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June 12, 2012

Comments on the Justification for the Lower Churchill Transmission Project (Labrador-Island Transmission Link)

submitted to the
Canadian Environmental Assessment Agency
Comprehensive Study on the Lower Churchill
Transmission Project
and to
Government of Newfoundland and Labrador,
Department of Environment and Conservation

on behalf of Grand Riverkeeper Labrador Inc.

by

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1. Mandate

1.1. Mandate

Grand Riverkeeper, Labrador Inc. has asked me to review the stated justification for the Labrador-Island Transmission Link ("the Project"), as presented in the Proponent's Environmental Impact Statement, taking into account the report of the Public Utilities Board of Newfoundland and Labrador (PUB), as well as that prepared for the PUB by its consultant Manitoba Hydro International Inc. (MHI).

1.2. Qualifications

Cofounder of the Helios Centre, Philip Raphals has extensive experience in many aspects of sustainable energy policy, including least-cost energy planning, competitive market design, utility regulation (including transmission ratemaking) and green power certification. He is the author of numerous studies and reports and frequently appears as an expert witness in the regulatory arena. He has explored in detail the interaction between competition and regulation as well as the environmental implications of electricity trade.

Mr. Raphals is also an authority in the area of hydropower and the environment. From 1992 to 1994, he was Assistant Scientific Coordinator for the Support Office of the Environmental Assessment of the Great Whale hydro project, where he coauthored a study on the role of integrated resource planning in assessing the project's justification.[1] In 2001, he authored a major study on the implications of electricity market restructuring for hydropower developments, entitled *Restructured Rivers: Hydropower in the Era of Competitive Energy Markets*. In 2005, he advised the Federal Review Commission studying the Eastmain 1A/Rupert Diversion hydro

[1] J. Litchfield, L. Hemmingway, and P. Raphals. 1994. *Integrated resources planning and the Great Whale Public Review*. Background paper no. 7, Great Whale Public Review Support Office, 115 pp. *(also published in French).*

project with respect to project justification. Later, he drafted a submission to this same panel on behalf of the affected Cree communities of Nemaska, Waskaganish and Chisasibi.

Mr. Raphals chairs the advisory committee for renewable energies of the Low Impact Hydropower Institute (LIHI) in the United States, and has participated actively in the developing the low impact renewable electricity guideline for the Canadian Ecologo programme. Mr. Raphals is a frequent expert witness before the Quebec Energy Board (the Régie de l'énergie du Québec), notably with respect to transmission regulation.

Mr. Raphals has testified before the Joint Review Panel for Lower Churchill Generation Report, and before the Public Utilities Board of Newfoundland and Labrador, with respect to its review of the Muskrat Falls project.

He studied at Yale and at Boston University.

2. Project justification in the EIS

The Proponent's stated justification for the proposed Project is presented in Chapter 2 of the EIS, entitled "Projet Rationale and Planning". In this chapter, after presenting the provincial energy plan (section 2.1), the Proponent describes the "Need, Purpose and Rationale" for the Project (section 2.2), its Justification in Energy Terms (section 2.3), and its Economic Analysis (section 2.4).

It then proceeds to discuss "Alternative Generation Sources" to the Muskrat Falls generation project (section 2.5, and the Development of Least-Cost Expansion Plans (section 2.6).

In section 2.7, it presents a Discussion of the Economic Analysis; in section 2.8, the project's Financial Benefits; and in section 2.9, its Environmental Benefits. Section 2.10 addresses Risk Management; section 2.11, Project Planning; and Section 2.12, Alternative Means of Carrying out the Project.

In section 4 of this report, we will comment on several of these elements.

3. Project rationale

In section 2.2 of the EIS, the Proponent clearly articulates its rationale for the Project:[2]

> By constructing the Project, Nalcor will develop a long-term asset to meet this requirement for least-cost energy. The rationale for the Project is that its construction enables the transmission of energy from Muskrat Falls in Labrador: the least-cost option to meet long-term supply of power to the Island.

Thus, the Project is required to transmit the energy from the Muskrat Falls generation facility to the Island of Newfoundland. The stated justification for the Project is that, in combination with the closely related Muskrat Falls facility, it would constitute "the least-cost option to meet long-term supply of power to the Island."

This same question has already been addressed by two public bodies: the Joint Review Panel for the Environmental Assessment of the Lower Churchill Generation Project, and the Public Utilities Board of Newfoundland and Labrador, in response to a reference from the provincial government.

Neither of these two bodies concluded that the proposed project is justified. The high-level conclusions of these two bodies are described in the following subsections.

3.1. Report of the Joint Review Panel

Section 4.2 of the Report (Alternatives to the Project) concludes at page 34 as follows:

> **The Panel concludes that Nalcor's analysis that showed Muskrat Falls to be the best and least cost way to meet domestic demand requirements is inadequate and an independent analysis of economic, energy and broad-based environmental considerations of alternatives is required.** (bold in the original)

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[2] EIS, page 2-3.

Given that a Joint Review Panel, after several years of effort, found Nalcor's analysis showing Muskrat Falls to be the best and least cost way to meet domestic demand requirements to be **inadequate**, it is hard to see how the Responsible Authorities or the Agency, in a comprehensive study, could ever find the same analysis to be convincing.

That said, Nalcor has included in the LITL EIS certain information which it did not present to the Review Panel. It is thus relevant to ask whether the new information presented in the LITL EIS, which was not made available to the JRP, could be sufficient and adequate as a matter of fact to put to rest the concerns raised by the JRP? We will address this question from a factual perspective in our concluding chapter.[3]

3.2. Reference to the Public Utilities Board

On June 17, 2011, the government of Newfoundland and Labrador announced that it had mandated the provincial Public Utilities Board ("PUB") to conduct a review of the Muskrat Falls component of the Lower Churchill Generation Project and the Labrador-Island Link transmission line ("PUB Review of Muskrat Falls").

The Reference Question that the Province referred to the PUB is that "[t]he Board shall review and report to Government on whether the Projects represent the least-cost option for the supply of power to Island Interconnected Customers over the period of 2011-2067, as compared to the Isolated Island Option". This reference to the PUB is also mentioned by Nalcor in section 2.2 of the EIS.

[3] I understand that several issues related to these questions are currently being argued before the Federal Court. I do not purport in any way to comment, in this document, on any matters of law in relation to that proceeding.

Following a call for tenders, the PUB engaged Manitoba Hydro International as a consultant to assist it in the process. MHI produced a two-volume report entitled *Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System* in January 2012.[4]

In its report, MHI gave qualified support to Nalcor's conclusion that the Cumulative Present Worth (CPW) of the Infeed Option (including Muskrat Falls and the LITL) was lower than that of the Isolated Island Option as defined by Nalcor and as included in the PUB's Terms of Reference. It found Nalcor's analysis to be correct, given the inputs used, and it found these inputs to be "generally ... appropriate" (v. 1, p. 15). However, it identified a number of risks, related in particular to assumptions regarding load forecasts, capital cost estimates and fuel price, that could affect this outcome. And it found these risks to be substantial, given the 50+ year timeframe of the CPW analysis. MHI also raised a number of important concerns about design choices and reliability, where are summarized below.

In its report,[5] however, the Public Utilities Board of Newfoundland and Labrador did **not** make a determination as to the cost effectiveness of the Interconnected Option as compared to the Isolated Island Option, but rather concluded that the information provided to it was not adequate to support such a determination. On page iv, it wrote:

> **The Board concludes that the information provided by Nalcor in the review is not detailed, complete or current enough to determine whether the Interconnected Option represents the least-cost option for the supply of power to Island Interconnected customers over the period of 2011-2067, as compared to the Isolated Island Option.**

The Board based this conclusion in large part on the inadequacy of the information provided to the Board and its consultants.

In the final section of its report, the Board addressed in detail many of MHI's comments concerning planning criteria, AC integration studies, reliability assessment and adherence to

[4] Available at http://www.pub.nf.ca/applications/MuskratFalls2011/MHIreport.htm.

[5] Available at http://www.gov.nl.ca/lowerchurchillproject/muskrat_falls_pub_final_report.pdf.

NERC standards. In particular, the Board rejected Nalcor's justification for the use of a 1:50 return period for the reliability assessment of the HVDC line.

> Nalcor's reasoning for its rejection of this recommendation is not supported by the facts. Nalcor is relying on its own operational experience to support a design standard for a critical component of the Island's transmission infrastructure, even though it has no experience with the transmission line conditions in the alpine areas contemplated by the proposed route. **Nalcor proposed a "worst case" two-week scenario** to compare a prolonged HVdc bipole outage to a similar two-week outage on the existing system. **The Board agrees with MHI that this two-week period is not realistic and is not an industry accepted metric. Nalcor does not plan to add backup generation, such as combustion turbines, on the Island in the event of a major failure of the HVdc line** with or without the Maritime Link. The Board is of the view that Nalcor should address these significant gaps related to a major component of the Interconnected Option before proceeding to the next decision phase.[6] (emphasis added)

The Board also expressed concern about the possibility of load shedding on the Avalon and possibly the Burin Peninsula, in the event of an HVDC bipole outage (p. 85).

The Board considers that its statutory responsibility for reliability obliges it to consider these issues, even though Nalcor is exempted from the EPCA. It concludes:

> In the Board's opinion, when considered together, **these gaps related to power system reliability raise serious concerns in relation to Nalcor's assessment of the interconnection of the significant generation associated with the Muskrat Falls generating facility to the Island Interconnected system**. These deficiencies should be addressed by Nalcor in a meaningful way should the Interconnected Option proceed to project sanction.[7] (emphasis added)

None of these deficiencies are addressed in the EIS.

As noted above, the PUB concluded that the information provided to it was not detailed enough, complete enough or current enough to support a determination as to the superiority of the Interconnected Option as compared to the Isolated Island Option. The information provided in the EIS with respect to project justification represents only a small subset of the information

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[6] Ibid., p. 99.
[7] Ibid., p. 100.

provided to the PUB, and it is neither more detailed, more complete nor more current.[8] The full body of information presented by Nalcor to the PUB was inadequate to convince the Board of the superiority of the Infeed Option, compared to the Isolated Island Scenario defined by Nalcor. One must therefore conclude that the PUB's review, like that of the Joint Review Panel, fails to support the project justification submitted by Nalcor in support of the LITL project.

4. Detailed Comments

In this section, I will comment on a number of specific elements raised by Nalcor in its chapter 2 of its EIS.

4.1. Project planning and risk management

4.1.1. Planning process

In section 2.3 of the EIS, the Proponent explains its planning process has three basic functions:

1) The development of a long-term energy and capacity forecast.
2) An evaluation of whether existing supplies are adequate to meet forecasted requirements.
3) The development of expansion plans to meet the forecast.[9]

The Proponent asserts that the Isolated Island alternative presented in the EIS, which was developed using *Strategist* software, "represents the optimum portfolio of available generation

[8] On page 2-2 of the EIS, Nalcor indicates that this chapter is largely based on Nalcor's submission to the PUB.

[9] EIS, p. 2-3.

sources without the Project."[10] However, no demonstration is made of this assertion, either in the EIS or in other documents made public to date by Nalcor.

According to the *Electrical Power Control Act, 1994*, s. 3(b)(iii), the province's power system should be managed and operated in a manner that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service.

Utilities across North America and abroad have put planning processes in place to determine the least-cost portfolio of resources to meet forecast demand. Such processes generally include several common features:

- Inclusion of supply-side (generation) and demand-side (demand management and conservation) resources;
- Evaluation of several alternative resource portfolios that meet projected demand; and
- Comparison of portfolios based on various parameters (cost, reliability, risk and, in many cases, environmental and social considerations).

There is no indication to the effect that any such process has been carried out by Nalcor or its subsidiary NLH in determining that the Isolation Island Scenario described in Table 2.6.1-1 actually represents the least-cost portfolio.

It is important to understand that planning programs like *Strategist* represent important inputs into a least-cost planning process, but can in no way substitute for such a process.

Back in 2007, the PUB found that "an IRP (Integrated Resource Plan) undertaken as part of a generic process as described in Order No. P.U. 14 (2004) is an important planning tool and would enhance the information available to the Board and other parties regarding future generation and supply options in the Province."[11]

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[10] EIS, p. 2-66.

[11] Order P.U. 8 (2007), p. 60.

In that decision, the Board quotes P.U. 14 (2004) as follows:

> *"...implementation of Integrated Resource Planning may present sound opportunities for coordinated planning and improved regulation involving both utilities. This process brings together strategic planning, future supply and demand, least cost analysis, demand side management options and environmental considerations."*

According to Nalcor's testimony before the Joint Review Panel for the Lower Churchill Generation Project, there has been no progress since that then with respect to integrated resource planning, either from the PUB or from the regulated utilities. This is unfortunate, because IRP is one important tool (among others) needed to properly compare the economic and environmental implications of alternate solutions to providing reliable electric power. Had Nalcor or its subsidiary NLH undertaken an integrated resource planning process *prior to* choosing a resource development strategy, the controversy surrounding the justification of and alternatives to the Muskrat Falls Generation and Transmission projects might well have been avoided.

While the restructuring of electric markets has resulted in limiting the application of IRP in many regions, it remains very relevant, *especially* for isolated electric systems. The Hawaiian Electric Company is a leader in this regard. The utility explains its planning process as follows:

> How do we ensure that Hawaii's energy needs will be met reliably and affordably for the years to come? It takes selecting the best mix of energy resources. That choice is not a matter of "either/or," but rather an array of solutions, combining conservation and energy efficiency, renewables, distributed generation technologies as well as clean and efficient central power plants.
>
> To find the right mix, Hawaiian Electric uses a process called Integrated Resource Planning (IRP). The Hawaii Public Utilities Commission (PUC) established IRP in 1992 for electric utilities to forecast energy demand and analyze the best ways to meet it. No other sector regulated by the PUC goes through such a thorough and far-reaching planning process.
>
> In IRP, an outside advisory group representing business, government, energy regulators, consumers, environmentalists, and other interested stakeholders work closely with utility planners and engineers. They consider population growth, culture, lifestyle, the economy, the environment, available energy technology and other factors.
>
> Hawaiian Electric, Maui Electric and Hawaii Electric Light companies each undertakes a separate IRP process for its service territory.

> Hawaiian Electric has begun its fourth IRP Process which is expected to result in a new 20-year plan being developed and filed with the PUC in mid-2008.[12]

Hawaii, like Newfoundland, is anxious to find ways to use indigenous renewable energy to replace fossil fuels. However, unlike Newfoundland and Labrador, it is approaching the question in a structured fashion designed to discover and compare all possible solutions, in order to choose the best one.

Furthermore, given that it excludes *demand*-side resources (as discussed below), many of which are clearly cost-effective, it is virtually impossible that the portfolio developed by *Strategist* is indeed the least-cost portfolio.

For all these reasons, the Comprehensive Study Report should conclude that the Proponent has failed to demonstrate that the Muskrat Falls Transmission Project, in combination with the Muskrat Falls Generation Project, constitutes the least-cost option to meet long-term supply of power to Newfoundland Island.

4.1.2. Risk

Management of the risks and uncertainties related to the various resource options is an essential aspect of least-cost planning. In section 2.10, the Proponent addresses the question of Risks and Risk Management.

Unfortunately, this discussion remains entirely theoretical. It fails to address or specify in any way how the Proponent intends to address any of the specific risks related to the planning of its power system in general or the Muskrat Falls project in particular.

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12 http://www.heco.com/portal/site/heco/menuitem.8e4610c1e23714340b4c0610c510b1ca/?vgnextoid=b71bf2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=defau

The Comprehensive Study Report should therefore conclude that the Proponent has failed to adequately address the risks and uncertainties related to the various resource options it considers.

4.2. Needs

4.2.1. Load Forecast

The first step in the Proponent's planning process, as described above, is to develop a long-term energy and capacity forecast. This is indeed a critical step.

In its report, MHI indicated:

> "The amount of variability due to potential load changes is high and could materially impact the results of the cumulative present worth analysis" (v. 2, p. 39).

The implications are twofold: first, that the uncertainty with respect to the Proponent's load forecast is great, and second, that this uncertainty could invalidate the Cumulative Present Worth (CPW) analysis on which the Proponent's justification rests. It is thus important to look at the load forecast in detail.

The Proponent's load forecast projects "utility loads" (residential, commercial and institutional loads) increasing at 1.3% from 2009 to 2029, despite the fact that population is expected to decline gradually throughout this period (Table 2.3.1-2). The explanation is found on page 2-11, where Figure 2.3.1-4 shows that growth in the number of domestic customers has increased along with that of the population 25 and over, despite the decline in total population that began in 1993. The Proponent then explains that household and customer formation are most closely related to this age subset.

The EIS does not go deeper into the province's demographic projections, nor does it address load growth past 2029, despite the fact that planning period extends to 2067.

However, if the 25+ population has grown while the total population has declined, this inevitably means that the population under 25 has declined. Whether that is the result of an aging population that has fewer children, or of the emigration of young adults, we do not know. In either case, however, it suggests that the current pattern cannot sustain itself indefinitely. If current under-25 cohorts are smaller than the older cohorts, that could well suggest a long-term trend toward a significantly smaller population.

The MHI report points out that, for the last ten years, NLH's has consistently underforecast domestic energy consumption.[13] However, a systematic error in the past is no guarantee that future forecasts will err in the same direction. (The same issue arises with respect to fuel price forecasts, discussed below.)

Furthermore, MHI points out that the forecasting methodology used by Nalcor, based exclusively on econometric modeling, without any end-use modeling, does not represent best utility practice. Given that electric space heating is a key driver for electricity demand, end-use modeling is essential.

With respect to the industrial forecast, MHI shows that Nalcor and NLH's forecasts have dramatically overstated industrial demand over the years, as shown in the following table:[14]

Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
Industrial	5%	14%	27%	37%	50%	67%	76%	92%	119%	124%

As noted above, MHI concluded that "The amount of variability due to potential load changes is high and could materially impact the results of the cumulative present worth analysis."[15] MHI

[13] MHI, v. 2, p. 19, Table 4.

[14] MHI, vol. 2, p. 24.

also pointed out that Nalcor's industrial laod forecast assumed no change in status for the Corner Brook Pulp and Paper Mill.[16] However, as of this writing, the closure of the Corner Brook Pulp and Paper Mill appears probable, as NL Natural Resources Minister Jerome Kennedy recently announced that it is 'on the verge of bankruptcy'.[17]

MHI concluded that the loss of a load of this magnitude would on its own result in a reduction of the perceived CPW benefit of the Interconnected Option from $2.158 billion to $408 million, a reduction of over 80%.

I therefore conclude that the Proponent's load forecast does not provide a solid basis on which to base the conclusion that the Muskrat Falls option is preferable to the No Project option.

4.2.2. Conservation and demand management

In a one-and-a-half page section contained in s. 2.3.1.4 ("Key Forecast Assumptions and Drivers") of the EIS, the proponent describes the status and potential for Conservation and Efficiency in Newfoundland and Labrador. It indicates in the following section that "NLH has not explicitly incorporated these utility sponsored program savings targets into its PLF (Planning Load Forecast) due to the uncertainty of achieving dependable firm outcomes."[18]

The Proponent's exclusion of CDM from its planning process flies in the face of good utility practice. For example, MHI explains that, in the standard generation planning process, "Demand

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15 Ibid., p. 39.

16 MHI Report, v. 1, p. 85.

17 http://www.cbc.ca/news/canada/newfoundland-labrador/story/2012/06/08/nl-jerome-kennedy-mill-future-608.html

18 EIS, page 2-13.

side management is treated as if it were generation, as it represents a reduction from the base load forecast. The economics of DSM programs should be evaluated to ensure that they make a positive contribution to the overall financial well-being of the province."[19]

MHI criticized Nalcor for preparing its domestic forecast using only econometric modelling techniques which, it explains, are **not the best utility practices** in this area.[20] It points out that the domestic load forecast is primarily driven by electric space heat, and it emphasizes that developing an end-use forecasting model would have many benefits, including improving the design of CDM programs.

The forecasting methodology identified by MHI may be one of the reasons that Nalcor has failed to meet its own CDM objectives to date, and why its future CDM objectives are so weak.

CDM results to date, shown in the table 2.3.1-5 on page 2-13, demonstrate savings of only 5.3 GWh/year in 2010, or just 0.5% of the identified potential.

The Proponent states that "To date, the *response* to CDM programs and initiatives has been modest and lagging targets." [21] (emphasis added) However, it fails to point out that the **programs and initiatives themselves** have also been modest and lagging targets.
The following chart, drawn from my April 13, 2011 submission to the Joint Review Panel,[22] demonstrates that CDM funding by NLH and by NP lagged far behind that which was projected in their Five-Year Joint CDM Plan.

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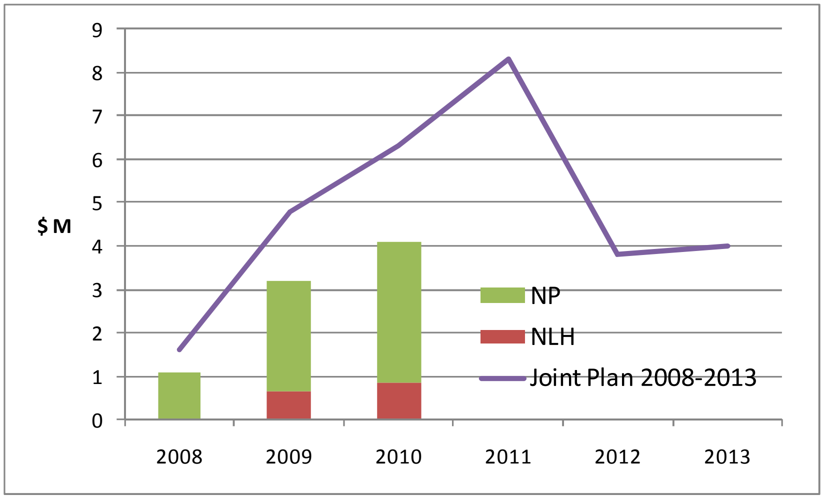
[19] MHI Report, vol. I, p. 31.

[20] Ibid., v. 2, pp. 20 and 39.

[21] P. 2-13.

[22] P. Raphals, "Comments on Proponent's Response to the Panel's Information Request of March 21, 2011," submitted to the Joint Review Panel for the Lower Churchill Generation Project, April 13, 2011, p. 9. Available on CEAA website.

CDM Program Funding



This is not particularly surprising: Most utilities perform very poorly when they first begin to pursue CDM savings. What is surprising is that, based on its admittedly poor performance in the first years of its CDM program, **NLH has chosen to exclude consideration of CDM savings as a resource in its 50-year power plan.** I am not aware of any other utility in North America that has so blatantly disregarded CDM as a resource.

The EIS also states: "As a *stand-alone option*, CDM is not a reliable alternative and cannot meet the long term electricity demands for electricity consumers in NL." (emphasis added). Obviously, CDM can never be a stand-alone option. This has not prevented it from being a major component of the least-cost resource plan of virtually every utility in North America.

Table 2.7.1-3 presents the results of five sensitivity analyses with respect to CDM, together with the resulting CPW preference for the Interconnected Island (Muskrat Falls) option. The results are as follows, expressed as a percentage reduction of the base case preference of $2,158 million:

1. Moderate conservation (375 GWh/yr boy 2031) — 21% reduction
2. Aggressive conservation (750 GWh/yr by 2031) — 41% reduction
3. Loss of 880 GWh/yr from 2013 on — 81% reduction

4. Loss of 1086 GWh/yr from 2013 on — 100% reduction
5. Low load growth (50% of projected load growth) — 65% reduction

Scenarios 3 and 4, which represent a sudden decrease of 11% or of 13% of total load, presumably model the sudden loss of an industrial load. While the relationship is not spelled out in the EIS, [23] Scenario 3 refers to the possible closing of the Corner Brook Pulp and Paper Mill. This possibility was invoked by MHI, at whose request this sensitivity analysis was carried out. The relevant passage of the MHI report reads as follows:

> **7.5 Load Forecast Sensitivity**
>
> Another consideration which could have a significant impact on the resulting CPW relates to the assumption used for the load forecast. The assumption used for the Isolated Island Option was based on the same planning load forecast69 (PLF) described in the 2010 Capital Budget Application to the Board, but extended to 2067. **However, the significance of a possible alternate future for the remaining pulp and paper mill was not considered as an additional Isolated Island scenario. The PLF makes the assumption that there is no change in status for the mill**. MHI requested Nalcor to perform a sensitivity analysis with a reduction in system consumption of 880 GWh per year, equivalent to the total electric energy requirement of the mill including purchases from Nalcor and their own generation. In Exhibit 43, revision 1, Nalcor indicated the CPW differential between the two Options would be reduced from $2.158 billion in the base case to $408 million in favour of the Infeed Option. [24] (emphasis added)

As noted above, the closure of the Corner Brook Pulp and Paper Mill appears probable. In other words, this Scenario 3, which now seems likely to occur, would on its own result in eliminating **four-fifths** of the perceived benefit of the Muskrat Falls scenario.

Scenarios 1 and 2 refer to "Moderate" and "Aggressive" conservation, with gains of 375 or 750 GWh/yr by 2031. However, it is important to note that, according to documents detailing these

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[23] See page 2-10.

[24] MHI Report, v. 1, p. 85.

scenarios filed with the PUB, the scenarios foresee no additional CDM gains between 2031 and 2067.

How "aggressive" is the Aggressive Conservation scenario? To answer this question, we need to refer to the study of the CDM potential in Newfoundland prepared by Marbek Resource Consultants in 2008.[26] It was filed in response to PUB Order PU 8 2007, which required NLH to file it and a five-year plan for implementation of CDM programs, starting in 2008.

The summary of the study findings, on page 9, identifies the Upper and Lower limits of Achievable Savings by the year 2026 as 951 and 556 GWh/yr, respectively. This table is reproduced on p. 2-12 of Nalcor's EIS.

This 2008 Marbek report, which is mentioned on page 2-12 of the EIS, and which is apparently the only serious study of conservation and demand management (CDM) potentials ever undertaken by NLH, identifies an upper achievable limit of 951 TWh, or 15% of total base-year consumption, as shown in Table 2.3.1-4.

It fails, however, to mention two important aspects of this estimate of an "achievable upper limit". First, it is based on a horizon of 2026.[27] Obviously, the achievable potential over the 50-year planning horizon for the Muskrat Falls project would be considerably greater.

Second, it is based on an avoided cost of just 9.8 cents/kWh.[28] In evaluating CDM potentials, a key parameter is the cost of energy the use of which could be avoided, since it is this cost which ultimately determines what CDM measures are cost effective. Given that, with or without the

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[26] Marbek Resource Consultants Ltd., CONSERVATION AND DEMAND MANAGEMENT (CDM) POTENTIAL, NEWFOUNDLAND and LABRADOR: Residential, Commercial and Industrial Sectors

– Summary Report, prepared for Newfoundland & Labrador Hydro and Newfoundland Power, Jan. 31, 2008.

[27] Ibid., p. 2.

[28] Ibid., p. 4.

Muskrat Falls project, the cost of wholesale power for NLH, at the margin, is anticipated to be around 16¢ by 2017, a similar study done today would use that higher avoided cost figure. **As a result, it would inevitably result in higher potentials, since, in addition to the CDM measures which were already deemed cost-effective in 2008, based on a lower avoided cost, more expensive CDM measures would now also become cost-effective.** Thus, the 2008 Marbek study necessarily **underestimates** the real CDM potential.7

I conclude that the EIS **fails to properly take into consideration the impacts on load growth of a properly designed and executed portfolio of CDM programs over the planning period. Had it done so, the CPW advantage of the Infeed scenario would be greatly decreased, if not eliminated, even before considering other sensitivities.**

As noted above, the generation planning methodology used by Nalcor explicitly excludes two important elements: demand side management options and environmental considerations. Instead, they are based on just one criterion: the reduction of costs to the utility. Benefits relating to reduced ratepayer cost are excluded from the analysis. According to a document provided by Nalcor to the PUB:

> The chosen resource plans (generation expansion plans) were selected on the minimization of revenue requirement, modeled as the "minimization of utility cost" objective function. **As there was only one objective function used, its weighting was 100 percent.** There were no objectives tied together as only one objective function was used.[29] (emphasis added)

Energy efficiency programs are generally measured by a number of tests, the most important of which is the Total Resource Cost test, which measures the total cost to a society, not just the cost to the utility. Thus, unlike the "minimization of utility cost" function, it also takes into account reductions of **customer** costs, resulting from reduced electricity use.

A recent study by the Regulatory Assistance Project in the US explains this as follows:

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[29] PUB, MHI-Nalcor-41 Rev. 1.

> The goal of an IRP is to identify the least-cost resource mix for the utility and its consumers. *Least-cost* in this case means lowest total cost over the planning horizon, given the risks faced. The best resource mix is typically the one that remains cost-effective across a wide range of futures and sensitivity cases — the most *robust* alternative — and that also minimizes the adverse environmental consequences associated with its execution.[30]

As noted earlier, if Nalcor had undertaken an IRP process in the past, as suggested by the PUB in 2007, most of the issues addressed in this brief would have been resolved prior to the initiation of the environmental assessment process.

As for environmental considerations, which play an important role in IRP, they are excluded from the Proponent's generation expansion planning.

The PUB declined to order implementation of an IRP in 2007, in anticipation of the provincial Energy Plan. I am not aware of any progress in that direction in the meantime.

Once again, we must distinguish between a generation scenario optimized on the basis of cost only, on the one hand, and a robust integrated plan, on the other. The Isolated Island Scenario is an example of the former. It constitutes an important input in the development of a plan, but should not be confused with the result.

The Comprehensive Study Report should therefore include the following findings:

- **that the Proponent has failed to present a coherent load forecast that properly accounts for the uncertainty of its forecast industrial loads, or the achievable levels of Conservation and Demand Management,**
- **that the Proponent has also failed to otherwise account for achievable levels of CDM in its resource strategy;**

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[30] Electricity Regulation in the US: A Guide, RAP, www.raponline.org, p. 73.

- **that, as a result, the Proponent has failed to demonstrate that its Isolated Island Option constitutes the least-cost option in the absence of the Muskrat Falls Generation and Transmission projects; and**
- **that, in consequence, the Proponent has failed to demonstrate that the Muskrat Falls Transmission Project, in combination with the Muskrat Falls Generation Project, constitutes the least-cost option to meet long-term supply of power to Newfoundland Island.**

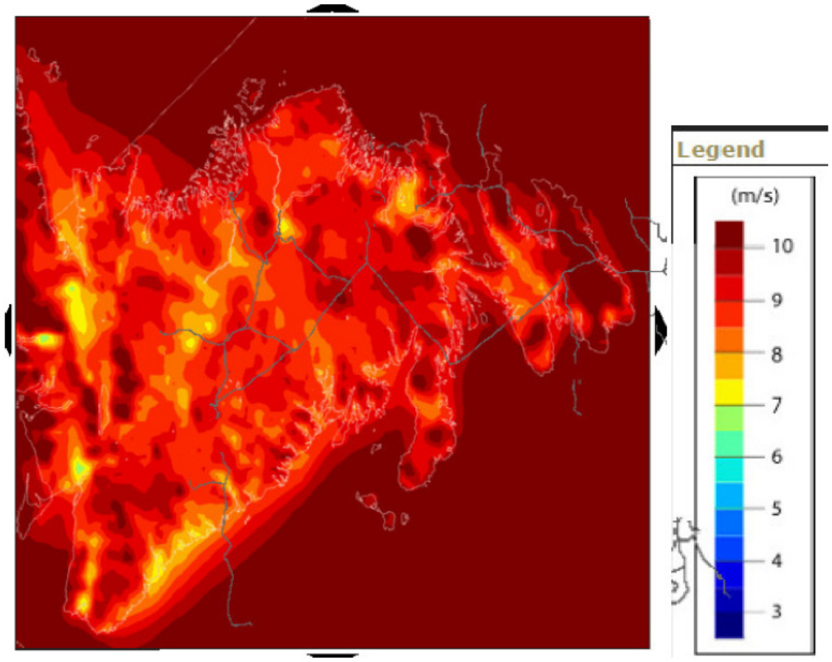
4.3. Alternatives

The EIS devotes some 30 pages to purporting to review generation alternatives to Muskrat Falls, as part of setting out its views on the justification of the Labrador-Island Transmission Link. Many aspects of this review are deficient, as indicated in the following sections.

4.3.1. Wind power

In section 2.5.8, the Proponent provides a summary description of wind power technology, and describes its costs and limitations for the Island grid.

The EIS states that “Good wind sites are often located in remote locations, far from places where the electricity is needed.” This is indeed often the case, but it is most certainly **not** the case on the Island of Newfoundland. As the following image from the Canadian Wind Atlas demonstrates, average wind speeds are over 10 m/s across virtually all Newfoundland, including on the Avalon Peninsula, where most of the load is located.



As for the limitations on wind power, the EIS indicates that they were established in a 2004 NLH study (*An Assessment of Limitations for Non-Dispatchable Generation f the Newfoundland Island System),* which was provided to the PUB as Exhibit 61.[31] The EIS states that "The limits identified in the 2004 study are still applicable today."[32] This statement is misleading and factually incorrect.

The EIS states that the study "established two limits regarding the possible level of wind generation integration on the Isolated Island system, an economic limit and a maximum technical limit."[33] The economic limit is that, in excess of 80 MW, "there would be a significant increase in the risk of spill at the hydroelectric reservoirs."[34] The study notes that an additional 20 MW of wind power could result in an increase in expected spill from 9 to 19 GWh/yr, with a cost of

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[31] A copy can be found at http://www.pub.nf.ca/applications/MuskratFalls2011/files/exhibits/Exhibit61.pdf

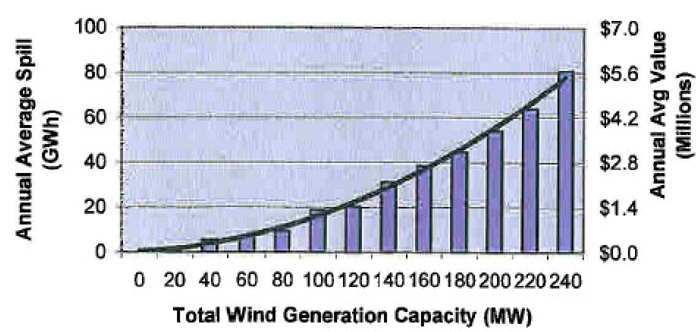
[32] Page 2-46.

[33] Page 2-45.

[34] Ibid.

$1.3 million/yr.[35] The technical limit could require curtailment of wind down to 130 MW during periods of light load.[36] To avoid incurring these costs, NLH recommended limiting installed wind power to 80 MW.[37] The graph related installed wind generation to the economic impacts of spill is reproduced below.[38]

Figure 7-3
Wind Turbine Impacts on Spill



Obviously, hydro spillage and wind curtailment are to be avoided as much as possible. However, in an economic analysis, it is the bottom line that counts. So we need to look a little closer.

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35 NLH, *An Assessment of Limitations for Non-Dispatchable Generation f the Newfoundland Island System*, p. 20-21 and 27. Available at http://www.pub.nf.ca/applications/MuskratFalls2011/files/exhibits/Exhibit61.pdf

36 Ibid., p. 16.

37 Ibid., p. 28.

38 Ibid., p. 20.

First, let's start with the cost of wind power. The EIS relies on an unidentified publication of the Pembina Institute, an Alberta environmental NGO, to state the cost of onshore wind as 8-12 cents/kWh,[39] pointing out that good wind sites on the island are "at the lower end of this range." In fact, based on data from the Canadian Wind Atlas, we estimated that wind power costs on the Island would be much lower – as low as $75/MWh, using conservative assumptions,[40] and as low as $65/MWh, using escalation factors similar to those used for the Muskrat Falls project.[41] Given that these costs are roughly half the cost of Muskrat Falls power delivered to the Island, wind power clearly merits an in-depth evaluation, not a cursory dismissal based on a preliminary study that is almost 10 years old.

According to Canadian Wind Atlas data, Island wind power would have a capacity factor as high as 45%. This means that an additional 20 MW of installed wind capacity would produce 79 GWh a year, at a levelized annual cost of around $5.2 million.

According to the 2004 NLH study, this additional 20 MW of wind power could result in increasing spillage by 10 GWh/yr, to a total of 19 GWh/yr, with a total value of $1.3 million. Charging that cost that to the wind project results in net generation of 79 GWh for a total cost of $6.5 million, or just $82/MWh, net of spillage. Given that this cost is significantly less than the cost of either Muskrat Falls or continued operation of Holyrood, there is no justification for excluding this additional 20 MW of wind power from the least-cost plan.

As for the technical limit, the EIS states that:

> "for wind generation above 130 MW it would not always be possible to maintain system stability particularly during periods of light load and <u>during these periods</u>

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[39] EIS, page 2-46.

[40] Philip Raphals, "Comments on Proponent's Response to the Panel's Information Request of March 21,2011," page 14. (Available at http://ceaa.gc.ca/050/documents/49714/49714E.pdf)

[41] Philip Raphals, Final Presentation to Joint Review Panel, April 14, 2011 (Transcript of April 14, 2011, http://ceaa.gc.ca/050/documents/49747/49747E.pdf, page 17).

> wind generation would have to be curtailed, again, reducing the economic benefit of the additional wind generation."[42]

In other words, since this technical limit can be resolved by wind curtailment during light load periods, it is in fact an economic limit as well. And since the economic parameters of the Island power system have changed so dramatically since 2004, economic limits based on 2004 avoided costs clearly cannot be relied on.

It goes without saying that wind generators don't like curtailment any more than hydro operators like spillage. However, in areas with open wholesale markets, wind generators are now frequently required to curtail generation when so required. If new wind generation is economic, *taking into account the cost of curtailment,* there is no reason to exclude it.

Finally, it is important to mention that the 2004 study made it very clear that it was a preliminary investigation:

> However, given the preliminary nature of this investigation, it would be prudent to further limit the initial quantities of wind generation into the system. Consideration should be given to a stepwise pattern of increased penetration levels over a number of years to gain direct operating experience with the technology and its integration into the Island system. This would allow Hydro to further define the opportunities and constraints associated with the resource without subjecting customers to undue expense or power quality issues. As well it would allow the industry to arrive at possible solutions which, along with the experience gained by Hydro, may permit penetration levels beyond those currently identified.[43]

Indeed, the Government of Newfoundland and Labrador seems to continue to be interested in the possibility of increasing wind penetration beyond the levels identified in the 2004 study. A Request for Proposals was issued last year by the provincial Department of Natural Resources

[42] EIS, pp. 2-45 and 2-46.

[43] NLH, *An Assessment of Limitations for Non-Dispatchable Generation f the Newfoundland Island System*, op. cit., p. 28.

concerning Onshore Wind, in Phase 2 of its Energy Innovation Roadmap process?[44] However, this reasonably foreseeable future activity is not considered in the EIS, and it should have been. A copy of this RFP is attached, as Appendix 1.

For Onshore Wind, one of the areas to be included in the Roadmap is identified as Grid Inflexibility/ Integration. The RFP states (p. 8):

> The ability of the grid to absorb higher penetrations of intermittent wind energy is a function of the flexibility of other generation supply, interconnection, customer loads, and the availability of electricity storage facilities. This is particularly challenging for Newfoundland and Labrador given the absence of these features at the present time.

One of the work products requested is to:

> "assess the flexibility of the existing generating capacity in Newfoundland and Labrador, particularly with respect to the integration of a significant amount of variable generation (e.g. wind power)". (p. 9)

The consultant is also asked to:

- "recommend options and technologies that could improve the flexibility of the existing generating facilities;"
- "recommend options which could lead to the development of new concepts for the techno-economic integration of high wind penetration systems featuring hydro and gas (possibly) and storage facilities;" and
- "**recommend options for the development of power management strategies and system designs that are tolerant of high proportions of wind generated power** and the consequent fluctuations in energy supply, by providing

[44] http://www.nati.net/membership/requests-for-proposals/rfp-energy-and-innovation-roadmap.aspx

> mechanisms such as storage loads or wide area balancing that provide grid stability despite unpredictable supply characteristics." (emphasis added)

Read together, the 2004 study and the 2011 RFP make very clear that the 80 MW limit is not only preliminary, but also that significant effort is underway to overcome it. While it may be prudent *today* to limit wind penetration to 80 MW, **it is not reasonable to assume that this limit will remain in place for the next decade, much less for the next 50 years.**

Thus, it is incorrect to conclude that the Isolated Island Scenario includes the economically optimal level of on-island wind generation.

Section 2.5.8 of the EIS concludes by stating that "Wind power has a place in the electricity generation mix on the Island and, due to its low environmental footprint, it will be incorporated whenever economically viable."[45]

It is clear from the foregoing that neither of the two plans proposed for study by Nalcor (the Interconnected Island Option, based on the Muskrat Falls project, and its Isolated Island Option) come anywhere near approaching economically viable levels of wind power.

The Comprehensive Study Report should therefore include the following findings:

- **that the study the Proponent has invoked to justify its decision to limit wind power to 80 MW until 2067 in the Isolated Island Option is both preliminary and outdated,**
- **that the Proponent has failed to present a reasonable estimate of the economically optimal level of on-island wind generation, in the No Project scenario,**
- **that, as a result, the Proponent has failed to demonstrate that its Isolated Island Option constitutes the least-cost option in the absence of the Muskrat Falls Generation and Transmission projects; and**

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[45] P. 2-46.

– **that, in consequence, the Proponent has failed to demonstrate that the Muskrat Falls Transmission Project, in combination with the Muskrat Falls Generation Project, constitutes the least-cost option to meet long-term supply of power to Newfoundland Island.**

4.3.2. Natural gas

In section 2.5.2, the Proponent explains its view that "'landed' Grand Banks gas is not a viable option to meet the Island's electricity needs" (p. 2-37), identifying several barriers that have, to date, prevented the development of offshore gas for domestic needs. In particular, it is mentioned that "natural gas from White Rose is being stored in an adjacent reservoir for future use," and that, "to date, no concrete plan for domestic natural gas development exists."

Given the recent collapse of North American gas prices, and the widespread expectation that the shale gas phenomenon will keep gas prices low for decades, it seems unlikely that expensive infrastructure will be developed to land offshore gas for the continental market and in the foreseeable future. That said, it also seems reasonable to presume that, if NL government policy were to favour such a solution, offshore gas could indeed be brought to the Island for power generation purposes at some time in the coming decades.

What does *not* seem reasonable is the presumption that, for fifty years, NL will continue to buy oil on the world market to run Holyrood, despite its domestic gas reserves. And yet, it is this hypothesis that underlies the Proponent's Isolated Island Alternative. Indeed, given the ever-increasing prices forecast for #6 fuel oil, which according to the PIRA forecast used by Nalcor increase to around $200/barrel by 2043[46], and to over $300/barrel by 2067[47], there is no doubt

[46] PUB, Exhibit 4, Nalcor, « NLH Thermal Fuel Oil Price Forecast Reference Forecast, », January 2010.

[47] Increasing by 2%/year from 2043 to 2067. MHI, vol. 2, p. 204.

that, in the No Project alternative, pressure will increase, decade by decade, to replace oil as a fuel. In such a context, it is difficult to imagine that offshore gas will remain in the ground for the next fifty years.

It is important to recall that, since fuel costs represent 69% of all costs in the Isolated Island Alternative,[48] any new development that reduces or replaces part of these costs can be expected to have a significant effect on the CWP analysis.

The Comprehensive Study Report should therefore include the finding that the Proponent has failed to adequately consider the possibility of refueling Holyrood with natural gas, sometime prior to 2067.

4.3.3. Electricity imports

In section 2.5.14, the EIS addresses the possibilities of regional power imports as a supply alternative. It judged these alternatives in terms of three considerations:

- Exposure to price volatility or significant price premiums,
- Security of supply, and
- Potential market structure/transmission impediments.[49]

The review was limited to two transmission paths (Churchill Falls to the Island, and Maritimes to the Island). The EIS states:

> For purposes of the screening review, energy was assumed to be ultimately sourced from the New York and New England markets as both regions have competitive wholesale generation markets.[50]

48 Figure 2.6.1-1

49 EIS, page 2-63.

50 EIS, page 2-62.

It is surprising that the possibility of a power purchase from Hydro-Québec was not even mentioned in this section. It is well known that Hydro-Québec has a great deal of surplus power, and is actively seeking purchasers under long-term contracts.

Hydro-Québec's recent long-term contract with Vermont was priced lower than the cost of Muskrat Falls power. While such purchases may well turn out not to be the best solution, there is no basis for excluding them from consideration *a priori.*

The Comprehensive Study Report should therefore include the finding that the Proponent has failed to adequately consider the possibility of regional imports from sources other than the New York and New England electricity markets, in particular the possibility of imports sourced from Hydro-Québec.

4.4. Reliability

In section 2.3.5, the EIS addresses issues related to transmission reliability.

In this section, the Proponent states that the two options were judged against NLH's "accepted" transmission planning criteria which, it states, "adhere to industry accepted practice."

The MHI report examined the question of reliability at length, and found that **NLH's transmission planning criteria do not meet industry standards.** In its report, MHI addressed at length Nalcor's compliance, or lack thereof, with NERC reliability standards, which are mandatory in the US. MHI found that compliance with these standards is now an essential element of Good Utility Practice, and has been adopted by virtually all other jurisdictions in Canada. It was very critical of Nalcor's statement that "it does not plan to address a 3 phase fault at Bay d'Espoir as the present system fails to maintain angular stability following this contingency under some operating conditions."[51] As NERC reliability standards would inevitably apply to the Labrador operations of the Lower Churchill Project, if and when the Maritime Link is commissioned, MHI considers this non-compliance to be a serious issue.

The Comprehensive Study Report should therefore include the finding that NLH's failure to conform to NERC reliability standards is a significant departure from Good Utility Practice.

4.4.1. HVDC Converter Stations and Electrodes

MHI was also very critical of the lack of risk review of the HVDC converter stations and electrodes. It noted that there was no comprehensive HVDC system risk analysis review of operations and maintenance for the overall HVDC transmission system.[52]

There does not appear to be any risk analysis done for the HVDC converter stations or the operational aspects of the LIL HVDC system. Converter station outages could be lengthy and could be very costly to repair. particularly if lost revenues are considered. MHI recommends that this be completed prior to the development of the HVDC converter station specification so any additional requirements can be included.[53]

The Comprehensive Study Report should therefore include the finding that NLH has failed to carry out a comprehensive review of the financial and reliability risks of the overall HVDC system.

4.4.2. HVDC Transmission Lines

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[51] MHI report, v. 2, p. 78.

[52] Ibid., p. 112.

[53] Ibid.

MHI pointed out that transmission losses for the proposed HVDC link would be approximately 10%.[54] It analyzed in detail the choice of design criteria for the transmission line, and criticized Nalcor's choice to design to a 1:50 year reliability return period. It pointed out that the international and Canadian standards for a line without an alternate source of power supply is 1:500 years, and, when an alternate source of supply does exist, it is 1:150 years. "MHI considers this a major issue and strongly recommends that Nalcor adhere to these criteria."[55] There has been no indication that it intends to do so.

The Comprehensive Study Report should therefore include the finding that the planning criteria used for the HVDC transmission lines is inadequate.

4.4.3. Strait of Belle Isle Marine Cable Crossing

MHI's review pointed out a number of risk factors with respect to the marine cable. Literature reviewed indicated cases of cable failures due both to external and internal causes. External causes include third-party mechanical damage (anchors, fishing trawlers, excavation activities). Lightning and of course icebergs – for which the risk is deemed significant -- represent other possible external causes of failure.

A number of HVDC failures over the last decade were attributed to internal causes, including two due to damage caused by installation difficulties. In other cases, the causes of failure are unknown.[56] Assuming that the cable will be problem-free, as Nalcor appears to do, would therefore be optimistic.

Based on historical data, MHI indicated that Nalcor should expect one cable failure every 10 years – though this figure does not take into account the particular characteristics of the Strait of

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[54] Ibid., p. 116.

[55] Ibid., p. 121.

[56] Ibid., p. 134.

Belle Isle.[57] The installation of a third cable will clearly alleviate the risk of a prolonged outage following a cable outage. However, a damaged cable must be repaired, and repairs can be expected to be costly and lengthy.[58]

The Comprehensive Study Report should therefore include the finding that Strait of Belle Isle Marine Cable Crossing creates risks that have not been recognized in the Proponent's EIS.

4.4.4. AC transmission upgrades

In section 2.3.6 of the EIS, the Proponent refers to the Island Transmission System Outlook Report, which identifies several transmission constraints that may need to be addressed in the next 5 to 10 years, depending on generation choices. It states that:[59]

> Following development of generation expansion plans through the generation planning process, the transmission system effects of the proposed generation sites can be more fully assessed and transmission system additions more fully defined.

It is important to note that MHI was very critical of Nalcor's failure to complete AC Integration Studies, which define the additional modifications to the Newfoundland transmission system that would be required in order to successfully integrate power from Muskrat Falls, prior to deciding to go ahead with Muskrat Falls. MHI states that these studies provided "do not adequately describe the facilities required to successfully operate the transmission system under the new configuration. As such, there may be unidentified risks in proceeding with this project at this time."[60]

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[57] Ibid., p. 135.

[58] Ibid.

[59] EIS, page 2-23.

[60] MHI report, vol. 2, page 75.

MHI states that "Good utility practice requires that these integration studies be completed as part of the project screening process (DG2); MHI considers this a **major gap** in Nalcor's work to date."[61] (emphasis added)

The Comprehensive Study Report should therefore include the finding that the Proponent's failure to fully assess the AC transmission upgrades required to integrate the Muskrat Falls project into its existing system is a major failing, and that this failing may create unidentified financial and reliability risks for the Island power system.

4.5. Fuel price forecasts

In section 2.7.1.1 of the EIS, the Proponent presents a sensitivity analysis based on the price of fuel. The analysis demonstrates that the justification of the proposed Project is highly dependant on fuel price forecasts. Thus, Table 2.7.1-1 shows that, under PIRA's Low World Oil Forecast, the preference for the Interconnected Island scenario, as compared to Nalcor's Isolated Island scenario, almost completely disappears, dropping from $2,158 million to just 120 million. In MHI's words:

> More interesting is the low price case, where **a near-term double-dip recession in the US might lead to fuel prices that are so low that the CPW gap almost disappears**.[62]

It is widely recognized that fuel price forecasts are highly uncertain and volatile. The recent drop in oil prices, which have fallen by almost 25% in the last month (from about $105 a barrel at the beginning May 2012 to just over $80 a barrel on June 4), only reminds us of this fact.

[61] Ibid.

[62] MHI, vol. 2, p. 205.

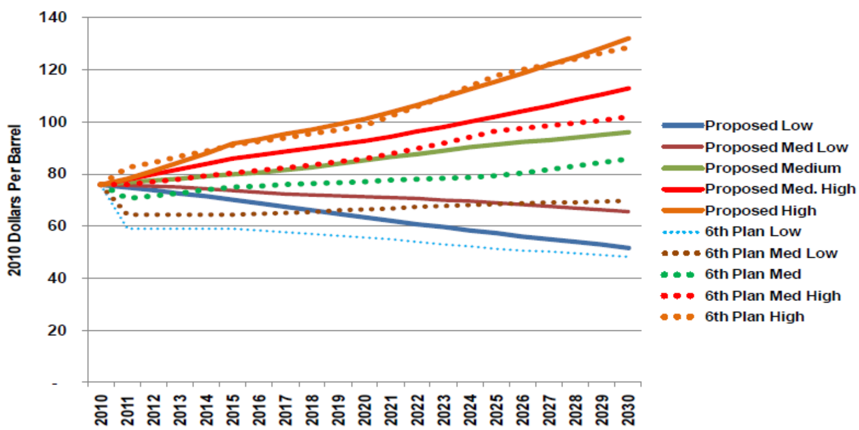
MHI pointed out this uncertainty as well, writing:

> It is clear there is much uncertainty related to the pricing of fuel for thermal-based power generation. Different scenarios can and should be run and compared, but **the results related thereto often have a short shelf life.** While the prospect of raising the necessary capital to finance and construct the Infeed Option may be daunting, **the uncertainty associated with forecasting the price of fuel for thermal generation over the long term might be, and likely is, even more so.** (emphasis added)[63]

The PIRA high and low forecasts have not been made public, so to get an idea of the extent of the typical spreads between high and low oil price forecasts, I had to look to other sources. The following chart presents the oil price forecast from the Northwest Power Planning Council's 2009 Power Plan.

63 Ibid.

Comparison of Revised and Sixth Plan Oil Price Forecasts
Refiners Acquisition Cost $2010/barrel



The high scenario shows prices more than twice as great as the low scenario (about $130 versus about $50 per barrel, in 2030). As MHI wrote in their report, long-term fuel price forecasts have a short shelf life.

The following table, assembled by the US Energy Information Agency, assesses the accuracy of its own fuel price forecasts from 1982 to 2010.

Table 4. World Oil Prices, Projected vs. Actual
(percent difference)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
AEO 1982	9.9	148.7	128.5	229.9	197.3	171.4																			
AEO 1983	7.4	110.0	80.2	170.0	154.8	144.6					492.7														
AEO 1984	7.7	110.0	70.8	133.2	105.9	87.6					331.0														
AEO 1985	0.0	84.7	36.9	78.9	64.2	55.1	97.7	122.7	165.8	202.5	189.6														
AEO 1986		4.1	-12.5	18.8	4.3	-5.2	19.0	39.4	84.3	124.7	132.9	117.3	168.3	351.0	241.7	132.5									
AEO 1987			-0.1	18.8	4.6	-8.4	11.8	19.6	48.7	77.3	86.9					108.4									
AEO 1989*				1.0	-17.4	-24.9	-5.1	5.2	34.3	62.5	68.7	61.3	104.1	252.7	168.6	80.4									
AEO 1990					-2.1	-19.6					55.1					66.7					41.4				
AEO 1991						1.1	32.4	40.6	63.9	76.3	65.5	42.6	64.8	166.0	98.6	33.2	81.1	82.8	69.9	42.0	13.0	0.6	-5.2	-27.1	21.2
AEO 1992							1.8	10.2	28.0	43.6	41.2	27.5	54.7	158.9	96.7	33.4	81.4	81.2	66.2	37.0	7.5	-5.3	-11.3	-31.8	13.9
AEO 1993								3.6	25.5	36.9	31.0	14.7	35.0	121.8	65.9	12.0	52.2	53.0	40.4	14.8	-10.7	-21.4	-26.1	-42.8	-3.9
AEO 1994									5.7	10.9	6.4	-5.9	11.4	83.7	37.7	-7.9	25.0	25.1	15.0	-5.3	-26.2	-35.0	-39.2	-53.3	-22.5
AEO 1995										-1.8	0.8	-11.7	4.0	69.4	25.1	-17.1	10.6	8.8	-1.6	-19.7	-37.8	-45.5	-49.4	-61.4	-35.8
AEO 1996											0.1	-14.0	0.3	63.8	21.5	-19.3	8.2	6.5	-3.6	-21.4	-38.9	-46.6	-50.6	-62.5	-38.1
AEO 1997												-3.1	4.8	62.4	16.3	-25.7	-1.5	-4.2	-14.3	-31.0	-47.1	-54.3	-58.1	-68.5	-48.7
AEO 1998													0.0	56.1	15.1	-24.4	-1.0	-5.0	-15.3	-32.2	-48.3	-55.9	-59.7	-69.8	-50.8
AEO 1999														3.8	-21.0	-47.0	-25.7	-24.6	-29.1	-41.1	-53.8	-59.0	-61.6	-71.4	-53.7
AEO 2000															0.5	-21.3	-4.6	-9.2	-20.4	-37.0	-52.5	-59.6	-63.4	-72.9	-56.3
AEO 2001																1.8	13.0	-3.7	-19.3	-35.8	-51.6	-58.9	-62.9	-72.6	-56.0
AEO 2002																	4.5	-7.3	-13.4	-30.8	-47.5	-55.1	-59.2	-69.6	-50.9
AEO 2003																		-0.3	-2.9	-28.4	-48.0	-55.8	-60.1	-70.5	-52.6
AEO 2004																			-0.2	-31.7	-50.0	-57.4	-61.4	-71.3	-53.5
AEO 2005																				-0.4	-27.6	-46.2	-56.0	-69.0	-52.0
AEO 2006																					4.3	-4.4	-18.3	-42.7	-12.9
AEO 2007																						7.8	-6.5	-33.8	0.1
AEO 2008																							-5.0	-18.1	22.7
AEO 2009																								6.3	-32.4
AEO 2010																									-3.1
Average Absolute Percent Difference (All AEOs)	6.3	91.5	54.8	93.0	68.8	57.5	28.0	34.5	57.0	70.7	115.5	33.1	44.7	126.3	67.4	42.1	25.7	24.0	22.3	27.2	35.6	39.3	41.9	53.4	34.0

The results are surprising. The forecasts produced from 1982 to 1985 were far too high – 133% too high, on average. From 1986 to 1995, the forecasts were still too high – by 35%, on average. But for the next 10 years, from 1996 to 2005, forecasts were all too low -- 32% on average.

This is particularly interesting, not just because it shows the inaccuracy of the forecasts, but because the errors are so systematic. We don't see random variation – we see that forecasters were systematically wrong, in the same direction, for years on end. From 1982 through 1994, they *consistently* over-forecast oil prices. And from 1995 until today, they have consistently under-forecast prices. What does that tell us about today's forecasts? That there is a very substantial chance that they will be wrong, and significantly so. We just don't know in which direction.

A forecast with this much uncertainty has little if any predictive value. Basing decision-making on calculations based on the median value is methodologically unsound. As Nalcor's CPW calculations depend heavily on such values, the conclusions drawn from them cannot be relied upon, as the PUB very correctly noted.

The Comprehensive Study Report should therefore include the findings:

- **that the Proponent's fuel price forecasts include a very high degree of uncertainty, and thus have little predictive value, and,**
- **that economic analyses based on a single value extracted from these forecasts, such as the Proponent's CPW calculations for the Isolated Island Option, also have little predictive value.**

4.6. Power purchase expense

In section 2.4.1.1 of the EIS (pages 2-30 to 2-31), the Proponent explains the power purchase agreement that would define the price paid to Nalcor by NLH for Muskrat Falls power. It begins the section by saying: "The price that NLH pays for power and energy from Muskrat Falls on behalf of Island ratepayers is a cornerstone for the Lower Churchill Project."[64]

It is noteworthy that, even though the price paid is a "cornerstone" of the Lower Churchill Project, most of the information provided in this section was not presented to the Joint Review Panel for the Lower Churchill Generation Project.

In this section, the Proponent explains that its proposed PPA was developed in order to address the fact that, under cost-of-service (COS) price setting, the price of Muskrat Falls power would be a significant burden for ratepayers in the early years:[65]

> Under a regulated Cost of Service (COS) price setting environment, the annual revenue requirement for a utility asset would be comprised of:
>
> > COS = Operating and Maintenance Costs + Power Purchases+ Fuel + Depreciation + Return on Rate Base
>
> Where Return on Rate Base would be comprised of a cost component for lenders (cost of debt) and a profit component for shareholders (return on equity) for a prescribed debt-equity capital structure. This annual COS would then be divided by the output produced and sold from the asset in question to derive an average selling price or rate (such as cents per kilowatt hour (kWh), or equivalent dollars per megawatt hour (MWh). An important feature of this pricing methodology is that under COS price setting, the unit rate revenue paid by ratepayers for a given asset is highest in the first year. This is because as a new regulated asset goes into rate base, the undepreciated cost of the asset is at its maximum and return on rate base is driven by undepreciated net book value. Another feature of this pricing framework is that as the equity investor earns its regulated return each year, the return in dollars is also highest in the first and initial years. This is not necessarily prudent for the Muskrat Falls development in that the Island ratepayer energy requirements at the time of plant commissioning is projected to be only about 40%, or 2 terawatt hours (TWh), of the plant's average annual production of 4.9 TWh. While the Island's energy requirements increase over time in line with economic growth, the early-year COS rate for Muskrat Falls power would be a significant burden for ratepayers in those years. The required COS revenue for Muskrat Falls would be at its maximum and the power required by ratepayers at a minimum. In an effort to address this issue, an alternative approach to Muskrat Falls power pricing was developed that affords a number of advantages for ratepayers.

However, the EIS fails to mention the advantages for consumers of COS pricing in later years, or the corresponding drawbacks of the proposed PPA approach.

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[64] EIS, p. 2-30. It is interesting to note that this issue was not addressed in the EIS of the Lower Churchill Generation Project.

[65] Ibid.

Traditionally, hydro projects have been developed as ratebase projects under COS principles, which implies higher costs in the first few years, that decrease dramatically over time. That's why the costs of many existing hydro projects such as Bay D'Espoir are so low. If they had been built under a PPA, instead of COS, it would cost consumers far more today.

In my comments to the PUB, I demonstrated why, under the proposed PPA, Muskrat Falls will probably never be a low-cost resource. The table presented in Appendix 2 is based on data provided by Nalcor to the PUB.[66] All the columns in white are from Nalcor's document; my additions are presented in yellow.

Nalcor's column 5 shows the nominal annual cost, in $/MWh, of the whole Lower Churchill Project (generation and transmission). This cost remains relatively constant, varying between $190 and $260/MWh over the life of the project.

My new columns 5a and 5b break down the nominal annual cost between MF and LITL, by dividing the incremental costs of each (columns 2 and 3) by the total energy (column 1). We see that, while the nominal annual cost of LITL falls (from $147/MWh at the beginning to $13 at the end), the annual cost of MF increases, from $92 to $247/kWh.

These combined costs are then levelized, on a nominal basis, in column 6, resulting in a fixed nominal dollar cost of $208/MWh. Again, I have broken this down into MF and LITL components, using the same methodology described in Nalcor's note 2. The levelized nominal LUEC for MF is $126/MWh, and that for LITL is $83/MWh.

In column 7, I have only changed the title. While Nalcor calls it an "escalating real LUEC", I find this confusing, since the figures are actually in nominal dollars, not real ones. I find it clearer to refer to it as a "Real LUEC expressed in nominal dollars". In other words, we have converted the nominal LUEC to real dollars, and then re-translated it back into nominal dollars, as a price that escalates with inflation. These are thus the actual prices, in current dollars, that

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will be charged to consumers for Muskrat power (delivered to the Island and blended, of course, with other sources), which starts at $152/MWh in 2017 and increases to $409/MWh in 2067. (Nalcor's figures, from col. 7.)

In column 7a, I have indicated the total annual payments (MF plus LITL), in current dollars. (That's the energy from column 1 times the current dollar prices, in column 7.) In column 7b, I have subtracted from that the LITL payments in column 3, to show the current dollar payments under the MF PPA. Then, in column 7c, I have calculated the current dollar unit cost for Muskrat Falls power (without transmission), by dividing by current dollar payments in column 7b by the amount of energy, from column 1.

Column 7c shows that the actual price paid to Nalcor for Muskrat Falls power starts at $5/MWh in 2017, and rises to $396/MWh in 2067. This result – more extreme than the blended result shown by Nalcor in column 7, results from mixing PPA and COS costs, and from the fact that customers must pay the full cost of LITL, under COS, but only for the energy they actually consume, under the PPA. But in either case, the price to be paid for Muskrat Falls power under the PPA in 2067 comes to around $400/MWh, or 40 cents/kWh.

The costs of Muskrat Falls power under a COS regime have not been produced by the Proponent. However, the information in this table allows us to estimate that as well.

Making the simplifying assumption that the capital structure and depreciation of MF are similar to that of LITL, we can simply inflate the LITL payments in column 3 to correspond to the MF CPW of $2.682 billion (column 2). The result, shown in column 8a, shows the annual current dollar payments that would be required to cover the costs of Muskrat Falls under a COS regime identical to one applied to LITL. These costs start at $407 million in 2017, and fall to $90 million by 2067. Column 8b then shows this amount divided by the total energy each year, giving the unit cost in $/MWh for Muskrat Falls energy under COS. It starts at $225/MWh in 2017, and then fall to $20/MWh by 2067. Of course, if consumers were credited with the revenues of third party sales, which would be normal in COS, the early-year costs would be lower.

This exercise shows the real difference between COS and PPA pricing. With the PPA, Muskrat Falls prices are much lower at first, but 20 times higher in 2067.

In other words, if Muskrat Falls were subject to COS regulation, in 50 years its power would be almost as cheap as any other low-cost old hydro project.

And what happens after 2067? Under COS, the unit cost from MF would remain stable, somewhere around $20/MWh or lower, like it does for other COS hydro projects.

Under the escalating price scenario, however, NF consumers would be paying $396/MWh for MF power in 2067. How much would Nalcor charge in 2068? Would it suddenly cut the price to $20/MWh, pointing out that, since all its costs incurred 50 years ago had now been paid, it had no reason to charge more? Or, more likely, would it keep on charging $400/MWh? Doing so would of course produce a windfall profit for Nalcor and its shareholder – paid from the pockets of Newfoundland consumers.

At Churchill Falls, Hydro-Quebec enjoys pricing very similar to COS pricing, and Newfoundland and Labrador certainly wishes that the pricing were more like the PPA proposed here. But in the case of Muskrat Falls, it is Newfoundland consumers who will be paying the escalating prices.

Thus, while the PPA is advantageous, compared to COS pricing for consumers in the project's first decade, it is very disadvantageous to consumers later on. This intergenerational equity issue is not addressed in the EIS.

The Comprehensive Study Report should therefore include the finding that the Proponent has failed to present the long-term disadvantages for Newfoundland consumers of its proposed PPA for Muskrat Falls power.

5. Conclusions and recommendations

As we have seen, the stated justification for the LITL is that **the Muskrat Falls generation project** represents "the least-cost option to meet long-term supply of power to the Island." From a justification perspective, the two projects are inseparable.

The previous (albeit partial) reviews of the justification of the Muskrat Falls project are thus entirely relevant to the assessment of the LITL. As we have seen, the Joint Review Panel for the Lower Churchill Generation Project was unable to resolve a number of key questions related to the project's justification, in particular with respect to alternatives to the project.

A great deal of new information has been made public since the issuance of the JRP report, in the process carried out by the PUB and in the EIS for the LITL. However, as we have shown above, the fundamental questions raised by the JRP still have not been resolved. **In my opinion, Nalcor's analysis showing Muskrat Falls to be the best and least cost way to meet domestic demand requirements is still inadequate.**

That is, the Proponent's attempt to demonstrate that Muskrat Falls represents the least-cost option to meet long-term supply of power to the Island fails, because it depends on the comparison with an Isolated Island Scenario which is in no way optimal, because it:

- is not the fruit of a true planning process, but is simply the output of a planning program.
- is based on a load forecast:
    - in which the forecast residential growth rate is inadequately substantiated, and
    - which fails to account for the potential closure of Corner Brook Pulp and Paper, which in itself would eliminate 80% of the CPW reduction under the Muskrat Falls scenario;
- fails to include **any** Conservation and Demand Management savings in the base plan, and the CDM scenarios explored in the sensitivity analyses remain modest, with no gains foreseen after 2031;
- ignores the phenomenal wind power potential near load centers on the Island based on a preliminary 2004 study, the underlying parameters of which are no longer valid;

- fails to address the possibility of purchases from Hydro-Québec;
- Relies on a CPW analysis that depends heavily on long-term fuel price forecasts, which are known to have a "very short shelf life" and which have so much uncertainty as to be of little or no predictive value;
- assumes that Holyrood will continue to burn oil until 2067, making the unjustified assumption that, in the absence of the Muskrat Falls project, offshore gas will remain untapped for the next 50 years.

Given these many and substantial flaws, the analysis comparing the Muskrat Falls Interconnected Island Scenario to the Isolated Island Scenario prepared by Nalcor should be judged, once again, inadequate.

I recommend that the Agency find that the rationale presented in the EIS for the proposed Labrador-Island Transmission Link is factually unsupported, for the reasons set out above. More specifically, it should find that said rationale is based upon unsupported assumptions and deficient analyses.

For all these reasons, the Comprehensive Study Report should conclude that the Proponent has failed to demonstrate that the Muskrat Falls Transmission Project, in combination with the Muskrat Falls Generation Project, constitutes the least-cost option to meet long-term supply of power to Newfoundland Island.

APPENDIX 1

NL DEPARTMENT OF NATURAL RESOURCES

REQUEST FOR PROPOSALS

ONSHORE WIND

PHASE 2 — ENERGY INNOVATION ROADMAP

APPENDIX 2

Exhibit GRK-3, as filed before the PUB

February 23, 2012