

Report to the Muskrat Falls Inquiry

Review of Several Financial Issues Relating to the Decision to Proceed with the Muskrat Falls Project

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May 2019

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Executive Summary

The Muskrat Falls Project (MFP) is an enormously complex, multi-part, multi-stakeholder agglomeration of electricity infrastructure assets and agreements that could only be created through years of work among governments and corporations. It does not fall into any of the simple categories of traditional electricity arrangements (e.g., regulated utility asset, power purchase agreement, merchant generator, etc.), because it has elements of almost all of them. It involves three governments, two corporate owners, and four electricity jurisdictions, and its many contractual agreements have terms lasting up to 50 years or more.

The Project was the centerpiece of the Interconnected Island Plan, one of two electricity system plans developed by Nalcor to serve the needs of Newfoundland ratepayers until 2067. In this plan, new assets beyond the MFP were not needed until at least 2032. The Holyrood Generating Station would shortly be retired, and new fossil fuel-based electricity generation would be limited to smaller turbine assets as required in the future. The plan was characterized by a single, very large upfront investment in the MFP, which would be paid for through a strictly defined Power Purchase Agreement (PPA) covering the cost of the Muskrat Falls Generating Station (MF) and the associated Labrador Transmission Assets (LTA). In addition, a traditional Cost of Service (COS) arrangement would recover the cost of the Labrador Island Link (LIL), the large high voltage transmission line that would carry power from Labrador to the Island of Newfoundland, and link it for the first time to the North American electricity grid. In addition to these MFP assets included in the Interconnected Island Plan, the MFP also included the Maritime Link (ML), an undersea high voltage transmission line carrying power from Newfoundland to Nova Scotia, and beyond to export markets in the United States. This second electrical link to the continent would be paid for by Nova Scotia ratepayers in exchange for some of the energy produced at the MF.

An alternative system plan was developed, the Isolated Island plan, which was determined by the Strategist modeling software to be the least cost alternative to serve Newfoundland ratepayers, based on the assumptions made by Nalcor. This plan featured the refurbishment and continued use of the Holyrood Station until the mid-2030s, supplemented by multiple investments in smaller wind, hydro and combustion turbine facilities. No link to the mainland was proposed in this plan, as indicated by the name.

A third option, which included a transmission link to the mainland without the rest of the MFP, but instead focused on imports as a substitute for the Holyrood station, was deemed to be unworkable, and not pursued. Finally, a fourth option, which consisted of the early elements of the Isolated Island Plan, but the later development of a link to the mainland to coincide with the availability of energy from the Churchill Falls Generating Station after 2041, was deemed to be too expensive, because of the stranding of assets developed in the years before 2041.

The two system plans – Interconnected and Isolated Island – were subjected to two rounds of financial modeling and testing, the first time as part of the Muskrat Falls Review before the electricity regulator, the Board of Commissioners, and the second time in 2012 for the purpose of facilitating a decision by the Government of Newfoundland. Good practice for this type of analysis would have included systematic review of all variables critical to the outcomes of each plan, including financial modeling of an extensive number of combinations of those variables, or scenarios. This work was not completed. Instead, a single Reference scenario was developed, and a relatively small number of sensitivities to individual variables were examined. During the Review process, a small number of multi-variable scenarios were tested, but not systematically, and not to the degree necessary for a fulsome and thorough review. In the second stage, no combinations of variables were tested.

This limited set of information is a suspect basis on which to make a judgement about the fairness of the proposed system plan to ratepayers. A proposed arrangement is fair for a stakeholder, from a financial point of view, if it can be shown that it is at least as economically favourable as all other available alternatives, within reason given the limits of uncertainty. Where there are inherent limits to certainty, and where arrangements are complex, support for fairness can be found if the distribution of costs, benefits, risks and rewards appears to be proportional among the stakeholders.

From the record of information reviewed, it is clear that there was an insufficient basis upon which to make a determination of least cost of available alternatives, on a risk-adjusted basis. This does not mean that the conclusion was not possible, only that it does not appear it could have been credibly arrived at given the analysis completed.

The outcome of the decision, seven years later, has been extremely negative for ratepayers, since the project is significantly over budget and behind schedule. Also, many of the conditions of other variables that would have contributed to a poor modeling result for the Interconnected Island plan have actually come to pass: low load, low export prices, low fuel costs, etc. However, even if this scenario was tested at the time – and it appears that it was not – the scenario would probably have been considered an unlikely outcome. One “extreme” potential outcome among many possible scenarios would not necessarily have decisively swayed judgement about the plans. It is improper to thrust today’s biases – based on lived experience – back in time to when all futures were still possible.

In addition to the murky uncertainty pertaining to the determination of least cost, the disproportionality of treatment among stakeholders also makes it difficult to support the fairness of the transaction. The plan called for ratepayers to accept the benefit of energy in exchange for a fixed term PPA and the cost of a transmission line. In addition, the arrangement required ratepayers to accept all downside risks of construction overruns and schedule delays, with little apparent in the way of compensating upside risks. This can be contrasted with the Government shareholder of Nalcor, which would gain broad societal benefits in several forms, plus guaranteed return on all committed equity capital, plus export revenues, plus the strategic benefits associated with the accomplishment of an alternate electricity export route to the United States through the ML.

This latter element, a subsea electricity export route, most directly related to the pre-existing Churchill Falls Generating Station, for which new commercial arrangements will be required in 2041. The MFP was profoundly important in relation to this asset, and yet the relationship was never made clear. Moreover, no commitment was made to ratepayers that they would participate in the upside opportunities associated with Churchill Falls in exchange for accepting downside risks in the MFP. The matter was not even addressed in those terms.

Now that the project has gone ahead, and an extremely unfortunate series of events has transpired, Newfoundland ratepayers face a period of 20 years of high and increasing burden to support the electricity investments made. Subsequently, with changed circumstances at Churchill Falls that may benefit ratepayers and alleviate some of their burden, and later, after 50 years, with the completion of the PPA, future ratepayers will be much, much better off. This inequity between generations is extremely problematic. The risk of this transpiring was evident from the materials available at the time of the decision, but was apparently not investigated, and hence thought was not invested in determining a potential mitigation strategy, should this inequity come to pass. That should be a priority now.

Morrison Park Advisors

MPA is an independent, partner owned investment banking advisory firm. We primarily advise clients on mergers and acquisitions, equity and debt capital raises, divestitures and restructurings. In addition, we provide formal valuations, fairness opinions, contract negotiation services, advice to special committees of boards of directors, advice on initial credit ratings, expert testimony before courts and regulatory bodies, policy development, and market analysis. Our ability to deliver top tier financial advisory services is based on decades of combined experience and expertise developed at some of Canada's leading investment banks, while serving many of Canada's largest and most sophisticated corporate clients as well as federal, provincial and municipal governments and quasi-government entities.

Our areas of specialty include utilities, infrastructure and power; mining; real estate and technology. In the electricity sector, MPA has direct and recent experience on a number of transactions and other advisory assignments involving electricity assets and has detailed knowledge and experience with this market, its participants and how they operate.

Information on the team members contributing to this report, as well as the scope of our assignment is attached in Appendices A through E.

For more information on MPA, please visit our website at www.morrisonpark.com.

1. Introduction

A. Muskrat Falls Inquiry

The Commission of Inquiry into the Muskrat Falls Project was created by Regulation 101/17 under the Newfoundland Public Inquiries Act. The Inquiry was given a broad mandate to review issues related to the decision to pursue the Muskrat Falls Project in 2012, and the reasons why the project has turned out differently than projected at that time.[1]

B. MPA Scope of Work

MPA was retained to review certain matters, primarily financial in nature, related to the Muskrat Falls Project. These include:

I. Review of the role and importance of certain financial assumptions that were relied upon in the 2012 decision to proceed with the Muskrat Falls Project, including those related to future domestic load, future fuel prices, and future energy export prices. These should be placed into the context of the many other assumptions that were involved in the financial analysis undertaken at the time.

II. Comment on the use of the Cumulative Present Worth metric relied upon in the supportive financial analysis undertaken in 2012, in the context of other alternative metrics for financial analysis, and any potential alternative conclusions that might have resulted from use of other metrics.

III. Comment on the decision to dismiss, without detailed financial consideration, alternatives other than the Isolated Island plan and the Interconnected Island plan featuring the Muskrat Falls Project. In particular, consider the possibility and cost of importing electricity from Quebec.

IV. Comment on the potential relevance, primarily in financial terms, to the Muskrat Falls Project of the completion in 2041 of the existing contract between Churchill Falls Corporation and Hydro Quebec.

Please see the Appendix E for a full description of MPA's scope of work.

C. MPA Approach

MPA is a financial advisory firm with deep experience in electricity-related projects, and as such regularly analyzes and reviews such projects from a financial point of view. The typical instrument used in such circumstances is the "Fairness Opinion": a financial analysis of a proposed project from the perspective of one or more stakeholders, which considers the likely outcome of pursuing the project or the viable alternatives to the project in financial terms. Usually, "fairness" is considered in two ways:

- First, from the perspective of a particular stakeholder (normally the client for the analysis): Is the proposed project at least as financially favourable as the available alternatives?

[1] Please see Exhibit 1 of the Muskrat Falls Inquiry for the full terms of reference.

- Second: Are the risks and rewards of the proposed project proportionately distributed among the stakeholders? In other words, given the costs, benefits, risks and opportunities arising from the project, is each stakeholder, and in particular the client stakeholder, bearing costs and risks in exchange for a share of the benefits and opportunities that is proportional to other stakeholders?

The first test is the primary test for fairness, from a financial point of view. In simple transactions where the conclusion is a financial close, no further test may be required. However, where a transaction gives rise to ongoing complex obligations and relationships among the parties, and in particular where there is inherent uncertainty of outcomes over time, the second test may be a valuable element in determining overall fairness. In addition, in complex transactions where outcomes are uncertain, "financially favourable" must be understood to include the concept of "risk adjustment", since the prima facie counting of benefits may be impossible, or may lead to apparent errors if the probability of outcomes is not taken into account. In these cases, the consideration of proportionality of distribution among stakeholders becomes even more important.

Financial tools used in preparing a Fairness Opinion generally include discounted cash flow models, comparison to past projects of a similar nature ("precedents"), and calculation of financial outcomes based on current market metrics that are relevant to the project ("comparables" or "comps"). All of these techniques inevitably rely on a host of subsidiary assumptions and projections for all aspects of the project, often prepared by third parties or project participants.

In fulfilling our scope of work to the Inquiry, MPA will use the structure of a Fairness Opinion to consider the financial issues we must address. However, this choice comes with some caveats:

- Obviously, we were not participants in the decision-making of 2012, and are only looking at the Project from the perspective of 2019, with all of the bias that inevitably results from seven years of subsequent events. We will attempt to make clear the issues and questions that would have been of concern at the time if we had been asked to review the project prior to its 2012 sanction, to the degree that is possible.

- This is not, and should not be considered a Fairness Opinion on the decision that was taken. It is nonsensical to undertake a fairness opinion after the fact, because a fundamental issue in many fairness opinions is the consideration of uncertainty, and the limits of knowledge. Today, we know what outcomes have resulted over the course of seven years, but at the time, a range of futures was still possible. Nevertheless, following the structure of a Fairness Opinion may be helpful to highlight various issues that might be considered important by the Inquiry.

D. A Note on Financial Projections and Models

The decision-making on the Project in 2012 relied heavily on financial models, and forecasts, estimates and projections of the future embedded in all of the financial model inputs. These forecasts, estimates and projections went forward into the future not only years, but decades. For any project that involves long-lived infrastructure, the use of such projections and models is inevitable and necessary, but must also be put into context and understood in an appropriate light. This is a point that we emphasize in all of our work: projections are useful and necessary tools, but they are only tools used in a process of making important judgements.

It is always assumed that the forecasts, estimates, and projections were prepared with all due care and professional diligence. MPA is not an expert in any form of forecasting, and defers to those experts that have prepared such reports. We recognize and accept that such reports, however well prepared, may not accurately predict the future of the subject matter to which they are addressed. Forecasts, estimates and projections are understood to be reasonable attempts at predicting the future from the point of view of a particular time.

Useful forecasts for the near to medium term are typically based on the belief – sometimes proven by subsequent events to be erroneous – that the future will consist of incremental changes to the practices of the recent past. However, the longer the time horizon of the forecast, the more likely that changes will cease to be incremental, and become truly unpredictable. What may appear to be reasonable today may at some point in the future – with the benefit of hindsight – look like a terrible mistake, or a massive stroke of luck. Prices change, technology changes, market dynamics change, the relative cost of goods changes: all in unpredictable ways over time.

Technological advances, in particular, can render assumptions obsolete even in relatively short periods of time. The development of hydraulic fracturing in the natural gas industry in the early 2000s is only a single example of expectations about future market conditions being totally and fundamentally undermined: widespread expectations in 2005 were that North America would within 10 years be supply-constrained and increasingly reliant on expensive imports of natural gas from elsewhere. Yet by 2010 the production of natural gas had dramatically increased, the North American price of natural gas had collapsed, and a rush was on to find ways to export the product internationally. In earlier decades similar received wisdom was overturned (for example, there was a time in the mid-twentieth century when many experts believed that nuclear power would render electricity "too cheap to meter". Needless to say, the aspiration was never achieved).

There is a significant danger in assuming that a view of the future from the perspective of today will be very accurate. All such assumptions should be approached with humility, and treated with respect as the best available basis for decision-making, but without claiming them to be more than what they are. Decisions cannot be made without taking a view of the future, but the future may prove unwilling to agree with the forecasts made of it.

It is commonplace that commercial transactions are analyzed using mathematical models, often providing a degree of precision measured in decimal points, which sometimes gives the illusion of accuracy or predictive power. We use such models in all of our work, and did so in the preparation of this Report. However, these models are only as accurate as the assumptions about the future that underlie them. Since those assumptions must be given a broad range because of the difficulty inherent in predicting the future, especially over decades, the models should and do result in outputs with an equally broad range. This means that mathematical models sometimes may be capable of excluding certain decision options from the realm of reasonable commercial choice, but cannot always point to a single preferred outcome among several. In these cases, decisions still must be made, but they must be rendered on the basis of judgement.

Commercial decisions are ultimately about judgement, and judgement is extremely difficult to quantify.

E. The Structure of this Report

The remainder of this Report will be organized in the following way.

Table 1: Report Structure

Section	Title	Matters Addressed
2	Muskrat Falls Project and Alternatives	• Electricity context for the Muskrat Falls Project • Description of the Muskrat Falls Project, its components and relevant stakeholders • Alternatives to the Muskrat Falls Project • Commentary on the relevance of Churchill Falls and the related option of importing power from Quebec
3	Comparing the Interconnected and Isolated Island Plans	• Cumulative Present Worth financial analysis and other options • Forecasts, estimates and projections critical to the comparison of the options • Commentary on the calculation of potential scenario outcomes
4	Distribution of Costs, Benefits, Risks and Rewards	• Review of the balance of costs and benefits, risks and opportunities for each stakeholder • Apparent Proportionality?
5	Additional Issues	• Approaching Churchill Falls Value • Generational Impact on Newfoundland Ratepayers
7	Summary Observations	

2. Muskrat Falls Project and Alternatives

A. Electricity System Context for the Project

The Muskrat Falls Project was designed to satisfy the electricity needs of the Province of Newfoundland and Labrador for a generation, and to exploit a critical natural resource in the province for export purposes. Put differently, the Project was possible because of the existence of a natural resource (the Churchill River in Labrador and the specific locations on it that might be exploited for the development of hydroelectric facilities), and apparently pursued for a variety of electricity system, economic and social reasons.[2]

Hydroelectric energy has been a staple of Canada for more than a century, and a critical component in the economic development of many provinces. The technology is very well understood, as are typically associated costs, benefits, risks and opportunities. Newfoundland and Labrador also has past experience in the development of large-scale hydroelectric resources in the form of the Churchill Falls Generation Station (which is a critical factor in the consideration of the Project, that will be explored further, below).

Newfoundland and Labrador is a relatively small province in Canada in both population and economic terms. As of 2010, the Province had a population of 522,000 people, and a GDP of $27.2 billion, or $52,000 in per capita terms (all references in 2010 current dollars). Consideration of a multi-billion-dollar project such as the Muskrat Falls Project is therefore a major undertaking. This is exemplified by the fact that at its 2012 budgeted cost, the Project would represent nearly $12,000 per capita in the province, an amount that can be put into context by the approximately $15,000 per capita provincial government net debt in 2010. Relatively overnight, the accumulated provincial government net debt would be almost doubled, were the Project to have been solely funded by the province of Newfoundland and Labrador.

The electricity system in the province prior to the Muskrat Falls decisions consisted of three separate components: an interconnected system on the Island of Newfoundland, an interconnected system in Labrador, and a series of small isolated systems on both the Island and in Labrador that were served by small diesel generation facilities.[3] The Island system was isolated from Labrador, and not connected to the broader North American electricity grid.

A critical driver for the Project was the perceived need to address the ageing Holyrood Generating Station on the Island of Newfoundland. The oldest parts of this 490 MW oil-fired facility were commissioned in 1971, and the whole facility would be reaching the end of its useful life within a decade. As with all major electricity infrastructure, the "end of life" date is a somewhat flexible concept, but planning for the replacement of such a facility should be considered appropriate.

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[2] The December 17, 2012, Government of Newfoundland News Release for the Project Sanction Agreement attributes the following to the Honourable Jerome Kennedy, Minister of Natural Resources: "Muskrat Falls will meet our province's future energy needs, stabilize rates for residents and businesses, while generating significant economic, employment, and social benefits for the people of our province, the Atlantic region and the rest of the country."

[3] A detailed description of the Newfoundland & Labrador electricity system can be found in "Review of the Newfoundland and Labrador Electricity System", a paper prepared in 2015 by Power Advisory LLC for the Newfoundland and Labrador Department of Natural Resources, and can be found at https://www.nr.gov.nl.ca/nr/publications/energy/review_of_nl_electricty_system.pdf

As of 2010, the province as a whole had a peak electricity requirement of 1478 MW, and total annual consumption of 8.33 TWh. Typically, between 15% and 25% of total provincial electricity demand was supplied by the Holyrood station, with a theoretical maximum of about 40%.

Nalcor Energy, the holding company formed to own and exploit the provincial government's electricity and hydrocarbon assets, is 100% owned by the Province of Newfoundland and Labrador. It is operated as a commercial enterprise and generates dividends for the province. Taxpayers, through the provincial government, invest equity in the corporation and its projects, and expect returns on that equity.

Nalcor is not the only electricity company in the province, however, as Newfoundland Power (a subsidiary of Fortis Inc.) is the electricity distribution company on much of the Island of Newfoundland, and also owns some generation capacity (a small amount of additional generation capacity is in the hands of various private actors). Regardless, Nalcor is the principal provider of both electricity supply and transmission in the province.

The Churchill Falls Generating Station, at 5428 MW the second largest in Canada, is located in Labrador. It is owned by Churchill Falls Labrador Corporation (CFLCo), which is in turn owned by Nalcor Energy (65.8%) and Hydro Quebec (34.2%). Unfortunately, since the Island of Newfoundland was historically electrically isolated from Labrador (and the rest of North America), this potential source of electricity was not available to ratepayers on the Island of Newfoundland. In any case, the vast majority of the output of the station is under contract to Hydro Quebec until 2041, and hence would not be available for the timely replacement of Holyrood.

In simplest terms, from an electricity system perspective there was a clear need for an investment plan as of 2012, if for no other reason than to prepare for the replacement of the Holyrood Generating Station.

B. The Muskrat Falls Project

The Muskrat Falls Project (MFP) is an enormously complex, multi-part, multi-stakeholder agglomeration of electricity infrastructure assets and agreements that could only be created through years of work among governments and corporations. It does not fall into any of the simple categories of traditional electricity arrangements (e.g.: regulated utility asset, power purchase agreement, merchant generator, etc.), because it has elements of almost all of them. It involves three governments, two corporate owners, and four electricity jurisdictions, and its many contractual agreements have terms lasting up to 50 years or more.

The sheer size and complexity of the Project make it obvious that it is not intended to simply meet the electricity system need to replace the ageing Holyrood Generating Station. While it certainly was intended to accomplish that, it is apparent that there are multiple other motivations and interests at play.

The Project consists of the following assets:

i. Muskrat Falls Generating Station (MF): An 824 MW nameplate capacity hydroelectric generating station on the lower Churchill River, expected to generate approximately 4.9 TWh of energy each year

ii. Labrador Transmission Assets (LTA): High-voltage AC transmission line between the existing Churchill Falls Generating Station and the Muskrat Falls Generating Station

iii. Labrador Island Link (LIL): High-voltage DC transmission line capable of carrying 900 MW of power between the Muskrat Falls Generating Station and the Soldiers Pond converter station on the Island of Newfoundland (near St. John's)

iv. Maritime Link (ML): High-voltage DC transmission line capable of carrying 500 MW of power between Bottom Brook Newfoundland and Cape Breton, Nova Scotia, plus associated upgrades to the transmission system in Newfoundland leading to Bottom Brook

v. Rights to transmit power through Nova Scotia, between Nova Scotia and New Brunswick, and between New Brunswick and Maine, that will facilitate the sale of power from Newfoundland and Labrador to markets in the northeastern United States

An additional element of the arrangement, not really an asset, but a critical part of the whole, is

vi. Federal Loan Guarantee (FLG): the Government of Canada agreed to guarantee debt amounting to approximately 70% of the capital cost of the Project to ensure that it received the lowest possible cost of debt, based on Canada's AAA credit rating

As of Project Sanction in December 2012, the construction budget for the entire Project was $7.7 billion, consisting of $6.2 billion for MF, LTA and LIL, and $1.5 billion for ML. In addition, financing and other costs amounting to nearly $1.5 billion were anticipated.

The following table summarizes the benefits, costs, risks and opportunities applicable to each of the major stakeholders of the Project, as of the Project Sanction date in 2012. Further notes on certain items appear after the table.

1 **Table 2: Muskrat Falls Project Stakeholders & Interests**

Stakeholder	Benefit	Cost	Opportunity	Risk
NL Ratepayers	• Energy from MF • Available energy from Churchill Falls until 2041 • Island of Newfoundland connection to North American grid for reliability purposes	• Full capital and operating cost of MF and LTA on a PPA basis • Full capital and operating cost of LIL on a COS basis • Operating cost of ML after 35 years of operation until end of life (expected life is 50+ years)	• Access to substantially more energy, at some possibly advantageous price, from Churchill Falls after 2041	• Cost and schedule overruns of MF, LTA and LIL • Failure of MF, LTA and LIL and necessary repair/replacement costs • Failure of ML after the first 35 years of service, and necessary repair/replacement costs
NL Government	• "Greening" of Newfoundland electricity supply • Jobs and regional economic development associated with construction of MF, LTA and LIL, including special arrangements with First Nations • PPA return on equity provided for MF and LTA, and regulated return for LIL (through Nalcor) • Net revenue received from the export of excess electricity from MF (through Nalcor) • Alternate route to market for excess Churchill Falls energy • Strategic value of demonstrating alternate route from Churchill Falls to US electricity markets	• 100% of the equity required for MF, and 51% of the budgeted equity required for LTA, LIL and ML (which will consist of 100% of equity required for LTA, 0% for ML, and remainder in LIL) • Legislative changes in NL to execute the agreement	• Future access, after 2041, to low cost electricity from Churchill Falls for economic development in Newfoundland, and for export purposes	• Additional equity required to fund cost overruns in MF, LTA and LIL • Loss of provincial economic competitiveness in the event that costs to ratepayers prove higher than budgeted

Stakeholder	Benefit	Cost	Opportunity	Risk
NS Ratepayers	• Contracted energy from MF for 35 years (including additional amount in first 5 years) • Opportunity to buy excess energy from Newfoundland at market prices for full 50+ year life of ML • Transmission fees charged to Nalcor for export of power through NS might marginally reduce transmission costs to NS ratepayers	• Full capital and operating cost of ML for 35 years on a COS basis	• Excess energy purchases from Newfoundland may be cheaper than all other potential sources	• Cost and schedule overruns of ML • Failure of ML during first 35 years and repair/replacement costs • Failure of ML after 35 years resulting in no access to additional energy
Emera	• Return on equity provided from investment in transmission assets	• Equity to fund 49% of the budgeted amount for LTA, LIL and ML (which will consist of 100% of equity required for ML, and remainder in LIL) • Transmission rights in NS, between NS and NB, and between NB and Maine transferred to Nalcor • Certain potential upgrade costs to transmission systems that might be required to facilitate exports of energy from Newfoundland through NS, NB and into Maine	• Future construction and ownership of additional transmission lines to facilitate export of power from Newfoundland through the Maritimes to the United States	• Additional equity to fund cost overruns in ML

Stakeholder	Benefit	Cost	Opportunity	Risk
NS Government	• "Greening" of NS electricity supply • Jobs and regional economic development associated with ML	• Legislative changes in NS to execute the agreement	• Access to lower cost power could enhance NS economic competitiveness	• Failure of the project to deliver lower cost energy could harm NS economic competitiveness
Government of Canada	• Jobs and regional economic development in the Atlantic Provinces • "Greening" of electricity supply in Newfoundland and NS, with consequent reduction of GHG emissions	• Multi-billion-dollar federal loan guarantee represents a contingent liability on the Government balance sheet, and reduces (marginally) the Government of Canada's total available borrowing capacity	• Future regional economic development of Atlantic provinces based on low cost energy	• Failure of the Project, and requirement of the Government of Canada to make good on its guarantee of funds lent to the Project • Cost and schedule overruns, which might necessitate additional debt capital, and hence a larger loan guarantee
Private Debt Providers	• Return on funds lent to the Project	• 70% of the capital cost of MF, LTA, LIL and ML		

B.1. Payment Mechanisms

Ratepayers in Newfoundland and Labrador will be paying for the Project based on two different payment mechanisms: Cost of Service (COS), and Power Purchase Agreement (PPA).

Cost of Service is the traditional way through which the costs of regulated utility assets are calculated and charged to utility ratepayers. For every asset, ratepayers are required to pay annual operating costs, plus the capital costs and taxes associated with it.

Annual operating costs are largely self-explanatory, and typically include such things as the labour and administrative costs of operating an asset, and the labour and materials required for maintenance of it. In the case of assets which require fuel for operation, annual operating costs include fuels, and therefore can be very high. Operating costs also often include such things as property taxes, licensing fees and other regulatory costs. Annual operating costs often rise over time on some inflationary basis, since the cost of labour typically rises according to collective bargaining agreements. The cost of materials and fuels are often based on competitive markets, and therefore are not predictable over long periods of time.

Capital costs consist of annual return of capital (i.e., "depreciation" in accounting terms), interest on outstanding debt, and return on outstanding equity (i.e., "net income" or "profit"). Assets are normally depreciated on a straight line basis over their expected useful life, which means that outstanding capital is much larger at the beginning of a project, and dwindles over time. Interest and return on equity costs are therefore also much higher in early years, and lower in later years. The result is that total capital costs are quite high in early years of an asset's life, and much less in later years, if an asset is managed on a Cost of Service basis. Income taxes that are payable on "net income" (return on equity) are also charged to consumers, to the extent that the equity provider is taxable.

Combining operating and capital costs results in an expected payment schedule for ratepayers over time. Depending on the relationship between operating and capital costs, the COS payment method can result in either rising or falling total costs. For example, where an asset uses expensive fuel and high cost labour that increases sharply in price over time, and has a relatively low capital cost (e.g., natural gas or oil-fired electricity generation plants), the COS payment method might result in rising costs over the 25 to 40-year life of an asset. Alternatively, when an asset has a very high capital cost, but a modest associated operating cost over time (e.g., for a hydroelectric generating facility or a high voltage transmission line), COS may result in high initial costs, but falling ratepayer burdens over time.

Another critical feature of the COS payment method is that charges to ratepayers are adjusted frequently to reflect actual ongoing costs. In other words, if operating costs rise more or less because inflation is higher or lower over time, costs to ratepayers reflect those changes. In addition, depending on payment terms for debt, changes in interest rates might be reflected in capital costs over time. Rates of return on equity may also be adjusted from time to time, based on economic conditions. The result is that ratepayers face some uncertainty in their total cost burden for any given year, but on the other hand amounts are based on actual prevailing conditions.

If the result of COS treatment is declining annual costs, however, this can be a difficult burden for ratepayers. Typically, general market prices and incomes rise over time with inflation. When ratepayers face an inverted cost expectation – high initially, but lower in the future – this can be perceived as unfair. Ratepayers in the early years of asset life will be paying a higher portion of the total full-life cost of the asset, and a higher portion of their disposable income, while ratepayers in later years will pay a lower portion of the full-life cost, as well as a much smaller portion of their inflated-over-time income.

Power Purchase Agreements (PPA) are an alternative mechanism to pay for electricity assets. In this case, the operating and capital costs of an asset are estimated on a full life basis, and the cost to ratepayers divided over the expected life of the asset. The annual cost burden can either be flat in nominal dollar terms, rising with inflation, or adjusted on some other basis. In some cases, annual cost adjustments can be fixed at the outset of the project, or in other cases reflect ongoing conditions (e.g., prevailing fuel prices, inflation, etc.). Since debt costs are often fixed for projects, these adjustments in ratepayer cost burdens are often accomplished by varying the timing of return on equity for investors (i.e., "profits" might be very low in the early years of an asset's life, but very high in the later years).

PPAs can reflect prevailing conditions (e.g., inflation, interest rates) to varying degrees depending on their design, but generally to a lesser extent than COS models. From a ratepayer perspective, however, PPAs can often be more consistent with common expectations of prices rising over time. Ratepayers in any given year would expect that their proportional burden of full life asset costs, adjusted for inflation, would be approximately flat (which would also be broadly consistent with growth of disposable income).

In the case of the Muskrat Falls Project, the decision to structure the MF and LTA costs as an inflation-adjusted PPA appears to be a deliberate attempt to proportionately share the cost burden among ratepayers over time. However, it is important to note that the LIL was not structured as a PPA, but rather a COS asset. This means that for Newfoundland and Labrador ratepayers, only part of the Project cost burden was organized on a rising cost basis.

B.2. Available Energy from Churchill Falls

While the vast majority of the output of the Churchill Falls Generating Station is under contract to Hydro Quebec until 2041, there are two blocks of output that are set aside for use by Nalcor. These are the "Recall Block" – 300 MW of power at a maximum 90% load factor – and the "Twin Falls Block" – 225 MW of power at a maximum 90% load factor. Together these represent a theoretical maximum of 4.14 TWh of energy per year (in practice substantially less than this theoretical maximum, since the output of Churchill Falls is more in the range of 65% than 90% on an annual average basis).

As of the date of Sanction of the Project in 2012, the Twin Falls power was fully contracted to certain mining concerns in Western Labrador, but only until 2014, when other arrangements might be possible. However, much of the Recall power was being sold to export markets through Quebec transmission corridors. With the development of the LTA and LIL and the resulting grid connection between Labrador and Newfoundland, any of this power could be used to supply Newfoundland needs. Alternatively, it could be exported through the LTA, LIL and ML to US export markets on the eastern seaboard, if that were advantageous.

B.3. Strategic Value of the Project to Churchill Falls, 2041, and Potential Benefit to NL Ratepayers

This issue will be addressed in greater detail in a separate section, below. However, in brief, the successful and economical construction of a route to US export markets through the LTA, LIL and ML would demonstrate that existing Hydro Quebec transmission corridors are not the only path to market for the output of the Churchill Falls Generating Station. This would fundamentally alter the negotiating position of Nalcor vis-à-vis Hydro Quebec, when the future of Churchill Falls beyond the 2041 expiration of the existing contract with Hydro Quebec is ultimately discussed. This change would potentially deliver significant value to both the provincial government of Newfoundland and Labrador (and hence taxpayers), as well as to ratepayers in the province.

B.4. Value of Interconnection to North American Electricity Grid

The Island of Newfoundland historically operated as an isolated electricity grid, consisting of sources of supply located on the Island, and customers also located on the Island. This contrasts with jurisdictions across North America that are interconnected: while each jurisdiction has its own sources of supply and customers, they also have live connections to other jurisdictions that can serve as emergency sources of electricity or customers (when a grid produces too much energy unavoidably, being able to ship it out to far away customers is often advantageous). Isolated systems must constantly be in balance (supply and demand of electricity must match), in all situations and under all conditions. Given the susceptibility of electricity systems to weather events (e.g., heat waves or cold snaps that cause demand to spike, or storms that could damage and put out of service critical sources of supply), access to a broader grid of interconnected electricity systems is a form of insurance against local challenges. Weather events are often local or regional in nature, so the larger the size of the interconnected grid, the more likely it is that grid resources are not all simultaneously facing the same challenges.

From this point of view, the connection of the Island of Newfoundland to the North American grid through both the LTA/LIL and ML is a significant benefit that is difficult to value in monetary terms. At the same time, the two interconnections allow for the potentially advantageous trading of energy, which could give ratepayers access to cheaper sources of electricity if local sources are, for whatever reason, rendered uncompetitive. While the province would be expected to have a surplus of energy available after the Project is completed, having the option of sourcing power from other markets is still valuable when considering future investments.

B.5. Jobs and Regional Economic Development

Not all electricity projects are equal from the point of view of local economics. Two projects delivering the same amount of power and costing exactly the same for ratepayers can have radically different local economic impacts. To illustrate with an extreme and simplistic comparison: imagine an electricity import project from a neighbouring jurisdiction sized at 100 MW. In this case, the local impact might be the construction of a small number of towers and wires to bring electricity into the jurisdiction. The price of the power could be fixed by contract, and ratepayers would pay that price. Alternatively, imagine that electricity was produced locally for exactly the same price to ratepayers, but the power was produced using machines that were invented, built, and operated by local labour and capital. The impact on ratepayers would be the same (since the prices and contract terms are the same by definition), but the impact on the economy is totally different.

Obviously, reality is never so neatly comparable. Some projects may involve more local labour and capital, but at higher costs or for different terms. While local economies might benefit, it could be at the cost of higher prices for ratepayers, or perhaps fixed versus variable prices for a different period of time.

To the extent that jobs and regional economic development are taken into account in decision-making about electricity projects, the trade-offs between impacts on ratepayers and impacts on other stakeholders must be clearly understood and defined.

C. Alternative Electricity System Plans

If the Muskrat Falls Project is understood narrowly as a response to an electricity system need for new supply resources, then logic suggests that a list of alternatives begins and ends with electricity system resources. Given that the need was on the Island of Newfoundland, which was, before the Muskrat Falls project, an isolated electricity system, then the alternatives naturally fall into two categories: those in which the Island remains an isolated system, and those in which the Island is connected to the continent.

Assuming the continuation of an isolated system, the full range of local resource options could be considered:

- Traditional fossil fuel-fired electricity generators, including coal, natural gas and oil;
- Nuclear energy;
- Mainstream renewable energy sources such as hydroelectric, onshore wind and solar photovoltaic;
- Still-developing renewable technologies, such as offshore wind, tidal, wave, geothermal, solar thermal, and biomass of various types;
- Demand-side resources such as demand management programs and policy-induced conservation; and
- Energy storage devices as solutions to peak requirements or as supplements to other resources.

In the alternative case of a connection to the North American grid, then a significant expenditure on transmission lines is assumed, plus one or more of:

- Any of the resources described above, except located in Labrador instead of Newfoundland; and
- Importing electricity from outside of the province.

C.1. Supply Options Reviewed in Phase 1 of the Muskrat Falls Process

The Muskrat Falls decision-making process included two phases of review of supply options: an initial phase during which a broad range of options were considered from a variety of standpoints, including feasibility, approximate cost, and expected environmental impact, and a second phase of detailed review and financial comparison.

The following options were considered in the first phase.

Table 3: Options Considered by Nalcor in Phase 1 Review[4]

Category	Option	Notes
Isolated Island	Nuclear	• Rejected as impractical because of the typical size of nuclear units, output profile compared to the system need, and existing laws disallowing nuclear power
	Natural Gas (engines or turbines, single cycle or combined)	• Rejected due to the lack of natural gas availability on the Island, and the excessive cost of developing infrastructure to give access to a viable supply
	Coal	• Rejected due to the environmental impacts of coal-fired power, and the likelihood of future restrictions on the use of coal for electricity generation in Canada
	Oil (engines, boilers or turbines, single cycle or combined)	• Current use in Newfoundland • Considered a viable alternative for the future, with the caveat that future environmental restrictions may increase the cost and other burdens of operation
	Wind	• Considered a viable resource, but limited in its applicability to the Isolated Island alternative, because of seasonal and unpredictable variation in the resource, and non-dispatchability
	Biomass	• Considered a viable resource, but only in very limited quantities because of limited availability of feedstocks and the high cost of electricity production
	Solar PV	• Considered a potential future resource, but prohibitively expensive in Newfoundland because of low solar insolation, and (at the time) high construction cost • Also considered problematic from a system integration perspective because of the non-dispatchable nature of the resource, and the fact that the resource supply profile does not match well with the provincial load profile
	Wave and Tidal	• Still experimental, prohibitively expensive, and not commercially viable at the time of the review
	Hydroelectric	• Three viable projects were identified on the Island of Newfoundland, including Island Pond, Portland Creek, and Round Pond, comprising 77 MW of peak capacity, and between 379 and 467 GWh per year • In addition, a number of smaller run-of-river projects were considered impractical, because of cost and the difficulty of integrating non-dispatchable resources into the Isolated Island electricity system • Even fully developed, these identified and available resources would not be sufficient on their own to replace Holyrood

[4] This summary table reflects the description available in pages 56 to 101 of "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 10, 2011, available at www.pub.nf.ca Hereinafter referred to "Nalcor Submission, November 2011."

Category	Option	Notes
Future Connected Island	Churchill Falls (post 2041)	• In this option, Newfoundland continues to be an Isolated Island system until 2041, when a transmission connection to Labrador and Churchill Falls is built, whereupon the Island is supplied from that resource • This option was rejected, but studied to a limited extent beyond Phase 1 screening, because Island supply resources would be required to be built to secure supply until 2041, but then would be rendered effectively surplus by the enormous supply available from Churchill Falls • In addition, the option was considered uncertain because of the shared ownership of Churchill Falls
Connected Island	Hydroelectric	• Labrador had two significant potential supply resources in Gull Island and Muskrat Falls, with Muskrat Falls being the smaller and more cost effective (on a unit cost basis) • Existing available hydroelectric resources (until 2041) would not be sufficient on their own to supply expected Newfoundland needs
	Imports	• Imports were considered possible through one of two routes: from New York through Quebec and Labrador and then to the Island; or from New England, through the Maritimes and to the Island • For pricing purposes, energy was always assumed to originate in the competitive markets of New York and New England • These possible options were rejected because of price volatility in those markets, challenges obtaining long-term transmission commitments, and potential lack of secure export supply

Note that while conservation and demand management programs were not included in the Phase 1 review of supply options, they were briefly discussed as part of the estimation of provincial load.[5] Given the limited success of conservation and demand management programs at the time of the screening, they were not given substantial attention.

C.2. Options Not Reviewed in Phase 1 Screening

According to the available record, Phase 1 Screening did not devote attention to the following options:

- Energy storage, either as an alternative to peak capacity requirements, or as a supplement to non-dispatchable energy sources such as wind, solar, run-of-river hydroelectric or other renewable sources;
- Geothermal, solar thermal and other heat-focused renewable resources, that might have specific application to residential or commercial heating requirements (a substantial portion of which are supplied by electricity in Newfoundland);

[5] *Ibid.*, pages 25 to 27.

- Large-scale conservation and demand management programs (such as the widespread replacement of resistance heating with much more efficient heat pumps, for example); and
- Import of electricity from Quebec (noting that Quebec, unlike New York and New England, could provide firm power resources), either as a permanent solution to provincial needs, or as a medium-term solution pending availability of power from Churchill Falls in 2041.

The lack of attention to the first two options is not surprising, given that they were not particularly well developed at the time the screening process was carried out (this is an instance where bias associated with more recent developments must be kept to a minimum). Given the focus on conservation and demand management in certain other Canadian jurisdictions at the time (for example, British Columbia and Ontario), it is not surprising that considerable attention was focused on this issue by some parties to the regulatory review process before the Board of Commissioners.

The final option, to potentially import power from Quebec, will be considered further below.

C.3. Phase 2 Development of Long-term System Plans

Nalcor developed two alternative long-term plans for the Newfoundland electricity system for the period from the present (at the time of the analysis) until 2067 (when a presumed Muskrat Falls Project would be 50 years old). One was based on the continuation of Newfoundland as an Isolated Island from an electricity point of view, and the other included the entire Muskrat Falls Project as its centerpiece (but also included a number of other investments), and hence would result in Newfoundland being connected to the North American electricity grid.

Both alternatives were designed to be cost-optimized plans that would meet fixed constraints, including projected demand for electricity capacity and energy; transmission system loading and reliability standards; assumed costs of construction, operation and fuel for various existing and potential new assets; and the planned retirement at specific times of system assets. These alternative long-term plans were designed with the help of the industry-standard "Strategist" electricity system modeling software.

It is perhaps useful to pause and consider more carefully what was proposed and analyzed. The Muskrat Falls Project was not analyzed as a "project" or an "asset", but rather as the main component of a broader 50-year system plan which included features and expenditures outside the scope of the Project itself. This "Interconnected Island" system plan featured a very large upfront expenditure in the form of the Muskrat Falls Project, plus early but very small investments in a combustion turbine and synchronous condensers at the Holyrood Generating Station. Then, between 2032 and 2066 a variety of other modestly-sized investments were assumed.[6] It should be obvious that these future expenditures were essentially placeholders, given that the first of them was at least 20 years away from the decision date. Conditions over such a time period could easily vary enough to substantially alter the details of eventual, post-2032 system requirements.

The alternative "Isolated Island" plan was a dramatically different system plan that included a variety of assets based on several technologies, as well as plan-specific transmission upgrades on the Island of Newfoundland. Expenditures were assumed to be spread relatively evenly over the full time period from 2015 to 2067.[7] Any of the individual components of the Isolated Island alternative plan could be altered over time depending on prevailing conditions and

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[6] *Ibid.*, please see Table 26 on page 117.
[7] *Ibid.*, please see Table 22 on page 106.

technology developments, but the "Reference" plan was based on a specific set of assumptions made at the outset (as every plan must be).

To put it differently, one 50+ year plan was developed which included the Muskrat Falls Project as negotiated, and a second 50+ year plan was developed which did not. Both of these plans were designed, through the use of the Strategist model, to meet all necessary boundary conditions (e.g., satisfy domestic energy and peak capacity requirements, respect transmission availability and safety limits, etc.), while being as cheap as possible for consumers, based on all of the assumptions loaded into the program.

This process gives rise to a series of questions:

- Why a timeframe of 50 years for the two plans? Many electricity system planning exercises in Canada are for 20-year periods, so 50 years appears to be a notable choice. Alternatively, assets are often considered on the basis of their full life cost to consumers (for example, based on their "Levelized Unit Electricity Cost", or LUEC, which will be discussed in greater detail below). Hydroelectric plants like MF often have expected lives in excess of 100 years, and transmission lines can last 60 years or more. Fossil fuel electricity generation plants of different kinds have expected lives of anywhere from 30 to 60 years or more. Since the two plans include a variety of different asset types, built at different points in time, the choice of a 50-year system plan timeframe is not obvious from an estimated asset life perspective. However, the fact that the Muskrat Falls Project itself contains contractual arrangements lasting 50 years from Project completion provides the immediate answer to the timeframe question. A deeper issue, however, is why a project feature in one of the plans to be scrutinized should drive the timeframe for analysis of options?

- Are these two system plans truly the "best" options under the binary condition being tested (i.e., with or without the Muskrat Falls Project, as negotiated)? The Strategist program is designed to provide the optimum electricity system solution to a set of conditions *based on the assumptions* loaded into it. Those assumptions include not only variables like future fuel prices which will affect cost calculations within scenarios, but the assumptions also include the specific types of assets that will be considered "available" by the program (e.g., since there is no natural gas available in Newfoundland, that entire class of assets will not be included in any possible plan by Strategist). By definition, changing the assumptions will alter the outcome produced by Strategist. The question quickly devolves into a debate about the assumptions made in the course of the analysis.

- Should the Muskrat Falls Project, as negotiated, simply have been accepted as is for the purpose of options analysis, or should the Project itself have been amenable to alteration? This question is relatively easy to answer: since the Project was the result of intense negotiations over a long period of time, and the outcome was a very complex set of co-dependent arrangements, it would be unreasonable to simply assume that any features of the Project could have been altered to suit the needs of any one stakeholder (like Newfoundland ratepayers).

Abstracting from the concerns about time period and assumptions raised above, it is important to acknowledge that Nalcor's approach in developing its system plans is actually consistent with the first test for "Fairness"; namely that a project is fair for a particular stakeholder if it is at least as financially advantageous as alternative options. If it is assumed that the stakeholder in question is Newfoundland ratepayers, and "financially advantageous" for this group means "lowest cost", then the Interconnected Island plan would meet the first test for fairness for ratepayers if it could be shown that it would be as low or lower in cost than available alternatives.

Since the Strategist model provides the lowest cost scheme given the assumptions loaded into it, and the Isolated Island plan was the outcome of the Strategist model when the Muskrat Falls Project was not pursued, then the Interconnected Island plan should have been considered "Fair" if it was at least as low cost as the Isolated Island plan, *and* if the assumptions underlying the modeling were believed to be reasonable. This was, in fact, Nalcor's basic contention.

However, the time period for analysis and all of the assumptions used in the Strategist model are the heart of the debate concerning the decision-making on the Muskrat Falls Project.

D. Churchill Falls 2041 and the Quebec Option

The Strategist model can only analyze the use of assets that are assumed to be feasible options, and loaded into the program. For example, since the use of natural gas-fired electricity generators was not considered to be a realistic option in Newfoundland because of the lack of economically viable natural gas supply resources, natural gas-based assets were not included in Strategist model runs. Similarly, nuclear assets were excluded, large scale battery storage assets were excluded, wave and tidal resources were excluded, etc. More controversially, because imports from outside the province were considered to be unrealistic as a result of the Phase 1 screening process, they were given only limited time and attention in Strategist modeling.

Delaying interconnection with the mainland until 2041 and then obtaining power from Churchill Falls was also considered problematic for various reasons, but was briefly examined as an option.[8] This would constitute a sort of hybrid as between the Interconnected Island plan (with the Muskrat Falls Project) and the Isolated Island plan (with no connection to the mainland during the 50-year time horizon). However, the outcome of Strategist modelling completed for the Muskrat Falls Review was that such a "connection later" strategy would be economically unfavourable, at least in part because of the need for significant expenditures on the Island before 2041 that might be stranded before the end of their useful lives. The modeling of this option was not repeated in 2012, prior to Sanction.

As noted above, an option not apparently considered was the purchase of power from Hydro Quebec in the period between 2014 and 2041 through a transmission interconnect from Newfoundland to the mainland, potentially followed by obtaining power from Churchill Falls after that point. This option might have included building the LTA and LIL (perhaps smaller versions, since 900 MW of transmission capacity might not be required), but not MF and ML. At the same time, this option would not have required the construction of oil-fired assets on the Island to serve demand in the 2014 to 2041 period. However, rather than being considered separately, the Hydro Quebec option was included in the same category as imports from New York or New England, and appears to have been dismissed from serious consideration.[9]

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[8] Ibid., p. 128. Note that in the scenario tested, Churchill Falls energy was presumed to be priced at New York market prices in 2041.

[9] Please see the Request for Information from the Consumer Advocate to Nalcor as part of the Muskrat Falls Review, CA/KPR-Nalcor-32.

D.1. Would Peak Capacity and Energy Have Been Available from Quebec?

Between 2007 and 2011, Hydro Quebec achieved net exports of approximately 77 TWh of energy, for an average of over 15 TWh per year (but ranging between 10,700 GWh and 20,800 GWh, depending on annual water availability).[10] This compares to the entire Newfoundland and Labrador provincial load of approximately 8 TWh per year, and the Holyrood component being a fraction of that.

In 2009, Hydro Quebec broke ground on its 1550 MW La Romaine complex of hydroelectric plants, with an expected average annual output of 8 TWh. In-service of the assets was planned for 2014 to 2020. These facilities were primarily developed in order to serve the export market, as they were not required to serve Quebec domestic load and previously signed contractual commitments.[11] At the time, Hydro Quebec was also actively investigating up to 3500 MW of additional hydroelectric development opportunities as part of the *Plan Nord*.

The physical availability of potential electricity supplies for Newfoundland from Quebec in the period 2014 to 2041 would not have been seriously in doubt during the consideration of the Muskrat Falls Project.

D.2. Would Peak Capacity and Energy Be Available from Churchill Falls after 2041?

The Churchill Falls Generating Station has a rated capacity of 5428 MW, and produces between 30 and 35 TWh of energy per year, depending on water availability. Until 2041, approximately 90% of this output is under contract to Hydro Quebec, but after that point new commercial arrangements will be required.

The plant was commissioned between 1971 and 1974, so by 2041 the oldest parts of the facility will be 70 years old. The life of hydroelectric facilities is expected to be well in excess of 100 years, with proper maintenance and operation, so this age should not represent a concern.[12] Ongoing investment in components and parts that have a shorter service life ensures that the facility will continue to be capable of its full potential output.

The total operating cost of the plant in 2018, including depreciation and water rights, was slightly less than $90 million, which amounts to approximately $2.70/MWh produced at the plants 5-year average output of approximately 33 TWh/year. The plant has virtually no debt, and is essentially fully paid up. Most of the cash flow from the operation is being reinvested in equipment in order to maintain and prolong the plant's life.[13]

When the output of the plant is no longer under contract to Hydro Quebec in 2041, it will represent one of the lowest cost forms of electricity available on the North American continent for the following 50 years. This is not unique, in that it is a characteristic shared by all large hydroelectric facilities that have paid off their initial capital cost. However, given that Churchill Falls is the third largest such facility in North America (after Grand Coulee Generating Station in Washington State, and Robert Bourassa Generating Station in Quebec), it will be in very select company.

It is difficult to imagine a future in which the output of the plant is not valuable. Technology would have to change radically, such that producing electricity is nearly costless everywhere, or demand for electricity would have to

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[10] Please see Hydro Quebec Annual Reports for the years 2007 to 2011.
[11] Please see, for example, Hydro Quebec Strategic Plan 2009-13, pages 18 to 20 and 25 to 27 for discussion of the La Romaine project, and Hydro Quebec's export strategy.
[12] The Sir Adam Beck I Generating Station at Niagara Falls was commissioned in 1922, and is approaching its 100th anniversary of continuous operation. Many other hydroelectric facilities in Canada are older.
[13] Please see the Churchill Falls Corporation Financial Statements for 2018, available at https://nalcorenergy.com/about/transparency-accountability/reports/annual-quarterly-reports/2018-business-and-financial-report/

completely collapse (which appears counterintuitive given climate change concerns, and the environmental preference for non-fossil fuel-derived electricity over all other forms of energy). While the marginal cost of operating wind and solar photovoltaic facilities is approximately equally as low as the marginal cost of operating hydroelectric facilities, the fact that typical wind and solar facilities must be fully rebuilt/replaced every thirty years means that their total cost is not competitive with fully paid up hydroelectric facilities. Even the cheapest wind and solar facilities on record in the world have a full life cost of approximately US$20 to $25/MWh. In Canada, the 2018 Alberta Request for Proposals for renewable energy resulted in 760 MW of 20-year projects at a price of $39/MWh.[14] This was a near record for Canada, but demonstrates the value of the Churchill Falls facility, which operates at a small fraction of that cost.

D.3. Commercial and Strategic Issues

The Churchill Falls Generating Station is owned and operated by Churchill Falls Labrador Corporation (CFLCo), a private company owned by Nalcor (65.8%) and Hydro Quebec (34.2%). As a private company, the firm exists primarily to generate returns for its shareholders, similarly to every other private company. The fact that the two shareholders are themselves fully owned by provincial governments, however, likely complicates perceptions about their motivations and intentions.

As mentioned above, the output from Churchill Falls is under contract until 2041. This contract has been the subject of dispute, and has been reviewed by courts as a result. The contract appears to have resulted in considerable and lasting enmity between the governments of Newfoundland and Quebec.

Long before the expiry of the contract in 2041, arrangements will need to be made for the future. The 30 to 35 TWh of energy produced by the plant is equivalent to approximately one fifth of the Province of Quebec's annual domestic electricity consumption, or approximately four times the total consumption of the Province of Newfoundland and Labrador. It is an enormous quantity of energy that requires substantial infrastructure to transmit and manage.

D.3.a. Options for Churchill Falls GS in 2041

There appear to be five conceivable alternatives for Churchill Falls in 2041:

- Come to an agreement with Hydro Quebec for continued sale of the station's output (i.e., a new contract);
- Come to an agreement with Hydro Quebec for transmission of the station's output across Quebec territory to export markets in New York, Ontario or elsewhere. Nalcor currently has an agreement with Hydro Quebec for 265 MW of firm transmission from Churchill Falls to export borders at a price of approximately $20 million per year. Theoretically, in 2041 this agreement could be scaled up, so that CFLCo (rather than Nalcor) could have firm transmission rights for the entire 5428 MW of station capacity. This option is complicated by the fact that the Quebec transmission assets currently serving the station will be the same age as Churchill Falls, and likely will require significant reinvestment for prolonged service (while hydroelectric assets last more than 100 years, transmission asset life is typically 50 to 60 years). Moreover, since Hydro Quebec is pursuing its own continued development of new assets across the province, and it automatically has preferred access to its own transmission system, the availability of transmission capacity cannot be assumed. Finally, it is notable that Nalcor filed two separate applications for transmission services

[14] Government of Alberta announcement on December 17, 2018, https://www.alberta.ca/release.cfm?xID=6225465E583D7-C8A6-0844-D9754D497BA00D68#toc-1

through Quebec in 2006 and 2007, in anticipation of developing the Lower Churchill sites at Muskrat Falls and Gull Island, and was rejected in both cases.[15] In practical terms, this transmission option and the first option of a renewed contract with Hydro Quebec effectively collapse into one: a new negotiated solution with Hydro Quebec;

- Build a transmission line from Churchill Falls to US markets independently of Quebec (e.g., following the LTA/LIL/ML route, plus additional transmission capacity from Nova Scotia to Massachusetts because existing transmission infrastructure would be insufficient to handle the volume of energy that would come from Churchill Falls);
- Build industrial facilities in Newfoundland and Labrador to consume the energy locally (which is highly unlikely, given the volume of energy in question); and
- Mothball the facility, despite its remaining useful life.

Only the first three options appear to be commercially realistic, however the first two options (which are effectively one option together) require the overcoming of the enmity that has built up historically over Churchill Falls. The third option is conspicuously related to the Muskrat Falls Project.

D.3.b. Pricing and BATNA

Securing a new contract with Hydro Quebec or securing 5000 MW of transmission services through Quebec would require commercial negotiations between Nalcor and Hydro Quebec. As with any negotiation, each party would have its own interests, and each party would seek to maximize its economic outcomes.

Hydro Quebec has benefitted enormously from the contract it negotiated with CFLCo, and the surrounding arrangements (including guaranteed water rights from the Province of Newfoundland and Labrador). Currently, it purchases power from CFLCo at a price of $2/MWh, which price will stay in place, without inflationary adjustment, until 2041. This compares to bulk power prices in many jurisdictions in Northeastern North America of $40 to $60/MWh. In its 2018 annual report, Hydro Quebec indicates that its net exports amounted to 36.1 TWh, which generated $1575 million in net export revenue, or approximately $43/MWh.[16] Since Hydro Quebec received approximately 29 TWh from Churchill Falls in 2018, the margin on Churchill Falls power amounts to almost $1.2 billion for Hydro Quebec. Understandably, looking forward to 2041, Hydro Quebec would seek to negotiate arrangements that would retain a large portion of this benefit. Also understandably, Nalcor would seek to capture as much of this potential benefit as possible.

A traditional negotiating concept is to understand each party's Best Alternative to a Negotiated Agreement (BATNA). This helps to clarify the commercial interests at stake for the parties, since it sets the floor for either party's position (in the context of a rational commercial negotiation).

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[15] A summary of this application process and its outcome can be found in Legal Options, November 2012, Newfoundland and Labrador Department of Natural Resources, also available as Muskrat Falls Inquiry Exhibit 63.

[16] Hydro Quebec 2018 Annual Report, p. 47. Note that gross exports amounted to 36.5 TWh for gross export revenue of $1731 million, amounting to an export sale price of over $47/MWh. This suggests that the gross margin on Churchill Falls output was closer to $1.35 billion for Hydro Quebec in 2018. However, this does not take into account transmission losses that would apply, the cost of transmission rights at borders, or other costs such as the fees for guaranteed winter capacity availability at Churchill.

For Hydro Quebec, which has relied on the energy it purchases from Churchill Falls to meet domestic and export demand, contemplating a future without that supply means that it may need to build alternative sources of supply. Given the company's track record of construction, this is not impossible or unreasonable with sufficient time and planning. However, the breakeven cost of the partially-completed La Romaine complex has been estimated to be approximately \$60/MWh,[17] which based on current export prices in the mid-\$40 range, would appear to be unprofitable. Construction of similar new facilities would appear to be a poor substitute for Churchill Falls energy at today's prices, if the sole purpose of that energy would be for export purposes. If, however, Churchill Falls energy is destined for consumption within Quebec in order to meet required domestic demand, then construction of new supply resources, at whatever price, could be justified.

In short, for Hydro Quebec, the BATNA to a new Churchill Falls arrangement might be no action, as long as the focus is exports. In other words, unless it faces an imminent domestic supply shock, Hydro Quebec could be in a position to "take it or leave it". It would have the incentive to maximize its share of Churchill Falls value, but all the while being prepared to walk away from the table. This might be considered the definition of a strong negotiating position.

For Nalcor (and its shareholder, the provincial government), the development of new and incremental domestic load sufficient to consume 30 TWh of energy should be considered practically impossible, as that would represent a fivefold expansion of total provincial load from now to 2041, and moreover that new load would have to appear overnight in 2041 to take advantage of the available supply. Mothballing the generating facility would similarly be unthinkable, because at almost any export price it represents billions of dollars in shareholder value.

The only commercial alternative to a negotiated solution with Hydro Quebec is therefore construction of a route to export markets that does not traverse Quebec. This was as true in 1969 when the original contract with Hydro Quebec was signed, as it was in 2009, or indeed today in 2019. However, in 1969 transmitting power across Labrador, underwater to Newfoundland and across the province, and then underwater to the Maritime provinces and beyond was rejected as unworkable. In effect, there was no BATNA to a contract with Hydro Quebec at the time. Hence, CFLCo's negotiating position was particularly weak.

The Muskrat Falls Project, with its LTA/LIL/ML transmission route, highlights what is now possible. From a technical and engineering standpoint, the work done to advance the Muskrat Falls Project demonstrated that a transmission connection *could* be built from Churchill Falls all the way to US markets. Constructing a line large enough to carry all of the output of Churchill Falls would not be inexpensive, and would also come at the cost of transmission losses significantly higher than a shorter route through Quebec, but it is clearly possible.[18]

In a rational, commercial process, Nalcor and Hydro Quebec would come to an agreement where Churchill Falls output transits through Quebec to export markets (because this route is shorter and more efficient from a transmission perspective), and the two companies would split the net proceeds in a way that results in CFLCo

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[17] Based on the published capital cost of \$6.5 billion, amortized over 50 years, with a production of approximately 8 TWh per year.

[18] Note that the LTA/LIL/ML route is not necessarily optimized for direct export to US markets, because of repeated conversions from AC to DC and back, and because of interconnections with all of the intervening electricity systems in Newfoundland and the Maritimes. A dedicated transmission line would likely have fewer off-ramps and be more efficient, both in cost and transmission losses.

achieving at least the level of profit it would achieve with the longer and more complicated subsea transmission route.[19]

A purely theoretical illustration of options, based on current approximate prices and costs, may be helpful:

Table 3: Illustrative Options for Churchill Falls Exports

	Sale Contract at Quebec border	Quebec Transmission Access to Export Markets	Subsea Route to Export Markets
Churchill Falls Output	35 TWh	35 TWh	35 TWh
Churchill Falls Costs	$2.75/MWh - $95 million	$2.75/MWh - $95 million	$2.75/MWh - $95 million
Transmission Losses to Sale		5%	15%
Annual Transmission Tariff[20]		$400 million	$700 million
Realized Price per MWh at point of sale	$14 - $31 / MWh	$40 - $60 MWh	$40 - $60 MWh
CFLCo Operating Profit	$395 - $990 million	$835 - $1,500 million	$395 - $990 million
Operating Profit per MWh produced	$11 - $28 / MWh	$24 - $43 / MWh	$11 - $28 / MWh
Effective Price at Churchill	$14 - $31 / MWh	$27 - $46 / MWh	$14 - $31 / MWh
Effective Discount to Export Market Price	$26 - $29 / MWh	$13 - $14 / MWh	$26 - $29 / MWh
Nalcor Share (65.8%) of Profit	$260 - $651 million	$549 - $987 million	$260 - $651 million
Hydro Quebec Share (34.2%)	$135 - $339 million	$286 - $513 million	$135 - $339 million
Assumed Nalcor Tx Equity Investment	$0	$0	$4+ billion
Assumed Quebec Tx Equity Investment	$2+ billion	$2+ billion	$0
Nalcor assumed Tx Profit	$0	$0	$325 million
Hydro Quebec assumed Tx Profit	$200 million	$200 million	$0
Hydro Quebec arbitrage to export market price	$440 - $510 million	$0	$0
Nalcor Total Profit	$260 - $651 million	$549 - $987 million	$585 - $976 million
Hydro Quebec Total Profit	$775 - $1049 million	$486 - $713 million	$135 - $339 million

In this illustrative example, Nalcor would earn approximately the same total profit whether it invested in a subsea transmission route, or if Hydro Quebec offered transmission access to export markets based on a "normal" transmission tariff arrangement. However, to build the subsea route, Nalcor would have to invest and put at risk more

[19] Note that it is CFLCo that would be selling power in this example, and not Nalcor. Given the shared ownership of CFLCo, that entity would be obligated to maximize its profit, which would then be split between the shareholders. An alternative would be for the two shareholders to each take ownership of their relative share of the output of the station, and then separately manage the sale of energy. However, given that a significant benefit of a station like Churchill Falls is its ability to time its output to meet peak export prices, it may be that managing the station separately would be sub-optimal.

[20] For the Quebec route, the assumption is a simple a 20x multiple of the current cost to Nalcor for transmission through Quebec. For the subsea route, the assumption is a $10+ billion cost to construct a new HVDC line, amortized over 50 years, plus operating costs. In either case, the transmission provider makes typical profits.

than $4 billion of equity, plus in all likelihood guarantee $6 billion or more of debt. A large fraction of its total profit in this scenario would be compensation for this investment and the risk it represents. If the transmission project cost more than projected, or suffered failures, then returns could be significantly lower.

On the other hand, re-contracting with Hydro Quebec and selling power at the Quebec border at the same effective spread to exports as the subsea option (note the two shaded boxes in the table) would mean that Nalcor would put no capital at risk, but still earn the same amount of Churchill Falls profits (but no profit on transmission services). Note that this option represents the lowest Nalcor total profit of three scenarios, but it is still far, far more than the current arrangement. In effect, for Nalcor this "worst case" scenario *only* exists because the subsea transmission route is now an option. If there were no subsea route practically available, then Hydro Quebec would have no commercial incentive to offer a price any higher than the minimum operating costs of the facility, or perhaps $3/MWh – which is essentially the existing, much reviled, contractual arrangement.

For Hydro Quebec, the "do nothing" position means they will still earn $135 to $339 million because of their ownership stake in CFLCo, while putting up no capital and taking no risk. On the other hand, building and offering a refreshed transmission line would require a substantial investment, but with associated profits. Obviously, buying the power at the Quebec border at a low price would offer substantially more profit than simply offering transmission services at "normal" terms. However, the risk for Hydro Quebec is that pushing for this "maximal" position would risk that Nalcor would simply put up the money to proceed with the subsea transmission route, in which case Hydro Quebec would fall to the lowest profit option. The existence of the subsea route as a real option constrains Hydro Quebec's flexibility to negotiate too aggressively.

It should also be recalled that the seller of power from the Churchill Falls Generating Station is CFLCo and not Nalcor, which is a not insignificant potential complication. In both the Quebec sale and Subsea options described above, CFLCo would earn the same operating profit, albeit at much less risk in the first case (because a shorter overland route would be less risky than a longer subsea transmission route). An argument could still be made, however, that opting for the subsea route in that case would be a legitimate course of action for this private company.

On the other hand, if Hydro Quebec made CFLCo an offer at a more reasonable price, with results somewhere between the first and second columns, then CFLCo, as a private company with more than one shareholder, might be obligated to pursue that route, or face legal action by its minority shareholder. In effect, while the third column is maximally profitable for Nalcor, it is not maximally profitable for CFLCo, and CFLCo is the owner of Churchill Falls. Nalcor might find that it is compelled to pay compensation to Hydro Quebec, as a minority shareholder in CFLCo, if the decision is taken to pursue the subsea route instead of an alternative offered by Hydro Quebec which would result in higher profit for CFLCo (but not necessarily for Nalcor). In such an outcome, Nalcor might find that pursuing a subsea route might lead to a requirement to make whole Hydro Quebec as a minority shareholder in CFLCo, which would reduce the overall attractiveness of this option.

The optimal solution for the two parties, acting in a commercially rational fashion, is likely somewhere between the first and second columns. Nalcor would NOT put up a significant amount of capital to pursue a long and potentially risky subsea transmission route, while Hydro Quebec would earn something less than the maximal profits possible, but still more than would strictly be required through a straightforward transmission access agreement. Meanwhile, CFLCo profits would be higher than the minimal case, and no legal complications would arise between the shareholders. In all cases, Nalcor would be entitled to a substantial stream of profits for 50 years or more, in contrast to the existing arrangement.

This illustration also helps to identify how a price for power at the station might be commercially calculated. Not all of the energy produced at Churchill Falls need be exported to foreign markets, since both Nalcor and Hydro Quebec might want some of it for domestic purposes. The reality is that domestic customers would get the benefit of the "Effective Price at Churchill", which is NOT "power at cost" or some other artificial minimum, but which is still a substantial discount to export market prices. At this price, CFLCo and both of its shareholders should be satisfied to sell unlimited quantities of energy domestically (to either Nalcor or Hydro Quebec). In either case, the question of what each shareholder does with their share of the profit margin from CFLCo domestic sales (pay dividends to the provincial shareholder or use the margin to subsidize domestic purchases) would be up to them.[21] Moreover, it is highly likely that the price for this supply would be far lower than could be achieved by any other alternative on the Island of Newfoundland, or even from Labrador, especially if some of the profit margin is used to lower the domestic price.

To repeat, this is just an illustrative example of options that might be faced when the time comes to consider the future of Churchill Falls. Given that this is still 20 years away, and export prices, transmission costs, competing technologies, and many other variables are almost impossible to predict, it would be unreasonable to place much stock in any specific prediction. However, the illustration suggests how the various commercial realities will contribute to an ultimate solution.

The illustration also suggests that Churchill Falls will be a significant source of continued economic profit for decades to come after 2041, generating today's equivalent of hundreds of millions of dollars of value every year for both shareholders. Only catastrophic failure of the facility, or a complete technological revolution rendering electricity almost worthless would derail this outcome.

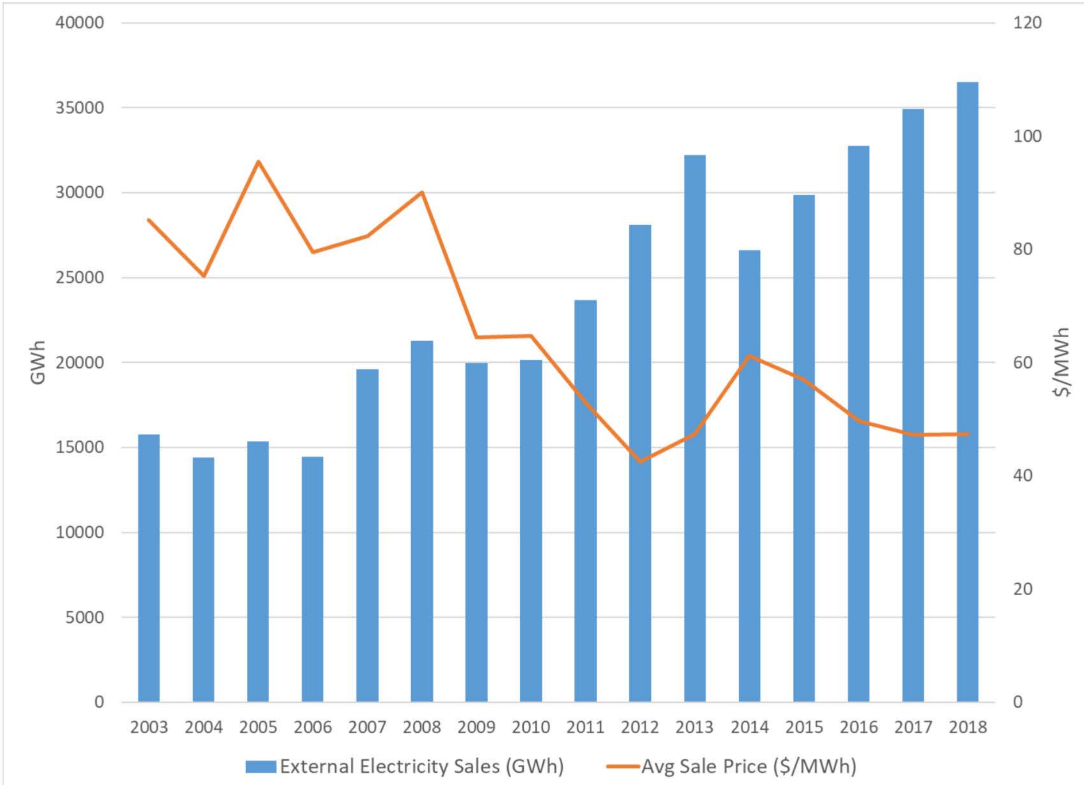
D.3.c. Price for Energy before 2041

While the above analysis suggests that the future price and availability of power from Churchill Falls will be attractive, what of the price for power that might be available from Hydro Quebec before 2041?

It may be useful to consider the actual experience of Hydro Quebec in selling its electricity externally.

[21] For example, assume that the effective price at Churchill is \$35/MWh, and the operating profit margin is \$32/MWh. Since Nalcor is entitled to 65.8% of the operating margin, or approximately \$21/MWh, that operating margin could either go to the provincial shareholder as profit, be used to discount the domestic price down to \$35 - \$21 = \$14/MWh, or any combination between the two.

Chart 1: Hydro Quebec External Electricity Sales (current dollars)



Source: Hydro Quebec Form 18k for the years 2007 to 2018

The chart above depicts Hydro Quebec's annual gross external electricity sales over the period 2003 to 2018, and the average revenue per MWh received for those sales. Note that this is a combination of both long-term contracts and spot market sales, and also does not reflect the cost to Quebec of power purchases and trading from external sources, transmission rights, or other export-related costs. However, this track record does reflect one firm's results from sustained activity in the electricity export and trading market in Northeastern North America over an extended period of time. Annual average prices for power realized over the period range from $43/MWh to over $90/MWh, with a general downward trend notable from 2008 to 2012, and a more or less flat trend before and after that. Moreover, as these amounts are not adjusted for inflation, it should be clear that the relative economic value of electricity exports has been falling.

At the time the Muskrat Falls Project was being considered, in the 2010 to 2012 period, prices had only recently come down from their high levels in the 2003 to 2008 period, and the perception was that the economic downturn beginning in September 2008 was a major contributor to that decline (many electricity systems experienced loss of industrial and commercial load during the recession, and the consequent oversupply of available electricity naturally drove down wholesale prices). While the price of natural gas, which is closely related to the price of electricity in the Northeastern United States markets that Quebec primarily sells to, had also collapsed over the same period, it may not have been widely understood that the decline in the price of both commodities was a structural rather than temporary phenomenon.

It should also be noted that if Nalcor had pursued discussions with Hydro Quebec for an energy supply arrangement for the 2014 to 2041 period, a significant component of the supply would have had to have been "firm", in order to replace assets in Newfoundland and ensure that the Island always had sufficient capacity resources. Contracts for firm energy supplies are generally more costly than flexible spot market transactions, for obvious reasons. Since the chart above depicts Hydro Quebec's combined sales of both contract-based firm supplies and spot market sales, it should be assumed that firm supplies would have been priced above the curve.

In response to a Request For Information during the Muskrat Falls Review, Nalcor noted that it analyzed the import option based on New York and New England market prices, and since Hydro Quebec primarily exports to those markets, it was assumed that a price for Newfoundland would be no better.[22] There is no reason to believe that this would not have been the case. The fact that prices in those electricity markets were actually just beginning a long period of weakness was of course a forecasting issue that will be addressed below. In the 2010-2011 period, however, it was not unreasonable to believe that contracts for firm energy supply from Quebec would be priced equivalently to the long-run cost of natural gas-fired electricity available in New York or New England. The international firm Lazard publishes annually a report on the Levelized Unit Electricity Cost of competing electricity technologies, which is largely based on pricing and experience in the US and European electricity markets. In their June 2011 report, they estimated that the cost of baseload natural gas-fired electricity was US$69-97.[23] This finding is consistent with the position taken by Nalcor in the Muskrat Falls Review.

The cost of importing energy from Hydro Quebec under a firm long term contract, therefore, would likely have been in excess of US$70/MWh, plus inflation and indexing to natural gas prices and the Canada-US exchange rate, plus the cost of building assets equivalent to the LTA and LIL to import that power into Newfoundland. While natural gas prices subsequently fell, and would have reduced the cost of any contract indexed to natural gas, this was of course not known at the time.

While the models and assumptions related to the Interconnected Island plan will be discussed further below, the assumed starting price for the MF/LTA PPA in the Reference scenario was less than CDN$66/MWh in 2010$, which compares favourably to the possibility of a US$70/MWh price for a Hydro Quebec contract equivalent (which would not have included the cost of the LTA, in contrast to the MF/LTA PPA price). Since both options would have included a similar plan for the LIL, it is reasonable to believe that Nalcor would have concluded that a contract option with Hydro Quebec would have been uncompetitive. Moreover, a contract option with Hydro Quebec would have included exposure to volatile natural gas prices and exchange rates, which the Muskrat Falls Project did not feature.

D.3.d. Package Deal or No Deal

Perhaps more important than price in any negotiation with Quebec, is the issue of what a negotiation would really have been about, had it occurred.

First, the commercial logic described above pertaining to Churchill Falls is well understood, if not widely understood. Hydro Quebec will lose a substantial portion of its profit from Churchill Falls after 2041, though under no scenario all of it, and the amount it will lose will depend on challenging negotiations.

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[22] CA/KPR-Nalcor-32.
[23] *Levelized Cost of Energy Analysis – Version 5.0*, June 2011, Lazard.

Second, in 2010 Nalcor launched a court case in Quebec Superior Court seeking to reopen the existing Churchill Falls contract. This was the latest in a history of attempts by the Government of Newfoundland and its agents to challenge the arrangement and alter the flow of economic benefits.

In this context, it is inconceivable that there would be a "normal" commercial negotiation pertaining to electricity sales from Hydro Quebec to Nalcor during the period 2014 to 2041, regardless of the prices on offer. Hydro Quebec's commercial interest would clearly be to require not only a commercial price for its energy, but also an agreement on the disposition of Churchill Falls after 2041, and an end to all challenges pertaining to the existing arrangement. In essence, the negotiation for 25 years of power supply from 2015 to 2041 would morph into the negotiation described above relating to Churchill Falls, only with the added complication of a power supply agreement in the interim, and taking place a full 30 years before the expiry of the existing Churchill Falls contract. Nalcor may have found itself in a position of having to trade away its potential BATNA for the Churchill Falls negotiations, in order to secure an interim power supply agreement.

It is not surprising that this course was not taken, or even seriously considered. Pursuing the Muskrat Falls Project creates an effective demonstration of the BATNA for Churchill Falls, and sets the stage for future negotiation. At the same time, since power prices in US markets were perceived to be high and potentially trending higher, Nalcor could investigate both the Interconnected Island and Isolated Island plans in the belief that any Quebec import alternative would be extremely expensive.

D.3.e. Strategic Value of Muskrat Falls Project

As illustrated above, the stage has been set for a tough commercial negotiation between Nalcor and Hydro Quebec on the future disposition of the output of the Churchill Falls Generating Station. This will not occur in 2041, but up to a decade earlier, when both companies are looking forward in their strategic plans, and determining what steps they will need to take to maximize their opportunities. The transmission components of the Muskrat Falls Project demonstrate what is possible, and will provide real world experience that will inform the discussions about transmission options out of Churchill Falls.

Would the option of building a subsea transmission line have been compelling in 2041 (or whenever negotiations begin) even if the Muskrat Falls Project had never been pursued? Would Nalcor have had equally as strong a negotiating position to argue for a high floor price in any arrangement with Hydro Quebec on Churchill Falls? It is impossible to quantify the value that has been created by the real experience of the Project, given that the outcome of Churchill Falls negotiations is many years away. Nevertheless, it is a real consequence, and should be included as a benefit when considering the value of the Muskrat Falls Project, both to Nalcor and its provincial government shareholder, and potentially to ratepayers.

Nalcor's stronger negotiating position on Churchill Falls will result in more profit than would otherwise have been available. At the same time, Newfoundland ratepayers may have access to lower cost power from Churchill Falls after 2041 (and potentially very low cost, depending on the choices made at the time about the use of Churchill Falls margin to potentially reduce the electricity price for domestic customers). It is highly unlikely that any new electricity resources, other than additional transmission access to Churchill Falls, will ever be required on the Island of Newfoundland after 2041, unless new electricity generation technology proves to be amazingly inexpensive, or if export opportunities are richer than the cost of local electricity generation. Moreover, depending on the timing of negotiations with Hydro Quebec, this access could occur earlier than 2041 as part of an agreement.

In the intervening period, Newfoundland ratepayers are bearing the cost of the Muskrat Falls Project. Ratepayers in the future will reap the strategic benefit of the decision to invest now. This timing difference between investment and benefit is a not uncommon feature of large infrastructure projects, but in the case of the Muskrat Falls Project the interval is long, the degree of benefit is uncertain, and the very existence of the benefit has not been widely acknowledged.

3. Comparing the Interconnected and Isolated Island Plans

Nalcor and the government of Newfoundland argued that the Interconnected Island Plan, which included the Muskrat Falls Project as its centerpiece, was the best option for Newfoundland ratepayers from a cost point of view. This argument depended on models of the future, and comparison with similar models of the Isolated Island Plan.

A. Cumulative Present Worth Analysis and Alternatives

"Cost" from a ratepayer perspective is a more complicated concept than may first appear.

In the normal course, utility ratepayers, considered as a collectivity (which ignores classes of ratepayers and the division of utility costs among those classes), are required to pay for the operating costs and capital costs of the system that serves them. Operating costs are fairly clear: fuel, labour, materials, professional services, etc. Capital costs consist of interest on debt, regulated return on equity (i.e., "profit" in accounting terms), income tax on the regulated return on equity, if applicable, and depreciation (which is a non-cash item, but which creates cash flow that is used to repay debt principal and return of equity to investors).

For an electricity system as a whole, all of these cost elements are added up to an annual total. The total is then typically used to set prices for the utility's services, in this case the sale of electricity, and those prices charged to ratepayers.

Ratepayers often pay for electricity on a consumption basis (sometimes also including a fixed charge per month, and sometimes not), so the annual system cost can be divided by total customer consumption to arrive at an average system cost per unit consumed, in terms of $/MWh or ¢/KWh.

The two competing system plans offered by Nalcor each cover a time period of more than 50 years, so these exercises could be repeated for each year, resulting in a system cost curve over time, measured either in the form of annual total cost, or annual cost per MWh. Moreover, if the total for every year were summed instead of being displayed as a curve, then the result would be the total cost of the plan over 50 years. If the annual cost per MWh were summed and divided by the total number of years, the result would be the average per MWh cost of the plan over the whole 50 years. These would be "nominal" or "current" dollar calculations, as they would have to include the expected prices for all of the components of the cost structure for each year projected into the future, as well as the expected total consumption in MWh.

From a customer perspective, however, costs for goods like electricity are not experienced in isolation, but rather in conjunction with prices for all other goods. In general and on average (by definition), prices rise over the long term at the general inflation rate. As a result, the future cost curve could also be expressed in inflation-adjusted dollars (based on an assumed future rate of inflation), both for annual total costs and annual cost per MWh. If system costs are anything other than flat when adjusted for expected inflation, this would mean they are changing with respect to general prices, and are becoming more or less burdensome to consumers than other everyday goods.

Adjusting future cost calculations based on inflation is a form of discounting – or adjusting streams of cash flows based on a factor meant to take into account the changing value of money over time.

Cumulative Present Worth (CPW) is in fact just another use of discounting, except using a discount rate other than inflation. The nominal dollar annual cost curve described above is discounted by the applicable discount factor. Then, after discounting, the annual amounts are added together to result in a single, period-spanning figure for the discounted total cost of the system for the number of years in question.

Another possible calculation, though one typically found only in system planning documents, is LUEC, or Levelized Unit Electricity Cost. In this case, the annual total cost amounts described above are discounted by a certain discount factor and summed for the period in question, and the forecast annual electricity consumption is also discounted by the same factor and summed. The total discounted cost is then divided by the total discounted consumption, to arrive at an average discounted cost per discounted MWh for the whole time period. Normally, LUEC calculations are applied to cash flows pertaining to a single asset over its full expected lifetime, rather than being applied to an entire electricity system plan, because LUECs are often used to compare various technology choices that might be used to solve a specific electricity need. For example, technology A might have a LUEC of $X, and technology B has a LUEC of $Y, and since $X is less than $Y, technology A is "cheaper" in the long run. Newfoundland was not strictly making a technology choice, but nonetheless, LUECs can also be applied to system plans like the Interconnected and Isolated Island options.

From a ratepayer perspective, there turn out to be at least 12 different ways to express "cost" based on three different variables:

- Time: annual figures depicted as a curve over time so they can be analyzed as they having varying impacts on ratepayers, or a sum for a specific period of time
- Unit: total dollar cost for all ratepayers cumulatively, or average dollars per MWh
- Discounting: no discounting (nominal dollars), inflation-adjusted, or discounted at some rate (more on this below)

Table 4: Alternative Ratepayer Cost Calculations

Discounting	Unit	Annual	Life of Plan
Nominal	$	Annual Costs	Total Cost
	$/MWh	Annual Unit Cost	Average Unit Cost
Inflation-adjusted	$	Real Dollar Annual Costs	Total Real Cost
	$/MWh	Real Dollar Annual Unit Cost	Average Real Unit Cost
Discounted	$	Discounted Annual Costs	CPW
	$/MWh	Discounted Annual Unit Cost	LUEC

Each of these different methods provides different information that may provide insights on the strengths and weaknesses of different plans. Nalcor chose to focus largely on one, CPW, but it may be useful to review others to determine if there are other insights that shed light on the alternative system plans.

It is important to note that there are still other ways to examine the system plans, but these are not necessarily applicable to ratepayers.

From an investor's point of view, and in the case of the Muskrat Falls Project the investor is the Government of Newfoundland on behalf of taxpayers, there are three metrics (among many others) that often provide some insight when comparing investment options, and might be helpful here:

- IRR, or Internal Rate of Return: this measures the stream of cash flows that will result over time from an initial investment, discounted at some rate (usually the investor's hurdle rate, or assumed cost of capital, more on this below), in order to determine an average annual percentage return on the initial investment over some specific period of years. For Nalcor, a target IRR was embedded in calculations about the price of the MF/LTA PPA, and the LIL COS tariff;

- NPV, or Net Present Value: directly related to the IRR calculation, the NPV calculation sums the expected discounted future cash flows, subtracts the initial investment from that sum, and results in a total dollar value of the investment opportunity; where the IRR provides a sense of the size of the future cash flows relative to the initial investment, the NPV provides an indication of the absolute size of the cumulative profit opportunity;

- Simple Payback: unlike the first two measures, which focus on discounted cash flows, simple payback looks at the number of years that will be required for the expected cash flows to equal the initial investment in nominal dollar terms; the longer this period, the more the initial investment is "at risk".

All of these metrics provide valuable insight and information to different investors in different situations. The focus of analysis in this report is cost to ratepayers, and not return to investors, but there may be instances where measuring returns may have been a relevant consideration.

Finally, from a taxpayer and government point of view, several other measures may have some relevance and import in the comparison of the two system plans:

- Payments to government for water rental, property tax and other fees and charges;

- Payments to First Nations and other stakeholder groups; and

- Local employment and procurement as part of capital and operating costs.

All of these factors are important to government and certain other stakeholders when they consider choices among options, but are irrelevant to ratepayers, who are focused on value for their money strictly in electricity terms. As noted at the outset of this Report, these kinds of metrics were clearly of importance to the government, as they were mentioned in the public announcement of Project Sanction. Consideration of these issues is well outside the scope of this Report, but it is a factor when considering the distribution of benefits and burdens arising from the Interconnected Island Plan that was approved by the government, and pursued by Nalcor.

A.1. Discount Rate and Complications

As mentioned above, adjusting a stream of future cash flows for expected inflation is a form of discounting. The result of doing so is sometimes referred to as "real" dollar or "inflation-adjusted" costs, as opposed to "nominal" dollar costs.

There is fairly widespread agreement among economic forecasters that the level of inflation will center around approximately 2% for a number of years to come, at least in part because this rate has been the official target of the

Bank of Canada for many years.[24] As a result, discounting future cash flows by this inflation target is a relatively simple and uncontroversial exercise.

Discounting by some other factor, in order to calculate CPW, LUEC, IRR, NPV or other measures, begs a question about which discount rate to use, and why?

Economic theories about discount rates are closely tied to economic theories about investments and their returns. In the context of investing, applying a discount rate to cash flows that are expected to be generated by a potential investment makes sense for three reasons: the time value of money, the opportunity cost of making any given investment, and the risk associated with the investment itself.

- Time Value of Money: A dollar tomorrow is not the same as a dollar today, typically because of changing prices in the form of inflation. All future cash flows should be discounted by at least the projected inflation rate.

- Opportunity Cost: The world is filled with investment opportunities. Choosing one and locking money in for a period of time means losing the ability to make other investment choices during that period. As a result, the investment that is chosen should be at least as profitable (in IRR terms) as the alternatives not taken were expected to be. Discounting based on this alternative "hurdle rate" ensures that investment choices can be evaluated using the same scale.

- Risk: Not all investments are the same. Some are stable, secure and predictable, like government bonds, while others are wildly unpredictable and potentially worth nothing in the end, like private investments in new start-up ventures. Risky options should be evaluated with a higher hurdle rate, commensurate with that degree of risk, if they are going to be compared to other investments with a lower degree of risk. However, understanding the sources of potential risk in an investment, and determining how those translate into discount rates is difficult. In fact, associating a particular discount rate with the risk features of investment opportunities is one of the most challenging problems in investment analysis.[25]

Another and often less analytically rigorous way of considering discount rates is on the basis of "cost of money".

Assuming that an investor is not simply investing their own funds, they must consider the sources of their funds, and the expected returns associated with those funds. For example, assume an investor is actually the manager of a fund that has access to debt and equity. What is the cost of the debt that the manager has access to? What is the cost of equity expected by the fund's shareholders? Defining these requirements will define the minimum hurdle rate for investments that the fund manager will be expected to achieve, and hence the minimum discount rate that the fund manager will have to apply to any investment opportunity. Note, however, that this expedient of defining a discount rate based on the cost of money is simply a way of pushing off analysis of the ultimate sources for the rates being

[24] Details about inflation forecasts and other financial variables will be discussed further below.

[25] An alternative way of managing risk in investment analysis is to NOT include a risk factor in the hurdle rate chosen for discounting, but instead consider various potential levels of cash flow that might result from an investment. For example, choosing "high-medium-low" versions of an investment outcome, applying probabilities to each scenario, and then averaging them based on those probabilities would result in a "risk-adjusted" cash flow. The difficulty here is that the problem of identifying an appropriate relationship between hurdle rate and risk has just been transformed into a problem of choosing "probabilities" for the "high-medium-low" estimates. Regardless of the means chosen to depict risk, whether through a higher discount rate or scenario testing of cash flows, the risk never goes away.

charged: the debt and equity providers themselves must consider time value of money, opportunity cost and risk when they determine what *their* return requirements are, when they consider giving money to the fund manager. However, in a competitive market for capital, the practical solution is often simply to consider the "cost of money" path to a discount rate as the expedient shorthand for the purposes of analysis.

In the case of Nalcor's CPW analysis of the Interconnected and Isolated Island plans, the company's expected Weighted Average Cost of Capital, or WACC, was used to select the discount rate. In effect, they chose the discount rate in a way that a fund manager might. This is a combination of the company's expected long term cost of debt (7.35% was chosen for the 2010 analysis, and 6.25% for the 2012 analysis), and the company's long term expected cost of equity capital (10% was chosen in 2010 and 9.25% in 2012), multiplied by the proportion associated with each in the capital base of the company (75% and 25%, respectively at both times). The result was a discount rate of 8% for the 2010 CPW analysis, and 7% for 2012.[26]

If the purpose of choosing a discount rate was to determine which investment would be more profitable for *Nalcor*, then this logic would be entirely appropriate (arguments could be made about the figures chosen, of course). However, ratepayers are not investors, and their interests do not necessarily align with Nalcor's. Impact on ratepayers is the purpose of the CPW analysis, so a discount rate relevant to ratepayers should have been considered.

In fact, however, ratepayers are a heterogeneous group who have a wide range of interests and circumstances. Some may have a very high cost of money, while for others the cost may be low. Business customers will have a cost of money defined by their own sources of debt and equity (which are usually, but not always more expensive than Nalcor's), while residential ratepayers will have costs of money defined by their own circumstances, which could be anywhere from very low (for ratepayers who have disposable income that they typically invest in government bonds) to almost infinite (for ratepayers who have no disposable income and are at the poverty line, and for whom any cost increase in necessities like electricity mean that they will have to go without other necessities, like food). There is a range of academic literature available about discount rates that are potentially appropriate for consumer markets, but in general these discount rates are typically higher than what is usually chosen for utility investment purposes.[27]

The choice of electricity system plans could also be considered a public policy problem, rather than an investment choice or a ratepayer test, since it applies to an entire population over a very extended period of time. Moreover, it is a decision that is explicitly being made by a provincial government (albeit on behalf of ratepayers for the purposes of this analysis, not taxpayers). Public policy decisions about society-wide long term investments or programs also have to be considered using discount rate analysis, or "Social Cost of Capital" discounting. In both Canada and the United States, recent decisions on this issue have tended to select relatively low discount rates, in the range of 3% plus expected inflation.[28] Since inflation is typically assumed to be 2% over the long term, this suggests a discount rate of 5%, rather than the 8% or 7% chosen by Nalcor.

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[26] Nalcor Submission, November 2011, page 157 describes 2010 calculation. Explanation for 2012 calculation can be found in Muskrat Falls Inquiry Exhibit 112.
[27] Please see Appendix F for references to some of this work.
[28] Please see the Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates (March 2016), available at http://ec.gc.ca/cc/default.asp?lang=En&n=BE705779-1 This document also provides references to recent work from the United States, and from academic literature.

Given these varied potential perspectives on discount rates for the analysis, and the powerful impact that discount rates can have on financial calculations, it may be useful consider the analysis of impact on ratepayers not from a single discount rate perspective, but from a range. Since Nalcor selected 8% and 7%, and "Social Cost of Capital" discounting might suggest 5%, it may be useful to also consider a rate of 10%, which would stand in for those categories of consumers that face higher costs of capital.

A.2. Choice of time period

As discussed above, analysis was conducted on the basis of 50 years of life for the Muskrat Falls Project, which was presumed to come into service in 2017, therefore setting the end date of the analysis in 2067. Some of the included transmission assets would have an estimated 50-year life themselves, and perhaps more importantly some of the contractual features of the Project were structured on a 50-year basis. As far as it goes, this is a reasonable basis upon which to justify analysis of the Muskrat Falls Project, *if the purpose was to decide whether Nalcor should invest in the project*. However, the CPW analysis was used to justify the choice of the Interconnected Island plan as against the Isolated Island plan for *ratepayers*. Ratepayers who would have different identities, composition, and interests over the course of that time. Also, crucially, ratepayers who would be facing different levels of risk in terms of the likely outcomes of the two plans, since uncertainty in either plan would grow over time.

This lack of attention to the timing effects of planning choices is one of the inherent weaknesses in the "cumulative" aspect of CPW. As a result, considering the impacts of the plans over different time periods, and not just a single period might be useful.

The analysis of the plans was first conducted on the basis of the period 2010 to 2067, or 57 years. For the Sanction decision in 2012, analysis was updated to the period 2012 to 2067, or 55 years. In reality, the first investment difference between the two plans as calculated in 2012 occurs in 2015, where the Interconnected Island plan calls for investment in a combustion turbine, while the Isolated Island plan calls for an investment in both a combustion turbine and a wind farm PPA. This makes the true period of comparison 2015 to 2067 (53 years, inclusive), whether as measured in 2012 dollars or in any other adjusted dollars.

Logical divisions of the 53-year period could be to consider some of the following:

- The impact of the plans over the first 25 years of Muskrat Falls Project life versus the later 25 years, but the preliminary 3-year period would unbalance the division, making it 28 years and 25 years. Also, other than arbitrarily dividing the expected life of the Project into halves, there does not seem to be any compelling argument for this division;

- The time could be divided into three uneven periods of 17, 18 and 18 years, or 18, 18 and 17 years, but this possible division also bears no particular relation to any of the features of either of the alternative plans. Similarly, decadal cohorts (2014-2023, 2024-2033, etc.) could be tested;

- The period until the first new supply resource after the Muskrat Falls Project is presumed to be necessary, namely a new combustion turbine in 2032, which would mean considering the first 18-year period, and the later 31 year period. This option is obviously unbalanced, but is at least related to one of the plans in some meaningful way, and would highlight a period during which a major assumption can be tested. Conveniently, in the Isolated Island Plan, this year also coincides with the last year before the Holyrood facility begins the process of being taken out of service.

Other divisions are also possible, but the utility of examining endless options for analysis is likely limited.

One final point on time periods is relevant. The analysis is limited to the period ending in 2067, because that will be the expiry date of Project contractual agreements. Most importantly for ratepayers, the expiry of the PPA for MF/LTA is in 2067. Immediately after that expiry, operating and maintenance costs will continue, of course, but a new and likely dramatically cheaper pricing arrangement will need to be put in place. As a result, ratepayers on “the day after” can be expected to be much better off. Given the expected lifetime of MF, which is well beyond 50 years, this significant change in financial burden from one day to the next may be worth considering further.

B. Modeling Assumptions

In order to make use of the Strategist model, Nalcor was required to make assumptions about the following:

- Existing system assets, including their expected remaining life, performance characteristics, transmission requirements, interoperability with other assets, operating costs, etc. These assumptions would be common to both the Interconnected Island and Isolated Island plans;
- Feasible new system assets, including required construction period, construction cost, performance characteristics, transmission requirements, interoperability with other assets, operating costs, etc. This category would also include reinvestment in existing assets to extend life or otherwise re-use invested capital. All of these options were defined in the screening phase of analysis, so many theoretically possible but locally impractical options would not be included;
- Domestic Load requirement, projected out to 2067;
- Fuel prices, projected out to 2067;
- Export prices, projected out to 2067; and
- Financial assumptions, including inflation, interest rates, and equity return rates, projected out to 2067.

The first three assumptions – existing assets, feasible assets and domestic load, are very much locally specific, and require intimate knowledge of local conditions in addition to general industry knowledge. The second three assumptions – fuel prices, export prices and financial assumptions, are typically not locally specific, and can be obtained by reference to recognized experts, forecasters and consultants.

A typical procedure is to consider “Low”, “Reference” and “High” scenarios for each of the classes of assumptions. That would not be particularly relevant to the first set of assumptions around existing asset characteristics because these are usually very well known and understood, but might for example apply to expected remaining life of critical assets, if there were some considerable range understood to be at play. In Nalcor’s case, they clearly did not consider it necessary to test alternate assumptions about the longevity of existing assets.

For feasible new assets (and reinvestment in existing system assets) – leaving aside the Muskrat Falls Project itself for a moment – which were already subject to screening, it could be argued that Low/Reference/High scenarios would also be unnecessary. However, this presumes that the construction times, capital costs and operating characteristics of the technologies that were screened were stable, and would not change. In the analysis it presented at the Muskrat Falls Review, and later to support the Sanction of the Project, Nalcor did not appear to take into account the longer term flexibility of these assumptions. This issue will be addressed further below.

For the Muskrat Falls Project, which is a special case in the category of feasible assets, it was obviously necessary to test achievement of construction budget and schedule targets. Given the size of the Project and its potential impact on ratepayers, for decades to come, testing at least Low/Reference/High cases was necessary.

For the remaining four categories, Load, Fuel Prices, Export Prices and Financial Assumptions, testing of scenarios was definitely required, as all of these projections five decades into the future are subject to considerable margins for error. Even considering only three representative Low/Reference/High options for these four assumptions would have required that 81 different possible combinations of variables be tested to get a complete picture of the potential performance of the two different plans being compared.

Nalcor prepared a number of scenarios before and during the Muskrat Falls Review process, all based on 2010 CPW calculations, but not in a systematic way. Some were prepared before the Review, and others at the behest of Review participants. The number of scenarios presented publicly did not approach 81, much less the larger set of 243 or 729 scenarios had Muskrat Falls Project construction budget and schedule also been addressed in combination. Similarly, at the Sanction phase in 2012, fewer than 15 scenarios were tested and reported, not 81 or any number approaching that many.

B.1. Technology and Market Change

The decision-making around the Muskrat Falls Project addressed a period of time from 2015 to 2067, or 53 years. Assumptions were made about that period of time which were founded on an understanding of what was feasible and realistic at the time the decision was to be made (during 2010 to 2012). For example, it was assumed that nuclear power is a somewhat dangerous and expensive technology that is not easily portable, and that electricity derived from solar photovoltaic panels is extremely expensive and uncompetitive unless subsidized. In 2019 the first assumption is still true, though many research projects are ongoing around the world trying to develop small scale nuclear technologies that may eventually bear fruit. The second, however, has seen dramatic change, such that in many parts of the world, solar PV projects are not only competitive, but are now cheaper than all other electricity generation options.[29]

A more prosaic assumption relates to the operating characteristics of combustion turbines and wind farms. Recent combined cycle equipment has been marketed with a claim of 64% fuel efficiency[30] (i.e., conversion of available energy in fuel to electricity), which is significant progress over past iterations (59% a decade ago, mid 50% a decade before that). Also, in the past, it was thought extremely difficult and expensive to integrate more than a modest amount of intermittent wind-fueled (and solar based) electricity into grids, but recent progress around the world is upending this assumption.[31] Dropping prices for grid-scale batteries also represent a potential sea-change in the

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[29] Recent auctions in Chile and Dubai have resulted in long-term contracts for solar PV facilities priced at approximately US$30/MWh, without any government subsidies. These are acknowledged as some of the best locations in the world for solar pv, but the prices nevertheless demonstrate what is now possible.

[30] Please see, for example https://www.ge.com/power/gas/gas-turbines/9ha

[31] In the Nalcor Submission, November 2011, a limit of 100 MW of wind in 2025 was considered economically feasible for the Isolated Island system, which would amount to much less than 10% of total capacity. This can be contrasted with ongoing work at the Midcontinent Independent System Operator, which acknowledges that in that system, 20% renewable penetration is manageable, 30% would entail some cost, and 40% would give rise to considerable costs and challenges. Every system is different, but progress is being made everywhere. Please see, for

ability of intermittent renewables to interact with existing electricity grids. And while a decade ago it was not uncommon for wind turbines to be sized in the range of 2 to 2.5 MW with hub heights at 70 or 80 m, recent onshore turbine installations have been based on 3.3 to 3.5 MW designs with hub heights above 90 m. This results in greater efficiency and lower net prices for power. Offshore systems are substantially larger still, and expected to keep growing in the future, with 10 MW behemoths already being tested.

These kinds of changes in generation technology are very difficult to incorporate into long term models, as they cannot be forecasted with any confidence. Some technologies have changed very little over long periods of time (such as hydroelectric, coal and nuclear), while others have undergone more rapid development. Moreover, testing some different assumptions in a modeling exercise such as the use of Strategist will result in different asset plans over time, creating entirely new scenarios which would then have to be run through all other combinations of variables.

Nevertheless, the potential for technology progress must be considered as a possibility when any major long-term fixed investment, like the Muskrat Falls Project, is being considered. Choosing the Interconnected Island option essentially means that no other generation technology would be needed in the system until at least 2032 (in the Reference scenario). In contrast, choosing the Isolated Island option would mean that technology change could affect the choice of actual investments at any point before 2032, potentially improving the economics of the Isolated Island plan over time under all scenarios. In an important way, the potential for technology improvement means that the asset choices embodied in the Isolated Island option are the *worst case* scenario, from a technology point of view, because these choices assume no technology improvement at all. To be fair, the Interconnected Island plan could also benefit from technology improvement, but only after 2032, presuming that the estimated time for new investment proved accurate. As has been seen from recent experience, changes can occur much more rapidly than on 20-year time scales.

Technology progress can also be expected to have important impacts on other variables, such as load, export prices and fuel prices, but these will be addressed below.

Contrary to technology, markets can affect asset assumptions in both positive and negative ways. For example, many renewable energy technologies rely on rare earth metals for critical components. Market prices for these materials have been fluctuating wildly, which could have an impact on both the availability and price of different electricity generation technologies in the future. Similarly, large scale civil works projects, such as hydroelectric dams, coal plants and nuclear plants, rely on the availability and competitive pricing of construction labour. Even wind farm construction, which is not generally included when thinking about large scale construction, relies on the availability of very large cranes and the specialized operators who can use them. However, in the 2000s, during the oil boom in Alberta and the simultaneous residential construction boom in Toronto, qualified construction labour, and cranes, were in notoriously short supply on a national basis, which impacted all construction projects underway at that time. The occurrence of these types of market changes is unpredictable, for good or ill. However, simply assuming the continuation of whatever conditions are present at the time of decision-making is not necessarily a robust method of analysis.

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example https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/#t=10&p=0&s=&sd= For a 2018 update on the PJM market, and its belief that it could manage 30% renewable penetration, please see https://thesef.org/wp-content/uploads/Kenneth-Schuyler-Integration-of-Renewables-to-the-PJM-Grid.pdf

B.2. Budget and Schedule Overruns for Construction Projects

Large construction projects are always susceptible to budget and schedule overruns. Dam projects have historically been particularly susceptible to this problem.

Budget increases can occur in two main ways: because component prices increase (such as the price of steel used in a project, the price of turbines or other major equipment, or because more labour is required than planned), or because construction takes longer than anticipated (which usually increases labour costs, as well as the cost of financing the project).

Failure to meet planned schedules, for whatever reason, can have other consequences besides project budget impacts: in particular, increasing the cost of maintaining existing electricity supplies longer than anticipated (e.g., additional fuel costs, additional maintenance costs, possibly life extension costs, possibly import costs, etc.).

At the time of decision-making for the Muskrat Falls Project, information was readily available on the history of budget and schedule overruns for all large scale construction projects, and for dam projects in particular. The World Commission on Dams produced a report in 2000 which highlighted this issue[32]: it noted that three quarters of all large-scale dam projects from 1945 to 2000 that were surveyed for the report exceeded their planned budget.[33] The average budget increase was 54%, as compiled for that report. In terms of schedule, only 50% of the projects surveyed for the report were completed on schedule, while 30% were delayed one to two years, 15% between three and six years, and a few more than 10 years.[34] All of this analysis was based on a compendium of public information and databases widely available.

While every project proponent strives to complete their construction under budget and ahead of schedule, clearly many do not. This is not only true for dams, but also for other major projects, including transmission lines.[35] Testing for the possible consequences of budget and schedule failures during the decision-making process is obviously required.

In the case of the Interconnected Island plan, sensitivities for construction cost overruns were calculated in the 2010 version of the models.[36] Note, however, that in 2012 CPW calculations, cost overrun sensitivities were not specific to the Muskrat Falls Project, but were instead calculations of generally increased capital costs for all plan assets over the entire 50-year span.[37] Moreover, model runs which included schedule failures were not made public during the Muskrat Falls Review process, and no such model runs from 2012 were included in information made available to MPA for this report.

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[32] *Dams and Development, A New Framework for Decision-making: The Report of the World Commission on Dams*, November 2000, available at https://www.internationalrivers.org/resources/dams-and-development-a-new-framework-for-decision-making-3939
[33] *Ibid*., p. 39.
[34] *Ibid*., p. 42
[35] The Bipole III transmission line project in Manitoba was originally expected to cost $2.2 billion in 2007, but was increased to $3.3 billion in 2011, $4.6 billion in 2014, and $5 billion in 2018.
[36] Naclor Submission, November 2011, page 126 summarizes the scenarios that were tested and made public, which included 20%, 25% and 50% capital cost overruns for MF and LIL based on 2010 CPW calculations.
[37] Note that calculations were made separately of the impact of 25% capital cost overruns for the MF/LTA PPA and the LIL COS. As a result, these could have easily been inserted into the Reference scenario to determine the impact of an isolated MFP cost overrun. However, this step was apparently not taken in the 2012 model runs. Model runs were for -10%, +10% and +25% changes in capital costs generally.

The 2012 version of the budget for the Project (excluding the ML) was $6.2 billion in construction cost, with $2.9 billion of that for MF, and the remainder for the two transmission assets. In addition, financing costs and other costs were budgeted to be $1.2 billion. Increasing the construction budget for the Muskrat Falls Generating Station by 50%, consistent with the historical experience suggested by the World Commission on Dams report, would have meant a $1.45 billion increase in project budget (a 23% increase in the total $6.25 billion cost of construction), plus additional financing costs on a proportional basis, for a total budget increase including financing of $1.75 billion. However, if that construction budget increase was associated with a delay in scheduled completion of an additional two years, also consistent with many projects reviewed in the World Commission report, then financing costs would have had to increase more than proportionately,[38] and additional costs associated with prolonging fossil fuel generation on the Island after 2017 would have also had to be taken into account. Moreover, a legitimate question would have had to have been explored about the possibility that the MF and transmission portions of the Project may not have been completed at the same time, with a variety of potential consequences, including whether parts of the Project should come into service, and hence into the regulated ratebase and customer bills, before the whole project was completed.

The above example assumes that only the dam project might suffer budget or schedule failures, but of course the transmission part of the project, which included a relatively risky undersea component, could also itself potentially suffer budget and schedule failures (which, of course, it did, though not to the same extent). A 25% construction budget increase and 2-year delay should have been investigated and modeled, at a minimum. Thorough investigation would have included an even higher level of overrun, and a longer delay.

There has been extensive analysis about the budgeting that was conducted prior to approval of the Project, and the various steps taken to ensure that budget was both accurate and robust. Even if all of that process was perfect, and was deemed at the time to be entirely reliable, a modelling exercise of massive project failure (i.e., cost and schedule overrun) should have been completed, in order to understand the magnitude of the risk for ratepayers inherent in the Project. The historical record makes very clear that despite all of the best intentions, cost and schedule overruns have happened many times before at projects all over the world. For a Project as large in both absolute terms and proportionately to the ratebase as this one, a paper modeling exercise was not a significant burden to undertake in a years-long decision-making exercise.

Based on the existing 2012 CPW calculations that are available, the 25% budget increase scenario that was tested at that time can be arbitrarily increased to a higher level to examine potential effects on ratepayers. However, it is not possible to model schedule delays without access to the original Strategist model, which is beyond the scope of this Report.

B.3. Newfoundland Load

In system plans, supply is required to meet projected load. Changes in load projections are therefore fundamental to system plans, since these changes will alter the timing of asset construction and required in-service dates. Over a long period of time in a system plan, even small changes in projected load growth can have significant impact on the timing and performance of asset choices, accentuating the importance of load projections.

[38] In its publicly available June 2017 update on the Muskrat Falls Project budget and schedule, Nalcor estimated an increase in construction budget of 63%, from $6.2 to $10.1 billion, and an increase in financing and other costs of 217%, from $1.2 to $2.6 billion.

For the Muskrat Falls Review, a Reference Load Projection was prepared, and described in some detail. Based on this Load Projection, CPW analysis was prepared at the Reference level, but also at several lower levels of various design.[39] No higher load case was apparently tested. For the 2012 decision, no alternate load cases, other than the Reference scenario, were tested according to the information provided to MPA for this Report. The 2012 model runs were based on the updated 2012 Planning Load Forecast (PLF).

The lack of a formal review of Low/Reference/High cases for load projections, particularly in the work prepared for the decision stage in 2012, is extremely surprising, and indicative of grossly incomplete analysis and comparison of the two options.

In the Muskrat Falls Review CPW analysis, the load cases were all tested while assuming all other variables were at their reference level. Nonetheless, at least one of the lower load cases was able, entirely on its own, to erase all of the CPW difference between the two plans.[40] This illustrates the importance of load projections in 50-year system plans. On this basis alone there should have been additional scenario modeling and analysis before the 2012 decision.

It is not possible to calculate with any certainty the impact on the 2012 CPW calculations of alternate load cases without complete Strategist runs of the sort completed in 2012. Changes in load projections not only affect, for example, projections for the use of energy for domestic vs. export purposes (and hence the MF/LTA PPA price), but actually alters the timing and nature of future asset development, which would have compounding financial impacts over time.

Actual load performance has been significantly lower than the 2012 reference load forecast that was used in CPW calculations. The 2017 load forecast for 2018 and 2019 prepared by Newfoundland and Labrador Power for its regulatory submission is also significantly lower than the 2012 forecast during the years in which they overlap.[41] This has obvious consequences for the actual price of power in Newfoundland going forward, and simply highlights the fact that further analysis on load assumptions should have been completed in 2012.

B.4. Fuel Prices

As an island not connected to the North American natural gas pipeline system, Newfoundland depends on imported fuel oil for combustion purposes. As a result, it is exposed to global oil price volatility and uncertainty. At any given time, a variety of pressures affect current ("spot market") petroleum prices, as well as expectations about future prices, including geopolitical events, the expected pace of global economic development, technology and political choices in major consumer economies (such as the United States, China, India, etc.), weather events that may be affecting supply chains in key areas, the cost of capital, inflation, and so on.

Markets exist for the trading of petroleum at spot prices, and for delivery in the near to medium term (from one month to approximately 10 years). These prices change daily, seasonally and annually.

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[39] Involving different levels of conservation success, the loss of significant industrial customer load, or slower overall growth in provincial demand. Summarized on page 126 of the Nalcor Submission, November 2011.
[40] Details can be found in Exhibit 43 Rev. 1 of the Muskrat Falls Review.
[41] Please see Schedule 3-1 of the Newfoundland and Labrador Hydro General Rate Application 2017, Vol 1.

Professional forecasters use all of the information at their disposal to project prices into the future. Like all other forecasts, they should be considered best efforts, and based only on the information that is available as of the time the forecasts were prepared.

Nalcor obtained professionally prepared forecasts for oil prices, which included Low/Reference/High scenarios, as would be expected, and these forecasts were updated during the decision-making process. These were used to prepare both the 2010 and 2012 versions of the CPW analysis. The Low scenario reflected prices that were approximately 37% lower than in the Reference scenario, in real dollar terms, as reported by the forecaster.[42]

Chart 2: WTI Daily Spot Prices (Jan 2000 to April 2019)

Source: Bloomberg

The above chart depicts daily spot prices for West Texas Intermediate crude oil in nominal US dollars per barrel. The WTI spot price is one of the common proxies for “global” oil prices at any given time. A general upward trend in oil prices can be observed from mid-2003 to mid-2014 (with a sudden peak and trough immediately before and after the financial crisis), after which there was a major collapse in prices that has not since been reversed. The average nominal dollar spot price for WTI for the four-year period January 2010 to December 2013 was approximately US$91.50. The average spot price for the four-year period January 2015 to December 2018 was approximately US$52. Adjusting the latter average for five years of inflation that on average occurred between these two periods reduces the second average by 7.8%, to approximately US$48. The real dollar decline in these averages was approximately 47.5%.

[42] PIRA price forecast methodology, Update October 26, 2012, PIRA Energy Group.

The decline in real prices has been more than the difference between the Reference and Low oil price scenarios provided to Nalcor in 2012. However, that should not be viewed as troublesome or problematic. First, the oil price scenario provided spanned 15 years, to 2025 and beyond, and there is no way to know for certain whether in fact average prices will be as low as they are now throughout this period. As can be seen from the chart above, there is ongoing volatility in prices. Second, the Low scenario that was provided, which was 37% lower than the Reference scenario, was a representative scenario of potential low prices, not a guaranteed minimum scenario. Had the forecaster been asked to provide five scenarios, no doubt the lowest would have been lower than the Low scenario actually delivered.

To be clear: *all* forecasts are *always wrong* for constantly varying global prices like oil. It is the nature of forecasting that the course of actual events will defy predictions. However, there is value in having forecasts and making use of them in analysis. Nalcor received an oil forecast with three appropriate scenarios, and used them to run their model at Low, Reference and High levels. If there was any failure, particularly at the 2012 stage of decision-making, it is that these oil forecasts were not used in combination with Low/Reference/High scenarios for other variables, but were instead modeled *only* with the Reference levels of all other assumptions.

B.5. Export Prices

Export prices were not tested in CPW analysis at either the 2010 or 2012 stages. Yet export prices were an important variable in the calculation of the MF/LTA Power Purchase Agreement price used for the purposes of CPW analysis, which is critical to Newfoundland ratepayers.[43]

The critical ingredients in the calculation of the PPA were:

- Total delivered capital cost of the MF and LTA, including accumulated financing, to determine how much was to be recovered from Newfoundland ratepayers over 50 years (note that at least two cost overrun scenarios were tested in the 2012 version of this model, consistent with the CPW analysis, but both with Reference Export Prices);
- Projected operating and maintenance costs for MF and LTA, which also would have to be recovered;
- Debt interest terms, which would be paid on the total capital cost;
- Projected Newfoundland load, to determine how much of MF power output would be required domestically, and how much would be available for export;
- Projected export prices, which are multiplied by the projected power available for export to calculate the expected export revenue;
- Target equity return on the entire project, which would determine the total revenue that would be required, and allow for the calculation of the target domestic revenue after the projected export revenue had been accounted for.

[43] The final version of the PPA formula, settled after the Federal Loan Guarantee was finalized in late 2012, makes no reference to export prices. Therefore, as a practical matter for Newfoundland ratepayers, export prices have no bearing on the actual PPA price. However, when the PPA price was calculated for the purposes of CPW analysis, export prices were taken into account, and therefore affected the decision-making process.

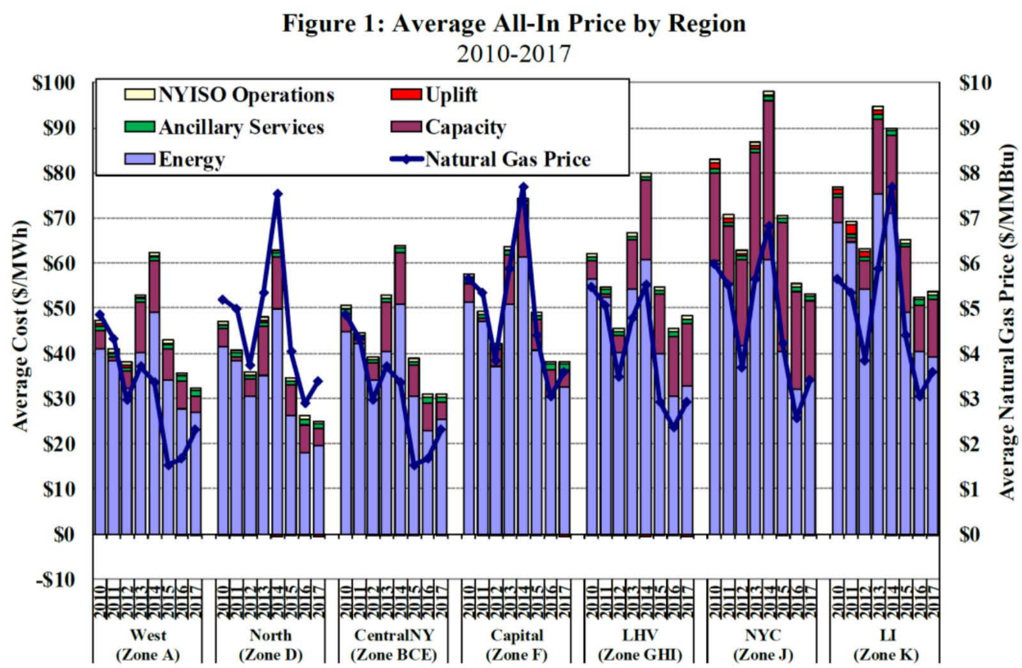
The PPA price was not found through the use of a simple mathematical formula, but instead was the result of iterative financial modeling.[44] This was required in part because of the commitment to make the PPA an inflation-adjusted fixed price for 50 years (i.e., the initial price would be set at in-service, then adjusted upwards every year by the projected 2% inflation rate).

As should be understood from this description of the PPA price derivation, if export prices were projected to be higher, then more of the revenue required to meet the profit target for the MF and LTA would have been provided by exports, and the cost to Newfoundland ratepayers in the CPW analysis would have been lower (assuming all other variables were constant). On the other hand, if export prices had been projected to be lower, then Newfoundland ratepayers would have been expected to pay a higher PPA price, and the CPW analysis would have been less favourable for the Interconnected Island Plan.

Various scenarios for export prices were not tested in the versions of the PPA calculation that were shared with MPA for this report. The developers of the PPA model, PriceWaterhouseCoopers, no doubt produced countless versions of this model over the course of the 7 years of their work, but whether that included explicit tests of the impact of export prices is not known, and does not appear in the list of CPW sensitivities completed in 2012.

Recall Chart 1 in section 2.D.3.a. above, which depicted Hydro Quebec export sales volumes and average realized prices over the period 2003 to 2018. In that chart, it can be observed that Hydro Quebec achieved very high average export prices in the period 2003 to 2008, which then tumbled over the next four-year period to 2012, and have remained at a fairly steady lower level since then.

Chart 3: New York Zonal Market Prices, 2010-17



Source: New York ISO, State of the Market Report, 2017

[44] Please see Muskrat Falls Inquiry Exhibit 725 for a review of this modeling process.

The chart above depicts the all-in average wholesale market prices for each of the state of New York's electricity zones in the years 2010 to 2017. While prices differ from zone to zone (as does the price of natural gas available in each region), the general pattern is largely similar across most of the zones, with prices falling from 2010 to 2012, spiking upwards in 2013 and 2014 when energy markets were challenged by the polar vortex, among other events, and then falling to significant lows from 2015 to 2017. Recent prices in the West, North, Central and Capital zones have been below US$40/MWh, with only the New York City and Long Island areas retaining higher price levels.

The assumed export prices used in the calculation of the PPA price model began at a starting point in 2017 which might be broadly consistent with prices that were recorded in 2011 (i.e., Hydro Quebec's achieved export sales prices in 2011 were approximately $53/MWh on a blended all-in basis, which is "in the ballpark" for prices that were assumed for 2017 in the PPA model, in nominal dollar terms), and escalated aggressively from there.[45] Hydro Quebec actually achieved only an average of $47/MWh in 2017, and the same in 2018, with no substantial escalation in sight. Instead, the projection for Export Prices in the PPA model included increases of 9% per year in the 2017 to 2020 period, followed by 5% per year on average from 2021 to 2025, 3% per year in the later 2020s, and 2% per year steadily for the remainder of the model.

Hydro Quebec's actual exporting experience demonstrates that the electricity price in Northeastern North America actually bears no particular relationship to inflation (even in the 2003 to 2011 period that would have been known prior to the 2012 decision), and has instead been driven by multiple other factors. Moreover, instead of growing it has actually declined. New York wholesale market prices also suggest a general downward trend, except always subject to short-term factors. Since export prices were already in decline at the time of the Muskrat Falls decision-making process, there should have been at least some testing of scenarios which included this possible future.

In short, export prices were projected to grow much, much faster than inflation from 2017 to 2030, before retreating to inflationary growth thereafter. This assumption was embedded into the PPA price, and hence was a feature of the CPW analysis. Had a lower export price scenario been tested, it would have resulted in a higher PPA price, and hence a less compelling picture for the Interconnected Island plan in the decision-making process.

It is a significant analytical weakness that Nalcor did not test a variety of export price scenarios in its PPA price modeling, and hence its CPW analysis.

Two reasonable objections to this criticism can be raised and examined.

First, since the actual export revenue that is achieved over time does not affect the PPA price (because it is set at in-service and not adjusted over time based on export revenues), it is the shareholder/taxpayer that is taking export price risk and not the ratepayer. This is true, however, the point remains that for the purpose of CPW analysis and comparison of the Interconnected Island and Isolated Island plans, an aggressive export price was projected, and a less aggressive price was not tested.

Second, the total revenue over 50 years that was calculated in the PPA model and used to set the PPA price overwhelmingly consisted of domestic revenues rather than exports (in the Reference model, the split is approximately 94.4% domestic and 5.6% export when total revenues are summed in nominal dollars over the 50 year

[45] Projected Export Prices were extracted from the model NLH.PF-2012v13.292-12.MF MK FLG LRA DG3C HOA Base 27Jul12. This was the Reference PPA model for the 2012 Sanction decision. Variants of the model which were used to examine higher and lower construction cost scenarios were also examined to determine their consistency with respect to Export Price projections. The same Export Price projection was used in all models.

PPA life), because exports represent a fairly small portion of the total projected available energy from MF (not including the exports to Nova Scotia as part of the ML arrangement). As a result, it may seem that changing the export price would not have had a significant impact on the PPA price, and hence testing the sensitivity should not be a priority concern. However, the target IRR in the PPA model was 9.67%, which effectively means that all of the revenues should be discounted at this rate to understand their impact on the final shareholder results. On a discounted basis, exports actually make up 15% of the total shareholder return, principally because of the stronger impact that results from early years of revenues in a discounted model, and the prevalence of export revenues in the early years. Put differently, if there were no exports assumed, the PPA price would have had to have been approximately 18% higher than it was in order to achieve the shareholder's equity return objective. Very roughly, for every 5% difference in average discounted Export Price from the Reference projection, there was a 1% change in PPA price. This can be compared to the impact of construction cost overruns, which was tested in the 2012 CPW modeling. It was calculated that a 10% change in the capital cost of the MF/LTA would have approximately a 12% impact as against the Reference PPA price. Another way of looking at this is to say that export prices which were 20% lower on a discounted basis would have the same impact as a 5% capital cost overrun on MF and the LTA. Since Hydro Quebec's average realized export prices declined 40% between the 2003-8 and the 2012-18 periods, changes of this magnitude are definitely possible. More model testing, with varied assumptions about export prices, should have been completed before the 2012 decision.

B.6. Financial Assumptions

Three categories of financial assumptions were utilized in Nalcor's Strategist and CPW modeling throughout the decision-making process: Inflation Rates, Interest Rates and Rates of Return on Equity. In addition to these a standard assumption was made about debt to equity ratios. All of these rates were updated through the various stages of the process, and several versions of each were used for different purposes.

B.6.a. Inflation

Inflation is the most straightforward of the financial assumptions. For most purposes, a long-term general inflation rate of 2% was assumed in all models. This was and is consistent with virtually all forecasters, and is standard practice in financial modeling today, and over the past decade. While in the short term inflation forecasts are often slightly higher or lower than 2%, longer-term forecasts are nearly always at that level.

In the November 2011 Submission, Nalcor clarified that inflation rates other than 2% were used for a limited number of specific purposes, such as expected labour cost escalation (at 3%), and near term cost escalation for certain electricity industry cost inputs.[46] This is entirely in keeping with standard practice and experience in the electricity industry.

No modeling scenarios were tested around alternative long-term general inflation rates, either higher or lower than 2%. Given that the purpose of the analysis was to compare two options, one with an upfront lump sum expenditure that would not be very much exposed to inflationary pressure, and the other characterized by many expenditures over time that would be affected by inflation, the outcome of such modeling would be wholly predictable. Moreover, given that the Bank of Canada has officially targeted 2% inflation since 1991, and has never indicated a preference for any other target, the lack of testing is entirely understandable.

[46] Nalcor Submission, November 2011, page 37.

B.6.b. Interest Rates

Interest rate assumptions are critical to the lifetime cost of capital goods for ratepayers, as ratepayers must pay for the interest costs charged against debt used to purchase electricity system assets.

In reality, there are two different interest rates that are important: the interest rate charged to the Muskrat Falls Project as supported by the Federal Loan Guarantee, and the interest rate that forms part of the normal regulatory process for all other Newfoundland electricity assets over time.

By the time of the 2012 analysis for the Sanction decision, most of the financial terms and conditions of the Federal Loan Guarantee had been discussed (though could not be considered final until the announcement of the agreement on November 30, 2012). As a result, these were included in the model runs used to calculate the PPA price, and the regulated tariff for the LIL (which was calculated on a Cost of Service basis). For the purposes of this analysis, the interest rate associated with the FLG was the forecasted Government of Canada Long Term Bond Rate, with no addition or amendment (since the FLG required that the Project receive the full benefit of Canada's AAA rating). This forecast was provided by an external source,[47] and began from then current rates in 2012, slowly increasing to an ultra-long-term average that would be applicable from 2030 onwards (4.83%). The FLG-related calculations (the PPA for MF/LTA, and the COS calculation for the LIL) therefore used a detailed annual interest rate forecast to estimate the cost of the various bonds that would be issued for the Project.

The Reference interest rate that was assumed for all other assets, including all of the assets in the Isolated Island Plan, was consistent with the interest rate used to determine the Discount Rate of 7% that informed all of the CPW calculations (i.e., 6.25% interest). This was a different rate from that assumed for the FLG bonds, though derived from the same underlying long-term bond forecast.

The Reference long-term interest rate consisted of:

- Estimated Long Term Government of Canada Bond Rate of 4.83%
- Historical Spread for Newfoundland and Labrador Hydro of 0.90% above Canada Long Bonds
- Debt Guarantee Fee paid by NLH to the Government of Newfoundland of 0.50%

Therefore, the total of the three components was 6.25% (rounded). In effect, the interest rates used for the assets to be supported by the FLG were not only 1.4% lower than the rate used for everything else (because of the benefit of the FLG in avoiding the historical spread and guaranty fee), but were also lower because they took into account the currently low rates at the time of the analysis for a project which was intended to get underway soon.

In the month of July, 2012, Government of Canada long bonds ("Over 10 Years") had an average yield of 2.10%. The benchmark 30-year bond had an average yield of 2.22%. Setting the Reference long-term interest rate on the basis of an assumed 4.83% for long Canada bonds was a significant spread above rates current at the time.

[47] Conference Board of Canada.

Chart 4: Canada Bond Yields, "Over 10 Years" (monthly average)

Source: Bank of Canada

The chart above depicts the longest available time series of Canadian bond yields, the average of bonds "Over 10 Years". More than 100 years of data is depicted, from January 1919 to April 2019. As is obvious from the extreme right side of the curve, Canada has been experiencing historically low bond rates for the past 10 years, since before the Sanction of the Project. However, given the 50-year time horizon of the two system plans being considered, it was appropriate that the Reference long-term interest rate be based on something other than the current rate at the time. Nalcor obtained the forward rate assumption from reputable outside consultants, which automatically lends credence to its use, but some review of the historical facts might also be useful.

For example, over the 100 years of data available on long bonds, the 20-year moving average yield is 6.10% (with a standard deviation of 2.55%), and the 50-year moving average yield is 6.43% (with a standard deviation of 1.28%).

The period from the first oil shock in 1973 to the aftermath of the first Gulf War in 1991 experienced the highest interest rates in history, and includes all of the months where average yields for long bonds ever exceeded 10%. If this 19-year period is excised from the data set, then the 20-year moving average falls to 4.73% (with a standard deviation of 1.26%), and the 50-year moving average to 4.75% (with a standard deviation of 0.24%).

Historical experience, at least, appears to support a long-term debt rate in the range of what was chosen for the Reference case.

In addition to the Reference case for the interest rate, a low rate was calculated on the basis of a minus 0.25% spread, and higher rates were calculated on the basis of plus 0.5% and 1.0% spreads. Given where rates were at the time, well below the long-term rate used in the analysis, it is somewhat surprising that only a very modest Low case was analyzed. If rates persisted at a low level (as they did), then they would be significantly lower than any of the analysis completed. At the same time, given historical experience with sudden and random spikes in interest rates (as can be seen in the chart above), testing a high case only 1% above the assumed rate was perhaps not thorough enough.

Moreover, it is also somewhat concerning that a detailed interest rate forecast was used for the PPA and LIL COS calculations, but not for any other assets, including the entire Isolated Island plan. While the underlying calculations for asset costs in the Interconnected Island plan benefitted from lower prevailing and expected interest rates in the first few years of the plan, the Isolated Island plan was not afforded the same benefit, despite the fact that there were some early asset purchases in that plan as well. While the asset expenditures were lower in the Isolated Island plan in the early years, and so the impact of this different interest rate treatment is relatively muted, this was still a form of built-in "penalty" or bias against the Isolated Island plan.

B.6.c. Equity Rate of Return

As with interest rates, two different Equity Rates were adopted in the analysis, though the purposes are slightly different: one for use in the PPA design, and the other for all other purposes.

In general, the Equity Rate was set 4.4% above the assumed Long Term Canada Bond Rate (hence 4.83% + 4.4% = 9.25%, rounded). For the purposes of calculating the PPA price, the target Equity Rate was approximately 0.5% higher, at a total of 9.7%.

In general, this Equity Rate spread above Canada bonds appears low, as a more typical spread would be 5% for low risk, fully regulated electricity utilities.[48] In the case of the MF/LTA PPA, which includes considerable risk because of assumed exposure to export market prices, the effective spread of just under 5% above bonds appears to be particularly thin.

No sensitivities were performed on equity rates, in any of the calculations. Interestingly, even when interest rate sensitivities were tested, and the long term interest rate increased by 1%, the Equity Rate was not modified as part of the analysis (which is odd, since if the interest rate rises, and the spread is constant, then Equity Rate should rise by 1% as well). While it is true that equity spreads for regulated utilities are not simply static over time, and the spread used in long-term modeling is meant to be a long-term average, it is peculiar that no impact whatsoever was modeled. The effect is to simply mute the expected overall impact of changes in financial rates.

B.6.d. Debt Ratios and Debt Terms

The Federal Loan Guarantee specified that the debt ratio for the MF/LTA must be not more than 65:35, for the LIL not more than 75:25, and for the ML 70:30. In addition, the time period for amortization of the associated debts was 35 years, 40 years, and 40 years. In addition, the FLG specified minimum Debt Service Coverage Ratios (DSCR) that were required for each of the arrangements. All of these particulars, and other terms and conditions, were built into the calculations for the MF/LTA PPA, and for the LIL COS calculation.

[48] See, for example, the ample analysis contained in and referred to in *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, Ontario Energy Board, EB-2009-0084.

For all other assets in both plans, the assumed debt ratio was 75:25, in keeping with Newfoundland and Labrador Hydro typical practice. Moreover, as most other assets are accounted for on a COS basis (with the exception of certain privately own generation assets based on PPAs), terms were asset specific, and based on amortization over each asset's expected useful.

No alternate scenarios were tested on any of these assumptions, nor would any be expected.

C. Scenarios

Scenarios are combinations of modeling assumptions. Sensitivities are simply the impact of a change in any single variable on a Reference case. The Reference case is itself just one scenario, which posits the Reference level for every variable. Typically, it is considered the most plausible or "reasonable" scenario.

If each variable has some probability attached to it (like the Low = 25%, Reference = 50%, High = 25%), then it would be conceivable to calculate the numerical likelihood of different scenarios by multiplying all of the probabilities together. However, these "probabilities" are themselves often just indicators of the forecaster's general sense of confidence in a particular future path for a variable, and it is unlikely that assigning probabilities to scenarios has much real value (why assign 25% vs. 30% to a "Low" level for a variable?). Having said that, it should be intuitively recognized that outcomes which can only occur given a very unique set of variables, such as Low-Low-Low-Low-Low, should be less likely than outcomes that can result from a number of mixed combinations of variables, *if the variables are all truly independent*.[49]

For the purpose of decision-making, it is valuable to understand the impact of different combinations of variables on each of the plans available. If many of the combinations result in "satisfactory" outcomes, but only a small number result in "disaster" or "stellar", then the plan might be considered robust. On the other hand, if a plan responds very strongly to many different combinations, then it may be difficult to have confidence in the future under that plan.

"Disaster" scenarios for any particular plan should be a particularly strong focus for analysis, because the preconditions for "disaster" need to be thoroughly understood, and the possibilities for mitigation in the course of such a scenario should be considered. If a plan is ultimately chosen, the combination of variables that might lead to disaster should always be top of mind.

When comparing plans, if one plan is superior in most scenarios, then it might be cast in a favourable light. However, if there is a particular scenario or group of scenarios that decisively flips the order of preferred plans, then it might make sense to investigate that set of variables more thoroughly. Even though one plan may be beneficial in a majority of scenarios, if the effects of the "disaster" scenarios are more severe, or if the incidence of disaster is more likely, it may ultimately not be the preferable plan.

[49] For example, if oil prices, interest rates and load were all truly independent, and all three combinations of "high-low-high" lead to a certain modeling outcome, then that outcome would be more likely than a different outcome which could only occur with a "low-low-low" scenario. On the other hand, if oil prices and interest rates usually move in lock step, then there really is only one scenario that results in "high-low-high", which is when oil and interest rates would be high, and load low. Since there is only one possible combination with that feature, then it would have a similar likelihood to the "low-low-low" scenario.

No plan will *ever* be optimal under all conceivable conditions. If one plan is superior in every single imaginable scenario, then the decision-making process is a waste of time.

Scenario modeling, like the process of financial modeling in general, is just an aid to *judgement,* and not a replacement for making judgements. Decision-making is *always* a bet on future outcomes, and bets can ultimately go either way. A "calculated risk" is one that is entered into with the best information available, and in full awareness of the potential consequences, *whatever* they might be.

In the Muskrat Falls Review process before the Board of Commissioners, there was some attempt to test different scenarios. Nalcor was asked to provide CPW results for various combinations of variables, including capital cost overruns, oil prices, and interest rates. However, prior to Sanction, the available information shows that only a few scenarios were tested, only by changing single variables against all other Reference variables.

The scenario modeling and analysis was grossly incomplete overall, particularly given the magnitude and importance of the decision to be made. It was not thorough, deep, or nuanced. There was insufficient acknowledgement of the scenarios in which each plan was superior, and no in depth review of cases where "disaster" would strike, and no analysis of the severity of those consequences.

The following is a summary of the variables discussed above.

Table 4: Summary of Variables

Variable	Can be modeled?	CPW Modeling?		High Case Tends to Favour…
		2010	2012	
Technology Progress	X			Isolated
Market Dynamics	X			X
Cost Overruns	√	√ combinations	√	Isolated
Schedule Delays	√			Isolated
Domestic Load	√	√ combinations		Interconnected
Fuel Prices	√	√ combinations	√	Interconnected
Export Prices	√			Interconnected
Inflation Rate	√			Interconnected
Interest Rate	√	√	√	Depends on timing
Equity Rate	√			Isolated

It should also be stated here that Churchill Falls, and the dramatic strengthening of Newfoundland's strategic position vis-à-vis Churchill Falls, was not addressed as part of the scenarios and models presented. In certain versions of models presented at various stages of the decision-making process there was reference to the eventual availability of energy from Churchill Falls after 2041, but the broader issues of strategic and commercial value were simply never addressed. This was not in any way taken into account in the CPW calculations, nor was there any attempt made to suggest, in any addendum, how the value of Churchill Falls might play into the decision-making process. In addition to the overall lack of scenario modeling, the complete lack of acknowledgement of this issue was another significant failing of the process.

C.1. 2012 Reference Scenario CPW Calculations

The 2012 versions of the Interconnected and Isolated Island plans used for CPW modeling were identical for the first three years, 2012 through 2014.[50] Differences between the plans appeared only in Year 4, 2015. Practically speaking, there was no reason for the first three years to be included in either plan, as doing so simply added the same output and dollars to each stream of data.

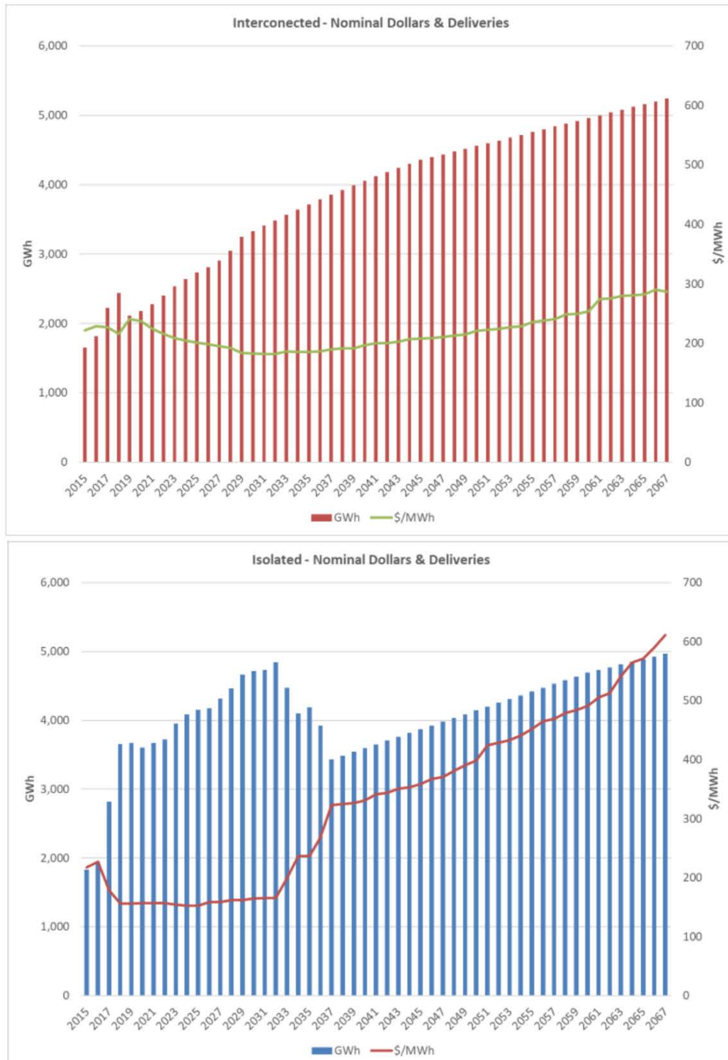
It is also notable that the plans did not include all Nalcor assets (through whichever subsidiary), but only assets that would be treated somehow differently as between the two plans. This is in keeping with standard practice, since it is useful to isolate differences between plans, rather than pad them with identical filler (however, that begs the question why the first three years were included in the calculations…).

An interesting difference between the two plans is that they deliver different amounts of power to the Island of Newfoundland from the first year modeled through the last (2015 through 2067). Despite the fact that both plans are meant to totally satisfy Island demand (Strategist runs automatically satisfy this condition), it is clear that each plan places different burdens on the assets that are not explicitly included in the plan calculations presented (i.e., power is assumed to be coming from other assets not included in the CPW calculations, and each plan assumes a different amount of that power, at some cost not disclosed in the model). Given the structure of Strategist, and the rules it uses to select different assets to operate in an electricity system, it can be assumed that it is always seeking to minimize the marginal cost of operating the system, and therefore that the differing volumes of output between the two plans are consistent with that goal.

As a result of the fact that many Nalcor assets are not included in the financial models (nor are any Newfoundland Power assets or independent power producer assets either), it is not possible to make any calculations about ultimate ratepayer prices or total costs based on the information presented (though Nalcor did so during the Muskrat Falls Review, based on additional information). The CPW models available deal only with part of the power supply for the Island, and can only be evaluated based on how well they do what they aim to do.

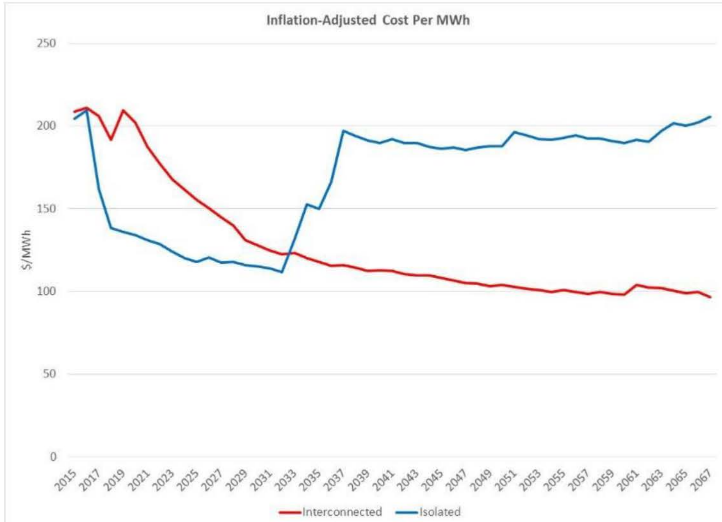
[50] All figures in this section are drawn from PLF12 Iter1 CPW Analysis 2012Aug1.

Chart 5: Plans at Nominal $/MWh and GWh Deliveries



The two charts have been depicted at identical scales, and show power deliveries in GWh, as well as plan costs per MWh delivered in nominal dollars for each year. It is obvious that the Isolated Island plan is delivering more total power to Newfoundland ratepayers through its collection of assets (217 TWh vs. 205 TWh over the course of 53 years), but also that the costs per MWh start out low, and then rise dramatically, and without stopping. The sudden increase in costs in the 2033 to 2037 years coincides with the final decommissioning of the Holyrood facility, and the coming into service of several wind farms and combustion turbines at much greater cost. The Holyrood units are also producing a considerable amount of energy while they remain in service, presumably displacing other sources of power on the Island that might be more expensive to operate. In the case of the Interconnected plan, Muskrat Falls power is delivered on schedule, based on what is necessary to satisfy Island load, and required by the PPA. The slight ripples in the Interconnected curve beyond 2032 are the projected in-service dates of other plan assets.

Chart 6: Inflation-adjusted Comparison



All figures in 2012$

Comparing the two cost trend lines for $/MWh on an inflation-adjusted basis clearly shows the different impact that the two plans will have on different cohorts of ratepayers through time (i.e., the curves are adjusted by a 2% discount rate, applied from 2012 forward, so the chart appears in 2012$). Electricity costs relative to the rest of the economy in the Isolated Island Plan will get cheaper for about 18 years, then suddenly get much more expensive, and then stay fairly flat for 30 years. Some ratepayers would be much better off than others, if divided by time. For the Interconnected Island plan, the further out in time a ratepayer lives (or a company operates), the better off they are. It should also be recalled that off the right edge of the curve, there will be a significant step downward for the Interconnected plan curve, because both the PPA will end, and the LIL will be fully amortized, resulting in a steep drop in costs for the next cohort of ratepayers, 50 years into the future (unless the LIL actually needs to be replaced at that point, assuming its budgeted end of life is actually its true end of life). In terms of rank ordering, the Isolated Island plan is superior for ratepayers in the first 20 years, and then the Interconnected Island Plan is decisively superior for the remainder of the period.

The inflation-adjusted curve also highlights the fact that the superiority of the Interconnected Island plan, in the Reference Case, will very much depend on the fact that the replacement assets for Holyrood in the mid-2030s will be very, very expensive in comparison to what they are replacing. If for any reason they were not as expensive as predicted in the plan, and bearing in mind that from the decision date in 2012 to that point was more than 20 years away, then the case in favour of the Interconnected plan would become much weaker. This is a clear illustration of the importance of technology assumptions, or more specifically the assumption that technology will not improve. Additional investigation of technology trends and possibilities might be warranted in this type of case.

Viewing the inflation-adjusted price curve and comparing it to the nominal dollar curves on the previous page also sheds light on the impact of assuming constant inflationary increases in operating and fuel costs (which is the case in the Reference Scenario, and in pretty much every scenario or model that has to project forward decades into the future). In the nominal dollar curve for the Isolated Island plan, the cost per MWh delivered rises increasingly rapidly from 2037 onwards, but it turns out that is mostly just the operation of inflation on fuel and operating costs. The seemingly dramatic nominal dollar curve will not be "felt" by ratepayers as dramatic, because everything else in the economy is presumed to be rising by the same 2% inflation. The inflation-adjusted curve is nearly flat for 30 years, with small bumps that coincide with asset additions and retirements from time to time, using COS economics. The Interconnected Island curve, on the other hand, shows a steady but slow decline as the COS tariff for the LIL declines, but the PPA cost for MF/LTA rises by inflation. The net combined result is a very, very gentle downward curve when the figures are inflation-adjusted.

Table 5: Discounted Cost Comparisons

	Interconnected	Isolated	% Difference
Nominal Total $	$46.0 B	$73.2 B	59
Inflation Adjusted $	$24.3 B	$36.7 B	51
5% Discount Rate	$11.2 B	$15.6 B	39
7% Discount Rate	$7.5 B	$9.9 B	32
10% Discount Rate	$4.6 B	$5.8 B	26
LUEC at 7%	$210/MWh	$221/MWh	5

All figures in 2012 $ except nominal

Considering not just the 7% discounted CPW that was provided as part of Nalcor's analysis, it can be seen that in the Reference Case, the Interconnected Island plan is convincingly superior on a 53-year total dollar basis across all measures, including LUEC (all figures discounted back to 2012 dollars). The fact that the relative gap narrows progressively with the discount rate is entirely due to the superiority of the Isolated plan from a cost perspective in the first 18 of the 53 years. A higher discount rate places greater importance on the early years of any plan, while a lower discount rate places relatively greater importance on the future. Nominal dollars, with no discounting, treat all years as having the same relative weight. The LUEC calculation also discounts the delivery of energy, instead of just discounting dollars, and hence the greater deliveries of energy in the far future of both plans are discounted away in importance. Since the Isolated Island plan delivers more energy in the early years and at a lower price than the Interconnected plan, the gap between the LUECs is much narrower.

C.2. Is the Isolated Plan Really So Bad?

Given the significant difference in outcome between the two plans, it is worth investigating further what is happening in the Isolated Island Plan, particularly in the period of the big leap in cost in the mid-30s.

Table 6: Isolated Island Plan Before and After the Big Leap

	2032		2037		% Increase
	Nominal $	% of Total	Nominal $	% of Total	
Fixed Charges	$270,211	34	$343,749	31	*27*
Operating Costs	69,896	9	72,532	7	*4*
Fuel	420,459	52	659,918	59	*57*
No. 2 Fuel	*10,248*	*45,714 bb*	*659,918*	*2,669,302 bb*	
No. 6 Fuel	*410,211*	*2,866,920 bb*	*0*	*0*	
Power Purchases	42,359	5	32,859	3	*-12*
Total	802,924		1,109,057		*38*
Energy (GWh)	4,841		3432		*-29*
Energy Cost ($/MWh)	166		323		*95*

All figures in 2012 $ except nominal

The Holyrood station is by 2032 very, very old (first commissioned in 1971). As a result, it does not contribute much to fixed charges. When it is closed and replaced by a combination of new facilities, fixed charges rise by 27% in nominal dollars over 5 years, which is more than double the rate of inflation. However, operating costs don't change much over that period, and in inflation-adjusted terms would actually fall, as new facilities do not need as much maintenance and upkeep as old ones do. However, fuel costs leap forward dramatically, because the new facilities require much more expensive No. 2 light fuel oil to operate, rather than heavier but cheaper No. 6 oil. The new facilities are actually producing less energy, and burning fewer barrels of fuel, but the fuel is so much more expensive that fuel costs increase by 57%.

Obviously there would be ancillary environmental benefits to burning cleaner light fuel oil than dirtier heavy fuel oil. But from a ratepayer cost perspective, the consequences are dire.

Assuming that the Interconnected Island plan were not an option, what would be a plan to manage this outcome? First, since 59% of the cost of every MWh produced is due to fuel in 2037, the answer would be to not consume as much. The value of conservation would be very, very clear and easily communicable. Any conservation program which cost less than an effective $190/MWh would make economic sense to pursue. Second, prior to investing in the replacement equipment for Holyrood, consideration would have to be given to the most efficient machines possible (i.e., improved turbines with higher fuel efficiency, therefore burning fewer barrels for the same output). Even if they were more expensive, they would likely prove economical.

In the background is the possibility of technology change: if wind turbine and battery technology has improved by then, or natural gas becomes an option, then the picture could dramatically shift. Nevertheless, conservation might be the best and only certain way of reducing the negative impact that this future might have held, had it been pursued.

Risks in this plan would focus on the cost of fuel (since it is so central to the economics of the plan), and on the possibility that the Holyrood plant would fail earlier than planned (which would bring forward in time the need to use more expensive fuels, and make the outcome even worse for ratepayers).

C.3. Isolated Plan Best and Worst Cases

Since the Interconnected plan is so much superior to the Isolated plan in the Reference Scenario, investigating Scenarios which make the Isolated plan economics even worse is not particularly fruitful. It is clear what those are: any scenario that includes higher fuel costs, or higher load (which would require burning more fuel in the planned facilities, and in the extreme would require construction of more fuel-burning facilities). As was reported in the 2012 modeling runs, the High Fuel scenario with all other variables at Reference resulted in a CPW more than 40% higher at the chosen 7% discount rate. Carbon taxes, which also increase the effective price of fuel, also would be very negative for the Isolated Island plan (and carbon taxes could obviously offset any reductions in fuel prices that might otherwise occur).

On the other hand, lower fuel prices would simply translate the entire cost curve downwards. Lower load would also drop the curve because of the impact on fuel consumption, but would have a more complex impact on the timing of assets: Holyrood might still need to be replaced at the same time because of its age, but later asset expansions might be pushed further into the future. However, post-2037 asset expansion does not really have much of an impact in inflation-adjusted terms anyway, so the fuel consumption impact of lower load is likely to be a more significant driver. On the other hand, lower load also means that less energy would be produced for the same fixed charges, so the ratepayer experience of cost per unit energy might be less improved than otherwise thought (in the extreme, assets must be paid for even if they are not used, but since in this plan assets are fairly modular, this outcome can be avoided by not building new assets until they are really needed).

In 2012, the "Low" energy price scenario was tested, and it was found that the 37% reduction in the fuel price forecast (according to the forecaster, PIRA) resulted in a 20% reduction in CPW of the plan (as measured at a 7% discount rate), with all other variables at Reference levels. Clearly, this was not sufficient to close the gap between the Isolated and Interconnected Island plans (recall that in the Reference scenario, the Isolated Island plan is 32% more expensive than the Interconnected plan, so low fuel prices do not by themselves overcome the difference), even without considering the mild benefit of lower fuel costs for the Interconnected Island plan because of its own collection of fuel-fired assets.

What about lower load combined with lower fuel prices, which would likely be the best case for the Isolated Island plan? This option was not considered in 2012, but several variations were considered during the Muskrat Falls Review. These included steady reductions in projected consumption due to conservation, cutting presumed load growth (perhaps because of economic factors?), and sudden and permanent drops in demand caused by the closing of industrial facilities.

> *This is where a pause in the analysis is required: Strategist model runs were not prepared and made available in 2012 which tested varying levels of load. As a result, it is not possible to accurately understand the full impacts on each plan of a changing load forecast. In essence, a changed load forecast would have altered the shape of the curves that result from each of the plans, whether those curves represent annual dollars or annual output (and hence the curve for $/MWh would change too). Without Strategist models, all that can be done is financial approximations of the impact of changes to load. In essence, the curves will remain the same shape, but will be translated up or down. This is the extent of the analysis possible with the tools available, but it is sub-optimal, and a result of the insufficient work done in 2012. This should be borne in mind for the rest of the analysis in this section.*

It should be recalled that the 2012 load forecast upon which both the Isolated and Interconnected plans were based assumed Island Interconnected load of 8745 GWh in 2015, rising to 10,012 by 2031. The Isolated plan as modeled would only provide 1834 GWh in 2015 and 4735 GWh in 2031, so the majority of power was being provided by other electricity assets on the Island of Newfoundland that are not included in the plan model. Any reduction in load should reduce the output of the most expensive asset on the Island from the perspective of marginal cost of production, and it is unknown whether that would be assets included in the Isolated plan. However, if some simplifying assumptions are made, then it should be possible to test the results of load reduction in addition to a low fuel price scenario, at least on a directional basis.

A 1% reduction in overall expected load would represent 87 GWh in 2015, rising to 100 GWh in 2031. Beyond 2031 load was forecast to rise at 0.8% per year, so this across the board reduction of 1% would represent 133 GWh in 2067. It is notable that the 2012 load forecast included an expected increase of 93 GWh from observed 2011 load to projected 2015 load, so a reduction of 1% in 2015 would be approximately the same as modeling flat load from 2012 until 2015, and then allowing load to grow at the rate that had been forecast in the 2012 load forecast. This kind of marginal change may not have forced different decisions in new asset construction, but that is unknown without a Strategist model run.

Another alternative is to model an economic downturn, where load remains flat at 2011 levels for a decade, and then begins to climb by 0.8% per year. In fact, load on the Island has declined since 2011, so this scenario is definitely possible, and it could have been tested in 2012. However, this scenario is so significantly different that it is highly unlikely that future asset construction decisions would have been unaffected. For example, by 2035 load would be 1700 GWh lower than implied by the 2012 load forecast, meaning that some of the assets assumed to be constructed in the Isolated Island plan probably would not be constructed. To make a proper analysis of this kind of option, a Strategist model run would be required, which was not practical for this report. Nevertheless, for the sake of review, a purely financial based adjustment to the model could be made, solely to achieve some understanding of what the size of the consequences might be.

Table 7: Isolated Plan Fuel and Load Scenarios

	Reference	Low Fuel Cost	Low Fuel - 1% Island Load	Low Fuel & Flat Island Load to 2020
Nominal Total $	$73.2 B	56.6 B	55.7 B	41.6 B
Inflation Adjusted $	36.7 B	28.6 B	28.1 B	21.2 B
5% Discount Rate	15.6 B	12.3 B	12.1 B	9.4 B
7% Discount Rate	9.9 B	7.9 B	7.7 B	6.0 B
10% Discount Rate	5.8 B	4.6 B	4.5 B	3.6 B
LUEC at 7%	$221/MWh	$176/MWh	$178/MWh	$231/MWh
Total Production	217 TWh	217 TWh	211 TWh	123 TWh

All figures in 2012 $ except nominal

As expected, the loss of 1% of Island load from 2015 onwards makes a marginal difference in the Low Fuel scenario, but it is slightly more than 1% (because the plan was only serving a fraction of Island load, so 1% of Island load loss is actually almost 3% of total plan load over 53 years).

Trying to project a significant load reduction using this model is illuminating, but unsatisfactory: the total loss of load is very large compared to the modeled plan, which means that while costs do fall substantially, the fixed cost portion of the total cost results in much higher per unit prices. More properly, a Strategist model run would have resulted in a different asset plan, with delayed construction of new assets, and hence even lower costs (and quite likely somewhat ower per unit costs as well).

Nonetheless, this type of Low Fuel and Low Load scenario should be assumed to be "best case" for the Isolated Island plan, other than considering significant improvements in technology that might be available in the 2030s to avoid the need to purchase expensive fuel.

C.4. Interconnected Island Plan Variants

The Interconnected Island plan is in many ways less flexible than the Isolated Island plan.

The PPA requires that Newfoundland ratepayers purchase a fixed volume of power each year for 50 years, which was determined based on the outlook for domestic requirements prevalent at the time of the PPA signing. Based on the budget for the MF and LTA at that point, the annual cost for the PPA-controlled power was set, according to the 2% annual inflation over time formula. Any *post facto* change in domestic load requirements or export prices would not affect this annual cost (but changes in export prices *would* affect the returns ultimately earned by the shareholder/taxpayer on the excess power sold in the export markets).

Similarly, the LIL was structured as a COS project, and therefore would enter the Newfoundland ratebase when in-service. The full cost would be payable, regardless of how much energy flowed across the wires at any given time.

Of course, budget and schedule performance of the construction project could affect these costs, since they would change the final in-service costs of the two elements of the Project. If the budget were exceeded (as it has been), the starting price of the PPA and the ratebase of the LIL would be adjusted upwards in order to service the associated debt and return on equity, and in the much less likely case of an under-budget completion, the price and ratebase would be adjusted downwards. Schedule delays, as discussed above, would have additional impacts.

A reduction in future load requirements would result in availability of excess power from the block provided by the PPA. In that case, other planned production on the Island could be curtailed in response (which might save some fuel costs), or more likely, that power could be sold on the export markets for whatever net price could be achieved (because the export value of energy is often more than the marginal cost of fuel for the same amount of energy, at least during the day). In that way, some or all of the cost of the fixed block of power could be offset. In the case of higher than expected load requirements, power from MF could be purchased that would otherwise be destined for export. In order to keep the shareholder/taxpayers whole, however, the price of this excess requirement should be set by reference to the net revenue that would otherwise be achievable through export, taking into account the losses that would be incurred in delivering power at Soldier's Pond.[51] But if this price were higher than the marginal cost of producing power in Newfoundland, then fuel should simply be burned in existing plants to do so.

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[51] For example, if 100 GWh of power was destined for export at $100/MWh, but at a cost of 10% transmission losses and $10/MWh of transmission fees, while the transmission loss to Soldier's Pond would be 5% and transmission across the LIL is already paid for, then the price for Newfoundland ratepayers should be $84.21/MWh for the 95 GWh delivered at Soldier's Pond.
(100 GWh * (1 – 10%) * ($100/MWH) – (100GWh * $10/MWh)) / (100 GWh * (1 – 5%)) = $84.21/MWh

Changes in interest rates only affect the PPA and LIL if they occur during construction, since once the long-term bonds have been issued, they are fixed for their terms. If rates rise in the future, there will be no impact on the PPA for MF/LTA or on the LIL. However, if equity rates change over time in response to interest rates, the required spread for utilities, or underlying inflation rates, then the cost of equity in the LIL would likely change, since it is a normally regulated COS asset. The equity return in the PPA was fixed at the time of signing, however, and so would not change with other financial conditions. Financial conditions would affect all assets that are required in the future, but not until after 2032 (or later) in the Interconnected plan.

Technology change could benefit the additional assets included in the Interconnected Plan, but also only after 2032. And at the same time, if progress in electricity generation technology caused prevailing market costs to come down, then export prices might fall as well, which could be problematic for Newfoundland ratepayers if load were low, and PPA power needed to be resold abroad.

All in all, much is "fixed" in this plan, not just the initial expenditure itself. The PPA arrangements, and the terms and conditions of the FLG ensure that there are only limited ways to mitigate changes that might occur as the plan progresses.

This was well-understood in 2012 when analysis was done prior to Sanction, and yet only a limited number of scenarios were tested to examine the consequences of different potential outcomes.

Given the clear superiority of the Interconnected plan in the Reference scenario, further tests in upside scenarios were of limited utility (such as where the construction projects come in under-budget, or interest rates are even lower than in the Conference Board forecast at the time). In scenarios where the Isolated Island Plan suffers, such as higher fuel costs or higher load, the Interconnected plan is largely impervious, because fuels are not a major part of the cost base, and the costs of additional load in the Interconnected plan would be either the same as or less than the cost in Isolated Island plan.

The real issue was to test the impact of scenarios where the Isolated Island benefits, such as low fuel prices and lower load, to see how the two plans compared. In low load cases, projected export prices also become relevant (and so are fuel prices, to the extent that fuel prices are related to export prices), because the consequences of lower Island load might or might not be offset by exports in different future scenarios. Also, the impact of progressively larger cost overruns obviously should have been considered, in conjunction with these other factors, since these cost overruns are specific to mega-projects like MFP.

The 2012 analysis included runs of the PPA and LIL models with 25% cost overrun plus Reference for all other variables. In addition, general CPW models for Low Fuel prices and Reference for all other variables were prepared. The higher PPA and LIL costs can be substituted in to the Low Fuel scenario to obtain a sense of that combined outcome.

No runs were provided that included Low Load in the 2012 CPW analysis. However, if the simplifying assumption can be made that all excess PPA supply resulting from lower load can be sold in the export market for some chosen price, then an attempt to understand the magnitude of the problem can be made. Of course, making this assumption penalizes the Interconnected Island plan after 2032, when the first new asset is added, since in a low load environment that asset would not be added at all, therefore mitigating cost (returning to the issue of changing the shape of expected curves, rather than just translating the existing curve up or down). However, it is not possible to properly take this into account without a full Strategist model run, so some general indication of impact will have to suffice.

Hydro Quebec sold power in export markets for an average price of $53/MWh in 2011. For the sake of modeling simplicity, it will be assumed that excess power in low load scenarios will be sold for a net price of $50/MWh, inflated after 2012 by 2% per year. This is a lower price than was included in the PPA model in 2012, but higher than actual market prices since then (recall that in 2018 Hydro Quebec's average sale price for exported power was only $47, instead of the $57 included in the modeling below). It is therefore something of a compromise figure, used only for the purposes of creating a test that might have been done back in 2012, when future export performance was thought to be stronger.

Table 8: Interconnected Plan Fuel and Load Scenarios

	Reference	Low Fuel Cost	Low Fuel - 1% Island Load	Low Fuel & Flat Island Load to 2020
Nominal Total $	$46.0 B	45.6 B	45.0 B	36.1 B
Inflation Adjusted $	24.3 B	24.0 B	23.7 B	19.0 B
5% Discount Rate	11.2 B	11.0 B	10.8 B	8.7 B
7% Discount Rate	7.5 B	7.3 B	7.2 B	5.8 B
10% Discount Rate	4.6 B	4.5 B	4.4 B	3.5 B
LUEC at 7%	$210/MWh	$205/MWh	$209/MWh	$339MWh
Total Production	205 TWh	205 TWh	199 TWh	111 TWh

All figures in 2012 $ except nominal

The above table shows the results of the Low Fuel scenario combined with two levels of lower load, with the export price assumption described above.

Note that the Low Fuel + Flat Load result is almost identical to the outcome in the Isolated Plan, described above in Table 7. Given the crude nature of this modeling, it should be assumed that these outcomes are certainly within the margin of error.

The next table adds in the impact of a 25% cost overrun for the MF/LTA/LIL.

Table 9: Interconnected Plan Fuel and Load Scenarios with 25% MFP Cost+

	Reference	Reference + 25% MFP Cost	Low Fuel Cost + 25% MFP	Low Fuel - 1% Island Load + 25% MFP	Low Fuel & Flat Island Load to 2020 +25% MFP
Nominal Total $	$46.0 B	53.6 B	53.3 B	52.7 B	43.8 B
Inflation Adjusted $	24.3 B	28.3 B	28.0 B	27.7 B	23.1 B
5% Discount Rate	11.2 B	13.1 B	12.8 B	12.7 B	10.6 B
7% Discount Rate	7.5 B	8.7 B	8.5 B	8.4 B	7.0 B
10% Discount Rate	4.6 B	5.4 B	5.2 B	5.1 B	4.2 B
LUEC at 7%	$210/MWh	$244/MWh	$239/MWh	$244/MWh	$409MWh
Total Production	205 TWh	205 TWh	205 TWh	199 TWh	111 TWh

All figures in 2012 $ except nominal

As can be seen from the above two tables, when load drops significantly, the cost of the Interconnected plan rises dramatically, across all metrics. When there is also a cost overrun in the MFP, the two costs together become particularly onerous.

The Isolated Island is effectively equal or superior to the Interconnected Island plan in the Low Fuel +25% MFP scenario, and when Low Load is added the result becomes dramatic.

Table 10: Plan Comparisons

	Low Fuel Cost	Low Fuel Cost + 25% MFP	Low Fuel Cost & Flat Island Load to 2020	Low Fuel & Flat Island Load to 2020 +25% MFP
	Isolated	Interconnect	Isolated	Interconnect
Nominal Total $	56.6 B	53.3 B	41.6 B	43.8 B
Inflation Adjusted $	28.6 B	28.0 B	21.2 B	23.1 B
5% Discount Rate	12.3 B	12.8 B	9.4 B	10.6 B
7% Discount Rate	7.9 B	8.5 B	6.0 B	7.0 B
10% Discount Rate	4.6 B	5.2 B	3.6 B	4.2 B
LUEC at 7%	$176/MWh	$239/MWh	$231/MWh	$409MWh
Total Production	217 TWh	205 TWh	123 TWh	111 TWh

All figures in 2012 $ except nominal

It bears repeating that these calculations are poor substitutes for proper Strategist model runs. They can only be considered indicative of direction, and nothing more. While the PPA and LIL COS costs are relatively fixed because of contractual terms, there are clearly adjustments that could be made under all of the plans when significant changes in load forecasts occur. These complicated effects cannot be reflected here with simplistic financial models, but require the more complex operational analysis at the disposal of electricity companies.

Nevertheless, these results are indicative of a fact that should be intuitive: there are scenarios, combinations of variables, where the Isolated Island plan would deliver a superior result to the Interconnected Island plan. These should have been identified and carefully considered in the decision-making process.

C.5. Probabilities and Scenarios

In the summer of 2012, when West Texas Intermediate crude oil was trading at US$90/bb, would you have bet on a high oil price scenario for the next 10 years, or a low one? Given that electricity prices had only recently fallen by 20%, would you have bet on a further 20% decline, or a return to higher prices? With bonds flirting with historic lows, what probability would you have placed on bonds actually trending down to absolute historic lows, versus moving back up to the mean? There is no particularly good way to answer all of these questions, especially *simultaneously*. Yet that is what is required when choosing whether or not to endorse a system plan that contains an irrevocable element: once something like the Muskrat Falls Project is underway, it cannot be easily stopped or reversed without the expenditure of billions.

Disaster scenarios could be defined for both plans: high oil prices would lead to crippling electricity costs if Holyrood was replaced with facilities that no longer burned the cheap but dirty No. 6 fuel oil. The only immediate choice would be aggressive conservation. Or, in the face of extremely high costs, some way to restart the Muskrat Falls Project, or something like it, if that would even be possible in the aftermath of a failed process in 2012 (bearing in mind that selecting the Isolated Island plan in 2012 would have killed significant goodwill among all the parties that had participated in developing it).

For the Muskrat Falls Project, historical examples from around the world of construction projects gone wrong abounded, but every effort is always made, before every mega-project, to display reassurance that this will be one of the good ones, not the disasters. At the same time, load decline was an enormous Achilles Heel for a Project that created massive excess supply at significant expense. However, placing a probability on load decline would be contrary to the positive and upbeat forecasts for the future upon which pictures of progress and success depend.

In the Muskrat Falls Project decision-making process, it appears that scenarios were not clearly defined and thoroughly tested, that little attempt was made to systematically describe the conditions under which each alternative plan would fail, the probability of those conditions arising, the consequences of that failure, and whether there would be the ability to mitigate the worst consequences if that scenario came about. Some effort was put into defining scenarios and conditions, but not enough and not thoroughly. Hundreds of Strategist runs should have systematically described the variety of potential outcomes, so that clear thinking and understanding of the range of potential outcomes could have been addressed forthrightly.

Looking back now, based on the limited available data from the time, plus some attempt to reconstruct scenarios that might have been tested, does it seem as though there would have been sufficient grounds to believe the Interconnected Island plan could pass the test of being at least as low cost as the Isolated Island plan, within reason?

To be clear, this question *cannot* be interpreted to mean “Is the Interconnected Island Plan cheaper in every possible scenario?”, because no credible process will ever come that conclusion. To the extent that the 2012 list of sensitivity analysis showed not a single scenario in which the Isolated Island was superior is a symbol of the gross incompleteness and insufficiency of the process undertaken. There are always scenarios that work for or against every plan.

On a risk-adjusted basis, was the Interconnected Island plan acceptable, on the facts both observed, and which can be parsed out of the record now?

There are some scenarios, such as Low Fuel-Low Load-25% Cost Overrun, in which the Interconnected Island plan fails. Even the Low Fuel-Reference Load-25% Cost Overrun appears sufficient to tip the scales, but less decisively.

These situations are also problematic because there appears to be very limited ability to mitigate the consequences for ratepayers: nothing can be "unbuilt" or avoided, because the MFP is a complete project unto itself. Conservation might only make things worse, since a lack of load is part of the problem, and there is no change in policy or direction that will make a significant difference for ratepayers, because the arrangements are locked in for 50 years.

On the other hand, there appear to be many scenarios in which the Interconnected plan is superior, even if some things go wrong, like not insignificant cost overruns of 25% (in Reference Load-Reference Fuel, the Interconnected Plan is still superior even with a 25% Cost Overrun).

If the dataset on scenarios had been complete and thoroughly analyzed, then a large majority would have been favourable to the Interconnected Island plan. Analysis would still have raised trouble spots, because of the rigidity of the Interconnected Island plan and the inability to recover from or mitigate the worst impacts from certain combinations of conditions, but it would have been difficult to argue that in most futures, as developed and presented by a variety of reputable forecasters, the Interconnected Island would not have been at least as low cost as the Isolated Island plan.

There is no question the dataset was grossly incomplete. A complete dataset would not have resulted in an obvious choice. An answer to the question would have required careful judgement, and the weighing of significant risks relating to both plans. However, it should be said that the ingredients would likely have been present to support a judgement in favour of the Interconnected Plan, always assuming thorough analysis.

Today, when the exact worst case scenario for the Interconnected Island plan has come about – massive cost overrun, Low Load, Low Fuel Prices, Low Export Prices, Improving Technology, etc. – it is imperative to resist the temptation to look back with hindsight when considering the decision taken. It may appear that the judgement was horribly wrong. In fact, it does appear true that the analytical process was horribly lacking, but that is not the same thing.

As a final caveat, it is necessary to point out, again, that all of the above comparison of the plans did not take into account the strategic impacts of the Interconnected Island plan on the Churchill Falls situation. Had that also been added into the analysis, there may have been an even stronger case for the Interconnected Island plan.

4. Distribution of Costs, Benefits, Risks and Rewards

In section 2, the stakeholders and interests at play in the Muskrat Falls Project were described. With the benefit of some analysis of scenarios that might occur if the project were pursued, it is important to return to the question of whether costs and risks were properly distributed with benefits and opportunities among stakeholders. In any transaction, it is important for fairness that not only is the proposal at least as good as the available alternatives, but that the transaction also respects, in broad strokes, the principle of proportionality. It should be stressed that this is not a mathematical calculation, particularly in complex arrangements. Instead, the exercise is intended to uncover any obvious and striking lack of proportionality, which would be a strong indicator of a fairness failure, even if the analysis of alternatives may have tended to the positive, and especially where the analysis of alternatives was complex and uncertain.

Note that this section now <u>*assumes*</u> that the Interconnected Island plan met the least cost test, at least within reason and a normal range of uncertainty. The question now is whether the arrangements that constituted the Muskrat Falls Project were reasonably proportionate among stakeholders.

A. Stakeholder Trade-offs

A.1. Government of Canada and Commercial Lenders

The Government of Canada and the commercial lenders to the project are the most straightforward participants, and easiest to dismiss from analysis.

Commercial lenders entered into standard debt transactions for long terms at low rates, as set by the market. The rates are low because of the bond terms and conditions, which include the sovereign guarantee. All of this is transacted in a free and liquid market, and as such can be considered inherently proportional.

The Government of Canada provided a debt guarantee for the Project, and effectively took the entire debt of the Project as a contingent liability on the Canada balance sheet, allowing the project to benefit from a much lower interest rate than would have otherwise been possible. However, the FLG required stringent commercial terms to support the project such that the scenarios in which there is a default that would invoke the federal government's participation are almost certainly limited to natural disasters of epic proportions. If a truly massive storm were to wipe out the LIL, for example, effectively stranding the power of MF for two years or more, the Government of Canada might be required to step in and support debt repayments. However, in this kind of a dire situation in a province (where there would no doubt be many other impacts besides to the electricity system), the Government of Canada would likely participate, even if it had not provided the FLG. The incremental "cost" to the Crown, then, is likely fairly limited, on a risk-adjusted basis.

The benefit for the Government of Canada was the development of renewable energy, reduction in greenhouse gas emissions associated with electricity in Atlantic Canada, and regional economic development. All of these seem worthy, if indirect benefits to the federal government. Since the only project participant that pays federal income tax is Emera, even that avenue of indirect benefit is limited. As both costs and benefits are relatively modest, there seems no obvious concern about proportionality.

A.2. Nova Scotia Ratepayers, Emera and the Nova Scotia Government

The Maritime Link was budgeted, rightly or wrongly, as being approximately 20% of the overall construction cost of the Muskrat Falls Project. As a result, Nova Scotia ratepayers were given the right to 20% of the energy output of the facility (notionally, since the amount would be provided over 35 years rather than 50). In addition, because Emera contributed certain transmission rights into the Project to allow Nalcor to have access to US markets, Emera was given the right to participate in the equity funding of the LIL. For the Government of Nova Scotia, the Project facilitated their green energy targets, and represented an opportunity for the Province to become part of an ongoing energy trading route in the Northeastern part of the continent, rather than being at the end of a line.

All of the risk associated with building, operating and maintaining the Maritime Link rested with Nova Scotia ratepayers, subject to Emera meeting normal regulatory standards of prudence in its work. As was pointed out in the regulatory process in Nova Scotia, Nova Scotia ratepayers tacitly accepted the entire risk that the project would be delayed because of circumstances outside their control, as in fact has occurred. This is a clear weakness, in that there is no sharing of this risk among stakeholders. On the other hand, Nova Scotia ratepayers may benefit in the future from access to power beyond the committed amount, and potentially at lower cost than can be achieved elsewise in the market, because of an advantageous position along the electricity trading route that has been established. No party other than ratepayers in Nova Scotia has the right to benefit from export/import electricity trading opportunities, as Nova Scotia Power is required to return to ratepayers any profits from such transactions. Overall, Nova Scotia ratepayers accepted cost responsibility in exchange for energy, albeit at a higher than market price, and risks were balanced by opportunities to purchase lower cost power.[52] While there may be some concern about this balance, it is not a striking and obvious imbalance. The decision to accept the project was made in a professional, thorough and transparent manner after consideration by the regulator, and ratepayer advocates participated throughout.

Emera, like the lenders, has invested funds in regulated businesses, and expects typical regulated returns in exchange for prudent management and operation of the project. Arguably Emera was instrumental in the development and initial support of the project, but at the same time, Emera also committed transmission rights and other consideration that were key parts of making the Project a complete package for access to US markets. Emera avoided any responsibility for delays, defaults or failures, excepting any which might arise from actions contrary to regulatory standards and practices that it might be directly responsible for. Their rate of return was not put at risk in any way. However, Emera was not a decision maker on behalf of ratepayers, and had no conflict of interest in its pursuit of a commercial opportunity.

A.3. Newfoundland Ratepayers

Newfoundland ratepayers are obliged to pay the costs of the MF, LTA and LIL, in exchange for receiving a fixed schedule of energy. That is a similar situation as that of Nova Scotia ratepayers. Those costs were to include a return on equity to the proponent. That energy was deemed, at the time of the decision, to be at least as inexpensive as other energy opportunities. There was always the possibility that this would not be true, because of the unpredictable nature of oil prices, interest rates, changing technologies, etc., but it was considered to be the case, on balance of probabilities, by the decision-maker. One of the critical difficulties that undermines this statement, however, is that the

[52] One other benefit was gained for Nova Scotia ratepayers, which is also difficult to quantify: some additional system reliability as a result of having a sizeable transmission connection to Newfoundland, in addition to existing transmission connections to New Brunswick. This should be considered a real benefit, and not just an "opportunity".

decision-maker was the shareholder/beneficiary of one of the main proponents of the Muskrat Falls Project. This is a significant contrast to the situation in Nova Scotia. Part of the decision-making process in Newfoundland was an open review, in which ratepayer representatives participated, but it concluded without a decision. The final decision was, in effect, thrust upon ratepayers by a party who would be a direct beneficiary from the transaction.

Newfoundland ratepayers were made, by the nature of the arrangements, liable for any and all cost overruns and failures in the Project (excepting the ML). The economic terms, including with respect to the return on equity were dictated by the shareholder of the proponent, and ratepayers had no say in that decision, nor recourse to independent and public arbitration. In Nova Scotia, the exchange for accepting project risks was the opportunity to benefit from additional purchases of lower cost energy. That was likely to be a benefit in almost any scenario (though the exact value of that benefit was and is uncertain), because Nova Scotia ratepayers are expected to require additional clean energy sources in the future. In Newfoundland, however, it is not clear that access to additional energy from MF is a compensating benefit for the risk of cost overruns. The Strategist modeling did not suggest any additional purchases of energy beyond what was included in the PPA, presumably because that would not be the low cost option for the ratepayer.

The disposition of Churchill Falls may ultimately be of benefit to Newfoundland ratepayers circa 2041 and beyond as a result of the plan adopted, but this potential benefit was not elucidated, nor was there any clear commitment that ratepayers should or would benefit by some specific scheme. Theoretically, all benefit associated with Churchill Falls could stream to the Newfoundland taxpayer/government/shareholder of Nalcor. Newfoundland ratepayers could be obliged to pay export-equivalent prices for Churchill Falls power, in an uncertain export market future. While there may be potential benefit for ratepayers, there is no contractual right to a benefit associated with Churchill Falls, should one materialize.

The proponent/shareholder/decision-maker was obviously the Government of Newfoundland, on behalf of taxpayers. There is just as obviously clear overlap as between ratepayers and taxpayers, so it can be argued that benefits accruing to taxpayers will also benefit ratepayers. However, overlap between taxpayers and ratepayers does not mean identity. Ratepayers pay electricity rates typically based on electricity consumption. Taxpayers pay personal, sales, corporate and other taxes in a way that is distributed entirely differently than electricity consumption. Should profits accrue to taxpayers in the future that ultimately derive from ratepayers, those profits may be distributed among taxpayers in a way that is highly likely to be disproportional to the way the value was generated.

It is difficult to conclude anything other than that the costs and risks borne by Newfoundland ratepayers are disproportionate to the benefits and opportunities afforded them in the transaction. This colours the perception of fairness of the transaction, particularly in light of the evidence on whether the plan was actually the least cost alternative for ratepayers.

A.4. Nalcor Shareholder/Newfoundland Government/Taxpayers

Many benefits arise from the pursuit of the Muskrat Falls Project, wholly incidentally to the electricity that is supplied and the rates paid for it. These include construction jobs, local economic development, payments to local First Nations, and the “greening” of the Newfoundland electricity grid. All of these are positive outcomes, and it is entirely understandable that a government would seek to pursue them. Cost overruns do undermine local economic benefits, however, to the extent that cost overruns lead to higher and uncompetitive electricity rates which hinder the local economy. The question of whether these benefits and risks are balanced for the government is potentially one for economists.

As a shareholder, the government will benefit from its return on equity contributed to the project, including for any equity contributed to cost overruns. The shareholder has no obligation to mitigate any of the consequences of cost overruns, even if they are the consequence of failures by the company in planning and carrying out of the project. Arguably, this is the same position of Emera in Nova Scotia, as Emera will receive its return on equity regardless of the ultimate budget performance of the project, as long as no failure to meet regulatory standards was shown. However, Emera was not the project decision-maker for Nova Scotia, and did not make the decision to proceed for ratepayers. The contrast with Newfoundland is obvious.

Nalcor is a commercial for-profit corporation with equity on its balance sheet. It is not a not-for-profit like Manitoba Hydro or certain other electricity enterprises in the United States (e.g., Tennessee Valley Authority). Taxpayers commit actual equity to the company in the form of retained earnings from not only the electricity business, but also fossil fuel activities. If this equity was not invested in the enterprise, it could be returned to taxpayers in some other form. As a result, it is appropriate that the equity earn a competitive return.

The Muskrat Falls Project is not a normal regulated utility asset. It is an extremely long-lived asset, imposed on ratepayers for 50 years, and without normal regulatory flexibility to manage ratepayer burdens or smooth out impacts. Payment for the PPA and LIL must be made according to schedule, and all financial covenants must be met. Many of the restrictions on ratepayers were requirements of the FLG, however, they are implemented and enforced through legislation, were agreed to by the Government, and thrust upon ratepayers by the government as decision-maker.

Pursuit of the Project has benefits for the province well beyond ratepayer interests, as mentioned above. In addition, the government/shareholder stands to benefit from any potential gains that may arise at Churchill Falls after 2041, which gains may have been either created or strengthened by pursuit of the Project. The shareholder has no obligation to share any of these possible gains with ratepayers. This benefit is all in addition to equity returns that are compensation for the actual investment in the Muskrat Falls Project.

Again, it is difficult to conclude anything other than that benefits and opportunities outweigh costs and risks for the Government of Newfoundland and Labrador/shareholder of Nalcor.

B. Proportionality

Even this summary review makes it apparent that the distribution of costs and risks on the one hand, and benefits and opportunities on the other, do not appear proportional for Newfoundland ratepayers and the Nalcor shareholder/government.

While other stakeholders can typically point to cost/benefit and risk/opportunity pairs that appear to be at least reasonably matched, Newfoundland ratepayers cannot do so. The arrangements put ratepayers at considerable risk, with full liability for cost overruns, and for future conditions which might render Newfoundland electricity rates uncompetitive. On the flipside, ratepayers have no corresponding rights to any significant opportunities, despite the potential availability of future benefits associated with Churchill Falls.

The Newfoundland taxpayer, on the other hand, was assured of equity returns on all investments by the arrangements, gained the benefit of regional economic development activity and environmental improvements, and has the right to whatever benefits may arise for the province from future arrangements around Churchill Falls.

As arranged in 2012, the Muskrat Falls Project does not appear to meet the test of proportional distribution among its participants, especially with respect to arguably the most critical stakeholder, Newfoundland ratepayers. This casts problematic light on any potential finding of Fairness, from a financial point of view, for ratepayers.

5. Additional Issues

A. Valuing Churchill Falls

In 2041, new arrangements will be in place to deliver Churchill Falls Power to market. The shareholders of CFLCo will be rewarded for their long patience in operating the facility during the period when the great majority of the value created by the production of electricity was absorbed by Hydro Quebec. The knowledge and certainty that this future outcome is true is the basis for the company's value. On the date that concrete plans and arrangements are put into place for the post-2041 period, whatever and whenever they are, that value will be crystalized.

Today, however, that value is inchoate. The cost of operating Churchill Falls is well known, and unlikely to change more than incrementally, barring some dramatic failure in infrastructure. More concerning is the possibility that climate change will affect precipitation patterns in unpredictable ways, changing the operating profile of the facility. However, that could just as easily be an improvement as a problem. Forecasting 21 years into the future is practically impossible with respect to export prices, and more importantly the exact commercial arrangements that will be required to get the energy to market are years out of reach, if not decades. Despite illustrative examples earlier in this Report, a truly defensible estimate of the cost of transmission infrastructure would be required to begin a process of calculating the quantum of commercial opportunity.

To the extent that it is possible to achieve an estimate of post 2041 value, there is the problem of time. At any reasonable discount rate, 21 years of delayed payment is dramatically corrosive to current dollar value ($100 in 2041 is worth $53.75 in 2020 at a 3% discount rate, $$35.89 at 5%, $24.15 at a 7% rate, and $13.51 at a 10% rate).

Nevertheless, the result of such an exercise would arrive at a large figure, given the size of the economic asset.

For example, assume that the economic value of Churchill Falls output in 2020, after subtracting the cost of access to market and the uncertainty of market prices, is $1 billion. Inflate that figure forward to 2041 at a 2% inflation rate, and continue that inflation for 50 years of operation. Discount that resulting stream of cash flows to 2020. At a government 3% cost of funds today, that stream of cash flows is valued at in excess of $30 billion, at a more commercial rate of 5%, the figure is halved. That amount, or some figure within the range of it, will be the subject matter of negotiations that will eventually take place between Nalcor and Hydro Quebec in determining the future of the station.

B. Generations of Newfoundland Ratepayers

Given the financial requirements of the FLG and the terms and conditions of already outstanding bonds, Newfoundland ratepayers for the next 20 years will absorb high and mounting costs for electricity from the Muskrat Falls Project. For the 30 years following, approximately, ratepayers may find that some of the burden is mitigated by the economic value that may be generated by the Churchill Falls Generating Station, assuming that arrangements are made by the government of the day to use some of the proceeds of Churchill to offset the burden of the MFP.

After those 50 years are up, there will be another step change, when Newfoundland will benefit from two sources of power which will be among the cheapest in the world, either for domestic use or export. At that point, the people and ratepayers of Newfoundland and Labrador will have access to over 7,000 MW of fully paid-up hydroelectric resources (between the facilities in Labrador, and existing facilities in Newfoundland). On a per capita basis, that will be more than any jurisdiction in Canada, and a spectacular wealth of resources.

The challenge with these facts is that they appear immutable: each step change is fixed in time, and surrounded by existing contractual arrangements. The step changes create significant inequities on an intergenerational basis, and there does not appear to have been consideration of how to manage them, or even whether they should be acknowledged and addressed.

The significant cost overruns associated with the Muskrat Falls Project have highlighted that the current generation of ratepayers were made to accept a risk, but the benefits that may correspond to that risk are far off. However, the occurrence of the cost overrun only uncovered the problem that was already structurally in place: the creation of benefits in the future, paid for by the consumers of today.

For the generation of ratepayers in the next 20 years, the problem will be most acute, and there will be almost no overlap with the privileged generation of ratepayers 50 years hence who will have access to a plethora of benefits.

Three steps may be helpful:

- Acknowledgement that intergenerational inequities have been created, and measure them to a reasonable standard of certainty;
- Exploration of whether there are mechanisms to address the inequities, potentially involving transferring benefits through time through financial means (which would have inevitable cost implications); and
- Determining whether it is worthwhile, on a societal basis, to act on the opportunity to use those mechanisms.

There are many instances where past generations invested at heavy cost, only to see benefits accrue to future generations. It is a commonplace argument to say that each generation finds a project with which to experience sacrifice, and that inequities between generations are managed by successive generations taking on ever more projects that entail returns delayed farther into the future. However, financial markets are now more sophisticated, more liquid and more transparent than every before, and may offer mechanisms which can be considered as a means, if desired and if it is deemed valuable, to avoid the sharp delineation of benefits and burdens through time.

6. Summary Observations

A transaction is fair for a particular party, from a financial point of view, if it can be shown that the transaction was at least as financial advantageous for the party as all other reasonably available options, on a risk-adjusted basis. In addition, and in particular where transactions are complex and there is inherent doubt about the outcome of this test, a second indicator of fairness is whether the costs, benefits, risks and opportunities in a transaction are distributed proportionately among stakeholders.

In order to determine the fairness test, financial models and analysis are typically assembled and explained. In the case of an extremely complex transaction, such as the Muskrat Falls Project, the data and analysis is typically voluminous.

The MFP is a complex assemblage of parties, assets, construction projects and contracts. Commitments will last 50 years or more, and some of the assets will last more than a century, all at a cost of billions of dollars. Approval of such an endeavour should come only after detailed analysis and sober reflection. Risks and caveats should be thoroughly understood and clearly explained, particularly where opportunities for mitigation might be lacking. Given the wide range of potential future conditions, it is intuitive that there will be some future scenarios which will be painful to imagine and plan for, but with so much at stake, that hard work is necessary.

The analytical process undertaken as part of the decision-making for the Project was seriously deficient. Where hundreds of scenarios should have been examined, not even dozens were addressed. Attention should have been focused on the potential conditions under which the project failed, but instead not a single scenario where the alternative plan was superior was given serious credence.

Some scenarios were modeled. Some evidence was assembled. Some indication was provided that the MFP was superior to the alternative in different scenarios. However, the volume and depth of analysis was insufficient to allow for a sober judgement and conclusion.

This does not mean that it was not possible. It is not appropriate to conclude, after the fact, that a "proper" judgement would have been in the negative. It only means that there is reason to cast doubt on the quality of the decision.

Analysis of the assembled and available information shows that current conditions, disastrous in the eyes of many, would have been considered the "worst case" scenario had a scenario been developed and tested with the features ratepayers are now living with (low fuel prices – low export prices – low customer load – massive cost and schedule overrun). This scenario ***should*** have been tested, but was not. There is no reason to believe, however, that had this scenario been tested, the conclusion would necessarily have been different from what occurred. Many other scenarios, in fact likely a preponderance of scenarios, would have suggested very different outcomes. The current situation would have been considered, at the time, a very low probability outcome. However, if it had been identified and flagged, thought may have been given in advance to steps that may have been taken, or may yet be taken, to mitigate the outcome for ratepayers.

Key strategic elements of the broader context were also missing from the analysis, which weakens it significantly. Development of a subsea transmission route that ultimately reaches export markets has an obvious and strategic impact on the future of the Churchill Falls Generating Station, a facility fully six and a half times larger than Muskrat Falls. While this impact is necessarily speculative, because it is far away in time, it cannot be denied that the impact will be real. However, no attempt was made to put this strategic impact into the context of the decision to proceed with the Project. Also, no attempt was made to formally include ratepayers in the future potential benefits from that strategic asset, despite the fact that ratepayers were burdened with a significant risk for which mitigation would be difficult, and ratepayers would be paying for the transmission assets that greatly strengthened the Churchill Falls value proposition for Nalcor and its provincial government shareholder.

Newfoundland ratepayers do not appear to be well-served by the arrangements. Whether or not it could be determined with any confidence that the MFP was – within reason given the levels of uncertainty – the least cost plan to serve ratepayers over the course of 50 years, ratepayers nevertheless appear to have accepted a disproportionate level of cost and risk in exchange for committed energy and limited upside opportunities. On the contrary, the Government of Newfoundland gained the ancillary benefits of regional economic development, First Nations arrangements, and reduced GHGs, while directly receiving the shareholder benefits of a guaranteed return on equity regardless of the cost and schedule performance of the project, a potentially higher return through export revenues, and the future benefits associated with the changed strategic positioning of Churchill Falls. This disproportionate distribution cries out for redress in some form. Investigation of possible mechanisms to redistribute benefits, potentially across time and cohorts of ratepayers and other stakeholders, may be a fruitful avenue to pursue.

Appendix A – MPA Utilities Practice Overview

Morrison Park Advisors has deep experience in the utility sector, including electricity generation, transmission and distribution, as well as natural gas pipelines and distribution utilities. Both as a firm, and as individuals with prior experience, we have worked with many of the leading utilities in Canada helping them to understand and maximize the value of assets and opportunities, whether for the purpose of mergers and acquisitions, new development and construction, or balance sheet management. Given our expertise, we are often called upon to provide clients with advice in challenging situations that do not fit typical investment banking categories.

Morrison Park Advisors

- Independent, partner-owned investment banking firm established in 2005
- Co-founded by David Santangeli and Brent Walker, now ten professionals, with over one hundred successful assignments with public and private companies, governments and quasi-public entities
- Value proposition is a unique combination of Tier 1 investment banking capabilities, comprehensive scope of expertise, and excellent client value
- Integrated advisory practice, covering all facets of investment banking, capital markets and Mergers & Acquisition services

Utilities Services

- Mergers & Acquisitions
- Strategic advice on market consolidation; potential investors & partners
- Financial advice on balance sheet management, growth capital, dividend policies
- Valuation
- Regulatory reviews and expert witness testimony in legal disputes

Utilities Reference Assignments

- Manitoba Hydro Public Utilities Board: Expert Witness on behalf of the Consumers Coalition and the Manitoba Industrial Power Users Group on the Manitoba Hydro General Rate Application for 2017/18 and 2018/19
- Nova Scotia Utilities Review Board: Consultant to the Board and Expert Witness on the Interim Cost Assessment Relating to the Maritime Link
- Manitoba Hydro Public Utilities Board: Consultant to the Board and Expert Witness on Manitoba Hydro's Needs For and Alternatives To Proposed Business Plan
- Nova Scotia Utilities Review Board: Consultant to the Board and Expert Witness on the review of the proposed Maritime Link transmission project to connect Nova Scotia with Newfoundland and Labrador Hydro
- Alberta Electric System Operator (AESO): capital markets view on Alberta electricity investing, interview of developers/owners/operators of electricity generation facilities, as well as capital providers and other capital markets participants
- Market Surveillance Administrator of Alberta: Analysis of electricity generation investment sustainability in Alberta based on market participant interviews and financial information
- Crown Investments Corporation of Saskatchewan: advice on the cost and commercial viability of a nuclear electricity generation plant in Saskatchewan.
- BC Hydro: strategic advice on market value and potential partnerships for new international and interprovincial transmission infrastructure
- City of London, Ontario: review of the value of and strategic opportunities for ownership of London Hydro
- PowerStream: financial advisor to PowerStream in its merger with Enersource Hydro and Horizon Utilities, with concurrent acquisition of Hydro One Brampton Networks, Inc., to create the new company Alectra Utilities
- City of Toronto: M&A advisor to the City of Toronto in the sale of its minority shareholding in Enwave, a district heating and cooling company in Toronto
- Altagas Utilities: independent valuation of distribution utilities for the special committee of the Board of Directors
- Oshawa PUC: advice to the Board with respect to potential merger, acquisition and sale opportunities
- Milton Hydro: advice to the Board and the special advisory committee to City Council with respect to the recapitalization of Milton Hydro, its dividend policy, and potential merger, acquisition and sale opportunities
- Enwin Utilities: strategic and financial advice on balance sheet management of electricity and water utility businesses, and advice on options available to the Board with respect to potential merger, acquisition and sales
- Haldimand Hydro: advice to the Board with respect to potential merger, acquisition and sale opportunities
- Woodstock Hydro: advice to the Board with respect to potential merger, acquisition and sale opportunities
- Hydro One: financial advisor for distribution industry consolidation from 2007 to 2009; completed valuations for more than 30 utilities; conducted negotiations; strategic advisory services in managing acquisition proposals

Sample Previous Experience of MPA Staff

- Hydro One: Directed acquisitions of Haldimand Hydro, Norfolk Power, Woodstock Hydro, and Terrace Bay Superior Wires, in addition to numerous discussions and negotiations with respect to potential transactions with electricity distributors across the province
- Province of Ontario: Development of provincial policies with respect to electricity distribution consolidation
- Province of Nova Scotia: Financial advisor to the Province on the sale of its interest in Nova Scotia Resources Limited
- Ontario Teachers, OMERS and SNC Lavalin: Advisor to consortium on the potential acquisition of 49% of Hydro One
- Fortis Inc.: M&A advisor on the $1.4 B acquisition of Alberta and BC electricity distribution assets formerly owned by Aquila Networks
- Newfoundland & Labrador Hydro: advisor on proposed privatization
- Advisor to a bidding consortium on the proposed acquisition of ENMAX, the electricity distributor of the City of Calgary

Appendix B – Summary of Relevant Experience

	Regulated Utility	Non-Regulated Utility	Generation	Transmission	Distribution	Sale Process	Fairness Opinion	Other	MPA Team Members
MPA Assignments									
City of London, Ontario: Review of London Hydro	X				X			X	Pelino Colaiacovo, Bill Meeker
PowerStream: Merger, Purchase and creation of Alectra	x				x	x	x		Pelino Colaiacovo
City of Toronto: Sale of Enwave		x				x	x		Pelino Colaiacovo
Altagas Utilities	x				x	x	x		Brent Walker
Oshawa Hydro	x				x			x	Pelino Colaiacovo, Brent Walker
Milton Hydro	x				x			x	Pelino Colaiacovo, Brent Walker
Enwin Utilities	x				x			x	Pelino Colaiacovo
Haldimand Hydro	x				x			x	Pelino Colaiacovo
Woodstock Hydro	x				x			x	Pelino Colaiacovo, Brent Walker
Hydro One	x				x			x	Pelino Colaiacovo, Brent Walker
Alberta Electric System Operator		x	x					x	Pelino Colaiacovo, Brent Walker
Manitoba Hydro	x		x	x			x		Pelino Colaiacovo, Ben Kinder
Nova Scotia Utilities and Review Board	x			x			x		Pelino Colaiacovo, Brent Walker, Ben Kinder
Market Surveillance Administrator of Alberta		x	x					x	Pelino Colaiacovo, Brent Walker
Crown Investments Corporation of Saskatchewan		x	x					x	Brent Walker
BC Hydro	x			x				x	Pelino Colaiacovo, Brent Walker
Prior Assignments of MPA Staff									
Hydro One acquisition of Haldimand, Norfolk, Woodstock distributors	x				x	x			Bill Meeker
Province of Ontario distribution consolidation policy	x				x			x	Pelino Colaiacovo
Province of Nova Scotia: sale of interest in Nova Scotia Resources		x				x	x		Brent Walker
Advisor to consortium for potential acquisition of Hydro One	x			x	x	x			Brent Walker
Fortis Inc. acquisition of Aquila Networks assets in BC and Alberta	x				x	x	x		Brent Walker
NALCOR: advisor on proposed privatization	x		x	x		x			Brent Walker
Advisor to consortium on proposed acquisition of ENMAX	x				x	x			Brent Walker

Appendix C – MPA Utilities Team

Pelino Colaiacovo

Pelino is a Managing Director at MPA. In this role he is responsible for origination and transaction execution, financial advisory and capital raising services. Since joining MPA Pelino has focused on advising clients in the energy, utilities, infrastructure and public sectors, and in addition assists clients in cleantech industry.

Utility clients have included Hydro One, BC Hydro, Enwin Utilities, Oakville Hydro, Woodstock Hydro, the Nova Scotia Utilities Review Board, the Alberta Market Surveillance Administrator, the Manitoba Public Utilities Board, and numerous others, and more broadly in the energy sector Pelino has worked on a number of M&A and capital raising assignments for renewable energy and cleantech companies.

Prior to joining MPA in 2005, Pelino was Chief of Staff to the Ontario Minister of Energy from 2003 to 2005. During that time, he assisted in significant restructuring of the Ontario electricity sector, including the drafting and implementation of new legislation, the creation of the Ontario Power Authority, and significant procurements of new electricity generation capacity for the province.

Previously, Pelino spent more than 10 years in management, policy and communications consulting in Canada and the United States, advising clients across a wide range of sectors, including energy, transportation, telecommunications, and healthcare.

Pelino holds a B.A. and an L.Lb., both from the University of Toronto.

Bill Meeker

Bill is a Senior Advisor at Morrison Park Advisors. Since joining MPA in 2014, Bill has focused exclusively on the utility sector. Bill brings over thirty years of utility experience with Ontario Hydro, Ontario Hydro International and Hydro One Inc. to helping clients understand and meet the challenges of today's utility environment.

Bill's career has focused on transaction development in the electric distribution and transmission businesses – both internationally and in Ontario. He has led cross-functional teams in due diligence, valuation, execution and regulatory approvals. Bill's experience includes directing the acquisition of assets and shares, the sale of strategic investments, structuring complex cross-border partnerships, managing investment partnerships, and structuring merger arrangements.

Bill also led Hydro One's asset management function for electric distribution for two years from 2010 to 2012. From 2012 to 2014 Bill led Hydro One's acquisition of Norfolk Power, Haldimand County Hydro, and Woodstock Hydro.

Bill has a Bachelor of Business Administration (B.B.A.) and Master of Business Administration (M.B.A.) from York University's Schulich School of Business.

Brent Walker

Brent Walker is a Managing Director and co-founder of MPA. In this role he is responsible for transaction origination and execution, financial advisory and capital raising activities across a wide spectrum of industry segments, including energy, technology, government and quasi-government entities and a variety of other commercial sectors.

Utility clients have included BC Hydro, Altagas Utilities, Crown Investments Corporation, Hydro One, Market Surveillance Administrator of Alberta, the Nova Scotia Utilities Review Board, the Ontario Ministry of Energy and many others.

Prior to founding MPA in 2004, Brent spent over 10 years in the investment banking and financial industry. From 1996 to 2004, he was a managing director in Scotia Capital's mergers and acquisitions department, where he was the most senior M&A banker in a number of sectors including power and infrastructure, pipelines, energy midstream and real estate. During this period, he worked on the sale of the Province of Nova Scotia's interest in Nova Scotia Resources Limited, the acquisition of Aquila by Fortis, the proposed privatization of NALCOR and Enmax, and many other utility assignments.

Brent started his investment banking career at Lancaster Financial, Canada's foremost independent M&A boutique which was acquired by TD Bank in 1994.

Brent holds a B.Sc. from Dalhousie University and an MBA from McMaster University.

Benjamin Kinder

Benjamin Kinder is a Director at MPA. In this role he is responsible for transaction execution, financial advisory and capital raising services.

Since joining MPA in 2009, Ben has focused on advising clients in public and private mergers, acquisitions and divestiture transactions, and has acted as an expert witness.

Prior to joining MPA, Benjamin spent two years in Scotia Capital's investment banking and equity capital markets divisions. While there, he focused on the communications, media and technology sectors, advising clients on mergers and acquisitions, and capital markets transactions.

Benjamin holds a Bachelor of Business Administration (B.B.A.) from York University's Schulich School of Business, a Master of Arts (M.A. Cantab.) in law from the University of Cambridge.

John Park

John Park is an Analyst at MPA. In this role he is responsible for research, modeling, and assisting with transaction, execution services.

Prior to joining MPA, John served as an analyst in the business development department of a major Canadian corporation.

John holds an Bachelor of Business Administration (B.B.A,) from the Ivey School of Business at Western University.

Appendix D – Statement of Qualifications & CV of Pelino Colaiacovo

Pelino Colaiacovo – Statement of Qualifications

Pelino Colaiacovo has been a Managing Director at MPA Morrison Park Advisors Inc. since 2005. He focuses on the utility, electricity and infrastructure sectors, as well as Crown Corporations and green technology more broadly. He advises corporate, government and not-for-profit clients on mergers and acquisitions transactions, the raising of new capital, the valuation of corporations and major assets, and the financial fairness of proposed transactions or initiatives to various stakeholders. As part of this work, he has built hundreds of financial models and analyzed the financial impacts and sensitivities of scenarios too numerous to count. He tracks the view of the capital markets on initiatives and developments in the utilities, power and infrastructure sectors, and provides advice and assistance to clients that must interact with the capital markets. He regularly speaks at and participates in conferences, roundtables and industry associations with respect to energy policy development, and the likely financial impact on utility companies of new policies, technologies and financial developments. He has provided advice to several governments about energy policy. He currently is a member of the Board of the Association of Power Producers of Ontario.

Before joining MPA, he served as the Chief of Staff to the Ontario Minister of Energy, and was integrally involved in a large number of significant reforms to the electricity industry in that province. Prior to that he was a consultant to a wide variety of domestic and international companies and industry associations on energy and other policy issues.

Pelino appeared in 2017 before the Manitoba PUB on the matter of the Manitoba Hydro General Rate Application for 2017/18 and 2018/19. Previously he appeared before the Manitoba PUB in 2014 as part of the NFAT process, and provided a view on the fairness of the NFAT to Manitoba ratepayers, and also commented on the financial viability of Manitoba Hydro's plan. He also appeared before the Nova Scotia Utilities and Review Board in 2013 on the fairness of the Maritime Link Project to ratepayers in that province, and appeared again in 2017 on a matter relating to the costs of that project. He has advised governments, Crown Corporations and public utilities in several provinces across Canada on potential transactions and strategic issues.

Pelino Colaiacovo, Managing Director

Professional Profile

- Well-known participant in the Ontario electricity sector
- Deep understanding of the Canadian utilities, energy, infrastructure and greentech sectors
- Over 20 years of experience in investment banking, government, corporate strategy, policy development, consulting

Professional Experience

August 2005 – Present — Managing Director, MPA Morrison Park Advisors Inc.

- MPA is an employee-owned independent investment bank focusing on mergers & acquisitions, capital raising, and other strategic advisory services to public and private companies, as well as governments, crown corporations, regulators and not-for-profit enterprises (note that MPA's name pre-2007 was Energy Fundamentals Group)
- As Managing Director and Shareholder, responsibilities include marketing, client origination, transaction analysis, senior counsel, and transaction execution

October 2003 – August 2005 — Chief of Staff, Office of the Ontario Minister of Energy

- Most senior advisor to the Minister
- Managed Minister's staff of 12

July 1993 – October 2003 — Various Positions, GPC International

- Consulting firm providing policy analysis, government relations, public affairs, public relations, corporate communications and management consulting services
- Positions held in Toronto, Ottawa and Washington DC
- Progress from junior consultant to Vice President and Practice Leader
- As Practice Leader, managed both a permanent team, as well as flexible multidisciplinary teams for individual client campaigns

Education

1993 Bachelor of Laws, University of Toronto

1990 Honours Bachelor of Arts, University of Toronto (International Relations and Economics)

Industry Involvement

Member of the Board, Association of Power Producers of Ontario

Detailed Experience

August 2005 – Present Managing Director, MPA Morrison Park Advisors Inc.

- Focus on utility and energy sector clients, and on infrastructure projects, crown corporations, and greentech (MPA also covers mining, technology, real estate and public company M&A)
- Expert Witness before the Manitoba Public Utilities Board on the Manitoba Hydro General Rate Application for 2017/18 and 2018/19
- Expert Witness and consultant to the Nova Scotia Public Utilities Board on the Interim Cost Assessment for the Maritime Link
- Advisor to the Alberta Electric System Operator: Capital Markets and Contract Term Length in the Context of a Capacity Market
- Advisor to the Alberta Electric System Operator: Capital market consequences of transition to Coal Exit and Capacity Market
- Financial Advisor to PowerStream in its merger with Horizon Utilities, Enersource and Hydro One Brampton to create Alectra Utilities
- Expert Witness for and consultant to the Public Utilities Board of Manitoba: Commercial valuation of Manitoba Hydro's multi-billion dollar plan to build new hydroelectric facilities and export-focused transmission lines
- Expert Witness for and consultant to the Nova Scotia Public Utilities Board: Commercial valuation of the proposed Maritime Link interprovincial electricity transmission line
- Report to the Market Surveillance Administrator of Alberta on the commercial viability of new electricity generation facilities in the Alberta competitive electricity market
- Advisor to British Columbia Transmission Co (now part of BC Hydro) with respect to proposed new transmission lines to the United States and Alberta
- Financial Advisor to the City of Toronto with respect to the sale of the City's minority interest in Enwave
- Financial Advisor to the City of Toronto with respect to the proposed financing for and development of the Tower Renewal energy conservation program
- Numerous assignments as financial advisor to electricity distribution companies with respect to financial valuations, strategic reviews and mergers & acquisition opportunities (e.g., Milton Hydro, Oshawa PUC, Woodstock Hydro, Enwin Utilities, Oakville Hydro, Hydro One)
- Numerous assignments as financial advisor to buyers and sellers of renewable energy generation assets (wind, solar and hydroelectric) and district energy facilities
- Numerous assignments as financial advisor to project developers raising capital for new energy and infrastructure projects, and/or bidding into competitive procurement processes
- Energy policy and strategy advisor to the Ontario Energy Association
- Typically, clients are Boards of Directors of public companies, or senior management of private companies or government entities
- Numerous presentations before City Councils, utility regulators, and other public bodies
- Speeches and appearances at energy conferences and roundtables, guest lectures at university courses on energy policy and utility regulation, expert opinion resource for media

October 2003 – August 2005 Chief of Staff, Office of the Ontario Minister of Energy

- Principal political and policy advisor to the Minister
- Primary liaison with the Office of the Premier and with the public service
- Managed Minister's staff of 12
- Final decision-maker for the Minister's public communication and stakeholder interaction
- Key accomplishments included:
    - Restructuring of the Ontario electricity sector through the passage of Bills 11 and 100
    - Development of a detailed plan to retire Ontario's coal-fired electricity generation fleet
    - Development of a smart metering strategy for Ontario
    - Creation of the Ontario Power Authority, selection of Board, appointment of CEO
    - New Board and senior management for Ontario Power Generation, new Board for the Independent Electricity System Operator
    - Review and approval of proposed refurbishment of Pickering A 1 nuclear unit
    - Negotiation of Bruce A nuclear refurbishment
    - Successful Requests For Proposals for new renewable energy facilities, and new gas-fired electricity generation plants

July 1993 – October 2003 Various Positions, GPC International

- Vice President and Corporate Practice Group Leader, Toronto
- Vice President responsible for integration of acquired offices in the United States, including Boston and Washington DC
- Senior Consultant, Ottawa
- Consultant, Toronto
- Focus on regulated sectors of the economy, including energy, transportation, media, healthcare and finance
- Leader of multi-disciplinary public affairs projects including policy development, government relations, media relations, stakeholder communications and polling
- Management consultant for large national and multi-national corporations with respect to public affairs

Appendix E – MPA Scope of Work

Morrison Park Advisors was retained by letter agreement data February 19, 2019.

MPA has been asked to comment on the following specific issues:

1. Review of specific assumptions, and their role in the financial analysis component of the business case
    - In particular, three assumptions should be addressed: domestic load, fuel prices, and export energy prices.
    - For each of these, consider the reference forecasts at the time of the decision, the more recent forecasts available now, and what impact the more recent forecasts would have had on the financial analysis, had they been available in 2012.
    - Given that the more recent forecasts were by definition not available in 2012, comment on whether they were, or should have been captured in the financial sensitivity analysis performed at the time.
    - In addition to the three identified assumptions, many other assumptions were also relevant to financial modeling, including, for example, expected capital costs for components of the Muskrat Falls development, expected capital costs and financial competitiveness of other alternatives, etc. Comment on the overall relevance and importance of the three targeted assumptions in relation to other assumptions, and the sensitivities performed for those.
2. Comment on the use of the "Cumulative Present Worth" metric used in the financial analysis of the business case.
    - Consider CPW in relation to other metrics that might have been used.
    - Based on the financial analysis at the time, express the results of the financial analysis using those alternative metrics, and comment on how those other metrics affect the analysis of the options considered.
    - Based on currently available financial assumptions, express the costs of the project in terms of CPW and the alternatives, and discuss what those alternative formulations highlight about the project.
3. Comment on the decision to dismiss, without detailed consideration, all options other than the Interconnected Island and the Isolated Island, with a particular focus on the option to purchase power from Quebec.
    - Was it, or should it have been, reasonably foreseeable at the time that Hydro Quebec would now have surplus power available for export to Newfoundland?
    - How would the costs of this option compare to construction of Muskrat Falls, considered from the point of view of assumptions current in 2012, and also assumptions current today?
4. Comment on the relationship of the Muskrat Falls Project to the completion of the Churchill Falls contract in 2041, in particular from a financial point of view.

Appendix F – References to Consumer Discount Rate Literature

An excellent overview of the theory of discount rates applicable to "public" projects was provided to the Australian Government Productivity Commission. While the emphasis is on the theory and calculation of "social" discount rates, the paper provides general insight into the various current schools of thought on discount rates (as well as relevant sources and texts), and describes the many different discount rates that may be applicable to different stakeholders, including consumers. Intergenerational issues are also specifically addressed.

Valuing the Future: the social discount rate in cost-benefit analysis, Mark Harrison, Visiting Researcher Paper, Australian Government Productivity Commission, April 2010.
Available at: http://pc.gov.au/__data/assets/pdf_file/0012/96699/cost-benefit-discount.pdf

The Northwest Power and Conservation Council (which includes Washington, Oregon, Idaho and Montana) prepares 20-year plans for electricity in the region. In a recent plan, they provide an overview of the possible "perspectives" that can underlie discount rates for their planning, including the "consumer perspective". The NPCC used a weighted average of various methods to arrive at the discount rate used in its plan.
Sixth Northwest Electric Power and Conservation Plan, February 2010, Appendix N: Financial Assumptions and Discount Rate.
Available at: http://www.nwcouncil.org/media/6332/SixthPowerPlan_Appendix_N.pdf

The United States Department of Energy, Energy Efficiency and Renewable Energy Office, calculated both residential and business consumer discount rates for use in the development of policies related to energy efficiency regulations. A specific example can be found related to the life cycle costs of lighting technologies. FINAL RULE TECHNICAL SUPPORT DOCUMENT (TSD): Energy Conservation Standards for General Service Fluorescent Lamps and Incandescent Reflector Lamps, Chapter 8: Life-Cycle Cost And Payback Period Analyses, July 2009.
Available at: http://www.regulations.gov/#!documentDetail;D=EERE-2006-STD-0131-0147

A broad historical and theoretical overview of time value of money, including consideration of different types of stakeholders and consumers and the problems inherent in making assumptions about them, is available in: Frederick, Shane, George Loewenstein, Ted O'Donoghue. 2002. Time discounting and time preference: A critical review. Journal of Economic Literature 40(2) pp. 351–401.

There is a substantial body of economics literature investigating consumer discount rates that are implied by consumer purchasing decisions for various products and services, ranging from energy efficiency products, to automobiles, to cell phone plans. Invariably, estimated discount rate ranges for consumers are very high. Three examples of this literature, including both one of the pioneering examples and more recent examples, are:

Hausman, J. A., 1979. Individual Discount Rates and the Purchase and Utilization of Energy-Using Durables, The Bell Journal of Economics, vol. 10(1), pp. 33-54.

Busse, Meghan R.; Knittel, Christopher R.; Zettelmeyer, Florian. Are Consumers Myopic? Evidence from New and Used Car Purchases, The American Economic Review, Volume 103, Number 1, February 2013 , pp. 220-256.

Song Yao, Carl F. Mela, Jeongwen Chiang, Yuxin Chen, 2012. Determining Consumers' Discount Rates with Field Studies. Journal of Marketing Research: December 2012, Vol. 49, No. 6, pp. 822-841.