12 Cumulative Present Worth Analysis

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12.1 CPW Approach

The Reference Question asks which of the Infeed or Isolated Island Options is the least cost of the two Options excluding consideration of the monetization of the excess power from the Muskrat Falls generating facility.

The metric of least cost is not defined in the Reference Question, but the analysis provided by Nalcor uses a Cumulative Present Worth (CPW) methodology. This approach focuses on incremental capital expenditures, fuel costs, power purchase costs, and operating expenses as related to each of the two Options. The CPW approach does not take cash in-flows related to revenues into account. Present Worth Analysis is generally accepted as a methodology for comparing mutually exclusive alternatives, as long as there is a fixed output or an objective that is common to both alternatives. In this case, the fixed objective is to meet the projected load forecast, assuming the same level of service and reliability targets for each of the two Options. The goal of the least-cost analysis is therefore to choose the Option which minimizes the present worth of costs.

Equivalent costs common to both options cancel out and therefore have not been taken into account. Examples of these costs are fixed administrative expenses, and operating and maintenance costs for existing generation plants that are unaffected by the choice of either Option.

12.2 Alternatives to CPW

Other types of analysis that are commonly used for determining the preferred option from a set of alternatives include Net Present Value (NPV) and Internal Rate of Return (IRR). Both of these methods require an estimate of the revenue stream generated by the power tariffs over the forecast period, as they weigh future cash in-flows related to revenue against cash out-flows, such as those associated with capital investment. These approaches rely on discounting future cash flows to the present and the result with the highest NPV is the preferred option. Differences in risk exposure are typically manifested in the choice of discount rate. MHI is satisfied that the CPW approach used by Nalcor is reasonable for the purpose intended, being to identify the least cost choice between the two Options.

12.3 PPA versus COS Approach

Nalcor used a Power Purchase Agreement (PPA) approach related to the capital assets and operating costs for the Muskrat Falls generating facility and a Cost of Service (COS) approach for all other asset additions and expenditures, irrespective of the Option.

The Muskrat Falls generating facility will be developed and owned by Nalcor. From the perspective of NLH, for purposes of this exercise, Nalcor is considered to be an Independent Power Producer who will contract with NLH to sell energy to the utility under a Power Purchase Agreement (PPA). The tariff formula defined by the PPA will result in a per-unit charge for energy from Nalcor, which will be treated by NLH no differently than power purchased from any other non-utility generator.

Even though essentially all of the capital expenditures related to Muskrat Falls will be expended by the in-service date of 2017, with the PPA approach the costs associated with Muskrat Falls are spread out over the 60 years (anticipated life of the asset) following the in-service date in the PPA rate that is expected to be uniform throughout the future period adjusted only for escalation.

In contrast, the capital costs associated with the Labrador-Island HVdc Link have been included in the CPW using a COS approach. Following a COS approach, the burden of the capital expenditure-related costs are greater in the earlier years and decline as the capital assets are depreciated over time.

MHI tested the outcomes for each of the two approaches and the resulting impacts on the CPW for each of the two Options. The results are set out in Table 29 below.

Table 29: CPW Sensitivity to Capital Cost Methodology

($ in Billions)	Nalcor Method (1)	COS (2)
Isolated	$8.81	$8.81
Infeed	$6.65	$6.58
CPW Gap	$2.16	$2.23

Column 1 represents the existing scenario provided by Nalcor. All expenditures have been included on a cost of service basis, excepting those related to Muskrat Falls which were included on a PPA basis.

Column 2 reflects including all assets on a cost of service basis, including the capital expenditures associated with Muskrat Falls, and AFUDC (Allowance for Funds Used During Construction) at 8% (column 1 is unchanged for the Isolated Island Option as this was already an entirely COS-based calculation).

The COS approach for the Infeed Option has a somewhat lower present value cost than shown in Column 1. Although discounting tends to shelter the growing PPA costs in Column 1, and customer costs would be higher in the near term with the COS approach, in the long term the ever-increasing PPA tariff pulls the present value of costs upwards.

In both cases the CPW for the Infeed Option is less than the Isolated Island Option, so the Infeed Option remains the lowest cost Option regardless of the costing methodology chosen. However, the PPA approach for Muskrat Falls results in a present value of approximately $70 million more than a COS approach.

Nalcor has stated that the PPA approach for Muskrat Falls costing is preferable because the PPA formula ensures that the ratepayer is not overly burdened in the earlier years by a rate shock resulting from the use of the COS methodology. The COS approach front-end loads the capital costs and spreads them over a smaller energy load that is only 40% of Muskrat Fall's firm energy in 2017.

12.4 Muskrat Falls PPA

The premise supporting the use of a PPA approach relies on the base assumption that NLH will sign a take-or-pay contract with Nalcor for the specified NLH energy purchases from Muskrat Falls that Strategist has projected. As equity owner of the Muskrat Falls project, Nalcor will eventually receive its target return on the investment over the life of the asset based on the volumes consumed.

To determine the PPA prices it was assumed that all firm output (4.5 TWh) generated by the Muskrat Falls generating facility would be sold, that the internal rate of return (IRR) would be 11.0% and equity financing would be 100%. These assumptions resulted in a price of approximately $76/MWh (2010$) escalated at 2% per year in nominal terms.

However, not all energy generated by the Muskrat Falls facility in the earlier years will be taken up by NLH. The corresponding IRR based on NLH's energy purchases is 8.4%. This was considered acceptable by Nalcor given the prospect of being able to secure financial leverage through debt financing at a lower cost to replace some portion of the equity portion assumed for the calculation and as well, the prospect of being able to sell some or all of the surplus volumes of generated power in the earlier years to third parties.[229]

12.5 Choice of Discount Rate

To convert future dollar costs to a present value, Nalcor used a discount rate that is equal to its weighted average cost of capital (WACC), based on a target 75:25 debt/equity ratio.

The cost of equity is estimated as described in the response to RFI MHI-Nalcor-32:

> *"Nalcor obtains a long term forecast of risk free Government of Canada bonds from the Conference Board of Canada and then applies the cost of equity formulation as approved by the Board for Newfoundland Power and applicable to regulated NLH at its next General Rate Application. These calculations result in a long run forecast average cost of equity of 9.94% which for analysis purposes was rounded to an even 10%."*

The cost of debt is estimated as the average rate from the Conference Board's long-term forecast of 10-year Government of Canada bonds, which is assumed to be risk-free. To this rate, Nalcor added a Province of Newfoundland and Labrador spread of 1.67% to result in an estimated 7.35% rate for the Province's cost of debt.

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[229] Response to RFI MHI-Nalcor-58

The weighting of 75% debt at 7.35% plus 25% equity at 10% results in a WACC of 8.0%.

Recognizing the choice of an appropriate discount rate may impact the results of the CPW analysis if there are significant differences in both the timing and scale of cost flows, MHI reviewed varying discount rates and ascertained that the choice of discount rate within a reasonably close band does not substantially affect the CPW values. As illustrated in Table 30 below, it is necessary for the discount rate to be elevated to over 17% before the CPW results for each of the two Options approximate each other. Within a band of 2% on either side of Nalcor's WACC, the differential in the CPW continues to favour the Infeed Option.

Table 30: CPW Sensitivity to Discount Rate

Discount Rate:	6%	8% (Nalcor)	10%	17.1%
Isolated	$13.241	$8.807	$6.353	$3.025
Infeed	$9.011	$6.651	$5.248	$3.025
Gap	$4.231	$2.156	$1.102	$0

(Source: MHI derived)

MHI is satisfied that the use of the weighted average cost of capital by Nalcor as a proxy for the discount rate is acceptable for the purposes of making a determination of the comparable CPW for each of the two Options.

12.6 Time Horizon for Analysis

The time horizon for the CPW analysis period was 2010 to 2067. This time frame is considered reasonable recognizing that the Muskrat Falls generating facility and the Labrador-Island Link HVdc system are the dominant capital related investments under review. The expected life span of Muskrat Falls is estimated at 60 years while the expected life span of the Labrador-Island Link HVdc system is 50 years from the date of commissioning in 2017.

12.7 Load Forecast Used in CPW

Nalcor used a single planning load forecast (PLF) for both the Isolated Island and the Infeed Options. The PLF provided in Exhibit 1 provides the forecast for total peak load and energy requirements for the island as a whole, to be provided by NLH and other suppliers. Even though Exhibit 1 does not distinguish between these two components of the system load forecast, only NLH's share of the total load forecast is factored into the CPW analysis.

In the response to RFI PUB-Nalcor-86, Nalcor acknowledges there were previously two PLFs in the NLH 2010 Capital Budget Application, and discusses the differences in the PLF between the two Options.

Using the process described in the Addendum to Exhibit 1, NLH developed a distinct load forecast for the Infeed Option, capturing the shift in demographics and economic factors that distinguish the Infeed Option from the Isolated Option. As documented in the NLH 2009 Capital Budget Application there are some small but noticeable differences between this and the status quo load forecast. There are three general observations that can be made about these differences:

1. In the earlier years of the 10-year load forecast period, increased levels of spending for project construction in the province lead to higher gross domestic product (GDP) and demographic drivers for a load increase and the Labrador-Island Link HVdc energy consumption rises above the base forecast.
2. In the immediate years following commissioning of the Labrador-Island Link HVdc system there is a cost-of-service rate shock that causes load growth to drop below the base forecast. This rate shock results from the up-front costs of the Labrador-Island Link HVdc assets in the rate base, and price elasticity for electricity depresses load growth which puts further pressure on consumption.
3. Eventually the relatively lower power costs associated with Muskrat Falls cause load growth to begin rising above the Isolated Island PLF, which is becoming further constrained as fuel oil prices continue to increase.

Without any adjustment, the Infeed Option would result in electricity rates initially being higher than would have been the case with the Isolated Island case. However, Nalcor made a policy decision that Muskrat Falls should never create an environment where rates would be higher than staying with the status quo.[230] This policy requires Nalcor to pursue rate management options that ensure Muskrat Falls would not impose a rate shock on island customers. At this point, the details of this mitigation strategy have not been identified, but the implication for the CPW analysis is that rates will be managed in order to ensure they never exceed what would have been attained using the base load forecast. The Isolated Island load forecast is essentially a proxy for the rate management strategies that will constrain rates to the level that would have otherwise been seen. If these strategies were known at this time, re-running the load forecast models should result in a load growth profile that is close to the current base forecast, and for this reason Nalcor only uses the single Isolated Island base PLF for both Options in the CPW analysis.

12.8 Least-Cost Generation Expansion Plans

Both the Infeed and the Isolated Island Options represent the least-cost sequence of new generation capacity from the two pre-defined sets of generation options for the island of Newfoundland, using standard NLH service parameters[231] and the current load forecast for the island. The generation facilities which come on-stream for each of the two Options over the period to 2067 are itemized in the 2010 PLF Strategist Generation Expansion Plan[232]. The sequencing for the facilities was determined by Nalcor using Strategist system planning software. Each of the two Options has been

[230] Response to RFI PUB-Nalcor-87
[231] Exhibit 16, Nalcor, “Generation Planning Issues 2010 July Update”, July 2010
[232] Exhibit 14 Rev.1, Nalcor, “2010 PLF Strategist Generation Expansion Plans”

evaluated based on the defined allowable mix of generation types and sizes unique to each Option. The 'least-cost' generation expansion plan is the sequence selected by the software which results in the minimum CPW, while still meeting all required service and load/energy constraints. Environmental and social considerations are factored into this analysis as direct cost inputs. This process is described in more detail in the July 6, 2011 Nalcor filing with the Board[233].

The Isolated Island Option is essentially represented by the generation expansion plan set out in Exhibit 14 Rev.1. It is limited to generation alternatives that are available on the island.

The primary capacity for the Infeed Option is the Muskrat Falls generating facility, but is supplemented with the addition of smaller additional generation constructed on the island to meet security of supply criteria. It is noted that energy may be expected to become available from the Upper Churchill facility post-2041. The Infeed Option introduces the sourcing of energy from the Upper Churchill facility beginning in 2057. The Upper Churchill capacity has not been identified in Exhibit 14 Rev. 1 even though it begins supplying energy to island consumers once the full firm capacity of Muskrat Falls is exceeded by island demand in 2057. Nalcor has indicated that Upper Churchill power is currently treated only as a placeholder for as-yet-undetermined additional sourcing required subsequent to 2057[234].

12.8.1 Capacity Plan for the Isolated Island Option

As earlier noted, the generation expansion plan for the Isolated Island Option reflects the new capacity options available on the island. The sequence developed by Strategist[235], incorporating planned additions and retirements of capacity and associated energy balances, is set out below in Table 31. Much of the incremental capacity which is projected to be brought on-stream over the period to 2067 is thermal-based. Currently, approximately 33% of NLH electricity is thermal-based, but with the incremental thermal capacity projected, by 2067 approximately 62% of capacity will be thermal-based[236]. Apart from the projected hydraulic facilities, which include Island Pond, Portland Creek and Round Pond, and the marginal capacity supplied by wind generation, all other additional capacity will be thermal-based. Accordingly, fuel costs associated with the Isolated Island Option are significant and represent nearly 70% of its CPW. In addition the increase in reliance on thermal generation brings with it the future, and somewhat unknown, challenges of meeting or exceeding new environmental targets.

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[233] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011
[234] Response to RFI PUB-Nalcor-92 Rev.1
[235] Exhibit 14 Rev.1, Nalcor, "2010 PLF Strategist Generation Expansion Plans"
[236] Derived from Exhibit 16, Nalcor, "Generation Planning Issues", July 2010 and Exhibit 14, Nalcor, "2010 PLF Strategist Generation Expansion Plans"

Table 31: Energy Balance for Isolated Island Option

	Forecast Requirement		Firm Avail.	Energy Surplus	Additions and Retirements		Addition	Retirement
Year	MW	Firm (GWh)	(GWh)	(GWh)	Addition	Retirement	(GWh)	(GWh)
2010	1,519	7,585	8,953	1,368				
2011	1,538	7,709	8,953	1,244				
2012	1,571	7,849	8,953	1,104				
2013	1,601	8,211	8,953	742				
2014	1,666	8,485	9,030	545	25 MW Wind		77.2	
2015	1,683	8,606	9,203	597	Island Pond		172.3	
2016	1,695	8,623	9,203	580				
2017	1,704	8,663	9,203	540				
2018	1,714	8,732	9,302	570	Portland Creek		99.0	
2019	1,729	8,803	9,302	499				
2020	1,744	8,869	9,410	541	Round Creek		108.0	
2021	1,757	8,965	9,410	445				
2022	1,776	9,062	10,685	1,623	170 MW CCCT	Hardwoods CT1 & CBP Co-Gen	1340.0	-65.0
2023	1,794	9,169	10,685	1,516				
2024	1,813	9,232	11,079	1,847	50 MW CT	Stephenville CT1	394.2	
2025	1,827	9,290	11,079	1,789				
2026	1,840	9,372	11,079	1,707				
2027	1,856	9,461	11,473	2,012	50 MW CT		394.2	
2028	1,872	9,543	11,473	1,930	2x27 MW Wind farms	2x27 MW Wind farms	167.0	-167.0
2029	1,888	9,623	11,473	1,850				
2030	1,903	9,701	11,867	2,166	50 MW CT		394.2	
2031	1,918	9,779	11,867	2,088				
2032	1,934	9,857	11,867	2,010				
2033	1,949	9,935	12,468	2,533	2x170 MW CCCT	Holyrood 1 & 2	2680.0	-2078.8
2034	1,964	10,014	12,468	2,454	25 MW Wind	25 MW Wind	77.2	-77.2
2035	1,978	10,084	12,468	2,384				
2036	1,992	10,154	12,891	2,737	170 MW CCCT	Holyrood 3	1340.0	-917.1
2037	2,006	10,225	12,891	2,666				
2038	2,020	10,295	12,891	2,596				
2039	2,033	10,365	12,891	2,526				
2040	2,046	10,428	12,891	2,463				
2041	2,058	10,491	12,891	2,400				
2042	2,070	10,553	13,285	2,732	50 MW CT		394.2	
2043	2,082	10,616	13,285	2,669				
2044	2,095	10,678	13,285	2,607				
2045	2,107	10,741	13,680	2,939			394.2	
2046	2,119	10,803	13,680	2,877	50 MW CT			
2047	2,132	10,866	13,680	2,814				
2048	2,144	10,928	13,680	2,752	2x27 MW Wind farms	2x27 MW Wind farms	167.0	-167.0
2049	2,156	10,991	13,680	2,689	50 MW CT	50 MW CT	394.2	-394.2
2050	2,167	11,046	15,020	3,974	170 MW CCCT		1340.0	
2051	2,178	11,100	15,020	3,920				
2052	2,188	11,155	14,625	3,470	170 MW CCCT	50 MW CT & 170 MW CCCT	1340.0	-1734.2
2053	2,199	11,210	14,625	3,415				
2054	2,210	11,264	14,625	3,361	25 MW Wind	25 MW Wind	77.2	-77.2
2055	2,220	11,319	14,231	2,912		50 MW CT		-394.2

	Forecast Requirement		Firm Avail.	Energy Surplus	Additions and Retirements		Addition	Retirement
Year	MW	Firm (GWh)	(GWh)	(GWh)	Addition	Retirement	(GWh)	(GWh)
2056	2,231	11,374	15,571	4,197	170 MW CCCT		1340.0	
2057	2,242	11,429	15,571	4,142				
2058	2,253	11,483	15,571	4,088				
2059	2,263	11,538	15,571	4,033				
2060	2,274	11,593	15,571	3,978				
2061	2,285	11,648	15,571	3,923				
2062	2,296	11,702	15,571	3,869				
2063	2,306	11,757	15,020	3,263	2x50 MW CT & 170 MW CCCT		2128.4	-2680.0
2064	2,317	11,812	15,414	3,602	50 MW CT		394.2	
2065	2,328	11,866	15,414	3,548				
2066	2,339	11,921	15,414	3,493	170 MW CCCT	170 MW CCCT	1340.0	-1340.0
2067	2,349	11,976	16,360	4,384	170 MW CCCT	50 MW CT	1340.0	-394.2

12.8.2 Capacity Plan for the Infeed Option

The generation expansion plan for the Infeed Option is accomplished primarily through the addition of Muskrat Falls hydraulic generation. The Portland Creek generation facility is scheduled to come on-stream in 2036. The existing wind farms are phased out in 2028. A limited amount of thermal capacity is added over the period to 2067 for peaking power. Holyrood thermal generation will be phased out and converted to synchronous condenser operation. In contrast to the Isolated Island Option where fuel costs represent approximately 69% of the CPW, with the Infeed Option fuel costs represent approximately 18% of CPW, and are mostly associated with the continuing reliance on thermal during the period prior to commissioning Muskrat Falls. By 2067, the generation capacity mix for the Infeed Option will be based on 65% hydroelectric and 35% thermal. Energy will normally be based on a dispatch pattern that minimizes fuel use. The sequencing developed by Strategist and the associated energy balances are set out below in Table 32.

Table 32: Energy Balance for Infeed Option

	Forecast Requirement		Firm Avail.	Energy Surplus	Additions and Retirements		Addition	Retirement
Year	MW	Firm (GWh)	(GWh)	(GWh)	Addition	Retirement	(GWh)	(GWh)
2010	1,519	7,585	8,953	1,368				
2011	1,538	7,709	8,953	1,244				
2012	1,571	7,849	8,953	1,104				
2013	1,601	8,211	8,953	742				
2014	1,666	8,485	9,347	862	50 MW CT		394.2	
2015	1,683	8,606	9,347	741				
2016	1,695	8,623	9,347	724				
2017	1,704	8,663	15,290	6,627	Muskrat Falls / HVDC Link		5943.0	
2018	1,714	8,732	15,290	6,558				
2019	1,729	8,803	15,290	6,487				
2020	1,744	8,869	15,290	6,421				
2021	1,757	8,965	12,294	3,329		Holyrood 1 ,2 & 3		-2995.9
2022	1,776	9,062	12,229	3,167		Hardwoods CT1 & CBP Co-Gen		-65.0
2023	1,794	9,169	12,229	3,060				
2024	1,813	9,232	12,229	2,997		Stephenville CT1		
2025	1,827	9,290	12,229	2,939				
2026	1,840	9,372	12,229	2,857				
2027	1,856	9,461	12,229	2,768				
2028	1,872	9,543	12,062	2,519		2x27 MW Wind farms		-167.0
2029	1,888	9,623	12,062	2,439				
2030	1,903	9,701	12,062	2,361				
2031	1,918	9,779	12,062	2,283				
2032	1,934	9,857	12,062	2,205				
2033	1,949	9,935	12,062	2,127				
2034	1,964	10,014	12,062	2,048				
2035	1,978	10,084	12,062	1,978				
2036	1,992	10,154	12,161	2,007	Portland Creek		99.0	
2037	2,006	10,225	13,501	3,276	170 MW CCCT		1340.0	
2038	2,020	10,295	13,501	3,206				
2039	2,033	10,365	13,107	2,742		50 MW CT		-394.2
2040	2,046	10,428	13,107	2,679				
2041	2,058	10,491	13,107	2,616				
2042	2,070	10,553	13,107	2,554				
2043	2,082	10,616	13,107	2,491				
2044	2,095	10,678	13,107	2,429				
2045	2,107	10,741	13,107	2,366				
2046	2,119	10,803	13,501	2,698	50 MW CT		394.2	
2047	2,132	10,866	13,501	2,635				
2048	2,144	10,928	13,501	2,573				
2049	2,156	10,991	13,501	2,510				
2050	2,167	11,046	13,896	2,850	50 MW CT		394.2	
2051	2,178	11,100	13,896	2,796				
2052	2,188	11,155	13,896	2,741				
2053	2,199	11,210	13,896	2,686				

	Forecast Requirement		Firm Avail.	Energy Surplus	Additions and Retirements		Addition	Retirement
Year	MW	Firm (GWh)	(GWh)	(GWh)	Addition	Retirement	(GWh)	(GWh)
2054	2,210	11,264	14,290	3,026	50 MW CT		394.2	
2055	2,220	11,319	14,290	2,971				
2056	2,231	11,374	14,290	2,916				
2057	2,242	11,429	14,290	2,861				
2058	2,253	11,483	14,684	3,201	50 MW CT		394.2	
2059	2,263	11,538	14,684	3,146				
2060	2,274	11,593	14,684	3,091				
2061	2,285	11,648	14,684	3,036				
2062	2,296	11,702	14,684	2,982				
2063	2,306	11,757	15,078	3,321	50 MW CT		394.2	
2064	2,317	11,812	15,078	3,266				
2065	2,328	11,866	15,078	3,212				
2066	2,339	11,921	15,472	3,551	50 MW CT		394.2	
2067	2,349	11,976	14,132	2,156		170 MW CCCT		-1340.0

12.9 Capital Costs

The actual cash costs for all new generation and transmission capacity investments do not flow directly into the CPW analysis at the time they are incurred. Instead as earlier noted, Muskrat Falls capital costs have been included in the CPW through a PPA tariff while the remaining costs have been included in the CPW on a COS basis.

The construction and operating costs associated with the capacity plans for each of the Options are based on estimates that were developed by different means and at different times. Considering the target level of accuracy for the DG2 threshold, Nalcor has either taken cost estimates from past engineering studies and escalated them to January 2010$, or they have re-established a recent estimate based on current costs as of January 2010$. The base dollar values for all monetary figures used in the CPW analysis are January 2010$.

Where past studies' estimates were required to be escalated to base dollars, Nalcor used data from Global Insight to compile detailed escalation data which was then applied to the base dollar cost estimates reported in the past engineering studies. In this manner, these estimates were brought to 2010$ values.

All 2010$ estimates were then escalated forward to the period when the actual costs would be incurred. Escalation rates were used rather than inflation rates because they reflect underlying economic conditions whereas inflation rates are tied to changes in the value of currency and other broader monetary impacts.

Each project's capital construction costs were cumulated and applied on the in-service dates of the generation plants, when they are producing full power. Table 33 lists the annual escalation rates applied by project type, apart from Muskrat Falls and Labrador-Island Link HVdc system, from 2010 to the year of commissioning each project. A single annual escalation rate was chosen for each project as input to Strategist, as it is only capable of using one escalation rate per project.

Table 33: Escalators used by Strategist

Type of Project	Annual Escalation Rate
Gas Turbine (GT)	2.0%
Combined Cycle Combustion Turbine (CCCT)	1.9%
Hydro	1.9%
Wind	2.0%

(Source: MHI-Nalcor-49.3)

The escalation factors for Muskrat Falls and Labrador-Island Link HVdc system were calculated using "a more sophisticated approach", as described by Nalcor in Exhibit 3 and the response to MHI-Nalcor 50. The escalation projection was performed using detailed Producer Price Index (PPI) projections by cost 'bin', as provided by Global Insight, to extrapolate the 2010$ estimate to the 2017$ commissioning date values. Evaluation of the detailed costing profiles for Muskrat Falls for example was performed in order that, for each year's cost flows in the construction project, each of the 41 escalator bins was assigned a weighting. The total weighting in each year is 100%, but the pattern of costs changes from year to year, reflecting different activities throughout the different project phases.

The calculated cumulative escalation factors for Muskrat Falls and Labrador-Island Link using the Escalation Model following this methodology are set out in Table 34 below.

Table 34: Cumulative Escalation Factors for Muskrat Falls and Labrador-Island Link HVdc

Component	2010	2011	2012	2013	2014	2015	2016	2017	2018
Muskrat Falls	1.00	1.02	1.05	1.11	1.16	1.20	1.23	1.26	1.30
Labrador-Island Transmission Link	1.00	1.02	1.04	1.08	1.12	1.16	1.20	1.24	1.29

(Source: Exhibit 3, Nalcor, "Nalcor Inflation and Escalation Forecast", January 2010)

Holyrood environmental and life-extension projects also have an escalation already built into the capital costs provided to Strategist.

In addition to base costs, contingencies, and escalation adjustments, Nalcor also provided values for AFUDC. The AFUDC is used to reflect the imputed financing cost incurred during the construction phase of a new asset, before that asset is added to the rate base and begins to generate revenues. Nalcor applied AFUDC to all projects that increase system capacity, but did not apply it to capital costs for the Holyrood related projects in either of the two Options.

Tables 35 and 36 list the base dollar costs, the related escalation amounts, and the AFUDC allowances that serve to generate the total in-service cost for each capital project in the Isolated Island and Infeed Options, respectively.

Table 35: Capital Costs for Isolated Island Option

Project	In-service year	Capital Cost ($)	Escalation ($)	AFUDC ($)	In-service Cost ($)
Island Pond	2015	166,220	15,033	17,874	199,126
HRD Envir. Upgrade	2015	581,976	0	0	581,976
HRD Life Extension	2016	100,000	0	0	100,000
Holyrood Low NOx	2017	17,500	2,317	0	19,817
Portland Creek	2018	89,909	14,998	6,034	110,941
Holyrood Misc.Cap.1	2019	105,190	15,788	0	120,978
Round Pound	2029	142,192	29,006	14,165	185,363
CCCT - 170 MW	2022	206,187	50,764	24,623	281,574
GT - 50 MW	2024	65,137	21,179	4,810	91,125
Holyrood Misc.Cap.2	2024	6,832	1,716	0	8,548
GT – 50 MW	2027	65,137	26,462	5,104	96,703
Wind - 2x27 MW	2028	125,458	54,336	9,099	188,893
Holyrood Misc.Cap.3	2029	2,550	1,127	0	3,677
GT - 50 MW	2030	65,137	32,069	5,416	102,622
CCCT – 170 MW G2	2033	206,187	109,870	30,287	346,344
CCCT - 170 MW G1	2033	273,920	144,480	46,549	464,949
Wind - 25 MW	2034	58,082	35,657	4,744	98,483
CCCT - 170 MW G1	2036	273,920	168,785	49,253	491,958
GT - 50 MW	2042	65,137	58,143	6,869	130,149
GT - 50 MW	2046	65,137	68,306	7,435	140,878
Wind - 2x27 MW	2048	125,458	141,706	13,521	280,686
GT - 50 MW	2049	65,137	76,473	7,890	149,501
CCCT - 170 MW G2	2050	206,187	229,051	41,708	476,946
CCCT - 170 MW G1	2052	273,920	324,355	66,562	664,837
Wind - 25 MW	2054	58,082	81,209	7,050	146,340
CCCT - 170 MW G2	2056	206,187	281,085	46,695	533,967
GT - 2x50 MW	2063	130,274	243,429	20,823	394,526
CCCT - 170 MW G1	2063	273,920	461,977	81,873	817, 770
GT - 50 MW	2064	65,137	125,452	10,620	201,208
CCCT - 170 MW G2	2066	206,187	281,997	56,365	644,550
CCCT - 170 MW G1	2067	273,920	519,520	88,275	881,714

It is noteworthy that Nalcor has incorporated a large investment programme in the Isolated Island Option for reducing the environmental footprint of Holyrood. The question arises as to whether or not this is necessary, as switching to 0.7% sulphur fuel oil has accomplished as much as is necessary to meet Provincial environmental targets for SO_x.

The impact on the CPW relating to the sensitivity of removing the cost of the Holyrood environmental upgrade for the Isolated Island Option was tested. If NLH did not proceed with the environmental upgrade for the Holyrood facility, the difference in the CPW between the Infeed Option and the Isolated Island Option is reduced from $2.2 billion to $1.8 billion.

Table 36: Capital Costs for Infeed Option

Project	In-service year	Capital Cost ($)	Escalation ($)	AFUDC ($)	In-service Cost ($)
50 MW CT	2014	65,137	5,672	3,945	74,755
HVDC Labrador-Island Link	2017	1,852,000	221,168	480,067	2,553,235
Sync. Condenser	2017	2,757	415	111	3,283
Holyrood Decomm. Ph.1	2025	12,000	3,452	0	15,452
Holyrood Decomm. Ph.2	2029	8,498	3,384	0	11,882
Portland Creek	2036	89,909	57,302	8,467	155,678
CCCT – 170 MW	2037	206,187	134,584	32,656	373,426
CT – 50 MW	2046	65,137	68,306	7,435	140,878
CT – 50 MW	2050	65,137	79,305	8,048	152,491
CT – 50 MW	2054	65,137	91,212	8,712	165,061
CT – 50 MW	2058	65,137	104,100	9,430	178,667
CT – 50 MW	2063	65,137	121,715	10,411	197,263
CT – 50 MW	2066	65,137	133,152	11,049	209,337

Capital costs are a significant input to the CPW analysis. The impact of changes in capital costs on the CPW results was tested. For example, if the Labrador-Island Link capital costs increase by 25%, the CPW differential in favour of the Infeed Option would be reduced by $398.0 million, and if the Muskrat Falls Generating Station capital costs increased by 25%, the CPW differential in favour of the Infeed Option would be reduced by $577.0 million[237]. If both the Labrador-Island HVdc Link and the Muskrat Falls Generating Station costs increase by 25%, the CPW differential in favour of the Infeed Option would be reduced by $975 million.[238]

12.10 Inventory

Nalcor did not include the carrying cost of fuel inventory which is normally part of the rate base component used in determining the cost of service for the utility.

In the current comparative analysis of CPWs, the value of fuel inventory would only be significantly different between the two Options in the period where Holyrood is no longer generating base load power, which exists mostly from 2017 and on. If fuel inventory carrying costs were included in the CPW analysis, the consequence would be an increase in the CPW for the Isolated Island Option, and accordingly would serve to further increase the gap between the two CPW values.

[237] Response to RFI MHI-Nalcor-41
[238] Exhibit 43 Rev.1, Nalcor, "Newfoundland and Labrador Hydro – 2010 Generation Expansion Analysis (Revision 1)"

12.11 Asset Life

The expected service life of an asset and its initial cost are the primary determinants of the annual depreciation expense and the annual regulatory return on the un-depreciated value of the investment. Nalcor has applied asset lives that are typical in the industry, as noted in Table 37 and 38 below, for each of the Isolated Island and Infeed Options respectively. All hydraulic facilities have been assigned an expected life of 60 years, while CCCT plants are 30 years, combustion turbines 25 years, and wind farms 20 years.

For Holyrood expenditures, the expected life assigned varies between scenarios. In the Isolated Island Option, investments related to Holyrood have been assigned a service life from the in-service date to the expected decommissioning date of Holyrood in 2036. In the Infeed Option, the project to convert the generators to synchronous condensers is assigned the life of its rotating machinery, and the latter decommissioning costs are amortized over 60 years. These assigned service lives are reasonable.

Table 37: Fixed Cost Parameters for Isolated Island Option

Project	In-service year	In-service Cost	Service Life (years)	Insurance Rate (%)
Island Pond	2015	199,126	60	0.100%
HRD Envir. Upg.	2015	581,976	21	0.125%
HRD Life Extension	2016	100,000	20	0.125%
Holyrood Low NOx	2017	19,817	19	0.125%
Portland Creek	2018	110,941	60	0.100%
Holyrood Misc. Cap. 1	2019	120,978	17	0.125%
Round Pond	2020	185,363	60	0.100%
CCCT - 170 MW	2022	281,574	30	0.125%
CT - 50 MW	2024	91,125	25	0.125%
Holyrood Misc.Cap.2	2024	8,548	12	0.125%
CT – 50 MW	2027	96,703	25	0.125%
Wind - 2x27 MW	2028	188,893	20	0.100%
Holyrood Misc.Cap.3	2029	3,677	7	0.125%
CT - 50 MW	2030	102,622	25	0.125%
CCCT - 170 MW G2	2033	346,344	30	0.125%
CCCT - 170 MW G1	2033	464,949	30	0.125%
Wind - 25 MW	2034	98,483	20	0.100%
CCCG - 170 MW G1	2036	491,958	30	0.125%
CT - 50 MW	2042	130,149	25	0.125%
CT - 50 MW	2046	140,878	25	0.125%
Wind - 2x27 MW	2048	280,686	20	0.100%
CT - 50 MW	2049	149,501	25	0.125%
CCCT - 170 MW G2	2050	476,946	30	0.125%
CCCT - 170 MW G1	2052	664,837	30	0.125%
Wind - 25 MW	2054	146,340	20	0.100%
CCCT - 170 MW G2	2056	533,967	30	0.125%
CT - 2x50 MW	2063	394,526	25	0.125%
CCCT - 170 MW G1	2063	817,770	30	0.125%
CT - 50 MW	2064	201,208	25	0.125%
CCCT - 170 MW G2	2066	644,550	30	0.125%
CCCT - 170 MW G1	2067	881,714	30	0.125%

Table 38: Fixed Cost Parameters for Infeed Option

Project	In-service year	In-service Cost ($)	Service Life (years)	Insurance Rate (%)
50 MW CT	2014	74,751	25	0.125%
HVDC Labrador-Island Link	2017	2,553,235	50	0.000%
Sync. Condenser	2017	3,140	60	0.125%
Holyrood Decomm. Ph.1	2025	15,451	60	0.125%
Holyrood Decomm. Ph.2	2029	11,881	60	0.125%
Portland Creek	2036	155,671	60	0.100%
CCCT – 170 MW	2037	373,411	30	0.125%
CT – 50 MW	2046	140,871	25	0.125%
CT – 50 MW	2050	152,483	25	0.125%
CT – 50 MW	2054	165,053	25	0.125%
CT – 50 MW	2058	178,658	25	0.125%
CT – 50 MW	2063	197,253	25	0.125%
CT – 50 MW	2066	209,327	25	0.125%

As a further comment with respect to asset life, the typical process for comparing alternatives requires that all options have the same lifespan so that the positive cash flows arising from the individual investments can be fully realized. Where there are differences in the asset life of investments between alternatives, adjustments can be made to compensate.

However, in the case of the current analysis, cash in-flows have been excluded from the CPW calculation. With the CPW analysis, using the COS methodology, the return on the rate base of an asset that is introduced into the generation sequence may extend beyond the end of the 2010-2067 analysis period. As a result, there will be some capacity increments whose full life-cycle benefit are not completely captured. The implications of this aberration have a more profound impact on the Isolated Island Option than the Infeed Option. Since the timeline for the analysis matches Labrador-Island Link HVdc system and approximates that of Muskrat Falls, the impact on the Infeed Option is minimal. In contrast, for the Isolated Island Option, there is a larger proportion of investment projects that are not fully depreciated by 2067. Making a compensating adjustment for this difference would likely add more costs to the Isolated Island Option, leading to an increase in the CPW differential between the two Options.

12.12 Depreciation Expense

For assets included in the analysis on a COS basis, a depreciation expense component related to each project asset is included in the CPW.

Ideally, the computation of depreciation expense should commence when the respective assets are placed into service, and the revenue generated from the use of that asset begins. Given the DG2 stage of development for each project in the analysis, Nalcor assigned a single in-service date for each identified project in the CPW analysis, even though in some instances the project asset is expected to begin generating revenue for NLH prior to the final commissioning date for the project. This potentially occurs where there is more than one generating unit in a project, such as wind farms, hydro stations, and double-unit CCCT projects.

The implication of using a single in-service date in the CPW analysis is that the work-in-process costs that are allowed to accumulate up to the final commissioning date will attract more AFUDC, and therefore make the final in-service costs somewhat higher than would be the case if there were multiple in-service dates for each generating unit. However, in the context of the CPW analysis, this is more than mitigated by the cumulative discounting of fixed costs in the final stages of the project. This is not expected to materially change the relative CPW values between the two Options.

12.13 Regulatory Return on Assets

The CPW includes a Return on Rate Base as a component of the COS. The computation of the Return component is in line with prior regulatory Orders of the Board. As noted above in section 12.5, NLH's Weighted Average Cost of Capital (WACC) is 8.0%. The rate base upon which the WACC is applied incorporates the net asset value of qualified investments that contribute to the production and sale of power to island customers. From the date each asset is commissioned, it is thereafter depreciated on a straight-line basis until the remaining book value of the asset is zero. The sum of the depreciation expense, insurance expense, and the regulatory return on rate base, which includes the net book value of the asset times the WACC, constitutes the respective "fixed cost" for each asset for purposes of computing the CPW values for each Option.

12.14 Insurance

Transmission and distribution assets are self-insured. All other property and equipment is insured on a replacement-cost basis in the general insurance market[239]. Based on discussions with Nalcor, property insurance costs included in the CPW are based on the original in-service cost, which for most types of plant amounts to $0.125 per $100 of original cost. Recognizing that the replacement cost of a current capital expenditure would be an escalated amount, one would reasonably expect that the insurance premium would also be escalated. However, the CPW assumes the insurance expense is constant until the plant is retired. Notwithstanding this point, the difference in insurance costs between fixed and escalated estimates only amounts to a discounted present value of less than $20 million, and accordingly does not have a material effect on the final CPW analysis.

[239] Response to RFI MHI-Nalcor-59

12.15 Thermal Heat Rates

The fuel costs included the CPW analysis are derived from the incremental cost for fuel consumed by thermal generation plants that are required to meet the requirements of the planned load forecast. The cost of fuel is a function of the volumes of each type of fuel consumed and the cost of fuel per unit of volume. All fuel costs included in the CPW are either #2 fuel oil for the combustion turbine units, or #6 fuel oil for HTGS.

The amount of fuel consumed is also a function of plant efficiency, which varies depending on the technology employed and plant efficiency. The term typically used for fuel efficiency is 'heat rate', which is the amount of input energy required to produce a unit of electricity. In addition, plants use some relatively small amount of electricity internally as part of normal operations, which is netted out. The specific net heat rate parameters used by Nalcor in the CPW analysis are set out below in Table 39.[240] The heat rate efficiencies are used as input to Strategist for minimum and maximum production levels, and Strategist uses this range to determine operating efficiency on an hourly basis."[241]

Table 39: Net Heat Rates for Thermal Plant

Plant Type	Fuel Type	Net Heat Rate (MBTU/kWh)
Existing CT	#2	12.263
New CT	#2	9.434
Diesel	#2	10.970
CCCT	#2	7.637 - 8.629
Holyrood	#6	9.780 - 10.388

[240] Exhibit 9 Rev.1, Nalcor, "Thermal Units - Average Heat Rates"
[241] Response to RFI MHI-Nalcor-49-1-a

12.16 Purchased Power

Another component of energy-related costs within the CPW analysis is purchased power. These sources include[242]:

- Nalcor-owned hydro-generation, including:
    - Star Lake – 15 MW / 144.5 GWh per year
    - Exploits River Partnership – 32.3 MW / 137 GWh per year
    - Exploits River generation – 58.5 MW / 479.7 GWh per year
- Non-utility generators (NUGs)
    - Corner Brook Co-generation – 15 MW / 65.3 GWh (until 2022)
    - Rattle Brook – 4 MW/14.5 GWh
- Wind-sourced power (until 2028)
    - Fermeuse – 27 MW / 84.4 GWh per year
    - St. Lawrence – 27 MW / 104.8 GWh per year
- New Wind Farm (2014) – 25 MW/87.6 GWh
- The proposed Nalcor-owned Muskrat Falls Generating Station

The PPAs for the two wind farms, Fermeuse and St. Lawrence, expire at the end-of-life for each facility in 2028. In the Isolated Island Option, these plants are assumed to be re-built by Nalcor and the capital costs of these re-builds are incorporated into the CPW analysis. In the Infeed Option, wind-sourced power is more expensive than Muskrat Falls-sourced power, and therefore the existing wind plants are decommissioned in this Option.

12.17 Operating Costs

Nalcor estimated operating costs for new generation facilities based on current NLH experience for similar types of facilities where possible. A distinction was made between fixed O&M costs and variable O&M costs for all facilities except Muskrat Falls and Labrador-Island Link HVdc system where a combined O&M amount was applied.[243] The operating costs were valued by Nalcor in 2010 base dollars, and an escalation factor was applied for future O&M costs.

During the technical review of the Infeed Option, MHI could only identify reference to a minimal amount of $2.5 million to cover the cost for operations over the entire 50-year life of the 1,100 km Labrador-Island Link HVdc system. Notwithstanding, Nalcor did incorporate in the CPW analysis a

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[242] Exhibit 6a, Nalcor, “Hydro PPA Details”, July 2011
[243] Exhibit 8, Nalcor, “Muskrat Falls HVdc Link Operating Costs Estimates”, February 2011

constant annual operating cost of $11.6 million (2010$) from 2017 to 2025, and $12.4 million (2010$) thereafter to undertake vegetation control programs. They also included a fixed $4.4 million (2010$) cost for periodic cable surveys for the Strait of Belle Isle crossing approximately every five years.

However, there does not appear to be any provision for capital maintenance of the converter transformers. In order to test the sensitivity of additional costs for this, MHI assumed the following:

- Fourteen converter transformers at $5 million each, distributed over years 20-30, leaving the Labrador-Island Link HVdc system asset fully depreciated in 2067

The effect of this is to add $7 million per year over the period from 2029 to 2038, which results in an increase in the CPW for the Infeed Option from $6.651 billion to $6.672 billion. The $70 million difference is effectively discounted to $21 million in the CPW calculation and is therefore not material to the current analysis.

With respect to operating costs, Nalcor provided cost escalation forecasts in Exhibit 3 for O&M expenses for both Options. These forecasts apply to both fixed and variable O&M costs.

The O&M cost forecast escalators are defined in terms of the balance between the composite cost of labour and materials, as described in the response to RFI MHI-Nalcor-50:

1. More material, less labour
2. Same material, same labour
3. More labour, less material
4. Labour only

Nalcor assumed an O&M cost escalation forecast of 2.5% based on the second type, “same material/ same labour” for Labrador-Island Link HVdc system and 2.8% based on the third type, “more labour/less material” for other new generation plants modeled.

12.18 Upper Churchill Power

MHI understands that the current Upper Churchill contract with Hydro Quebec expires in 2041. Nalcor had indicated that sourcing Upper Churchill power was not considered because of the uncertainty as to what will happen post-2041. However, in the document provided as response to RFI MHI-Nalcor-49.2(d), Nalcor shows a supply of energy for the Infeed case from a source labelled ‘Other’. This energy provided over the Labrador-Island Link to NLH, beginning in 2058, is priced at $2 per MWh, without escalation, which is the approximate price of Upper Churchill power. The timing of the introduction for Upper Churchill energy corresponds to the point at which NLH demand grows to the level it fully consumes Muskrat Fall’s average annual generating capacity.

12.19 Fuel Costs

In Exhibit 4, Nalcor provided reference fuel oil price projections[244] for #6 and #2 fuel for the period 2010 – 2025 from the PIRA Energy Group (PIRA), an energy consulting firm which provides analysis and price forecasting services for world energy prices. Nalcor escalated the price forecasts past 2025 at a rate corresponding to the 2% long-term CPI inflator. Since it is beyond a reasonable expectation for anyone to predict with accuracy to what extent fuel prices will escalate beyond 2025, MHI conducted a sensitivity analysis on the potential fluctuation of fuel costs beyond 2025.

It was determined using the original March 2010 reference prices for the various grades of fuel oil used by Nalcor in the Base Case, that changing the long-term price inflator by ±1% relative to the 2% used by Nalcor has a minimal effect as illustrated in Table 40 below. It is apparent that the CPW analysis is not particularly sensitive to the choice of the annual escalation factor applied to the base fuel prices, because the escalation is so far into the future that discounting minimizes their impact.

Table 40: Sensitivity of CPW to the Long-term fuel price inflator ($billion)

Long-term CPI	1%	2%	3%
Isolated	$8.677	$8.810	$8.962
Infeed	$6.651	$6.651	$6.651
Gap	$2.026	$2.159	$2.311

(Source: MHI derived)

What is more critical is the accuracy of the base price projections. This raises the issue of how to best incorporate such uncertainty.

PIRA generally provides four forecast scenarios for consideration by their energy clients:

- Reference price,
- Low price,
- High price, and
- Expected price.

The reference price forecast is the price for delivery at a specific location, based on a current 'reference' scenario for various world financial and economic drivers.

The high and low forecasts reflect alternate possible econometric scenarios that would lead to either higher price pressures or lower price pressures, respectively.

[244] Exhibit 4, Nalcor," NLH Thermal Fuel Oil Price Forecast Reference Forecast", January 2010

An expected price scenario is also calculated as the weighted average price forecast of the reference, low, and high cases. The expected price forecast encompasses the uncertainties associated in the other three scenarios into one.

PIRA also estimates the discrete probability of occurrence for each of the reference, high and low price forecast scenarios. The relative probabilities assigned to each scenario can vary sharply from one forecast to the next.

Nalcor used the reference price scenario in its original CPW calculation and subsequently provided corresponding CPW values in Exhibit 43 based on low and high fuel price forecasts.

The impact on the CPW of using the expected price rather than the reference price was examined. Based on the March 2010 forecast prices provided by PIRA set out on page 10 of 37 in Exhibit 43, and assumed weightings of 50%/25%/25%, the resultant expected prices are higher than the reference prices. The implication is that the CPW provided by Nalcor for the Isolated Island Option is understated. Alternatively, if one were to use a lower fuel prices forecast there is a strong possibility the expected price will be lower than the reference price, in which case the CPW for the Isolated Island Option would be reduced.

To illustrate how the CPW can change based on which scenario is used for analysis, Table 41provides CPW values based on the March 2010 reference, low, high, and expected price cases.

Table 41: CPW Sensitivity to Price Scenarios (March 2010 Forecast - $billions)

Price Case	Low	Reference	High	Expected
Isolated	$6.221	$8.810	$12.822	$9.363
Infeed	$6.100	$6.652	$7.348	$6.719
Gap	$0.120	$2.158	$5.474	$2.644

(Source: Low, Reference, High – Exhibit 43 Rev.1
Source: Expected – MHI derived)

The expected case based on the March 2010 forecast results in a slightly larger gap between the two Options, relative to that provided by Nalcor. This could however change using yet a different PIRA forecast. More interesting is the low price case, where a near-term double-dip recession in the US might lead to fuel prices that are so low that the CPW gap almost disappears.

It is clear there is much uncertainty related to the pricing of fuel for thermal-based power generation. Different scenarios can and should be run and compared, but the results related thereto often have a short shelf life. While the prospect of raising the necessary capital to finance and construct the Infeed Option may be daunting, the uncertainty associated with forecasting the price of fuel for thermal generation over the long term might be, and likely is, even more so.

12.20 HVdc System Losses

Nalcor assumed HVdc system losses are set at 5.0%. However, there is reason to believe they could be higher based on a response to RFI MHI-Nalcor-62. If the loss percentage is 10%, which is Nalcor's worst case design scenario, then there will be higher transmission losses associated with the Labrador-Island Link HVdc system when operating at capacity. An incremental increase of 5.0% to system losses may result in the addition of $150 million to the CPW costs for the Infeed Option.

12.21 Combined Input Sensitivities

Additional sensitivities were performed by varying multiple inputs. For example, if there is a 20% decrease in fuel costs, combined with a 20% decrease in the annual percentage load growth post 2014, and a 20% increase in the capital cost estimate for both Muskrat Falls Generating Station and the Labrador-Island Link HVdc system, the CPW differential would be reduced to $159 million in favour of the Infeed Option.[245]

Also, should the existing pulp and paper mill cease operations, and its generation capacity be available for use on the system (approximately 880 GWh), and should the capital costs of both the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects increase by 10%, the CPW for the two Options would be approximately equal[246].

12.22 CPW Sensitivity Analysis Summary

With projects of this magnitude, and considering the 50+ year (2010 – 2067) analysis period, there are risks and uncertainties associated with the key inputs and assumptions. Changes in these key inputs and assumptions will affect the financial results and must be assessed to determine materiality. These changes in key inputs and assumptions can impact the results of the analysis and shift the preference for what is the least cost option. Fuel costs and construction material costs are variable with world economic conditions. Load forecasts are a major input based on local conditions and must be carefully monitored to ensure that generation development occurs in compliance with future load requirements.

Table 42 summarizes the results of various sensitivities. Increases in capital cost, load forecast reduction, or fuel price reduction could result in the favourable CPW differential for the Infeed Option being substantially reduced or even eliminated.

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[245] Response to RFI PUB-Nalcor-56
[246] MHI derived

Table 42: CPW Sensitivity Analysis Summary

	Sensitivity Summary	Isolated Island Option	Infeed Option	Difference
1	Base case	$8,810	$6,652	$2,158
2	Annual load decreased by 880 GWh	$6,625	$6,217	$408
3	Fuel costs: PIRA's low price forecast	$6,221	$6,100	$120
4	Fuel price reduced by 44% from base case	$6,134	$6,134	$0
5	Labrador-Island Link capital cost increased by 25%	$8,810	$7,050	$1,760
6	Muskrat Falls GS capital cost increased by 25%	$8,810	$7,229	$1,581
7	Muskrat Falls GS and Labrador-Island HVdc Link capital cost increase by 25%	$8,810	$7,627	$1,183
8	Labrador-Island HVdc Link and Muskrat Falls capital cost increased by 50%	$8,810	$8,616	$194
9	Scenario with • Fuel cost decreased 20% • Annual load growth decreased of 20% • Capital cost increased for Muskrat Falls GS and Labrador-Island HVdc Link by 20%	$7,037	$6,878	$159
10	Scenario with • Annual load decreased by 880 GWh • Muskrat falls GS and Labrador-Island HVdc Link Capital cost increased by 10%	$6,625	$6,598	$27

Sources:

Scenarios 1,2,3,4,5,6,7: Response to RFI MHI-Nalcor-41 Revision 1 and EX-43 Rev.1
Scenario 8: Response to RFI PUB-Nalcor-118
Scenario 9: Response to RFI PUB-Nalcor-56
Scenario 10: MHI derived

Given the sensitivity of the load loss on the CPW, particularly in combination with potential variations in fuel price and capital cost estimates, MHI considers it imperative that Nalcor obtain as much understanding as possible regarding the future prospects for the continued operation of its industrial customers and in addition, develop contingency plans to address the implications of reductions in industrial loads.

12.23 Conclusions and Key Findings

When analyzing the least cost as determined by Nalcor, MHI reviewed all Nalcor exhibits and RFI responses that related to the calculation of the CPW figures. In reviewing this information submitted by Nalcor, MHI assessed the specific details of the methodologies employed, both to evaluate the approach used to construct Nalcor's two Options and to look for possible mechanical or methodological errors.

The key finding from the review of the CPW analysis is as follows:

- Based on the capital and operating costs estimated by Nalcor for each option and a common load forecast, Nalcor has determined that the Infeed Option has a lower cumulative present worth than the Isolated Island Option by approximately $2.2 billion. The detailed analysis performed by MHI determined that Nalcor's cumulative present worth analysis was completed using recognized best practices and the cumulative present worth for each option was correct based on the inputs used by Nalcor. These inputs were reviewed in the technical and financial analyses conducted by MHI and were generally found to be appropriate. There are, however, other considerations related to risks associated with the assumptions used for certain key inputs such as load, fuel prices and cost estimates which may impact the cumulative present worth analysis for the two options. These were tested with the use of several sensitivity analyses and the results of these are summarized as follows:
    - Load Forecast

      A major input to the cumulative present worth analysis is the load forecast, and as a result any large changes in the load would have a significant impact. For example, should the existing pulp and paper mill cease operations, and its generation capacity be available for use on the system, and should the capital costs of both of the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects increase by 10%, the cumulative present worth for the two Options would be approximately equal[247].

    - Capital Cost Estimates

      The current capital estimates are within the accuracy of an AACE Class 4 estimate which has a plus factor variance potential of as much as 50%. Should cost overruns reach that level, the difference between cumulative present worth values for each of the two Options would be less than $200 million in favour of the Infeed Option.

    - Fuel Price

      There remains significant uncertainty in fuel price forecasts. Global disruptions in supply could drive the price of oil well above inflation. However, new sources of supply, such as shale oil or downward trends in natural gas pricing, may have the potential to minimize fuel price increases.

      If fuel prices drop by 44% below those used by Nalcor, the difference between the two cumulative present worth results becomes neutral. However, if fuel prices rise more than the reference price used in the cumulative present worth analysis, an even greater difference between the cumulative present worth results would occur.

  The risks associated with these Inputs are further magnified considering the 50+ year period used in the preparation of the cumulative present worth analysis.

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[247] MHI derived from RFI MHI-Nalcor-41 Revision 1

Further considerations which cannot be overlooked relate to meeting environmental guidelines in the future which could be problematic. Nalcor stated that it may not be able to continue operating its oil fired generation facilities if a natural gas combined cycle benchmark for GHG emission intensity levels is applied to oil fired generation.[248]

It is also noted, that while no consideration has been given to carbon pricing in either option, the impact of any future value of carbon credits will be more significant on the Isolated Island Option, which will lead to increasing the differential between the two Options.

[248] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011, pg. 64