers consume significant amounts of energy in the higher-priced tail block each month.

Moving to an energy-only block structure for the industrial customers might have significant bill impacts for individual customers within the class. This problem could be eliminated by implementing a customer-specific first-block size that keeps customers' bills unchanged at the previous year's consumption level (or unchanged except for the percent change in the class' overall revenue requirement).[17] This approach is feasible because of the small number of customers in the class. New customers could be assigned a first-block size based on the average of the first-block sizes of all similar-sized customers in the class. Table 6 illustrates this rate structure (without identifying customer-specific block sizes) for forecast 2007 revenues and EPMC revenues.

The energy-only block structure would eliminate the incentive for industrial customers to sign up for interruptible service for a portion of their load, unless there were separate modifications of the interruptible rate. Currently, energy supplied on a curtailable basis is charged at the estimated marginal energy cost – in most cases the cost of energy provided from Holyrood. Interruptible loads do not incur a demand charge. Because the current interruptible rate would become the standard industrial tail-block rate for firm service, an energy-only rate design would not provide any cost savings to customers willing to take interruptible service. This issue is discussed in Section C below.

[16] A typical definition is the highest of (1) the contract demand ("Amount of Power on Order"), (2) 75 percent of the prior's year's contract demand or (if lower) the prior year's contract demand less 20,000 kW, and (3) highest metered demand taken in that calendar year (net of interruptible demand); with adjustments for supply interruptions, strikes and other *force majeure* events.

[17] Procedures might be developed to adjust the block size with a major change in an industrial customer's level of operations.

Table 6: Illustrative Industrial Energy-only Tariffs

	Energy-Only Rates	
	First Block Price (2007$ per kWh)	Second Block Price (2007$ per kWh)
With Class Revenue Equal to:		
Forecast 2007 Revenue	$0.0290	$0.0847
EPMC Revenue using 2007-2011 Average Marginal Costs	$0.0415	$0.0847

Notes:
The first block price in both structures is based on assumed total *class* block size of 50,000 MWh per month, or an average of 4,500 MWh per month per customer. The block size per customer could be customized to control adverse bill impacts.

(shaded) Indicates price equal to marginal cost.

A second option for industrial rate structure would be the demand/energy structure described for the NP rate. It would have time-differentiated demand charges in the winter, set at marginal cost and applied to billing demands reflecting current winter peak demand (or in the case of December, taking peak demand in the previous January-March into account), and a blocked energy charge with the tail block set at full marginal cost. Again, the first-block size could be customer-specific to reduce or eliminate adverse bill impacts. Table 7 illustrates the charges under this approach, using estimates of the new billing demands by period.

Table 7: Illustrative Industrial Energy/Demand Tariffs

	Energy/Demand Rates			
	First Block Price	Second Block Price	Winter Peak Demand Charge	Winter Off-Peak Demand Charge
	(2007$ per kWh)		(2007$ per kW/mo)	
With Class Revenue Equal to:				
Forecast 2007 Revenue	$0.0277	$0.0847	$1.67	$0.43
EPMC Revenue using 2007-2011 Average Marginal Costs	$0.0399	$0.0847	$1.67	$0.43

Notes:
The first block price in both structures is based on assumed total *class* block size of 50,000 MWh per month, or an average of 4,500 MWh per customer.
The block size per customer could be customized to control adverse bill impacts.

Billing demand would be highest 15-minute demand in the current winter season (Dec.-Mar.), with the December calculation taking into account the previous Jan. - Mar.

Indicates price equal to marginal cost.

This structure has the same efficiency benefits described for its use in the NP rate: the marginal price for energy and demand is equal to marginal cost; only modest implementation costs are likely; and the structure preserves the demand charge component which is likely to increase in importance in future years. This structure would maintain some incentive to participate in the interruptible program, but that incentive would be much reduced compared to current rates because the avoided demand charges would be significantly lower.

C. Options for Interruptible Rates

The results of the marginal cost study imply that interruptible load has little value on a planning basis, other than avoided energy costs when curtailments are called. However, interruptible load may have important benefits on an operational basis, which are not captured in a long-term marginal cost analysis. Such benefits could include avoided outages in years with low water or prolonged unit outages and other operational cost savings.

If industrial and NP rates are restructured to eliminate or significantly reduce demand charges, the benefits of participating in the interruptible program will fall dramatically. An alternative that would provide efficient incentives to participate would be to compensate interruptible load for the benefits provided at the time of interruptions.[18] The payments (or credits) could be based on the estimated value of avoided outages, and paid on the basis of kWh curtailed. Curtailable loads under the direct control of NLH's dispatchers might also be paid/credited an amount that reflects the option value of their immediate curtailability. Curtailable loads with characteristics capable of providing spinning reserves could be compensated for serving this function at the avoidable cost. This approach is similar to some of the demand-response programs being implemented by ISOs in the US. These programs compensate curtailable loads controlled by the system operator for operational savings they provide.

V. Impacts of Rate Structure Changes

Any analysis of alternative rate structures should take into consideration impacts such as utility revenue adequacy, customer load changes, implementation and administrative costs, and bill impacts.

A. Revenue Adequacy

Each of the rate structures discussed above could incorporate the RSP, which protects NLH's revenues from variations in water conditions, loads, and fuel costs. Modifications of the RSP's application could improve the efficiency of total prices. For example, adjustments due to changes in load or water conditions could be applied only or primarily to the first-block prices, and changes in fuel costs applied only or primarily to the tail-block price, thereby keeping that price closer to marginal cost.

B. Customer Load Changes

The purpose of marginal cost-based rate structures is to send efficient price signals to guide customer energy decisions (and therefore utility investment and system operation). The proposed elimination or significant reduction in demand charges is likely to encourage much more attention by NP and the industrial customers to demand-side management that affects their overall energy consumption, and less on mechanisms that flatten their loads. However, many of the energy-conserving technologies likely to be employed (such as added insulation, more efficient lighting and motors, and use of alternative fuels) will also cut demand in peak periods. Consequently, significant reductions in system load factor are unlikely. However, it would be prudent to discuss this issue with NP and the industrial customers before implementing a major change in rate structure.

C. Implementation and Administrative Costs

NLH has the metering in place necessary to implement the rate structures discussed above. Moderate changes in the billing system might be required for some of them, but this is not likely

[18] For example, NP might install radio-controlled switches on selected appliances of their customers, enabling these appliances to be cycled off for specific periods when NLH calls for curtailments.

to be a serious impediment. The small number of customers involved means that providing information on the new rates and counseling customers on what they can do to take advantage of the new structures are not likely to be onerous tasks.

D. Bill Impacts

A key benefit of the two-block energy charge structure for the industrial class is that customer-specific first-block sizes can be defined to protect customers, if necessary, from sudden changes in their bills, while still giving all customers efficient prices for marginal use. Adverse bill impacts on NP are expected to be unlikely, given that the class' revenue requirement would remain unchanged, if the rates are neutral by class, and decline if EPMC is applied. The impact on NP's retail customers will depend upon the extent to which NP reflects the new wholesale rate structure in its rates to retail customers.

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Memo

To: **Newfoundland & Labrador Hydro**
Date: June 28, 2006
From: Hethie Parmesano and William Rankin
Subject: **Revised Test 1 Marginal Cost Results and Rate Design Implications**

At your request, we have calculated a new set of marginal generation costs using the "Test 1" fuel price assumption mentioned in our original report—50 percent of NLH's Spring 2006 fuel price forecast.[1] This memo provides the results of that exercise, and its implications for rate structure.

Marginal Generation Capacity Costs

Dramatically lower fuel price forecasts change the generation expansion plan.[2] Two of the new hydro units in the base case plan are no longer cost-effective, and the combined cycle combustion turbine (CCCT) is moved up instead. The table below compares the two expansion plans.

[1] "NLH Fuel Prices Spring 2006.xls" provided by NLH in April 2006.

[2] The generation expansion plans (and associated LOLH and plant operation information) used in both the original marginal cost analysis and the Test 1 analysis described in this memo, were developed by NLH using a slightly earlier fuel price forecast that was lower in the early years and slightly higher (by about one percent) in the later years than the April 2006 forecast.

Table 1: Comparison of Expansion Plans

	Current	Test 1 (50 Percent Fuel Forecast)
2007		
2008	*25 MW Wind Farm (91 GWh)*	*25 MW Wind Farm (91 GWh)*
2009		
2010		
2011		
2012	*25 MW Wind Farm (91 GWh)*	*25 MW Wind Farm (91 GWh)*
2013	*25 MW Wind Farm (91 GWh)*	*25 MW Wind Farm (91 GWh)*
2014		
2015	*Island Pond (186 GWh)*	*Island Pond (186 GWh)*
2016		
2017		
2018	*Round Pond (128 GWh)*	*125 MW CCCT (986 GWh)*
2019	*Portland Creek (77.3 GWh)*	
2020	*125 MW CCCT (986 GWh)*	
2021		
2022		
2023		
2024		
2025		

The combination of the new expansion plan and lower fuel costs has several effects on the marginal cost of generation capacity. First, the energy savings provided by the remaining hydro unit in the plan (Island Pond) are reduced because of lower fuel prices, so the net annual cost of the new hydro capacity, including losses, is higher in the Test 1 case compared to the base case ($158.89 per kW compared to $6.41 per kW).

Second, the change in timing alters the pattern of annual loss-of-load hours (LOLH) after 2018. The ratio of expected-to-target LOLH is multiplied by the annualized net cost of the marginal capacity source to determine the annual cost in a give year. The table below compares the patterns of annual LOLH in the base case and Test 1.

Table 2: Annual LOLH

	Base	Test 1 (50 Percent Fuel Forecast)
2006	0.44	0.44
2007	0.51	0.51
2008	0.61	0.61
2009	0.64	0.64
2010	0.93	0.93
2011	1.31	1.31
2012	2.88	2.88
2013	2.86	2.86
2014	2.77	2.77
2015	2.61	2.61
2016	1.87	1.87
2017	2.36	2.36
2018	2.79	2.36
2019	2.68	0.49
2020	2.28	0.63
2021	0.47	0.78
2022	0.61	0.99
2023	0.89	1.42
2024	1.26	1.98
2025	1.57	2.46

Third, the basis of the generation capacity cost switched from the net cost of hydro capacity to the cost of the CCCT earlier, reflecting the change in the expansion plan.

There is one additional change reflected in the Test 1 results. A concerned was expressed that the regression equation used to estimate the loader for general plant in the original marginal cost study might not be representative of the marginal general plant associated with large generation additions, since there was only one such addition in the data set used for the regression. This becomes a larger factor when the generation capacity cost increases, as in Test 1. The marginal generation capacity costs for Test 1 presented in this memo reflect a lower general plant loader than the original report—15 percent instead of the original 24.7 percent.[3]

The table below compares the base case and Test 1 marginal generation capacity costs, stated in dollars per kW-month, for three groups of years: 2007-2011, 2012-2020, and 2021-2025.

[3] Fifteen percent is more consistent with: (1) the weighted average ratio of cumulative general plant to cumulative total plant less general plant additions for the period 1991-2004; and (2) coefficients of a range of alternative regression specifications where statistical significance could not be rigorously established due to a limited number and co-linearity of observations.

Table 3: Monthly Marginal Generation Capacity Cost

	Base Case	Test 1
	(2007 Dollars/kW)	
2007-2011	$0.15	$3.78
2012-2020	$0.49	$9.89
2021-2025	$5.98	$8.83

Marginal Energy Costs

The original marginal cost computations assumed that Holyrood would remain the marginal source of energy in all hours and all years. However, with the CCCT coming into service earlier under the Test 1 expansion plan, we have now assumed that the marginal energy source in 2019 and beyond will be the new CCCT. The table below, which compares the base case and Test 1 marginal energy costs, reflects this change as well as uses 50 percent of the Spring 2006 fuel price forecasts.

Table 4: Marginal Energy Costs

	Base Case	Test 1 (50 Percent Fuel Forecast)
	------------------ (2007 Dollars) ----------------	
	(1)	(2)
2007-2011	$0.085	$0.043
2012-2020	$0.086	$0.049
2021-2025	$0.087	$0.048

Marginal Cost Summary Tables

The following table summarizes the marginal costs of all system elements, using the Test 1 results for energy and marginal generation capacity costs.

Table 5: Total Marginal Costs

		Base Case			Test 1 (50 Percent of Fuel Forecast)		
		Winter			Winter		
		Peak	Off-Peak	Non-Winter	Peak	Off-Peak	Non-Winter
	2007-2011						
(1)	Energy (per kWh)	$0.085	$0.085	$0.085	$0.043	$0.043	$0.043
(2)	Generation Capacity (per kW-mo)	$0.38	$0.07	$0.00	$9.45	$1.81	$0.05
(3)	Transmission (per kW-mo)	$1.29	$0.35	$0.00	$1.23	$0.34	$0.00
(4)	Total per kW-mo	$1.67	$0.43	$0.00	$10.68	$2.15	$0.05
	2012-2020						
(5)	Energy (per kWh)	$0.086	$0.086	$0.086	$0.049	$0.049	$0.049
(6)	Generation Capacity (per kW-mo)	$1.22	$0.23	$0.01	$24.70	$4.73	$0.13
(7)	Transmission (per kW-mo)	$1.29	$0.35	$0.00	$1.23	$0.34	$0.00
(8)	Total per kW-mo	$2.51	$0.59	$0.01	$25.93	$5.07	$0.13
	2021-2025						
(9)	Energy (per kWh)	$0.087	$0.087	$0.087	$0.048	$0.048	$0.048
(10)	Generation Capacity (per kW-mo)	$14.93	$2.86	$0.08	$22.03	$4.22	$0.11
(11)	Transmission (per kW-mo)	$1.29	$0.35	$0.00	$1.23	$0.34	$0.00
(12)	Total per kW-mo	$16.21	$3.21	$0.08	$23.27	$4.56	$0.12

Rate Structure Implications

The Test 1 results, with much higher capacity costs and much lower energy costs, suggest a very different rate structure from that consistent with the base case marginal cost estimates. For purposes of discussing rate structure implications, we have used average marginal costs for the period 2007-2011, as we did in our previous rate structure analysis.

The table below compares the charges in current rates (forecast 2007 rates at current rate structures and base case fuel forecast) with the average 2007-2011 Test 1 marginal cost results for the three major classes: Newfoundland Power, Industrial (firm) and Non-firm Industrial. Use of the Test 1 marginal cost results would imply significantly higher demand charges for NP and firm Industrial customers, but applied only in the winter months (ignoring the very small capacity costs in non-winter months). Test 1 marginal energy costs imply large reductions in the tail block of NP rates, somewhat higher energy charges to firm industrial customers, and lower energy charges to non-firm industrial customers. It is important to note, however, that the "current" rates shown on Table 6 do not reflect the lower fuel price assumptions in the Test 1 marginal cost estimates.

Table 6: Comparison of Forecast Current 2007 Rate Structures and Average 2007-2011 Marginal Costs

		Energy 2007$/kWh	Demand 2007$/kW-mo.		
			Winter		Non-Winter
			Peak	Off-Peak	
Marginal Costs		$0.0434	$ 10.73	$ 2.16	$0.05
			All months (12-month ratchet)		
NP Rates	1st Block	$0.0054	$6.97		
	2nd Block	$0.0877			
Industrial Rates (Firm)		$0.0384	$6.38		
Non-Firm Industrial Rate		$0.0877	(Not applicable)		

Period Definitions (Newfoundland time)

Winter: Jan – Mar and Dec
Peak: Weekdays, 7:00 am to noon & 4:00 pm to 8:00 pm.
Off-Peak: All remaining hours.

Non-Winter: April – November
No time-of-day differentiation.