Commission of Inquiry Respecting the Muskrat Falls Project

Muskrat Falls: A Misguided Project

Volume 1: Executive Summary, Key Findings and Recommendations

Volume 2: Pre-Sanction Events

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The Honourable Richard D. LeBlanc
Commissioner

March 5, 2020

COMMISSION OF INQUIRY RESPECTING THE MUSKRAT FALLS PROJECT

MUSKRAT FALLS: A MISGUIDED PROJECT

VOLUME 2:

PRE-SANCTION EVENTS

The Honourable Richard D. LeBlanc, Commissioner

Submitted to:

The Honourable Siobhan Coady
Minister of Natural Resources
for the Province of Newfoundland and Labrador

March 5, 2020

www.muskratfallsinquiry.ca

About This Report

This Report quotes heavily from testimony and exhibits presented at or to the Commission during the activities of its inquiry. Documentary evidence was catalogued and made available to the public on the Commission's website. When cited in this Report, these public exhibits are referred to by their individual number (for example, P-00001). Similarly, testimony given by witnesses during the public hearings was transcribed and made publicly available at muskratfallsinquiry.ca. Quotes from testimony are cited with a date and transcript page number. Because both types of citations are so numerous in this Report, smaller type was used to reduce their intrusion in the text.

No changes to spelling or punctuation were made in any quoted material. The minimal additions to quotes that were made (for clarity) were inserted [like this].

It should also be noted that, unless otherwise indicated, all monetary figures are in Canadian dollars. As will be explained in more detail in the text, the "Muskrat Falls Project" and "the Project" both refer to the tri-part development that includes the infrastructure and generating station at Muskrat Falls, the Labrador-Island Link and the Labrador Transmission Assets.

For the convenience of the reader, a Glossary of terms, a list of Acronyms and a list of Names and Affiliations has been included in each of the first four volumes of the Report.

This Report is in six volumes.

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INTRODUCTION

The potential to be realized from the development of the Churchill River, including the lower Churchill River, has been the subject of significant interest, discussion, debate and controversy for decades in the province of Newfoundland and Labrador (NL). As will be seen in my later findings, the Muskrat Falls Project (the Project) is very much a product not only of the potential offered by the flow of the Churchill River but also of the history of the development of the upper Churchill River.

The Project is a hydroelectric and transmission development that Nalcor Energy (Nalcor), a provincial Crown corporation, sanctioned and built with the authorization of the Government of Newfoundland and Labrador (GNL or the Province).

It comprises the following components as defined in the *Energy Corporation Act*, SNL 2007, c. E-11.01 (P-00431):

> 2.1(1)(a) the design, engineering, planning, construction, commissioning, ownership, operation, maintenance, management and control of equipment and facilities, to be comprised of
>
> (i) the new hydroelectric plant to be constructed at Muskrat Falls on the Churchill River, and all associated facilities, including the intake structures, penstock, powerhouse, dams and spillways, [Muskrat Falls Generating Station]
>
> (ii) a new HVdc transmission line and all related components to be constructed between the Muskrat Falls hydroelectric plant on the Churchill River and Soldier's Pond, [Labrador Island Link (LIL)] including
>
> (A) foundations, underground services, subsea services, roads, buildings, erections and structures, whether temporary or permanent,
>
> (B) all other facilities, fixtures, appurtenances and tangible personal property, including inventories, of any nature whatsoever contained on or attaching to the transmission line, and
>
> (C) all mechanical, electrical and other systems and other technology installed under or upon anything referred to in clause (A) or (B),
>
> (iii) new transmission facilities to be constructed between the Muskrat Falls hydroelectric plant on the Churchill River and

the generating plant located at Churchill Falls, [Labrador Transmission Assets (LTA)]

(iv) new transmission facilities to be constructed by Emera Inc. between the island portion of Newfoundland and Labrador and Cape Breton, Nova Scotia [Maritime Link (ML)] including

(A) foundations, underground services, subsea services, roads, buildings, erections and structures, whether temporary or permanent,

(B) all other facilities, fixtures, appurtenances and tangible personal property, including inventories, of any nature whatsoever contained on or attaching to them, and

(C) all mechanical, electrical and other systems and other technology installed under or upon anything referred to in clause (A) or (B), and

(v) any associated upgrades to the bulk electrical system or related control facilities on the island portion of the province required as a result of subparagraphs (i) to (iv). (pp. 4–5)

When GNL and Nalcor sanctioned the Project in December 2012, the Project cost was estimated to be $6.2 billion plus financing and other costs of $1.2 billion, bringing the total to $7.4 billion. For a variety of reasons that will be discussed later in this Report, by June 2017 the Project cost estimate had increased to $10.1 billion plus financing and other costs of $2.6 billion, bringing the total cost estimate to $12.7 billion.

With the increase in the Project cost estimate and the significant delays in the delivery of first power, members of the public and some politicians voiced serious concerns about the assurances that GNL and Nalcor had made at Project sanction. Questions were raised about the validity of the assumptions underlying the justification for the Project as the least-cost option for supplying electricity to the island portion of the province and calls for a public inquiry were made. On November 20, 2017, GNL established the Commission of Inquiry Respecting the Muskrat Falls Project (the Inquiry or Commission; O.C. 2017-339) and I was appointed the Commissioner (P-00001). This Commission of Inquiry is subject to the provisions of the *Public Inquiries Act, 2006*, SNL 2006, c. P-38.1. This Report is the result of the investigations of the Project conducted by the Commission of Inquiry.

The Report is in six volumes. It relates the history of the Project based on my assessment of the evidence presented during 140 days of testimony from 134 witnesses, as well as my review of 4,559 public exhibits and 119 confidential exhibits. The evidence provided by many involved in the Project suggested that the cost overruns and delays resulted from a series of unfortunate, unforeseen and coincidental events. This is not the conclusion I have reached based on my assessment of the evidence. Certainly, there were some occurrences and events that may not have been reasonably foreseeable. However, much of what has transpired, in my view, should have been within the reasonable knowledge and control of GNL and Nalcor.

I have concluded that the business case for the Project was suspect from its early days and that the concerns expressed about the Project are deserved. It is apparent that the Project, which now accounts for approximately 30% of the Province's net debt, has saddled the ratepayers and taxpayers of the province with a burdensome financial obligation that will persist for many years to come. I say this even though I recognize that some potential benefits may ultimately accrue to these same ratepayers and taxpayers. However, such benefits are speculative and, if they do materialize, will be required to offset much of the cost of the Project. As was well stated by Premier Dwight Ball when, on July 5, 2019, he was questioned about the future or long-term benefits: "I don't deposit optimism in the bank account of this Province" (July 5, 2019, transcript, p. 4).

This Report begins with a review of the Commission's mandate, followed by historical information about previous attempts to develop the hydroelectric potential of the Churchill River. An overview of the development, approval and construction of the Project comes next. Then, to respond to the Commission's Terms of Reference, I focus on key areas, events and issues from both the pre- and post-sanction stages of the Project. I then discuss certain related issues regarding how the Province moves forward once the Project is completed and operating. My findings and recommendations are included in Volume 1.

I have carefully considered all of the testimony and exhibits that have come before me. In this Report, I have not recited the full evidence of each of the witnesses. Rather, I have summarized the facts about those occurrences and events that impacted both the Project's sanction and its construction.

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THE COMMISSION'S MANDATE

The Terms of Reference for the Commission of Inquiry are broad and are set out primarily in s. 4 of the Order in Council (O.C. 2017-339), as follows (P-00001):

4. The commission of inquiry shall inquire into:

 (a) the consideration by Nalcor of options to address the electricity needs of Newfoundland and Labrador's Island interconnected system customers that informed Nalcor's decision to recommend that the government sanction the Muskrat Falls Project, including whether

  (i) the assumptions or forecasts on which the analysis of options was based were reasonable,

  (ii) Nalcor considered and reasonably dismissed options other than the Muskrat Falls Project and the Isolated Island Option, and

  (iii) Nalcor's determination that the Muskrat Falls Project was the least-cost option for the supply of power to Newfoundland and Labrador Island interconnected system over the period 2011–2067 was reasonable with the knowledge available at that time;

 (b) why there are significant differences between the estimated costs of the Muskrat Falls Project at the time of sanction and the costs by Nalcor during project execution, to the time of this inquiry together with reliable estimates of the costs to the conclusion of the project including whether

  (i) Nalcor's conduct in retaining and subsequently dealing with contractors and suppliers of every kind was in accordance with best practice, and, if not, whether Nalcor's supervisory oversight and conduct contributed to project cost increases and project delays,

  (ii) the terms of the contractual arrangements between Nalcor and the various contractors retained in relation to the Muskrat Falls Project contributed to delays and cost overruns, and whether or not these terms provided sufficient risk transfer from Nalcor to the contractors,

  (iii) the overall project management structure Nalcor developed and followed was in accordance with best practice, and whether it contributed to cost increases and project delays,

(iv) the overall procurement strategy developed by Nalcor for the project to subdivide the Muskrat Falls Project into multiple construction packages followed industry best practices, and whether or not there was fair and competent consideration of risk transfer and retention in this strategy relative to other procurement models,

(v) any risk assessments, financial or otherwise, were conducted in respect of the Muskrat Falls Project, including any assessments prepared externally and whether

(A) the assessments were conducted in accordance with best practice,

(B) Nalcor took possession of the reports, including the method by which Nalcor took possession,

(C) Nalcor took appropriate measures to mitigate the risks identified, and

(D) Nalcor made the government aware of the reports and assessments, and

(vi) the commercial arrangements Nalcor negotiated were reasonable and competently negotiated;

(c) whether the determination that the Muskrat Falls Project should be exempt from oversight by the Board of Commissioners of Public Utilities was justified and reasonable and what was the effect of this exemption, if any, on the development, costs and operation of the Muskrat Falls Project; and

(d) whether the government was fully informed and was made aware of any risks or problems anticipated with the Muskrat Falls Project, so that the government had sufficient and accurate information upon which to appropriately decide to sanction the project and whether the government employed appropriate measures to oversee the project particularly as it relates to the matters set out in paragraphs (a) to (c), focusing on governance arrangements and decision-making processes associated with the project. (pp. 3–5)

In conducting the Inquiry, I am also directed to consider the following matters, as set out in s. 5 of the Order in Council (P-00001):

(a) participation in the inquiry by the established leadership of Indigenous people, whose settled or asserted Aboriginal or treaty rights to areas in Labrador may have been adversely affected by the Muskrat Falls Project;

(b) the need to provide consumers in the province with electricity at the lowest possible cost consistent with reliable service;

(c) the powers, duties and responsibilities of a Crown Corporation;

(d) the need to balance commercial considerations and public accountability and transparency in carrying out a large-scale publicly-funded project; and

(e) the need to balance the interests of ratepayers and the interests of taxpayers in carrying out a large-scale publicly funded project. (p. 5)

On March 14, 2018, I released a decision: "Interpretation of the Terms of Reference for the Muskrat Falls Inquiry" (Interpretation Decision). My purpose in preparing it was to inform parties applying for standing about how I understood and would interpret the Commission's scope, as well as the issues and matters it would investigate.

In calling the Inquiry, Premier Ball stated: "Through this public inquiry, we will learn if the project to date, is the project the people of the province were sold in 2012. While we cannot undo the past, we can learn from it and make more informed decisions as we take actions to minimize the impact of this project on ratepayers" (GNL press release, November 20, 2017).

I think it is important to discuss the meaning of the word "hindsight" here, because at the hearings it seemed that there was some misunderstanding about it. The *Canadian Oxford Dictionary* defines hindsight as "wisdom after the event." Gaining understanding from hindsight must be distinguished from examining circumstances that were known, or ought to have been known, by a person at a particular time in the past and then judging whether a decision that person made at that time was reasonable. Two simple examples will illustrate this distinction. In the first, a person decides to go for a walk on a fine day that has a completely clear long-term weather forecast, then is injured after being struck by lightning in an unexpected storm. In the second, a person decides to go for a walk during a lightning storm and is injured as a result of being struck by lightning. Hindsight shows that it was unfortunate that the first person chose to walk, but it is moot to criticize their decision because at the time they chose to go out there was no reasonable basis for believing there was any risk of a lightning strike—it was not foreseeable. However, in the second example, the person had key information at the time and so knew, or ought to have known, of the risk of a lightning strike and the possibility of injury—it was foreseeable both then and now. Hindsight plays no role in this. I see it as my responsibility, in this Report, to identify and distinguish between the foreseeable and unforeseeable events and consequences during the planning, development and construction of the Project.

I also recognize that the Commission's Terms of Reference refer to "best practice(s)" in several places. I am satisfied that, although there are certain established best practices in the areas of engineering and project management, there is also divergence of opinion as to what those best practices actually are. Where there is a divergence of opinion, I have considered the term "best practice" on the basis of the evidence heard. Where it was not possible for me to identify established best practice, that is noted. In those circumstances, I have considered what was a reasonable course of action for my determination of what is "best practice."

As the Interpretation Decision outlines, I decided to interpret the Terms of Reference broadly by focusing on the issues that are of concern to the public. I explained my interpretation of the focus of s. 4 of the Terms of Reference as follows:

> [29] Generally speaking, it is clear to me that the Order in Council, and specifically section 4, is geared to focus the Commission's work and mandate, primarily at the least, on the business case put forward by Nalcor leading to the official sanction of the Muskrat Falls Project by Government in December 2012 as well as the reasons why the costs of construction of the Project have escalated from the initial estimates made. By business case, I mean specifically the case advanced by Nalcor, and accepted by the Government, for the need, financial viability, costs and benefits of the Muskrat Falls Project. Really what is primarily being asked of the Commission is to explain what was done by Nalcor and the Government of Newfoundland and Labrador to cause the Muskrat Falls Project to be sanctioned, whether the analysis done by Nalcor and the Government was reasonable considering best industry practice and why the Project cost has escalated so significantly.
>
> [30] Also to be considered is why the Project was exempted from PUB [Board of Commissioners of Public Utilities] scrutiny, notwithstanding that ultimately a reference was made to the PUB to compare two potential options for supplying power to the island part of the Province. Once that assessment by the PUB was commenced, the Government decided it would not give the PUB the extension of time that it requested to complete its work. To assess the possible impact of the PUB exemption or lack of scrutiny of the development, costs and operation of the Project, the Commission will be investigating the full circumstances surrounding the PUB's degree of involvement.
>
> [31] Based upon section 4(d), it will also be necessary for the Commission to investigate the involvement of the Government in the Project prior to sanction and whether it was fully informed and was made aware of any risks or problems

> anticipated with the Project so as to assess whether it had "sufficient and accurate information upon which to appropriately decide to permit the Project to proceed". Once sanction was given, the Commission of Inquiry must consider what measures the Government has taken to oversee the Project. In doing so, the Commission is directed to focus on governance arrangements and decision-making processes as related to the Project. Such an examination will be a broad one and will have to include both the prior governments as well as the present government for the Province. (pp. 12–13)

I went on to state the following about the participation of Indigenous Peoples in the Inquiry:

> [47] Having said this, it is obvious to me that the Lieutenant-Governor in Council intended that the established leadership of the Indigenous people would have a part to play in this Inquiry. If that is so, the part that they should play would be in areas of concern or of interest to those Indigenous people. I note that paragraph 4(b)(v)(a) refers, as regards the issue of the cost escalation of the construction of the Project, to any risk assessments, financial or otherwise, conducted in respect to the Muskrat Falls Project. At present, while I do not have full information, I am aware that certain assessments likely were conducted, specifically risk assessments concerning environmental issues prior to, as well as subsequent to, sanction. I have decided here that a contextual and purposive review of the Order in Council permits me to investigate into what consultation occurred between the established leadership of the Indigenous people and Nalcor as well as the Government prior to sanction, what risk assessments and reports were done as regards the concerns of the Indigenous people, whether these assessments were appropriately and reasonably considered by Nalcor and the Government and whether appropriate measures were taken to mitigate against reasonably potential adverse effects to the settled or asserted rights of the Indigenous people both at the time of and post sanction. In investigating these matters, I will not be determining any claims or treaty rights for any of the Indigenous people as this clearly does not fall within the Commission's mandate. (pp. 47–48)

Public hearings commenced on September 17, 2018, and concluded on July 26, 2019. Final submissions were heard from August 12 to 15, 2019. The hearings were divided into three phases:

- Phase 1 covered the period leading up to Project sanction in December 2012
- Phase 2 covered the period between Project sanction and Financial Close, which occurred late in 2013, and addressed the issues related to Project construction

- Phase 3, much shorter than Phases 1 and 2, focused on issues that may arise as Project-related consequences in the future

The following parties were given full standing before the Commission:

- Charles Bown
- Consumer Advocate (Newfoundland and Labrador)
- Edmund Martin
- Former provincial government officials, 2003 to 2015
- Her Majesty the Queen in right of Newfoundland and Labrador
- Julia Mullaley
- Kathy Dunderdale
- Muskrat Falls Concerned Citizens Coalition Inc.
- Nalcor Energy
- Robert Thompson

The following parties were given limited standing before the Commission:

- Andritz Hydro Canada Inc.
- Astaldi Canada Inc.
- Barnard Pennecon Limited Partnership
- Conseil des Innu de Ekuanitshit
- Dwight Ball
- Emera Inc.
- Former Nalcor board members
- Grand Riverkeeper Labrador/Labrador Land Protectors
- Grid Solutions Canada ULC
- Innu Nation
- Manitoba Hydro International Ltd.
- Nunatsiavut Government
- NunatuKavut Community Council

- Siobhan Coady
- Terry Paddon
- The Newfoundland and Labrador Building and Construction Trades Council/Resource Development Trades Council of Newfoundland and Labrador
- Todd Stanley

One party, Newfoundland Power Inc., was given special standing in Phase 1 and Phase 2 and full standing in Phase 3.

On February 4, 2018, the Commission retained Grant Thornton LLP (Grant Thornton) to perform forensic audit services for the sanctioning and construction phases of the Muskrat Falls Project. Grant Thornton prepared a number of reports for the Commission including a *Sanctioning Phase* report dated July 16, 2018 (P-00014) and a *Construction Phase* report dated December 7, 2018 (P-01677).

Scott Shaffer was Grant Thornton's team leader for the investigation work and preparation of these reports. Mr. Shaffer received a Certified Public Accountant designation in 1980 following his graduation in 1979 from the University of Illinois at Chicago with a Bachelor of Science (major in Accounting) degree. He later attended the Lake Forest Graduate School of Management and was awarded an MBA degree in 2006. In 2010 he received his Certified Fraud Examiner designation and in 2013 he received his Certified Construction Auditor designation.

Mr. Shaffer is the Managing Director of Forensic Advisory Services at Grant Thornton's national office in Chicago, Illinois, and is also the leader of the firm's Wisconsin Advisory Services Practice. He has more than 30 years of experience as a litigation consultant, an expert witness, a forensic accountant and a fraud investigator. After hearing evidence on his education, his professional designation and his work history, I designated Mr. Shaffer as an expert who was qualified to provide opinion evidence in the areas of investigative and forensic accounting and analysis. Mr. Shaffer testified in both the Phase 1 and Phase 2 hearings.

In addition to the two reports noted above, the other reports prepared by Grant Thornton are also referred to in this Report.

Figure 2.1: Churchill Falls (Before Development)

CHAPTER 1: CONTEXT AND BACKGROUND

CHURCHILL RIVER DEVELOPMENT PRIOR TO 2007

The Commission engaged Dr. Jason Churchill to prepare a paper providing an overview of the history of negotiations leading to the development of the Churchill River. It covered the period from before Confederation (1949) to the 2007 publication of *Focusing Our Energy*, GNL's Energy Plan (Energy Plan, P-00029). Dr. Churchill is an historian and researcher with particular knowledge in the areas of energy, politics and public policy. I recognized Dr. Churchill as having expertise in historical information related to the development of the Churchill River. His paper (P-00008) outlines how attempts to develop the hydroelectric facilities along the Churchill River influenced the formulation of the Province's 2007 Energy Plan. Dr. Churchill identifies two key issues that dominated and shaped negotiations over the decades.

The first issue concerns the struggle of successive NL governments to gain unfettered access to North American energy markets by selling electricity produced by Churchill River hydro developments directly into those markets. The most efficient route for transmitting electricity from Labrador is through the province of Québec. But Nalcor, the Crown corporation that develops and manages NL's energy resources, does not have the right to wheel electricity through Québec. The inability to gain direct market access has weakened the Province's bargaining position in its negotiations with Hydro-Québec for many years.

The second issue concerns the 1969 signing of what is commonly referred to as the "Upper Churchill Contract." In the short term, this contract enabled development of Churchill Falls to proceed and be paid for by Hydro-Québec. In the longer term, however, it has resulted in the vast majority of the profits generated by the Churchill Falls facility going to Québec and not to the owner of the resource, NL. The Upper Churchill Contract does not expire until 2041.

Exploration of the potential development of the Churchill River began in 1927. At that time, the Government of Newfoundland[1] was preparing its case for jurisdictional control over the vast inland territory of Labrador, which would go before the Judicial

[1] Newfoundland and Labrador were not part of Canada in 1927, but formed a British Dominion called "Newfoundland."

Committee of the Privy Council (the Privy Council), the highest court in the British Empire. This territory included the Churchill River watershed. The Privy Council's ruling about the location of the boundary between Canada and Newfoundland gave jurisdiction over the Churchill River to Newfoundland, a decision that became of considerable importance during subsequent negotiations to develop the Churchill River's hydroelectric potential.

While the boundary decision of the Privy Council enabled the Newfoundland Government to pursue development, there were difficulties about how to get the energy to those who might buy it. Labrador is bounded by the Atlantic Ocean to the east and by Québec to the south and west—thus Labrador hydroelectric resources were geographically isolated from the eastern Canadian and American energy markets. Given Newfoundland's small population and limited industrial base, access to those markets was a prerequisite for the economic viability of any potential development. Over the following decades, these geographic realities gave Québec significant negotiating leverage over potential Churchill River hydroelectric development. Québec's insistence on being the sole broker for Labrador power was certainly evident in the 1960s. In 1965, for example, then Québec Premier Jean Lesage stated that Québec would never allow the construction through its territory of any transmission line owned by another province, and added that any electricity entering Québec would have to be sold to Hydro-Québec.

Canada has consistently maintained that the question of the export of electricity from Labrador is a matter for negotiation between Québec and GNL. Canada has been unwilling to impose measures that would interfere with what Québec has always considered to be its authority—the control of the transmission of electricity through its territory. This reluctance was evident as early as 1962 when then Prime Minister John Diefenbaker introduced the concept of an integrated national power grid. It was seen as a nation-building exercise, similar to earlier major construction projects such as the Canadian Pacific Railway and the Trans-Canada Highway. The Prime Minister subsequently decided to establish a Committee on Long Distance Transmission to study the matter. Consistent with its historic position, Québec opposed the idea from the outset. After five years of study, the final report of the Committee on Long Distance Transmission concluded that a national grid was not possible without Québec's participation. While it noted that an improved network would assist in the marketing of electricity produced on the Nelson River in Manitoba and on the Churchill River in Labrador, the Committee found that the overall benefits of a national power grid were marginal and further study was deemed unwarranted.

The concept of a national power grid was revisited more than three decades later, as a possible means to assist Canada in meeting its international obligations under the 1997 Kyoto Accord. GNL's position was that developing hydroelectricity from the lower Churchill River alone could cover 15% of Canada's greenhouse gas (GHG) emission-reduction obligations. Establishing a national power grid should therefore have been seen as a viable option to help Canada reach its international obligations. Québec again opposed the concept of establishing a national power grid and Canada stated that it would not impose a national grid on Québec.

It was clear that the only path forward would be through a plan negotiated between the two provinces. Canada offered to act as a mediator but was not willing to take further action until the two provinces could reach some agreement. The positions of Québec and Canada on the transmission of electricity through Québec, and also on the Upper Churchill Contract, have remained consistent from the 1960s through to today. Given that situation, it seemed evident that without co-operation between Québec and NL, meaningful negotiations for the sale of surplus energy from any future development of the lower Churchill was unlikely.

Since the signing of the Upper Churchill Contract, and under its terms, Hydro-Québec has purchased virtually all of the output from the Churchill Falls facility. While seen as economically beneficial to NL in the short term, the Contract did not provide the Province with direct market access for Labrador power. The original term of the Upper Churchill Contract expired in 2016, but it had a 25-year renewal term, extending it to 2041.

The Churchill Falls facility is owned by the Churchill Falls (Labrador) Corporation Limited (CF(L)Co). Newfoundland and Labrador Hydro, a wholly owned Nalcor subsidiary, owns 65.8% of CF(L)Co and Hydro-Québec holds the remaining 34.2%. Under the Upper Churchill Contract (P-00061, p. 6–7), CF(L)Co has the right to recall 300 megawatts of power (the Recall Block) plus a further 225 MW block (the TwinCo Block).

Figure 2.2: The Churchill Falls Powerhouse

The Upper Churchill Contract did not contain an escalation clause for the price paid by Hydro-Québec for Churchill Falls electricity. For this reason, the contract became an albatross around the neck of subsequent negotiators attempting to secure final agreements for the development of sites on the lower Churchill River, specifically at Gull Island and Muskrat Falls. Redress for NL, to compensate for the loss of what was perceived to be a windfall profit by Hydro-Québec from the sale of Churchill Falls electricity, was an obstacle during all of these negotiations.

The efforts of Premier Joseph Smallwood and subsequent premiers to introduce new approaches that could convince Hydro-Québec to provide NL with greater benefits from the Upper Churchill Contract were all unsuccessful. However, in 1998 and 1999, NL Premier Brian Tobin negotiated two new contracts with Hydro-Québec. Dr. Churchill summarized their terms and conditions as follows (P-00008):

> The first was a Shareholder's Agreement which allowed the Newfoundland government to put money into CFL Co. if an infusion of cash was needed. This ensured that Newfoundland would maintain its controlling 66% share in the company. Previously only Hydro-Québec had the right to inject funding and could have used the extra financing to purchase additional shares. The agreement also ensured that the price of electricity for Western Labrador would not increase beyond "reasonable commercial rates". Hydro-Québec waived its right to purchase a 225 MW block of power which would have become available in 2014.
>
> More significant was the agreement to enter into the *Guaranteed Winter Availability Contract* (GWAC). The GWAC guaranteed to Hydro-Québec 682 MW of additional capacity from Churchill Falls during the winter months. GWAC came into force in November 1998 and is set to last until the conclusion of the 1969 Contract in 2041 with periodic renewals. CFL Co. was expected to receive $34 million per year for guaranteed peak power supplies during the winter months. In contrast to the 1969 Contract, there is an escalation clause and after an initial period of a few years, the price paid by Hydro-Québec will automatically be tied to inflation. By the time the GWAC was renewed for a second time in 2004 it was expected that the renewal would net the province $230 million over the subsequent five year term. With GWAC, CFL Co's future financial stability was secured and the province expected to net an additional $1 billion dollars over the contract in additional revenues from the Upper Churchill. (pp. 19–20)

The long history of attempts to sign final agreements for the development of hydroelectric sites on the Churchill River was reflected in GNL's 2007 Energy Plan (P-00029):

> Too often in our history, however, this wealth was managed and controlled for the benefit of outside interests rather than for the people who live and work here. This Energy Plan will ensure that Newfoundlanders and Labradorians become the principal beneficiaries of our great supply of energy resources, which we refer to as our Energy Warehouse. (p. 7)

Québec attempted to impede any possible development of the lower Churchill River prior to the sanction of the Muskrat Falls Project. For example, Québec argued publicly that it was wrong for Canada to support the Project by providing a financing guarantee. In addition, there is a suggestion in the evidence that Québec's 2009 attempt to purchase assets of New Brunswick Power Corporation may have been motivated, in part, by its desire to curtail the ability of GNL to transmit electricity through New Brunswick and on to New England energy markets. In May 2010, the Québec regulator affirmed the decision of Hydro-Québec's TransÉnergie to deny Newfoundland and Labrador's application to gain access to the transmission facilities of Hydro-Québec, which would be needed to wheel power from the lower Churchill to markets in Canada and the United States. In his testimony before the Commission, former NL Premier Danny Williams expressed his view that "this was the worst, blatant, legal decision that I had ever witnessed in law" (October 1, 2018, transcript, p. 43). Evidence from an expert witness, however, indicated that it was exactly the decision that should have been reasonably expected by GNL in the circumstances (July 17, 2019, transcript, Pelino Colaiacovo, pp. 12–13).

The frustrations felt by politicians and others in Newfoundland and Labrador relating to Hydro-Québec, particularly as a result of the Upper Churchill Contract, were leveraged for the purpose of promoting the Project. They clearly contributed to the decision to proceed with it.

THE DEVELOPMENT OF MUSKRAT FALLS: A TIMELINE

As soon as land surveying began in Labrador in the early 20th century, it was clear that the Churchill River had potential as a source of hydroelectric power. Three sites—Churchill Falls, Gull Island and Muskrat Falls—were initially identified as being particularly attractive. The generating station built at Churchill Falls has been in operation since 1971.

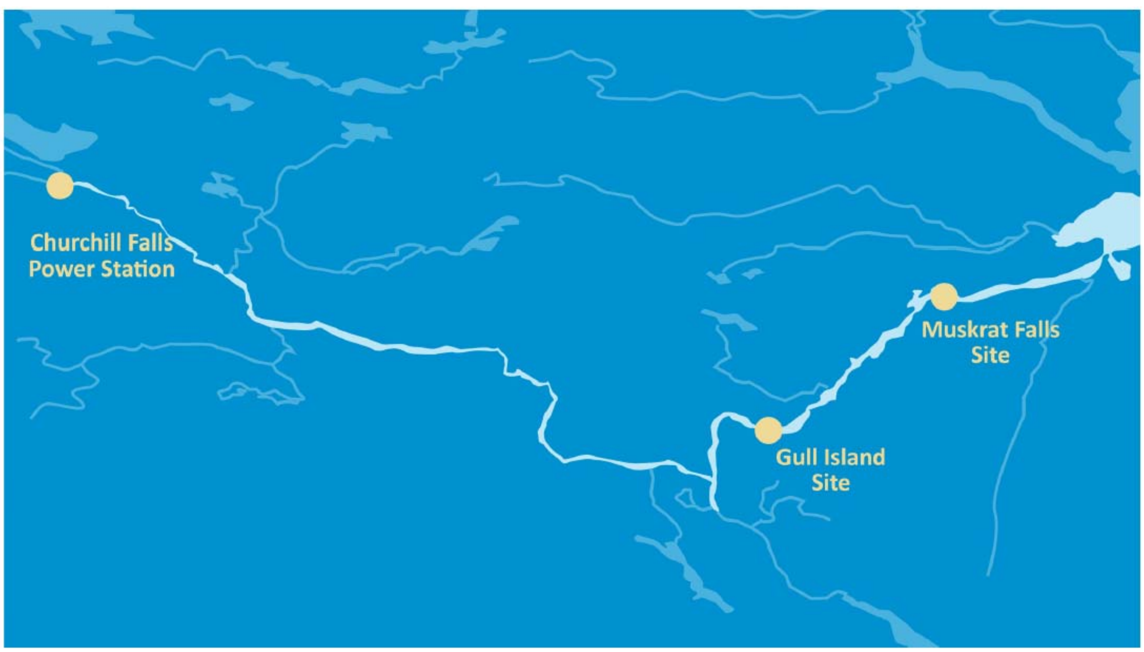

Figure 2.3: Churchill River Hydroelectric Sites

The following pages summarize the waypoints as governments of Newfoundland and Labrador moved toward additional hydroelectric developments on the River.

1998: Premier Brian Tobin (NL) and Premier Lucien Bouchard (Québec) announced the commencement of negotiations to develop Gull Island and to expand the hydroelectric generation capacity of the Upper Churchill.

1999: SNC-AGRA prepared a final feasibility study for Newfoundland and Labrador Hydro, which concluded that development of the Muskrat Falls site was "economically feasible, cost effective and attractive" (P-00022, p. 52). The capital cost estimate for the generation facility was estimated to be approximately $965 million (P-00022, p. 283).

2000: GNL exempted any hydro developments on the Churchill River from oversight by the province's Public Utilities Board. The impact of this exemption on the future development of the Muskrat Falls Project will be discussed later.

2002: GNL and Québec engaged in further discussions about the development of Gull Island.

2003: A Progressive Conservative Government under Danny Williams was elected in NL in October. The Williams Government ordered the development of an energy plan for the Province's petroleum (oil and gas) and electricity resources. The Williams Government was intent on developing the lower Churchill River and initiated several activities to advance this development.

2005: In January, the Williams Government and NLH requested Expressions of Interest (EOI) for the development of the lower Churchill River. In May, Gilbert Bennett was appointed NLH's Vice-President, Lower Churchill Project. His duties included initiation of the preliminary planning process for the development of the lower Churchill River. In July, Edmund Martin was appointed President and CEO of both NLH and the Churchill Falls (Labrador) Corporation.

2006: In January, NLH applied to Hydro-Québec TransÉnergie for the right to wheel electricity from Labrador to markets in Ontario, New Brunswick, New England and New York using existing transmission lines. This application led to a dispute about available transmission capacity and NLH filed complaints with the Québec energy regulator, the Régie de l'énergie. (These complaints were dismissed in 2010.)

Also in January, NLH outlined an early version of a "Decision Gate" process—a multi-stage decision-making framework to be used in any development on the lower Churchill River. Below is an outline of a later version of that process (P-00079):

> The NE-LCP Gateway Process . . . is a stage or phased decision gate assurance process that will be used to guide the planning and execution of the business opportunity presented by the lower Churchill River from identification through to operations. (p. 7)

I agree with the following conclusion in Grant Thornton's *Sanctioning Phase* report (P-00014):

> We have determined that the Decision Gate process followed by Nalcor is considered a best practice and is commonly used in mega projects globally across a variety of industries including its application to other developments across Canada. (p. 12)

The approach included five "Decision Gates" (DG1, DG2, etc.), dividing the stages in the development process as follows (P-00079):

- Gate 1 – Approval to Proceed with Concept Selection
- Gate 2 – Approval of Development Scenario and to Commence Detailed Design
- Gate 3 – Approval to Commence Full Construction
- Gate 4 – Approval to Commence First Power Generation
- Gate 5 – Approval to Commence Decommissioning (p. 8)

NLH also described six sequential phases in its adopted Gateway process:

> **Phase 1 – Opportunity Identification and Initial Evaluation**
>
> Includes the initial feasibility evaluation of the identified business opportunity, which in the case of the Project is the development of the hydropower potential presented by the lower Churchill River. This phase culminates at Gate 1, at which a decision on whether the Project is feasible and worth pursuing further is made.
>
> **Phase 2 – Generate and Select Alternatives**
>
> The objective of this phase is to generate and evaluate a number of development options from which a preferred option to develop the business opportunity is selected. This phase culminates at Decision Gate 2, at which point approval is sought for the recommended development option, the execution strategy, and to proceed with the start of detailed design. This phase

> involves aboriginal negotiations, environmental assessment process, field work, power sales and access, financing strategy, advanced engineering studies, early construction planning and economic analysis.
>
> **Phase 3 – Engineering and Procurement/Contracting**
>
> Culminating at Gate 3, this phase involves the finalization of all front-end engineering work and completion of sizable portion of all detailed engineering and procurement/contracting activities in order to meet the project financing requirements and to commence construction immediately after successful passage through Gate 3. Gate 3 is the point that the Project is given approval to commence construction. In this phase the environmental assessment is completed and release from Environmental Assessment is a predecessor to passage through Gate 3.
>
> **Phase 4 – Engineering, Procurement, Construction and Commissioning**
>
> This is the building phase of the Project in which the hydroelectric facility and associated transmission takes shape and peak employment occurs. Concurrent to the start of early construction activities, the remaining engineering, procurement and contracting activities are completed. This Phase ends at Gate 4, which signifies a readiness to commence production of electricity.
>
> **Phase 5 – Start-up and Operate**
>
> The construction is substantially completed and electricity production occurs and transmission systems are energized. This includes facility maintenance and daily operation of the facilities.
>
> **Phase 6 – Decommissioning**
>
> A decision regarding the decommissioning of the hydroelectric development when the facility has reached the end of its productive life occurs at the beginning of this Phase, signified by Gate 5. Following passage through this Gate, decommissioning of the plant occurs. (p. 10)

In May, Premier Danny Williams announced that, having reviewed the EOI to develop the lower Churchill River, “the province in partnership with Newfoundland and Labrador Hydro will lead the development of the Lower Churchill” (P-00028, p. 1).

In November, NLH submitted a project description to the Government of Newfoundland and Labrador and the Government of Canada for the Lower Churchill Generation Project, to determine whether an environmental assessment was necessary under provincial and federal legislation. It described the proposed Gull Island and Muskrat Falls generation facilities and transmission lines connecting them to Churchill Falls, but did not refer to the Labrador-Island Link, a transmission line connecting the power-generation facilities on the lower Churchill with Soldiers Pond on Newfoundland's Avalon Peninsula. Both governments determined that the Lower Churchill Generation Project required an environmental assessment under each jurisdiction's legislation. The two governments agreed to set up a Joint Review Panel (JRP) to assess the project for joint environmental approval and its effects on Indigenous Peoples.

2007: GNL enacted water management legislation and regulations allowing the PUB to order all parties holding the right to generate power from the same river to enter into an agreement to "result in the most efficient production, transmission and distribution of power" (P-00087, p. 7).

In September, GNL published its Energy Plan, *Focusing Our Energy*. Among other things, it included the proposed creation of an energy corporation. This occurred in October, with the passage of the *Energy Corporation Act* and the creation of a new publicly owned energy corporation with a mandate that included administration of NLH's interests in CF(L)Co, in the Province's oil and gas assets, and in the Bull Arm fabrication site. The company, named "Nalcor"[2] in 2008, was also tasked with the development of the lower Churchill River and the implementation of the policy objectives of the Energy Plan.

While the evidence is not entirely clear about the exact date, it appears that, early in 2007, Nalcor also gave approval to proceed with Decision Gate 1 concept selection for the development of the lower Churchill River.

2008: GNL and the Innu Nation entered into negotiations that led to the signing, in September, of the Tshash Petapen (New Dawn) Agreement. This agreement resolved key issues about a land claim settlement and included both an Upper Churchill Redress Agreement, which provided compensation for the original Churchill Falls development, and an Impacts and Benefits Agreement (IBA), which did the same for the proposed development of the lower Churchill.

2009: In March, Nalcor registered the Labrador-Island Link component with the governments of NL and Canada, in order to proceed with a separate environmental impact assessment of this component of the project. Both governments agreed to

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[2] As used in this Report, "Nalcor" may also indicate the Energy Corporation of Newfoundland and Labrador, the Crown corporation established on October 11, 2007. The Energy Corporation was renamed Nalcor Energy on December 11, 2008.

proceed with an environmental impact assessment and also to issue joint environmental statement guidelines.

Nalcor and CF(L)Co management negotiated a draft water management agreement but the CF(L)Co board of directors did not approve the proposed agreement.

On November 10, Nalcor referred the matter of a water management agreement to the PUB, requesting an order for the establishment of the terms of such an agreement between Nalcor and CF(L)Co with respect to the Churchill River.

2010: On March 9, the PUB issued an order to establish the terms of the water management agreement that was negotiated by the management of Nalcor and CF(L)Co.

The same month, Nalcor and Emera Inc., which is a diverse energy and services company headquartered in Nova Scotia, signed a Memorandum of Understanding (MOU) to investigate options that could optimize the existing energy resources of Nalcor and Emera, assist them both in addressing future power and energy requirements in their respective provinces, and enable them to develop renewable energy resources and explore potential market opportunities (P-00805).

In July, NLH released its annual generation planning forecast, which showed expected generating capacity deficits and an inability to meet peak loads starting in 2015. Energy deficits were not forecasted to occur until 2019 and later (P-00034, p. 5).

In October, Premier Williams announced that Muskrat Falls, not Gull Island, would be the first development on the lower Churchill River. Gull Island had been screened out because it was not economically feasible.

On November 16, the Muskrat Falls Project passed through DG2 with the approval of the recommended development option and commencement of front-end detailed engineering and design. At DG2, the approved development scenario consisted of:

1. A dam and generating station at Muskrat Falls with a capacity of 824 MW of power and an estimated average annual energy production of 4.9 terawatt hours (TWh)
2. Labrador Transmission Assets, being high-voltage cables to transmit power between Muskrat Falls and the Churchill Falls generating station

3. Labrador-Island Link, being high-voltage cables capable of transmitting 900 MW of power from Muskrat Falls through Labrador, under the Strait of Belle Isle and across the Island to arrive at Soldiers Pond on the Avalon Peninsula

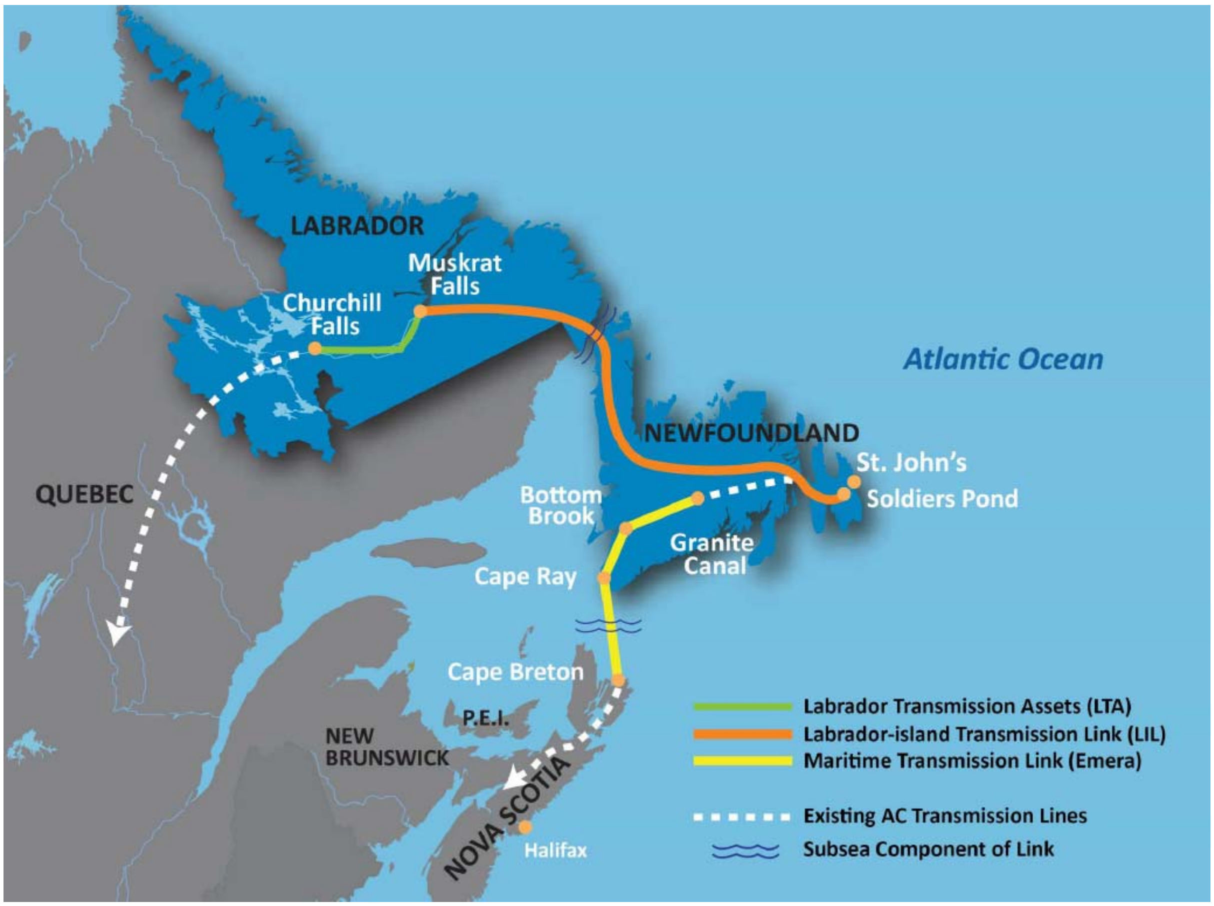

Figure 2.4: The Muskrat Falls Project and Maritime Link

At DG2, the cost of these components was estimated at approximately $5 billion before financing costs.

On November 18, Nalcor signed a Term Sheet with Emera. In its recitals, it outlined the intention of both parties (P-00227):

> **AND WHEREAS** Emera has expressed an interest in obtaining renewable energy to reduce greenhouse gas emissions and to meet the existing and future renewable energy targets and load requirements in the Province of Nova Scotia **("NS")** and New England **("NE")**;

> **AND WHEREAS** Nalcor has expressed an interest in delivering power and energy from the Muskrat Falls Plant and in obtaining a transmission path into and through NS, and the Province of New Brunswick **("NB")** and into NE;
>
> **AND WHEREAS** the Parties have concluded that in exchange for an investment in the Maritime Link and transmission in NS, Emera would receive twenty percent (20%) of the output of the Muskrat Falls Plant and further Nalcor requires Emera to provide transmission services in NB and NE and in exchange Emera will receive investment opportunities in NL regulated transmission assets;
>
> **AND WHEREAS** the Parties have investigated the options and now wish to confirm their common understanding of the purpose, process and timing for the supply and delivery of power and energy from the Province of Newfoundland and Labrador **("NL")** to NS, other Canadian provinces and NE and the associated transmission access;
>
> **AND WHEREAS** Emera has expressed an interest in investing in transmission assets in NL both to facilitate the delivery of power and energy to NS and otherwise; (emphasis in original, p. 3)

The Term Sheet called for the building of the Maritime Link, a 500 MW high-voltage connection between Granite Canal, on the Island of Newfoundland, and Woodbine, Nova Scotia. The ML was intended to be used to meet Nalcor's obligations to deliver electricity to Emera and to export surplus power from Muskrat Falls through Nova Scotia. At the time of DG2, the estimated cost of the ML was $1.2 billion plus financing costs.

The Term Sheet was based on the "20 for 20 principle." It stipulated that Emera would pay 20% of the total capital costs in exchange for 20% of the energy and capacity from Muskrat Falls.

On December 3, following the Project's passage through DG2 and the signing of the Term Sheet, Premier Danny Williams resigned and Premier Kathy Dunderdale took office. Since 2006, Ms. Dunderdale had been GNL's Minister of Natural Resources, the department most closely involved with the development of the Project.

After the Project passed through DG2, Nalcor proceeded with finalizing all front-end engineering, design and detailed procurement/contracting activities for the Project. At this point, GNL adopted as its primary criterion for approving construction that the Project be the least-cost option for providing electricity to the ratepayers on the Island of Newfoundland. Earlier, this criterion had been just one of several. This change reflected the adoption of a more utility-based rationale.

2011: On February 1, Nalcor signed an Engineering, Procurement and Construction Management Services contract with SNC-Lavalin Inc. (SNC or SLI)[3] for the Muskrat Falls Project. The contract excluded the undersea cable crossing of the Strait of Belle Isle (SOBI). It also placed responsibility for the engineering, procurement and construction management of the Project in the hands of SNC. Nalcor representatives were to take a more supervisory oversight role.

GNL sought a loan guarantee from Canada, as this guarantee would result in a lower interest rate for the portion of Project financing it covered.

On the public front in this same period, some citizens were voicing doubts about Nalcor's position that the Project would provide the least-cost power to Island ratepayers. Concerns were also being expressed that the Project could jeopardize the Province's financial position. Internal GNL documents obtained by the Commission revealed that in 2011, two cabinet ministers identified the need for GNL to retain an independent consultant to conduct a review of the Project and to conduct its own due diligence, completely independent of Nalcor (P-00807).

Although Nalcor had assured GNL that several third-party assessments confirmed that the Project was the least-cost option, GNL decided to send a Reference Question to the PUB (P-00537, p. 2), asking it to review and report to GNL on whether the Project represented the least-cost option for the supply of power to Island ratepayers over the period of 2011 to 2067, as compared to the "Isolated Island Option."

Designed by system planners at Nalcor, the Isolated Island Option was a combination of thermal, wind and small-scale hydro-generation projects on the Island designed to meet the energy needs of Island ratepayers from 2011 to 2067. As is discussed in Chapter 3, the Isolated Island Option that Nalcor considered may not have been the only option that should have been compared to the Interconnected Island Option (the Project) to determine the "least-cost" choice.

To respond to the Reference Question, the PUB engaged Manitoba Hydro International Ltd., an electrical power consulting company owned by Manitoba Hydro, to provide advice. The PUB attempted to obtain up-to-date information from Nalcor to answer the Reference Question but was forced to rely on the DG2 capital cost estimates and schedules Nalcor prepared in 2010.

[3] SLI (SNC-Lavalin Inc) is the abbreviation Nalcor frequently used. This Report uses "SNC" to refer to the same firm.

In August, the governments of Canada, Nova Scotia and Newfoundland and Labrador signed a Memorandum of Agreement outlining that Canada would provide a loan guarantee for the Project and the ML (P-00040). The same month, the environmental Joint Review Panel filed its report, which contained 83 recommendations and stated (P-00041):

> 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. (p. 68)

On September 22, the PUB wrote to the Minister of Natural Resources advising that it could not meet the December 30 deadline for submission of its report on the Reference Question. The PUB also advised that it could not determine a realistic date by which it could address the Reference Question, "until we have a better idea as to when Nalcor will answer the outstanding information requests and file the Submission contemplated in the Terms of Reference" (P-00567). On December 12, GNL granted a deadline extension to March 31, 2012 (P-00045). On December 16, the PUB requested (P-00046) a further extension to June 30, 2012, which GNL denied (P-00047).

On October 18, GNL provided Nalcor with a commitment letter stating that it would provide base level and contingent equity financing to complete the Project, if and when necessary (P-00868).

In November, the governments of Nova Scotia and Newfoundland and Labrador entered into an MOU for a benefits framework for the ML (P-00044).

2012: In March, the governments of Canada and Newfoundland and Labrador responded to the Joint Review Panel report, accepting some recommendations but rejecting others. GNL rejected a further independent analysis to determine whether the Project was the least-cost option for Island ratepayers. Nalcor received the approval of both GNL and Canada to proceed with the Project from an environmental point of view, with conditions.

On March 30, the PUB released its report on the Reference Question and reached this conclusion (P-00600):

> The [PUB] 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. (p. 6)

In response to the PUB's report, GNL made arrangements for a review of Nalcor's DG3 cost estimates. On June 5, MHI, which had concluded that the Project was the least-cost option based on the DG2 estimate, was retained by GNL to perform the DG3 review.

On July 31, GNL, Nalcor, Nova Scotia and Emera signed formal agreements for the Project and the ML (P-00056).

In October, MHI delivered its report to GNL, in which it concluded (P-00783):

> MHI believes the Lower Churchill Project to be technically achievable, economic, and the best option for the next large generation resource to meet the load requirements of Newfoundland and Labrador. (p. 41)

As is discussed in Chapter 7, GNL had placed significant limitations on MHI's scope of work, thus rendering questionable the conclusions that MHI reached. Nevertheless, GNL relied on MHI's generally positive review of Nalcor's work on the Project.

On October 30, GNL released the DG3 cost estimate for the Project—$6.2 billion before financing and other costs. GNL also released the MHI report on the DG3 cost and schedule review and its conclusion supporting Nalcor's position that the Project was the least-cost option.

On November 1, GNL released a report from Ziff Energy Group (Ziff) that reviewed natural gas as an option for power supply to the Island (P-00060). The report concluded that Grand Banks natural gas and liquefied natural gas were not viable alternatives as a future energy supply for the Island. On November 26, GNL released a report by Wood Mackenzie Limited (Wood Mackenzie) that reviewed Ziff's report on natural gas (P-00091). GNL also released other reports on issues related to the Project at or about this time.

Finally, on November 30, the governments of Canada, Nova Scotia and Newfoundland and Labrador signed a Term Sheet for the Federal Loan Guarantee (FLG), by which Canada agreed to guarantee up to $5 billion of debt for the Project and $1.3 billion for the ML, subject to GNL's sanction of the Project and Nova Scotia's sanction of the ML.

On December 6, GNL gave Nalcor approval to sanction and proceed with the development of the Project. On December 17, Nalcor and GNL announced Project sanction. In the related announcement, Premier Dunderdale stated (P-01635):

> Harnessing the vast hydro-electric power of the Lower Churchill is a promise that has been hovering just on the horizon for over 50 years, but has remained out of reach for successive Governments of Newfoundland and Labrador. However, today, history is being made, as we, together with our partners in Nova Scotia and the Innu Nation, set in motion a project, whose impacts will be felt for generations. Through an unprecedented link to the North American electricity grid, the Muskrat Falls Project will unlock the potential of Newfoundland and Labrador's energy warehouse and help drive our economy for 100 years to come.
>
> It will allow stable, affordable electricity to power our homes and businesses. It will power industrial development in Labrador. It will open the door to further development of limitless renewal energy resources and make us energy self-sufficient—all are important benefits, all are significant. But most importantly, this development allows us, as Newfoundlanders and Labradorians, to stand tall and proud on the national stage, knowing that as our forebearers persevered to etch an existence on the edge of the North Atlantic, so will we—with unrelenting focus and steadfast determination—overcome all obstacles and transform challenges into success. (pp. 1–2)

Although the Project was sanctioned, Nalcor still needed to finalize financing for construction, which was dependent on the outcome of negotiations with Canada on the FLG. A delay in those negotiations had occurred, caused in part because Emera had not yet received approval from the Nova Scotia Utility and Review Board, the Nova Scotia regulator, on its application for the ML.

2013: On July 22, the UARB gave conditional approval of Emera's application, which led to further negotiations between Nalcor and Emera. The UARB gave final approval to the ML on November 29.

At this point, the estimated capital cost of the Project had increased from $6.2 billion[4] to $6.531 billion. It is clear that some, but not all, GNL officials were aware of this increase.

Meanwhile, Nalcor selected Astaldi Canada, Inc. to construct the powerhouse and spillway, which was the Project's largest contract.

On September 24, Nalcor issued Astaldi a Limited Notice to Proceed (LNTP) that authorized Astaldi to commence work (P-02139).

On November 29, the documents for the FLG were signed.

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[4] Unless otherwise stated, references to the Project's capital cost estimates are exclusive of interest and financing costs.

2014: In March, GNL announced the establishment of an Oversight Committee to oversee the construction and costs of the Project.

As the year progressed, Nalcor officials became aware of further increases to capital cost estimates for the Project. In June, Nalcor announced that the estimated capital cost of the Project had increased to $6.99 billion.

2015: In September, Nalcor further revised the capital cost estimate to $7.65 billion. By this time, Astaldi was experiencing financial problems and was seeking additional funds from Nalcor to complete the Project.

On November 29, Paul Davis' Progressive Conservative Government was defeated at the polls and a Liberal Government under Dwight Ball was elected.

2016: In January, GNL retained Ernst & Young to conduct a full review of the Project cost, schedule and related risks.

In April, Edmund Martin left his position as President and CEO of Nalcor. He was replaced by Stan Marshall. Mr. Marshall made changes to the Project's management structure and schedule.

In June, Nalcor revised the capital cost estimate of the Project to $9.13 billion.

In July, Nalcor and Astaldi signed a Bridge Agreement that provided Astaldi with a cash advance, which it required in order to continue its work on the Project. This was followed, in December, with the signing of a Completion Agreement between Nalcor and Astaldi. This resulted in Nalcor revising the capital cost estimate of the Project to $9.40 billion.

2017: In June, the cost estimate of the Project was further revised to $10.12 billion.

At the time of the writing of this Report (winter 2019–20), the capital cost estimate for the Project remains at $10.12 billion. First power was scheduled for the fall of 2019, but did not happen. First power is subject to the resolution of protection and control software development and other remaining work for the LIL.

With this contextual and general background, I will now discuss certain events, issues and actions that relate to the questions I must answer in responding to the Commission's Terms of Reference.

CHAPTER 2: SETTING THE STAGE

THE PROVINCIAL ELECTION OF 2003

In or about the fall of 2002, the Government of Newfoundland and Labrador, led by Premier Roger Grimes, was in the midst of negotiating a deal with the Province of Québec to develop the Gull Island project (Gull Island). Two concerns with the terms of the proposed deal were Hydro-Québec acting as the financier and Hydro-Québec being the sole broker for the electricity. Such a situation would have provided Newfoundland and Labrador with no redress for the inequities of the Upper Churchill Contract and increased the sense of injustice stemming from the deal made with Québec for the Churchill Falls project.

Danny Williams, then Leader of the Opposition and a strong critic of the potential deal, was against any involvement of Québec in the development of Gull Island. This was evident from Mr. Williams' much later statements in the House of Assembly, made on May 12, 2010 (P-00154):

> I find it really difficult to understand how they [Québec] could have done us such a grave injustice back in the 1960's, which carries on to this very day, which has cost us billions and will cost us billions and billions of dollars, has prevented us from being a have province for decades, to turn around then and to be so small to try and prevent us now proceeding with the Lower Churchill Project. (p. 22)

Just over a month later, on June 14, 2010, Mr. Williams further declared:

> Mr. Speaker, the hon. member opposite talks about taking power and taking it across Labrador and across the Gulf and down through Newfoundland, across the Gulf and through the Maritimes and down into the State of Maine. As if: Look, you know, this is just too much trouble. We really should not bother with this. What we should do is—she should go back to her previous position. We should just give this all away to Québec. Which is exactly what her government and her Premier and previous governments have been prepared to do is give it to Québec.
>
> An article appeared in the *Montreal Gazette* just this weekend. Do you know what it is entitled? "Let it go, Newfoundland." Let it go. That is what we should do. We should listen to the hon. member opposite and we should listen to the members of the Opposition. We should just let it go. We should give it all way.

> In that particular article they also say, “Williams isn’t wrong on the facts.” So everything that we laid out in Ottawa last week, every single fact is correct. They acknowledge that, but instead Québec has this patronizingly colonial attitude: Let it go, Newfoundland and Labrador, give it all to us and we will take care of it. Well, over my dead body that is going to happen, I can tell you right now. (p. 38)

Because members of the public, individuals within GNL and other critics raised significant concerns at the time, the proposed deal did not conclude.

In October 2003, Mr. Williams became Premier with the election of a Progressive Conservative Government. His party’s platform was described in detail in its campaign “Blue Book,” *Our Blueprint for the Future* (P-00277). Energy development generally and the development of the lower Churchill in particular were key components of this platform. Further, the Conservatives’ campaign strongly promoted developing the lower Churchill River as a “by Newfoundland and Labrador, for Newfoundland and Labrador” project.

In his testimony, Mr. Williams stated that the lower Churchill was to be developed only if it were financially viable (October 1, 2018, transcript):

> But, yes, I did like the idea of getting us independent of Québec, and that’s part of the masters of our own destiny piece. But it was not at all cost. I mean, I’ve seen—the term has been used that it was, you know, [to] be done at all cost. You know, myself, Minister Dunderdale, and I think Mr. Martin, have all said that there was never, you know, any presupposition position here that this was going to be done at all cost. And, you know, going back to [the] “damn the torpedoes” line, it’s not at all. You know, every decision was going to be based on economics and finances and good, sound judgment. (pp. 22–23)

I find that GNL’s policy after the 2003 election favoured both the development of the lower Churchill River and the stipulation that such a project would be led by Newfoundland and Labrador. Nalcor, with the full support of GNL, then took as its mandate the planning, development and execution of a project on the lower Churchill River, which ultimately became the Project.

The Energy Plan

After the election, GNL’s Minister of Natural Resources was authorized to proceed with the development of a comprehensive provincial energy plan by an Order in Council dated December 10, 2004 (P-00157). Reflecting what had been stated in the Conservative Party's Blue Book, the purpose of this plan (P-00029) was to ensure

> that all energy sources are used first to provide a reliable, affordable supply of power for domestic use and for Province wide economic development, and then to take advantage of business opportunities and export markets to sell energy that is excess to our needs on terms that secure maximum benefits for the Province. (p. 92)

The Order in Council stated (P-00157):

> The objective for the Energy Plan is to produce a roadmap of the of [*sic*] major directions and policies that will guide Government's management of the energy sector to ensure that: (i) the energy sector of the Province is a significant long term contributor to the social, economic and environmental sectors; (ii) the revenues and economic benefits generated by the energy sector are optimized; (iii) the energy industry contributes to the protection, and where possible improvement, of the environment of our air, land and the water; (iv) Newfoundlanders and Labradorians have the skills, training and education necessary to capture and create opportunities related to the energy industry; and (v) a business climate is fostered that encourages economic growth both domestically and for exporting opportunities and the development of products, services and R&D/technologies. (p. 2)

The resulting Energy Plan included a discussion of topics related to offshore oil, offshore natural gas, electricity and land-based energy sources, as well as energy and economic development, energy production's impact on air pollutants and climate change, and energy issues related to fisheries and oceans. It was also intended to guide the Province's policy for energy resource development.

To create the Energy Plan, GNL undertook extensive consultations with the public, as well as with Indigenous Peoples, experts in various fields and a range of organizations throughout the province. The final plan, *Focusing Our Energy* (P-00029), was publicly released in September 2007 (P-00188) and set out the Williams' Government's policy and strategy in relation to energy resource development.

As Dr. Jason Churchill stated in his report prepared for the Commission, the Energy Plan took an optimistic view of the province's potential for future prosperity and was influenced heavily by historical challenges the province had experienced (P-00008):

> The plan expressed great optimism for the future and argued that the province was at a watershed; it had faced challenges in the past that had taught some hard lessons, but the lessons had been learned and the province was now

> potentially on the cusp of sustained prosperity. It was clear that the province's future prosperity was to be anchored on natural resource development that included exploiting a wide range of non-renewable and renewable energy sources including existing and new hydroelectric developments in Labrador. The key to achieving that prosperity was to have a flexible strategy with contingencies in place to mitigate, as far as possible, the vagaries of resource development, jurisdictional politics, and emerging opportunities resulting from global struggles to combat climate change.
>
> *Focusing Our Energy* also illustrated the persistence of a key fact that had frustrated successive provincial governments from the time of Confederation with Canada to Premier Williams. The vast hydroelectric resources in Labrador were isolated from the lucrative North American energy markets. That basic fact was exacerbated by the additional fact that the province had perpetually struggled to overcome various obstacles— technical, economic and political— and had never been able to find a permanent solution to facilitate the full development of the hydroelectric resources available on the Churchill River. (p. 3)

In relation to the Lower Churchill Project, the Energy Plan stated (P-00029):

> The Lower Churchill Hydroelectric Project is the most attractive undeveloped hydroelectric project in North America. Its two installations at Gull Island and Muskrat Falls will have a combined capacity of over 2,800 MW and can provide 16 .7 Terawatt hours (TWh) of electricity per year—enough to power *1.5 million* homes without a requirement for significant reservoir flooding. The project will more than double the amount of renewable electricity available to the province and will dramatically increase the amount of power available for economic development in Labrador and on the Island.
>
> . . .
>
> To ensure this project has every opportunity to move forward, the Provincial Government is leading its development through the Energy Corporation. The Energy Corporation has established a comprehensive and clearly-defined project execution plan and will continue to advance the project on multiple fronts, including engineering and the environmental assessment process, analysis of market access options and market destinations, and a financing strategy. The project is targeting sanction in 2009, with in-service of Gull Island in 2015. (p. 40)

Dr. Churchill stated that development of the lower Churchill River was the primary focus of the Energy Plan. However, it did reference an alternative, to be considered in the event such development could not be completed at a reasonable cost (P-00008):

> The electricity chapter of the [*sic*] *Focusing Our Energy* reflected caution towards future developments when it stated that if plans to develop the Lower Churchill did not proceed as planned then the province had a back up plan to fill expected demand using a combination of thermal, wind and small hydroelectric developments. (p. 25)

The reference to an alternative indicates that GNL had not committed fully to the development of the lower Churchill River at the time. The Energy Plan strongly endorsed the development of the lower Churchill River, on condition that Newfoundland and Labrador received maximum benefits from the development. Even later, when the decision not to develop Gull Island was made, Nalcor was primed by the Energy Plan to proceed with the Muskrat Falls Project.

The letter from the Premier published in the Energy Plan reiterated some of the "Newfoundland and Labrador first" sentiments prevalent during the 2003 election campaign (P-00029):

> The days of our resources primarily benefiting others are gone. A bold new attitude of confidence has taken hold in our province. Since 2005, when we finally became principal beneficiaries of the Atlantic Accord, we have been more determined than ever to harness our vast energy resources for the benefit and long-term self-reliance of Newfoundlanders and Labradorians. Focusing Our Energy lays the strategic direction for development, with far-reaching implications for our economy and our people. Responsible decision-making means basing our choices on the clearest possible understanding of our needs and the long range implications of our options. Getting it right is especially important for our non–renewable resources. The finite nature of these valuable assets means that once they are exploited they are gone forever. So ensuring revenues from these sources today will benefit further generations as a core component of this Plan. (p. 5)

In his testimony, Gilbert Bennett, who was Vice-President of the Lower Churchill Project at the time of the Energy Plan's release, confirmed that Nalcor, created in 2007, considered the Plan to be a mandate document that it was expected to execute (November 26, 2018, transcript, pp. 4–5). Nalcor counsel's final submission to the Commission suggested the very same (Final Submission of Nalcor, pp. 15–16). So, even though it had been noted that the cost of the Project had to be reasonable and the Project itself had to be viable, the direction was set and Nalcor adopted that direction as its mandate.

CREATION OF THE ENERGY CORPORATION

On May 8, 2006, prior to the finalization of the Energy Plan, GNL announced that Newfoundland and Labrador Hydro would lead the development of the Lower Churchill Project.

Next, NLH went through an internal reorganization of its operating departments and leadership team. Then, on October 11, 2007, the *Energy Corporation Act* was proclaimed. It established a provincial corporation to be known as the Energy Corporation of Newfoundland and Labrador (Energy Corporation). The intent was to create a parent company that would manage the Province's investment and involvement in the development of the energy sector, as envisioned by the Energy Plan. The Energy Corporation became the sole shareholder of NLH. A Memorandum to Executive Council on May 1, 2008, included these goals for the Energy Corporation (P-00193):

- ensuring as much legal protection of the assets of NLH and CF(L)Co as possible;
- ensuring appropriate public accountability for the Corporation and its subsidiaries; and
- ensuring the Corporation and its subsidiaries could operate in a commercially competitive business environment. (p. 3)

Edmund Martin, the CEO and President of NLH, became CEO and President of the new Energy Corporation. All of the directors of NLH became the first directors of the Energy Corporation.

The Energy Corporation was a new Crown corporation with NLH as its subsidiary. The purpose of this corporate structure was to separate NLH's regulated public utility business and activities from the unregulated activities to be undertaken by the Energy Corporation in the electricity and oil and gas sectors. NLH remained subject to the *Public Utilities Act*, RSNL 1990, c. P-47, but this legislation did not apply to the new Energy Corporation.

In May 2008, GNL introduced amendments to the *Energy Corporation Act* that would impact the public disclosure requirements of the corporation and the conditions under which its subsidiaries would operate. GNL had created the Energy Corporation with the intent that its subsidiaries could be separated into commercially competitive activities, such as oil and gas exploration, and public sector enterprises (including NLH and CF(L)Co). To inform its May legislative amendments, GNL looked to jurisdictions that had state-owned energy corporations, such as Norway and Denmark. The goal was to make the Energy Corporation publicly accountable while protecting commercially sensitive information that would allow it and its subsidiaries to operate in a competitive environment.

These amendments provided that Cabinet would direct the creation of any Energy Corporation subsidiaries and that such entities would be fully accountable to Nalcor's board of directors. Subsidiaries would only engage in business activities within the scope of the Energy Corporation's permitted business activities. GNL could also direct whether a subsidiary was to be an agent of the Crown. The intent was to limit the liability of both the Energy Corporation and GNL from risky commercial activities undertaken by subsidiary companies.

In order to protect the Energy Corporation's (and its subsidiaries') commercially sensitive information, GNL also introduced amendments to other pieces of legislation, including the *Access to Information and Protection of Privacy Act, 2015,* SNL 2015 c. A-1.2 (ATIPPA); the *Auditor General Act*, SNL 1991, c. 22; the *Public Tender Act*, RSNL 1990, P-45 (repealed) and the *Citizens' Representative Act*, SNL 2001, c. C-14.1.

On December 11, 2008, the Energy Corporation was renamed Nalcor Energy (P-00030). Its corporate structure is as follows:

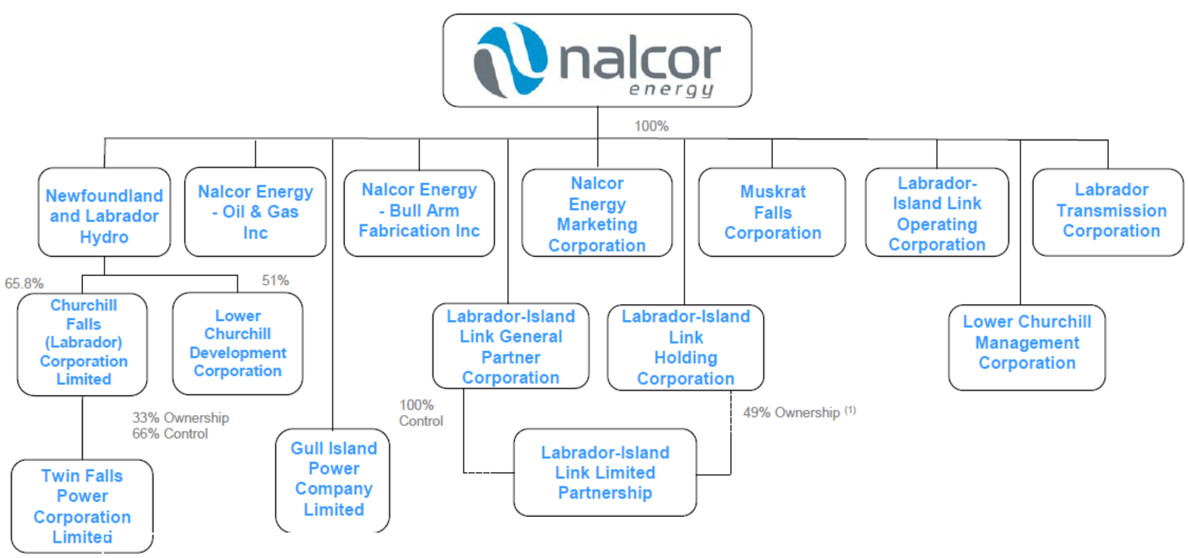


Figure 2.5: Nalcor Energy Corporate Structure (March 31, 2018)

Of note, the corporate structure shown in Figure 2.5 reflects the interests that Nalcor Energy holds in the regulated and non-regulated electricity sectors, various companies related to the Project, and other industry sectors (offshore oil and gas, energy marketing and fabrication).

In this Report, references to Nalcor may include any one or more of its subsidiary corporations as the context permits.

NALCOR'S EXECUTIVE

The members of Nalcor's executive who had direct involvement with the Muskrat Falls Project were Edmund Martin, Chief Executive Officer and President, Gilbert Bennett, Vice-President, Lower Churchill Project, and Derrick Sturge, Vice-President and Chief Financial Officer. A summary of the education and work history of these three individuals follows.

Edmund Martin

Edmund Martin graduated from Memorial University with a Bachelor of Commerce degree in 1980 and from the University of Calgary with an MBA degree in 1988. In early 2005, Mr. Martin applied for the positions of President and Chief Executive Officer of Newfoundland and Labrador Hydro. He was interviewed by the NLH board of directors and by Premier Danny Williams. The board appointed him to these positions in August 2005. During his testimony, Mr. Williams stated that he provided the final signoff for the hiring of Mr. Martin.

Prior to joining NLH, Mr. Martin had worked for more than two decades in the oil industry in Canada. This work included holding various senior positions with Mobil, Hibernia Management and Development Company and Petro-Canada. Immediately before joining NLH, he was employed by Petro-Canada in St. John's as Manager, Joint Ventures. He was a member of the East Coast senior leadership team with responsibility for managing Petro-Canada's interests in Hibernia, Terra Nova, White Rose, Hebron and other new developments, as well as shuttle tankers and the Newfoundland Transshipment Limited crude oil terminal. Mr. Martin was also Petro-Canada's representative on the Hibernia Executive Committee, the White Rose Management Committee and the Hebron Management Committee and was a board member of Newfoundland Transshipment

Limited and Chair of the offshore oil companies' joint Regional Tanker Steering Committee. Prior to joining Petro-Canada, he had been the Chief Financial Officer and the Lifting and Transportation Manager with the Hibernia Management and Development Company.

Mr. Martin's approximately 25 years of work in the oil industry consisted mainly of the management of financial, business and other commercial matters. It appears that he did not have any direct involvement in significant engineering, construction or project-management endeavours. Of note, Mr. Martin did not have any prior experience with hydroelectric or transmission line projects.

Gilbert Bennett

Gilbert Bennett graduated from Memorial University with a Bachelor of Engineering (Electrical) degree in 1986. From 1986 to 2005, he held a series of senior positions in the telecommunications industry. He was involved primarily with network planning, network design, business case analysis, operations and engineering design. Before joining Nalcor, the largest project that he had worked on was a $100 million network rebuild while he was employed by Cable Atlantic.

In early 2005, Mr. Bennett was approached by Dean MacDonald, the Chair of the NLH board of directors. Mr. Bennett had worked previously with Mr. MacDonald at Cable Atlantic. Mr. MacDonald advised Mr. Bennett that NLH was looking to fill a position to initiate the preliminary planning process for hydroelectric development along the lower Churchill River. There was no job posting or interview process for this position. In his testimony, Mr. Bennett said he did not know whether other candidates were interviewed or considered for this position.

In May 2005, Mr. Bennett was appointed as Vice-President, Lower Churchill Project. Mr. Bennett had no prior experience in hydroelectric or transmission line projects and had no experience in construction management. He had not worked on any megaprojects prior to joining Nalcor. Mr. Bennett continued in his position until June 2016 when, upon the appointment of Stan Marshall as President and CEO of Nalcor, he became Executive Vice-President, Power Development.

Derrick Sturge

Derrick Sturge graduated from Memorial University with a Bachelor of Commerce degree in 1982 and from Durham University (England) with an MBA degree in 1996. He is a Certified Professional Accountant.

Mr. Sturge began his career at Touche Ross, a public accounting firm. Thereafter he worked in various businesses in the field of financial management. This work included employment with NLH as Manager of Internal Audit (1989) and later as Director of Rates, Customer Service and Financial Planning (1990 to 1996). From 1996 to 2006, he held senior financial positions at Voisey's Bay Nickel Company, CHC Helicopter Corporation and Deloitte. He assumed the position of Vice-President and Chief Financial Officer of Nalcor in 2006. Mr. Sturge was not directly involved in the construction phase of the Project but was responsible for arranging its financing and for general financial oversight of Nalcor's operations.

Nalcor's Board of Directors

At the time of Project sanction in 2012, the members of Nalcor's board of directors were Terry Styles (Chair), Ken Marshall, Gerry Shortall, Tom Clift, Leo Abbass, Erin Breen, Allan Hawkins and Edmund Martin. Mr. Marshall, Mr. Shortall and Mr. Clift were on the initial Nalcor board and each had served for more than eight years. Mr. Styles was appointed a director and board Chair in June 2012, six months before Project sanction. During the time Mr. Martin served on the board, he was not considered to be an independent director because he was also President and CEO of Nalcor.

Mr. Martin controlled communications between Nalcor's executive and its board of directors. He ultimately decided which documentation and other information would be provided to the board when it was considering a resolution or other matters. From time to time, Mr. Martin would be accompanied at board meetings by Gilbert Bennett, Derrick Sturge or other members of the executive or Project Management Team, which was responsible for the management of the Lower Churchill Project.

From my review of the evidence of Mr. Marshall, Mr. Shortall and Mr. Clift, it is clear that they spent long hours in discharging their duties and in reviewing voluminous documents they would receive in preparation for board meetings. This was particularly so during the Project development phase. In addition to sitting on the board of Nalcor and its subsidiaries, they were also members of various board subcommittees. Mr. Marshall and Mr. Shortall both estimated that they spent approximately 100 hours a month in the discharge of their board duties, while Mr. Clift and Mr. Styles indicated that they spent about 80 hours a month, during the months leading up to Project sanction and also during the Project's construction phase (October 15, 2018, transcript, pp. 15–17).

For the most part, Nalcor's independent directors were experienced business people. In addition, Mr. Shortall certainly had significant finance and accounting experience. These independent directors did not receive appropriate financial compensation or other benefits for their services as directors and as board committee members. They were essentially volunteers who received only a modest stipend for the work they did.

Early on, the independent directors recognized that there were too few directors on the Nalcor board and that the board lacked expertise in the areas of large-scale engineering projects, international projects, finance, accounting and labour relations. The board wrote to GNL on September 2, 2008, outlining these concerns (P-00395, p. 1). In October 2008, both GNL and Mr. Martin advised the board that the compensation issue would be addressed, but nothing ever materialized (P-00395, p. 1). In January 2012, Mr. Clift wrote Robert Thompson, then Clerk of the Executive Council of GNL, identifying several of the board's concerns (P-00395, p. 1). GNL did not address any of the concerns expressed at the time.

The issue of compensation was obviously important, not only because it would provide remuneration to existing board members for the time they were spending on Nalcor business, but also because it would support the recruitment of new board members who had the expertise that was missing on the board. At the time of writing this Report, the issue of compensation still has not been addressed by GNL.

GNL expected the board members to provide oversight and good judgment and to exercise their fiduciary duty, even though GNL was fully aware that the board lacked the ability to adequately do so. I am satisfied that all directors made sincere and dedicated efforts to properly discharge their duties. It is clear, however, that collectively the board lacked the necessary knowledge and expertise to effectively challenge management and to appropriately oversee the sanctioning and execution of the Project.

Nalcor's Core Project Management Team

The core members of Nalcor's Project Management Team at the time of Project sanction (2012) were:

Paul Harrington	Project Manager and Project Director
Ronald (Ron) Power	Deputy Project Director, Muskrat Falls Generation Project
Jason Kean	Deputy Project Manager, Labrador-Island Link
Scott O'Brien	Project Manager, Muskrat Falls Generating Station
Lance Clarke	Business Services Manager, Lower Churchill Project
Patrick (Pat) Hussey	Supply Chain Manager
Darren DeBourke	Project Manager, HVdc Specialties

Based on the evidence, I find that these individuals had the primary responsibility for the development and construction of the Project on behalf of Nalcor. Their backgrounds and how they came to be hired are described below.

Paul Harrington

Paul Harrington is registered with the Engineering Council of the United Kingdom and is a Fellow of the Institute of Measurement and Control, UK. He has more than 25 years' experience working on megaprojects in Europe and Canada (P-01156; November 19, 2018, transcript, pp. 2–3), which includes management positions on the following:

- 1977 to 1987: offshore oil projects in Norway
- 1987 to 1991: a large magnesium project in Bécancour, Québec
- 1991 to 2000: the Hibernia offshore oil project
- 2000 to 2005: various oil projects, including Terra Nova and White Rose

At the hearings, Mr. Harrington was questioned on his work history and the level of responsibility he had on other projects, in particular Hibernia. He testified (November 19, 2018, transcript):

> **MS. O'BRIEN:** Okay, and if you could just for the Commissioner—the previous work that you'd done—in what previous position did you have that was closest

in scope and responsibility to that that you eventually took on with the Lower Churchill Project.

MR. HARRINGTON: I would say the Hibernia Project, just because of its sheer size, its, you know, its complexity, the fact that it was, you know, being fabricated in various module yards across the world, and we needed to get the very tight procedures—project management procedures—in place to develop a project management system that would ensure consistency of application of all of these procedures in all of the module yards and the Bull Arm site as well. So that was our role to make sure that we were basically the home office tying all that together.

MS. O'BRIEN: Okay. So at—on the Hibernia Project, what specifically was your title?

MR. HARRINGTON: I was the—initially, the mechanical completion or completions manager—or completions lead I think they used to call it then, and then I was the deputy RFO [ready for operation] manager.

MS. O'BRIEN: So as deputy RFO manager, who did you report up to—what position?

MR. HARRINGTON: It was—he was the RFO manager himself, right? So—gentleman called Troels Erstad. (p. 3)

In the fall of 2005, Mr. Harrington was contacted by Edmund Martin. Mr. Harrington had known Mr. Martin since 1992, when they had worked together on the Hibernia project. He later worked with Mr. Martin on the Terra Nova project. Mr. Martin requested that he attend a day-long "brainstorming session" to discuss the formation of a team to work on the implementation of plans for a hydroelectric development on the lower Churchill River. In addition to Mr. Martin and Mr. Harrington, the session was attended by Brian Crawley, Paul Humphries and Gilbert Bennett, among others.

Before the end of 2005, Mr. Harrington was appointed Project Manager and Project Director for the Lower Churchill Development. He worked as an independent contractor, not as an employee of Nalcor. There was no job posting or interview process put in place for this position. Mr. Harrington was simply selected for the position. From the evidence, it appears that no other candidates were considered. Although Mr. Harrington had experience working on megaprojects, he had no previous experience as the lead project manager or project director of a megaproject. Furthermore, he had no previous experience in either the construction of hydroelectric or transmission projects or the pre-sanction assessment of strategic risks for megaprojects.

He testified that the work he had done that was closest in scope and responsibility to the Project was at Hibernia. There he acted as the Mechanical Completions Manager and thereafter as Deputy Ready-for-Operations Manager. It is clear that his scope of work and level of responsibility at Nalcor was significantly greater than his scope of work and responsibility at Hibernia.

Ronald (Ron) Power

Ron Power graduated from Memorial University with a Bachelor of Engineering (Civil) degree in 1977. Between 1977 and 2011, he worked on various hydroelectric projects in the province, including Granite Canal, Silver Mountain, Paradise River, Island Pond, Cat Arm and Hinds Lake, and also primarily in engineering and design positions on non-hydroelectric projects. The work he performed for these projects was varied (P-03676; May 21, 2019, transcript, pp. 2–10), as the following list details:

- Granite Canal: preparation of a feasibility study and management of a final field investigation program
- Silver Mountain: preparation of a feasibility study
- Paradise River: resident construction manager
- Island Pond: feasibility study work
- Cat Arm: feasibility, design and survey work
- Hinds Lake: civil design activities

From 1990 to 1992, Mr. Power worked as a construction engineer and then a construction manager on a project to rehabilitate control structures for the Churchill Falls generating station. Earlier, between 1982 and 1986, he was a construction engineer on the intake structure, and an area construction manager for the powerhouse and intake structure for a 560 MW hydroelectric project in Jebba, Nigeria. In 1991, he worked for two to three months as a project engineer on a right-of-way clearing program connected to the relocation of two transmission lines over a distance of 8 to 10 kilometres at the Marble Mountain ski resort.

In 1993, Mr. Power began working in the Newfoundland and Labrador offshore oil and gas industry. Initially he was involved in the design of the gravity base structure for Hibernia. He then began to work on the Terra Nova project, where he was an Interface Manager initially and later became involved in operations and construction management.

Mr. Power was recruited to the PMT by Jason Kean. He had previously worked with Mr. Kean, Paul Harrington, Scott O'Brien and Pat Hussey on the Terra Nova offshore oil project. In January 2008, Mr. Power joined Nalcor as an independent contractor. In 2016, he was appointed Deputy Project Director for the Muskrat Falls generation project.

<u>Jason Kean</u>

Jason Kean graduated from Memorial University with a Bachelor of Engineering (Mechanical) degree in 1998 and received an MBA degree from Memorial University in 2010. From 1998 to 2007, he worked in various engineering positions in the province's offshore oil industry (P-00954; November 7, 2018, transcript, pp. 34–36), including the following:

- 1998 to 2000: Facilities Engineer at Petro-Canada, planning phase Terra Nova
- 2000 to 2001: Facilities Engineer at Petro-Canada, Offshore Development and Operations
- 2001 to 2002: Future Developments and Strategic Technology Coordinator at Petro-Canada
- 2002: Asset Lead at White Rose
- 2005: Project Services team lead, Terra Nova project

In the summer of 2006, Mr. Kean had discussions with Mr. Harrington about job possibilities at Nalcor. He had known Mr. Harrington from the offshore energy industry. In September 2006, following up on a job posting in *The Telegram*, Mr. Kean applied for a position at Nalcor. He was interviewed and appointed to the position of Project Services Manager in early 2007. He, too, was hired as an independent contractor. In 2011, he was appointed the Deputy Project Manager for the LIL and he continued in that capacity until late 2016, when he became Project Manager, Overland Transmission Lines. He resigned his position in January 2017.

<u>Scott O'Brien</u>

Scott O'Brien graduated from Memorial University with a Bachelor of Engineering (Civil) degree in 1996. He went on to earn a Master of Engineering (Ocean Engineering) degree from Memorial in 1998.

In his testimony, Mr. O'Brien indicated that his work experience included the following:

- 1995: Hibernia, Weight Control Group
- 1997: Subsea Group oversight, lead engineering role and project manager for second phase of capital expansion, Terra Nova project
- 2001: Project Manager for subsea components of expansion project with oversight of manufacturing activities, Petro-Canada/Terra Nova Alliance
- 2002: forensic investigative role, Engineering and Technology Group with a focus on managing major projects on the east coast
- 2003: contract documentation and policy procedures for Terra Nova Far East Development
- 2004: subsea facilities lead for Petro-Canada's engineering and technology group
- 2005: project manager in an offshore subsea repair campaign
- 2006: pipeline manufacturing manager, North Amethyst project with Husky
- 2009: support roles on the Hebron project with Chevron (P-03862, pp. 53–56; May 30, 2019, transcript, pp. 62–67).

In early 2011, Ron Power asked Mr. O'Brien to submit a resumé to Nalcor. Mr. O'Brien had previously worked with Mr. Power on the Terra Nova project and he also knew Edmund Martin, Paul Harrington, Jason Kean and Lance Clarke from previous work engagements.

Mr. O'Brien joined Nalcor as an independent contractor in March 2011. In 2012, he was appointed Project Manager for the construction of the Muskrat Falls generating station, a position he continues to hold at this writing.

Lance Clarke

Lance Clarke graduated from Memorial University with a Bachelor of Commerce degree in 1994. From 1994 until 1997, he held a series of positions in the NL civil service.

From 1998 through 2007, he held several commercial positions in the province's offshore oil and gas industry and in the Alberta oil industry (P-03791; May 23, 2019, transcript, pp. 2–4).

In early 2007, Mr. Clarke applied for a position at Nalcor after reading a job posting. He was interviewed by a group of Nalcor representatives that included Mr. Harrington. Mr. Clarke had worked with Mr. Harrington previously on the White Rose project. In March 2007, he was hired by Nalcor as an independent contractor. He was appointed Business Services Manager for the LCP and remained in that position until he resigned in November 2017.

Patrick (Pat) Hussey

Pat Hussey graduated from Memorial University with a Bachelor of Arts (Economics) degree in 1976 and with a Bachelor of Commerce degree in 1979. From 1980 to 2007 he worked in the supply chain management field in eastern Canada, in the offshore oil and gas and the mining industries (P-02091; March 1, 2019, transcript, pp. 2–3). This work included assignments on the Hibernia, Terra Nova and Sable Island projects.

In 2007, Lance Clarke informed Mr. Hussey that Nalcor was looking for a lead for the Project's supply chain management. Mr. Hussey had worked previously with Mr. Clarke and Jason Kean on the Terra Nova project. Mr. Hussey applied to Nalcor and in June 2007 he was appointed Supply Chain Manager. He, too, worked as an independent contractor.

Darren DeBourke

Darren DeBourke graduated from Northeastern University with a Bachelor of Science (Mechanical Engineering) degree. He worked for approximately 25 years in the energy sector, including assignments on the Sable Island, Terra Nova and Hibernia offshore projects (May 10, 2019, transcript, pp. 1–2).

In 2011, Mr. DeBourke was asked by an employment agency to apply to Nalcor for the position of Area Manager. He was interviewed and in September 2011 was appointed to the position. He was later promoted to the position of Project Manager, HVdc Specialties. He remained in that position until he resigned in November 2016. He worked in these positions as an independent contractor.

Based on the evidence, I make the following comments on the experience and expertise of the core PMT members. I accept that each of the core members worked in some capacity on megaprojects, particularly in the oil and gas industry. What is clear though, is that none of the core members of the PMT had worked in positions equivalent to, or at such senior levels, as they did for this Project. For these reasons, while no doubt they were hardworking and intelligent individuals, I do not accept that they were highly experienced in project management to the degree that was required for their positions on this Project.

Also, with the exception of Ron Power, the core members of the PMT had no experience with hydroelectric or transmission line projects. Mr. Power's experience in these fields had been acquired many years earlier and does not appear to have been at the senior management level that he took on for this Project. I note that he did work on the Jebba project in Nigeria from 1982 to 1986. This would have been five years after he obtained his BEng degree. As well, the experience that Mr. Power indicates he acquired from working on other hydroelectric projects in NL does not appear to have been at any similar top-management level. The two or three months of experience that he gained while working on the Marble Mountain right-of-way transmission project in 1991 would have been of minimal, if any, benefit to him in his role on the Project.

Partly in recognition of the fact that the core members of the PMT, with the exception of Ron Power, had no experience in the construction of a hydroelectric generating station and transmission lines, Nalcor eventually deemed it necessary to retain SNC-Lavalin Inc. as the Project's engineering, procurement and construction management contractor. With this assignment, SNC was responsible for providing all project design, engineering, procurement, contract administration and construction management on all components of the Project, with the exception of work on the Strait of Belle Isle undersea cable installation. Based on the evidence, SNC was chosen because of its extensive experience and contemporary knowledge of the engineering, planning and construction of hydroelectric projects.

SNC was awarded the EPCM contract on February 1, 2011. Shortly thereafter, Nalcor's PMT became dissatisfied with SNC's performance. Nalcor's PMT proceeded to steadily downgrade SNC's role as the EPCM contractor and, over time, introduced an Integrated Management Team model to manage the Project. In that model, the members of the PMT became key decision makers for the Project. These changes took place during 2011 and 2012, but it was not until March 12, 2013, that Gilbert Bennett advised Project staff of the change from the EPCM model to an IMT model.

From my perspective, while members of the PMT had worked previously on megaprojects, mostly in the offshore oil and gas industry, they definitely did not have the level of experience and knowledge that SNC had and that was required for the management of this hydroelectric project. In this regard, shifting the management role to the PMT was not in the best interests of the Project.

Despite the PMT's lack of experience with hydroelectric and transmission line projects, my review of the evidence indicates that the PMT, at times, exhibited a culture of superiority when confronted on issues that arose during the construction phase of the Project. The evidence indicates that members of the PMT often exhibited a "we know best" attitude on matters related to the Project. Consequently, I find that individuals working on the Project who did have the requisite experience in hydroelectric and transmission line construction were not adequately consulted, nor was their advice properly adopted on many occasions. The transition from an EPCM model under SNC to an IMT model resulted in added risk to Nalcor, which it appears to have largely ignored.

Individuals such as Normand Béchard of SNC, who had extensive hydroelectric project management experience, would have contributed to the success of the Project construction had they been properly utilized.

John Mulcahy is a professional engineer with more than 50 years' experience in heavy construction. During his career, Mr. Mulcahy worked in senior management positions on the construction of more than a dozen hydroelectric generating stations in Canada including, in Newfoundland and Labrador, on Paradise River, Upper Salmon, Hinds Lake, Cat Arm, Star Lake and Granite Canal. In 2010, Ron Power asked Mr. Mulcahy to come out of retirement to work on the Lower Churchill Project. He accepted this offer and was appointed to the position of Hydroelectric Construction Specialist.

Mr. Mulcahy testified that it was "very critical" for the most senior people on the construction site to have hydroelectric construction experience (May 2, 2019, transcript, p. 4). Based on the personal observations he made, including during visits to the Muskrat Falls site, the PMT lacked this necessary experience. While he agreed that it was less important for Paul Harrington (the Project Director) to have hydroelectric experience than those making day-to-day decisions on construction issues, Mr. Mulcahy was certain that persons occupying the positions held by Ron Power and Scott O'Brien required this experience and also that such personnel should have been present on site more often. Mr. Mulcahy was aware that Mr. O'Brien had no previous hydroelectric experience and believed that the experience of Ron Power in on-site hydroelectric construction management was not extensive.

Dr. Bent Flyvbjerg, who was qualified to give expert opinion evidence on megaprojects, was asked to comment on whether the skills and experience of project management personnel in the oil and gas sector could be transferred from those types of projects to a hydroelectric dam and transmission line project. Dr. Flyvbjerg responded (September 17, 2018, transcript):

> I would say, yes, a lot of skills can be transferred and it would be a huge advantage that, if you are working on any megaproject, that you worked on another megaproject before. That being said, however, I would say that there would also need to be people on the team who have specific domain experience from the—from dams, if you're building a dam. And so it would increase the risks if you took, let's say, two situations.
>
> One situation: You have people who are—you only have people who build oil and gas projects before now doing a dam. That's one situation. The other is that you have people who build oil and gas but you also have people who have built dams before—large dams before—on the team. The first team would face larger risks than the second team, because the second team has domain experience from the specific type of project that they are actually building. (p. 20)

I accept the opinion of Dr. Flyvbjerg on this issue. I am satisfied that the core members of Nalcor's PMT had experience working in oil and gas megaprojects. While not as extensive as portrayed by some, this experience likely did provide some advantage that could be transferred to the Project. Further, I am aware that Nalcor and SNC supplied personnel to the Project, including skilled construction managers, who had significant experience in the construction of hydroelectric generating stations and other Project components, to supplement the lack of hydroelectric development experience among members of the PMT.

Nevertheless, I do not accept that this level of prior work experience or the addition of other personnel with hydroelectric experience can in any way be regarded as a substitute for the lack of senior project management experience and the lack of hydroelectric and transmission experience of the PMT's core members. I conclude that it likely did contribute to cost overruns and schedule delays.

The Province's Lower Churchill and Energy Policies

Following DG2, Nalcor saw the Muskrat Falls Project as the best way to implement two different government policies:

- The Province's Lower Churchill policy, which required Nalcor to develop the lower Churchill River's hydroelectric resources
- The Province's energy policy, which required NLH to provide electrical energy at the lowest cost consistent with reliable service

The Province's Lower Churchill Policy

As stated earlier, developing the lower Churchill River was a major element of Danny Williams' 2003 campaign platform (P-00277) and subsequently formed a key part of the Province's 2007 Energy Plan (P-00029). The focus was on the importance of capturing the full value of the natural resource, regardless of whether the power was to be used for export or to support domestic needs.

The Project represents only a partial fulfillment of the Province's Lower Churchill policy. In fact, if Muskrat Falls were the only generation opportunity on the lower Churchill, it is questionable whether there would even have been a Lower Churchill Project. Muskrat Falls has only a fraction of the lower Churchill's potential. The Gull Island site offers far more energy and capacity at a significantly lower unit cost. It is primarily the transformative potential of the larger Gull Island site that has inspired generations of political leaders. However, by 2010, with no market for Gull Island power, the Project was the only part of the Province's Lower Churchill policy that seemed achievable.

The Province's Energy Policy

The Province's current energy policy is set out in the *Electrical Power Control Act, 1994*, SNL 1994, c. E-5.1, s. 3. It has remained largely consistent since 1994 and reads, in part (P-00087):

> 3. It is declared to be the policy of the province that
>
> . . .
>
> (b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner

> (i) that would result in the most efficient production, transmission and distribution of power,
>
> (ii) that would result in consumers in the province having equitable access to an adequate supply of power,
>
> (iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service,
>
> (iv) that would result in, subject to Part III, a person having priority to use, other than for resale, the power it produces, or the power produced by a producer which is its wholly-owned subsidiary,
>
> > (iv.1) that would result in open, non-discriminatory and non-preferential access to, interconnection with and service on the integrated electric system,
>
> (v) where the objectives set out in subparagraphs (i) to (iv) can be achieved through alternative sources of power, with the least possible interference with existing contracts,
>
> and, where necessary, all power, sources and facilities of the province are to be assessed and allocated and re-allocated in the manner that is necessary to give effect to this policy; (pp. 6–7)

The energy policy contains intrinsic ambiguities. As was pointed out by expert witnesses Pelino Colaiacovo of Morrison Park Advisors and A.J. Goulding of London Economics International LLC, the *Electrical Power Control Act, 1994* is unclear on what constitutes "reliable service." Additionally, when one generation plan is expected to have lower costs in the short run and another is expected to have lower costs in the long run, which is "the lowest possible cost"? And how does risk factor into the "lowest possible cost" analysis?

In practice, these theoretical questions are usually resolved by the Public Utilities Board, which interprets the Province's energy policy on a case-by-case basis. The vagueness of the Act's wording, in fact, is a common legislative approach to unanswerable questions. Thus instead of trying to decide in the abstract how to balance the interests of one generation against another, how to deal with risk and uncertainty, and how much reliability we can afford, the legislature has handed a vague statement of principle to the PUB, a quasi-judicial decision maker, and left the PUB to work out answers one case at a time.

The Muskrat Falls Project, however, was exempted from ordinary review by the PUB. Because of this exemption, the Province's energy policy became more of a political commitment than a legal one. The responsibility for interpreting the energy policy's vague statements about "reliable service" and "lowest possible cost" passed to Nalcor and to the provincial civil service. As will be seen, both entities had reason to interpret the ambiguities inherent in the Province's energy policy in favour of the Project.

During the lead-up to Project sanction, it was possible for Project proponents to advocate for the Project without emphasizing NL's energy policy. In fact, when the Project was first announced in November 2010, the emphasis was on its broad economic, environmental and strategic benefits. The prospect of lower rates was one small part of the business case and the Province's energy policy was rarely, if ever, mentioned (P-00036).

In 2011 and 2012, however, as GNL faced key decisions, the narrative shifted toward emphasizing the Province's energy policy. Despite the Exemption Order that excluded the Project from PUB scrutiny, Premier Kathy Dunderdale and Minister of Natural Resources Jerome Kennedy repeatedly stated at the time that the Project would only be sanctioned if it provided the "lowest possible cost" for securing the Province's energy needs. The decision to proceed with the Project became a more traditional utility-based decision.

Even after the Province's energy policy became a significant test of the business case for the Project, as well as a larger factor in the Project sanction decision for GNL, Nalcor continued to emphasize the additional benefits of the Project to both GNL and the public. Most notably, Nalcor prepared a "net benefits" analysis that quantified the total benefits of the Project at $61.8 billion over its life (P-00254). I discuss this net benefits analysis in more detail in Chapter 4. After 2010, the broader economic benefits of the Project were always framed as an additional benefit rather than as the reason for sanction. The decision to sanction turned on the Province's energy policy.

Today, cost overruns and schedule delays, low loads and low fuel prices have all undermined the Project's claim to provide the lowest-cost way to meet the province's energy needs. Project advocates such as Danny Williams, Kathy Dunderdale and Edmund Martin sought in their testimony to change the scoring criteria that supported Project sanction, focusing now on whether the overall benefits of the Project justify the overall cost, or on whether sufficient rate mitigation is available to compensate ratepayers.

These alternative questions are interesting and are considered to some extent later in this Report. Perhaps GNL and Nalcor could have successfully presented the business case in 2011 and 2012 without emphasizing the Province's energy policy. But these alternative questions were not the test that the Project's proponents set for themselves at the time. The decision to sanction must be judged primarily by the standards that were chosen by the Project's proponents and presented to the public and to the House of Assembly. It is now too late to change the rubric.

In theory, the Project could have both achieved the Province's Lower Churchill policy goals and fulfilled its energy policy. It might have been the best way to develop the lower Churchill and the lowest-cost way to meet the province's upcoming electrical generation needs. But this could only have come about through a happy coincidence and not by necessity.

In particular, the Project could easily have been the best way for Nalcor to develop lower Churchill hydroelectricity without providing power to ratepayers at the lowest cost consistent with reliable service. From some perspectives, this was almost certain to be the case. The Project's high upfront cost meant that it could only be paid off over a long period of time. In the short term, it would never be the lowest-cost option, even if it had come in ahead of schedule and under budget. Only in the long run could it possibly be the lowest-cost option.

For as long as the Project actually was the best way to implement both policies, the path forward was clear for Nalcor and GNL. When the two policies began diverging, however, Nalcor and GNL would have had to choose between developing the lower Churchill or providing electricity to the province at the lowest possible cost. Neither Nalcor nor GNL were interested in abandoning or modifying either policy, however. This created an incentive to focus on perspectives from which the Project *seemed* to meet both policy objectives, rather than on the realities and perspectives that required difficult choices.

CHAPTER 3: THE OPTIONS CONSIDERED

The business case to inform a decision about whether to proceed with the Project as it was presented to the public and the House of Assembly between 2010 and 2012 focused on comparing the cost of two different plans to meet the Island's energy needs. The first plan, called the Interconnected Island Option, centred on the development of the lower Churchill River. The second, the Isolated Island Option, met the Island's energy needs without building a transmission line between Labrador and Newfoundland. The business case consisted of the proposition that the Interconnected Island Option met the Island's energy needs at a lower overall cost.

The comparison between an "infeed" scenario (a hydro project in Labrador and a long transmission line) and an isolated scenario (without these elements) had a long history. Newfoundland and Labrador Hydro had been performing essentially this exercise since at least the 1980s. Sometimes the proposed Labrador hydro project was to be Gull Island, at other times it was to be Muskrat Falls.

Even though NLH had been performing this particular comparison for a long time, it was not necessarily the best way to analyze the Project's business case, in my view. Many of the deficiencies inherent in the comparison are reviewed in this Report. However, it is important to note that the fundamental premise underlying the comparison was that the Interconnected Island Option and the Isolated Island Option, as prepared, were the two best ways to meet the Island's generation needs.

If that premise had been true, then the cheaper of these two options, as presented, would be the lowest-cost way to meet the province's future energy needs. From my point of view, this was unfortunately not true.

THE SCREENING PROCESS

Nalcor arrived at these two options by creating a list of potential generation options and then screening out the ones it did not consider viable. That exercise was the first step in a two-step screening process. Nalcor's evaluating factors included principles of security and reliability, cost to ratepayers, environmental considerations, risk and uncertainty and the financial viability of any non-regulated elements (P-00014, p. 14; P-00077, p. 4).

I accept that many options were reasonably screened out during the first analysis step. Nuclear power was illegal in the province. Coal was being phased out in other provinces for valid environmental reasons (P-00077, p. 72). Solar generation was far from cost-effective, given the Island's latitude and cloud cover (P-00077, pp. 88–89). Wave and tidal generation, at the time, cost three to four times as much as wind generation (P-00077, p. 92). Biomass generation was seen as inherently expensive because of the need to maintain and harvest wood (P-00077, pp. 84–85).

Grand Banks natural gas, liquefied natural gas, Churchill Falls power after 2041 and imports from Québec were also removed from consideration. The rationales for screening out these options are analyzed below, as are the decisions to limit the amount of wind generation and additional Island hydro sources.

In addition to the Project, the following five options/assets also passed through the first screening process.

1. <u>The Holyrood Generating Station</u>

The Holyrood thermal generating station has three steam-powered turbines that burn heavy fuel oil. This station has been a cornerstone of the Island's electrical system for decades. During winter months, Holyrood contributes 465.5 MW of firm generating capacity to help meet Island peak loads. It has a firm energy capability of 2,996 gigawatt hours (GWh) per year (P-00077, p. 73), though in practice its production varies significantly from year to year. To minimize fuel costs, NLH has been using resources to replace Holyrood production, including, recently, imports over the Maritime Link.

By 2012, Holyrood was considered to be near the end of its useful life. Two of its three units had been in service since 1971 and the third since 1979 (P-00077, p. 73). Exactly when its useful life would end, however, was uncertain. Holyrood operated seasonally, which could extend its useful life. On the other hand, it faced harsh marine conditions that could shorten its life.

In addition to the greenhouse gases that Holyrood emitted, it produced considerable local air pollution, particularly sulphur dioxide. By 2012, NLH had been reducing Holyrood's pollution levels by using more expensive low-sulphur fuel. If Holyrood's life were to be extended to 2035, Nalcor planned to install electrostatic scrubbers and precipitators to further reduce pollution, which would enable it to revert to using cheaper but dirtier fuel. The estimated cost to install scrubbers and precipitators was $602 million (P-00077, p. 75).

Beyond the expense of installing scrubbers and precipitators, Nalcor estimated that extending the life of Holyrood into the mid-2030s would cost an additional $233 million (P-00077, p. 75). Thus the total cost of refurbishing Holyrood ($835 million) would be more than the cost of building a new modern plant. Notwithstanding this, I have no basis to disagree with the evidence of Paul Humphries, a member of Nalcor's System Planning division, that the estimated capital expense would have been justified by cheaper fuel costs.

In the lead-up to Project sanction, during the PUB's efforts to respond to GNL's 2011 Reference Question, several parties suggested that air pollution from Holyrood could be more cheaply addressed by using low-sulphur fuel rather than by installing expensive scrubbers and precipitators. The cost/savings of that suggestion would depend, however, on how much fuel Holyrood would be consuming. The more power Holyrood produced, the greater the cost of fuel and the more critical would be the mitigation of air pollution. I find that Nalcor's approach to Holyrood was generally reasonable. However, as I discuss later, if other parts of the composition of the Isolated Island Option were changed, replacing Holyrood with a modern plant could have been attractive.

An important feature of Holyrood is its "thermal minimum." Its steam turbines heat up slowly and need to be kept warm once heated. Consequently, Holyrood is operated continuously from October to March, sometimes producing more power and sometimes less but always burning some fuel. This is different from combined-cycle combustion turbine plants, which can ramp up and down more quickly. As a result, when it is operating, Holyrood's thermal minimum requirement limits the amount of wind generation that can be economically integrated into the grid.

2. <u>Simple-Cycle Combustion Turbines</u>

Simple-cycle combustion turbines use natural gas or light fuel oil to generate electricity. They are mechanically simple with low construction and maintenance costs. These combustion turbines "can be started, connected to the power system and loaded to [their] rated output in minutes" (P-00077, p. 77). This makes combustion turbines a cost-effective way to meet peak load demands and to provide backup generation.

On the other hand, simple-cycle combustion turbines use fuel less efficiently than steam turbines or combined-cycle turbines. When used for long periods, they become an expensive source of energy. Therefore, they are best used to meet peak loads and to provide backup generation.

3. Combined-Cycle Combustion Turbines

A combined-cycle combustion turbine consists of a combustion turbine, a heat-recovery system generator and a steam-cycle turbine. A combined-cycle plant has higher construction and operating costs than a simple-cycle combustion turbine, making it a more expensive way to meet peak loads. However, this type of turbine produces energy more efficiently and can operate more economically. Combined-cycle combustion turbines are thus suitable for providing base load power over protracted periods.

4. Island Hydro Sites

Three Island hydro sites also passed screening as potential generation options at DG2 and DG3: Island Pond, Round Pond and Portland Creek.

Island Pond is located on the North Salmon River within the watershed of the Bay d'Espoir hydroelectric development. If it were to be developed, its generating station could draw water from both Island Pond itself and the existing Meelpaeg Reservoir. A 36 MW hydroelectric development would be capable of producing approximately 172 GWh of annual firm energy (P-00077, pp. 94–95).

Round Pond is also within the Bay d'Espoir watershed, downstream of the Upper Salmon generating station and upstream of the main Bay d'Espoir Plant. If developed, it would be an 18 MW facility that would generate approximately 108 GWh of annual firm energy (P-00077, p. 97).

Portland Creek is on Main Port Brook, near Daniel's Harbour on the Great Northern Peninsula. If developed, it would be a 23 MW facility that would generate 99 GWh of annual firm energy (P-00077, p. 96).

These three were the only Island hydro sites screened in by Nalcor, notwithstanding that others existed in the NLH inventory. I discuss Nalcor's decision to screen out other hydro sites later in this chapter.

5. Wind Generation

Wind generation has the great advantage of producing clean energy cheaply in all seasons of the year. It has the great disadvantage of being intermittent—it is only available when the wind is blowing. In contrast, thermal plants and hydroelectric facilities with reservoirs are "dispatchable," which means they can be turned on or off, up or down, as needed.

In the Interconnected Island Option, power generated by the lower Churchill in Labrador would produce so much energy that the Island would have little need for wind generation. In the Isolated Island Option, in contrast, wind generation was expected to produce energy at a significantly lower cost than thermal generation. The fundamental question became—how much wind generation could be economically and reliably integrated into the Isolated Island Option?

At DG2, Nalcor limited total additional wind capacity to 80 MW (P-00077, p. 82). At DG3, it re-evaluated that conclusion and determined that the system could take an additional 50 MW every five years until it reached a peak of 229 MW of total wind-generated capacity in 2030. This limit on wind generation is also discussed below.

"Optimizing" the Two Options: The Strategist Program

In the second step of Nalcor's screening process, the various generation options that had passed initial screening were assembled into two plans. The details of these plans were determined using a computer software program called Strategist. There was evidence that many public utilities use Strategist to optimize their energy generation plans. The program calculates and minimizes the cost of meeting anticipated energy demand for every hour of every year, suggesting what new generation assets should be built and when.

Strategist optimizes perfectly—based, of course, on the assumptions used to run it. Strategist depends on the utility to identify all viable generation options and to accurately estimate capital, operating and fuel costs, as well as loads. As expert witness Pelino Colaiacovo noted in his report, "The question quickly devolves into a debate about the assumptions made in the course of the analysis" (P-04445, p. 23).

Both the Isolated Island and Interconnected Island options included a mixture of choices that were hard-coded into each option and choices that Strategist could freely optimize.

The Strategist Inputs

In optimizing the two options, Strategist depended on the following key assumptions/inputs from Nalcor (P-00077):

- **Annual Load Forecast:** NLH's System Planning division provided information about Island loads—both a forecast of each year's load and a "shape" that was based on annual load and showed how much energy would be used in each hour of the year; Strategist used these inputs to extrapolate future hourly energy use
- **Capital Cost of Constructing Generation Assets:** The inputs Strategist required here were the most current capital cost estimates for each generation asset, plus "escalation series" showing how construction costs would change from year to year
  - At DG2, most of these inputs were determined by NLH's System Planning division; Muskrat Falls Project costs were determined by the Project Management Team
  - At DG3, all of these inputs were determined by the PMT; Strategist then used the escalation series to estimate the cost to construct each asset in each year
- **Other Generating Costs:** Strategist used a fuel price forecast, an estimate of all power purchase costs, an estimate of "thermal heat rates" (the amount of energy each thermal asset gets from a unit of fuel) and an estimate of each asset's fixed and variable operating and maintenance costs (O&M)
- **Firm Capacity and Annual Firm Energy:** Strategist was fed an estimate of how much firm capacity and annual energy each asset under consideration was capable of producing as well as estimates of each asset's forced outage rate and its maintenance schedule; Strategist then suggested which assets were needed to ensure that

the province would have enough generation assets to meet forecast loads

- **Asset Service Life:** Strategist used an estimate of each generation asset's service life to determine capital replacement schedules
- **Discount Rate:** Strategist used a discount rate to estimate the current value of future costs

As noted above, the PMT provided the DG2 capital costs for the Project as inputs for Strategist. Capital costs for the other generation alternatives came from NLH, which maintained estimates for combustion turbines, combined-cycle combustion turbines and wind farms. It also had estimates for the proposed Island Pond, Round Pond and Portland Creek developments, which it escalated to 2010 and 2012 prices using its own escalation indices. It commissioned a new cost estimate for Holyrood refurbishments.

At DG2, the NLH estimates were taken as is and entered into Strategist. At DG3, however, Nalcor's PMT took charge of all the capital costs entered into Strategist. It requested the companies that produced the DG2 estimates for NLH to re-evaluate them. On average, a 16% contingency was added to both options. The logic behind this contingency was that the capital cost estimates of the Isolated Island Option assets were preliminary and based on little engineering. They were thus less certain than estimates for the Project, which were Association for the Advancement of Cost Engineering (AACE) Class 3 estimates based on 40% of the engineering completed. Nalcor's rationale was that the lower the quality of the estimate, the greater the contingency required.

This position seems plausible, initially. The engineering for the Project was, indeed, far more advanced than the engineering for Round Pond, for example, or for the Holyrood refurbishments. Further work on these projects might lead to a significant re-evaluation of costs, as had occurred with the Project between DG2 and DG3. On the other hand, as Mr. Colaiacovo testified, many of the generation alternatives—including simple-cycle combustion turbines, combined-cycle combustion turbines and wind farms—are standard "off-the-shelf" construction projects (July 17, 2019, transcript, p. 22). The cost of these projects, in his view, was much more stable than the cost of unique developments such as the Project. In Mr. Colaiacovo's view, there was less need to use a large contingency percentage for the off-the-shelf assets. I accept this evidence.

Using a large contingency factor for these assets had implications. Because these off-the-shelf projects made up a significant portion of the Isolated Island Option's capital cost, applying this contingency to them drove up their cost, which had the effect of favouring the Interconnected Island Option.

The Interconnected Island Option

The central feature of the Interconnected Island Option was the Muskrat Falls Project and it was hard-coded into Strategist. It produced, on its own, most of the additional energy and capacity the Island system was expected to need until 2067.

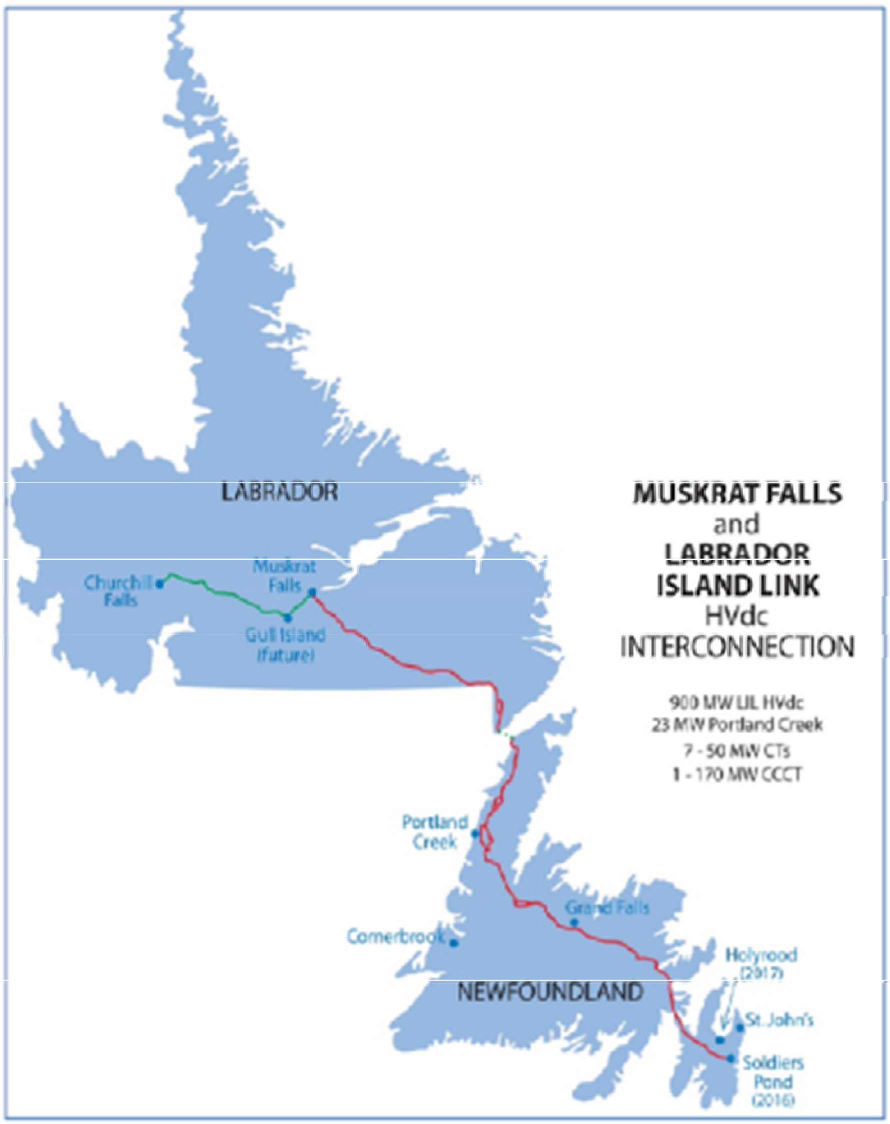
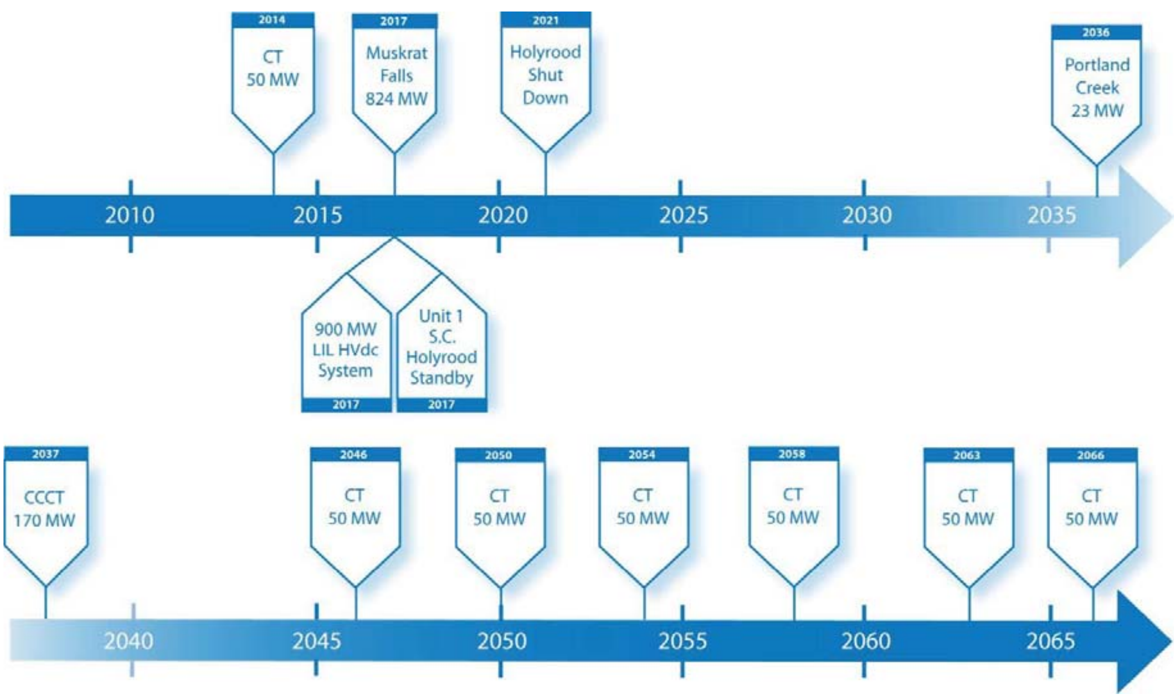


Figure 2.6: Decision Gate 2 – Interconnected Island Option

To help support the Project, Nalcor planned to keep part of Holyrood operational as a synchronous condenser, which would help stabilize the grid's voltage and would be needed to support the HVdc transmission line. The rest of Holyrood would be decommissioned. This conversion was also hard-coded into Strategist.

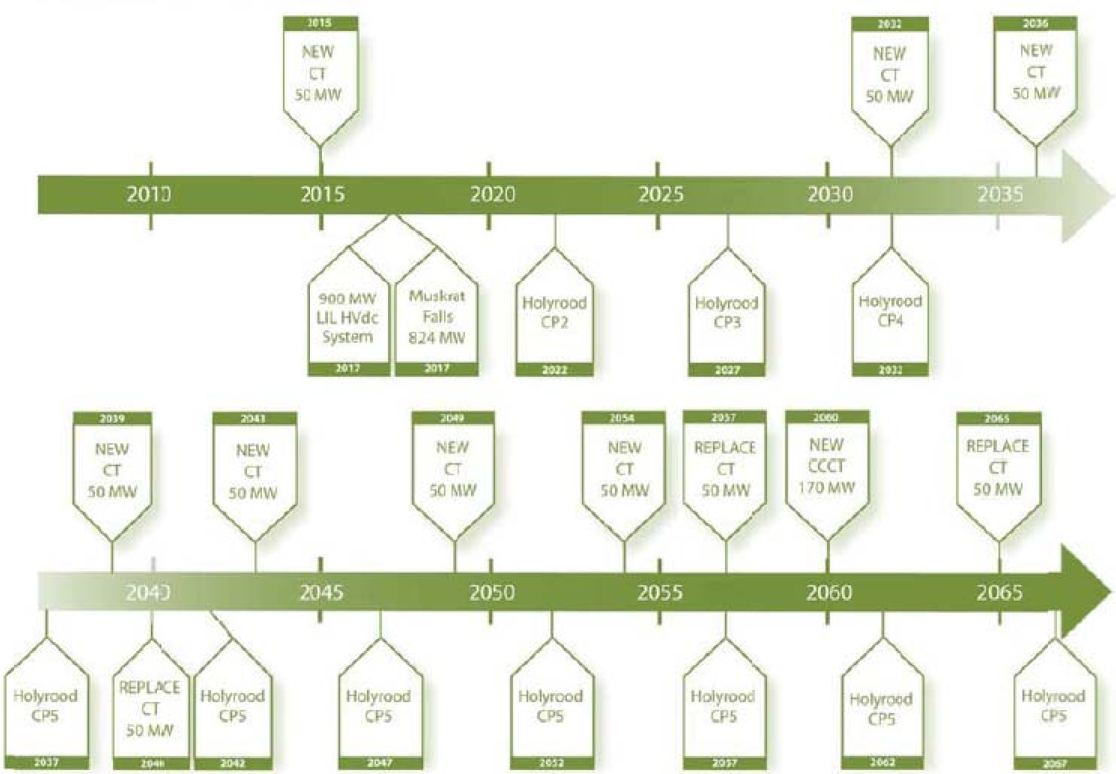
With the establishment of the basic structure of the Interconnected Island Option (the Project), Strategist selected a combination of simple-cycle and combined-cycle combustion turbines to meet the Island's remaining power-generation needs. At both DG2 and DG3, a simple-cycle combustion turbine was planned for 2015 to meet short-run capacity needs. More assets were to be added in later years. At DG2, the Interconnected Island Option was mapped like this (P-00048, p. 30):



NOTE: "CT" is a simple-cycle combustion turbine; "CCCT" is a combined-cycle combustion turbine

Figure 2.7: Decision Gate 2 – Interconnected Island Option Generation Plan

At DG3, the Interconnected Island Option was mapped like this (P-00058, p. 16):



NOTE: "CP" refers to life extension and decommissioning investments as part of the Holyrood 20-year capital plan.

Figure 2.8: Decision Gate 3 – Interconnected Island Option Generation Plan

The Isolated Island Option

The Isolated Island Option began with the refurbishment of Holyrood, which included both its life extension and the installation of the electrostatic scrubbers and precipitators. This choice was hard-coded into Strategist, as was Nalcor's timeline for integrating wind power (80 MW total at DG2 and 229 MW total at DG3).

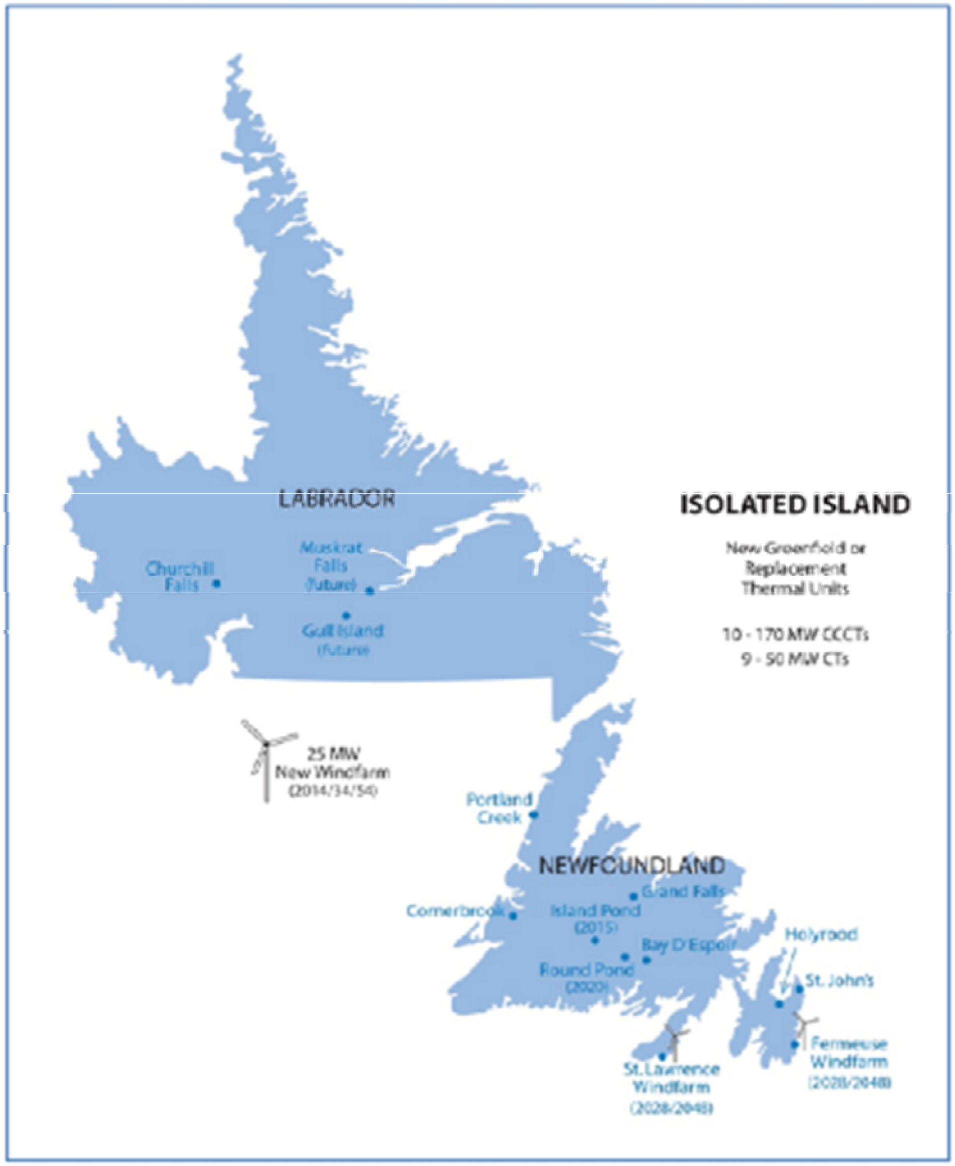


Figure 2.9: Decision Gate 2 – Isolated Island Option

At both DG2 and DG3, the Strategist software optimized the remaining assets, indicating construction of all three Island hydro projects previously discussed. It met the Island's remaining needs with a mixture of simple-cycle and combined-cycle combustion turbines, as shown in Figures 2.10 and 2.11.

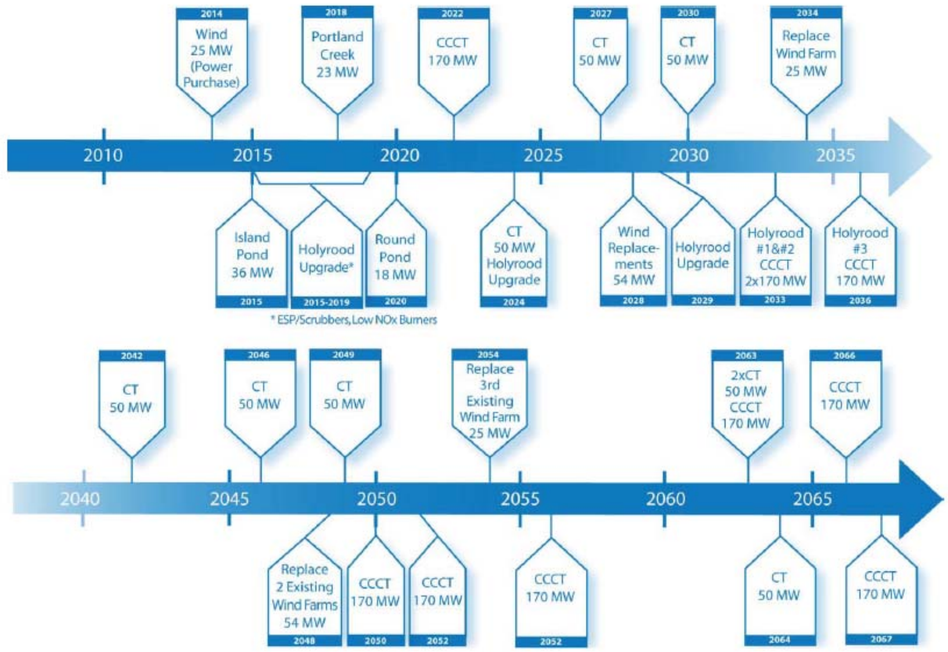


Figure 2.10: Decision Gate 2 – Isolated Island Option Generation Plan

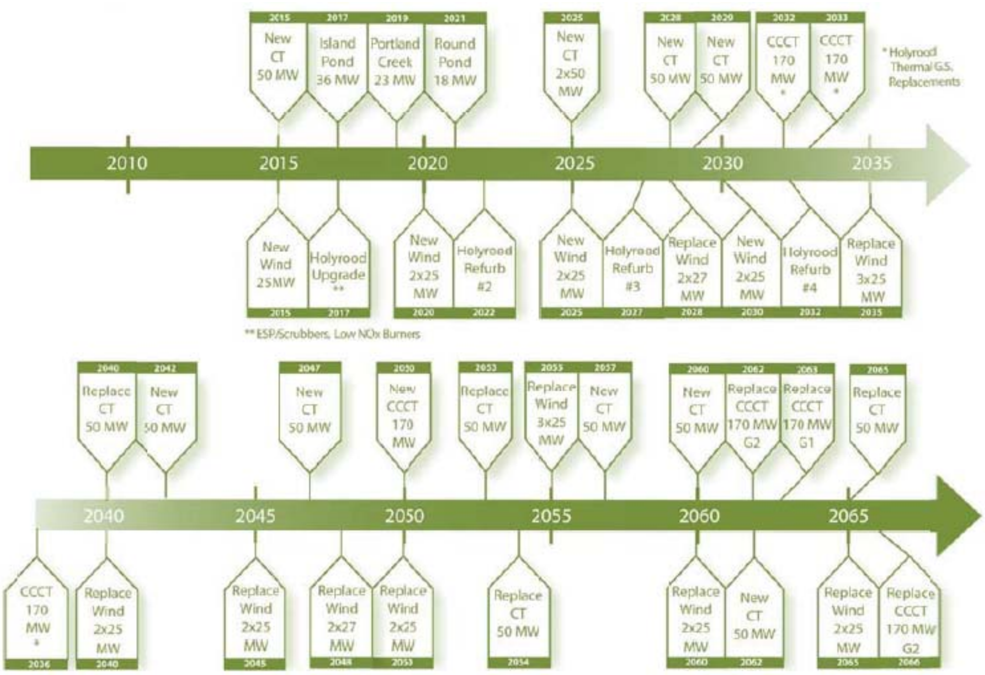


Figure 2.11: Decision Gate 3 – Isolated Island Option Generation Plan

The Strategist program filled out the Isolated Island Option with thermal generation assets. This does not mean Strategist was indicating that thermal generation was optimal. On the contrary, once the limited wind and hydro assets were built, thermal assets were the only option Strategist had in its database that could be added to meet rising loads. It could control the number, timing and selection of thermal generation sources, but could not integrate any other options because they had been screened out by Nalcor. In other words, the choice of a thermal future was made at the initial screening stage and not by the Strategist program.

The System Planning Team

The screening and evaluation process and the use of the Strategist program were managed by Robert Moulton and Paul Stratton of NLH's System Operations and Planning (System Planning) division. Mr. Moulton and Mr. Stratton were long-standing employees of NLH who had experience in electricity system planning for the province as it had been performed up to that time. They had come to NLH with little specific formal education in system planning and, based on what I heard in evidence, their skills were learned primarily on the job. They used the same methods in evaluating the two options that they had always used.

I found NLH's System Planning staff to be knowledgeable about the Island's electrical system and history, and about NLH's methods. Their experience obviously was of benefit to any system planning exercise. At the same time, the System Planning team did not, in my view, demonstrate a deep knowledge of other utilities' approaches or of new methods. They also showed little willingness to expand their knowledge base or innovate in the process that they were undertaking.

The decision to sanction the Project was the largest utility decision NLH had made in many decades, if ever. From my point of view, it would have been appropriate for NLH to expand its system planning capacity in order to give its existing staff new training opportunities and to bring on new staff who had experience with new approaches and methods being used in other jurisdictions. It would also have been appropriate to re-evaluate the methods NLH had previously been using to assess projects.

To the extent that the System Planning team contributed to decisions that I review critically in this Report, any fault, in my view, lies with the Nalcor executive, who selected and managed the system planning team effort and who chose not to supplement the NLH team when it should have appreciated the need to do so.

THE OPTIONS NOT CONSIDERED BY NALCOR

As noted earlier, Nalcor's business case consisted largely of the proposition that as long as the Interconnected Island Option could be shown to cost less than the Isolated Island Option, it was the lowest-cost option. In my view, this claim is dubious on its face. Could there not be another cheaper option? Nalcor's theory was that the Isolated Island Option was optimized by Strategist to be the cheapest possible isolated option, and that the Interconnected Island Option had been shown by Nalcor's internal testing to be the cheapest possible interconnected option. The strength of these claims requires review.

Additional Wind Generation

As discussed earlier, at DG2 Nalcor decided, based on several factors, to limit additional wind-generation capacity to 80 MW. This decision was based on a 2004 NLH study that stated that adding wind generation to the provincial system could crowd out some energy from existing hydro-generation facilities, which would increase water in reservoirs beyond the levels those facilities could use. Eventually some of this water would "spill" without generating electricity. That study concluded that as much as 80 MW could be added into the grid from wind generation "with little risk of additional spill" (P-00068, p. 5).

Philip Raphals is the Executive Director of Helios Centre and an expert witness who testified at the hearings. He pointed out a problem with limiting wind power in order to reduce the risk of spillage. He testified that wind generation can be economically viable even if it sometimes leads to some spillage. Spillage is an economic cost and wind energy is so cheap that it could still be an economical option even after some spillage costs are incorporated.

Having apparently realized that the 80 MW limit was too restrictive, Nalcor commissioned further work to be completed for DG3 in order to determine how much wind could economically be integrated into the Island system. At DG3, with the benefit of studies prepared by NLH's System Planning division (P-00950), the consulting firm Hatch

Ltd. (Hatch, P-00057) and MHI (P-00059), Nalcor revised its inputs so that up to 10% of the Island system's energy requirements could come from wind.

This new higher target left room for more wind power to be considered. Nalcor decided to add 50 MW of wind-generation capacity every five years to the Isolated Island Option, until the total energy from that source approached 10% penetration in 2035. No additional wind generation was added beyond that point. This decision was hard-coded into the Isolated Island Option and was not optimized by Strategist.

The key question to be asked is: Did the above-noted studies support the limited amount of wind-generated power hard-coded into the Isolated Island Option?

An August 2012 study prepared by NLH's System Planning team focused on whether adding much larger amounts of wind-generated power to the system (increasing "wind penetration") could destabilize it. The study stated (P-00950):

> Based on the studies conducted, the transient stability constraint is found to be the limiting factor in determining the amount of wind penetration during the extreme light load conditions. Thus, it is recommended that no more than 225MW and 300MW of net wind generation is dispatched during the extreme light load conditions during the years 2020 and 2035, respectively. However, the extreme light loading conditions are likely to occur for very short durations of the year, particularly during night hours of the summer season, when the wind generation profile is usually at its minimum. Thus, it is anticipated that the available wind generation under light load conditions is in close proximity to the wind penetration level limited by the transient stability constraint. It is recommended that historical wind data be obtained for potential wind sites across the island. This data can then be used to determine time and duration of minimal wind generation profiles coinciding with minimum system loading. (p. 6)

This study was reviewed and its conclusions confirmed by Hatch's study.

It appears that Nalcor planned to add wind so slowly that the limits in the System Planning study could never be reached. If wind were added more rapidly, the limits in the System Planning study could be avoided by curtailing wind during the "very short durations of the year" when loads fell to the "extreme" levels tested in the study. This would increase the cost of wind, but because these conditions would occur rarely, curtailing wind during these periods would not increase its cost significantly. I find that the System Planning study did not justify the limits Nalcor imposed on wind integration into the Isolated Island Option at DG3.

Hatch's study appears to have been the most substantive study done on wind penetration. It was the source of the limit that shaped Nalcor's DG3 wind choices. Hatch performed a literature review of other jurisdictions' experience with high wind penetrations. This review did not suggest that there were theoretical barriers to high wind penetrations nor that other jurisdictions had experimented with high wind penetrations and failed. Rather, it suggested that high wind penetrations might create practical implementation problems. It stated (P-00057):

> A wind energy penetration rate of 10% is the maximum recommended for the Island of Newfoundland system due to the uncertainty of the technical and economic impacts at the higher penetration rates which are yet to be proven under isolated system circumstances. (p. 30)

Hatch's literature review suggested that, as of 2012, there was significant uncertainty about the upper limits of wind penetration and about the prerequisites for an isolated system (as in the Isolated Island Option) to achieve a high wind penetration. It did not predict that 10% would remain a long-term limit on wind penetration. In addition, only two isolated jurisdictions were surveyed, New Zealand and the Hawaiian island of Oahu. New Zealand, a much larger isolated system than Newfoundland's system, was aiming for a 20% wind penetration rate by 2020. Oahu considered 20% penetration attainable with "the implementation of a sophisticated wind forecasting system, generation system modifications (to allow lower minimum unit outputs, fast starts and higher thermal ramp rates), increase of reserve requirements and the implementation of aggressive load management methods" (P-00057, p. 29).

In short, although the literature review identified uncertainty about implementing wind penetrations above 10%, it also suggested both that this uncertainty would be resolved within the near future and that the most likely outcome was that higher penetrations would be possible. The literature review did not suggest that 10% was a probable long-term ceiling on wind penetration. Rather, it indicates some uncertainty about what the long-term ceiling would be and about the kind of system changes that would be needed to support higher penetrations.

Nalcor's consideration of technological change is addressed in more detail later in this Report. Here, it is enough to say that it was unreasonable to limit the Isolated Island Option to 10% wind penetration forever, since 10% was unlikely to be the long-term limit. If Nalcor had performed a full Integrated Resource Planning process, it could have explored scenarios in which higher wind penetrations became feasible, and other scenarios in which they did not.

Even if the 10% limit was justified, Nalcor should have added more wind power to maintain a 10% penetration after 2035. I say this because the Isolated Island Option assumes falling wind percentages after 2035, despite rising loads and fuel costs. This point is a matter of concern.

Hatch's main analysis was on the economic effectiveness of incorporating additional wind beyond the DG3 plan. It focused on the key question of how effectively wind energy could displace fuel use and pointed to the following significant limits on the economic effectiveness of additional wind:

- As wind is added, the additional energy it creates during the spring and summer needs to be stored: "The hydroelectric generation facilities have to absorb and re-regulate the irregular wind generation and the impact on reservoir levels is quite significant" (P-00057, p. 25)
    - The Island's reservoirs and hydro facilities could not always effectively deal with additional wind energy; rising water levels in the reservoirs "is the primary causative factor for increased spill, lower hydro generation efficiencies, and thus reduced thermal displacement efficiency" (P-00057, p. 25)
- In the Isolated Island Option, Holyrood would operate at a minimum level all winter long, which significantly reduced the amount of fuel that wind could displace—Holyrood had to burn some fuel even when wind was blowing
    - Hatch tested a scenario in which Holyrood was replaced by a new combined-cycle combustion plant that did not have a thermal minimum, concluding that "significantly more wind development could potentially be economically viable without the thermal minimal constraint" (P-00057, p. 31)

The economic effectiveness analysis provided a real constraint on wind penetration but did not, in my view, justify the limits Nalcor hard-coded into Strategist for the DG3 analysis. The analysis consistently showed that some amounts of additional wind energy at levels above Nalcor's plan were, in fact, economically effective (P-00057, pp. 21–24). In particular, it is likely that the economic effectiveness of wind would rise significantly after the 2030s, when Holyrood was scheduled to be replaced by a new facility with no thermal minimum. The fuel that this new facility would burn could be even more expensive than Holyrood's fuel, further improving the case for additional wind generation. Also, other jurisdictions would by then have had decades to resolve the uncertainty surrounding high wind penetrations. The prospect that significantly higher wind generation could be economically added to the system after the mid-2030s was potentially significant, particularly with the Isolated Island Option expected to be cheaper than the Interconnected Island Option until that time.

In addition, Hatch did not consider additional hydro-generation options, such as Bay d'Espoir Unit 8 or Cat Arm Unit 3, when it concluded that increasing wind penetrations would increase reservoir levels and thus increase the risk of spill and reduce generation efficiency. Nalcor's current CEO, Stan Marshall, testified that these other generation options would likely have enabled additional wind to be economically added to the Isolated Island Option. I accept Mr. Marshall's evidence on this point.

The third study on wind, prepared by MHI, had two main tasks:

1. "Complete a due diligence review of the studies provided by Nalcor to determine if the study goals have been met" (P-00059, p. 7).

   MHI reviewed the System Planning and Hatch studies and confirmed that these analyses were "technically sound, met their study goals, and were performed in accordance with good utility practices" (P-00059, p. 7). This conclusion is unobjectionable. My concern is not that the studies were wrong but that they could have allowed more wind to have been integrated into the Isolated Island Option.

2. Address these questions: "In an isolated island scenario, can sufficient wind be developed to replace the Holyrood Thermal Generating Station and meet future demand? Is this a technically feasible and economic alternative to Muskrat Falls and the Labrador Island Link?" (P-00059, p. 7).

> MHI studied a scenario in which a large wind farm was developed as a full replacement for Holyrood, with a) combustion turbines, or b) batteries as back up. It concluded that both scenarios would have a less favourable Cumulative Present Worth than the Isolated Island Option—$11.86 billion for wind farms backed by combustion turbines and $17.43 billion backed by batteries (P-00059, p. 8).

This second conclusion says little about the realistic uses or limits of wind generation. The real question should not have been whether wind generation was viable in 2012 as a full replacement for Holyrood. It should have been: how much wind could be practically and economically integrated into the Isolated Island Option?

Additional Island Hydro

The Island of Newfoundland has abundant hydro resources. In addition to NLH's existing hydro-generation assets, which provide the lion's share of the Island's energy and capacity, NLH has identified hundreds of potential hydroelectric generation sites (P-00159; P-01023; P-01025 through P-01029; P-01138).

The three Island hydro sites that passed Nalcor's initial screening (Island Pond, Round Pond and Portland Creek) were hard-coded very early into the Isolated Island plan analyzed by Strategist. This suggests that additional hydro options may also have been cost-effective additions to the Isolated Island Option. Nevertheless, Nalcor screened out other potential hydro sites at both DG2 and DG3. This decision calls for some analysis.

In 2011, in response to the Reference Question from GNL, Nalcor presented the PUB with a two-part rationale for limiting Island hydro (P-00077). The first part stated that, other than Island Pond, Round Pond and Portland Creek,

> [m]ost of the remaining projects do not have storage capability and are referred to as "run of the river" facilities. Run of the river hydroelectric facilities have operating attributes very similar to wind generators as they only operate when there is water in the river and there is no certainty that the plants will be available to provide capacity at time of peak load. (pp. 97–98)

The second part of the rationale stated that there was "an economic preference for wind over small hydro," explaining the conclusion as follows (P-00077):

> In 1992 NLH Issued a Request for Proposals (RFP) for the purchase of up to 50 MW of small hydro production from non-utility generators (NUGs). . . . [T]here were eleven projects submitted for consideration. . . . NLH accepted four of the eleven proposals of which two were constructed—Star Lake 15 MW and Rattle Brook 4 MW. The others, Northwest River 12 MW and Southwest River 7 MW, were halted prior to construction due mainly to public opposition. Following this chain of events, the Government of Newfoundland imposed a moratorium on further small hydro development in 1998. This moratorium is still in effect today.
>
> The seven unsuccessful projects from the 1992 RFP can be considered to be representative of the most attractive of the remaining undeveloped small hydro on the island. Based on submission data these project[s] had an average bid price of 6.64 cents per kWh (1992$), escalating this price to 2010$ using Nalcor's/NLH's "Hydraulic Plant Construction" escalation series, results in a current estimate of 10.4 cents per kWh (2010$). In comparison, NLH is carrying 9.2 cents per kWh (2010$) for the wind PPAs used in current modeling. This indicates that NLH would pay a premium of approximately 13 percent for small hydro. The estimated costs reflect single small scale installations and while this would include basic grid interconnection it does not cover costs associated with major transmission upgrades that maybe required for larger or multiple small scale installations. (pp. 98–99)

It should be noted that the analysis of these projects considered only economic factors and outcomes. Although a few projects were not developed in the 1990s because of public opposition and environmental concerns, not every project would encounter these difficulties. Nalcor's submission to the PUB suggested that the remaining projects would be uneconomical.

The rationale that Nalcor used in its response to the PUB's 2011 Reference Question cannot be the original reasoning for screening out other Island hydro sites, as it is not borne out by the chronology as outlined below. Also, with respect to the 1998 moratorium on small hydro developments, the 2007 Energy Plan had already committed the Province to a review of its small hydro resources in 2009, concurrent with a decision about whether to proceed with the Lower Churchill Project.

Regarding timing, the components of the Isolated Island Option are largely set out in the PUB's Reference Question, which was dated June 17, 2011 (P-00038). Therefore, Nalcor's screening process must have been completed by that date. However, the rationale it would put forward to explain limiting Island hydro was developed later, in August 2011, through a dialogue between Todd Williams of Navigant Consulting Ltd.

(Navigant) and Paul Humphries of NLH's System Planning team (P-01033; November 13, 2018, transcript, p. 24). The decision to screen out additional sites in June cannot have been made based on reasons developed months later.

A more fundamental flaw in the stated rationale is that, while it is accurate for Nalcor to state that "most of the remaining projects do not have storage capability," it is noteworthy that many of the remaining projects actually did. Mr. Humphries admitted that many projects had storage. Some plants were dispatchable (they can be turned on or off, up or down as needed) or, as in the case of the Exploits River projects, which have upstream storage, some were "quasi-dispatchable" (November 13, 2018, transcript, pp. 25–29). The rationale used by Nalcor in its submission to the PUB cannot explain or justify the decision to screen out these projects.

A further flaw in Nalcor's rationale is that the "seven unsuccessful projects from the 1992 RFP" were not necessarily "representative of the most attractive of the remaining undeveloped small hydro on the island," as Nalcor stated in its PUB submission. The 1992 RFP was not open to all Island hydro projects. It was specifically limited to those with a capacity between 10 MW and 15 MW in which water rights were held by a private-sector owner not NLH (P-01031, p. 2). Other types of projects might well have had a lower cost.

Paul Humphries' testimony presented another rationale for screening out many Island hydro projects. NLH's System Planning division maintains a portfolio of its most viable generation projects. These projects go through several layers of feasibility screening before being put forward for possible development, including a preliminary level of engineering. Most of these projects are screened out somewhere along the way. In 2010 and 2012, Island Pond, Round Pond and Portland Creek were the only projects then in NLH's "possible" portfolio, which is why they were the only projects considered.

However, just because a project is not included in NLH's portfolio at any given time does not mean it is not a viable project. For instance, NLH's 2018 list of options contains several projects omitted from its 2010 and 2012 lists, which were known but not included in the "possible" list at the time. These projects included Badger Chute, Red Indian Falls, Bay d'Espoir Unit 8 and Cat Arm Unit 3 (P-03658, pp. 282, 558). Significantly, NLH's System Planning documents described its portfolio of possible options as "near-term resource options" (P-00164, p. 13; P-00034, p. 19; P-01136, p. 22). This wording—"near-term"—is important. The list does not contain all possible or viable projects, just those that are or could be ready in the near-term.

I accept that maintaining a short list of this kind was a reasonable way to sift through hundreds of possible projects in order to make immediate decisions. I also accept that NLH viewed Island Pond, Round Pond and Portland Creek as the best hydro options and the only ones worth considering for its "near-term" needs. The problem is that whether or not to proceed with the Muskrat Falls Project was not a near-term decision. Many projects that were not worth considering in 2010 to 2020 might well have been worth pursuing between 2020 and 2067. Before screening out all other Island hydro sites, NLH should have performed a deeper analysis of its options to consider which sites, if any, might have been viable long-term options. This analysis was not done.

It is difficult to know what the results of such an analysis might have been. How many other sites were potentially viable? How might they have improved the Isolated Island Option? Unfortunately, we can only speculate. It is regrettable that a deeper evaluation was not undertaken by Nalcor and NLH's System Planning group.

Finally, it is important to recognize that adding Island hydro sites could also allow additional wind generation to be integrated into the Isolated Island network. As mentioned earlier, Stan Marshall testified that two particular Island hydro options, Bay d'Espoir Unit 8 and Cat Arm Unit 3, could have presented an appealing alternative to the Project. Both these projects were screened out at both DG2 and DG3. Neither of them were new hydro sites. Both would have involved adding turbines to existing hydro sites. Neither project would offer much, if any, additional energy over the course of the year as existing generating stations can already use the water in the Cat Arm and Bay d'Espoir systems. By adding capacity, however, the additional units would allow Bay d'Espoir and Cat Arm to be used less as steady base-load power sources, and more as peaking plants that produce abundant energy when needed.

The additional capacity provided by these projects would help meet the Island's power needs and reduce the requirement for new thermal assets. An added potential benefit is that their additional capacity would enable NLH to counterbalance intermittent wind power. Production at both Bay d'Espoir and Cat Arm could be reduced when the wind is blowing and increased when it is not. This would help mitigate the concern expressed in the Hatch report (P-00057) that increased spill would offset the economic benefits of additional wind generation.

Both Paul Humphries and John Mallam questioned the value of this combination of wind and extra turbines. But what did they base this on? There is no evidence that this combination of assets was considered or modelled at the time. The Hatch report certainly indicates no awareness that there was an option of adding additional generation units to existing hydro facilities.

Unfortunately, the evidence does not allow me to conclude one way or the other whether this combination would have improved the Isolated Island Option. This combination does, however, seem to be a plausible alternative that Nalcor did not sufficiently explore.

Deferral to 2041

Nalcor also screened out the option of purchasing power from Churchill Falls after 2041, the year in which the existing Upper Churchill Contract with Hydro-Québec expires. As a broad strategy, however, waiting until 2041 has an intuitive appeal.

In its early years, the Project will produce far more energy and have more capacity than the province needs. In addition, the analysis showed that the Isolated Island Option, as presented, was cheaper than the Interconnected Island Option until the mid-2030s. After 2041, the enormous capacity and production of Churchill Falls becomes available at a very low production cost. Instead of building a new, expensive hydroelectric facility, Nalcor ought to have considered finding a way to get to 2041 and then begin purchasing power from Churchill Falls.

The arguments against waiting until 2041 for Churchill Falls power were many and they were uneven in quality. Nalcor suggested that waiting for Churchill Falls power would have three inherent negatives: reliance on fossil fuels in the interim with the resultant environmental consequences, a risk of carbon regulation and unstable rates tied to fluctuating fuel prices (P-00077, pp. 100–101). However, these points are the disadvantages of thermal generation, not of deferring until Churchill Falls power is available. They pertain to using simple-cycle and combined-cycle combustion turbines, both of which options passed initial screening, rather than using Churchill Falls power, an option that was screened out.

Nalcor also suggested that waiting for Churchill Falls power to become available would delay developing the province's energy warehouse and would remove the economic benefits associated with the Project (P-00077, p. 101). The first point is an argument against an isolated plan, the second is an argument against any plan except the Project. Neither is appropriate for not conducting a screening analysis of waiting until 2041 for

Churchill Falls power. In addition, both points deal with the broad provincial economic benefits of the Energy Plan rather than the impact on ratepayers. These arguments are not germane to an analysis seeking to identify the way to produce power at the lowest cost.

All this said, even though Churchill Falls power has an intuitive appeal, I recognize that it might well be a challenge to build a generation plan around it. The difficulties include the following:

- A plan that involved extending the life of the Holyrood plant until 2041 would create the risk of Holyrood's aging turbines failing in the 2030s, since by that time Units 1 and 2 would have exceeded their expected life by more than 100%
- A plan that called for building additional assets—for example, a new set of combined-cycle plants in the 2030s—would leave those assets stranded in 2041, when the abundant power from Churchill Falls becomes available
- The full capital cost of any new assets would have to be paid after only a few years' use, thereby potentially cancelling out any economic advantages of waiting for 2041

These arguments cannot justify the decision to reject 2041 Churchill Falls power at the screening level, however. To determine fairly whether Churchill Falls power could have been the centrepiece of a viable generation plan, Nalcor would have had to accept it as a viable supply option and invest resources in optimizing a generation plan around it.

In addition, both Nalcor and GNL raised concerns about the Island's legal ability to secure power from Churchill Falls even after 2041 (P-00077, p. 100; P-00061). As stated earlier, NLH owns 65.8% of CF(L)Co and the remaining 34.2% is owned by Hydro-Québec. If NLH attempted, through CF(L)Co, to sell energy to Island ratepayers at discounted prices, it is possible that Hydro-Québec would take legal action, claiming its rights as a minority shareholder were being abused. This is a legitimate point.

While the cost of producing electricity at Churchill Falls is, and will remain, very low, Island ratepayers will not have the right to purchase it at the low cost of production. They would have to pay a fair price, possibly a price that would provide CF(L)Co with the same return earned by selling it to New York markets through the Québec grid, adjusted for transmission costs and losses. Alternatively, Hydro-Québec could offer CF(L)Co a price for Churchill Falls energy that NLH would have to match. The requirement to pay a fair price for power could, in fact, reduce the appeal of waiting for 2041. At DG3, Nalcor projected that the long-term export price of Churchill Falls energy would be higher than the cost of energy from the Project. If true, then ratepayers might have been required to pay a higher price after waiting for 2041 than they could have obtained without waiting.

However, it must be noted here that after 2041, approximately two-thirds of CF(L)Co's profits will go to the Province. The sale of Churchill Falls power after 2041 will increase the Province's revenues creating an additional revenue stream that could be used to mitigate rates should NLH have to pay market prices for Churchill Falls power.

When asked whether GNL could expropriate Churchill Falls after 2041, Danny Williams indicated that this could not take place. Considered on a strictly legal basis, this comment is surprising. Churchill Falls is an asset within the province and GNL can, with a sufficiently clear statute, legally expropriate assets here without paying compensation. This would obviously be subject to legal challenges. However, expropriating Churchill Falls would make it significantly more difficult to negotiate a transmission deal for Churchill Falls power through Québec. Expropriation may be a more plausible option if no deal with Québec is achieved.

Despite ostensibly screening out Churchill Falls power as a supply option for the Isolated Island Option, Nalcor did include some Churchill Falls power in the Interconnected Island Option at DG2. While this is surprising, even more remarkable is Nalcor's assumption that this power would be available at "historical power contract prices" rather than at market prices. This error was not repeated at DG3 and its effect on the DG2 CPW analysis proved to be minor. However, it is an interesting example of a double standard. When Churchill Falls power was proposed as an alternative to the Project, its weaknesses were identified exhaustively, if not exaggerated. When the same power source was proposed as a supplement to the Project, the same issues were not raised.

During its planning exercises prior to DG2, Nalcor used Strategist to develop a generation plan centred on 2041 Churchill Falls power. The scenario assumed that extending Holyrood's life to 2041 would cost $200 million, and that after 2041 energy would be available from Churchill Falls at New York market prices. Using these inputs, the CPW of waiting for 2041 came out higher than the CPW for the Interconnected Island

Option, but lower than that of the Isolated Island Option. This conclusion underlines the inappropriateness of screening out the Churchill Falls option. Building a generation plan around 2041 Churchill Falls power availability may well have been difficult, but it avoided the upfront capital cost of the Interconnected Island Option as well as the associated long-term high fuel costs of the Isolated Island Option.

Churchill Falls power is viable in scenarios when export prices are low and fuel costs are high and less viable when export prices are high and fuel prices are low. In a full Integrated Resource Planning analysis, it would be significant that the decision to pursue Churchill Falls power does not need to be made until the mid-2030s. If Churchill Falls power is less viable in the mid-2030s, the options to pursue the Project or an isolated future would have remained available.

Finally, the Churchill Falls power option potentially has some synergies with other supply options that Nalcor screened out. For instance, Dr. Stephen Bruneau, a Professor of Engineering at Memorial University, suggested that a Grand Banks natural gas plan that was designed to supply power until 2041 might be significantly cheaper and more secure than a plan that aimed for 2067 (October 5, 2018, transcript, p. 14).

The Recall Block

The Upper Churchill Contract allows CF(L)Co to withhold up to 300 MW of Churchill Falls power otherwise destined for export outside the province of Québec (P-00018, p. 21). This block of power is referred to as the “Recall Block” and has been sold to NLH, which uses it to supply Labrador customers. It exports any excess through a booking on Hydro-Québec’s transmission system. Over the course of a typical year, most of the Recall Block is available. However, 220 MW from the Recall Block is typically needed to meet Labrador winter demand peaks, leaving only 80 MW of spare Recall Block capacity to meet Island winter demand peaks.

Nalcor indicated that it screened out the Recall Block as a power-supply option because the 80 MW spare firm capacity was not enough to replace the significant winter capacity of Holyrood. While this calculation is true, the assessment is incomplete. The Recall Block could be a valuable option even if it does not fully replace Holyrood’s power output.

Nalcor appears to have used the Recall Block in the Interconnected Island Option despite having screened it out of the Isolated Island Option. The associated CPW analysis assumed that 900 MW of firm capacity would be available from Labrador and would be carried to Newfoundland by the LIL. At sanction, the Project's generating station was rated at only 824 MW. How was this 900 MW total reached? Though not specified, the remaining 76 MW could only have come from the Recall Block. This use was compatible with the contractual limits of the Recall Block and demonstrated its potential value.

However, the Recall Block could also have provided a valuable supplement to other power options. For instance, some plans that involved post-2041 Churchill Falls power faced the challenge of meeting possible power shortages in the late 2030s, either because of load growth, natural gas supply issues or Holyrood maintenance issues. Any assets built to meet those needs would be expensive because, as outlined, they would be stranded after 2041. Building the LIL early would have given the Island access to the Recall Block, however, which could provide energy without the need to build new assets.

Importing Electricity from Québec

Nalcor considered power imports from New York or New England as part of its screening process, but it did not consider power imports from Québec. This decision was a subject of interest during the hearings.

Québec has exported large amounts of energy from its hydropower generation assets for many years. This energy could meet the Island's needs for part of the calendar year, but questions were raised about whether there was enough capacity from Québec available to meet wintertime demand. Like NL, Québec has a cold climate and most of its households use electric heat, thus its highest loads occur in the winter. This contrasts with its primary export markets. In New York, New England and Ontario, peak loads are driven by air conditioning used in the summer. As well, Québec has abundant hydro-generation capacity that produces a large surge of power in the spring when snow melts.

Consequently, assessments by Nalcor of Québec's ability to export energy, and even export firm capacity, suggested in the mid-2000s that it had little to no spare capacity on the coldest days of winter, when that power might be needed on the Island. In fact, I heard evidence that Hydro-Québec was facing capacity shortages and was building additional generation assets (July 17, 2019, transcript, p. 51; December 10, 2018, transcript, pp. 57–58). However, this evidence does not eliminate the prospect of buying firm winter capacity from Hydro-Québec. Hydro-Québec may not have had spare winter capacity to offer without having to build new assets. Nevertheless, the evidence is that winter capacity would probably have been available for a price.

No evidence was presented on the question of whether Hydro-Québec could have offered a price for power that was competitive with the price offered by the Project. While the Project may produce power efficiently, ratepayers will pay a high cost per unit in the early years because they use only a fraction of the available units. It is possible that Hydro-Québec could have offered a better price than the Project by providing only the units the province would need. In the medium term, its capacity is determined not only by its existing resources but also by its undeveloped opportunities. Without discussions with Québec, it was not possible for Nalcor to have known which projects, if any, they were considering nor what price they would or could offer as a result. I reject the testimony of those witnesses who testified that no firm energy was available for purchase from Hydro-Québec.

If Hydro-Québec was considering a large hydro site with greater economies of scale, it could have found an export opportunity to this province advantageous. A good example of this in practice is the Muskrat Falls Project itself. Nalcor offered Emera a fairly attractive price for a firm block of energy and capacity because Nalcor wanted to develop a large site and needed a firm market for some of its surplus power. There were advantages for both parties in the deal.

Could something similar have occurred by opening discussions with Québec? Some witnesses suggested that no negotiations with that province would have been feasible. The turbulent history of the Churchill Falls power development meant that any negotiation with Hydro-Québec for the sale of power from Labrador would be politically sensitive. In 2010 particularly, the political environment and the following events would have made it difficult to conduct even an ordinary commercial negotiation with Hydro-Québec because:

- The Québec regulator had just denied Nalcor's application to wheel electricity through Québec's electrical grid
- CF(L)Co was challenging the Upper Churchill Contract in court, a challenge that the Supreme Court of Canada would later dismiss
- GNL had recently condemned Hydro-Québec's plan to invest in New Brunswick Power

However thorny these facts potentially made the proposition, they do not mean that Québec imports ought to have been screened out. I believe it is appropriate to consider not only whether Québec imports were possible in the political environment of 2010, but whether they could have been viable if different political choices had been made.

The Commission's Terms of Reference direct me to consider whether "Nalcor considered and reasonably dismissed options" (P-00001, p. 3) and whether "the government had sufficient and accurate information upon which to appropriately decide to sanction the project" (P-00001, p. 5). In my view, Nalcor was not entitled to screen out viable options simply because they were not politically welcome. GNL was required to select the best option based on all available information about costs and benefits. When Nalcor ignored the advantages of negotiating with Québec for political reasons, the decision not to negotiate was made on the basis of deficient information.

Before building an expensive transmission line from Churchill Falls to the Island, Nalcor would have had to secure a long-term contract with Hydro-Québec for the delivery of firm power. Pelino Colaiacovo testified that this negotiation would not happen in isolation. It would quickly have become a larger discussion about the future of Churchill Falls after 2041. I accept this evidence.

In 2010, Hydro-Québec faced a possible shortage of winter capacity. Negotiations with Hydro-Québec could have led to a discussion about the development of the entire lower Churchill River, including Gull Island. Hydro-Québec could have used its own large domestic and export market to justify and support development of Gull Island, thereby offering this province's ratepayers low-cost energy.

At this stage, one can only speculate as to what might have come from negotiations with Hydro-Québec. A mutually beneficial deal was always possible. However, Nalcor's decision to screen out negotiations with Québec altogether is another example of its failing to adequately consider all potentially viable options.

Grand Banks Natural Gas

Newfoundland and Labrador has abundant offshore natural gas that has never found a commercial market. At DG2 and DG3, Nalcor screened out Grand Banks natural gas as a supply option. This decision was publicly questioned at the time and also at the hearings, most notably by Dr. Stephen Bruneau.

Nalcor's original screening rationale relied heavily on a 2001 report by Pan Maritime Kenny-IHS Energy Alliance (P-00088). As interpreted by Nalcor, this report found that the local market for gas was "too small to absorb the considerable project risks, capital investment, and operating costs of a Grand Banks natural gas development" (P-00077, p. 66). The report went on to state that "the economic threshold for development of Grand Banks gas is a production rate in the order of 700 million standard cubic feet per day," seven times that required for the Island's thermal generation needs (P-00077, p. 66).

As noted by Dr. Bruneau, the 2001 study focused on a large system designed "to export gas from offshore Newfoundland to Eastern Canada and on to the US" (P-00088, p. 3). A smaller system for domestic use would, according to Dr. Bruneau, be less costly and could have been justified with less production.

The original screening rationale was assembled without the participation of James Keating, then Nalcor's Vice-President of Oil and Gas. Mr. Keating later outlined a different rationale for screening out this source, which is more difficult to evaluate. It is significant that this subsequent rationale was developed after the original screening decision.

Dr. Bruneau proposed Grand Banks natural gas to the PUB (P-00089) at a public presentation in March 2012 (P-00090) and in other writings. Dr. Bruneau observed that large amounts of natural gas existed on the Grand Banks. This natural gas was referred to as "associated," meaning it came mixed with oil. The offshore producers were using some of this gas to generate electricity on the offshore facilities themselves. They also reinjected it into the reservoir to extract more oil. The remainder of the gas was either flared off or reinjected for storage. Dr. Bruneau suggested that the amount of gas reinjected for storage, particularly at the White Rose development, could supply far more power than what would be needed to replace Holyrood.

Dr. Bruneau estimated at the time that a 500 MW natural-gas-fired combined-cycle plant would have cost $500 to $800 million to build (P-00090, p. 37). He also estimated that a pipeline large enough to power this plant would have cost between $760 million and $950 million (P-00090, p. 42). Other elements would have added approximately $100 million to the cost (P-00090, p. 43). In addition to this, the offshore producers would have required a fee for the sale of the gas.

As the natural gas was stranded and being reinjected at a cost, Dr. Bruneau believed the offshore producers could profitably offer the gas at a reasonable price if Nalcor covered the cost of building a pipeline needed to create a market for the gas. For the purpose of analysis, he assumed that the proponents would accept the US market price for natural gas and he estimated that at that price Grand Banks natural gas would have been considerably cheaper than the Project.

Ziff Energy Group was engaged by GNL in April 2012 to examine the potential of natural gas as a power-generation source for the Island. There is evidence that Nalcor attempted to persuade Ziff that Grand Bank natural gas was not a viable option. Soon after the firm was hired, Mr. Keating assured a senior representative of Husky Energy: "We will work with Ziff so they understand our NG [natural gas] opportunity or lack thereof" (P-01196, p. 1). The following day, Mr. Keating asked this representative of Husky, "Could I take you up on you [*sic*] offer to meet with someone in your shop to get some alignment on piped gas issues" (P-01197). After a discussion with Ziff nine days later, Mr. Keating sent an email to Edmund Martin, stating that he had "pile drived" issues leading to "End of pipe option." Mr. Martin replied "Bingo. Are they definitely done? We will still need your stuff, with a bow" (P-01200).

In its report, the Ziff analysis stated as a key finding that none of the existing offshore energy operators were interested in selling their associated natural gas. As a result, Ziff concluded that there was "no low-cost Grand Banks natural gas available for transporting to shore for domestic use" (P-00060, p. 16). In their private meetings, Husky advised Ziff that it "wishes to maintain the optionality to use White Rose natural gas for enhanced oil recovery as in Hibernia and Terra Nova" (P-00060, p. 38).

From this starting point, Ziff concluded that Grand Banks natural gas would require either a stand-alone Grand Banks gas development, a refit of the SeaRose FPSO or the addition of gas facilities to the contemplated West White Rose project. It assumed that Nalcor would have to cover the capital cost of infrastructure and pay the offshore operators for the gas.

Ziff also concluded that the oil reserves at White Rose could run out as soon as 2028, leaving any natural gas project bearing the full cost of the facility (P-00060, p. 40). This was one of the points that Mr. Keating had apparently "pile drived" to them (P-01200). In the end, Ziff estimated that Grand Banks natural gas would be too expensive. Nalcor estimated the CPW of a Grand Banks natural gas option roughly in the range of $12.8 billion to $15 billion (P-01204, p. 1).

A subsequent report by Wood Mackenzie, also done at the behest of GNL, endorsed Ziff's findings on natural gas (P-00091). It stated: "If anything, Wood Mackenzie's estimates of costs in this area would tend to be higher, rather than lower than those determined by Ziff" (P-00091, p. 3).

The work of Dr. Bruneau, Ziff Energy and Wood Mackenzie was discussed in some detail by Dr. Bruneau and by Mr. Keating in their testimony. The fundamental area of disagreement between them was whether the Grand Banks oil producers would be interested in selling natural gas if Nalcor was willing to cover the cost of the pipeline. Dr. Bruneau said that it was apparent from public filings that the natural gas available was of little value to the oil producers and, in fact, was probably a cost to them. If so, he thought that there would be room for a mutually advantageous arrangement.

Mr. Keating's position was that Nalcor was aware from its private discussions with the oil producers that they were not interested in selling gas in small quantities, either in 2012 or later. If the oil producers were interested, he indicated, they would have said so. He stated that, at the time, the oil producers were unwilling to be drawn into a public debate that might stir up the issue.

The next issue was the probable life of the White Rose field, which Dr. Bruneau testified had particularly abundant gas and for which its producers had no profitable use. Dr. Bruneau's position was that, with the approval of the North Amethyst Extension, the White Rose field was expected to produce oil until 2045, which in turn ensured that White Rose would have natural gas available past 2041. If so, a pipeline from White Rose could have ensured a supply of natural gas until Churchill Falls power became available.

Mr. Keating disagreed with this position. He believed that it would have been difficult in 2012 to have confidence that the North Amethyst field would proceed since it had not yet been sanctioned. Further, according to him, even if it had been sanctioned, it might not have had enough reserves to operate until 2041.

For me, the key issue with natural gas is one of trust. All the publicly available information suggested that Dr. Bruneau's views were potentially viable and worth investigating. If so, the next step would have been a more formal dialogue with the oil producers to see what price they would have charged to make natural gas available. Perhaps the price would have been prohibitive, perhaps not.

Nalcor's response to this position was that its private relationship with the oil companies revealed that the opportunity was not viable. According to Nalcor, the oil companies would not have been willing to part with the associated natural gas at any reasonable price for reasons that they were unwilling to publicly disclose.

Nalcor's position on this cannot be evaluated from the public information available. It is pure assertion, and its credibility depends on having confidence that Nalcor was using best efforts to explore all potential alternatives to the Project. Based on the evidence, however, I find it difficult to have this confidence. If anything, it appears to me that Nalcor impeded an appropriate assessment of the natural gas option. In addition, GNL made no apparent effort to deal directly with Husky or other potential gas producers. This is surprising, especially since the government's own Energy Plan had directed that natural gas options should be explored. As a result, I conclude that Nalcor's exclusion of Grand Banks natural gas as a supply alternative was unreasonable.

<u>Liquefied Natural Gas</u>

Liquefied natural gas is another form of natural gas that Nalcor screened out. Natural gas is usually too bulky to be transported by ship. If cooled to -163°C, however, it becomes liquid and shrinks to 1/600th of its volume (P-00077, p. 67). This allows it to be transported in insulated containers. On arrival at its destination, it is converted back into gas ("regasification") and can be used to power combined-cycle combustion plants.

At DG2 and DG3, Nalcor screened out LNG as a power-supply option. At DG2, the screening rationale was fairly brief and was subjected to some criticism at the time. This led both Nalcor and GNL to commission additional reports on the viability of LNG at DG3.

The main public rationale for screening out LNG as a potential supply option was provided in the previously referenced Ziff Energy Group report (P-00060), which GNL, not Nalcor, had commissioned. According to the Ziff report, the cost of LNG included the cost of the LNG itself plus the costs of shipping, a jetty, a regasification facility and storage tanks. Ziff estimated that before investing significant resources in LNG facilities, NLH would need a long-term supply contract with a well-established LNG supplier. The price of such a contract would likely be higher than spot market prices. Ziff estimated the long-term contracted LNG price would be 80% to 90% of world oil prices (P-00060, p. 34). The jetty, regasification facility and storage costs would be fixed, so with only a small amount of natural gas being produced, the cost per unit of natural gas would be high (P-00060, pp. 27–29). Based on information from Ziff, Nalcor estimated that the CPW of a generation plan built to use LNG would cost $10.7 billion to $11.2 billion (P-01204, p. 1).

By comparison, the Isolated Island Option had a CPW of $10.8 billion (P-01204, p. 1). So, based on Ziff's report, the CPW of LNG was therefore competitive with the Isolated Island Option and potentially lower. This, too, raises a significant question about the decision to screen out LNG as a potential supply option.

It is also noteworthy that Nalcor commissioned a report on LNG (P-01203) from PIRA Energy Group (PIRA). The PIRA report concluded that the "high price threshold combines with a high cost of regasification in Newfoundland and Labrador to make potential LNG import extraordinarily costly by international standards" (P-01203, p. 4). Interestingly, the comparison was to natural gas prices elsewhere rather than to the price of the Isolated Island Option.

Based on PIRA's estimates, the likely cost of LNG would have been $18.40 to $24.39 per Mcf[5] after delivery, storage and regasification (P-01203, p. 6). Those prices were substantially lower than the Ziff estimates of $25.10 to $27.15 per Mcf, after delivery, storage and regasification (P-00060, p. 8). Interestingly, Nalcor did not prepare a CPW estimate based on the information in PIRA's report, but it is clear that it would have been significantly lower than the Isolated Island Option.

Nalcor had permission to publish the PIRA report, but it never did. James Keating explained that Edmund Martin decided not to use the report when he was advised that no one from PIRA could come to present it. It is troubling that the PIRA report was not shared, particularly given that its LNG cost estimates were lower than those in the Ziff report.

I conclude that the explanation provided by Mr. Keating for not making the PIRA report public is implausible. I find that the true reason for Nalcor's decision to withhold the report is that it might have raised questions about Nalcor's decision to screen out LNG as an option.

As well, GNL received only one final Ziff report on natural gas (P-00060). However, Ziff had initially prepared two reports, one for Grand Banks gas and another for LNG. GNL engaged Wood Mackenzie to review Ziff's draft report on LNG. Wood Mackenzie subsequently prepared a draft report in which it estimated not only that regasification costs would be 50% lower than estimated by Ziff, but also that they could be further reduced by leasing a floating regasification facility. It concluded: "Relative to the use of

[5] One thousand cubic feet

LNG imports as a fuel, Wood Mackenzie's research would tend to have lower costs than those determined by Ziff" (P-01312, p. 10).

Yet Nalcor did not perform a CPW analysis on LNG based on Wood Mackenzie's cost information. Had it done so, it is clear that LNG would have been significantly cheaper than the Isolated Island Option. If the Wood Mackenzie report had been released in its entirety, that would likely have raised questions about why Nalcor had screened out LNG. Instead, Charles Bown, GNL's principal liaison with Nalcor, directed Wood Mackenzie to remove the LNG review from its report (P-01578, p. 1). Mr. Bown testified that he did so based on the direction of the then Minister of Natural Resources, Jerome Kennedy, and that he would not have done this on his own (December 5, 2018, transcript, pp. 74–75). Wood Mackenzie eventually released a final report that addressed only the issue of Grand Banks natural gas (P-00091). Its conclusions on LNG were not made public until its draft report was presented at the hearings.

Some evidence suggested that there may have been some security of supply issues related to LNG. However, the nature of these issues would depend on the supply contracts that Nalcor eventually secured. The decision to screen out LNG meant that no contracts were even considered.

It is now impossible to determine whether the actual cost of LNG would have come closer to Ziff's pessimistic estimate or to Wood Mackenzie's more optimistic estimate. In either case, it was at least competitive with, and potentially significantly cheaper than, the cost of the Isolated Island Option. To determine which estimate was the most accurate, Nalcor would have had to contact potential LNG suppliers, seek quotes and invest resources to obtain a better estimate of regasification costs. This work was never done.

The decision not to further investigate LNG in the face of the information that was available at the time undermines the narrative that Nalcor and GNL were impartially seeking the lowest-cost power. The decision to screen out LNG as a supply option was unreasonable. I recognize that in its *Sanctioning Phase* report, Grant Thornton reached a different conclusion for both natural gas and LNG (P-00014):

> Nalcor's decision to eliminate NG and LNG as a power supply option was based on an expert review dated from 2001 (10 years old at the time of their submission to the P.U.B.). At the time of the P.U.B. review, there were public submissions which opposed this conclusion. The GNL engaged external experts that supported their decision. Based on our review nothing has come to our

> attention which would suggest that excluding natural gas and LNG was unreasonable. (p. 22)

This conclusion may have been reasonable based on the evidence that was reviewed by Grant Thornton on natural gas and LNG. However, the Commission's review was based on additional documentary evidence that was not available to Grant Thornton and on the testimony of witnesses at the hearings.

CONCLUSIONS ON PHASE 1 SCREENING

In summary, I have concluded that many of Nalcor's screening decisions were incomplete or unreasonable. This does not mean that the options screened out were ready to be entered into Strategist. Most of the potential viable alternatives that Nalcor screened out would have required additional work and exploration before being included in a generation plan. For example:

- Assessing more wind generation would have required a more comprehensive analysis of the long-term limits on wind penetration and of the cost of higher penetration
- Assessing more small-scale hydro sites would have required a study of NLH's archives, the identification of the most promising sites and the preparation of up-to-date cost estimates
- Assessing deferral to 2041 would have required at least a discussion with Hydro-Québec
- Assessing imports from Québec would have required discussions with Hydro-Québec
- Assessing Grand Banks natural gas would have required discussions with the oil companies
- Assessing LNG would have necessitated discussions with potential LNG suppliers and further work to estimate regasification costs

Each of these steps would have required Nalcor to invest real resources into fully optimizing the Isolated Island Option. As Philip Raphals suggested to the PUB (P-00360):

> Strategist is just a beginning. Then, it takes a lot of hard work, to find ways to improve the plan, to make it better and more robust.

> This, indeed, is one of the most important differences between the Interconnected scenario and the Isolated Island scenario: the former has had thousands of man hours of effort put into it to perfect, optimize, and reduce uncertainty. . . . The Isolated Island scenario remains an early draft. (p. 4)

Even after the PUB responded to the Reference Question, there were concerns about the reasonableness of the estimates for the components for the Isolated Island Option. MHI's Rich Horocholyn observed this in an email sent to Mack Kast of MHI on May 1, 2012 (P-00744):

> Re: DG3 for the Isolated Option, I don't believe what we had previously even met DG2 standards and Nalcor themselves virtually admitted much *[sic]* when they described the level of effort that went into the cost estimates for items in that planning scenario. If they bring MF/LIL to DG3, and even if we ask them to claim the costs for Isolated also meet DG3 levels, unless we can see substantive studies and estimates I don't believe it would be credible for MHI to accept those costs also should be handled with +30/-10%. (p. 1)

It is unfortunate that MHI chose not to state this in its January 2012 report for the PUB.

Even if some of the cost estimates were later updated, it is clear that Nalcor was not interested in expending the cost and effort of optimizing the Isolated Island Option because it already had committed to the Lower Churchill Project. While this commitment was often justified by referring to the Province's 2007 Energy Plan (P-00029), that Plan did not call on Nalcor to curtail its exploration of alternatives to the Lower Churchill development. Rather, it called for Nalcor to "conduct a comprehensive study of all potential long-term electricity supply options in the event that the Lower Churchill project does not proceed" (P-00029, p. 40). Furthermore, GNL did little to ensure that Nalcor had complied with the requirement to do this comprehensive study of all potential long-term electricity supply options.

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CHAPTER 4: BUILDING THE CASE

NALCOR'S ASSUMPTIONS AND FORECASTS

To determine whether the Project would meet the Island's electrical energy needs at the lowest possible cost consistent with reliable service, Nalcor was required to:

- Choose definitions of "cost" and "reliability" from a wide range of possibilities
- Finalize a series of complex assumptions and forecasts about how much energy the Island would need
- Assess which alternatives to the Interconnected Island Option would be considered
- Determine the cost of each of those alternatives (as well as the cost of the Interconnected Island Option)

None of these tasks can be resolved by mechanically applying accepted principles or best practices. Each is an exercise in judgment, and each carries with it the opportunity for optimism or bias to influence the analysis. What follows is a brief summary of Nalcor's methods of analysis of the various options, as well as an examination of the assumptions and forecasts used in those analyses.

Cumulative Present Worth

As has been shown earlier, Nalcor chose to evaluate the cost of generation-expansion options using calculations of Cumulative Present Worth. This method required the determination and comparison of all costs (capital, operating, fuel and power purchase) associated with each component of the two Options under consideration.

I agree with the following conclusion of Grant Thornton in its *Sanctioning Phase* report (P-00014):

> CPW methodology in assessing the lowest cost option is both used and considered acceptable practice in the utilities industry. (p. 42)

Methodology

Nalcor's CPW analysis considered only costs that were specific, and thus incremental, to both the Isolated Island and the Interconnected Island options. Costs that were common to both, such as the cost of maintaining the Bay d'Espoir plant or its transmission lines, were appropriately excluded because they would not alter the outcome of the analysis.

Because CPW is a multi-year analysis, a "discount rate" was applied to future costs to determine their present value, thus reflecting the "time value of money." Simplistically, this is how CPW works: the present value of a $100 expenditure today is $100. Applying an annual discount rate of 10%, the present value of a $100 expenditure made one year from now is $90. Using the same discount rate of 10% yields $81 for the present value of a $100 expenditure made in two years.

There is no widely agreed-on, single best discount rate to be applied in such analyses. Although a discount rate reflects all the factors that affect the time value of money, which include inflation, financing costs and capital structure, these factors are different for different investors, so different discount rates are appropriate for different investors.

Nalcor chose to set its discount rate to equal its cost of capital—that is, the annual cost to Nalcor of raising money. Nalcor financed the Project through a mixture of debt and equity, so the discount rate it used in its CPW analyses was equal to the weighted average of the interest rate on its debt and the return on its equity. At DG2, Nalcor used an 8% discount rate and at DG3 it used 7%. The Commission heard evidence from Pelino Colaiacovo that the 7% discount rate used at DG3 reasonably reflected Nalcor's situation as a potential investor in the Project. However, it did not take into account ratepayers' situations or the underlying public policy analysis, which might have led to different rates, as outlined below. Mr. Colaiacovo indicated that the discount rates for groups of consumers are generally higher than Nalcor's 7%.

For GNL or any other institution analyzing the Project as a public policy choice, a discount rate of 7% might not have been appropriate, since public policy should not unduly benefit the interests of the current generation over future generations. Mr. Colaiacovo further indicated that the current literature on "social discount rates" suggests that for a government performing a public policy analysis, a discount rate of 5% is more appropriate (July 17, 2019, transcript, p. 6).

Having considered this evidence, I find Nalcor's 7% discount rate was reasonable. It strikes a reasonable balance between the ratepayers' interests, which might call for a higher discount rate, and the Province's interests, which might call for a lower discount rate. It also reflects Nalcor's interest as an investor.

However, I accept Mr. Colaiacovo's observation that it would have been better for Nalcor and the PUB to have considered the Project decision using a range of discount rates. Doing so would have provided more information about how the decision to sanction would affect different generations of ratepayers.

The CPW method considers only the costs, not the benefits, of a project. For the Muskrat Falls Project, it did not take into consideration benefits such as export sales of surplus energy, net dividends, environmental advantages and stimulation of the local economy. This exclusive focus on cost made the CPW method an appropriate way to determine the option that had the lowest possible cost for ratepayers, a stated objective of the Province's energy policy. Ratepayers have no right to revenues from export sales or to net dividends.

The CPW's exclusive focus on cost, however, did not provide a fair analysis of the Province's policy for developing the lower Churchill because it excluded many economic, strategic and environmental reasons why the development was deemed desirable. If these potential benefits were considered, it was entirely possible that a project could provide a net positive benefit to the Province without providing the lowest cost to ratepayers.

As well, if Nalcor had explored some worst-case financial scenarios, the exclusive focus on ratepayer costs and the exclusion of possible rate mitigation would have made the analysis unrealistic. For example, if the Project experienced higher capital costs, schedule overruns and low load, some rate mitigation would have been seen as necessary. Evaluating worse-case scenarios without rate mitigation has little or no practical benefit. In other words, a more thorough analytical process might have forced Nalcor and GNL to consider up front the extent to which it would be possible to mitigate worst-case scenarios. But as is discussed in more detail later in this chapter, Nalcor did not fully explore worst-case scenarios, so rate mitigation was not considered.

It is important to note that Nalcor deviated in practice from the standards of CPW analysis that it had articulated publicly. In 2012, Nalcor's Investment Evaluation team and financial advisors noticed that the FLG provided an advantage: it made exports from Muskrat Falls more profitable than they would have been otherwise (June 4, 2019, transcript,

p. 68). Nalcor's Auburn Warren (Manager, Investment Evaluation) directed that the additional profitability of exports be used to reduce projected rates in the Interconnected Island Option. In turn, this decision, implemented through complex financial modelling, reduced the CPW of the Interconnected Island Option by $69 million.

The decision to make these calculations is inconsistent with the CPW principles Nalcor was espousing at the time, which claimed that only the costs, not the benefits, of the Project were being considered. It was also inconsistent with Nalcor's repeated public statements that the Project was being evaluated as if surplus energy was being spilled. If surplus energy was to be spilled, there would be no additional $69 million in export profitability.

Nalcor explained its decision to include some export revenue in the CPW analysis by saying that one of the principles of the FLG was that its full benefit was intended to go to the ratepayers. The final Power Purchase Agreement (PPA), which directly affected what ratepayers would pay, did not reflect this additional export profitability. More fundamentally, if the CPW analysis had included some export profitability, it should not have been presented as if it assumed all surplus energy was spilled.

The inclusion of the $69 million in savings (October 26, 2018, transcript, p. 6) is an example of how arbitrary choices can affect the judgment calls implicit in CPW analysis. The decision to include export profitability was dubious. The subsequent decision to present the CPW analysis as if it excluded all export revenues was, in fact, misleading. Both decisions made the Project look better than it otherwise would have appeared.

The Maritime Link

It is also important to examine how the Maritime Link was treated in the CPW analysis. From DG2 onward, the ML had been integral to the Project. Nevertheless, both the DG2 and DG3 CPW analyses excluded it. This seems reasonable, since ratepayers were not supposed to pay for it directly—it was to be built and paid for by Emera in exchange for the delivery of power to Nova Scotia for 35 years. Similarly, the value of export sales delivered via the ML did not belong in the CPW analysis, because that revenue would also flow to Nalcor and on to GNL.

However, the arrangement between Nalcor and Emera for the ML did have effects that are relevant to ratepayers. The energy and capacity that Nalcor committed to Emera, for example, would not be available for use to meet Island loads. While Nalcor's forecast showed the Project producing enough power to both meet the Island's loads and supply Emera, it is possible that Island loads might become higher than forecast. In that scenario, the need to find an alternate source of power would be a cost to ratepayers because of the commitment to supply firm power to Emera. If Nalcor had analyzed a full range of possible load scenarios, it would have encountered some in which the Emera transaction would be a cost to ratepayers.

In addition, Nalcor's filings with the PUB indicated that the ML played an important role in supporting reliability on the Island. It could provide significant backup potential if the LIL failed (P-01669, p. 12) because power could be imported from Nova Scotia, if needed. If the ML ended up not being sanctioned, the PUB, which was the regulator responsible for reliability, could require the addition of more backup generation capacity in the Interconnected Island Option.

Finally, the FLG was a key part of the business case at both DG2 and DG3. At DG2, it appears that the prospect of an FLG was a reason for not establishing a management reserve to cover strategic risks (P-00077, p. 249). At DG3, the FLG was assumed to be available and was included in the CPW analysis. However, at the time of sanction (December 2012), the FLG was not yet a certainty because it was contingent on the approval of the ML by Nova Scotia's Utility and Review Board. That approval was not granted until November 2013. The CPW advantage for the Interconnected Island Option would have been significantly reduced had the FLG not become available. This scenario was never taken into consideration in the CPW analysis.

<u>A 50-Year Time Frame</u>

The Project required a large upfront capital investment but, once built, it would produce abundant power with relatively low operating costs for a long period of time. Given the Project's long-term nature, Nalcor chose to evaluate it over a 50-year period beginning in the year that the Project was to be completed. Nalcor felt that the 50-year period allowed the costs of the Project to be evaluated over a time frame that was long enough to yield a more reasonable comparison to the alternatives. First power was expected in 2017. In 2010, this led to a 57-year evaluation period from DG2 (2010) or a 55-year evaluation period from DG3 (2012).

Long time frames were not new to Nalcor. For decades, NLH had been using a 50-year period to evaluate versions of the Lower Churchill Project. Choosing to use a long time frame was, nevertheless, one of the most significant decisions that Nalcor made in performing the CPW analysis on the Project, and one that was criticized throughout the hearings.

A long time frame has a major disadvantage: it relies on assumptions about the distant future. Some of these assumptions are explicit forecasts of critical parameters, such as load forecasts, construction costs and fuel prices. Others are implicit assumptions about society and technology. What new power-generation technologies will develop? How will expectations about the reliability of an electrical grid evolve? What rules or expectations will develop about the use of fossil fuels?

It is not possible to forecast accurately so far into the future. It is, of course, possible to produce estimates, but even precise ones will be inaccurate. A CPW analysis that is extended half a century into the future becomes a mix of reliable estimates in the early years and nothing more than guesswork in later years.

Pelino Colaiacovo provided the UARB with the following "perspective on the use of forecasts and projections", which it quoted in its July 2013 decision on the application for the ML (P-00245):

> 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 past. However, the longer the time horizon of the forecast, the more likely that changes will cease to be incremental, and hence 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. . . .
>
> 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. . . . 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. (pp. 30–31)

Mr. Colaiacovo presented a nuanced perspective on the 50-year time frame at the hearings. A long-term perspective presents valuable information about the Project, but so do other perspectives. Short-term perspectives are very important, particularly because short-term forecasts are much more reliable. A perspective beyond 50 years is also valuable. After 2067, the Project will produce very cheap power for a long period of time, a significant benefit that is not included in the 50-year analysis.

Mr. Colaiacovo's analysis suggests that, by taking Nalcor's assumptions and forecasts at face value, the Interconnected Island Option was more expensive than the Isolated Island Option at least until the mid-2030s, as can be seen in Figures 2.12 and 2.13 prepared for the Commission by Mr. Colaiacovo in 2019 (P-04445, p. 59).

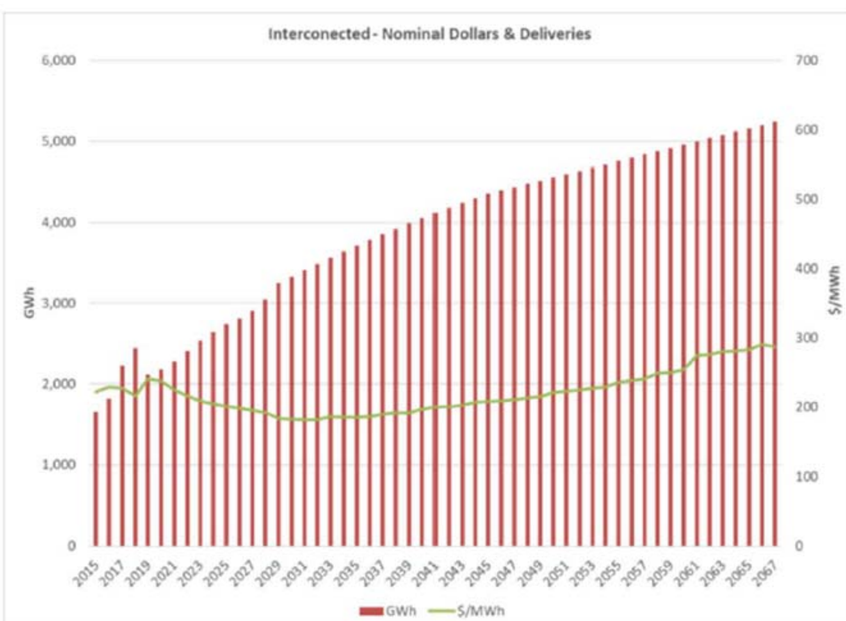


Figure 2.12: Interconnected Island Option – Nominal $ per MWh and GWh Deliveries

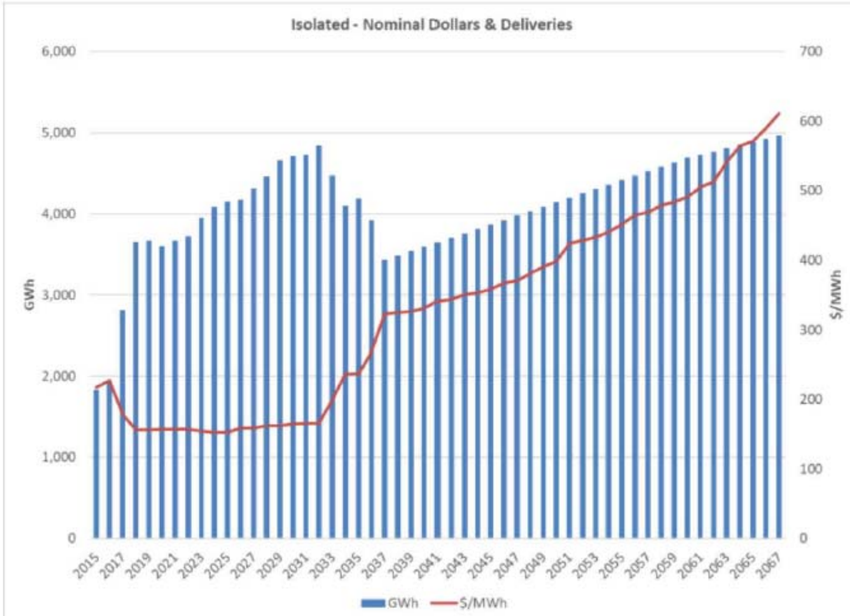


Figure 2.13: Isolated Island Option – Nominal $ per MWh and GWh Deliveries

The reason the Isolated Island Option increases so dramatically in cost in the 2030s is that Holyrood would be replaced by expensive new thermal facilities at that time. These new facilities would consume diesel fuel rather than the cheaper Bunker C fuel now used. The CPW advantage for the Interconnected Island Option was driven by the cost of these capital expenditures in the mid-2030s and the effective elimination of fuel costs once Muskrat Falls power becomes available.

While the use of a longer period in CPW analyses may well be acceptable, decision makers should not expect or demand certainty when only an uncertain prediction is possible.

Decades ago, when NLH started modelling the LCP using 50-year infeed models, its models stopped before 2041. These models were focused on the natural question of how to get to 2041, the year when the Upper Churchill Contract will end and abundant power and energy from Labrador will become available. But 2041 lies near the mid-point of the long CPW evaluation period. There can be certainty that the end of the Upper Churchill Contract will change the province's electrical system profoundly, but it would have been, and still is, difficult to know exactly what will change and thus how the event might affect the business case for the Project. The nature of the changes and effects will become clearer as negotiations proceed in the years leading up to 2041. Having 2041 lying in the middle of the analysis period significantly increases the uncertainty already latent in the long-term forecasts used by Nalcor.

I find that it would have been more appropriate for Nalcor to consider the Project over several different time frames rather than focusing exclusively on the 2012 to 2067 period. Such analyses would have revealed that the preference for the Interconnected Island Option was mostly derived from the period from the 2030s to the 2060s, the period in which forecasts were the most uncertain. It would also have revealed that the Project would likely provide benefits in the 2070s and beyond.

A long-term analysis was necessary in evaluating the Project. However, using a long-term time frame placed great weight on long-term forecasts. As a result, the uncertainty inherent in long-term forecasts is of paramount importance in the analysis. As will be seen, Nalcor failed particularly in its treatment of long-term uncertainty.

Load and Demand Forecasts

NLH produces a load forecast every year that predicts electricity use for the following 20 years. These load forecasts predict both the total amount of electrical energy use and peak demand for electrical power for each of the 20 years. Their main purpose is to ensure that NLH's generation assets will produce enough energy to meet annual demand and can reliably produce enough power to meet any peak demand. Generation assets take a long time to build, so it is important to identify potential shortfalls years in advance.

At DG2 and DG3, NLH produced extended load forecasts to 2067 for both the Isolated Island and Interconnected Island options. These load forecasts were significant inputs into the CPW analysis.

NLH had used the same method for producing load forecasts for decades. It divided its customers into three classes: residential, industrial and commercial (the latter two sometimes classified together as "general service" customers). Different methods were used to estimate the load for each class of customer, then the results were totalled to produce a load forecast.

At DG2 and DG3, to estimate load for residential customers (or "domestic service" in NLH parlance) NLH used an econometric model. NLH tracks the historical relationships between changes in specific indicators and changes in the demand for electricity, and it used that information to predict future demand for electricity. As usual, NLH considered the main indicators affecting residential load to be:

- **Housing starts:** As more homes were built, energy consumption would increase
- **Personal disposable income:** As people acquired more money, they would use more electricity
- **Electricity prices:** As rates rose, people would use less power
- **Fuel prices:** When electric heat was cheaper than oil heat, new homes would be built with electric heat and existing homes would possibly shift slowly from oil to electrical heating
    - NLH forecasted this process would continue in this province until a saturation point is reached—about 80% of homes having electric heat, a factor based on Québec's long history with cheap electricity
- **Technological change:** As appliances became more energy efficient, residential customers would generally use slightly less power (better insulation and other energy-efficient measures were also contributors here); NLH assumed this trend would continue

NLH relied on GNL's Department of Finance for data and for forecasts of indicators such as housing starts and disposable income. It obtained fuel price forecasts from PIRA, a reputable international forecasting agency, and adjusted them to account for shipping, currency conversion and other costs. It estimated electricity rates internally.

NLH's "industrial" customers are large facilities that use significant amounts of power. They include the Corner Brook Pulp and Paper mill (Kruger), the Come-by-Chance oil refinery (North Atlantic Refining), the Long Harbour nickel processing facility (Vale), the Long Harbour oxygen processing facility (Praxair) and the Duck Pond copper-zinc mine (Teck Resources). Because its pool of industrial customers is so small, NLH consults its customers directly to estimate industrial load.

At both DG2 and DG3, Teck advised that the Duck Pond mine would close fairly early in the forecast period. As a result, its load did not form a significant part of the long-term forecast. NLH assumed that the load from other industrial customers would remain constant throughout the forecast period.

Finally, to estimate load for “commercial” customers (small and medium-sized businesses), NLH used an econometric model. The main inputs were the growth in the province’s gross domestic product (GDP) and the estimated investment in commercial building space. GDP estimates were obtained from GNL’s Department of Finance.

As stated earlier, NLH typically prepares a 20-year load forecast every year. Even the two-decade period raises significant challenges for accurate forecasting. MHI estimated that a good load forecast would likely err by 1% for every year in the future, so a 10-year forecast could be off by 10% and a 20-year forecast by 20%. The Project was to be evaluated on a 55-year time frame, however, so NLH had to extend its 20-year load forecast by another 35 years. To do so, it made these assumptions:

- The total industrial load would remain largely unchanged throughout the forecast period
- The commercial load would increase at a constant rate
- The residential load would expand at a constant rate until the electrical heat saturation point was reached, then it would expand at a slower rate

<u>A Top-Down Forecast</u>

In its DG2 report, MHI suggested that NLH should also have prepared an end-use forecast. This would involve estimating and compiling more detailed data about electricity use in the province—for example, whether energy was being used for heat, hot water, lighting or other appliances and devices from households and businesses (P-00048). NLH rejected this recommendation, suggesting that this type of forecast would be far more expensive to do and it would not necessarily add accuracy to the forecast. As I understand it, however, the primary point of doing a bottom-up forecast is not to increase accuracy but to gather information about how electricity is being used, which can help identify opportunities for conservation.

On its face, a bottom-up forecast about end users may be equally as speculative as a top-down term forecast of overall power use. That said, I cannot conclude whether the information presented from an end-use forecast would have been worth the cost of collecting the data or would have changed Nalcor’s business case analysis.

Department of Finance Data

The first of two Grant Thornton forensic audit reports (*Sanctioning Phase* (P-00014), dated July 16, 2018, and prepared at the request of the Commission) noted that the GNL Department of Finance economic projections, which NLH used for its load forecast, were different from those of the National Energy Board, Statistics Canada and the Conference Board of Canada (P-00014, p. 34). The decision to use Department of Finance data dates back to the 1990s and there is no evidence that replacing or supplementing it with data from other forecasters would have reduced uncertainty about the load forecast or improved the business case analysis to any extent.

Demographic Change

Ronald Penney and David Vardy, members of the Muskrat Falls Concerned Citizens Coalition, proposed to the Commission that NLH's load forecast methodology did not take into account the province's aging population. They suggested that senior citizens are likely to live in smaller spaces and use less energy than younger people. As a result, they said, NLH's residential load forecast may well have overstated demand.

While this suggestion has some intuitive appeal, the relationship among population, demographics and load forecasts may be more complex than that. Even if it were clear that this relationship was exactly as Mr. Penney and Mr. Vardy suggested, I am unable to conclude whether or by how much the addition of population and demographics to the load forecast model would have improved its overall accuracy.

Island Industrial Load

Nalcor's assumption that industrial load would remain unchanged is fragile. In particular, the pulp and paper mill in Corner Brook, the single largest electricity user in the province, could close at any point in the forecast period. Other industrial users might emerge to replace this loss of load, but that would take time and is impossible to predict with any confidence or guarantee of accuracy.

NLH assumed that the Island's industrial load would remain unchanged, even though it also assumed, in the Interconnected Island Option, that it would stop buying electricity from the Corner Brook Pulp and Paper mill's co-generation plant. That action would remove one of the Corner Brook plant's sources of revenue. Although there is no evidence about the extent to which this would affect the Corner Brook plant's viability, it adds to the uncertainty of the plant's future.

Unlike the Isolated Island Option, the Interconnected Island Option assumed that energy from Muskrat Falls and the Island grid would be able to support industrial development in Labrador, a benefit of the Interconnected Island Option. That would be a benefit for the Province, however, rather than for Island ratepayers. The possibility of industrial development in Labrador, in fact, only adds to the uncertainty of the load forecast.

I conclude that NLH's assumptions about industrial load were reasonable. However there remains a question as to whether these assumptions added to the intrinsic uncertainty about the long-term load forecasts.

Price Elasticity

No discussion of load or demand for power is complete without some discussion of price elasticity, which measures the responsiveness of demand for electricity to a change in its price. Because NLH assumed the industrial load would remain constant, the price elasticity for industrial load would be zero. Based on decades of data from tracking local loads, NLH estimated that residential consumers had a price elasticity of 0.3. This meant that a 10% price increase in electricity cost, for example, would reduce residential energy use by 3%. NLH was unable to estimate any effect of price changes on commercial energy use and so did not include price elasticity in its commercial forecast.

In both the Interconnected Island and Isolated Island options, electricity rates were likely to rise significantly. High price elasticity would reduce loads in both models. This would tend to favour the Isolated Island Option over the Interconnected Island Option because, in the Isolated Island Option, reducing loads would reduce fuel costs, a significant cost component of this option. With the large upfront investment for the Interconnected Island Option, a reduction in loads would have had less effect on the overall cost.

Several witnesses provided evidence to the Commission about price elasticity, including Dr. James Feehan, a Professor of Economics at Memorial University. After Project sanction, Dr. Feehan conducted a review of literature on price elasticity and developed his own econometric model of it that was based on data from other jurisdictions. His research suggests that, in the long run and particularly with larger price increases than this province has experienced to date, both residential and commercial consumers would have significantly higher price elasticities than NLH's model suggested.

Dr. Feehan's work on price elasticity was not available at the time of Project sanction, but some of the literature and data he reviewed was. I cannot conclude, one way or the other, whether the estimates that Dr. Feehan considered in his research are more or less accurate than NLH's. I can conclude that there is a range of uncertainty surrounding NLH's price elasticity estimates, particularly given the size of the potential price increase for electricity and the length of the time involved in the scenarios. This all adds to the uncertainty surrounding the load forecast.

A load forecast normally also includes some consideration of technological changes and of Conservation and Demand Management, steps that utilities take to encourage customers to conserve energy and to reduce their peak load demand. CDM programs include public education campaigns, subsidies for energy-efficient appliances, and lighting and electricity pricing designed to encourage conservation.

The closest NLH's model comes to acknowledging the potential effects of CDM is the use of a "technological change" variable in the residential load forecast. This variable reflected the observation that, after accounting for income and electric heat penetration, households in this province have tended to use less electricity over time, in part because appliances become more efficient. Nalcor suggested that its technological change variable reflected the impact of past CDM programs. However, up to 2012, CDM programs in the province were relatively small compared to programs in similar jurisdictions. Little money had been spent to little effect. This suggests that the technological change variable Nalcor used does not reflect the historic influence of CDM, nor can it suggest the possible effects of a significant future CDM program. The potential for any such CDM program affecting load forecast is discussed in greater detail later in this chapter.

I conclude that the DG2 and DG3 load forecasts were based on assumptions that were generally reasonable. Other forecasters might produce different, perhaps even better, forecasts using different choices and factors. As I discuss below, however, Nalcor's team did not appear to appreciate how many valid forecasting alternatives were possible, nor how different the outcomes might have been.

That said, I would emphasize that reasonable assumptions cannot eliminate uncertainty. There are significant limits to the accuracy of a forecast of electrical loads 55 years into the future. This can easily be seen by turning the 55-year time frame backward and imagining a forecast that predicted loads for 2012 from the perspective of 1957—before the development of an interconnected Island grid, modern appliances and computer/device use, rural electrification, or the developments at Bay d'Espoir, Churchill Falls or Holyrood. How accurate could such a forecast be? How much weight could be put on it?

In its October 2012 report, and as referred to above, MHI stated: "A reasonable performance measure is a maximum forecast deviation of ±1% per year. A 10-year-old forecast, for example, should be within ±10% of actual energy load observed" (P-00058, p. 24). This implies a broad range of uncertainty, particularly in the latter years of a 55-year forecast. The effect of this uncertainty on the business case was not considered by Nalcor.

Further, sensitivity analyses conducted by Nalcor revealed that the CPW analysis was highly sensitive to the load forecast. Nalcor ought to have understood that, given this high sensitivity, the results of the CPW analysis were uncertain. This was a significant issue for the business case that was not appreciated or adequately communicated to the decision makers, in particular to GNL. The primary interaction between the load forecast and the business case is that, in the long term, lower loads tend to favour the Isolated Island Option.

At DG2, capacity deficits were forecast to emerge in 2015 and grow each year thereafter. Nalcor's plan was to build one small combustion turbine to meet the most urgent deficits, while waiting for the Project to come on-line (P-00034). By DG3, even with the addition of the planned combustion turbine, the forecast had small capacity deficits on the Island system in the winter of 2014–15. This risk, however, was seen as acceptable (P-01136). The decision to accept this risk of capacity deficits failed to account for the uncertainty inherent in the load forecast or for the risk that the Project would be behind schedule. As it has turned out, the schedule overruns at Muskrat Falls have been partially offset by lower-than-forecast system loads. If system loads had grown as quickly as foreseen at DG3, capacity deficits in 2017, 2018 and 2019 would have been an even more pressing issue.

Fuel Price

Nalcor's estimates of fuel price were based on 20-year forecasts from PIRA. PIRA produced low, reference and high fuel-price prediction series in US dollars (USD) for the period between 2012 and 2031. Nalcor took these predictions, converted them into

Canadian dollars (CAD) using Conference Board of Canada projected CAD/USD exchange rates, and adjusted them to reflect shipping costs. According to the testimony of Paul Stratton, a senior market analyst with NLH, Nalcor increased the PIRA forecast price series for the period from 2032 to 2067 by 2% per annum compounded annually for every year in that period (September 26, 2018, transcript, pp. 29–30). Nalcor's core CPW analysis used PIRA's reference fuel-price forecast. The sensitivity analyses done at both DG2 and DG3 considered the low and high fuel-price series determined by PIRA.

A report from Westney Consulting Group (Westney) indicated that, given that Nalcor was running only one fuel-price scenario, the most reasonable forecast would have been an "expected" forecast that averaged all three series, rather than one that used only the reference forecast. Using the expected forecast would have been slightly more favourable to the Interconnected Island Option. I find that little turns on this point.

Nalcor's use of the PIRA forecast for the 20-year period from 2012 to 2031 was reasonable. However, Nalcor's adjustments to PIRA's forecast numbers for the later period (2032 to 2067) were unreasonable because Nalcor escalated each fuel price series at the same 2% rate, freezing the ratio of the low, reference and high forecasts to each other. In other words, Nalcor assumed that the uncertainty in the long-term fuel forecast was fixed, so that forecast prices for 2067 were as certain as those for 2032.

The real uncertainty about fuel forecasts grows with each year you move into the future. By the end of the forecast period, it would have been unclear whether there would even be a legal trade in fossil fuels at all. Nalcor's long-term projection understated the uncertainty implicit in the type of fuel forecast it used.

Regulation of Greenhouse Gas Emissions

At both DG2 and DG3, Nalcor assumed there would be no carbon pricing and no significant regulation of GHG emissions. This was consistent with Nalcor's general assumption that policy and technology would remain static until 2067. I find this highly questionable.

As Nalcor's submission in 2011 to the PUB acknowledged, Canada had already gazetted regulations requiring coal plants to significantly reduce their emissions. In the same document, Nalcor indicated that it expected similar limitations would be extended to heavy fuel oil facilities such as Holyrood (P-00077, p. 120). It is striking that in 2011 Nalcor acknowledged expecting more regulation than it built into its analysis model.

At the time, it seemed likely that future federal governments would take more aggressive steps to curb emissions in the years leading to 2067. This was a real threat for the Isolated Island Option, which consisted largely of fossil-fuel generation assets. Of all Nalcor's questionable choices, leaving out the potential for this type of regulation is the only one that significantly favoured the Isolated Island Option. It is still too early to tell what action current and future governments may take on GHGs and what the consequences of that action may be for the Project's business case.

Other Deficiencies in Nalcor's Assumptions and Forecasts

Conservation and Demand Management

NLH and Newfoundland Power Inc. (Newfoundland Power) had been collaborating on Conservation and Demand Management initiatives for some time before Project sanction. Indeed, CDM was referred to in GNL's 2007 Energy Plan (P-00029) and conservation was key to GNL's 2011 Energy Efficiency Plan (P-00789). Nevertheless, as stated above, the CDM programs in place prior to Project sanction were significantly less extensive than those in effect in other jurisdictions.

Many jurisdictions have built CDM into their energy generation and planning processes by adopting what is referred to as "least-cost planning." Least-cost planning requires utilities to consider CDM as an alternative to new generation. Instead of holding demand constant and finding the lowest-cost supply to meet it, utilities are trying to minimize the cost of meeting electricity needs. In many cases, this is achieved through CDM and other measures aimed at reducing demand for electricity.

NLH has never adopted least-cost planning and did not consider CDM programs as an alternative to generation expansion. The primary reason for this approach is that, in the case of an isolated system that cannot import power, demand reductions stimulated by CDM are said to be too speculative to count on. A reliance on CDM to reduce load demand, in NLH's view, could lead to generation shortages and blackouts.

In addition to rejecting least-cost planning, NLH did not include the projected savings from ongoing CDM programs as a factor in its load forecasts. The technological change variable, discussed above, predicts that gradual increases in energy efficiency will steadily continue into the future, regardless of CDM. As a result, NLH's load forecast would remain unchanged if spending on CDM programs either suddenly quintupled or was suddenly cancelled.

I accept that savings resulting from CDM programs could be less certain than the increased capacity offered by a new generation facility. CDM programs might reduce the demand either more or less than expected, depending on how effectively those efforts affected consumer behaviour. This uncertainty is particularly significant in an isolated system. I cannot accept, however, that this is sufficient reason to entirely discount CDM as a viable alternative to generation. Furthermore, even if their results are difficult to count on, I cannot accept that CDM efforts have no impact at all on loads.

Utilities already make generation planning decisions despite considerable uncertainty about load growth, forced outage rates, weather and many other factors. They accommodate this uncertainty by using conservative estimates and creating reserves. These techniques can also be applied to any uncertainty concerning CDM and I do not accept that projected CDM savings cannot be accommodated reasonably inside this process. Perhaps CDM savings could be discounted to reflect uncertainty. Perhaps CDM savings could be considered as a tool to meet long-term capacity and energy deficits, rather than short-term deficits, so that if savings failed to materialize there would be time to make adjustments.

Similarly, NLH's load forecast already accounts for many uncertainties. Depending on how conservative a forecast is desired, savings from ongoing CDM programs might be discounted considerably when included in a load forecast. These efforts are relevant to long-term load forecasts. The announcement of a substantial CDM program should have some impact on load forecasts.

NLH's treatment of CDM—ignoring it, basically—was doubly flawed. It failed to consider ongoing CDM in future load forecasts and it failed to consider expanding CDM efforts as an alternative to generation expansion and increased fuel expenditures. Both flaws are significant in light of the structure of the Island's electrical load and the sensitivity of the business case to the load forecast.

<u>The Structure of Island Loads</u>

The structure of the Island's electrical supply and demand made CDM initiatives particularly attractive.

The bulk of the Island's energy and capacity comes from hydroelectric facilities that were developed decades ago and have likely been fully paid off: Bay D'Espoir, Cat Arm, Hinds Lake and many others. These facilities produce very cheap power, but they can only provide part of the system’s energy and capacity.

The main source of the remaining energy and capacity has been thermal generation, most notably the steam turbines at Holyrood. Powered by oil, these are far more expensive to operate than the Island’s cheap hydroelectric facilities, but they have the ability to produce large amounts of reliable winter power and as it is needed. As loads fluctuate and grow from year to year, the additional demands on the Island system are mainly covered by Holyrood.

The Island’s rate structure averages out all the costs of operating the electrical system, including the costs of the distribution system, the costs of cheap hydroelectric power and the costs of expensive thermal power. Rates are higher than the cost of cheap hydroelectric power would suggest, but significantly lower than the cost of expensive thermal generation would suggest. The full implications of this will be explored shortly.

The main residential use of electricity is to create heat to warm homes and water. With no local natural gas service, the main sources for home heating and hot water have been oil and electricity. Most homes on the Island have either an oil furnace, which provides both hot water and heat, an electric hot water tank paired with electric baseboard heaters or some combination of electric and oil devices. Electric systems have been cheaper to install and operate for decades, so an ever-rising share of homes use electricity for heat and hot water.

This outcome has been wasteful and inefficient. Each home that converted from oil to electric essentially shifted its power source from an oil furnace to an oil turbine (Holyrood). As I understand it, furnaces turn oil into heat far more efficiently than turbines turn oil into electricity. The evidence before me is that steam plants such as Holyrood convert oil into electricity with an efficiency in the range of 35% to 45%, whereas a home oil furnace turns oil into heat at a much higher efficiency in the range of 70% to 95%.

This situation could be seen as a major public policy failure. The widespread conversion of homes from oil furnaces to Holyrood-powered baseboards and hot water tanks means that the Island burns far more oil to create the same amount of heat that could be generated by oil furnaces. This is wasteful economically and environmentally.

The conversion of home heating from oil furnaces to electricity was not an inevitability, it was a policy choice. Other jurisdictions have had incentives to encourage conversion away from electric heat and hot water. Others had robust CDM programs. Still others had different pricing structures, as will be discussed shortly. The Province, in the face of slowly rising reliance on electrical heat and hot water systems, did nothing.

The move toward inefficient, thermal-generation-powered baseboard heaters should not have been seen as irreversible. Other technologies exist for generating domestic heat and hot water, including oil furnaces, wood stoves, air-sourced heat pumps and geothermal systems. Public policy could be designed to encourage the use of alternatives to baseboard heaters.

The Isolated Island Option assumed that the Island would use electric baseboard heaters to power more and more homes until the market was saturated. It would do this in the face of ever-rising fuel prices and ever-rising reliance on thermal generation. Nalcor's plan was to accept this future and take no significant policy measures to avert it. I cannot accept that this plan was reasonable. I also find that this approach was contrary to the Energy Plan, which clearly favoured strong CDM. Nalcor appears to have understood the Energy Plan very selectively.

Before continuing, I should emphasize that the policy issues surrounding electric heat will change entirely once the Muskrat Falls generating station starts supplying the power to meet Island loads. Baseboard heaters will no longer be drawing on expensive Holyrood fuel but instead will be using Muskrat Falls power, which must be paid for even if it is not used. Policies to reduce winter demand, which were sorely needed from the 1970s to the early 2010s, will no longer be beneficial.

<u>Alternative Energy Pricing</u>

Dr. James Feehan presented a perspective on the public policy failure just outlined. The problem, as he expressed it, is that electricity is mispriced in the province. According to Dr. Feehan, consumers use resources such as electricity more efficiently if they are paying the actual cost of producing those resources. If the price they pay is less than the cost of production, consumers will consume too much of those resources.

As Island consumers convert from oil to electric heat, NLH must generate additional power at Holyrood. Producing additional power is expensive, but its extra cost is not fully passed on to consumers. Instead, they pay the average cost of producing power, which is relatively low because of the Island's cheaper hydroelectric power. In essence, cheaper hydroelectric power subsidizes more expensive Holyrood power, so consumers buy Holyrood power for less than it actually costs to produce it.

Dr. Feehan suggested that if consumers paid the cost of generating additional electricity instead of the average cost of electricity, they would install alternatives to electric baseboard heaters. They might keep their oil furnaces, for example, or they might put in more insulation and/or invest in heat pumps.

I accept that it is possible to design pricing systems that provide consumers with incentives, so that they consider the cost of additional generation, even while leaving average rates unchanged. For example, Dr. Feehan suggested using seasonal pricing to bring prices in line with cost. In the summer months, existing hydro power is capable of meeting demand and the cost of producing additional energy is low. However, in the winter months, the cost of producing additional energy is high. If, under seasonal pricing, consumers paid higher rates in the winter than in the summer, Dr. Feehan suggested they would consider the true cost of additional winter demand before installing electric heat. Seasonal pricing is used in many jurisdictions and I was given no explanation as to why it would not have worked here.

The principle underlying seasonal pricing can be further refined with time-of-day pricing, a billing structure in which consumers pay more for power used in daytime peak hours than power used at night. Time-of-day pricing is also applied in many jurisdictions and encourages more efficient consumption. Unlike seasonal pricing, which can be accommodated with existing electric meters, time-of-day pricing requires the installation of more sophisticated meters, entailing a capital cost.

Multi-tier pricing (charging different rates for different amounts of electricity) is another example of an efficient pricing mechanism. This system is already implemented in the province's isolated diesel networks because their cost of generation is even higher than Holyrood's. These consumers pay average Island rates for an initial block of electricity but a higher rate for additional power. The effect is that they pay an affordable rate for lighting and appliances but are discouraged from using baseboard heaters. Like seasonal pricing, this system is easy to implement with existing meters.

NLH uses a version of multi-tier pricing in selling electricity to Newfoundland Power. An initial cheap block of power represents the Island's cheap hydroelectric power, with a subsequent expensive block of power representing more expensive thermal generation. Newfoundland Power does not pass this two-block structure on to consumers. Instead, it charges them a single average rate for their electricity. Thus the two-block system fails to create incentives for efficiency. At least one NLH employee responded to Dr. Feehan's suggestion with this observation (P-00325):

> NFLD Power needs to pass along our efficient cost structure as they incur it instead of bundling [it] wholesale into distribution and then charging retail customers a blended overall rate. (p. 5)

If the PUB had adopted more efficient pricing models decades ago, the Province could have avoided increasing its oil-generated power to meet the demand from electric baseboard heaters. If the Island had adopted efficient pricing in the early 2010s, I find that it could have slowed, or possibly reversed, the growth in the use of electric heat, thereby significantly improving the business case for the Isolated Island Option.

The Marbek Study on Conservation and Demand Management

In 2007, the PUB ordered NLH to do a study on CDM and create a five-year plan for its implementation. NLH and Newfoundland Power partnered to commission Marbek Resource Consultants (Marbek) to report on CDM's potential (P-00246). At the time of Project sanction, this study was the best summary of the Island's potential CDM savings.

The Marbek study started by estimating all the potential electricity savings that would be cost-effective. To determine whether a particular saving would be cost-effective, it estimated that each kilowatt hour of electricity conserved saved the system 9.8 cents. At that cost, a wide range of measures were cost effective, including installing energy-efficient lighting, adding insulation and using more energy-efficient appliances in residential and commercial sectors, as well as various system improvements in the industrial sector.

Marbek recognized that, even with encouragement, consumers are unlikely to avail themselves of every economically advantageous savings opportunity. It outlined two scenarios, an Upper Achievable Potential that "assumes a very aggressive program approach and a very supportive context" and a Lower Achievable Potential that "assumes that existing CDM programs and the scope of technologies addressed are expanded, but at a more modest level than in the Upper Achievable Potential" (P-00246, p. 9). In total, the Marbek study found that CDM programs could lead to very significant reductions in total energy and peak loads, as outlined in Figures 2.14 and 2.15 (P-00246, p. 13; P-00246, p. 15).

Service Region	Milestone Year	Peak Load Savings (MW)	
		Upper Achievable	*Lower Achievable*
Island and Isolated	2011	27	14
	2016	60	36
	2021	99	61
	2026	144	83
Labrador Interconnected	2011	1.4	0.9
	2016	3.8	2.4
	2021	6.4	3.8
	2026	9.7	5.5

Figure 2.14: Total Achievable Peak Load Savings Potential

Milestone Year	Reference Case	Achievable Savings (GWh/yr.)		Achievable Savings As % of Reference	
		Upper	*Lower*	*Upper*	*Lower*
2006	6,468	-	-	-	-
2011	6,888	211	117	3.1	1.7
2016	7,139	437	261	6.1	3.7
2021	7,427	679	414	9.1	5.6
2026	7,685	951	556	12.4	7.2

Figure 2.15: Achievable Electricity Savings Potential

Following its review of the Marbek study, NLH and Newfoundland Power developed a five-year CDM plan. Implementation results lagged behind targets for both companies.

In his testimony, Philip Raphals explained that in 2009–10, about half the amounts budgeted for CDM had been spent, achieving about half the targeted savings. In addition, the utilities' total investment in CDM was about 0.75% of utility expenditures (P-00358, p. 9), compared to Marbek's recommendation of 1.5% for a utility "in the early stages of CDM programming" (P-00246, p. 35). In dollar terms, Mr. Raphals observed that the province's utilities were spending $2.22 per capita on CDM compared to $29.02 in Québec and $40.63 in British Columbia (P-00358, p. 10).

For reference, Marbek concluded that "once program delivery experience is gained," spending could rise to 3% or higher (P-00246, p. 35). Even with funding at 3% of spending, Marbek observed that utilities often had “more cost-effective CDM opportunities than could be met by the 3% funding” (P-00246, p. 36). Given Island ratepayers’ reliance on baseboard heating and the utilities’ lagging implementation of CDM, it was reasonable to assume that the Island would have had many opportunities for cost-effective CDM investment.

Marbek evaluated CDM opportunities based on technologies that were available in 2008. Technological improvements between 2008 and 2067 could offer additional ways to improve energy efficiency. All of this casts further doubt on Nalcor’s claim that the technological change factor it used in its analysis fully addressed the potential of CDM.

The Marbek report and its implementation confirm my impression that the Island had a significant opportunity to reduce loads through CDM. However, it missed this opportunity in favour of looking at building new generation.

It should be noted that another consultant firm, Navigant, subsequently reviewed the Marbek report as part of its review of Nalcor’s DG2 supply decision. Navigant concluded that Marbek’s Upper Achievable Potential was “very aggressive,” concluding that “it would not be reasonable to utilize the Upper Achievable Potential for system planning purposes” (P-00042, pp. 41, 42). Navigant outlined two potential scenarios (P-00042, p. 42) that it saw as more realistic, which had the following annual reductions after 20 years (in 2031): 750 GWh (an upper planning estimate) and 375 GWh (a lower planning estimate).

Navigant and Nalcor prepared some analyses of how these two scenarios would affect the CPW of the Interconnected Island and Isolated Island options. The “lower planning estimate” reduced the Interconnected Island Option’s CPW advantage by approximately 20%, and the upper planning estimate reduced its CPW advantage by approximately 40% (P-00042, p. 64). At DG3, Nalcor did not perform an analysis of how CDM might affect the CPW analysis.

There are several reasons to believe that the potential for conservation might have significantly exceeded the results of Navigant’s and Nalcor’s sensitivity analyses:

- While it was possible that Navigant’s lower estimate of achievable CDM savings was more realistic than Marbek’s higher analysis, the opposite is also possible; Nalcor chose to focus only on the expert that was more pessimistic about the potential for CDM

- Marbek's estimate of which CDM methods would be cost effective was based on the estimate that reducing energy use would save the system 9.8 cents per kilowatt hour (kWh), and Nalcor's Isolated Island Option assumed ever-rising fuel costs until 2067 and an even greater reliance on thermal generation, so both these forecasts imply that conservation would become more valuable, justifying increasing investments in energy efficiency; Navigant's analysis does not explicitly consider the cost-effectiveness of CDM, but it is logically germane to any analysis
- Marbek estimated potential CDM savings only until 2026 and Navigant only until 2031; the analysis of the Isolated Island scenario would run until 2067, during which time additional savings would have been likely
- The efficient pricing systems advocated by Dr. Feehan were natural complements to an incentive-based CDM program, since efficient pricing would have given consumers additional reasons to take advantage of conservation initiatives; incentives would also help soften the impact of efficient pricing on consumers who were reliant on electric heat

To recap, the province's utilities under-invested in CDM for decades leading up to Project sanction. The inefficient design of Island rates offered Holyrood power to consumers at less than the cost of its production, encouraging an economically and environmentally wasteful reliance on electric heating and hot water boilers.

A large-scale investment in CDM combined with efficient pricing had the potential to substantially erode the CPW preference for the Interconnected Island Option. This opportunity was known at the time and was, in my view, unreasonably discounted by Nalcor. There was bias against CDM evident in the testimony of some Nalcor staff and members of the executive. Paul Stratton of NLH's System Planning division admitted in his testimony that he personally did not think that utilities should pay people not to consume power (September 26, 2018, transcript, pp. 36–37). Those who did not disclose their private opinions nevertheless offered what I believe are weak arguments against CDM.

One possible reason for a bias against CDM is that higher CDM levels tended to benefit the Isolated Island Option significantly over the Interconnected Island Option.

Another possible reason is found in Philip Raphals' testimony (and reflected in Paul Stratton's remarks). Mr. Raphals indicated that utility companies are often in a conflict of interest in implementing CDM. They are in the business of selling power. Paying people not to consume power is intrinsically opposed to their business model.

I find that Nalcor unreasonably limited CDM in its generation planning, which negatively influenced the effectiveness and value of its load forecasting. This approach favoured the Interconnected Island Option.

INTEGRATED RESOURCE PLANNING

Integrated Resource Planning is a process that many utilities use to plan power generation. Developed in other jurisdictions in recent decades, the approach is used to make major utility decisions. The Project's Joint Review Panel recommended that Nalcor conduct an IRP analysis. Navigant's draft report made a similar recommendation. Years before Project sanction, the PUB had attempted to investigate how or if it should integrate IRP into its own analysis methods.

Philip Raphals, Pelino Colaiacovo and Dr. Guy Holburn, an expert retained by the Commission who is a Professor of Business, Economics and Public Policy, as well as Suncor Chair in Energy Policy, at Western University's Ivey Business School, explained what IRP entails in some detail in their testimony. In addition to treating CDM as an alternative to generation, IRP aims to better address the uncertainties associated with long-term forecasts and to account for externalities, such as pollution and GHGs, that are involved in generation decisions.

IRP is a methodology that evolved from least-cost planning, but it is not a single method expounded by an authoritative source. Rather, it is a collection of methods that have been developed and adapted by various utilities and regulators over the last 40 years. In addition to hearing considerable evidence about the principles underlying IRP, I also heard evidence about IRP processes used in Nova Scotia, Ontario, Manitoba, Québec, British Columbia and several American jurisdictions. Outlined below are the broad principles of IRP.

A recent document prepared by the UARB of Nova Scotia on Integrated Resource Planning stated, in part (P-00380):

> What is an Integrated Resource Plan ("IRP")?
>
> Planning and operating a large electrical utility is a complex process. Various types of electricity generation must be carefully balanced to meet customer demand. Many factors can affect how that balance may be achieved. A process that considers a combination of factors and related costs over the next 25 years is used to develop an IRP.
>
> We know there will be changes in the future. For example, if the goal is to reduce air pollution, it might mean that less coal should be burned when producing electricity. If generation by coal is replaced with generation by wind, the costs to do that will be different. Also, more efficient electrical devices might reduce the amount of electricity that is needed. In addition, certain industries that use electricity may expand while others may close.
>
> The IRP process involves a detailed analysis of many factors that impact future generation options. It is important to test different scenarios to identify the best plan that meets our future needs. A preferred generation resource plan will typically have the lowest long term cost. However, it must also be flexible enough to accommodate changing conditions. In addition, it must be able to supply power to customers in a reliable manner. The IRP should be viewed as a strategic guide for future development of the electrical system. (p. 1)

IRP starts with the insight that generation planning is not about regular decision-making choices but about fluid re-analysis over time. No single generation plan is ever likely to be followed for long. Loads, prices and options will change, and the original plan will become obsolete. A major generation decision does not lock a utility into a fixed plan. Rather, it changes the utility's portfolio of assets and options.

To develop this idea: the decision to sanction Muskrat Falls did not commit Nalcor to building a combined-cycle combustion turbine in 2060, though that was part of the DG3 Interconnected Island Option generation plan (P-00058, p. 16). Instead, the gist of the Interconnected Island Option was building the Project plus a combustion turbine. All other decisions would be made later as required by evolving circumstances.

Assuming for the moment that Nalcor's screening decisions were correct, choosing the Interconnected Island Option meant that Nalcor had to face an uncertain future with a specific portfolio of assets and options—the Island's existing hydro, thermal and wind assets, the Project and an additional combustion turbine. To these it could add a certain amount of wind, the Island's three hydro sites and any combination of combustion turbines and combined-cycle turbines.

Similarly, choosing the Isolated Island Option meant that Nalcor would face an uncertain future with a different portfolio of assets and options. It would start with the Island's existing generation sources, supplemented by a refurbished Holyrood plant, the Island's three hydro sites and one additional wind farm. To these it could add some additional wind and thermal assets over time.

Instead of optimizing a single generation plan to meet one particular forecast, as Nalcor did, an IRP analysis models many different possible scenarios to see how each portfolio responds. As Philip Raphals stated in his evidence before the PUB, "[T]he real challenge is to find a plan that is optimal, not just based on current assumptions, but that is **robust** over a broad range of possible futures" (emphasis in original, P-00360, p. 5).

As with any sophisticated financial decision-making model, a utility decision is shaped by many uncertain parameters. These include long-term fuel costs, load forecasts, capital costs for a range of assets and interest rates. A utility generates a range of forecasts reflecting the long-term uncertainty around each parameter. For example, instead of a single fuel-price forecast, the utility could have a low forecast, a reference forecast and a high forecast. The key is that the forecasts should attempt to capture honestly and fully the range of uncertainty surrounding long-term fuel prices.

Based on this analysis, the utility then produces a "reference model," which takes the reference forecast for each uncertain parameter. The next step is to optimize a generation plan for the reference model using each portfolio of resources being considered. The exercise will produce generation plans, like Nalcor's Isolated Island or Interconnected Island options.

However, the IRP method does not end there. The utility then runs the reference model again, changing one parameter at a time. These model runs, called "sensitivities," allow the utility to better estimate how sensitive the model is to each parameter and thus to identify the parameters that drive outcomes.

Having identified the most consequential parameters, the utility would then seek to identify possible combinations of those parameters, called "scenarios." For example, one scenario takes the reference value for each parameter. Another might take the reference value for fuel prices, high load forecast and low capital cost. It is common to test hundreds of scenarios to try to capture the full range of possibilities.

For each scenario, the utility develops an optimized generation plan from each portfolio of resources available. So, for example, instead of having one Interconnected Island generation plan and one Isolated Island generation plan that corresponded to a single reference scenario, each scenario would have its own generation plan built from the Interconnected and Isolated Island portfolios. Comparing how the Interconnected and Isolated portfolios respond to the various scenarios would fairly represent the range of possible futures.

Some IRP processes take into account the environmental and social impacts of different generation plans. Some utilities have a mandate to minimize costs as long as particular renewable targets are met. Others have a broader mandate to consider externalities as part of their planning process, which can be accommodated either through a weighting system or through the exercise of judgment.

Nalcor used a single measure—a CPW analysis using a 50-year time frame and a 7% discount rate—to compare its Isolated Island and Interconnected Island options. Mr. Colaiacovo testified that IRP processes tend to evaluate scenarios using multiple measures. For each scenario, a utility presents results for CPWs and Levelized Unit Electricity Cost over different time frames using different discount rates. The purpose of using multiple measures is to provide as much information as possible about how each choice affects different groups of stakeholders in different scenarios. Some options may have long-term benefits with higher short-term costs, others vice versa. Using multiple measures gives decision makers more details about the costs, benefits and tradeoffs that must be considered when making decisions.

When many scenarios are being evaluated using a wide range of measures, it is extremely unlikely that a single option emerges as the most preferable in all cases. The scenario analysis is a guide to, not a substitute for, judgment. The IRP exercise gives decision makers enough information about the advantages and disadvantages of the various options to make a well-informed decision. As Mr. Colaiacovo wrote in his report for the Commission (P-04445):

> [M]athematical 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. (p. 8)

IRP exercises are typically conducted as part of a utility's regulatory hearing process. This process is a vital part of the planning methodology.

Several expert witnesses testified about a recognized phenomenon in planning: how teams and companies are biased toward their own projects, either consciously or unconsciously. Bias and strategic misrepresentation can distort screening decisions, forecasts and estimates. An analytical framework such as IRP cannot be expected to detect and compensate for these distortions. On the contrary, any analytical method that relies on biased inputs is more likely to produce unreliable outputs.

Similarly, independent consultants cannot be relied on to guard against bias or misrepresentation. Consultants may have limited terms of reference or limited access to information, which occurred in many instances with this Project. Their conclusions may also be affected by their financial interests and sensitivity to a client's wishes. It can be difficult to assess the quality of a consultant's analysis.

The regulatory process helps counteract bias by giving independent stakeholders an opportunity to scrutinize a utility's analysis in detail. Stakeholders will often have the resources and the motivation to find and probe the weak points in this analysis.

The regulatory process also places the final evaluation of the advantages and disadvantages of each choice in the hands of a disinterested regulator, rather than in the hands of any interested party. Given that an IRP process is likely to indicate that several approaches have advantages and disadvantages, using it could give a biased party ample material to justify any preferred course of action. A disinterested decision maker helps to guard against this.

I am not suggesting that a regulatory process is the only possible method of reducing bias, because I have not investigated how comparable investment decisions in the private sector are conducted. From the evidence I have heard, however, an independent regulatory process is the current best practice in the public sector, and it would be unwise to dispense with the regulatory process without some other effective means to control bias.

The PUB considered adopting IRP as early as 2004. It concluded that it had the authority to require IRP and that it was a valuable planning tool. However, it decided that adopting IRP was so costly that the decision to adopt it deserved a planning process of its own. This would ensure that the PUB had information about the costs and benefits of IRP before passing those costs on to ratepayers.

When the PUB returned to the topic in 2007, NLH made these arguments against adopting IRP (P-01876):

- Hydro already prepares an annual system planning report, which reviews the latest long term load forecast, generation expansion requirements, options, costs and issues;
- Demand side management is a key element of an IRP and a study of the technical and economic potential for conservation in the Province will be underway in 2007;
- The Board addressed an IRP for Hydro in Order No. P. U. 14(2004) and expressed its preference for a generic process;
- The BC Hydro model… demonstrates the scope and enormity of the process;
- The Board does not have an accurate estimate of the costs of an IRP; and
- Most importantly the Province's Energy Plan, which will establish provincial policy for the supply of energy, has not yet been released but is anticipated in the coming months. (p. 63)

The PUB remained "convinced that an IRP 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" (P-01876, p. 64). But it still made this decision: **"The Board will not establish at this time a process with respect to the commencement of an IRP exercise"** (emphasis in original, p. 64).

Following release of the Province's Energy Plan, the PUB held a meeting to discuss the desirability of IRP. NLH stated its position on the idea in a letter dated November 12, 2008, that it sent to the PUB. It said, in part (P-01164):

> However, in Hydro's view, the Board and the parties are constrained from undertaking a full ranging IRP because, (1) under the Province's Energy Plan, the Province's preferred view is to meet the longer term electrical generation needs through the development of the Lower Churchill Project, and (2) the Board's jurisdiction to review Hydro's planning and [*sic*] surrounding this project is ousted by the Labrador Hydro Project Exemption Order.

> The Lower Churchill Project is a 2800 MW project comprising two hydro-electric sites, and a transmission link between Labrador and the Island and perhaps other locations on the mainland of Canada. The cost of this project is estimated to be between $6 and $9 billion. The targeted sanction date for the project is 2009; the targeted in-service date is 2015.
>
> . . .
>
> Prudent planning includes the prudent expenditure of funds and effort in the planning process. A thorough consideration of the issues raised by the various aspects of the Isolated Island Case would require a considerable amount of effort which would represent a waste of the ratepayers' money. (pp. 2–3)

The suggestion that the policy to develop the Lower Churchill Project was a justification for not pursuing IRP is puzzling. The LCP decision was one of the most expensive and significant generation planning decisions in the province's history. If there was ever a decision that justified the full scrutiny of a modern planning process, such as IRP, I believe this was it. Deciding not to pursue IRP because of the LCP exemplifies putting the cart before the horse. The decision to pursue the LCP ought to have been the conclusion of a rigorous analysis. Instead, a rigorous analysis was not performed because of the decision to pursue the LCP. Furthermore, it is disingenuous for Nalcor to attempt to justify the decision not to invest in exploring alternatives to the LCP in the name of the Energy Plan. The Energy Plan called for alternatives to be canvassed.

As noted earlier, the Navigant consultants' draft review had recommended an IRP. It is troubling that this recommendation was removed in the final version of their report, at Nalcor's request.

After hearing significant evidence related to the need, purpose and justification for the Project, in August 2011 the JRP also recommended a wide-ranging independent review of the business case for the Project. The JRP concluded that Nalcor had not shown that the Project was justified in either energy or economic terms. It suggested that Nalcor's analysis, which concluded that the Project was the least-cost option, was inadequate. The JRP's "Recommendation 4.3 – Integrated Resource Planning" states (P-00041):

> The [Joint Review] Panel recommends that the Government of Newfoundland and Labrador and Nalcor consider using Integrated Resource Planning, a concept successfully used in other jurisdictions. Such an approach would involve interested stakeholders and look simultaneously at demand and supply solutions and alternative uses of resources over the medium and long term. (p. 69)

In its March 2012 response to the JRP, GNL specifically accepted this recommendation (P-00051, pp. 2–3).

The Province's internal Information Note, approved by Charles Bown, relating to the response to the JRP's recommendation 4.3 includes as part of its rationale: "If IRP is implemented, it would apply to future projects and not be retroactive to the Project" (P-00921, p. 5). To me, this rationale was absurd and robbed the JRP recommendation of its meaning. Why would Integrated Resource Planning be needed to address any resource planning decision other than the one that was before the JRP?

Neither Nalcor nor GNL took any steps to implement IRP despite the JRP's recommendation.

NALCOR'S SENSITIVITY ANALYSIS

Having described what an Integrated Resource Planning process would have entailed, the context is now set to outline the sensitivity analysis Nalcor did use at DG2 and DG3 to reflect the uncertainties inherent in the business case.

Nalcor did not have or use an integrated system for preparing sensitivity analyses of the Project. Any sensitivity that modified the load forecast was sent to NLH's System Planning team, which used Strategist to produce a new generation plan. Having been given only a few generation options, the Strategist program could do little more than change the timing of when these components were introduced. In a high load sensitivity, assets were built more quickly; in a low load sensitivity, they were built more slowly.

Nalcor's Investment Evaluation division used a spreadsheet mockup of the reference case to do all the sensitivity analyses of the Project that did not involve changing the load forecast or the generation options. For example, a change in fuel prices was modelled by increasing or decreasing the price of fuel and leaving everything else constant. This process did not allow for any load or generation optimization because it did not allow changes in fuel price to affect NLH's reliance on thermal assets.

At DG2, Nalcor produced many sensitivity analyses for the Joint Review Panel, Navigant and the PUB. The table in Figure 2.16, prepared by Grant Thornton for the Commission, summarizes the sensitivities analyzed at DG2 (P-00014, p. 54):

Summary of Sensitivities at Decision Gate 2 **			
CPW ($ millions)	Isolated Island	Interconnected Island	Difference
Base case	8,810	6,652	2,158
Annual load decreased by 880GWh	6,625	6,217	408
Fuel costs: PIRA's low price forecast	6,221	6,100	120
Fuel costs: PIRA's high price forecast	12,822	7,348	5,474
Fuel costs: PIRA May 2011 update for Reference Oil Price Forecast	9,695	6,889	2,806
Fuel price reduced by 44% from base case	6,134	6,134	-
Moderate Conservation (375GWh by 2031)	8,363	6,652	1,711
Aggressive Conservation (750GWh by 2031)	7,935	6,652	1,283
Low Load Growth (50% of 2010 PLF post Vale)	7,380	6,628	752
200MW Additional Wind (100MW in 2025 and 100MW in 2035)	8,369	6,652	1,717
MF and LIL Capital Cost +20% & Fuel Cost Reduced by 20%	7,600	7,217	383
MF and LIL Capital Cost +25%	8,810	7,627	1,183
MF and LIL Capital Cost +50%	8,810	8,616	194
Labrador-Island Link capital cost increased by 25%	8,810	7,050	1,760
Muskrat Falls GS capital cost increased by 25%	8,810	7,229	1,581
Federal Loan Guarantee	8,810	6,052	2,758
Holyrood to 2041, then CF at Market Price	7,935	6,652	1,283
Carbon Pricing on Fossil Fuel	9,324	6,669	2,655
CF Energy Post 2067 at Market Rates Instead of Cost	8,810	6,664	2,146
Scenario with: - Fuel cost decreased 20% - Annual load growth decrease of 20% - Capital cost increased for MF and LIL by 20%	7,037	6,878	159
Scenario with: - Annual load decreased by 880GWh - MF and LIL capital cost increased by 10%	6,625	6,598	27

** As adjusted by evidence of Bob Moulton (September 26, 2018, transcript, p. 46)

Figure 2.16: Summary of Sensitivities at Decision Gate 2

These sensitivities accomplished the principal purpose of a sensitivity analysis, in that they show how sensitive the CPW is to various parameters. The CPW preference for the Interconnected Island Option was large, but it was highly sensitive to changes in fuel price, load and capital costs. Adding more wind integration and Churchill Falls power after 2041 also significantly reduced the CPW gap between the two options.

These sensitivities also display the limitations typical of a sensitivity analysis. Only a few combinations or scenarios were run, and none was run that would probe the disaster or worst-case scenario outcomes for either the Isolated Island or Interconnected Island options. For example, while the sensitivity analysis showed that a high fuel price/high load scenario would be very unfavourable for the Isolated Island Option, it did not indicate exactly how unfavourable it would be.

No sensitivity was run in which the Isolated Island Option was favoured, even though many possible combinations of circumstances would have existed that would plainly favour that option. The reluctance to display any scenario in which the Isolated Island Option was preferred reveals a fundamental analytical flaw. As Mr. Colaiacovo wrote in his report (P-04445):

> [I]t 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.
>
> . . .
>
> 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. (p. 69)

Even if combinations had been systematically tested, the sensitivity analysis would have revealed very little about Nalcor's ability to mitigate the worst-case scenarios because the screening process had left Nalcor with few alternatives and little room to optimize. In reality, if Nalcor had encountered a high fuel price/high load situation on the Isolated Island Option, it would then have conducted a rigorous exploration of additional renewable options and of CDM, which Nalcor had ruled out from the start.

Finally, the sensitivities themselves reveal several omissions. No analysis was done of any capital cost overrun above 50%. At DG2, with 5% of the engineering complete, the cost estimates for the Project were high-level screening estimates only and the potential for large cost overruns above these screening estimates should have been apparent.

Additionally, schedule delays are a common and foreseeable construction risk, yet no schedule delays were tested. As quoted in Grant Thornton's *Construction Phase* report (P-01677), dated December 7, 2018, Edward W. Merrow, the founder and CEO of Independent Project Analysis, Inc. (IPA), stated: "Schedule pressure dooms more megaprojects than any other single factor. When there is pressure to move a project along quickly from the outset, corners get cut and opportunists have a field day … But taking risks with megaproject schedules is a fool's game" (P-01677, p. 13). Yet, the potential impact of schedule delays was not tested by Nalcor at all. Given that the Island was counting on Muskrat Falls power, schedule delays would result in increased fuel costs. If existing generation was inadequate to meet rising loads, delays could also lead to the installation of new combustion turbines on the Island.

Load and fuel sensitivities were also significantly narrower than the uncertainty implicit in these variables.

At DG3, the sensitivities assessed by Nalcor were fewer and even more limited than those at DG2, as can be seen in the following table prepared by Grant Thornton (P-00014, p. 55):

Summary of Sensitivities at Decision Gate 3			
CPW ($ millions)	Isolated Island	Interconnected Island	Difference
Base case	10,778	8,366	2,412
PIRA Fuel Price - Expected	11,391	8,376	3,015
PIRA Fuel Price - Low	8,584	8,000	584
PIRA Fuel Price - High	15,435	8,836	6,598
Increase Capex 10%	11,034	8,882	2,152
Increase Capex 25%	11,417	9,654	1,763
Decrease Capex 10%	10,523	7,837	2,686
Increase Interest Rate 50 bps	10,863	8,604	2,259
Increase Interest Rate 100 bps	10,947	8,851	2,096
Decrease Interest Rate 25 bps	10,736	8,250	2,486
Carbon Pricing commencing 2020	11,360	8,368	2,992

Figure 2.17: Summary of Sensitivities at Decision Gate 3

Nalcor's DG3 analysis shared all the deficiencies of its DG2 analysis and failed to include sensitivities of load forecasts, as well as the possibility of a failure to sanction the Maritime Link or the inability to secure the Federal Loan Guarantee.

In its sensitivities on capital costs, Nalcor changed not only the capital costs for the Project but also costs for all other capital expenditures in the Isolated Island and Interconnected Island options. This approach was clearly unreasonable. As Mr. Colaiacovo indicated, as a unique project, the Muskrat Falls development was far more likely to encounter a large capital cost overrun than were any of the Isolated Island Option's capital projects, particularly those involving off-the-shelf thermal or wind assets. The result was a dampening of the effect of any Project overrun on the CPW because any such overrun would be partly offset by an assumed overrun on projects in the Isolated Island Option.

At DG3, Nalcor did not test any cases involving the sensitivity of large capital cost overruns. The Commission engaged Grant Thornton to analyze the impact on the CPW resulting from changes in capital expenditures (Capex) and/or fuel costs. The following table shows how this analysis summarized the sensitivities (P-00015, p. 4):

Infeed	Fuel -50%	Fuel -40%	Fuel -30%	Fuel -20%	Fuel 0% (Base)	Fuel +20%
Capex -10%	$ 7,179,184	$ 7,310,855	$ 7,442,522	$ 7,574,195	$ 7,837,527	8,100,863
Capex 0% (Base)	$ 7,707,654	$ 7,839,325	$ 7,970,992	$ 8,102,665	$ 8,365,997	$ 8,629,332
Capex +10%	$ 8,223,745	$ 8,355,416	$ 8,487,083	$ 8,618,756	$ 8,882,088	$ 9,145,424
Capex +25%	$ 8,995,337	$ 9,127,008	$ 9,258,675	$ 9,390,348	$ 9,653,680	$ 9,917,016
Capex +50%*	$ 10,294,417	$ 10,426,088	$ 10,557,755	$ 10,689,428	$ 10,952,760	$ 11,216,096
Capex +75%*	$ 11,590,381	$ 11,722,052	$ 11,853,719	$ 11,985,392	$ 12,248,724	$ 12,512,060

Isolated	Fuel -50%	Fuel -40%	Fuel -30%	Fuel -20%	Fuel 0% (Base)	Fuel +20%
Capex -10%	$ 7,175,721	$ 7,845,126	$ 8,514,530	$ 9,183,935	$ 10,522,745	$ 11,861,554
Capex 0% (Base)	$ 7,431,315	$ 8,100,720	$ 8,770,125	$ 9,439,529	$ 10,778,339	$ 12,117,148
Capex +10%	$ 7,686,909	$ 8,356,314	$ 9,025,719	$ 9,695,124	$ 11,033,933	$ 12,372,743
Capex +25%	$ 8,070,301	$ 8,739,706	$ 9,409,110	$ 10,078,515	$ 11,417,325	$ 12,756,134
Capex +50%	$ 8,709,286	$ 9,378,691	$ 10,048,096	$ 10,717,501	$ 12,056,310	$ 13,395,120
Capex +75%	$ 9,348,272	$ 10,017,677	$ 10,687,082	$ 11,356,486	$ 12,695,296	$ 14,034,105

Figure 2.18: Sensitivity Analyses of Capital Expenditures and Fuel Costs

Grant Thornton's sensitivity analysis reveals some of the dynamics that would have been more fully explored in an IRP process. Even Nalcor's unsophisticated sensitivity analysis revealed that the Interconnected Island Option fared relatively poorly with low fuel prices, as shown above. It also fared poorly with low loads, no GHG regulation and large capital cost overruns. Extended schedule delays, while not considered in any of the sensitivity analyses, would have adversely impacted the Interconnected Island Option as well. Conversely, the Isolated Island Option fared poorly with high fuel prices, high loads and significant GHG regulation.

In some cases, these factors are related. Capital cost overruns and schedule delays, for example, often occur together because the same construction and commercial challenges that increase costs also lengthen schedules. Similarly, fuel prices have a significant effect on load. In the province's oil-driven economy, both fuel prices and load affect GDP, which in turn is a factor in the commercial load. They also affect disposable income and housing starts, both of which are factors in residential load. As well, they directly affect the relative cost of electric and oil heat, additional factors in residential load.

The capital cost and schedule estimates used in the CPW analysis at DG3 were significantly more optimistic than Nalcor's own internal estimates of capital cost and schedule risk. It is my conclusion that Nalcor had estimated that strategic risk would likely increase capital costs and that a significant Project cost overrun was likely.

Nalcor's position would have been difficult to maintain in an independent regulatory process in which stakeholders could submit requests for information. In all likelihood, an independent regulator that was fully aware of Nalcor's strategic and time-risk analyses would have made provision for these risks in evaluating the CPW of the two options.

Accounting for strategic risk would have increased the CPW for the Interconnected Island Option. Similarly, accounting for schedule risk would have led to increased fuel costs in many scenarios in the early years and may have precipitated the need to add more generation assets. I find that both changes would have significantly reduced, and in some cases erased, the Interconnected Island Option preference.

<u>Conclusions: Integrated Resource Planning</u>

Many of the environmental and social issues raised about the Project could have been dealt with effectively through an IRP process, including:

- The social value of reducing GHGs
- The relative merits of installing scrubbers and precipitators at Holyrood
- The advantages and disadvantages of purchasing less expensive fuel and accepting increased atmospheric pollution

Basically, an IRP process could have offered Nalcor and GNL many advantages while it was considering its course of action and evaluating its options. To summarize, a list of what could have been possible and the lost opportunities follows:

- IRP was the accepted, best way to decide whether to approve the Project; it could have ensured that many of the weaknesses in the business case that are now apparent were fully explored before the decision to sanction was made
- From an analytical perspective, IRP could have ensured that a full range of scenarios was considered and these scenarios would have

reflected the uncertainty implicit in Nalcor's assumptions and forecasts

- IRP would have enabled the Isolated Island portfolio's flexibility to be properly weighed against the various benefits of an Interconnected Island portfolio; it might also have ensured a proper analysis of the various disaster scenarios implicit in each portfolio and the options for mitigating them
- IRP would have allowed a more realistic treatment of CDM options, thus addressing a deficiency in Nalcor's analysis
- Depending on the PUB's precise mandate, IRP might have provided another way to deal with the environmental implications of the decisions, though it is less clear how this might have changed the eventual decisions or public confidence in them
- There is no excuse for not using IRP, which was the leading utility-industry process at the time, to make the biggest utility decision in the province's recent history; an IRP process might have been costly, contentious and inconvenient, but the risks of using a substandard analytical method to make a multi-billion dollar decision speak for themselves
- From a procedural perspective, a full regulatory process involving multiple stakeholders could have ensured that some of the weaknesses in Nalcor's screening process, cost estimates and schedule estimates were brought to light and corrected
- It was unreasonable for Nalcor to use legalistic arguments to rebut the PUB's suggestion to implement IRP planning, and for GNL to disregard the JRP's suggestion to do the same

I can only conclude that NLH and Nalcor effectively obstructed the establishment of an IRP framework. Its absence was not an oversight.

It is impossible to know what would have been the outcome of a proper IRP process, had it been applied to analysis of NLH's options and opportunities. What is known is that the analytical method that was followed was inadequate and left both the decision makers and the public with a distorted sense of the costs and benefits of the Project.

Today, the worst-case scenario for the Project appears to have materialized—low fuel prices, low loads, significant capital cost overruns and schedule delays. The situation would be challenging even if the people of the province had decided to accept this risk with their eyes open, following a full and transparent process. It is now even more difficult and more demoralizing for the taxpayers and ratepayers of Newfoundland and Labrador, because it is abundantly apparent to me that the analysis was flawed and that the scenario the Province now faces was never considered.

Cost of Service Versus Power Purchase Agreement

The Muskrat Falls Project was a large undertaking by a public utility and the borrowing and investment it required needed a mechanism for repayment. Two different models were chosen to determine how the costs of different components of the Project would be repaid. The Cost of Service (COS) model was used for the Labrador-Island Link and a Power Purchase Agreement model was used for the Muskrat Falls Generating Station and Labrador Transmission Assets components. Both models require some description for the purposes of this Report.

Traditionally, a COS model is used to pay for large public utility projects in this province, and elsewhere. The COS model allows public utilities to recover, every year, both the year's annual operating cost plus a "rate of return" on the utility's assigned rate base.[6] Once a new project is completed, the public utility can begin to include that project's full capital cost in its rate base and receive a rate of return on that full cost. Each year thereafter, the repayments reduce the project's capital cost, so the regulator sets the utility's annual rate of return on a lower capital cost amount every year until the project is fully paid off.

In practice, the COS method leads to high payments in the early years following a new project's completion. These payments then decline over time as the project is paid off. Hydroelectric projects, which have long lives and relatively low operating costs, eventually produce very cheap power using COS accounting.

Paying for the entire Project using the COS method was impractical because of the amount of the cost and the length of the repayment period. As I understand the evidence,

[6] A "rate base" is the value of property on which a public utility is permitted, by its regulatory agency, to earn a specified rate of return.

in the early years, if COS repayment was applied to the full Project cost, ratepayers would have faced an extremely high price, even though they would use only a fraction of the power that the Project would eventually produce. By the time loads had grown enough to take advantage of the Project's full benefits, the cost would largely be paid off and the power would be very cheap. But the COS was being applied over 50 years, so not only would the initial immediate increase or "bump" in rates be so significant that it would shock consumers and likely lead to a decrease in demand in the early years, using the COS method could be seen as being unfair. Those early ratepayers would pay a very high price per kWh for comparatively little power, while later generations would pay a very low price per kWh and have access to much more power.

From the early stages in its planning process, Nalcor was aware of the risk of a huge bump in rates if the COS method was used for repaying the cost of all of the new assets. To minimize this, it decided not to use COS accounting for the Muskrat Falls generating station and the LTA. Instead, capital costs for those components would be recovered using an escalating supply price through a method called a Power Purchase Agreement. The PPA was organized as follows: NLH would agree, in advance, to buy an increasing amount of Muskrat Falls energy every year from Project start-up (forecasted for 2017) until 2067. The PPA was a "take or pay" arrangement, meaning that NLH would pay for the agreed-on amount of energy whether it used it or not. The price of this energy would cover monthly operating and maintenance costs of the Project's generating station and the LTA, plus all associated capital costs.

Nalcor used sophisticated financial modelling to calculate what those capital costs would be, to ensure that the capital and financing costs were divided equally among all of the energy purchases that NLH would make over the entire payment period. For ratepayers, this meant that instead of a high initial cost per kWh that would fall over time, the cost per kWh would stay the same until 2067, in inflation-adjusted dollars, that is, during the entire 50-year lifetime of the PPA.

As noted above, under the PPA, NLH committed to buying increasing amounts of energy throughout the 50-year contract period. Since the cost of that power was fixed in inflation-adjusted dollars, this implied that payment amounts would increase throughout the payment period and that most of the cost would be paid off in the PPA's later years.

This difference in the timing of repayment of the two methods—that is, of when the largest portion of the Project cost would be paid off—is the biggest difference between the COS and the PPA models. In COS accounting, the costs are paid quickly, with high energy bills in the early years. Under the PPA model, the costs are paid off far more slowly, with moderate early bills that rise steadily until the end of the 50-year period.

Pelino Colaiacovo provided two distinct criticisms of the fairness of the overall financing arrangements Nalcor used. First, the Isolated Island Option was looking to be cheaper than the Interconnected Island Option until the mid-2030s—even with the assumption that the Interconnected Island Option was overall the least-cost option. In other words, under the COS the Project would increase ratepayer bills for the first few decades after construction, in exchange for significantly reducing bills later on. As Mr. Colaiacovo observed, the ratepayers in the early years who pay higher bills are different from the ratepayers in the later years who pay lower bills. Even if, after analysis of the options, the Project was the least-cost option overall, under the COS system it disadvantaged ratepayers in the early years. They would pay higher bills in the short run but most would not benefit from lower bills in later years. It would be more fair to transfer some of the savings from ratepayers in the later years to ratepayers in the early years (P-04445, p. 77).

I accept this criticism and note that GNL is now instituting a rate-mitigation strategy that, in some respects, restructures financing of the cost of the Project to mitigate rates in the early years.

Mr. Colaiacovo's second criticism was that ratepayers assumed all the risk and cost of building the Project, even though many of its environmental, financial and strategic benefits flow to all taxpayers, not just to ratepayers. The result is not fair to ratepayers, who are assuming an excessive share of the risk for an inadequate share of the benefits (P-04445, p. 4).

I accept this criticism as well. Again, however, I would note that GNL's proposed rate-mitigation strategy will transfer to the ratepayers potentially significant revenue streams that would otherwise have flowed to taxpayers. These could include revenue from export sales.

In 2012, prior to Project sanction, the Department of Natural Resources separately commissioned former PUB chair Robert Noseworthy and Power Advisory LLC, a Massachusetts consulting firm, to review the Term Sheet for the Project (P-03440). In his report, Mr. Noseworthy observed that the contract did not appear to benefit ratepayers for the first 15 to 20 years. Both he and Power Advisory observed that, in general, ratepayers appeared to take on a disproportionate amount of the risks when compared to the rewards that they would receive.

In my view, these opinions correspond closely to Mr. Colaiacovo's concerns. It would have been reasonable to respond to these concerns at the time, by transferring some of the benefits of the Project from taxpayer to ratepayers.

Kathy Dunderdale, who was premier when discussions of financial arrangements for repayment were occurring, testified that she was encouraged to commit to rate mitigation (December 19, 2018, transcript, p. 15). Such a commitment would have alleviated fairness concerns about who shouldered most of the cost, but it also would have improved the CPW advantage of the Project. In addition, she testified that she felt, as a matter of principle, she could not commit a future government to rate mitigation.

I understand Ms. Dunderdale's explanation. The concerns about potential unfairness of the PPA were understood at the time, as was the option of rate mitigation. The government of the day reached a principled decision to leave the questions of fairness and rate mitigation to a future government. As events have transpired, a rate-mitigation plan is now under consideration and will result in a significant transfer of the burden from ratepayers to taxpayers, so as to address at least some of the unfairness implicit under the PPA.

Some people might think that the "take or pay" nature of the PPA also seems unfair because, if loads prove to be lower than expected, the PPA commits NLH to pay for power that it will not need. In practice, however, it would have been impossible to raise the money to build this Project without a firm commitment to pay the money back, and the commitment of ratepayers to pay the costs of the Project was a condition for the FLG. So the alternative was not a more favourable PPA, but no Project at all. If the Project was the least-cost option for ratepayers, which I question, a binding "take or pay" contract was advantageous in the circumstances.

It is clear that large projects such as this one must borrow and use money years before they have any revenue to pay it back. By the time the Project is up and running, the cost of completing it will include not just construction costs but also interest on loans and a return owed to investors for equity invested during the construction period.

POTENTIAL BENEFITS OF THE PROJECT

The Muskrat Falls Project is said to come with many benefits beyond providing power to ratepayers. In 2019, many Project proponents continue to highlight these additional benefits. It is important to note that the Project was not ultimately sanctioned on the basis of these benefits. It was sanctioned on the basis that more power was needed on the Island and that the least-cost option for ratepayers on the Island was the Interconnected Island Option. Nevertheless, for the purposes of this Report, it is helpful to examine Project benefits a little more closely.

In my consideration of Project benefits, I make reference to the "Net Benefits to NL at DG3" table, reproduced below, which was prepared in late 2012 by Nalcor's Investment Evaluation division at the request of Edmund Martin (P-00254):

Net Benefits to NL at DG3

[redacted]	Isolated		Interconnected		Net	
$000	Nominal	PV	Nominal	PV	Nominal	PV
CPW	74,221,796	10,778,339	46,916,599	8,365,997	27,305,197	2,412,342
CPW Induced	22,266,539	3,233,502	14,074,980	2,509,799	8,191,559	723,703
Income (Direct, Indirect and Induced)	7,744,518	1,352,918	5,777,301	2,307,718	(1,967,217)	954,800
Dividends	4,473,138	512,337	22,181,019	1,489,981	17,707,881	977,644
Treasury (Direct, Indirect and Induced)	1,095,016	189,118	862,797	347,562	(232,219)	158,444
Export			3,016,812	746,318	3,016,812	746,318
Water rentals			1,236,980	192,412	1,236,980	192,412
Carbon	(4,868,605)	(629,233)	(33,166)	(2,232)	4,835,439	627,001
Carbon Induced	(1,460,581)	(188,770)	(9,950)	(670)	1,450,631	188,100
Innu dividends			303,146	58,991	303,146	58,991
Total					61,848,209	7,039,755

* PV is present value (2012 dollars)

Figure 2.19: Net Benefits at Decision Gate 3

At the hearings, Auburn Warren described this Net Benefits Analysis as follows (September 26, 2018, transcript):

> So what the net benefits—what it tries to lay out is provide both the nominal and the present value of various benefits that are available under either the Isolated Island scenario or the Interconnected scenario, and then it provides kind of what the net benefit is between those two scenarios.
>
> . . .

> I think Mr. [Edmund] Martin, at the time, just wanted to have an understanding of looking at it at a bigger picture. What both of these scenarios—what type of benefits could be seen, not just for ratepayers but for all of the Province in which those ratepayers live as well. (pp. 78, 95)

Mr. Warren testified that, to his knowledge, this benefits comparison was not reviewed by Manitoba Hydro International as part of its DG3 analysis because it was prepared after the MHI report was submitted. Mr. Warren was not aware of any independent review of this analysis (September 26, 2018, transcript, p. 96).

Despite its many flaws, this Net Benefits Analysis is the most comprehensive attempt to analyze the overall benefits of the Project that I was shown at the hearings. It quantifies and compares the net benefits of the Interconnected Island and the Isolated Island options that were under consideration. The conclusion apparent in the comparison is that the net benefits of the Interconnected Island Option exceeded those of the Isolated Island Option by an estimated $61.8 billion in nominal terms and $7 billion in present value (2012 dollars) terms over the expected life of the Project.

As with its CPW calculations, Nalcor applied a discount rate of 7% in its Net Benefits Analysis. As described earlier in this chapter, when evaluating societal benefits from a public policy perspective, a lower social discount rate of 5% is appropriate. This means that the net benefits analysis might well understate the significance of benefits that occur far into the future.

I understand the following from my examination of the Net Benefits Analysis and its categories:

1. **CPW:** This shows the much-discussed "CPW advantage" that Nalcor calculated, in which the Interconnected Island Option would benefit ratepayers by $27.3 billion (nominal) or $2.4 billion (2012 dollars).

2. **CPW Induced:** This shows estimates of the economic spinoffs arising from ratepayers spending the savings resulting from lower electricity rates. Mr. Warren described this phenomenon as spending the "dollars in their jeans" (September 26, 2018, transcript, p. 78). This spending would create economic spinoff in the province, estimated to be worth $8.2 billion (nominal) or $723 million (2012 dollars).

3. **Income (Direct, Indirect and Induced):** Mr. Warren stated that this benefit "is based on actually employing people during the capital process and through the operating phase" (September 26, 2018, transcript, p. 78). He described each of the elements of this benefit as follows:

> Direct . . . are actual people who are involved, like workers, so the construction workers. Indirect would be people who are supporting that, and induced would be more like the economic—the fact that there's money in the economy induces other growth and other employment. (p. 79)

The analysis found that, over a 55-year time frame, the Isolated Island Option was expected to result in economic spinoff that exceeded that of the Interconnected Island Option by an estimated $2 billion (nominal). Because the Project was constructed in the early years of that time frame, however, the present value of this economic spinoff favoured the Interconnected Island Option by $955 million (2012 dollars).

4. **Dividends:** This represents the Province's net return on its equity investment in both options. Mr. Warren described this component of the Net Benefits Analysis as follows (September 26, 2018, transcript):

> So it's—the shareholder, in this case with Muskrat [Falls] it's the Province of Newfoundland and Labrador, is being provided a return of the 8.4[%]. So when you look at the injections of equity during the construction phase and then when in service is attained, you start getting revenue, and the net of revenue and costs and all—and your debt service provides you a return. So . . . when you hit in service you start returning equity—or returning dividends to the shareholder. When you look at that series of cash flows, it yields 8.4 per cent IRR [Internal Rate of Return]. Now, the revenue comes from the ratepayer. (p. 78)

Nalcor estimated that the Province's dividends (net of the cost of debt service) for the Interconnected Island Option would be higher than those of the Isolated Island Option by an estimated $17.7 billion (nominal) or $978 million (2012 dollars).

5. **Treasury (Direct, Indirect and Induced):** Mr. Warren described this benefit as follows (September 26, 2018, transcript):

> Treasury is similar to the [I]ncome line, but that is an estimation of what taxes the province would receive under both [Isolated Island Option and Interconnected Island Option] scenarios. (pp. 78–79)

   As with the Income (Direct, Indirect and Induced) benefit, the Isolated Island Option was expected to result in tax revenue that exceeded that of the Interconnected Island Option by an estimated $232 million (nominal). Once again, because the Project was constructed in the early years of the time frame, the present value of this tax revenue favoured the Interconnected Island Option by an estimated $158 million (2012 dollars).

6. **Export:** This represents the net revenue from export sales of excess electricity. It includes the impact of "ponding," which Mr. Warren explained as follows (September 26, 2018, transcript):

> [P]onding is a term of basically being able to shape your exports accordingly so that you can either import during off-peak hours, let your water rise up, and then when you get a better price during peak hours, you draw down your water, and you, basically, are able to generate additional revenue. (p. 79)

   The Isolated Island Option considered in DG3 resulted in neither excess power-generation capacity nor the ability to export any excess power via the Maritime Link and thus earn export energy revenue, so this benefit was only included in the Interconnected Island Option. Nalcor estimated that this benefit would amount to $3 billion (nominal) or $746 million (2012 dollars).

7. **Water Rentals:** This represents revenue that the Province would derive from a "water-power-rental charge" based on energy produced by the Muskrat Falls generation facility (September 26, 2018, transcript, p. 79). It does not apply to any other asset in the Interconnected Island Option nor to any asset in the Isolated Island Option.

As with the Export benefit, this benefit is only included in the Interconnected Island Option. Nalcor estimated that this benefit would amount to $1.2 billion (nominal) or $192 million (2012 dollars).

8. **Carbon:** This represents the estimated value of avoiding a carbon tax. It was based on the assumptions used in the sensitivity analysis that Nalcor performed at DG3. It assumed a tax of "around $30" per ton of carbon emitted (September 26, 2018, transcript, pp. 50-51).

   Under the Interconnected Island Option, the Island's electricity would be based almost exclusively on renewable energy, thereby largely avoiding the impact of any potential carbon tax. The Isolated Island Option, on the other hand, would continue to rely heavily on generation assets that create carbon and so would be subject to any carbon tax. Nalcor calculated that the net benefit of avoiding a potential carbon tax, which ratepayers would have been expected to pay through increased electricity rates, would favour the Interconnected Island Option by an estimated $4.8 billion (nominal) or $627 million (2012 dollars).

9. **Carbon Induced:** Nalcor calculated this benefit in a manner similar to the "CPW Induced" benefit, in that the savings for ratepayers from avoiding the inclusion carbon tax in electricity rates would result in ratepayers spending a portion of those savings. This spending would create economic spinoff in the province estimated to be worth an additional $1.5 billion (nominal) or $188 million (2012 dollars).

10. **Innu Dividends:** Mr. Warren explained this benefit as follows (September 26, 2018, transcript):

    > [T]he Innu dividends is—as a part of the Interconnected and development of Muskrat Falls, the—under the terms and conditions of the Innu Benefits Agreement, the IBA [Impacts and Benefits Agreement], there's dividends that will be provided to the Innu. (p. 79)

Nalcor calculated that these dividends, created only in the Interconnected Island Option with the completion of the Project, would have a benefit of an estimated $303 million (nominal) or $59 million (2012 dollars).

These are my observations about the Net Benefits Analysis:

1. **CPW:** If Nalcor's CPW analysis had been correct, I would have been prepared to accept the CPW benefits outlined in Figure 2.19. It is clear to me, however, that the CPW analysis overstated the preference for the Interconnected Island Option. A correct CPW analysis would have resulted in a greatly reduced CPW advantage or a possible CPW disadvantage for the Interconnected Island Option.

2. **CPW Induced:** The CPW induced benefit tracks the CPW benefit. Thus, a correct CPW analysis would have resulted in a greatly reduced CPW induced advantage or possibly a CPW induced disadvantage for the Interconnected Island Option.

3. **Income (Direct, Indirect and Induced):** I accept that this is a Net Benefit arising from the Project. To the extent that the Project understated construction costs, it also understated the economic spinoffs for construction. As the Project's costs have increased significantly, the economic benefits from incomes paid have also increased significantly.

4. **Dividends:** At DG3, it was assumed that the Province would borrow billions to invest in either the Isolated Island or the Interconnected Island option. Nalcor assumed that in return it would receive dividends. The rate of return the Province is entitled to receive for its investment is higher than the interest rate it pays on the debt incurred to fund the investment. The net dividend the Province receives is a benefit of the Project.

   In the years since 2012, Project cost overruns have meant that GNL has invested far more than it had planned. This has increased GNL's net dividends significantly and also increased credit risk costs.

In principle, dividends (net of the cost of related provincial debt) can be used to increase public services or to cut taxes. However, the current Government plans to use some of the Project dividends for rate mitigation due to Project cost overruns.

5. **Treasury:** I accept that there would be tax revenue generated from the Project, subject to my observations above regarding increased capital costs as well as my comments below about opportunity costs.

6. **Export:** I accept that benefits will be derived from the export of surplus energy. The Net Benefits Analysis assumed that surplus energy would be sold into Nova Scotia and New England markets.

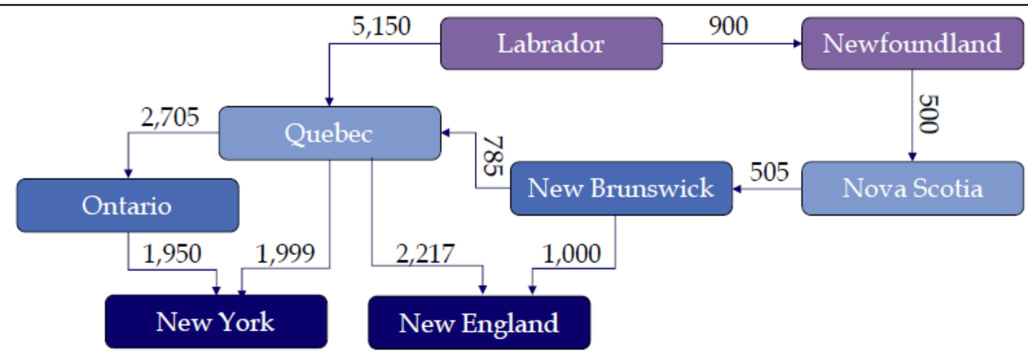
I have no reason to question the reasonableness of Nalcor's estimates of the value of surplus energy sales (including ponding) at the time the Net Benefits Analysis was created. Since then, however, export prices have fallen considerably. This is something that Nalcor could not have reasonably known at the time.

Notwithstanding that Nalcor could not have reasonably expected the considerable drop in export prices that has occurred, the possibility of falling prices should have garnered more consideration in any analysis done of the benefit of export sales.

Of greater significance in any export benefit analysis is the matter of transmission constraint for export sales. Transmission rights through Québec have already been discussed. With Nalcor's minimal ability to use Québec's transmission system, a Maritime route was chosen. As seen on the diagram reproduced in Figure 2.20 (P-04457, p. 57), assuming there is available energy to export and that a market exists for it, there are constraints on the amount of electricity that can be transmitted via this route.

Significantly, while up to 500 MW can be transmitted to Nova Scotia via the ML, there is at present a constraint through New Brunswick of 350 MW of export transfer capability. While the diagram shows a capacity of 505 MW, that will only be available subject to certain Maritime Link upgrades.

I do not know whether these constraints have been built into the benefits analysis done by Nalcor. As a result, I am left to question whether the benefit as calculated is fully accurate. In any event, the current lower export price makes the number calculated inaccurate.



Note: According to NSPI's 10-year system outlook report, the NS-NB interconnection currently provides 350 MW of export transfer capability. However, the figure above presents the capability at 505 MW as NSPI's Q4 2017/2018 Nova Scotia Transmission System Operating Limits document mentioned that 'the Maritime Link Upgrades will increase export Total Transfer Capability up to 505 MW.'

Sources: Newfoundland and Labrador DNR's "Gull Island: Why not develop Gull Island first?" (November 2012); Hydro Quebec TransEnergie's Transmission System Overview; Emera's Maritime Link map; ISO-New England's "Forward Capacity Auction 14 Transmission Transfer Capabilities & Capacity Zone Development – Planning Advisory Committee" presentation (March 21, 2019).

Figure 2.20: Transmission Export Capabilities in Selected Jurisdictions (MW)

7. **Water Rentals:** On the surface, I accept that this could be considered a net benefit arising from the Project. The charges for the water rentals, however, would be paid by Nalcor or ratepayers to GNL, therefore it is difficult to understand how, in substance, this can be considered a net benefit.

8. **Carbon:** I accept that there are potential benefits derived from savings in carbon taxes.

   In addition to the financial impact of avoiding carbon taxes, the Project will reduce the province's GHG emissions and thus have global environmental benefits. It will also have local environmental benefits through reduced local air pollution, particularly in the Holyrood area.

I find that the Net Benefits Analysis did not go far enough on this point. It does not reflect the potential financial impact that more stringent emissions regulations in the future might have. For example, a higher carbon tax was possible at some point in the years between 2012 and 2067.

9. **Carbon Induced:** I accept that potential savings from avoiding carbon taxes and thus providing lower electricity rates would result in ratepayers spending at least a portion of those savings, and so create economic benefits.

10. **Innu Dividends:** I accept the Net Benefits Analysis regarding Innu Dividends.

I have these further observations with respect to matters not addressed in the Net Benefits Analysis:

1. **Opportunity Costs:** The Net Benefits Analysis fails to account for what economists call "opportunity cost."

   Many of the workers hired to work in Labrador for the Project already had jobs elsewhere that they had to leave behind. Some would have been replaced, but to some extent their departure would simply raise the local cost of construction. Other projects that might have taken place would have been cancelled or postponed.

   Similarly, GNL could have found other uses for the billions of dollars it has invested in the Project. Some of these uses may have had a higher social or financial return than the net benefits from the Project.

   I am unable to quantify these opportunity costs but find that they would reduce the net benefits.

2. **Industrial Development:** At DG3, Nalcor noted that surplus energy and capacity from the Project combined with interconnection with the Island could enable local industrial development both in Labrador and on the Island. While not explicitly considered in the Net Benefits Analysis, GNL did take some steps to analyze this.

   Two papers, "Labrador Mining and Power: How Much and Where From?" by GNL's Department of Natural Resources (P-00071) and "Economic Impact and Analysis of Iron Ore Mining Industry in Labrador, 2011–31" by Dr. Wade Locke (P-00069), noted several potential mining developments in Labrador. These projects, for which the availability and cost of power would be major considerations for potential investors, represented billions of dollars in investment and spinoffs.

   The papers were unable to estimate the impact that the Project's completion would have on development decisions.

3. **Preparation for 2041:** The preparation for 2041, when the Upper Churchill Contract ends, was another benefit omitted from the Net Benefits Analysis. Pelino Colaiacovo testified that, by demonstrating its ability to bypass Québec and build an independent transmission line to export markets, the Project has strengthened the Province's negotiating position with Hydro-Québec leading up to 2041. He testified that he had heard Edmund Martin discuss this as a Project benefit prior to Project sanction. In his report, he stated (P-04445):

   > 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. (p. 34)

I accept that the Project may well strengthen the Province's negotiating position in preparation for 2041 and that this may result in a significant benefit.

4. **Impact on the Province's Debt:** Terry Paddon, a former Deputy Minister of Finance and former Auditor General, explained that the Project does not increase the Province's "net debt" because the Province's equity investment provides an asset that offsets the debt the Province incurred to invest in the Project. I accept Mr. Paddon's evidence on this matter. Nevertheless, I have no doubt that the cost of the Project has caused an increase in the Province's overall debt, which could have an effect on the Province's credit rating and borrowing capacity.

5. **Environmental Costs:** The Net Benefits Analysis failed to consider the environmental cost of the Project, notably the increase in methylmercury levels in country food and the risk of a failure of the dam structure, which would cause environmental and other damage. Placing a value on these items would have been difficult, but they were relevant considerations.

6. **Relationships with Indigenous Peoples:** It is worth noting that the Project has had real implications for GNL's relationships with Indigenous Peoples, which are discussed later in Volume 3. At the time, these implications may have been difficult to fully appreciate, let alone value, but they are significant and certainly relevant to the decision to sanction the Project.

I would also like to make a few observations about how the economic and social benefits of the Project have changed since 2012. With low loads, low fuel prices, large capital cost overruns and significant schedule delays, the Isolated Island Option now has a significant CPW advantage. Cost overruns have significantly increased the economic benefits of construction. Finally, the credit risk associated with the Province's increased debt load, which may have seemed remote in 2012, has become pressing.

Overall, I conclude that the Project has brought some benefits to the Province. Some of these benefits (economic spinoffs, tax revenue, dividends, energy exports and carbon tax reductions) can be quantified. Others, such as the potential for Labrador industrial development and preparing for 2041, have economic consequences that are difficult to quantify. Still others, such as reduced emissions and air pollution benefits, are intangible.

The Project also has some costs, including the potential of methylmercury contamination, the risk of dam failure and the damage to relationships with Indigenous Peoples, that were not captured in the Net Benefits Analysis.

While the Net Benefits Analysis is Nalcor's most thorough analysis of the broader economic and social benefits of the Project, it considers only some of the relevant factors and even in dealing with those it fails to consider important issues such as opportunity cost. The potential benefits of Labrador industrial development and preparing for 2041 are not considered at all. If the broad social benefits of the Project had formed a significant part of the business case, this Net Benefits Analysis would have been a very inadequate basis on which to make a multi-billion-dollar decision.

I cannot reach any firm conclusion about the extent of broader economic benefits flowing from the Project to the Province. However, as noted above, the Net Benefits Analysis was not communicated by Nalcor or GNL as forming part of the justification for Project sanction.

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CHAPTER 5: PREPARING FOR DECISION GATE 2

On October 10, 2010, Premier Danny Williams announced that the Government of Newfoundland and Labrador was proposing to develop the lower Churchill River by proceeding at Muskrat Falls first and Gull Island later. He also advised that a federal loan guarantee was being sought and that discussions were ongoing with Emera for the creation of the Maritime Link for the export of surplus energy (P-00219).

On November 16, 2010, Nalcor issued a document entitled “Lower Churchill Project Gatekeeper’s Decision Support Package: Request for Approval to Proceed to Gateway Phase 3” (P-00078). The recommendation in that package was:

> After a thorough and comprehensive assessment of the options and alternatives to develop the hydro potential of the lower Churchill River for domestic use and export, a phased development of the Project has been selected as the basis of the Gateway Phase 2 recommendation. Nalcor Energy (Nalcor) believes this is the best alternative to meet the Island’s electricity needs, when considering the circumstances with respect to options for energy export.
>
> Phase I will include the development of the Muskrat Falls 824 MW generating station, associated HVac transmission along with an HVdc Transmission Link to the Island, associated Island upgrades, and an HVdc Maritime Transmission Link to Nova Scotia. First power from Muskrat Falls is targeted for the end of 2016.
>
> Phase II, which is expected to proceed no earlier than three years after the start of Phase I, will consist of the 2,250 MW Gull Island hydroelectric generation project and associated HVac transmission to Churchill Falls and export markets. (p. 5)

Gull Island was put on hold in 2010, when Québec refused Nalcor’s application for transmission rights through that province for the Lower Churchill Project. Pending an appeal, access to Hydro-Québec’s transmission lines was limited to the earlier booking of the Upper Churchill Recall Block.

Although the Decision Gate process appears to have provided Edmund Martin with the authority to approve the Project’s passage through the various decision-gate milestones, he did bring the proposal before the Nalcor board for approval, which it granted on November 16, 2010. On the same day, John Ottenheimer, board chair at the time, wrote to the Premier and Minister of Natural Resources reporting the decisions that had been taken.

On November 18, 2010, GNL issued a news release entitled “Lower Churchill Project to Become a Reality; Province Signs Partnership Agreement with Emera Inc. for Development of Muskrat Falls” (P-00036). The signing of this agreement, the Term Sheet, signified GNL’s direction to proceed with the development of the Project. In turn, it was completing the agreement with Nova Scotia that ultimately led to the federal government’s decision to provide a loan guarantee for the Project and the Maritime Link.

THE EMERA TERM SHEET: NEGOTIATIONS AND AGREEMENTS

The signing of the Term Sheet on November 18, 2010, signified the true beginning of the Muskrat Falls Project. Following the signing, negotiations continued to develop several binding agreements, which were already underway.

The Project was expected to produce a total of 4.98 TWh of energy. Based on Nalcor’s load forecast, it was estimated that approximately 40% of the energy (2 TWh) would be required to meet the Island’s demand for energy after Holyrood’s decommissioning. It was thus estimated that 60% of the energy generated at Muskrat Falls would be surplus to the province’s power needs.

The proposed arrangement between Nalcor and Emera meant that some of the energy that was transmitted from Labrador across the Strait of Belle Isle could be delivered to Nova Scotia via the ML. This enabled Newfoundland and Labrador to export anticipated surplus power from the Project to Nova Scotia and through Nova Scotia and New Brunswick to the New England states.

The Term Sheet introduced the concept of the “20 for 20 principle,” whereby Emera would receive 20% of the energy output from the Project in exchange for a 20% investment in its development and operating costs. The benefits for Emera in making this deal included a supply of renewable energy to meet both Nova Scotia’s power requirements and its renewable energy targets.

The Commission retained Grant Thornton to review and report on the Emera agreements and related events connected to Nova Scotia’s utility regulator, the UARB. Grant Thornton issued its report, which was written by Tom Brockway, on September 7, 2018 (P-00453). Mr. Brockway, a partner at Grant Thornton, is a Chartered Professional Accountant with experience in assurance and accounting services. He provides advisory services, such as assistance with financing capital transactions, in a wide variety of industries including the utility sector. He also reviews and interprets commercial agreements. Mr. Brockway was qualified as an expert witness for the purpose of providing opinion evidence on the Emera agreements.

The Grant Thornton Emera and UARB review describes 13 agreements that were concluded to fulfill the terms and conditions of the Term Sheet. They were all signed on July 21, 2012, and most were subsequently amended on July 31, 2014. The agreements formalized the rights and responsibilities of each party and set up a governance structure under which each party's rights and responsibilities would be managed. They also dealt with the development, operation and ownership of the Defined Assets.

Grant Thornton reviewed and reported as follows on five of the most significant agreements, which are related to the Project's development and operational activities:

<u>Two Development Agreements</u>

1. **The Newfoundland and Labrador Development Agreement** established a joint development committee for the Project and provided the mechanics for both the formation and funding of the LIL and the capital structure and rate of return for Nalcor's and Emera's investment in the LIL.
2. **The Maritime Link Joint Development Agreement** established the joint development committee and governance structure for the ML and set out the details of how the ML's development cost would be shared, as well as providing the details for the terms of the ML and the sharing of cost overruns.

<u>Three Operational Agreements</u>

1. **The Energy and Capacity Agreement** provided detailed instructions and requirements for the delivery of power from the Muskrat Falls generating station to Emera and the consequences if the power was not delivered as promised.
2. **The Joint Operations Agreement** established a Joint Operations Committee for the LTA, the LIL and the ML and provided standards of operation for these assets and the mechanism for the 80/20

sharing of operating costs. It also established the conditions for the transfer of the ML to Nalcor 35 years after first commercial power.

3. **The Labrador-Island Link Limited Partnership Agreement** established the structure of the partnership between Nalcor and Emera for the LIL and how that partnership was to be managed, and provided the mechanics for distributions of income to the partners after first commercial power.

Details About the Defined Assets

The various agreements contained many specifics about the development, ownership, and operating and maintenance costs of three Defined Assets: the generating station at Muskrat Falls, the LIL and the ML. They specified the following:

- Nalcor would construct, own and operate the Muskrat Falls generating station and the LTA and would be fully responsible for the cost of the development of these assets
- Emera would construct, own and operate the ML
    - It would be responsible for the cost of the development of the ML and up to 20% of the total estimated development costs of the Defined Assets
    - Costs in excess of the estimated development cost of the ML, as approved by the UARB, would be shared as follows: the first 5% to be paid by Emera, next 5% to be paid by Nalcor and any excess cost greater than 10% to be shared equally by Emera and Nalcor
- Nalcor would construct, own and operate the LIL and be fully responsible for its development cost; Emera would purchase a minority interest in the LIL
- Emera would be responsible for 20%, and Nalcor for 80%, of the O&M costs of the Defined Assets up to the date of first commercial power

- At the time of first commercial power, an in-service Long-Term Asset Management Plan (LTAMP) would be finalized for all Defined Assets; the LTAMP would estimate the O&M costs for the 35 years following the commissioning of the Project
- Emera would be responsible for 20%, and Nalcor for 80%, of the total estimated O&M costs for the Defined Assets
- Emera would pay for the actual O&M costs of the Maritime Link, and Nalcor would pay for the actual O&M costs for the Project
- A "true-up" payment would be made on a one-time basis when the LTAMP was finalized, to yield a true 80/20 split of total actual O&M costs

- Emera would reimburse Nalcor for ML-related development costs that Nalcor incurred internally up to July 31, 2014
  - Emera and Nalcor would share equally any third-party ML-related development costs that occurred before July 31, 2014; all ML development costs incurred after July 31, 2014, would be fully borne by Emera, subject to the 20% limit of the total estimated development costs for all Defined Assets
  - In the event of failure to complete the Project, penalty provisions would apply; there were also complex calculations designed to keep Emera whole if this circumstance arose
- Emera would have the opportunity to invest in the LIL and earn a rate of return on that investment
  - Regardless of the eventual actual development costs for each of the transmission assets, Nalcor would take a 51% interest in the LIL transmission assets and Emera would take a 49% interest, each through their respective investments in the LIL
  - Subject to the maximum equity percentage approved by the PUB for privately owned, regulated electrical utilities, which is set at 45%, Emera would be allowed to decide, at its

discretion, how much of that interest would be funded by debt and how much by equity

- Emera would receive 20% and Nalcor 80% of the funding from any P3 Canada Fund support or other federal funding obtained to support project development

The various agreements also specified details about the supply of energy that would be transmitted to Emera. They included the following specifics:

- Emera would receive energy for use in Nova Scotia at no cost in excess of the development cost of the ML and 20% of the O&M costs of the Defined Assets
- The energy destined for Emera would be known as the "Nova Scotia Block" and would have these two components:
  - An annual energy amount, not including Supplemental Energy as discussed below, that was 20% of the estimated output of the Muskrat Falls generating station (4.98 TWh), which would be delivered to Emera every year and throughout the year during peak hours (7 a.m. to 11 p.m.), for a period of 35 years, based on the premise that Nova Scotia ratepayers should be effectively made whole because they would receive power for only 35 of the 50-year service life of the ML
  - Emera would receive Supplemental Energy of approximately 240 GWh every year for the first five years of power delivery in the months of January to March and November to December, during off-peak hours
- Emera would receive greenhouse gas credits associated with the Nova Scotia Block energy from the Project for 35 years, which it would not be allowed to sell or transfer
- Penalty provisions, as outlined below, would arise if Nalcor failed to deliver the Nova Scotia Block:
  - If the failure to deliver was related to a *force majeure*, a planned maintenance period, a safety event or events defined in the Agreement as "forgivable events," the amount of

undelivered energy would be called "Block A" and the parties would agree to work together to reschedule its delivery under the specified Late Delivery Procedure

- If the failure to deliver was caused by any other reason, penalty provisions would be triggered and Nalcor would have to deliver 120% of the energy as Compensation Energy, which would include transferring the Compensation Energy's associated GHG credits to Emera; if the undelivered power was not delivered within a year, Emera would have the option to require Nalcor to pay a monetary equivalent

Nalcor's Rights

Under the agreements, the following rights were assigned to Nalcor:

- The right to assume ownership of the ML after 35 years, which Emera would transfer for $1 when the term of the Nova Scotia Block ended
- The right to the transmission capacity of the ML in excess of its capacity to deliver the Nova Scotia Block
- Transmission rights into and through Nova Scotia, and then into and through New Brunswick and into New England

The Energy Access Agreement

In addition to the agreements referred to above, Nalcor and Emera also signed an Energy Access Agreement (EAA) with Emera's electric utility, Nova Scotia Power Inc. (NSPI). The EAA was negotiated to satisfy the UARB requirement that there be a formal commercial agreement in place to ensure that NSPI had access to market-priced energy generated by the Project. The significant provisions of the EAA include the following:

- Nalcor committed to make available, on average, 1.2 TWh of "non-firm" energy, meaning its delivery time would be at Nalcor's discretion, every year from the date of first commercial power to August 31, 2041; Nalcor's total commitment would therefore be equivalent to 1.2 TWh times the number of years between the date of first commercial power and 2041

- There would be no restriction on where Nalcor sourced this energy and it would have full discretion about when and how it would be delivered
- The energy to be provided in any one year would range from 0 TWh to 1.8 TWh; in years when Nalcor's available energy falls short of the 1.2 TWh annual amount, it would be obliged to make up the shortfall by providing additional available energy in excess of 1.2 TWh in other years
- The energy to be made available to NSPI would be in excess of the energy required by Nalcor to satisfy NL's native load and the Nova Scotia Block, defined in this agreement as "Available Energy"

The process for supplying the energy to Nova Scotia under the EAA was outlined as follows:

- Nalcor committed to providing a rolling 24-month forecast of expected non-firm Available Energy every month
- Once a year, NSPI would have the option to solicit non-firm energy for the coming contract year and Nalcor would be committed to respond and bid for up to 1.8 TWh
- Nalcor would be allowed to bid any price for its energy, up to and including the Mass Hub price from ISO New England, or the higher price of any alternative liquid market opportunity available to Nalcor
- Nalcor's bid price to NSPI would be limited to energy and Nalcor would not be able to include any tariffs or transmission costs incurred in sourcing the energy
    - In order to minimize the cost of tariffs and transmission costs, Nalcor would therefore be incentivized to source NSPI's energy from the Project rather than, for example, incurring additional tariffs and transmission costs from importing Mass Hub energy through New England

<u>Benefits: Real and Potential</u>

The Grant Thornton report prepared by Tom Brockway also reviewed the potential and real benefits that the deal with Emera and its related agreements could deliver to Nalcor and to taxpayers and ratepayers in this province. They include:

- **Potential Benefit:** The arrangements specify that Emera's investment is 20% of the estimated—not actual—total development costs of the Defined Assets, and for this Emera will receive 20% of the energy produced by the Project even if Emera's share of the development cost turns out to be more than 20% of the estimated total development costs of the Defined Assets—in other words, if the actual costs were to come in lower than the estimated costs; in that scenario, Nalcor could receive 80% of the energy from the Project having incurred less than 80% of its development costs
- **Potential Benefit:** By stipulating parameters for the shared operating and maintenance costs for the Defined Assets (Emera being responsible for 20% of estimated (not actual) future O&M costs for 35 years), if actual O&M costs are less than the estimates at first commercial power, Nalcor's O&M costs are reduced
- **Real Benefit:** With Emera responsible for the construction of the ML, at a cost of up to 20% of the estimated development costs of the Defined Assets, Nalcor's upfront investment and borrowing requirements were reduced
- **Real Benefit:** The FLG was contingent on Nova Scotia's involvement in the Project; with this partnership, Nalcor could access the reduced interest rates on its borrowing costs that an FLG provided
- **Real Benefit:** Emera's investment in the LIL reduced Nalcor's equity requirements for that asset
- **Potential Benefit:** Energy is effectively being provided to Emera for 35 years at a fixed price that is calculated on the development costs of the ML and 20% of the estimated O&M costs of the Defined Assets, so Emera's cost for the energy it will receive is not affected by future market prices; lower future market prices could mean that

Emera is effectively paying more than market price for the energy it receives under the Nova Scotia Block

- **Real Benefit:** The ML's capacity to transmit more power than required for the Nova Scotia Block gives Nalcor the ability to sell the excess power at market rates to Nova Scotia, New Brunswick and/or New England markets
- **Potential Benefit:** If the actual power output of the Project is greater than 4.98 TWh, Nalcor will receive more than 80% of the estimated power output; with a link to the mainland, Nalcor can potentially capitalize on this surplus power by exporting it

Risks: Real and Potential

The potential for benefits also brings the potential for risk. Tom Brockway also reviewed risks and costs that the agreements exposed Nalcor and NL taxpayers and ratepayers to. They include:

- **Real Risk:** Emera's investment in the Defined Assets is effectively capped, subject only to the sharing of cost overruns on the ML, which leaves Nalcor fully responsible for the cost overruns of the Project
- **Potential Risk:** Emera's investment is limited to 20% of the estimated, not actual, total development costs of the Defined Assets and it will receive 20% of the estimated energy output (this percentage being fixed) from the Project, which means that if actual costs were to be more than estimated costs, Emera's share of the development costs would be less than 20% of the total development costs of the Defined Assets; in those circumstances, Nalcor would pay development costs for the Defined Assets that are greater than 80% of their estimated cost, but still only receive 80% of the energy output from the Project
- **Real Risk:** Nalcor is also required to pay for a portion of any cost overruns of the ML that are not approved by the UARB as outlined above
- **Potential Risk:** Emera is responsible for 20% and Nalcor for 80% of estimated (not actual) future O&M costs of the Defined Assets and

Nalcor is responsible for paying actual O&M costs in relation to the Project; if/when actual O&M costs exceed the estimates, there will be an additional cost to Nalcor

- **Potential Risk:** A higher equity investment in the LIL by Emera than would have been made by Nalcor on its own has the potential to result in a higher return on equity (rather than on debt, which would be at a lower cost), thereby potentially resulting in higher electricity rates to Island ratepayers
- **Potential Risk:** Regardless of the actual amount of energy output at Muskrat Falls, Emera is entitled to receive 0.986 TWh for 35 years, plus an additional 240 GWh for five years, under the agreement for the Nova Scotia Block—and under the EAA, Nalcor must make available to NSPI an additional 1.2 TWh of energy on average, every year from the date of first commercial power to 2041; this all means that in the event that output from the Project is lower than expected in any particular year and/or native load is higher than expected, Nalcor may be required to purchase additional energy and incur additional tariffs and transmission costs to fulfill its commitments with respect to the Nova Scotia Block, the EAA and/or native load (Nalcor's position on this is that the risk of requiring it to import energy to fulfill its obligations under the EAA is very low; Grant Thornton agrees)
- **Real Risk:** Nalcor may incur penalties if it does not deliver power as required under the agreements
- **Real Risk:** Energy is effectively being provided to Emera at a fixed price for 35 years based on the development cost of the ML and 20% of the estimated O&M costs of the Defined Assets, consequently Emera's cost for the energy it receives will not be affected by changes in future market prices; if market prices increase in the future, Emera may effectively pay less than market price for the energy it receives under the Nova Scotia Block

Calculation of Costs to Nalcor and Emera

A question raised during the hearings was whether it is possible to evaluate if the 80/20 cost split envisioned by the Term Sheet has been achieved. Based on my calculation of the actual development costs incurred in relation to the ML and the current estimated cost to complete the development of the Project, the respective percentages of total costs come to 12.1% for Emera and 87.9% for Nalcor, as shown in the table below. The energy sharing, of course, remains at 20% for Emera and 80% for Nalcor.

In Billions	ML	MFP, LTA, LIL	TOTAL
Construction Costs	$ 1.60	$ 10.10	**$ 11.70**
IDC*/AFUDC**	0.15	1.80	**1.95**
Other	-	0.80	**0.80**
TOTAL	**$ 1.75**	**$ 12.70**	**$ 14.45**
Percentage of Total	12.1%	87.9%	100.0%

*IDC: Interest during construction
**AFUDC: Allowance for funds used during construction

Figure 2.21: Cost to Complete the Project and Maritime Link

Nalcor's Accounting: The Maritime Link

Emera retains legal ownership of the ML and includes it on its own financial statements. Nalcor reflects the ML in its accounting as well, concluding that Nalcor controls the ML and, in substance, Emera is providing financing for this asset's construction in return for receiving energy (the Nova Scotia Block). In its financial statements, Nalcor reports the Maritime Link as an asset valued at $1.75 billion. It also reports a related liability—a deferred energy sales credit of $1.748 billion—related to Muskrat Falls power not yet produced and sold through the ML.

In Nalcor's view, the development and O&M costs of the ML, paid for by Emera, are equal to the value of the power Nalcor supplies to Emera. In other words, the revenue that will flow to Nalcor from power sales to Emera will equal the development and O&M costs of the ML. The arrangement with respect to the ML is effectively a purchase of the ML from Emera that has been financed by Emera through the costs it assumed and that will be paid for on an in-kind basis through the supply of energy for no cash consideration.

Benefits of the Emera Deal

Several witnesses testified about the agreements related to the Term Sheet, including Stan Marshall, Edmund Martin and Pelino Colaiacovo. It is evident that conflicting views exist about the benefits of the Emera deal for this province.

Stan Marshall testified that the Emera deal benefits Nova Scotia more than it does Newfoundland and Labrador. He acknowledged that Nova Scotia was instrumental in moving the FLG forward because the federal government would not have offered it had the development involved only one province. He also testified that allowing Emera to invest in the LIL and earn a utility rate of return will mean Nalcor has a higher financing cost for the LIL than for the remaining components of the Project. He also believes that once Nalcor has supplied the energy that it has committed to Emera and met the energy needs of this province, there will be little firm power from Muskrat Falls left to sell. This will limit Nalcor's ability to offset the cost of the Project by selling excess power.

Mr. Marshall's views contrast with those of Mr. Colaiacovo and Mr. Martin, both of whom expressed the opinion that the Emera deal is good for Newfoundland and Labrador. In fact, Mr. Colaiacovo testified (July 18, 2019, transcript):

> And so if you look at the $1.6 billion of the Maritime Link and you trade that 895 GWh of power, for someone else spending that $1.6 billion of capital cost, it actually works out to be significantly advantageous. It's a good trade, frankly, for Newfoundland to have made. (p. 45)

Mr. Colaiacovo went on to state that Nova Scotia will have access to other power sources at potentially an even lower cost than power from the Project, yet it must continue to take Project power. Furthermore, giving Emera the right to invest in the LIL, in his view, was in exchange for Emera arranging transmission through New Brunswick based on transmission rights that Emera had previously secured. Therefore, although Emera did acquire the right to invest and receive a commercial rate of return on its investment in the LIL, Mr. Colaiacovo recognized that this was in exchange for transmission rights that will be valuable to NL and Nalcor.

Negotiations with Emera

With respect to the negotiation process between Emera and Nalcor, Mr. Martin testified that he negotiated directly with Chris Huskilson, Emera's Chief Executive Officer, on the respective contributions toward the costs of the Project and the ML to be borne by Nalcor and Emera. In his evidence, Mr. Martin said that he entered into these negotiations with “a number in mind” for what the respective contributions should be. He stated that he began the negotiation by “padding” his estimate of the total cost: “Naturally, my starting point would be higher than where I would like to end up” (December 11, 2018, transcript, p. 11). Mr. Martin added: “[E]ssentially I went into a negotiation with him to see if we could land on a number that was acceptable to both of us” (p. 11). Later in his testimony, Mr. Martin stated: “I mean, they were trying to meet a number that suited them. And we were getting to a number that suited us. And we landed in the right place” (p. 13).

In other words, Mr. Martin characterized the negotiations with Mr. Huskilson as a standard commercial negotiation in which the parties go back and forth with numbers and finally end up with a compromise that is acceptable to both but is different than their opening positions.

In an interview with Commission counsel, Mr. Huskilson was asked about the negotiation process with Mr. Martin over the cost sharing. When Mr. Martin’s evidence was put to him, Mr. Huskilson stated (P-01670):

> [W]hat I do know to be true is that when we began the discussion with Nalcor in 2010—and I think that started sometime in the spring, but certainly continued through the summer and into the fall—when we began the discussion with them, their estimate was $6.2 billion—
>
> . . .
>
> —$5 billion dollars for the—for their part of the project and 1.2 billion for the Maritime Link. And when we signed the term sheet, the cost for the project was $5 billion for their end of the project and 1.2 for the Maritime Link. So over that entire discussion never did the cost of the entire project change. So I guess I just don’t know what would have come out if in fact the cost of the entire discussion was the same. $6.2 billion when we started and we signed the term sheet at $6.2 billion. (p. 7)

Later in Mr. Martin’s testimony at the hearings, he was again questioned on the negotiations with Mr. Huskilson and was advised by Commission counsel of the position taken by Mr. Huskilson. In response, Mr. Martin made what I see as an abrupt change in his description of the negotiations with Mr. Huskilson over cost sharing (December 13, 2018, transcript):

> **MS. O’BRIEN:** But in terms of dollar amounts, was there any negotiations between you and Mr. Huskilson with respect to dollar amounts?

MR. E. MARTIN: No, not—from my perspective, no. After we landed on the 6.2, I was good.

MS. O'BRIEN: And 6.2 was where you started with him?

MR. E. MARTIN: That's correct. (p. 86)

It is clear that Mr. Martin's initial testimony on the negotiation process with Mr. Huskilson was incorrect.

Conclusions on the Emera Agreements

In conclusion, I find that:

- Nalcor and NL taxpayers and ratepayers received some benefits from the Emera Agreements
- The FLG would not have been available without the involvement of Nova Scotia
- Nalcor obtained transmission rights that potentially benefit NL, depending on export market availability
- Emera built and paid for the ML and Nalcor will eventually own it after 35 years
- Based on the latest cost estimate for the Project, Emera will get 20% of the energy provided but pay only 12.1% of the total costs, so the "20-for-20" principle no longer holds

The Navigant and Natural Resources Canada Reports

After DG2, Nalcor commissioned Navigant to prepare a report on the long-term supply options for electricity for the Island, as an independent review and to check on its own processes to date. During the following months, Natural Resources Canada (NRCan) independently produced its own report on the Project's economic viability. According to the testimony of Kathy Dunderdale, who was premier at the time, and her Minister of Natural Resources, Jerome Kennedy, both of these reports played a role in GNL's decision to sanction the Project.

The Navigant Report

In the spring of 2011, Nalcor issued a Request for Proposals for an independent review of the long-term supply options for electricity that it had been developing. Navigant was already doing work for Nalcor on Lower Churchill export opportunities at the time. The firm responded to this new RFP and the contract, with an estimated value of $250,000, was awarded to Navigant on June 30, 2011.

Specifically, Navigant was asked to review the Isolated Island and Interconnected Island options that Nalcor had identified, along with the associated assumptions for each and the screening and evaluation process of the options' components. As an independent reviewer, Navigant was asked for its opinion on whether the Project was the least-cost option when factors of security of supply, environmental responsibility and risk were considered. It was also asked for an opinion on Nalcor's electricity rate projections.

In its final report of September 14, 2011, Navigant listed 43 key findings, including endorsement of the following (P-00042):

- Nalcor's decision-making processes, including the Gateway process, and its decision to promote the Interconnected Island Option
- The level of information provided by Nalcor
- The 50-year analysis period
- The load and fuel forecasts
- Nalcor's schedule and capital estimates
- The CPW method and sensitivity analysis
- The inclusion of Round Pond, Island Pond and Portland Creek—and the exclusion of all other potential hydro sites—for the Isolated Island Option
- The screening out of solar, wave and tidal, biomass, coal, nuclear, Grand Banks natural gas and LNG generation options (pp. 10–13)

Navigant also made the following recommendations (P-00042):

- Nalcor could include up to 100 MW of additional wind power in 2025 in the Isolated Island scenario, plus an additional 100 MW of wind in 2035

- Nalcor should consider adding more CDM
- Nalcor should consider potential emissions regulations, including carbon tax, in more detail (pp. 30, 42, 57)

Prior to producing its final report, Navigant submitted a draft to Nalcor on September 9, 2011. This draft included a recommendation that Nalcor consider an Integrated Resource Planning process, as described in Chapter 4 (P-01451):

> In order to provide a more robust decision, Navigant recommends that Nalcor undertake a more holistic, integrated approach in its development of options for and analysis for DG3 that would include:
>
> - Additional renewables, CDM and transmission expansions/upgrades, with a primary focus on their application in the Isolated Island case.
> - Explicit consideration of the impact of potential GHG legislation on costs.
> - Explicit identification and consideration of scenarios (plausible combinations of key assumptions) in its analysis with re-optimized expansion plans for each of the scenarios.
> - Monte Carlo analysis of assumptions to more fully explore the variability in costs in the alternative cases being considered. (p. 10)

Auburn Warren responded to the draft report with a series of comments. He marked on the IRP recommendation: “TO REVIEW WITH GILBERT [Bennett]” (P-001451, p. 10). At the hearings, Mr. Bennett testified that he was unable to recall discussing this recommendation at any time (November 27, 2018, transcript, p. 39).

Navigant’s final report, submitted a few days later, highlighted Navigant’s experience in IRP but the recommendation that Nalcor pursue IRP is missing. I can only conclude that Navigant removed this recommendation at Nalcor’s request.

It is notable that, in its report, Navigant discussed and endorsed Nalcor’s DG2 time-risk assessment, which indicated that Nalcor’s full power date of May 1, 2017, was at a P1 probability value (a very low likelihood). Yet Navigant found “the level and accuracy of the information used in Nalcor’s DG2 Island Supply Decision,” which included the same schedule and power-delivery date, was appropriate for a DG2 decision (P-00042, p. 10). Either Navigant endorsed the time-risk assessment without understanding its content, or Navigant did understand the time-risk assessment and endorsed the schedule anyway. Either possibility is troubling and raises concerns about the quality of Navigant’s work.

Nalcor also planned that Navigant would prepare a second report using DG3 Project cost and schedule information (P-00042, p. 7). This was not done.

The NRCan Report

The stated purpose of the NRCan 2012 Project review was "to help inform decision making under the Canadian Environmental Assessment Act." The title of its report is *Economic Analysis Lower Churchill Hydroelectric Generation Project* (P-00054). The Terms of Reference for this Commission of Inquiry do not allow me to investigate how or why Canada undertook this review. However, GNL decision makers testified that they placed some reliance on it when sanctioning the Project. It is appropriate, therefore, to examine this report to determine whether there was a reasonable basis for this reliance.

The NRCan report focused "predominantly on the economics of the project and its ability to meet Island demand at the lowest cost while reducing greenhouse gas emissions within Newfoundland and Labrador" (P-00054, p. 6). NRCan acknowledged that the Project might have larger benefits, but it stated that they were beyond the report's scope.

The report also focused on Nalcor's analysis of the Project's finances and alternatives. It accepted Nalcor's cost and schedule estimates without analysis. Given the limited information available to NRCan, this is understandable. The report relied solely on DG2 cost estimates as well as on information found in the Joint Review Panel report, the Navigant report and in exhibits filed by Nalcor before the PUB. It did not rely on any additional or confidential information from Nalcor.

The NRCan report contained some criticism of the Navigant/Nalcor analysis, such as the following (P-00054):

> There are a few concerns to note with respect to the Navigant/Nalcor analysis. The analysis examined and discussed all the above options in a piece-meal fashion. It did not look at combinations of the different options. Nor did it consider the possibility of incorporating a combination of options in order to delay the project and its large capital costs. (p. 35)

The report also accepted many of Nalcor's conclusions, however. For example, it found that:

- The Interconnected Island Option would likely be a lower cost alternative if loads continued to rise as foreseen

- The Isolated Island Option would be a lower cost alternative if loads remained flat
- It was unclear whether Grand Banks gas would be available and in what quantities

The NRCan report concluded that the Muskrat Falls Project was probably the lowest-cost option in most scenarios. If demand were low, however, the lowest-cost option would likely be a mixture of wind power, small hydro and CDM. That combination could have effectively allowed the Province to postpone a decision about large-scale development on the lower Churchill until the mid-2030s, when Holyrood would be retired. At that point, the Province could then consider whether experimental technologies had advanced sufficiently to replace Muskrat Falls as the least-cost option.

In hindsight, this analysis certainly remains plausible. While the NRCan report could be used to provide some support for sanctioning the Project, I believe that any decision maker who read it as an endorsement of the Project would have read it incorrectly or without fully understanding the report's limitations.

ESTIMATING THE PROJECT'S CAPITAL COST AND SCHEDULE

The Project's capital cost estimates and schedule were the subject of a significant amount of evidence at the hearings.

Early Estimates

Since the 1970s, engineering work had been undertaken to investigate and support the development of the lower Churchill River. Two early cost estimates for the Project and the LIL are in evidence and are worthy of consideration.

The first is a June 1980 recommendation from the Lower Churchill Development Corporation Limited (LCDC) to the provincial and federal governments (P-00019). At that time, the contemplated development of Muskrat Falls was smaller than the current Project and featured a 618 MW generating station and an 800 MW Labrador-Island link. SNC, the engineering consultant engaged by LCDC, estimated the cost of the generating station at $1.6 billion, the overhead transmission lines at $1.2 billion and a trench and cable under the Strait of Belle Isle at $380 million, for a total of $3.18 billion in 1980 dollars. Using the Bank of Canada database for conversion, this equates to approximately $8.4 billion in

2012 dollars. Even with this fairly high estimate, LCDC thought that the Muskrat Falls development "should be exploited at the earliest possible opportunity" in the context of the fuel price and load expectations in play in that period (P-00019, p. 2).

The second cost estimate was a feasibility study produced by SNC-AGRA for NLH in January 1999 (P-00022). It featured an 825 MW generating station without a link to the Island or other transmission lines. The estimated cost was $965 million in 1999 dollars (approximately $1.28 billion in 2012), a significant reduction from the 1980 estimate.

The 1999 feasibility study included an engineering analysis of the Muskrat Falls site that remained the most recent until the DG2 estimates were completed. So the work on the Project from 2003 to 2010, including the 2007 Energy Plan, was based on that 1999 estimate. Long before DG2 and DG3, this second, lower estimate may have influenced the thinking of political leaders, utility executives and the PMT.

In 2010, to support the decision at DG2 to move to detailed design work, a capital cost estimate for the Muskrat Falls development was prepared. This estimate was used in the Joint Review Panel and the PUB's reviews, as well as in the first MHI report, the Navigant report and the NRCan report.

Components of the Estimate

The Project cost estimates prepared for DG2 and DG3 had four components:

1. Base estimate
2. Contingency (tactical risk)
3. Management reserve (strategic risk)
4. Escalation allowance

The base estimate component included the "most likely costs for known and defined scope" of the Project at each decision gate (P-00808, p. 5). To determine the base estimate, the Project was divided into distinct packages of work and the cost of each was estimated. The costs of most items in the base estimate were calculated using quantities of concrete, steel and other construction materials and were provided by the engineering team. Based on experience as well as data from other projects, the estimators also determined how much labour would be required for construction and the cost of that labour. To reflect costs that had not yet been fully defined, the estimators added allowances to the quantities in the base estimate.

The second and third components of the estimate were contingency and strategic risk exposure. Contingency covers what Nalcor called tactical risks and management reserve covers strategic risks. These concepts are best understood together. Nalcor took its definitions of these concepts from the Westney Consulting Group, a Texas-based company Nalcor engaged in 2007 to help with its risk analysis (the concepts of tactical and strategic risk are not unique to Westney, however).

A memorandum dated June 1, 2011, from Richard Westney (the founder of Westney) to Jason Kean, contains the following overview of tactical and strategic risks that Nalcor relied on in developing these estimate components (P-00808):

> Large engineering and construction projects are exposed to two sources of cost and schedule risk: tactical risks and strategic risks. Tactical risks are those that project teams typically assess and control; these include design development changes, execution variations, and normal deviations in quantities and pricing. Strategic risks are those that require management attention, these typically involve the external factors impacting the project. Conventional project risk management focuses on tactical risks, hence Westney Risk Resolution® focuses on both tactical and strategic risks to ensure all sources of project risk are properly accounted for. (p. 36)

Tactical risks include the risk of the design maturing after the estimate has been prepared, as well as normal variations in performance, weather, prices and so on. Tactical risk do not include any allowance for scope changes, price escalation or foreign currency changes or events such as strikes or natural disasters.

Strategic risks are events that are outside the control of the project management team, typically pertaining to external issues. These risks include enterprise-level issues, governance, financial markets, stakeholders, hyperinflation and regulatory approvals (P-00808, p. 7).

The fourth component of the cost estimate is the escalation allowance. This provides for the increase in labour costs and material prices over the course of construction. In addition to taking into account general inflation, the escalation allowance incorporates the impact that a large project has on regional or local prices.

The DG2 Estimate

In 2010, the Project cost at DG2, before inclusion of the strategic risk (management) reserve, was estimated at $4.929 billion, as shown in Figure 2.22 (P-00077, p. 238).

Muskrat Falls Project
Decision Gate 2 Estimate
($ millions)

Muskrat Falls Generation (Including LTA)	
Base estimate	
Historical costs	$ 20
Future costs	2,186
Contingency (15%)	328
Escalation allowance	335
Sub-total - Muskrat Falls Generation/LTA	**2,869**
LIL	
Base estimate	
Historical costs	42
Future costs	1,574
Contingency (15%)	236
Escalation allowance	208
Sub-total - LIL	**2,060**
Total Muskrat Falls Project Capital Cost	**$ 4,929**

Figure 2.22: Decision Gate 2 Estimate

Nalcor's Treatment of Risk

Risk management has always been a key part of the vision of the Lower Churchill Project. In 2006, when the Province decided not to accept any of the expressions of interest for the Lower Churchill and instead have NLH lead the development, the logic

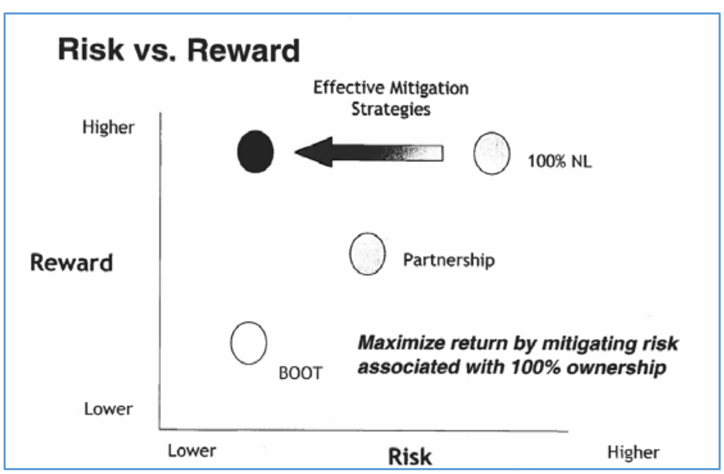

Figure 2.23: Nalcor's Low Risk–High Reward Theory

was essentially that risk mitigation would allow the Province to receive the full benefit of the project without the risks. NLH conveyed this in a 2006 presentation (P-00169, p. 25):

In its own estimation, *circa* 2011, Nalcor saw its risk management program as "best-in-class," although admitting that it is "impractical to think that [Nalcor] can identify and manage all risks to which the Project may be exposed" (P-00097, pp. 5, 12). This represents a significant downgrade in hopes. Adopting industry best practices can only produce industry-leading results, rather than eliminating the risks that the rest of the industry accepts.

In the years leading up to DG2, Nalcor's risk management techniques focused primarily on strategic risks, although, as seen below, they also identified other risks as well. Nalcor and Westney identified and quantified 33 high-level strategic risk frames that outlined the nature of each key strategic risk, a strategy for managing it, the action plan for each strategy and the people responsible for managing each action plan (P-00097).

Quantifying Risk

Nalcor and Westney quantified three types of risk—tactical, strategic and time—using a technique called "risk ranging." This process required setting best- and worst-case values for every item to be evaluated. Westney took these best- and worst-case values and used them to simulate thousands of possible Project outcomes. The results of these simulations were presented in a diagram showing an S-shaped curve (S-Curve), as illustrated in Figure 2.24. In a cost analysis, the curve simulated the likelihood of achieving

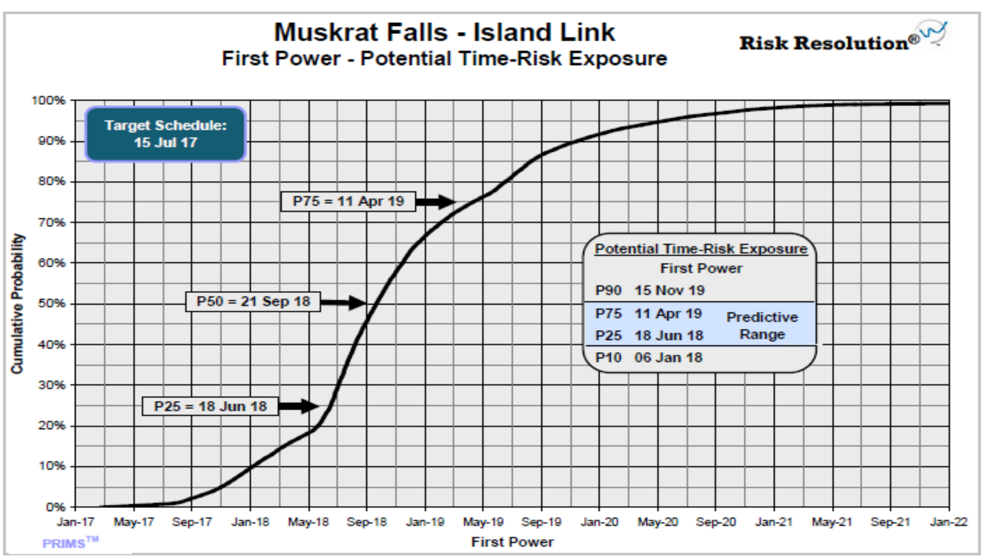

Figure 2.24: S-Curve of Project First Power Time-Risk Exposure

a capital cost. Similarly, in a time-risk analysis, the curve simulated the likelihood of achieving Project completion on various dates.

The probability range went from 0 to 100 ("P100" or 100% probability). Thus P25 meant that 25% of the simulations showed a lower cost or an earlier completion. Similarly a P75 meant that 75% of the simulations showed a lower cost or an earlier completion. If the S-Curve was accurate and unbiased, then there would be a 25% chance that the project would cost less than the P25 cost and a 75% chance that it would cost more. The risk-ranging process was implemented slightly differently for tactical and strategic risks. Because tactical risks are assessed for specific construction issues, they were discussed and quantified in the context of the construction packages. For each package, Westney guided Nalcor through a discussion of the best-case and worst-case cost scenarios and Nalcor ultimately chose the best- and worst-case values to put into the risk analysis. Typically, tactical risks are estimated and the cost to cover them is set aside as a contingency, which the PMT can draw down as the Project unfolds. In normal circumstances, developers expect the contingency funds to be fully spent by the time a project is completed.

While the best- and worst-case values for tactical risks were estimated by construction package, the best- and worst-case values for strategic risk were estimated by the individual type of risk. The logic for this is that strategic risks affect an entire project, rather than a specific construction package.

On many projects, the estimate to cover strategic risks is treated as a "management reserve" and is managed by the developer's CEO. In the case of the Muskrat Falls Project, the PMT recommended that a management reserve be established to cover strategic risks but Edmund Martin rejected the recommendation and did not inform GNL that he had done so. Instead, Nalcor relied on the Province's commitment to fund cost overruns with equity from other sources and considered that the Project's strategic risk exposure was funded through that commitment.

<u>DG2 Tactical Risk Quantification</u>

Westney performed a risk analysis for DG2 and prepared a report in July 2010, which predated completion of the final Project configuration. At that time, the plan was to build a 600 MW transmission line, not the 900 MW transmission line announced in November 2010 (P-00808, pp. 16–17).

Westney's DG2 risk analysis was designed around a project with a base cost estimate of $3.359 billion, a figure that had been produced by the PMT with the assistance of an outside consultant (P-00808, p. 130). Westney made the following recommendation in the Assessment Summary of its analysis (P-00808):

> The P50 value of $3,885 million compares to an estimate of $3,359 million, suggesting that an estimate contingency of $526 million (16%) would be appropriate for Muskrat Falls combined with the Island Link. (p. 111)

Following Westney's July 2010 risk analysis report, when the Project shifted to a 900 MW transmission line, Nalcor increased the Project base estimate to $3.76 billion. It provided the following explanation for that decision (P-00808):

> Many of the tactical risks identified and quantified in the June 2010 analysis have since been incorporated in the Base Estimate which has increased from the then $3,359 million to the current $3,760 million, an increase of approximately $400 million. (p. 25)

At DG2, Nalcor decided to use a 15% contingency for tactical risk. When calculated from the higher base estimate, it came to $564 million. While Westney had recommended a 16% contingency, Nalcor noted that "it was decided to prudently use 15% as a reasonable P50 proxy for Estimate Contingency for Capital Cost" (P-00808, pp. 24–25).

Strategic Risk Quantification

Richard Westney also noted the importance of strategic risk in a memorandum to Jason Kean dated June 1, 2011 (P-00808):

> The Risk Resolution® methodology uses a purpose-built analysis model known as PRIMS (Predictive Risk Indicative Modeling System). Input to PRIMS is based on scenarios representing best- and worst-cases for various types of strategic risk. These scenarios are then modeled using Monte Carlo simulation to develop the project's cost- and time-risk exposure. The analysis also indicates the most important drivers of risk exposure, to serve as a basis for stress-testing project plans and developing mitigation strategies. (p. 36)

In his *Gate 2 Project Risk Analysis* report of June 16, 2011 (P-00808), Mr. Kean noted:

> Westney's Risk Resolution® methodology represents a departure from the conventional approach to project risk management whereby risk analysis is focused on tactical risks. According to Westney, conventional project risk management fails to consider larger "strategic" risks that have had a predominant influence on mega-projects in recent years. . . . [T]hese strategic risks have large levels of volatility and exposure. (p. 9)

Nalcor's and Westney's July 2010 risk analysis suggested a predictive risk range for strategic risks after mitigation activities of P25 to P75, which translated to $187 million to $413 million. This was reflected in Westney's strategic risk assessment (P-00808) when it recommended

> that a P75 reserve be established to cover the Mitigated Risk Exposure level of $413 million. This Strategic Risk Exposure amount is in addition to the Estimate Contingency and equates to approximately 12% of the Base Estimate. (p. 22)

Despite the central role strategic risk played in Nalcor's plan to mitigate the risks of full ownership, Nalcor steadily whittled down the strategic risk estimate to nothing. The first step in this whittling was when Paul Harrington and Jason Kean, notwithstanding Westney's recommendation for the establishment of a strategic risk reserve of $413 million (P75 level), decided to reduce the reserve to $225 million, a level approaching the original P25 value of $187 million. The principal reason they gave for this reduction was a Project decision to use conventional line-commutated converter (LCC) technology rather than state-of-the-art voltage source converter (VSC) technology for the HVdc transmission lines (P-00808, p. 25).

The PMT recommended this reduced $225 million strategic risk reserve to the Nalcor executive. But, in a second and questionable step, the recommendation was rejected and no strategic risk reserve at all was added at DG2. The initial rationale for this rejection is stated as a note in Nalcor's *Gate 2 Project Risk Analysis* report (P-00808):

> During the negotiations of the Term Sheet with Emera, Senior Management elected to drop the Strategic Risk Exposure allowance of 6% from the overall capital cost recommendations for both the Muskrat Falls and Labrador–Island Transmission Link Projects in order to address Emera's concern regarding its ability to sell the Strategic Risk concept to it's [*sic*] the Nova Scotia regulator, the Nova Scotia Utility and Review Board. (p. 26)

On November 25, 2018, a letter from Chris Huskilson, Emera's President and CEO at the time of the Term Sheet negotiations (2010), was entered into evidence (P-01462). In it, Mr. Huskilson stated:

> 3. You have requested my comment on a statement made in the second-to-last paragraph of the Pre-Sanction Briefing note prepared by the Nalcor project team in 2018 for the use of the Commission/Grant Thornton (CIMFP Exhibit P-00264, p. 19), which indicates that Nalcor's Executive decided to "drop the provisional strategic risk allowance . . . to respond to Emera's

concern regarding its ability to sell the strategic risk concept to the Nova Scotia regulator…”.

4. In order to understand that reference it is important to understand:

   A. Emera and the UaRB do not use the term or terminology “Strategic Risk” in presenting risk associated with project cost estimates for the purposes of project assessment and approval; and

   B. the costs and risks assessed and included in a project cost estimate are a separate matter from the choice of terminology or language used to describe allowances for risks included in project budgets or estimates.

   While some project advisors may choose to analyze and reflect project cost risks using “strategic risk” terminology, in Emera’s case, its approach to all projects including the Maritime Link project was, and is, to present a project cost estimate developed on a line by line basis to determine a project budget; including a determination of all risks represented in the base project estimate and the project contingency within the overall project budget. This is how Emera presents project cost estimates to the UaRB for approval, including for the Maritime Link project. Given the commercial arrangements and the 80/20 approach, it was, of course, important for both Nalcor and Emera to use the same terminology when presenting costs associated with project risk to allow for an “apples to apples” comparison of the project cost estimates for the Maritime Link and Muskrat Falls projects.

5. I therefore requested that the parties use the same terminology in presenting costs associated with project risk. That is not to say that I expected removal of any costs Nalcor felt were appropriate to include in its overall cost estimate. Specifically, with regard to the Exhibit P-00264 paragraph referenced above, I cannot speak to what the author(s) of that report might have exactly meant by those words, but, I can confirm that Emera did express concern to Nalcor about using the “strategic risk” terminology for costs associated with project risk, as Emera intended to present the project costs for both projects on the same “apples to apples” comparative basis as outlined above, and for the reasons outlined above. Emera was not involved in how Nalcor subsequently chose to deal with costs associated with project risk in its overall project cost estimate, but Emera did subsequently receive cost estimates in a format that was consistent with Emera’s standard format; which, in turn, allowed for the desired “apples to apples” comparative analysis and presentation. As the Exhibit P-00264 paragraph states, the concern expressed was about the “strategic risk <u>concept</u>” (emphasis added), which was not a project cost “concept” typically used in similar UaRB regulatory approval processes.

The evidence suggests that Nalcor treated Emera's position on strategic risk as an invitation to remove costs from the Project's cost estimate.

By June 2011, Nalcor was aware that it would be required to disclose information on Project costs to the PUB. On September 15, 2011, Nalcor prepared a revised *Gate 2 Project Risk Analysis* report, in which it stated a new rationale for excluding strategic risks from the Project's cost estimate. This new rationale was based on two principal considerations (P-00097, p. 26):

- A reduction of $100 million, which reflected the P50 value of eliminating the VSC technology
- A $300 million reduction, which reflected the P50 value of obtaining the FLG

This revised rationale was plausible enough to satisfy the PUB, but it created its own problems. In the first place, Nalcor had publicly announced the cost estimate ten months earlier and that estimate already excluded any amount for strategic risk reserve. The revised rationale was a justification for a previous decision, not the actual reason for it. In addition, although the July 2010 risk analysis included as a strategic risk the category "Federal government support for generation and transmission projects" (that is, the FLG), it did not quantify a benefit for that support.

Even more fundamentally, the FLG reduced the financing costs, not the construction costs. Financing costs were never part of the DG2 capital cost estimate and, in my view, using financing cost savings to justify a lower construction cost estimate is inappropriate. Finally, it should be noted that the $100 million reduction for the elimination of the VSC technology appears to already have been reflected in arriving at the $225 million strategic reserve that Mr. Harrington and Mr. Kean had earlier recommended. This benefit should not have been counted twice.

<u>Accuracy of the DG2 Estimate</u>

In the lead-up to DG2, the Project design was evolving in major ways, but Nalcor was estimating using only preliminary outlines and engineering—that is, a "project definition" that was only a 5% to 10% representation of the Project's final design and the related costs. The evolving nature of the Project is captured in this example—in the months leading up to the DG2 estimate, the LIL changed from being a 600 MW line using VSC technology to a 900 MW line using LCC technology. This fundamental change in the nature of the Project occurred after the final risk sessions with Westney were completed.

According to the recommended practice (17R-97) of the Association for the Advancement of Cost Engineering, an internationally recognized organization involved in cost estimating, cost estimates based on only a 5% to 10% project definition yield only a Class 4 estimate (P-00105, p. 3). Class 4 estimates are typically used at the concept study or feasibility estimate stage of a project. By DG2, the Project was beyond "concept," but was still in its early stages of design development.

It should be noted that an estimate's class category does not automatically correlate with its accuracy. According to the AACE, many factors contribute to estimate accuracy, including the quality of reference data used, the estimator's skill and knowledge and the technical uniqueness and complexity of the project under consideration (P-00105, p. 6). The more unique and complex a project is, the lower the accuracy of an estimate. The higher the quality and relevance of the reference data, the greater the accuracy of the estimate.

Nalcor described the Project as being based on mature, generic technology and described the estimate as being based on highly relevant benchmarking data. Both these assertions are questionable. Yes, hydroelectric dams and transmission lines are mature technologies, but the Project was unique in many respects. As for the benchmarking data, it is examined in more detail below, at the discussion of the DG3 estimate.

At the hearings, opinions on the accuracy of the DG2 cost estimate varied. Paul Harrington testified that he expected it would be within +20% to -15% of the final cost. The PUB and MHI accepted a wider range of accuracy, from +50% to -30%. If Mr. Harrington was right and the estimate was accurate within +20%, the range of Project costs could increase as high as $6.2 billion. If the PUB/MHI's more conservative assumption was right, the range could increase as high as $7.5 billion.

The evidence suggests that design and quantity changes between DG2 and DG3 were to be expected. With a project definition only 5% to 10% complete, significant changes in project definition were to be anticipated, along with significant changes in cost to follow.

The low level of Project definition at DG2 had significant implications for the reliability of the DG2 estimate. Because the DG2 estimate was used in most of the independent reviews of the Project's financial viability, the estimate's limited accuracy diminished how much weight should reasonably have been placed on any of them. While the PUB plainly understood the unreliability of the DG2 estimate, GNL's understanding was, at best, limited.

CHAPTER 6: PREPARING FOR DECISION GATE 3

In 2012, the DG3 cost estimate was presented in a similar format to that of DG2, with the exception that the costs for the Labrador Transmission Assets were reported separately from those of the Muskrat Falls generation facility. The DG3 estimate was calculated as follows:

Muskrat Falls Project
Decision Gate 3 Estimate
($ millions)

Muskrat Falls Generation	
Base estimate	$ 2,512
Contingency	227
Escalation allowance	162
Sub-total - Muskrat Falls Generation	**2,901**
LTA	
Base estimate	601
Contingency	54
Escalation allowance	35
Sub-total - LTA	**690**
LIL	
Base estimate	2,360
Contingency	87
Escalation allowance	164
Sub-total - LIL	**2,611**
Total Muskrat Falls Project Capital Cost	**$ 6,202**

Figure 2.25: Decision Gate 3 Estimate

Estimating Base Cost

In accordance with the Engineering, Procurement and Construction Management services contract it signed with Nalcor in 2011, SNC was responsible for preparing the DG3 base cost estimate. SNC was to provide its own EPCM costs. Nalcor was responsible for preparing the estimate for both the owner's costs and the construction/installation costs for the Strait of Belle Isle cable.

SNC assembled an estimating team that included several consultants. The SNC engineering team provided the material quantities. The SNC estimating team provided equipment cost estimates and labour productivity assumptions. Nalcor provided the hourly cost of labour.

On December 15, 2011, SNC delivered a base cost estimate of $5.1 billion, of which $4.5 billion was for construction costs and $600 million for EPCM costs (P-00860). Nalcor expressed concern about the documentation and quality of the estimate. According to a timeline prepared by Jason Kean for the Commission, Nalcor saw the estimate as being of poor quality because it did not follow the requirements in the EPCM services agreement (P-00862, p. 19). As a result, the SNC estimating team was moved into “the bullpen” at the Project office in St. John’s, where they worked under the direction of Nalcor representatives to re-evaluate the estimate (P-00857). This process, described by Nalcor as “Phase 2” or “finalization” of the DG3 estimate, lasted until mid-June 2012. It resulted in reducing construction costs by $260 million. SNC’s estimate for EPCM costs was totally rejected.

Changes to the SNC Estimate

In its original proposal to Nalcor, SNC had estimated that 2.5 million work hours (an expense of approximately $300 million) would be required for EPCM (P-00858, pp. 2–3). When preparing the DG3 base estimate, SNC more than doubled this to 5.5 million work hours ($648 million). Nalcor took the position that the increase had not been approved and that the additional resources were unnecessary. It rejected this EPCM estimate and produced its own internal estimate, in which the EPCM costs were $403 million, a reduction of $245 million in SNC’s initial DG3 base cost estimate (P-00094, pp. 115–20).

Nalcor also indicated that the resource requirements SNC had included were “unacceptable,” stating: “The Project will not pass through DG3” (P-00858, p. 4). This implies that Nalcor thought that the proposed cost increase for the EPCM contract was of such a magnitude that it would prevent Project sanction. The $260 million reduction in the capital cost estimate resulted, in part, from simple corrections such as eliminating double-counting and ensuring consistent parameters. However, more than half of it came from the personal intervention of Jason Kean. On April 23, 2012, Mr. Kean advised in an email to Nalcor and SNC staff: “I have taken the following decisions that will become the basis of forward planning and the DG3 estimate. These items are not open for discussion” (P-00872, p. 1). The items in question related to the cost of vehicles, laboratory and survey services, and airfare. Mr. Kean’s decision resulted in a $134 million reduction in the Project’s capital cost base estimate.

Labour Productivity for Concrete: Power House and Intake

The base estimate contained thousands of individual judgment calls, each of which is highly technical and cannot be evaluated without extensive evidence. It was impractical for Commission counsel to assess the quality of all of these judgment calls. They did focus on one, however—the labour productivity assumptions for concrete placement for the powerhouse and intake.

At DG3, the powerhouse and intake were estimated to require 328,000 cubic metres of conventional concrete. Commission counsel focused on the labour costs incurred from the time the mixed concrete was delivered until the time it was cured and finished. That is, the focus was on the cost of fabricating, erecting and stripping formwork, placing the concrete and incidentals such as curing, sandblasting, patching and foundation preparation.

This cost item included the direct cost of construction labour and the indirect cost of on-site supervision, but it did not include related costs for the labour camp, transportation and the owner's or other offsite activities, which were dealt with elsewhere in the estimate.

Paul Lemay, SNC's chief estimator, explained that the labour costs were calculated by multiplying the quantity of concrete in the powerhouse (in cubic metres) by labour productivity norms in hours per cubic metre, resulting in the number of labour hours required. Multiplying the number of labour hours by the labour rate in dollars per hour yielded the total labour cost in dollars.

The remainder of this section focuses on labour productivity norms, or the number of labour hours needed to place each cubic metre of concrete. These productivity norms were chosen by SNC based on previous project data from cold-climate hydroelectric projects. As Mr. Lemay explained in his testimony, this data already reflected weather problems, site congestion, labour disputes and uneven supervision quality—problems that had arisen on these other projects. Previous project data showed the production levels that could reasonably be achieved over the course of the entire Project.

Mr. Lemay's reliance on previous project data was logical, but it was entirely dependent on using reference data that were a good match for the characteristics of the Muskrat Falls powerhouse and intake.

Mr. Lemay used the following comparators to develop and estimate the labour productivity for the powerhouse and intake:

- The estimate he had prepared for Eastmain-1 and Eastmain-1-A hydroelectric projects in Québec
- The completed data from the 1986 Nipawin hydroelectric project in Saskatchewan

Mr. Lemay stated that he did not have complete project data from Eastmain-1 and Eastmain-1-A. Rather, he had his own estimate and, from early participation in these projects, a sense that the work was going as planned. He did not know whether these projects had ultimately come in on time or on budget.

Were these examples good comparators for Muskrat Falls? The Eastmain-1 and Eastmain-1-A projects were both large, cold-climate projects that included winter work performed under a shelter, as was initially proposed for the Project. Unlike the Project, however, they were planned for and executed by a Québec workforce that had extensive experience building hydroelectric dams. Furthermore, those Québec workers were generally members of the same union, which eliminated jurisdictional issues (this would not be the case at the Muskrat Falls site). Finally, while the Project had a shorter powerhouse that was built to hold Kaplan turbines, Eastmain-1 and Eastmain-1-A had tall powerhouses built for Francis turbines.

Saskatchewan's Nipawin project had been completed a quarter-century earlier (1986) and Mr. Lemay had full project data from it. Although he testified that this project was the most comparable of the ones he examined, he knew very little about it beyond what the data said. For example, he did not know whether it was built with a unionized workforce, whether concrete was poured in winter, whether construction occurred using night shifts, or whether workers had stayed in an on-site camp or elsewhere.

Mr. Lemay's reliance on these projects as the reference data for the Project is troubling, given that SNC's database included a range of other projects that could have been comparators. Notably, however, Eastmain-1, Eastmain-1-A and Nipawin had the best productivity of the projects in the SNC database. The others had worse labour productivity performances, some significantly worse.

It appears that Nalcor was not shown the range of project data that SNC had available to choose from. It was shown only Nipawin data, labelled "Project A." SNC did not share the name of the project, nor that its estimating team had very little information about it.

I conclude that it is questionable whether Eastmain-1, Eastmain-1-A or Nipawin were good comparators for setting labour productivity norms for the Project's powerhouse and intake.

<u>SNC's Added Hours</u>

Mr. Lemay testified that in late November 2011, SNC added 200,000 hours to its estimate of the cost of structural concrete in order to cover productivity lost to site congestion, plus extra productivity required to meet the demands of the aggressive schedule. Even after this adjustment, the Muskrat Falls' labour norms were still more aggressive than most of the other projects in SNC's database (P-00861, pp. 81–82; P-02645, p. 4).

<u>Mr. Lemay's Allowances</u>

Mr. Lemay also testified that in late November or early December 2011, he directed his team to add a further $200 million allowance to cover labour productivity risk, plus a $100 million allowance to cover geotechnical risks on the HVdc transmission line. These allowances are in addition to the 200,000 work hours noted above. Mr. Lemay stated that the extra $200 million labour productivity cost reflected a 20% loss of productivity. Even with this allowance, the estimate was aggressive compared to other projects in SNC's database.

It is unclear whether these two allowances, which totalled $300 million, were actually included in SNC's final estimate. Mr. Lemay was unable to indicate where these allowances were found in the estimate. He did not know whether they were included as a single line entry or whether they had been distributed among different line items.

For his part, Jason Kean testified that he was unaware of the existence of these allowances. This is striking, since Mr. Kean reviewed the estimate with SNC in mid-November 2011 and had been responsible for overseeing the estimate for Nalcor. A $300 million increase in late November or early December 2011 would no doubt have attracted his attention. Mr. Lemay's and Mr. Kean's confusion does little to increase my confidence in the quality or thoroughness of the DG3 estimate.

My concerns about the thoroughness of the estimate were amplified by a table in Nalcor's "Decision Gate 3 Basis of Estimate" document, which summarizes some of the productivity norms used to calculate labour costs (P-00094, p. 69). According to Mr. Lemay, these assumptions are slightly different than those used in SNC's estimate. Mr. Kean indicated that no change was made to Mr. Lemay's norms, and that if Mr. Lemay said the "Basis of Estimate" numbers differed from SNC's estimate, the "Basis of Estimate" was probably wrong.

Building the powerhouse at Muskrat Falls would leave Nalcor highly exposed to performance and productivity issues, so Nalcor hired Paul Hewitt and John Mulcahy to perform independent check estimates of cost for the structural concrete required for the powerhouse, intake and spillway. Mr. Hewitt had assisted Nalcor with its DG2 estimate and Mr. Mulcahy was hired, as referred to earlier, based on his extensive experience in hydroelectric construction projects in the province and elsewhere. Their check estimates were comparable to Mr. Lemay's. Mr. Mulcahy's labour productivity assumptions were more conservative than Mr. Lemay's, but he also assumed lower profit and overhead. In my view, it was certainly prudent for Nalcor to commission these check estimates and I can see how they would reasonably have increased Nalcor's confidence in the quality of the DG3 base cost estimate.

Conclusions

I conclude that, overall, the DG3 base cost estimate was not of the highest quality and accuracy, as would have been an expected requirement for Project sanction. I also find that it was biased on the low side. My reasons for these conclusions are:

- Nalcor intervened directly to reduce the SNC estimate by approximately $134 million and replaced SNC's EPCM cost estimate with one that was $245 million lower; together, this amounts to a $379 million reduction in the estimate
- Even if it is accepted that these reductions targeted components of the estimate that Nalcor thought were too high, selectively second-guessing the parts of the estimate that appeared to be high while accepting the parts of the estimate that appeared to be low resulted in downward pressure on the estimate; selective scrutiny produces bias as effectively as direct pressure does

- Commission counsel examined one specific parameter—the labour productivity for construction of the powerhouse and intake—and the analysis showed the labour productivity assumption to be both aggressive and based on inappropriate comparators (Eastmain-1, Eastmain-1-A and Nipawin); the data that SNC relied on did not reflect the experience of all the comparables in its database and SNC generally ignored projects that were comparable but had worse productivity
- The documentation for the SNC estimate was so weak that Nalcor misunderstood the labour productivity assumption it had used and was not aware of whether a large allowance for labour productivity had been added

Estimating Risk at DG3

The DG3 base cost estimate should have been supplemented by a contingency estimate (related to tactical risks), a management reserve (related to strategic risks) and an escalation allowance (related to inflation). Nalcor began to quantify these risks in a workshop held on May 23 and 24, 2012. In a memorandum to Grant Thornton, Richard Westney commented on the event's purpose (P-01927):

> The workshop was led by Nalcor who had overall responsibility for the setting of [risk] ranges. Westney participants facilitated the discussions around the ranging and scenarios for specific cost elements.
>
> The workshop did not attempt to finalize ranges, but to capture the viewpoints of all parties and develop a basis for Nalcor to finalize the tactical cost, schedule and strategic risk ranges. (p. 2)

On the first day (May 23, 2012), the workshop focused on tactical risks and opportunities for the various construction packages the Project required. It was attended by a large group of Nalcor, SNC and Westney representatives. On the following day (May 24, 2012), the workshop focused on strategic risks. It was attended by a considerably smaller group—just Nalcor representatives and Jack Evans from Westney. No SNC representatives were involved.

It seems understandable that Nalcor would exclude SNC from a discussion of some strategic risks, particularly the breakdown of the EPCM relationship that was apparent by that time. However, it is difficult to understand the exclusion of SNC from the May 24 discussion of labour productivity and schedule risk. Nalcor's perception of labour productivity risk was heavily informed by SNC's confidence in its estimate, so Nalcor's decision to exclude SNC from this discussion was unreasonable. In addition, since SNC would be responsible for managing the detailed construction schedule and for estimating costs at that time, the decision to exclude SNC from the discussion of these matters was both surprising and unreasonable.

On June 4, 2012, Jason Kean and Paul Harrington travelled to Westney's offices in Houston to finalize the preliminary set of risk ranges that had been produced at the May 23–24 workshop. Only Westney representatives attended the meetings that followed. No one from SNC, nor anyone with a hydroelectric or transmission background, was present. Together with Westney, Mr. Harrington and Mr. Kean settled on the final risk ranges for each package (P-00130, pp. 239–47), which were significantly more optimistic than the preliminary ranges that had emerged from the May 23–24 workshop.

Contingency and Tactical Risk

The following points summarize the risk ranges (that is, the best- and worst-case values) that were determined for the five largest individual construction packages:

1. **Powerhouse, intake and spillway.** Range: $673 million (2.5% below base cost estimate) to $765 million (11% over base cost estimate). With a difference of just 13.5%, this is a narrow risk range.
2. **Muskrat Falls and Soldiers Pond converter stations.** Range: $359 million (5% below base cost estimate) to $406 million (7.5% over base cost estimate). Once again, this is a narrow range (12.5%), particularly considering that the contract scope for these packages was still only partly defined. Of note, the best-case scenario is almost as far below the base estimate as the worst-case scenario is above.
3. **Island portion of the HVdc transmission line.** Range: $320 million (12% below base cost estimate) to $510 million (13% above base cost estimate). Again, this range is almost symmetrical. It is a relatively large range, compared to the above-noted packages, but it is narrow when considering the following three

factors: the significant geotechnical risks the HVdc line was exposed to, the performance risks inherent in remote construction and the limited number of potential contractors. These factors were later cited by the PMT as “unknown strategic risks” or “Black Swan events”[7] (P-01769, pp. 11, 40). In my view, there was no reason that these could not have been foreseen and incorporated into the worst-case scenarios for any tactical analysis.

4. **EPCM contract.** Range: $380 million (6% below base estimate) to $500 million (24% over base estimate). Of note: the highest cost that Mr. Harrington and Mr. Kean considered was approximately $150 million less than SNC’s estimate for EPCM.

5. **Owner’s cost.** Range: $218 million (5% below base estimate) to $243 million (11% above base estimate). This range, too, is quite narrow (16%).

In my view, the risk ranges Mr. Harrington and Mr. Kean chose were unreasonably low and narrow. In some cases they were also unreasonably symmetrical. This conclusion is reinforced by the evidence provided by Keith Dodson of Westney, who was extensively involved in Nalcor’s DG3 risk analysis (February 25, 2019, transcript):

> **MS. O’BRIEN:** . . . Do you have any concerns that the ranges, the best case and worst-case ranges, were not being set widely enough?
>
> **MR. DODSON:** Yes.
>
> **MS. O’BRIEN:** Okay—
>
> **MR. DODSON:** I mean, it’s a common problem, we have that all the time. In order to make Monte Carlo work we have to get significantly out on the fringes. These ranges were relatively tight.
>
> **MS. O’BRIEN:** Okay. So, is that—I don’t want to put words into your mouth—but you did talk earlier about there being optimism on the project management team, would that be another manifestation of optimism, or not?
>
> **MR. DODSON:** Oh, absolutely. No, absolutely.

[7] According to Westney, “Black Swan events” are risks that are considered to be outliers and thus ignored until they occur with great impact, at which point explanations are quickly concocted to make them seem to have been predictable (P-01140).

> **MS. O'BRIEN:** Okay. And did you raise this concern with the project management team?
>
> **MR. DODSON:** We had a significant discussion on the topic of strategic risk and this project and the condition of the world, the fact that the work in Alberta was declining, a lot of people from Newfoundland were coming home; they visualized the risk lower than we would have settled with (inaudible) from a global basis.
>
> **MS. O'BRIEN:** Okay. The Commissioner heard evidence in Phase 1 from Professor Bent Flyvbjerg. Are you familiar with Professor Flyvbjerg?
>
> **MR. DODSON:** Yes, I am.
>
> **MS. O'BRIEN:** Okay. He did give evidence about optimism bias. Are you talking about a similar thing here or is this something different?
>
> **MR. DODSON:** No, it's absolutely the same. (pp. 14–15)

I accept Mr. Dodson's evidence. The effect of choosing such a narrow range of best- and worst-case values was such that, when Westney simulated thousands of possible combinations of package costs, many simulations came quite close to the base cost estimate. Few ended up "out on the fringes." In particular, the worst-case simulations did not reflect the unfavourable outcomes that were likely in reality.

The same conclusion is reinforced by examining the size of the contingency that Nalcor used in its DG3 estimate. At DG3, Nalcor included a contingency of $368 million to cover tactical risks. This represented only 6.7% of the base estimate and raised the probability rating of the base estimate to P50. On a component-to-component basis, the contingency percentages of future expenditures were calculated as follows: Muskrat Falls generating station 9.4%, LTA 9.2% and LIL 3.8% (P-00014, p. 61).

In recommending a contingency of less than 7% for tactical risk, Westney observed that: "[T]his project's degree of design development definition, and methodology is consistent with an AACEI Class 2 estimate" (P-00130, p. 265). It is unclear how Westney could have reached this conclusion, since Nalcor had represented its estimate as being only a Class 3. A Class 3 estimate is a lower quality than a Class 2 estimate and would thus require a larger contingency.

At the hearings, criticisms of Nalcor's contingency level were put forward by:

- John Hollmann of Validation Estimating, LLC (Validation), who did not testify but was interviewed by Grant Thornton: Mr. Hollmann indicated that the 7% contingency suggested "something is very wrong" (P-00014, p. 62)

- Professor George Jergeas, an expert witness for the Commission: Professor Jergeas testified (June 18, 2019, transcript, pp. 72, 78) that AACE typically recommends a contingency between 5% and 15%, which in his opinion is conservative; he added that mature projects should have a 15% contingency and less mature projects should have a 25% contingency (Nalcor's overall contingency is at the lower end of the AACE recommended range and the LIL contingency level is entirely below it)
- The Independent Engineer's report of December 30, 2013 (P-01930), which criticized Nalcor's low contingency as follows:

> [T]he IE [Independent Engineer] is of the opinion that the calculated overall 6 percent scope contingency representing an adder of $368M to the project budget is not conservative relative to our legacy experience with similar remote heavy-civil construction endeavors, and is, therefore, judged to be somewhat optimistic. (p. 113)

I conclude that the contingency level for the Project was unreasonably low. Given the long and well-documented history of cost overruns on megaprojects, Nalcor was, or should have been, aware of the inadequacy of the contingency level it used.

Strategic Risks

As noted earlier, Westney and Nalcor had identified 33 key strategic risks at DG2. At DG3, Nalcor decided to quantify only three strategic risks. For one of these risks, the availability of skilled labour, Nalcor identified two cost components—completion bonus and wage rate. Nalcor's quantification of these risks appears in Figure 2.26 (P-00832, p. 7).

	Potential Impact ($ millions)
Potential Schedule Risk – Time Extension	$ 184
Potential Performance Risk – Productivity	161
Potential Skilled Labour – Completion Bonus	82
Potential Skilled Labour – Wage Rate	70
Total of Mean Values	**$ 497**

Figure 2.26: Strategic Risks at Decision Gate 3

By the time it was preparing the DG3 estimates, Nalcor considered the 29 other previously identified strategic risks to be fully (or almost fully) mitigated or to be best considered as tactical risks at that point. As a result, it made no attempt to quantify several long-identified strategic risks, including:

- A delay in the environmental assessment process for the LIL, or the imposition of restrictive conditions as a result of it
- The limited availability of experienced hydro contractors
- A lack of support from Indigenous Peoples that could potentially lead to protests (some money was set aside, however, to deal with legal challenges to the environmental assessment release)

In its 2018 Briefing Note for Nalcor's counsel, "Muskrat Falls Project Post Sanction," the PMT identified some of these risks (particularly the protests) in the "unexpected event/unknown strategic risk" category of risks that had led to cost overruns (P-01769, p. 46). I note that these risks had been included in the DG2 risk register and they remained foreseeable at DG3.

In addition to shortening its existing list of risks at DG3, Nalcor did not add any new risks for issues that had emerged or were emerging after the preparation of the DG2 estimates. For example, the PUB's report on the Reference Question (P-00052) had been critical of the reliability return period specified for the HVdc transmission line. It noted that, although it did not have direct supervisory authority over the Project, it did have the power to require reliability upgrades after the Project was completed (P-00052, p. 109). The risk of reliability-driven scope change should have been apparent to Nalcor in the period leading up to DG3.

Similarly, despite the deterioration of its relationship with SNC during the spring and summer of 2012, Nalcor did not include that situation as a strategic risk. According to Jason Kean (May 6, 2019, transcript, p. 78), this was because "it was an item that was underway." The PMT's 2018 "Post Sanction" Briefing Note also listed the deterioration of the relationship between Nalcor and SNC as an unexpected event/unknown strategic risk (P-01769, p. 37). The evidence clearly establishes that the difficulties with SNC were far from unforeseen at the time of the DG3 strategic risk analysis. In fact, this risk was obvious.

In his testimony at the hearings, Keith Dodson stated that he had recommended including $300 million as a strategic risk reserve at DG3 to cover political and social risks.

Nalcor rejected this recommendation and instead made no provision for political or social risks in its DG3 strategic risk register. Several of the unforeseen/unknown strategic risks, such as protests and changing internal and external leadership, that were identified by the PMT in its 2018 "Post Sanction" Briefing Note (P-01769) can fairly be described as political or social risks. If Nalcor had accepted Mr. Dodson's recommendation and included political and social risk among the risks it analyzed, it would have covered at least some of the cost of these so called "unforeseen" overruns.

The PMT recommended that a management reserve of $497 million be established to cover strategic risks. This would have brought the total estimate to just under $6.7 billion. Edmund Martin rejected this recommendation and did not share the results of the DG3 strategic risk analysis with GNL or the public. As a result, there was nothing in the DG3 cost estimate to cover strategic risks. Mr. Harrington and Mr. Kean did not make this decision.

In the following sections, I consider the strategic risks identified above that made up the $497 million strategic risk recommendation.

DG3 Strategic Risk 1: Labour Productivity/Labour Strategy

"Potential Performance Risk – Productivity" was one of the four strategic risks that Nalcor and Westney identified and analyzed at DG3. In their DG3 report, *Analysis of Potential Management Reserve and Lender's Owner Contingency for the Lower Churchill Project*, Nalcor and Westney summarized this risk in these words (P-00832):

> The performance rates, estimating norms, or productivity used in the estimate including contingency are significantly better than the worst cases currently being experienced in Canada; some of which are in Newfoundland / Labrador. Experienced front-line supervision, a key to performance, is now a world market and will likely experience high demand during this project.

Later in that report they noted:

> Construction productivity has been on a steady decline for twenty-five years. A key element of this is the availability of front line supervision. This project likely has significant performance risk exposure. On the positive side, there has been significant effort to secure a Project Labor Agreement (PLA) that will minimize exposure to labor excesses. While negotiation is not complete, positive concepts like "work teams" have been accepted.
>
> . . .

> Productivity – The Long Harbour and western Province projects are experiencing poor productivity and some jurisdictional problems. The weather is problematic at this site, compounding the productivity issue. (pp. 4, 6, 14)

SNC had expressed confidence in its productivity estimates, but Nalcor was aware that the labour productivity factor that SNC used was far better than what was being achieved at the time at Long Harbour and Bull Arm in this province, and also in the western provinces.

Westney had prepared what it described as a “straw man” estimate of $600 million for the worst-case exposure on labour productivity. Discussions during the June meetings in Houston covered the number of labour hours in Nalcor’s estimate, how the productivity level compared to other projects and what the cost of additional hours would be.

Paul Harrington and Jason Kean ultimately selected a range for the unmitigated labour productivity risk of between nil (best case) to $350 million (worst case), with a mean value of $161 million. The worst-case assumption of $350 million reflected 3.5 million additional labour hours needed to make up for a productivity decrease of approximately 35% from SNC’s productivity estimate.

I find it difficult to accept that the worst-case scenario for labour productivity was 35% lower than the base estimate. Mr. Dodson testified that the labour productivity rate that Nalcor had actually achieved on the Project was only half the rate that had been estimated, but it was comparable to productivity rates being experienced around the world at the time. I accept Mr. Dodson’s evidence on this point. If Nalcor had based its estimate on the best information available to Westney, the labour cost estimate would have been $1 billion higher. Nalcor’s worst-case input of $350 million failed to reflect the extent to which productivity could reasonably differ from SNC’s estimates (P-04020; P-04022; P-04023; P-04024; May 6, 2019, transcript, p. 73). Why Nalcor’s estimate failed to reflect the best information available to Westney is unclear—nor was it satisfactorily explained.

<u>Strategic Risk 2: Wage Rates and Completion Bonuses</u>

Nalcor identified competition with other projects for the limited pool of skilled labourers and construction supervisors as a key strategic risk. It recognized that Nalcor would have to increase compensation to attract workers and decided to capture the associated strategic risk under two components: “Potential Skilled Labour – Completion

Bonus" and "Potential Skilled Labour – Wage Rate." These risk categories were defined by Nalcor and Westney as follows (P-00832):

> Payment of Completion Bonuses – It is known the Western Canada projects are planning to pay completion bonuses of $10 per work-hour. Assuming not all workers would achieve the required hours, $8 is used for impact calculation purposes.
>
> Wage Rate – The Hebron wage rates used in the estimate are roughly $5 per hour to the person less than the Western Canada rates. The mining projects in the west of the province are currently paying Alberta rates. (p. 13)

For the completion bonus strategic risk, Nalcor chose a risk range of $50 million (best case) to $120 million (worst case). For the wage rate strategic risk, Nalcor chose a risk range of nil (best case) to $150 million (worst case). They concluded that the mean values for these two strategic risks was $82 million and $70 million, respectively.

I find that these risk ranges were reasonable.

<u>Strategic Risk 3: Schedule</u>

At DG3, Nalcor and Westney identified "Potential Schedule Risk – Time Extension" as a strategic risk, stating (P-00832):

> There is potential time or schedule risk exposure beyond the plan, due to the weather and the volume of work in the powerhouse. The current schedule assumes aggressive performance in powerhouse concrete, and a few sections of the transmission line are challenging.
>
> . . .
>
> The current schedule is aggressive, given the northern location and the sustained concrete placement production rates required.
>
> . . .
>
> Schedule Extension – If weather, logistics, and / or productivity reduce the production rates required to meet the current schedule, a time extension will be the most economical solution to the issue due to the labour concerns in recovery or acceleration scenarios. (pp. 4, 6, 15)

The ranging for the unmitigated schedule risk was nil (best case) to $400 million (worst case), with a mean value of $182 million. The best case assumed that the Project would be completed on schedule. The $400 million worst case was based on multiplying the expected schedule overrun by the expected monthly carrying cost of the Project. It should be noted that the carrying cost did not include the cost of additional Holyrood fuel or of any other actions that might be needed to support Island loads if the Project was not completed on schedule. Although these costs would not form part of the Project's capital budget, they would be borne by ratepayers. In the absence of any analysis of the effect of schedule delay on the CPW analysis, the strategic risk analysis was the only place they could possibly have been captured.

Time Risk

Tanya Power, the Project Controls Manager with Nalcor, testified that Nalcor and SNC built and maintained a detailed construction schedule that had 10,000 line items representing all the activities in the various construction packages (May 24, 2019, transcript, p. 8). Among other things, this schedule tracked, for each activity, the time estimated to complete it and its start/end dates, its links to the various Project activities, key weather windows (some activities could only be executed at certain times of the year), key milestones and a critical path. The length of the work week was a key assumption in this schedule—it affected both overall Project duration and Project cost. Based on this schedule, Nalcor publicly announced at DG3 that first power from the Project would be achieved by July 2017 and full power by December 2017.

I accept that Nalcor's detailed construction schedule was a useful tool for managing the Project. I find that it:

- Reasonably captured the important activities required for completion of the Project
- Determined the critical path of the Project, as well as which activities could be delayed without affecting schedule and which ones had to be completed for the Project to meet schedule
- Set targets for each stage of construction, which could be used to set expectations for individual contractors

What this construction schedule does not show, however, is the probability of achieving the desired goal of first power or full power by specific dates. The entire schedule is based on the assumption that the thousands of different construction activities would generally proceed in a manner that would not adversely affect the overall critical path. There is a major problem with that assumption, since some activities were bound to be delayed and some of those delays would adversely affect the critical path.

At DG3, Nalcor recognized this problem and engaged Westney to perform a time-risk analysis of the schedule. The full 10,000-line construction schedule was far too detailed to simulate in the analysis, so Nalcor and Westney built an abbreviated version of the Project schedule that captured 78 key construction activities. For each activity, Nalcor estimated a best-case and worst-case duration. Westney then ran 10,000 simulations of the abbreviated schedule based on these inputs from Nalcor.

At several points during the hearings, it was suggested that when Nalcor estimated the durations for each activity in the schedule, it had not accounted for the fact that the detailed construction schedule assumed a six-day work week. After my review of the evidence, I cannot accept this position. It is far more likely that Nalcor's PMT, and Paul Harrington and Jason Kean in particular, had incorporated all the information at their disposal when estimating these durations. In addition, the notes accompanying the best and worst cases refer explicitly to "some savings on the expected 1/day per week of NPT [nonproductive time]." This confirms that one day per week of nonproductive time was considered (P-00130, pp. 258–59), and thus a six-day work week had been used.

The DG3 time-risk analysis of the 78 schedule components was first performed in June 2012. The results were discouraging for Nalcor. At P25, the schedule delay was 11 months beyond the proposed completion dates, and at P75 it was 21 months beyond it. The results also put both the July 2017 first power date and the December 2017 full power date at P1. In other words, the schedule to achieve them had a 1% probability of being met (P-00832, pp. 17–18).

Instead of adjusting the target dates in light of these results, Nalcor appears to have taken a four-pronged approach to neutralize their importance.

First, it internally questioned the reliability of Westney's work. In contrast to the upbeat risk reports it had accepted at face value, Nalcor emphasized that the results of this downbeat model of time risk, based on the abbreviated version of the Project schedule that Westney had used, had been dependent on numerous assumptions and had not incorporated all possible mitigations. Several witnesses made this argument, none more determinedly than Edmund Martin.

I reject these explanations. Like all models, the analysis of time risk had limits and its results could only be interpreted in light of the assumptions used. However, this should not be an excuse for disregarding the valuable information conveyed by this analysis. Although it was simpler than the detailed construction schedule, Westney's work contained what Nalcor had identified as the main construction activities and was the only analysis that took account of time risk.

Second, Nalcor attempted to take concrete steps to reduce the schedule risk. Most notably, it awarded the bulk excavation contract, a major schedule risk driver, before Project sanction.

Third, as revealed during questioning of Edmund Martin at the hearings, Nalcor began referring internally to “the natural schedule reserve that exist between July 2017 and December 2017 or when power is required on the Island to meet energy requirements” (June 14, 2019, transcript, p. 145; P-00130, p. 15). The idea was that Muskrat Falls power was really only needed in the winter, so the date for achieving first power could slip to late 2017 without affecting the Island’s needs. While that was possibly true, this five-month schedule reserve would not compensate for a potential 11- to 21-month delay.

At Project sanction, Nalcor assumed that Muskrat Falls power and capacity would be fully available for the winter of 2017–18. Prior to sanction, it does not appear that Nalcor conducted any analysis to determine the consequences of a delay beyond this target date. The analysis that it did after sanction is best described as “rough.” In 2013, Nalcor shifted the first power date to late 2017. At that point, it calculated that the delay would increase the CPW of the Interconnected Island Option by about $200 million, mostly because of additional fuel consumption at Holyrood. The cost consequences of an 11- to 21-month delay were never calculated.

Fourth, Nalcor began to de-emphasize the schedule target dates in its internal and external communications. For example, in an email to Derek Owen dated September 3, 2012, Mr. Harrington wrote (P-00508):

> [N]ote Ed Martins article in the Globe and mail today wherein he states that power will be flowing from Labrador to the Island in 2017. That is consistent with the messaging so far which will continue - we can bring power into the Island via LTA and LIL without the need for MF initially. (p. 2)

Despite this change in communication strategy, the original target dates remained unchanged in internal and external communications and were provided to GNL to support sanction (P-00130; P-00505; P-00508).

On August 31, 2012, Mr. Owen, who led the Independent Project Review (IPR) team, advised Mr. Martin that the schedule was a P1. In an email to Mr. Owen later the same day, Mr. Harrington described this disclosure as being “most unfortunate” and “a major blow" (P-00505, p. 1). On September 5, 2012, Mr. Kean wrote Jack Evans of Westney advising that he had changed the time model logic to reflect the steps taken to improve schedule risk. He requested a re-evaluation of the P value of the schedule and questioned whether the changes would bring the schedule from a P1 to "P20 or P30" (P-00130, p. 326). The following day, Mr. Evans replied that, after incorporating the changes, a P25 schedule reflected a seven-month delay in full power and the P75 schedule reflected a delay of 18 months. He added that, in Westney's view, the December 2017 full power target date was now at a P3 level. In other words, while Nalcor's changes had improved the schedule, they were not nearly enough to make the original target dates realistic (P-00130, pp. 321–22). Mr. Evans did not provide alternative dates for first power.

Although the PMT recognized that the schedule targets were highly unlikely to be achieved, it continued to state that the schedule was more likely than Westney's P3 indicated. For instance, on June 6, 2016, Paul Harrington wrote Stan Marshall with thoughts and concerns about the Project, noting (P-01962):

> [T]he direction that was provided to the Project Team was to set a very aggressive schedule with a First Power target that was recognized as being in the P5 to P10 range. The unlikely probability of achieving these cost and schedule targets was well known. (p. 2)

Nalcor's official interpretation of Westney's work on the schedule was that it "reaffirmed" that "powerhouse concreting and associated weather windows is the most significant influencer of the risk adjusted schedule" (P-00130, p. 16). However, it does appear that the implications for the business case arising from schedule delays were unacknowledged.

With the benefit of hindsight, it seems that the results of Westney's analysis of time risk were reasonable and I see no reason to question the choices of inputs or Westney's methods. While capital costs have now exceeded even the worst case that was contemplated in the DG3 estimate, the DG3 time-risk projections were plausible. Despite all of the setbacks that the Project has endured, the current projected first power date is approximately P90 on Westney's time-risk analysis (P-00832, p. 16).

Significantly, Nalcor failed to consider the business case implications of its analysis of time risk. If that analysis had been taken into account, the Interconnected Island Option's CPW advantage would have been reduced by hundreds of millions of dollars. An aggressive target may be appropriate for construction contracts but it is not appropriate for system planning or accurate cost estimating.

Richard Westney explained that, for projects with "very, very strong commercial drivers," there may be good reasons to set targets that are more ambitious than a P50 schedule. In his words (November 16, 2018, transcript):

> So my point here is, when you see the probability is P1, you might as well just say: This is a completely unrealistic schedule, we cannot work with this. We need to go back and have a schedule, which at least as its base value, is somewhere around P50. (p. 17)

I find that Nalcor's decision not to adjust its target dates for first power and full power was unreasonable.

OPTIMISM BIAS, STRATEGIC MISREPRESENTATION AND POLITICAL BIAS

During the hearings, several explanations were offered for why costs regularly exceeded estimates—on this Project and on other large-scale developments. They included optimism bias, strategic misrepresentation and political bias.

In his expert testimony, Professor Bent Flyvbjerg stated that limited information and/or bad luck cannot fully explain cost overruns or schedule delays on megaprojects. He contended that, in theory, luck and error should lead estimators to overstate costs as often as they would to understate them, but statistical analysis shows that estimates for megaprojects are consistently too low. "The problem," he wrote in his report for the Commission, "is not even cost overrun, it is cost underestimation" (P-00004, p. 17).

Professor Flyvbjerg presented two explanations for systemic underestimation. The first is "optimism bias" or self-deception, which is exhibited when project teams hope that projects will succeed and this hope distorts their judgment and leads them to unconsciously overestimate benefits and underestimate difficulties. The second is "political bias," also explained as deliberate deception or strategic misrepresentation, which is demonstrated when project teams want projects to be approved so they deliberately exaggerate benefits and understate difficulties.

Another expert witness, Professor George Jergeas, rejected the theory of strategic misrepresentation. He did not believe project teams would deliberately underestimate costs. He advanced a theory of systemic error, in which project teams, particularly in the early stages of engineering and when a project is not fully defined, are unable to grasp a project's complexity. This theory suggests a systemic bias, apart from optimism and political bias, that could lead to underestimation.

Richard Westney presented another error theory: understated estimates caused by the failure of project teams to fully account for strategic risk and scope changes. He believed that his proprietary risk-resolution methodology would allow teams to identify strategic risks and produce accurate results—if followed.

Most error theories are vulnerable to Professor Flyvbjerg's argument that, if the problem was simply that estimates are too low, performance would improve over time as awareness of the systemic error grows. One possible reason why this does not occur was provided by John Hollmann, who indicated that "management will not believe the truth after being fed unreality for decades" (P-03237, p. 11).

My purpose is not to attempt to determine why cost estimates on megaprojects generally are too low. I am focused on why the cost estimates for this Project were too low. To answer this question, I consider not just abstract theories of estimation but the concrete evidence of what happened here.

To begin with, consider Westney's September 2012 risk report for DG3. This report considered the Project's tactical, strategic and time risks. It found the Project cost approached $8 billion as the P value neared P100 (P-00832, p. 12). Nalcor and Westney were not merely predicting that the current capital cost of $10.1 billion was unlikely but that it was essentially impossible. Now that the impossible has happened, it shows that Nalcor's estimate of the range of possible costs was wrong.

Next, Professor Flyvbjerg and many other witnesses testified about how common it is for project teams to significantly understate construction costs. This evidence reinforced my sense that it is more likely that the original cost estimate for the Project was underestimated, not that the current Project cost is a result of an unforeseeable cost overrun.

Third, I considered the estimate itself and how it was prepared. It is evident that Nalcor intervened to reduce SNC's aggressive estimate, that it underestimated the worst-case scenarios when assessing cost estimates and that it failed to quantify material strategic risks. Each of these actions reduced the estimate's accuracy and increased its bias.

What about Mr. Westney's error theory, that underestimates are caused by a failure to adequately account for strategic risk? Both of the Westney witnesses who testified at the hearings, Richard Westney and Keith Dodson, indicated that, in their experience, project teams generally have optimism bias. Mr. Dodson testified that project teams are "always" motivated to keep the cost estimates low and they regularly reject Westney's advice as a result (February 25, 2019, transcript, p. 11). In fact, he recommends the use of a P75, rather than P50, estimate value, because P75 tends to be more accurate. That implies that the estimates Westney works on are usually biased and underestimated.

Westney's assertion that its methods would have worked on the Project cannot be tested here because it is clear that Nalcor, like project managers before them, rejected Westney's advice on many critical points and instead chose to substitute its own perception of risk. Mr. Dodson specifically confirmed this.

The decisions Nalcor made to reduce the cost estimate in the period leading to DG3 must be seen as part of the pattern of questionable decisions that systematically tended to overstate the Project benefits, understate its cost and disregard alternatives. This pattern included the decisions to screen out viable power-generation alternatives, to exclude CDM and IRP, and to disregard recommendations that the Project's business case be subject to an independent review and rigorous scenario analysis.

I also find that there is significant evidence of what Professor Flyvbjerg calls strategic misrepresentation or political bias in Nalcor's estimates. One example is Nalcor's observation, in an April 2012 presentation, that SNC had "[u]nacceptable expectations for EPCM resource requirements," which meant that "[t]he Project will not pass through DG3" (P-00858, p. 4). Ron Power, a member of the PMT, prepared the presentation from which those quotes are taken. In his testimony, Mr. Power advised that he intended to send a message that the team had to "get smart about . . . the resource requirements to get that number down" (May 21, 2019, transcript, p. 34).

Edmund Martin, Gilbert Bennett and the PMT frequently took what I see as unprincipled steps to help secure Project sanction. They concealed information that would undermine the business case reported to the public, to GNL and to Nalcor's board of directors. The PMT did its best to narrow consultants' terms of reference to forestall independent review and it tried to influence the editing of reports to make conclusions appear more favourable to the Project. Many times, these decisions were made by the same individuals, Paul Harrington and Jason Kean, who had also determined the final inputs into the tactical and strategic risk analyses.

In the years leading up to Project sanction, the PMT performed two contradictory roles. They were expected, as managers, to advocate for the Project and also, as engineers, to analyze its merits. The tension between these roles cannot excuse their bias and underestimation of costs. Passing off advocacy as analysis is a form of deception.

Having considered all of the evidence, I conclude that Nalcor's cost estimates were affected by strategic misrepresentation, optimism bias and political bias.

INTERPRETING ESTIMATES

I heard a significant amount of evidence about choosing P values and about how to use capital cost estimates and schedules. Witnesses generally advocated one of two approaches to the P values shown on S-Curves and what they predicted. One approach assumed that a project's S-Curve after a Monte Carlo simulation would accurately represent the likely distribution of costs, while the other approach assumed it would not.

An S-Curve is not a crystal ball. It does not show the future. It shows only a simulation of possible project outcomes based on assumptions. If the assumptions are accurate and unbiased, then the S-Curve can represent an accurate and unbiased picture of the future. However, if the assumptions are inaccurate or biased, then the resulting S-Curve is unreliable.

Many witnesses interpreted P values on the Project analyses as true probabilities. That is, they assumed that there was a 50% chance that the Project costs would be greater or less than the P50 value. But this can only be true if the S-Curve is accurate and unbiased. If, for example, an estimate is too low to begin with, there is more than a 50% chance that the eventual project cost will exceed the P50 value shown on an S-Curve.

In its *Sanctioning Phase* report, Grant Thornton explained how to use P values based on the assumption that the estimate and risks are accurate and unbiased (P-00014):

> [T]he P50 value is essentially the 50th percentile of the Monte Carlo results. This means that the actual total cost could come in at 50% above or below the P50 value. AACE 42R-08 states that "management can decide how much risk they are willing to accept and therefore how much contingency will be required". Selecting the P50 value does not provide certainty that there will not be cost overruns. In order to be more certain that cost overruns will not occur, Nalcor could have chosen a P75 or a P90, meaning there would only be a 25% or 10% chance of overruns respectively, and therefore a 75% or 90% chance of no cost overrun.

> Grant Thornton asked Validation Estimating if selecting a P50 value for contingency was in accordance with best practice. In response, Validation Estimating noted, "P50 funding is a concept for portfolio—say you have a major company and you have 300 projects in your annual portfolio, if you fund them all at P50 level it means (half) 150 will be over and 150 will be under and your annual capital budget will be about right. It makes sense from a portfolio viewpoint but on a mega project where that one project is the company—the P50 is extremely aggressive. I don't know any company who will fund a single major project like that at P50. Most companies will fund it at a higher level—commonly P70 or P80." Validation Estimating also noted that Suncor used to fund at a P70 and the Department of Energy funds at a P90, and explained that somewhere between P70 and P90 would be best practice.
>
> . . .
>
> Grant Thornton also interviewed SNC employees who were involved with the LCP. Specifically, the Project Controls Manager and a Risk Director at SNC. Both stated that the SNC policy is to choose a P85 value. The Risk Director referred to a P50 as bad practice.
>
> Our third party expert, also noted that while selecting P50 as the confidence interval is within the AACE 42R-5 08 guidance, in their experience, they have typically observed their clients using P75 or above as the confidence level to provide a higher level of confidence that the estimated value will not be exceeded.
>
> If Nalcor had chosen a higher confidence level such as the P75 of $6,227 million or the P90 of $6,608 million, it would have resulted in a contingency value of $754 million or $1,135 million respectively; increasing the total capital cost estimate by $386-767 million. (pp. 62–63)

Another example of how best to use P values is found in the testimony of Richard Westney. He testified that it is not uncommon for project management teams to receive a budget based on a P50 tactical risk but, in these cases, boards of directors normally establish a management reserve based on the P75 strategic risk exposure before funding the project. If an S-Curve represents an accurate and unbiased picture of the future, the choice of P values depends on the owner's appetite for risk.

In his report, Professor Flyvbjerg expressed observations similar to Grant Thornton's, also based on the assumption of an accurate and unbiased base estimate (P-00004):

> The P50 estimate is often used to forecast projects in a portfolio of projects, because in this manner on average underruns will compensate for overruns and the portfolio will balance overall. However, for big, one-off capital investment projects, decision makers will typically regard a level of 50%

> certainty to be too low. In this case, decision makers would typically want estimates with a higher level of certainty for staying on budget, often 80% certainty (P80), i.e. estimates with a 20% probability of being exceeded. An 80% certain estimate . . . requires an uplift of 104%. In this risk averse scenario, decision makers would have to apply a 104% uplift to their project proposal to ensure that the probability of a budget overrun is reduced to 20%. In some cases decision makers have asked for even higher levels of certainty than 80%, for instance 95% (P95) for UK's High Speed 2. (p. 25)

Professor Flyvbjerg, who argues that reference-class forecasting can help resolve the problem of underestimating and produce accurate S-Curves, suggested the use of a tiered contingency regime (P-00004):

> The full distributional information of a forecast could be used to design a tiered contingency regime. . . . For example, a contingency regime could consist of:
>
> - Contract contingency up to P30: small contingency allocated to key contracts with authority delegated to the contract manager, setting ambitious targets for contractors with downward pressure on costs and demonstrating efficient use of taxpayer money;
> - Project contingency up to P50: additional contingency whose spending authority is delegated to the project manager and which anchors the total cost of the project at the most likely cost estimate;
> - Funder's contingency up to P80: additional contingency whose spending authority is delegated to the project funder or project board, which covers cost above the most likely estimate and includes extreme downside scenarios.
>
> The key advantages of a contingency regime designed in this way are that:
>
> 1. Contractors and contract managers are given an aspirational target. Decision makers are able to set ambitious goals to safeguard value-for-money and incentivize contractors to be cost efficient and innovative;
> 2. The project is given a target in line with the likely cost, which follows common planning practice, i.e. uses most likely schedule and cost estimates, and holds project managers to account for their plans; and
> 3. The funders of the project reserve a contingency reflecting their level of, typically low, risk appetite. (p. 22)

Professor Flyvbjerg recognized that, in the absence of reference-class forecasting, P values cannot be taken as probabilities, at face value. He stated that, in order for a developer to reduce the risk of cost overruns, he would recommend using a P80 value for a multi-billion-dollar one-off project. He explained his rationale for this as follows (September 17, 2018, transcript):

> In my experience, a P50 is usually somewhere between a P25 and P40 because of the biases we talked about earlier and because of the Monte Carlo simulations that we talked about not taking all the variations into account, underestimating the risks. So people think they have a P50, but they have something less than a P50 and, therefore, a higher risk of going over budget. (p. 29)

Keith Dodson observed that, in his experience, the P75 value on the S-Curves that he works on tends to be more accurate than the P50 value. He indicated that this, rather than risk aversion, was the reason he recommended that projects use at least a P75 value to sanction projects. He went on to testify that because the Project is publicly funded and a political project, he said to Mr. Harrington and Mr. Kean: "I worked on a lot of projects with similar situations and, you know, my advice was you'll probably have a government change, which has happened and, you know, you ought to go with a P90" (February 25, 2019, transcript, p. 9).

Mr. Dodson also testified about his response to a pre-sanction request at DG3 from Mr. Harrington and Mr. Kean, regarding the strategic risk (February 25, 2019, transcript):

> Well they wanted us to say picking P50 was a good thing and we never would say it.
>
> . . .
>
> So I think, you know, a prudent person would say they wouldn't pick something that has a chance of being 50 per cent wrong; they would want a much more secure value. (p. 13)

Pelino Colaiacovo indicated that because cost estimates tend to be too optimistic, the standard practice in financial analysis is to adjust the S-Curve upward. He said that he would start with a P90 and consider scenarios that are higher still (July 17, 2019, transcript, p. 44).

MEGAPROJECTS AND OVERRUNS

As stated earlier, I heard evidence that megaprojects often face large capital costs and schedule overruns. For example, Professor Flyvbjerg's report to the Commission included a review of 274 hydroelectric dam projects and it noted that (P-00004):

- 77% of the projects encountered cost overruns with a median cost overrun of 32% and an average overrun of 96%
- 80% of the projects also encountered schedule overruns, with an average delay of 27 months
- The rate of overruns has not changed in the past 60 years (pp. 6–7)

Professor Flyvbjerg's research found that large cost overruns and schedule delays were also common for other types of megaprojects. Transmission projects, however, had significantly lower cost overruns, with an average of only 8%.

The 2014 study of hydroelectric dams on which Professor Flyvbjerg's report was based was not available at the time of Project sanction. However, the data on which that study was based was available long before sanction. There is nothing surprisingly new about the observation that megaprojects often overrun budget and suffer schedule delay.

Prior to sanction, Nalcor and GNL should have known, or could easily have learned, that megaprojects have a long history of large cost overruns and schedule delays simply by considering the published works of its own consultants. For example:

- Keith Dodson and Richard Westney, Nalcor's risk consultants, wrote several papers on how to avoid cost overruns of 50% to 100%, of which, they write, "there is no shortage of examples" (P-01140, p. 1; P-01148, p. 4); Westney's approach to modelling risk for the Project was shaped by "the many published overruns of costs" (P-00097, p. 37)
- Edward Merrow of Independent Project Analysis, which produced reports for Nalcor, published *Understanding the Outcomes of Megaprojects: A Quantitative Analysis of Very Large Civilian Projects* in 1988 (P-03234), in which he analyzed 47 large projects and found an average 88% cost overrun and a 17% schedule overrun
- Similar observations are found in the words of John Hollmann of Validation Estimating (P-03237; P-00959)

Yet Nalcor did not demonstrate any awareness of the problem of large capital cost overruns. In fact, on October 31, 2011, Paul Harrington wrote in an email to Derrick Sturge and Charles Bown: "We do not have any analysis on hydro project overruns" (P-00810, p. 1).

I conclude that, before sanction, it would have been very easy for Nalcor and GNL to have educated themselves on the history of cost overruns and schedule delays for megaprojects and that their failure to do this is indefensible.

In summary, I find that:

- **P50 is not really P50.** For various reasons, cost estimates often understate both the cost of the project and the risk of large overruns; until that changes, decision makers must look past the project team's assessments of a project's likely cost
- **Nalcor knew the P50 value was not the most likely cost.** I accept Keith Dodson's evidence that Westney advised clients that projects were more likely to end up near the P75 costs than the P50
- **Nalcor should have used a P75 estimate, including strategic risk, in its CPW analysis.** Nalcor knew the best estimate of the Project's most likely cost was the P75 estimate of $7.5 billion, inclusive of strategic risk, and it should have used that figure, at a minimum, as the base case in the CPW analysis; for future large publicly funded projects of this size, I recommend the consideration of an even higher P value—P80 or P90
- **A reasonable reserve for strategic risk should have been included in the Project's estimate.** There was no reasonable basis on which to support the decision to exclude strategic risk from the CPW analysis or the Project cost estimates
- **Nalcor should have considered worst-case scenarios.** In addition to considering the most likely cost of the Project, Nalcor should have considered worst-case scenarios with large cost and schedule overruns that reflect the kinds of severe, adverse outcomes that have happened on other projects; this analysis should be standard in the future for large publicly funded projects
- **Nalcor should have considered the full cost of schedule delays.** These costs include the cost of additional Holyrood fuel and the potential need for new generation capacity

- **Mr. Martin should have communicated the full project cost estimate, including strategic risk exposure, to Nalcor's board of directors and to GNL before Project sanction.** In the future, Nalcor's board of directors and GNL should be fully informed of all costs and risks for any publicly funded project

THE VALIDATION ESTIMATING DRAFT REPORT

Validation Estimating, based in Virginia, is an American company owned and operated by John K. Hollmann, an internationally recognized expert consultant in the fields of project cost estimates and cost/schedule risk management functions.

Mr. Hollmann, on behalf of Validation, began a review of Nalcor's DG3 cost estimate on April 2, 2012. The review was intended to be both qualitative and quantitative, but Mr. Hollmann quickly determined that it was not possible to conduct a quantitative review for two reasons: first, the DG3 estimate was still undergoing final changes and corrections, so no overall cost summary or compilation was available, and second, the contingency and escalation estimates had not yet been prepared. Mr. Hollmann's review was thus limited to an assessment of the processes that Nalcor had followed in preparing the DG3 cost estimate. He did not review the reasonableness of the amounts that were included in the estimate. This was acknowledged by Jason Kean in his testimony (November 7, 2018, transcript):

> So, just for—I just wish to clarify a statement you made. Mr. Hollmann didn't review the numbers. Mr. Hollmann reviewed the process upon which we arrived at the estimate, not a quantitative review to say that the numbers were good. That was done by others.
>
> This is a qualitative process check to ensure that we put together an estimate that adheres to good process. That was the intention. He didn't have time to do a fully quantitative review in this scope. (p. 76)

On April 9, 2012, Validation emailed a draft report to Jason Kean. Under the heading "Assessment Findings," the report stated (P-00610):

> First, it should be noted that while not perfect, the LCP Gate 3 estimate in its current state is one of the best mega-project "base" estimates that this reviewer has seen in some time. My conclusion is that this is in large part due to the active involvement of the owner leads in striving for best practices and quality within the construct of a solid phase-gate system. (p. 10)

Much of the remainder of the draft report contained blunt and severe criticisms of Nalcor's approach to cost, schedule and risk management (P-00610). These criticisms included the following:

Cost/Schedule Integration and Tradeoff Strategy

- Ambiguous: The statement that cost and schedule will be managed "holistically" is repeated in several documents, however, nowhere is the interface of estimating and schedule discussed other than in the context of final loading of cost into the schedule to get resource curves and a cash flow.
- Estimating and Scheduling Marginally Integrated: There is no discussion of resource planning or resource loading in estimating or planning and scheduling plans and documents. There is a focus on "Constructability-is that a proxy for schedule integration (if so, say so).
- Cost and Schedule Risk Quantification are not integrated: There is no explicit connection of cost and schedule risk analysis and quantification. Resource planning is aided by understanding how the plan can be made "risk-tolerant".
- RESULT: Implied strategy Is expensive (including having NO schedule contingency): my reading is that that the first power date is involute; but does this mean "at all costs"? I found places that estimators were adding allowances for schedule Issues. Cost contingency will be high if every risk response must recover schedule at all costs.

Risk Management Strategy

- Disconnects Between the Risk Policy/Philosophy and Estimating. Some examples are below;
    - Philosophy says risk is "improved when achievable objectives" are first established; so what is the cost objective? (see above).
    - Philosophy says decisions are facilitated "through a comprehensive understanding of risks"; so what is comprehensive about estimating contingency with methods that do not tie to identified risks? Why is escalation estimated deterministically? Why are cost and schedule risks analyzed separately?
    - Policy says "Improve decision-making by thoroughly understanding project risks and uncertainties". So why was there no funding of strategic risks (many with 100% probability of occurring); Why is no probabilistic information generated for consideration in economics? In actuality, absolutely no uncertainty information is

being communicated in the Gate 2 estimate outcome (i.e., contingency is a control account that is expected to be spent and does not communicate uncertainty).

- Weak Logic in Treatment of Risk Costs: What message is sent when no reserves are included for 100% probable risks (e.g., shortages of labor)? If they are "balanced by opportunities", then include that in the method; what are those opportunities?
- Ambiguous or Confusing Terminology: "Tactical" and "Strategic" are mistakenly defined as synonymous with contingency and reserves respectively. Yet, most of the strategic risks are not negotiable and have 100% probability of occurring (e.g., shortage of labor); there is only uncertainty in scale of impact.
- Obfuscation: Trademarked, black box methods (and non-industry standard terminology) obscure the fact that the risk quantification methods used were not well aligned with industry risk analysis principles (e.g., did not explicitly quantify the risks identified).
- Other artifacts of risk policy/philosophy vs. practices disconnect:
  - No clear discussion of how contingency and reserves will be funded and managed in Change Management or Project Control plans.
  - No mention of risk "quantification" in the PEP.
  - No mention of schedule contingency or buffers in the Planning & Schedule Plans.
  - Misinterpretation of IPA cost growth metrics (there [*sic*] contingency p50 value is the starting point and does not cover project-specific risks; only systemic risks). (pp. 10–11)

A little more than an hour after he received the draft report, Mr. Kean forwarded a copy to Mark Turpin, a lead estimator at Nalcor, with the instructions (P-00957): "FYI - Do not circulate or leave lying around."

In presentations to the federal government on July 18, 2012 (P-01008), and to Nalcor's board of directors on August 23, 2012 (P-01009), Mr. Hollmann's introductory remarks were excerpted as follows:

> Third Party Validation
>
> "… the LCP Gate 3 estimate in its current state is one of the best mega-project "base" estimates that this reviewer has seen in some time. My

> conclusion is that this is in large part due to the active involvement of the owner leads in striving for best practices and quality."
>
> John K. Hollmann, PE CCE CEP, Owner – Validation Estimating LLC
>
> (Recipient of AACE's highest honor, the Award of Merit, for editing/authoring the Total Cost Management Framework and authoring or assisting in developing many of AACE's Recommended Practices) (pp 37, 87 respectively)

Nothing further in the Validation Estimating report was referred to.

The evidence establishes that these presentation decks were prepared by Jason Kean. Mr. Kean forwarded the first presentation to Auburn Warren, Derrick Sturge, Edmund Martin, Gilbert Bennett and James Meaney on July 17, 2012 (P-01008, p. 1). During his testimony, Gilbert Bennett made the following comment on the extract that was quoted (November 26, 2018, transcript):

> **MR. BENNETT:** He [Mr. Hollmann] looked at the estimating process.
>
> **MS. O'BRIEN:** Right. And if reading this quote someone is more likely than not to think he looked at the numbers and the fact of the matter is he didn't look at the numbers. Would you not agree with me that that makes this quote misleading?
>
> **MR. BENNETT:** If somebody relied on this statement to draw a conclusion on the quality of the estimate itself, then that's a little bit problematic. Yes.
>
> **MS. O'BRIEN:** That would be misleading.
>
> **MR. BENNETT:** Right. (p. 89)

I have reviewed Mr. Kean's evidence on the use he made of the quoted extract. I find that his explanation is self-serving, unconvincing and lacking in credibility.

I find that the deletion of the words "First, it should be noted that while not perfect" from the quoted extract in these slide decks is of relatively minor significance when measured against both the failure to disclose that the review was about process only and the failure to make any reference to Mr. Hollmann's extensive critical comments on costs, schedule and risk management, reproduced above.

Nalcor's (and in particular Mr. Kean's) distortion of the true substance of Validation's April 2012 draft report is a serious matter. I find that the selection of the extract quoted in the presentations to the federal government and Nalcor's board was an attempt, apparently successful, to instill confidence that the Project's DG3 cost estimate was reliable and had been endorsed by a highly respected consultant. The reality is that an important part of Validation's draft report was a condemnation of Nalcor's ongoing practice of failing to properly quantify cost and schedule risks and failing to include appropriate reserves for these in the Project's cost estimate. Mr. Hollmann was unable to make an assessment of the actual cost estimate due to insufficient information and he clearly identified this limitation on his scope in the draft report. Nalcor was well aware of these limitations but nevertheless chose to present unbalanced and misleading descriptions of Mr. Hollmann's overall findings.

In an email sent to Jason Kean on April 9, 2012, Mr. Hollmann wrote (P-00957):

> Please find attached Validation Estimating LLC's draft report of its review of Nalcor's Lower Churchill Project Gate 3 capex estimate. Given the estimate's status, the report does not include any quantitative analysis. Recommendations are included. (p. 3)

Nalcor did not retain Mr. Hollmann to do any further work on the DG3 estimate.

INDEPENDENT PROJECT REVIEWS

I have already referred to situations in which Nalcor representatives attempted to influence both the information provided to independent reviewers and the content of the reports these reviewers prepared. It is evident that some Nalcor representatives had a distorted view of the meaning of "independence" in these contexts.

In this section I discuss independent project reviews, a form of independent review used by Nalcor.

On September 20, 2010, Nalcor prepared a document entitled "The Fundamentals … Independent Project Reviews," referred to as the "IPR Document" here. This document defines an IPR as follows (P-00488):

> **What is an IPR?**
>
> - An IPR is a review of a project's underlying assumptions, decision logic, alternatives, forward plans and readiness.
> - The aim of the IPR is to validate and constructively challenge information in the Decision Support Package (DSP) and to provide additional input to support the Gatekeeper in making a high quality decision.

- The Reviewers are independent and will provide unbiased, expert review to constructively challenge the project. (p. 2)

For both DG2 and DG3, Nalcor retained a team of professionals to perform independent project reviews. Its IPR Document stated that the IPRs delivered value in several ways (P-00488):

What Value Does an IPR Add?

- Provides outside, unbiased recommendations to help the Project Team improve their plans and results.
- Provides Decision Makers more insight and a higher level of confidence in the business decision and execution plans.
- Transfer knowledge and lessons learned across projects.
- Result is one piece of the puzzle required to clear a Gate
- An IPR is **NOT** a detailed technical review (emphasis in original, p. 4)

It is clear that IPRs were not intended to be detailed technical reviews or comprehensive audits, but more of a high-level readiness check.

For DG2 and DG3, Nalcor assembled an IPR team and drafted an IPR Charter that defined the purpose and focus areas of each review. The IPR team was then given approximately two weeks to review a number of foundational Nalcor documents and policies. These included the project governance plan, basis of design, risk management plan, contracting and procurement strategy, project schedules, estimate summaries and monthly progress reports. After this review, the IPR team divided into teams by focus areas. These teams had one week to interview several key Nalcor staff and managers. The IPR focus-area teams would meet at the end of each day to discuss their findings. During the interview week, the IPR team informally reported findings and observations to the PMT. At the end of the interview week, the IPR team formally presented its report to the PMT and to the Gatekeeper, Edmund Martin. The final IPR report, which was in the form of a PowerPoint presentation, stated the IPR team's overall conclusions and recommendations, provided a review of the focus areas, identified opportunities for improvement and determined specific activities that needed to be actioned.

The IPR Team

In 2006, Paul Harrington retained Derek Owen as a consultant. Mr. Owen had extensive experience in the oil and gas industry and had worked in senior project positions for major EPC (Engineer, Procure and Construct) companies and for Mobil Oil/ExxonMobil. The two men had worked together on several projects, including a Norwegian project in the 1980s, the Sable Offshore Energy project and the Hibernia project. Mr. Harrington had worked under Mr. Owen on these projects, although he did not report directly to him.

The IPR process commenced in late 2006, when Mr. Owen assisted in the drafting of the DG2 IPR Charter (P-00493). The other members of the IPR team were Bernie Osiowy, John Mallam and Richard Westney.

Mr. Osiowy, retired at the time, had been a section and department manager at Manitoba Hydro in the Hydro Power Planning-Power Supply business unit. He had an extensive background in hydroelectric projects. He had also participated in the management of engineering and design studies for hydroelectric projects such as the Waskwatim, Conawapa and Keeyask projects in Manitoba.

Mr. Mallam had worked for NLH and Nalcor for more than 35 years. He was appointed NLH's Vice-President of Engineering in March 2006 and he retired in 2012. Before joining the IPR team, he had not been involved in the Project. Mr. Harrington recruited Mr. Mallam to join the DG2 IPR team in 2010. Later that year, Mr. Mallam performed some work on the Project, which included dealing with operational issues such as plant maintenance and staffing requirements, and reviewing drawings, equipment purchases and operating-cost estimate preparation.

Richard Westney has been introduced earlier in this Report. He is the founder of Westney Consulting Group, which began providing substantial consulting services to Nalcor and the Project in 2007. Before starting his firm, Mr. Westney had worked for Exxon in its project management department. He is the co-author of several books on project management and has taught at various universities. Mr. Westney is also a member of several professional societies and a board member of many corporations. He has considerable experience conducting IPRs for other companies.

The Scope of Work for the IPR

Mr. Harrington engaged Mr. Owen on July 24, 2006, to provide advisory services, check progress and provide strategic input. Mr. Owen testified that his initial work for Nalcor involved discussions with Edmund Martin, Gilbert Bennett and Paul Harrington on how the Project should be organized and executed. Mr. Owen's contract specified that Mr. Harrington was to be his single point of contact at Nalcor. Mr. Owen's role evolved to include leading Nalcor's IPRs at both DG2 and DG3, as well as coordinating a Team Effectiveness Program in 2012. Mr. Owen testified that he continues to be involved in the Project and has been contacted by Nalcor to lead an IPR at DG4, when the Project enters its operations phase.

The DG2 IPR team began its work in 2010. Enclosed in an email dated April 5, 2010, Mr. Harrington sent a draft of the DG2 IPR Charter to Edmund Martin and Gilbert Bennett and two other Nalcor employees. Mr. Harrington made suggestions about the composition of the IPR team, including that Derek Owen be the Team Lead. He cited Mr. Owen's megaproject and IPR experience. He also suggested that a GNL representative be appointed to the IPR team for the purpose of providing economic expertise. Mr. Harrington indicated that a representative from Independent Project Analysis be appointed to the team to cover areas such as environmental assessments and Indigenous, marine and construction issues. He also suggested that the IPR team have eight to ten members, all of whom would be independent of the Project (P-00482, p. 1).

The objectives of the DG2 IPR are stated in its Charter document (P-00493):

- Provide an independent assessment of the work performed by the collective NE-LCPMT and the deliverables from the Phase 2, with special emphasis on the processes and outcomes of these processes that have been used to arrive at the NE-LCPMT's conclusions and recommendations.
- Identify observations and findings and provide recommendations relative to the observations and findings that require NE-LCP VP disposition to responsible managers, action and closeout, at an appropriate time during Phase 3.
- Provide an independent assessment and recommendation to Nalcor's leadership regarding the Project Readiness of People, Processes and Tools to proceed through Gate 2 based on the evidence provided during the IPR and the deliverables defined as being necessary to pass through Gate 2.

- LCP team to demonstrate due diligence and provide a record that an independent third party expert review has occurred relative to the Gate 2 IPR and approval sought, in accordance with the gateway process. (pp. 6–7)

At DG2, the areas of expertise required of the IPR team included (P-00493):

- Project Management - with experience as a Project Manager on major projects.
- Risk Management - with extensive risk identification and mitigation on major projects.
- Power Sales - with knowledge and experience in closing power purchase agreements.
- Project Finance - with knowledge and experience in financing of major projects.
- Environmental - with knowledge and experience in the environmental assessment process on major projects.
- Engineering and Construction Specialist(s) - with knowledge and experience in dam, transmission, HVdc design, construction and commissioning. (p. 11)

By August 2010, a four-member DG2 IPR team had been appointed. Mr. Owen testified that, although he had participated in other cold-eyes reviews with nine or ten people on the team, he felt that the IPR focus areas could be covered by the four people selected.

At the beginning of the IPR process, Mr. Owen asked the IPR team members to indicate their areas of expertise based on 35 focus areas that were set out in the DG2 IPR Charter. At least two team members had some specific expertise in most of the 35 focus areas. However, there were some areas for which either just one or no team member had any specific expertise. For example, no member had specific expertise in health and safety, financing options, transmission agreements or power sales. When asked about the absence of specific expertise in financing options, Mr. Owen's response was that the IPR team felt that it would be able to gain sufficient information from Nalcor in order to make appropriate findings (October 17, 2018, transcript, p. 59).

Mr. Owen organized the IPR team into subgroups and the subgroups conducted interviews. Some interviews required the attendance of all IPR team members, others required the attendance of only two. The interviews were held during the week of September 13 through 17, 2010. Several PMT members and Nalcor employees were interviewed but, surprisingly, Mr. Bennett was not. The DG2 IPR report was presented on September 17, 2010. It marked the end of the IPR process for DG2.

The report's main finding was that the Project was ready for a DG2 decision because it complied with applicable best practices and was consistent with Project specifications (P-00491). The IPR team noted that in most focus areas, assessing readiness for DG2 achieved high scores. This was "particularly impressive in light of the recent strategy change to MF first" (p. 5). On the whole, the DG2 IPR team provided positive feedback on Nalcor's state of readiness for DG2.

However, the IPR team identified nine "priority focus areas" that required Nalcor's attention and action. The concerns highlighted by the IPR team included the unrealistic contract schedule for the award of an EPCM contract by December 2010, the requirements of the Impacts and Benefits Agreement and the date for Project sanction. The IPR team felt that it was unlikely that the award of the EPCM contract could even be achieved by October 2011, which was the scheduled date for sanction at the time (P-00491, p. 23). The following concern was also noted:

> It is essential that the mindsets and behaviors of the NALCOR Phase 3 team be appropriate for the Owner role in oversight and guidance of work by the EPCM (many owner teams have difficulty "letting go" of the actual engineering work thereby rendering the contractor ineffective). The proposed organization, consisting of Home Office and Project Teams, must function as a matrix with all the well-known challenges that implies. There remain important strategic decisions as to exactly how this will work (e.g., "strong" vs "weak" matrix) and these should be taken seriously. (p. 27)

The conclusions of the DG2 IPR report were included in the "Lower Churchill Project Gate 2 Decision Support Package Summary Recommendations to Nalcor's Board of Directors," which was issued on November 17, 2010 (P-00093).

Notably, the DG2 IPR Charter was not issued until January 10, 2011, almost four months after the DG2 IPR had been completed. Mr. Owen acknowledged that this was not within expected Nalcor practices.

In February 2012, Mr. Harrington retained Mr. Owen to conduct a "mini" cold-eyes review to identify possible serious gaps that would need to be addressed before any DG3 IPR was undertaken. The mini "cold-eyes" review team that was formed consisted of Mr. Owen, Mr. Westney and Stan Genega from SNC. I understand that this review was at a very high level.

In the months leading up to the DG3 IPR process, several emails were exchanged by members of the PMT that discussed the composition of the IPR team. In an email dated August 6, 2012, Mr. Owen suggested to Mr. Harrington that a representative from Emera and a representative from GNL be added to the team to include areas of expertise not covered by Mr. Osiowy, Mr. Westney and Mr. Mallam. Mr. Owen indicated that the team would need an Emera representative with expertise on transmission lines and a GNL representative for expertise in the areas of health, safety and environment, quality and labour relations.

On August 7, 2012, Mr. Harrington forwarded these suggestions to Jason Kean, Lance Clarke, Ron Power, Brian Crawley and Gilbert Bennett. The response of Mr. Power on August 8, 2012, was (P-00498):

> I have reservations regarding the Government rep. To date, we have had some issues with provincial government staffers who, for whatever reason, are not aligned with our project delivery objectives. Suggest the any involvement of government be kept minimal. (p. 1)

Mr. Harrington replied on August 9, 2012, with "Agreed. Gov person is dropped" (P-00498, p. 1). There was no GNL representative appointed to the DG3 IPR team.

The DG3 IPR team consisted of the members of the DG2 IPR team plus Tim Leopold, the Director of Engineering for Emera's Maritime Link project. Mr. Leopold's background was entirely in the electrical utility industry, mostly with Nova Scotia Power. He had held several positions with Emera, including Director of Engineering Services and Director of Transmission Project Implementation.

The DG3 IPR Charter was issued on August 24, 2012. It was similar to the DG2 Charter but included many more areas of focus. The DG3 IPR interviews began the next day, and took place through to August 30, 2012. Several PMT members and Nalcor employees were interviewed, including Paul Harrington, Jason Kean, Lance Clarke, Ron Power, Pat Hussey, Darren DeBourke, Scott O'Brien and Greg Fleming. In addition, several SNC representatives were interviewed, including Normand Béchard.

The DG3 IPR Charter specified that the IPR team would brief the Project Director and Vice-President on the morning of August 31, 2012. That afternoon, a presentation of the draft findings and observations would be made to the CEO, Vice-President and selected members of the PMT (P-00502, p. 15). In that briefing, presented to Mr. Martin, Mr. Bennett, Mr. Harrington and some other members of the PMT, the following was noted (P-00083):

> Decision Gate (DG) 3 is particularly critical as it enables full project funding and the commitment to execute, startup and operate. The role of the IPR at this point is to help ensure that the investment decision is well-founded. (p. 3)

Several key findings and recommendations were made in that report. Its first key message was: "The LCP exhibits a degree of readiness for Decision Gate 3 that meets or exceeds Nalcor and industry requirements" (P-00083, p. 13). But according to the testimony of Mr. Mallam and Mr. Westney, the IPR team had concerns about the Project cost, contingency and schedule that Nalcor had provided to the IPR.

Another key finding in the DG3 IPR report was:

> The IPR Team finds that best practice risk analysis processes were followed that can reasonably be expected to indicate adequate and realistic cost and schedule allowances. However, since the Project Sanction documentation is not yet complete, the IPR Team cannot comment upon how these allowances have been or will be included in the Project Sanction cost and schedule. (p. 14)

Mr. Mallam and Mr. Westney both indicated that because Nalcor had not received a final risk analysis, the IPR team could not comment on the process used to determine appropriate cost contingency. Instead, Nalcor had applied a blanket contingency (10% was the figure Mr. Mallam recalled). Mr. Mallam testified that for a cost estimate completed at a P50 level, 10% was "well below what any reasonable standard would suggest should be required" (October 17, 2018, transcript, p. 15). Mr. Mallam also indicated that a contingency of 25% would be more in line with his expectations for a P50 cost estimate. Mr. Owen also confirmed that a contingency of 7% to 10% was far too low.

I take issue with Nalcor not providing the IPR with all available risk documents. The evidence establishes that Nalcor had received an early draft of Westney's May 25, 2012, report, *Analysis of Potential Owner Contingency for Financing of Lower Churchill Project*. Revisions were made to this draft between May 25 and September 19, 2012, when the report was finalized.

The testimony of Mr. Mallam and Mr. Westney indicated that the early draft of the Westney report was not given to the IPR team. The early draft would have provided an indication of the estimated tactical, strategic and schedule risk exposure at the time. Instead, Mr. Kean provided limited information to the IPR team, with no estimates of risk as contained in the draft report. Mr. Owen recalled that Mr. Kean advised the IPR team that the reason Nalcor could not provide a copy of the report was that Nalcor intended to get a new risk analysis done. Mr. Owen also noted that, for this reason, the IPR team felt that it had sufficient information.

This is an unusual set of circumstances. The risk analysis was an important document that would have assisted the DG3 IPR team in formulating its findings and recommendations. The May 2012 draft risk report had been prepared by Westney. IPR team member Richard Westney, as a principal in that firm, most certainly would have been aware of its contents. Presumably he was unable to disclose the contents of this report to the other team members because it had been provided to Nalcor on a confidential basis. This unique set of relationships raises serious questions about whether Mr. Westney had the required independence when discharging his duties on the IPR team. Mr. Westney testified (November 16, 2018, transcript):

> Certainly, when this was discussed in my interview with Grant Thornton, I was surprised by this comment. And this is the first time I had heard a comment like that, and it took me quite a while to wrap my head around the fact that, yes, this is a valid concern or a valid observation. (p. 31)

Regarding the IPR team report on the Project schedule, Mr. Mallam recalled that the allowance or “float” in the schedule was “very small, almost negligible” (October 17, 2018, transcript, p. 17). In a project of this magnitude, Mr. Mallam testified that he would have expected a float of six months to two years. Mr. Owen testified that when the IPR team presented its findings to Edmund Martin on August 31, 2012, the team commented on the Project’s P1 schedule. According to Mr. Owen, Mr. Martin appeared surprised when he was informed of a P1 schedule. Mr. Owen testified that he believed that the PMT had not yet communicated that information to Mr. Martin (October 17, 2018 transcript, p. 88).

As noted earlier, later that afternoon Mr. Harrington wrote to Mr. Owen from his personal email address stating that he took issue with the IPR team’s comments regarding the P1 schedule. He also indicated that Mr. Kean was in the process of preparing further documentation for an updated schedule risk analysis. He wrote (P-00505):

> Derek, it was most unfortunate that you used the P1 characterization of the schedule in the meeting this PM. That risk work on the schedule is dated and is in the process of being updated. Jason stated as much. We know that The probability will be less than P50 but for Ed to get the message that it has virtually no chance In such a manner has resulted in a major blow. We very recently stressed the importance with Ed of allowing the bulk excavation contract to be awarded prior to the sanction and with your statement that causes him to doubt the value of making that step now. The schedule risk

> model is a simplified activity schedule and some work is needed and the critical path assumed earlier regarding sanction being a prerequisite to bulk excavation award is one such change that is necessary and contributed to the low probability result
>
> So we need to meet and get this back on track so that we are not alarming Ed on dated information and analysis Pls call me Saturday or Sunday. (p. 1)

Mr. Owen replied to this email on September 2, 2012, suggesting that "we could add a Key Message endorsing the LCP strategy to commence the mass excavation in October/November 2012 as a schedule mitigation measure" (P-00505, p. 1). Mr. Harrington wrote back the same day, advising Mr. Owen that, following the meeting of August 31, 2012, Nalcor was taking action to update the schedule analysis and rerun the schedule risk analysis (P-00505). He stated:

> [A]nd the probability will be against the actual island need date for two MF units, which is late Jan early Feb 2018. The current target dates for first power and full power will remain as a motivating date for the project and the interval between when two units are planned to be available and the actual need date will. E [*sic*] shown as schedule reserve. This means that there is a 4 to 5 month schedule reserve. (p. 1)

On September 3, 2012, Mr. Harrington wrote to Mr. Owen, again from his personal email account, and attached two documents. The first document was a schedule reserve presentation deck to explain the issue regarding the schedule and how the PMT intended to represent the schedule reserve (P-00508, p. 2). In the second document, he proposed a rewording of the draft IPR report that was presented at the August 31, 2012, meeting:

> We are proposing some wording for the draft IPR report (slides 13 and 40) following our meeting later on Friday with Ed which we believe does not change the substance of the first draft and the messages it contained it simply uses language that could not be taken out of context and easily used in a negative sense. I know that was not the intent but we exist in a climate where words can be twisted and used in a manner that was not what the writer meant, So please review with Dick and see if we can agree on the final wording for this and item 1 above. (p. 2)

On September 3, Mr. Owen forwarded Mr. Harrington's email and attachments to Mr. Westney (but not to the other IPR team members), advising him that:

> My first reaction is that the rewording of Slides 13 and 40 seem to be acceptable. I do have the original wording available but I have no real objection. With regard to the Project Schedule Deck I see no reason for us the

> [*sic*] comment on this as I consider this to be project follow up on the theme on slides 13 and 40. (p. 2)

Mr. Westney replied later that day and attached two pages that highlighted the differences between the DG3 IPR report that was presented on August 31, 2012, and the version that contained Mr. Harrington's proposed rewording. His comparison of the two versions, reproduced below, demonstrates the significance of the changes Mr. Harrington had proposed (emphasis added).

August 31, 2012 DG3 IPR Report	September 3, 2012 Proposed Wording
The IPR Team finds that best practice risk analysis processes were followed that can reasonably be expected to indicate adequate realistic cost and schedule allowances. However, since the Project Sanction documentation is not yet complete, the **IPR Team cannot comment upon how these allowances have been or will be included in the Project Sanction cost and schedule.**	The IPR Team finds that best practice risk analysis processes were followed that can reasonably be expected to indicate adequate and realistic cost and schedule allowances. This information will inform the Gatekeeper and the DG3 decision regarding appropriate contingencies. The Project Sanction decision is subject to other pre requisites including economic and other analysis which are underway and not yet complete, the **IPR Team understands that appropriate cost and schedule allowances will be included in the Project Sanction cost and schedule.**
The IPR Team provides the following findings and **recommendations** concerning the use of Management Reserve and Schedule Reserve to account for the strategic project risks associated with mega-projects such as LCP.	The IPR Team provides the following findings and **observations** concerning the use of Management Reserve and Schedule Reserve to account for the strategic project risks associated with mega-projects such as LCP.
– The extensive and very public track record of large infrastructure projects provides many examples of substantial cost overruns and schedule delays. The size of these mega-projects increases their exposure to strategic risks such as regional and global economic conditions, market trends, changing governmental regulations, limits on resource availability, and declining global construction productivity. – Nalcor LCP management team has long recognized these risks and the need to account their potential impact on project cost and schedule. The LCP Project Execution and	– Nalcor LCP management team has long recognized the extensive and very public track record of large infrastructure mega-project risks and the need to account for their potential impact on project cost and schedule. – Front End Loading and pro active risk management has been a key feature of Nalcor's work leading up to DG3. – The size of these mega-projects increases their potential exposure to external risks such as regional and global economic conditions, market trends, changing governmental regulations, limits on resource availability,

Project Risk Management Plans describe the use of Management Reserve and Schedule Reserve for this purpose.	and declining global construction productivity. The LCP Project Execution and Project Risk Management Plans consider the appropriate use of Management Reserve and Schedule Reserve for this purpose.
Nalcor's decision gate process defines DG3 deliverables that **include both** Tactical and Strategic Risk Analyses; and the Nalcor team has invested considerable effort in these analyses which provide **the required quantification** of Estimate Contingency, Management Reserve, and Schedule Reserve.	Nalcor's decision gate process defines DG3 deliverables that **include appropriate** Risk Analyses and the Nalcor team has invested considerable effort in these analyses which have included **the quantification** of ranges of Project and other cost and schedule contingency and reserves.
The IPR Team concurs with the expectations set by the LCP Project Execution and Risk Management Plans that adequate provisions for Management Reserve and Schedule Reserve **be included** in the Project Sanction costs and schedules.	The IPR Team concurs with the expectations set by the LCP Project Execution and Risk Management Plans that adequate provisions for Management Reserve and Schedule Reserve **be recognized** in the Project Sanction decision-making process.

(Source: P-00508, pp. 3–4)

Mr. Westney was firm in his opinion that the IPR team should refuse to accept the rewording Mr. Harrington had proposed. He wrote to Mr. Owen (P-00508):

> Here is the first point: we absolutely cannot allow our work product to be dictated or edited by Nalcor management or LCH [*sic*] project management and then issued as IPR TEam [*sic*] work product. This violates our obligation to the Gatekeeper and our IPR charter, not to mention our professional ethics.
>
> What we can do is accept feedback and suggestions from the review as part of the IPR process, just as we do with other meetings and interviews, and prepare a final version of our report to reflect all the input we have received. Once we submit the final version, we do not change it.
>
> Second point: there are some suggestions I am comfortable with and some I am not; also some things that were deleted I feel should not have been. We need to discuss.
>
> For both of the above reasons, I do not agree that the changes are acceptable as given.
>
> THird point: the schedule reserve deck is out of IPR scope. THey are redefining schedule reserve as contingency planning, and we have not studied that, nor is it a DG3 key deliverable we were given to review. So I agree we should ignore it.

> So, I propose the path forward is for you to talk with Paul, understand his suggestions, but make no commitments, and then get the team together via teleconference to draft the final copy of the two slides. Once we complete that, it is the finished work product and not subject to change. You said earlier the team had to be 100% agreed on the report and I totally support that. (p. 1)

After receiving this communication, Mr. Owen attempted unsuccessfully to reach Mr. Harrington by telephone. Mr. Harrington wrote the following back to Mr. Owen on September 4, 2012 (P-00506):

> If we need to get folks together to talk about the characterization of schedule reserve for MF and LIL then let's do that. **Ed and Gilbert are on board with this and understand that the target schedule is just that and something that has low probability** (jason is having the schedule analysis updated) **but something we motivate the project team to achieve knowing that we have float or reserve in our pocket.** If we let the actual need date out we lose that leverage and motivation opportunity Let me know how we can advance this discussion. (emphasis added, p. 1)

Mr. Owen replied the same day, indirectly informing Mr. Harrington that the IPR team was unwilling to adopt Mr. Harrington's proposed wording or change the characterization of the schedule. He stated (P-00506):

> I do not consider the IPR team need to be involved with, or should comment on, any Project follow up actions resulting from the IPR key messages. Unless, of course, the IPR team is re-commissioned for that purpose. The Charter covers only the work made available during the review period. The report is so worded that the Project has full latitude to take the key messages and action them in accordance with the Project Plans and procedures. (p. 1)

At the hearings, Mr. Owen testified that there were a few subsequent telephone discussions with Mr. Harrington during which he would have emphasized that the IPR report could not be changed. Mr. Owen also followed up with an email to Mr. Harrington on September 5, 2012, stating: "On quiet reflection, and reviewing further your e-mails, it seems that there are varying perceptions of the role of the IPR team. Maybe it would be helpful if we had a chat. Let me know a good time to call you on your home number" (P-00506, p. 1).

In his reply, Mr. Harrington indicated that there was no need to have further discussions. The following day, September 6, 2012, Mr. Owen informed Mr. Westney (P-00509):

> Paul seems to have completely backed off. I believe he did not appreciate that the IPR team are not involved in evaluating the go-forward Project actions resulting from the Key Messages, In addition I believe finally Paul got the message that the Project could not embellish our Key Messages to the degree that they were no longer the IPR findings, I have requested confirmation that the report remains "as written." (p.1)

Mr. Westney was questioned on this sequence of emails about the proposed rewording of the DG3 IPR report. He testified that, in his experience on other IPR teams, he could not recall any other occasion in which he had been asked to change the opinions set out in the final work product. In his view, the report of August 31, 2012, was the final report and was not to be altered unless there was a factual error.

Mr. Harrington's response to this evidence was that he believed the report was in draft form only. He believed that his proposed rewording was to address incorrect IPR findings that were based on outdated information.

It is important to recall that the DG2 IPR report was included in DG2 support package that was provided to the Nalcor board of directors. The DG3 IPR report was not included in the DG3 support package. It was not provided to the Nalcor board despite the fact that the DG3 IPR Charter specified the following (P-00502):

> The IPR is regarded as an opportunity to assess readiness, to challenge the project team, and provide assurance that the project will deliver the required business results. The findings, observations and recommendations from IPR, as well as a gap closure plan, will be included in the Decision Gate Support Package when submitted to the Gatekeeper. (p. 6)

This Charter was approved for use by Mr. Harrington and other members of the PMT on August 24, 2012.

The exclusion of the DG3 IPR report from the Decision Gate 3 support package is significant since there is no evidence that the Nalcor board of directors was ever provided with the report or made aware of the IPR team's concerns regarding the schedule. Mr. Harrington testified that the DG3 IPR report was presented to Edmund Martin (the Gatekeeper), but that it was not provided to the Nalcor board (November 20, 2018, transcript, p. 29). Gilbert Bennett testified that he was of the same understanding. The former Nalcor board members who testified at the hearings stated that they could not recall whether they had been provided with this report. Ken Marshall, Nalcor board member, testified (October 15, 2018, transcript):

> So did we feel that anything was being withheld from us? No. Did we feel that we had sufficient information? Yes. Did we feel that there was a fair analysis done and a detailed analysis, and that we had asked the questions and pushed and pressed and prodded to make sure that this thing was, you know, tested? Yes, absolutely. So we were still reliant on if there was anything that come to light, had we any reason to think that somebody withheld? No, we did not. (p. 72)

Despite Mr. Marshall's assertions and the non-inclusion of the IPR report in the DG3 board package, it is evident that Nalcor held out the DG3 IPR report as one of many independent project reviews that Nalcor stated that it would obtain before sanction. In April 2011, GNL and Nalcor were engaged in a discussion about independent oversight for the decision on Project sanction. Nalcor argued against a review by the PUB: "A PUB review of any kind will require a delay in the project, perhaps by a year or so, to hold hearings, hire experts and prepare reports." To support its argument against a review by the PUB, Nalcor sent a Briefing Note to GNL that included the following (P-01384):

> Independent Reviews
>
> - Standard Nalcor practice for the successful achievement of DG3 includes the following independent reviews:
>   - Independent Project Analysis Inc. ("IPA") an international organization that specializes in the review of large scale projects;
>   - Independent Project Review ("IPR") a group of subject matter exerts who individually are recognized for their knowledge and experience in particular aspects of large scale project delivery and collectively can provide a thorough review and commentary on the readiness of the Project to proceed; and
>   - An independent review of the reasonableness of Island supply decision as described below (the "Supply Decision Review"). (p. 5)

As it turned out, Nalcor did not obtain a review from Independent Project Analysis, and although it did arrange for an independent project review, it did not provide GNL or the Nalcor board of directors with a copy of the DG3 IPR report.

Another example of Nalcor's use of the IPR process as an indication of independent oversight appears in its submission to the PUB of November 10, 2011 (P-00077):

> Independent Project Reviews
>
> To facilitate the Decision Gate assessment process, the Project Team utilizes Independent Project Review (IPR) Teams to provide independent assessments of the readiness of the Project to proceed at each gate.
>
> The Independent Project Reviews provide a degree of quality assurance required by the Gatekeeper for major decisions. The reviews are regarded as an opportunity to introduce external, constructive and holistic challenge to the Project Team, and provide assurance that the Project will deliver the required business results. The objectives of the IPR are to:
>
> - provide external challenge to the Project team at each Decision Gate, to help assess the validity and robustness of the work done in key areas requiring focused attention and to assist in maximizing the value of the business opportunity;
> - assess the suitability of the project plans and strategies; and
> - appraise the readiness and justification of the project to proceed to the next Gateway Phase (pp. 204–5)

It is clear that Nalcor promoted the IPR process as an important part of the independent oversight that would be carried out before sanction.

In my view, Nalcor should not have characterized the IPR it actually carried out as being a truly independent review, and it should not have overstated the scope and nature of both IPRs. It is clear that the two IPR Charters and the focus areas chosen by Nalcor significantly limited the ability of the IPR teams to fully and independently assess and challenge the work performed by the PMT. There are several reasons why I have come to this conclusion.

First, Nalcor tightly limited the IPR's scope by limiting the time permitted for such a review, the documents it supplied and the focus areas. Mr. Westney, who has considerable experience conducting IPR reviews, testified that Nalcor's direction over the process resulted in a comparatively superficial due-diligence effort (November 16, 2018, transcript):

> Well, there's actually several points, Ms. O'Brien, that you have raised there. I would say that I'm troubled as I listen to the testimony in this hearing that that IPR effort in August of 2012 is seen as some sort of due diligence in terms of readiness for an actual sanction gate. Of course, this occurred four months before the sanction decision actually happened, and so that would be the first point is that it's a kind of a snapshot of a project, where it stands now.
>
> But even more to the point, I guess my second point would be that, compared to other projects of this nature where due diligence of a $6, $7 billion capital

investment is so important, I kind of use the image in my mind if there was a scale of 1 to 10 with 10 being the level of due diligence effort that a petrochemical company, an oil company, a mining company might do for a project of this magnitude, and then you add to that that we have a Crown corporation, that we have a utility where people are directly impacted by the cost of the Project, we have a first megaproject ever for the organization and first hydropower project, that 10 might now be a 15, if I can kind of use that scale to represent level of due diligence you would expect to see before sanction.

This IPR, I would say, is maybe a 1 on that scale. And it was, I have to say, different from most other IPRs, even though IPRs can be many different things. But some of the differences are these: number one, it took place under an extremely compressed time schedule, over a period of essentially two weeks. Why the schedule was so limited in time, I don't know, that was never explained. Basically, you have a situation, which was the same as in DG2, but at DG2 it's not such a critical decision. So you're right, let's focus on DG3.

You had, I believe I went back and looked at the charter for a DG3 IPR, if I recall correctly there are 65 focus areas, as they were called, as such, and there were some around engineering, a lot of them around—maybe half of them around project management of various sorts, and so on and so forth. For each of these focus areas, there were documents that were uploaded to—I think it was called Aconex—the name of the document management system—it was uploaded there, we all had access to it.

So you have about a week in your office to review these documents that pertain to your area, which is really just enough to take a cursory view and say, hey, does this look like a project execution plan should look? Then we assembled on Sunday – and this is all documented in the agendas that I'm sure you have—to kind of get our team organized in how we're gonna approach it. And then Monday, Tuesday, Wednesday, there are a series of meetings. I don't know there were ever any one-on-one, although there could've been, but generally there are meetings with several people involved where we have anywhere from 30 minutes to an hour and a half to talk about the topic. Three days of that—remember, there's 65 focus areas. Thursday you start pulling everything together and then you present to the CEO and the executive team on Friday.

I'm hard-pressed to think of another situation where we made a C-level presentation, 24 hours after we finished our work. Normally, you would expect there's a week or two of report generation and analysis, et cetera.

So that's the next important point about the compression of the schedule, meant you could only have a superficial kind of view of things. And if you—I noticed that in Mr. Owen's testimony, he said, look, our job was not to validate or verify or audit, it was just like: Was there a reasonable process followed and

> do we see any—do we have any comments or recommendations on what we've seen? But we did not audit or validate or whatever.
>
> So my question would be: Well, okay, well if we didn't do it—and of course you couldn't possibly do it in two weeks—was it done? I—of course, I assume that all these things would have been done by IPA or somebody else. (pp. 29–30)

Second, it is also questionable whether Nalcor provided the DG3 IPR team with a complete set of documents. The team was unable to properly examine Nalcor's risk work because, according to an explanation Jason Kean provided to the team, the risk analysis was not complete. Consequently, the DG3 IPR's finding on Nalcor's risk analysis was qualified because the team was unable to comment on whether realistic costs and schedule allowances were included in the Project's cost estimate and schedule.

I also note Mr. Owen's confirmation that the DG2 and DG3 support packages (prepared for the Nalcor board) were not provided to the IPR teams. He stated that he had first seen them shortly before his testimony at the hearings. Following his review of the two packages, he concluded that the information they contained was inadequate in terms of cost analysis, benchmarking, and expression of estimate and schedule confidence.

At the hearings, Mr. Harrington's response to the evidence given by Mr. Westney and Mr. Owen about the limitations of the IPR process was that the IPRs were in line with other IPRs with which he had been involved. He testified that the decision about whether the IPR process and other independent reviews were adequate to assess Project readiness was a decision for the Gatekeeper and GNL to make.

It is clear that the DG3 IPR team was not intended to conduct an audit of the capital cost estimate. Mr. Mallam testified that the IPR's role was to assess the methodology used to perform the work and decide whether the methodology was consistent with good utility practice. However, it does not appear that Nalcor's structure for the IPR process allowed the IPR team to sufficiently probe project readiness issues. I agree with Mr. Westney's assessment that a two-week process could only result in a shallow examination of Project readiness.

Finally, the independence of IPR team members at DG2 and DG3 is problematic. As suggested earlier, Nalcor appeared to have a distorted view of what constitutes "independence." Examining some team members' connections to the Project a little more closely is helpful here.

Derek Owen

As stated earlier, Mr. Owen's involvement with the Project came through a recommendation from Paul Harrington, whom he had known for a long time and whom he considered to be a friend. Mr. Owen was already engaged in a few scopes of work for Nalcor, including providing advice to Nalcor's executive and the PMT. Considering Mr. Owen's relationship with Mr. Harrington and his various consulting contracts with Nalcor, I question whether Mr. Owen was in a position to provide a truly independent assessment of the Project. At least, I note that there is a perception that he was not truly independent.

In 2012, before the commencement of the DG3 IPR process, Mr. Owen had been retained by Nalcor to coordinate alignment workshops and Deloitte's Team Effectiveness Program related to the deteriorating Nalcor/SNC relationship. This is how the work for which Mr. Owen had been contracted was described (P-00494):

> **Project Execution Summary**
>
> Company has contracted with SNC Lavalin Inc (SLI) to provide Engineering Procurement and Construction Management services. The fabrication and construction contracts will be awarded by Nalcor and will be managed by SLI under the direction of Nalcor.
>
> The Project is currently in the regulatory process and passed the Decision Gate 2 in December of 2010. It is expected that Decision Gate 3 and Project Sanction will take place later in 2012. Both the Project teams of Nalcor and SLI are co-located in St. John's, Newfoundland and Labrador.
>
> **Scope of Services**
>
> The Project Alignment/Effectiveness Programme consultant will be required to undertake a review of the Project and will then develop a programme of workshops to be carried out throughout the life of the Project to meet the objectives of a developing "best-in-class" Project teams to ensure an optimum execution performance.
>
> The programme should recognize the challenges as the Project moves through the various execution phases and as major construction contractors come on board.
>
> The programme should be structured not only to address "real time" Project issues that are negatively impacting team performance but also should address behaviours and team dynamics that are not contributing to a collaborative working environment. (p. 7)

The DG3 IPR report found that Nalcor had addressed an earlier concern about the implementation of a construction management strategy allowing SNC to perform a management role. The IPR reported as follows (P-00083):

> Nalcor and SNC Lavalin had proactively addressed this concern using such tools as alignment workshops and a step-by-step approach as major construction contracts are awarded. The IPR Team commends this approach and **recommends its continued implementation** be considered a Key Success Factor (KSF) going forward. (emphasis added, p. 15)

Clearly, by the terms of the contract noted above, Mr. Owen stood to financially benefit from this IPR recommendation. At the hearings, an exchange with Counsel about whether he viewed this recommendation as a conflict of interest, went as follows (October 17, 2018, transcript):

> **MS. O'BRIEN:** So do you see any conflict of interest in that, in that as a team you were saying: look, here's one of—a key success factor here is that you essentially continue on this work; you had a financial interest in that work being continued. Do you not see that as a conflict of interest?
>
> **MR. OWEN:** Let me explain the background to that before I answer the question. One of the major difficulties in organizations on megaprojects is to get the project to accept and understand that they need help, external help, to help them with regard to team alignment, team effectiveness, accountability, responsibilities. And one of the best practices is that this effort starts at the beginning of the project and continues all the way through the project, so that's why the recommendation there is recommended to have it continued because it is a best practice.
>
> This comes from my background with the Sable Project, which was probably in terms of $96 [1996 dollars], was close to 1.5 billion, so God knows what it would cost now, where we had a totally integrated team from day one. And in order to make that team effective, we ran team effectiveness and behavioural workshops from day one, right through to the last moment of that project.
>
> . . .
>
> **MR. OWEN:** So that's where the recommendation comes with regard to the continued implementation. It is a best practice.
>
> It's very difficult for projects to do that. They tend to do it for a period of time, and then either they find that it's not necessary or they've perceived it's not necessary. So, the fact that I was doing the coordination for that work—maybe you could perceive it as a potential conflict, but the reason that we were suggesting that it continued was because it is a best practice. Unfortunately, they discontinued it in, I think, the second quarter of 2013.

> So, in my opinion, it was not a conflict of interest. It was a recommendation from the team. The team looked at the work that was being done. (pp. 78–79)

Mr. Owen was of the understanding that the other DG3 IPR team members were aware of his prior engagement as coordinator for the Team Effectiveness Program. However, when questioned on this point, Mr. Mallam stated that he had not been aware of Mr. Owen's prior engagement.

It is clear that Mr. Owen stood to benefit financially from this DG3 IPR recommendation. I conclude that these two relationships, one as a consultant and the other as an IPR team member, placed Mr. Owen in a position where, at the very least, there was a reasonable basis for concluding that he was in a conflict of interest, in the sense that he had a direct financial interest in the implementation of the recommendation.

Richard Westney

Richard Westney, through his company, was directly involved in risk management work for the Project. As noted earlier, his firm had done such work for Nalcor since 2007. It included the DG2 quantitative risk assessment (QRA) in July 2008, the DG2 QRA in 2010 and the DG3 QRA in 2012, which was in the process of being finalized on August 31, 2012, when the DG3 IPR report was issued. Westney was also contracted by Nalcor to provide other work on the Project, including workshops in preparation for the EPCM mobilization.

When asked about his connections to Nalcor at the Inquiry, Mr. Westney said (November 16, 2018, transcript):

> What would normally happen—and I will parenthetically say that in—for many, many years when I taught project management—I've taught engineers to be project managers—sometimes I was asked to include a module on ethics which is usually around conflict of interest. So I completely understand the idea that you do not have to benefit from a situation that's been created; as long as there's the possibility of benefit, then there's conflict of interest. In this case, it's probably less a matter of benefit than it is an ability to be objective.
>
> So I do see that more clearly now than I did at first. Normally, that what would happen is your client would be the project director, in this case Mr. Harrington, who is the same person who asked me for DG2 and DG3 to be on the IPR team. So, clearly, of all people, he would know exactly what my firm had been doing, although I, myself, really did very little consulting on the project, outside of my work on these IPRs. So, no doubt to him, it was like, okay, Mr. Westney understands the project somewhat, but he hasn't been directly involved, all

> except the fact that his company had been—and one of the items to be reviewed, one of the 65, would be the risk, the work on risk.
>
> And I was interested to note: In Mr. Owen's testimony he said that we all recognize that, and he said that he remembered my offering to say: Look, anybody who's going to be reviewing work by Westney—that should not be me. And Derek Owen said: No problem. He, himself, has a lot of knowledge of this subject and, no doubt, others on the team did, too, and so that I would be recused from that.
>
> As it happened, we never did review the risk work, but I do appreciate there could be that perception because of the more public nature of this project, as compared to a comparable situation in a private company. (p. 31)

Though Mr. Westney testified that he personally was not substantially involved in the risk work his company performed, I concur with Grant Thornton's view that there was clearly an independence issue with Mr. Westney's involvement on the IPR team. There was a potential benefit for Mr. Westney if the Project was sanctioned and continued to contract his firm's services. Mr. Westney recalled that the IPR team did not ultimately review the risk work prepared by Westney because Nalcor had not provided the team with the risk analysis documents to review. While this is true, it does not address the fact that the risk review work that Nalcor had received before August 31, 2012, had been prepared by Westney. It is likely that Mr. Westney would have been aware of the details of this risk work. As stated earlier, it is also likely that Mr. Westney was not able to share this information with the other IPR team members for confidentiality reasons.

Taking into account these considerations, I conclude that Mr. Westney was not fully "independent" when he carried out his duties on the DG3 IPR team. However, I commend Mr. Westney for his principled decision to reject the changes to the DG3 IPR report that had been proposed by Mr. Harrington.

John Mallam

I am satisfied that Mr. Mallam had not been substantially involved in the Project prior to participating in the DG2 IPR. However, once Mr. Mallam began doing other contract work for the Project, I am unable to conclude that he could serve as an independent member on the IPR team.

Mr. Mallam testified that, for a few reasons, he was not concerned about his independence when he performed the DG3 IPR. He felt that, because the IPR team was not reviewing the operations and maintenance work, he was not reviewing his own work.

He also felt that the operations and maintenance work had only just started at that point, and that other members of the IPR team could compensate for any biases that he might have. He further noted the following when asked about the possibility of conflict of interest (October 17, 2018, transcript):

> **MS. O'BRIEN:** And again, I'll just get you to address: Any concerns as you sit here today that there, you know, could be a conflict of interest or a perceived conflict of interest when the Independent Project Review team—some of those members—have actually been involved with the project itself?
>
> **MR. MALLAM:** I don't think there was any real conflict of interest. I can see how there could be a perception of a conflict. But I mean, if there was and if anyone thinks there was bias, then all they have to do is read our report. We were quite critical in some very important areas that they asked us to review. (p. 12)

What is stated by Mr. Mallam is certainly true to some extent but, again, the issue of independence is not fully addressed.

<u>Tim Leopold</u>

I also find that Mr. Leopold was not sufficiently independent to serve on the DG3 IPR team. Mr. Leopold was the Director of Engineering for the Maritime Link and Emera's interests were directly affected by the sanction decision. If Nalcor did not sanction the Project, the ML would not be constructed.

<u>Other Considerations</u>

The DG2 and DG3 IPR Charters allowed for Nalcor employees, consultants and specialists to be members of the IPR team. For example, the DG3 Charter states (P-00502):

> The IPR Team shall be comprised of qualified and experienced personnel who are independent from the Project, except for the IPR Coordinator, who may be active in the Project.
>
> The IPR Team may consist of Nalcor Energy employees, consultants and specialists who are knowledgeable and familiar with Nalcor's policies, processes and procedures and/or major project management execution, power sales and access, and project financing. (p. 11)

Paul Harrington maintained that all IPR team members, with the exception of Mr. Mallam, were separate from the Project and were not involved in the day-to-day business of the Project. He testified that the IPR was more like “peer review” or a “cold-eyes review.” He felt that there was really no issue with regard to the IPR team’s performance.

In summary, the IPR Document and the DG3 IPR Charter both indicate that Nalcor gave an expansive interpretation of the word “independent.” On one hand, the IPR Document states that “the Reviewers are independent and will provide unbiased, expert review to constructively challenge the Project” (P-00488, p. 2). The DG3 IPR Charter states that an objective of the DG3 IPR is to provide an “independent assessment” (P-00502, p. 7).

On the other hand, the DG3 IPR Charter allows persons who are not independent, in the true sense of that word, to be appointed to the IPR team, namely Nalcor employees, consultants and specialists. On this basis, some or all of the DG3 IPR members may have been properly appointed, in the sense that they fit the requirements of the DG3 IPR Charter. However, this does not mean that they were actually independent—and I find that they were not, for the reasons stated above.

Nalcor repeatedly held out the IPRs as truly independent reviews of the Project, but they did so without providing an accurate description of their nature. The IPR reports may well have been prudent and aligned with best practice—they enabled experts familiar with the Project to perform readiness reviews at certain junctures, as a type of quality assurance for Nalcor. As well, it may be prudent and best practice to perform such readiness reviews at important junctures with experts familiar with the Project. Also, the DG3 IPR team made many findings that challenged the work of the PMT. However, in my view, the characterization of the IPRs as “independent” is misleading.

I also note that Mr. Harrington proposed inappropriate revisions to the DG3 IPR report. At first, Mr. Owen was prepared to accept these revisions. However, to his credit, Mr. Westney firmly resisted these revisions on the basis that they would have changed the substance of the IPR’s observations and recommendations. After reflection, Mr. Owen accepted the opinion of Mr. Westney. Reading the proposed revisions makes it clear that they were substantive in nature and were not attempts to correct factual errors, nor were they minor corrections.

The conclusions and observations I have made on the IPR process can be generally applied to the MHI reports, which are reviewed in Chapter 7, and to other reports that GNL relied on as being truly independent assessments of Nalcor’s work on the Project.

Pre-Sanction Reliability

For the 40 years that preceded sanction of the Muskrat Falls Project, the electrical system on the Island of Newfoundland was supported primarily by a large hydroelectric facility at Bay d'Espoir and by the Holyrood generating station on the Avalon Peninsula. Once the Island was connected to hydro-generation sources on the Churchill River, the plan was to replace Holyrood with Labrador power delivered via a transmission line running approximately 1,100 kilometres from Labrador to Soldiers Pond, near St. John's. Some concerns were expressed during the hearings about this transmission line, which require consideration.

Engineers can design a transmission line to meet any level of reliability, but the more reliability that is desired, the more expensive the line will be. This section of the Report discusses how Nalcor decided how much to spend on transmission line reliability at DG2 and DG3, and the consequences those decisions had for the Project's business case.

The reliability of an overhead transmission line is generally measured by its "return period." A return period of 50 years (1:50-year return period) means the transmission line is designed to withstand weather conditions that will occur on average once in a 50-year period. A transmission line with a 1:150-year return period is designed to withstand weather conditions that will occur on average once every 150 years, and so on.

According to the Canadian Standards Association (CSA), all transmission lines should be built with a return period of at least 50 years. A 1:150-year return period is suggested for high-voltage lines as well as for lower-voltage lines that "constitute the principal or perhaps the only supply to a particular load." A 1:500-year return period is suggested for high-voltage lines that "constitute the principal or perhaps the only source of supply to a particular electric load" (P-00052, p. 90).

To design the transmission line, the return period must be translated into "loadings." The loadings outline the weather conditions that the line and towers must be able to withstand. For example, NLH designs transmission lines on the Avalon peninsula to withstand 75 millimetres of glaze ice, 130 kilometres per hour winds and a combination of 45 millimetres of ice and 60 kilometres per hour winds. Design engineers can use loadings to calculate the exact stresses the towers and lines are likely to experience and so ensure that they are robust enough to withstand them.

Calculating loadings accurately requires a thorough, detailed understanding of the weather experienced in particular environments. As a foundation for this knowledge, the CSA divides the country into climate zones and provides 50-year reference loadings for different conditions in each weather zone. It provides reference loadings for most of the weather conditions experienced along the Labrador-Island Link route, for example: high winds, glaze ice (which forms when freezing ice hits a tower) and a combination of glaze ice and wind. It does not provide reference loadings for rime ice, the ice that accumulates from freezing fog in mountainous regions, or combinations of rime ice and wind.

The CSA considers its reference loadings to be a starting point for understanding local weather, not the last word on it. It encourages transmission line designers to take advantage of additional data and/or local experience and to increase or reduce loadings as required.

In the years leading up to DG2, Nalcor focused on the construction of an HVdc transmission line that could carry the full power from Labrador to Newfoundland. Nalcor considered building this line to either a 1:150 or 1:500-year return period, consistent with the CSA's recommendations. It ultimately settled on a 1:150-year return period.

In early 2010, when it became apparent that Gull Island would not be viable, Nalcor shifted its focus to Muskrat Falls. When early versions of the Project did not appear viable, Nalcor experimented with a low-cost version of it (Case 8) that contained several changes intended "to get the cap cost down as low as possible" in order for the business case to work (P-04040, p. 1). Among these changes was a reduction of the return period of the transmission line to 1:50.

Case 8 was developed into the Project. Some of its cost-cutting changes were reversed, but at DG2 Nalcor retained a 1:50-year return period for the Project (P-00048, p. 65; P-03188; P-04040; June 25, 2019, transcript, pp. 16–17).

The reliability of the overhead transmission line was a focus of the Public Utilities Board during its consideration of the Reference Question that GNL put to it in 2011. Nalcor filed the weather loadings for the line with the PUB. The loadings in rime ice zones were based on special work commissioned by Nalcor and were designed to a 1:500-year return period. The remainder of the loadings were based on NLH's own transmission line standards, which were drawn from its extensive experience operating transmission lines on the Island as well as on historical research. NLH indicated that these loadings were more conservative than the CSA reference loadings. Despite this, NLH described them as

1:50-year loadings, as did Nalcor in its submissions to the PUB at the time. I accept that these loadings are 1:50-year loadings and that the reason they are more conservative than the CSA's loadings is that NLH has a different perception of the likely climate conditions in the province than the CSA does.

Nalcor attempted to justify its choice of a 1:50-year return period on the basis that building the LIL to a much higher level of reliability than the rest of the transmission network (the mainland sections) might not increase the overall reliability of the system when extraordinary circumstances occurred. According to Nalcor, any storm severe enough to damage the LIL would do even more serious damage to the rest of the transmission network (P-01669, p. 32). Nalcor also argued that if more reliability was desired, combustion turbines for backup power could supply it more cheaply than upgrading the transmission line to a higher return period (P-00077, p. 143).

In its review for the PUB (relating to the Reference Question, 2011), MHI rejected these arguments (P-00048, pp. 13–14). It thought that the line should be built with a return period of at least 1:150 years and perhaps 1:500 years, and it concluded that the lower return period was "a major issue." It estimated the cost of upgrading the transmission line to a 1:150-year standard was $150 million and the cost of upgrading to a 1:500-year standard was somewhere between $225 and $250 million.

In response to MHI's conclusions, Nalcor presented a new defence for its loadings specifications in its final submissions to the PUB. Based on NLH's research and experience, Nalcor compared its loadings with the 2006 CSA reference loadings, concluding that the NLH glaze ice factor was equivalent to a 1:500-year standard.

The PUB rejected all of Nalcor's arguments on this point. It found that Nalcor's proposed design criteria were "inadequate and contrary to Canadian Utilities Standards and Practices" and "not supported by the facts." It also observed that, although the exemption order prevented the PUB from ordering changes to the Project design or from disallowing its costs, the PUB would have the final say on whether the LIL was reliable enough to operate without backup generation (P-04273; P-00048; P-01669; P-00052).

Despite this criticism, Nalcor did not change its reliability return period or loadings at DG3. Increasing the reliability return period at that point would likely have required significant re-engineering. By the time the MHI report for the PUB was released (January 2012), which criticized Nalcor's proposed return period, the detailed design on the transmission line was already advanced and SNC had submitted an estimate based on

40% of the final engineering. By the time the PUB accepted MHI's criticism (March 2012), work had advanced even further. Changing the design criteria at that stage would likely have led to increased costs and delays.

Based on its understanding of the reliability of the overhead transmission at DG2, Nalcor estimated that moving to a 1:150-year return period would cost $150 million. After DG2, the detailed design work that had been completed revealed that the towers had to be significantly larger and heavier than expected in order to meet even the 1:50-year loadings. The factors that affected the DG2 estimate had a similar impact on the DG3 estimate. MHI's DG3 report, which it prepared for GNL, continued to support a 1:150-year return period (P-00058, p. 52).

Despite its decision to reject the PUB's criticism of the design criteria, Nalcor did not assess any risk for changing the reliability rating of the Project's overhead transmission and actually assessed a low level of tactical risk. In effect, Nalcor chose to accept the significant risk that its reliability decisions would be rejected and it chose not to factor the likelihood of this into its risk analysis, all apparently for the purpose of keeping the DG3 estimate lower.

CHAPTER 7: THE PUB REFERENCE QUESTION AND MHI INVOLVEMENT

On December 14, 2000, the *Labrador Hydro Project Exemption Order*, NL Regulation 92/00, was filed by the Lieutenant-Governor in Council pursuant to s. 5.2 of the *Electrical Power Control Act, 1994* and s. 4.1 of the *Public Utilities Act* (P-00023). In this Regulation, the Labrador Hydro Project is defined generally as any generation and related facilities at Churchill Falls, Gull Island or Muskrat Falls, as well as associated transmission facilities.

The Regulation exempts Newfoundland and Labrador Hydro from both the *Electrical Power Control Act, 1994* and the *Public Utilities Act*, with respect to the Labrador Hydro Project. At the time, GNL was contemplating the development of the lower Churchill for export purposes (P-00528, p. 3). However, the Order also exempts from regulation the transmission of power within the province, both to the Labrador–Québec border and to the Island of Newfoundland.

The *Electrical Power Control Act, 1994* gives regulatory oversight of electrical generation to the Public Utilities Board, a quasi-judicial body with a mandate to implement Newfoundland and Labrador's power policy. This gives the PUB the authority to ensure that power rates are just and reasonable and that the province's transmission and generation facilities are managed in a manner that results in the efficient and equitable delivery of an adequate supply of power to consumers in this province, at the lowest possible cost that is consistent with reliable service (P-00087).

Pursuant to s. 17 of the *Energy Corporation Act,* Nalcor is not a utility as defined by the *Public Utilities Act*. Therefore, the *Public Utilities Act* does not apply to Nalcor (P-00431).

Section 5 of the *Electrical Power Control Act*, *1994* states (P-00087):

> **5.** (1) The Lieutenant-Governor in Council may refer to the public utilities board
>
> (a) existing or proposed rates or a class of rates applicable between producers, retailers and customers;
>
> (b) matters affecting or related to rates charged by producers to retailers and customers;
>
> (c) the principles used by or appropriate for use by producers in determining rates for the supply of power to retailers and customers; or
>
> (d) another matter relating to power (p. 8)

Following a series of events that began in April 2011, GNL decided to send a Reference Question related to the Project to the PUB. A chronology of these events follows.

PRELIMINARIES: APRIL TO MAY 2011

April 11: Former PUB Chair David Vardy emailed Nalcor, inquiring about the comparison of the net present value of the Project (Interconnected Island Option) and the Isolated Island Option, as well as the plan for de-commissioning Holyrood.

April 14: GNL met with Mr. Vardy, after which GNL considered making arrangements for an independent review of the Project.

April 14: Robert Thompson emailed Nalcor's Edmund Martin and Gilbert Bennett and the Department of Natural Resources' Associate Deputy Minister Charles Bown with preliminary thoughts on retaining an independent consultant, using the following core terms of reference (P-01088):

- Taking as a given certain assumptions (e.g., pollution abatement requirements at Holyrood; PIRA forecast prices; NL consumers should bear full cost of supply of power to NL consumers; industry standards for reliability as applied by Nalcor);
- The "consultant" shall review Nalcor's revenue and cost estimates of the isolated Island and Muskrat Falls options, including a review of assumptions, demand forecasts, and costing methodologies;
- The consultant will draw conclusions about the reasonableness of the revenue and cost estimates of the two options. (p. 1)

The independent review being considered was primarily intended to appease the growing public pressure about and criticism of the Project. In his testimony, Mr. Thompson described GNL as being satisfied with the work and information flow from Nalcor at the beginning of 2011. However, growing public concern about the risk attached to the Project led to "a sense that there should be an independent review of the work that had been done to date." Mr. Thompson added that there was "this level of concern that we need to address and so the idea of an independent review started to emerge" (November 14, 2018, transcript, p. 42).

April 14: David Bazeley of GNL's Department of Natural Resources sent Mr. Bown a document summarizing his understanding of the differences between the "normal" process for public utility developments like the Project and the process that Nalcor was proposing. Nalcor's intention was summarized as: "Nalcor does not intend to present its plan to PUB, and asks Government to force PUB to accept MF & LIL as least-cost alternatives for Hydro" (P-01382, p. 2).

April 17: Mr. Thompson emailed Derrick Sturge, Nalcor's CFO, stating: "Ed [Martin] asked me to take up with you our dialogue on the independent study, or update. We had a productive conversation on Friday afternoon and are getting close to how the study should be framed" (P-01655, p. 4).

April 26: Mr. Sturge sent Mr. Thompson a draft of Nalcor's Briefing Note on the Project, which summarized NLH's Island-supply decision process, the historical regulatory treatment of generation and transmission projects in the province, the DG3 process, the proposed independent reviews and the regulatory undertakings required from the Province in order to secure project funding.

The Briefing Note (P-01653) detailed Nalcor's rationale for excluding PUB involvement. Its argument was that a Project review by the PUB would cause schedule delay, resulting in increased contract costs, loss of team members, higher financing costs and various other harmful effects. Nalcor proposed an alternative—engaging an independent consultant to review the two Island-supply options, to provide a preliminary draft report using DG2 estimates by mid-2011 and to provide a final report using DG3 estimates prior to sanction. Nalcor also suggested potential candidates who could perform this review: NERA Economic Consulting, Navigant Consulting, Ernst & Young and KPMG. Nalcor proposed that the scope of work would focus on the reasonableness of the "Island-supply decision."

April 28: Auburn Warren prepared responses to several questions arising from the draft Briefing Note and regulatory changes that Mr. Thompson and Mr. Bown had proposed.

Nalcor continued to have concerns about how the public could be assured that the Project was the best choice and it questioned what role the PUB could play in the process. Nalcor reiterated that the delay associated with the proposed PUB process would be unacceptable for the Project schedule, and stated: "The federal government will argue that the PUB process creates the risk that Muskrat Falls will not even be built" (P-01386, p. 2).

In response to questions about oversight (P-01386, p. 6), Nalcor pointed to information already provided, the proposed third-party review and added that “oversight by the Province is implicit as it is the shareholder of Nalcor.” It suggested that accountability to consumers could be promoted through an annual update process during the construction phase. In effect, Nalcor was proposing no oversight of the Project.

May 3: David Vardy and Ronald Penney wrote Minister Shawn Skinner (Natural Resources), requesting that he refer the Project to the PUB for review. Mr. Vardy and Mr. Penney were surprised to hear that the Project might not be reviewed by the PUB, given comments by Premier Dunderdale in the House of Assembly that seemed to imply that the PUB would have some degree of regulatory oversight of the Project (P-00330).

May 10: GNL and Nalcor prepared to announce the Project’s regulatory strategy and informed the PUB that it would not be involved in approving the Project. GNL prepared a draft letter to the PUB (P-01388) and an associated draft press release (P-01089), which stated that the Project was the least-cost option to address the projected energy capacity deficits in 2015 and 2019, and that GNL had decided to issue an exemption order allowing the Project to proceed without any review by the PUB. This was described as being necessary in order to ensure regulatory certainty prior to engaging financiers.

The draft release stated that, notwithstanding GNL’s confidence in Nalcor’s analysis, Nalcor would retain an external consultant to conduct a supply decision review prior to Project sanction. GNL considered defining the PUB’s involvement in the Project as consisting of an annual prudence review of the costs during the construction phase. Nalcor would also give the PUB a formal annual update on the Project and the PUB would be responsible for oversight of operating costs after construction was complete.

May 11: GNL prepared a final draft of the press release and discussed it with members of the Nalcor executive but did not decide, at that time, when it would be issued (P-01090).

May 12: Mr. Thompson sent Mr. Bown a document outlining the justification for the policy decision to exempt the Project from oversight (P-01092).

May 15: CBC journalist David Cochrane emailed the following message to Nalcor: “I’ve been told that the government is making Muskrat Falls exempt from PUB regulation. The net effect of this would be that the government and Nalcor could set electricity rates free from regulatory oversight. Is that the case? Is Muskrat Falls exempt from the Public

Utilities Board? If so, why is this necessary?" (P-00844). These questions appear to have put some pressure on GNL and Nalcor to reach a decision about the PUB's role.

BACKGROUND, CONTEXT AND FINDINGS

May 2011: Early in the month, GNL's Department of Finance had been preparing a recommendation for hiring an independent consultant to conduct a full review of the Project that would be broader in scope than any done or contemplated during the Muskrat Falls decision process. It was intended to be a review of the analysis and the due diligence conducted by Nalcor and its consultants (P-00807). The Decision Note containing this recommendation indicates that it was prepared by an employee of the Department of Finance, Paul Myrden, and approved by Terry Paddon, the Deputy Minister of Finance, as well as by Charles Bown on behalf of the Department of Natural Resources.

According to Mr. Bown's testimony, he and Mr. Paddon "had had a number of conversations over the months about the process going forward for Muskrat Falls, and we both felt that an independent review is necessary before Government made the sanction decision. And we prepared this Note; staff in my department worked with staff in the Department of Finance in preparing this Note" (December 6, 2018, transcript, p. 52).

The Decision Note states (P-00807):

> From a credit rating perspective, the best current indicator of the market's perception of the project comes from Standard and Poor's which recently upgraded its rating for the Province from A to A+. Commentary in the news release announcing the upgrade included the following statement—"While the decision to proceed with the Lower Churchill project augurs well for the local economy, we think it could expose Newfoundland to substantial construction risk and borrowing requirements." In terms of future outlook, they also made the following comment—". . . sustained deterioration in economic performance, operating surpluses, or liquidity, or any cost overruns or other developments at Lower Churchill that add material risk to the province or Nalcor could lead to a downgrade or an outlook revision to negative. Both statements should be interpreted as a warning regarding the potential for the project to have a negative impact on Provincial finances. (p. 2)

The Decision Note also pointed out that the work on the Project completed to that point had all been done from a Nalcor perspective, and that taking a broader view might reveal "issues or risks, of an overriding Provincial nature or concern, that may not be as apparent or relevant to Nalcor's considerations and its due diligence processes" (P-00807, p. 3). This was an acknowledgement that the Province might have had interests that were not exactly the same as Nalcor's, a thought that appears to have been exceedingly rare in any of the documentation that I have reviewed.

The proposed independent review was to look at the fundamental assumptions underlying the Project and the analysis completed to date by Nalcor, and it would assess the rigour of the due-diligence process. The review would also focus on different types of risk and their implications for the Province. As well, the consultant would review the Power Purchase Agreement between Nalcor and NLH.

Minister of Finance Thomas Marshall agreed that the review proposed in the Decision Note described the type of due diligence that should be done and gave his approval to send it to the Premier. He and Minister of Natural Resources Shawn Skinner both signed it, on May 10 and 11 respectively.

Premier Dunderdale rejected the Decision Note's recommendation for an independent review. In his testimony, Thomas Marshall stated that he did not believe that the Decision Note was referred to Cabinet for consideration. I am satisfied that the Decision Note was never referred to Cabinet, but was only considered by Premier Dunderdale.

Mr. Marshall was informed sometime later that the PUB would be engaged to review the Project, not an independent consultant as he and Mr. Skinner had proposed. In his testimony, Mr. Marshall said that he was satisfied that the PUB Reference Question was an adequate substitute for the risk review proposed in the Decision Note, "because I thought there would be—it would be the same. . . . Just a different group would do it. But they'd be independent of government" (November 6, 2018, transcript, p. 63).

Mr. Marshall did not play any role in the subsequent decision to limit the scope of the Reference Question given to the PUB, and he realized only after the fact that this scope was far more limited than he had initially thought. He testified: "But then I found out that it was a limited reference and I looked at that and I thought that the key thing for us and my colleagues was which one's the least cost. That was the key thing, which one would have the lowest rates for the people of the province. That was the key thing for us" (November 6, 2018, transcript, pp. 11–12).

The switch to pursuing a PUB Reference Question proceeded and no review of risks was ever undertaken by GNL. Charles Bown made the following observation in his testimony: "Generally, the process in government, you don't challenge the decisions that are made: that's the responsibilities of the ministers" (December 6, 2018, transcript, p. 53).

May 16: GNL decided to proceed with a Reference Question to the PUB.

The process by which this happened is not entirely clear. Ms. Dunderdale testified that "the view of two ministers—would have gone into the mix of discussion about what we would do in terms of an independent analysis," but she could not recall specifically whether the Decision Note from Minister Marshall and Minister Skinner actually reached the Cabinet table (December 18, 2018, transcript, p. 37). Mr. Thompson characterized the Decision Note as "part of the evolution of this issue that where we ultimately landed was a reference to the PUB" but could not say specifically if he discussed it with the Premier (November 14, 2018, transcript, p. 46).

Although in their testimony Ms. Dunderdale and Mr. Thompson described this Decision Note as a part of the process that resulted in a PUB Reference Question, it would be more accurate to say that the recommendation in the Decision Note was dropped entirely in favour of the PUB reference. However, the Reference Question, once drafted, did not address some of the important concerns the Decision Note had raised.

Ms. Dunderdale testified that when Nalcor learned that she was considering recommending to Cabinet even a limited Reference Question, "there was consternation at the table" and "they weren't very happy about it" (December 18, 2018, transcript, p. 51).

Regarding the considerations about whether the matter should be referred to the PUB, Mr. Skinner stated that several concerns were taken into account. They included the letter from Mr. Vardy and Mr. Penney, questions in the House of Assembly, people speaking directly to him about the Project, media editorials and radio call-in shows. He testified that "there were some people who were out there who were saying that they felt they needed a, you know, a cold-eyes review. The Public Utilities Board had a role to play and they should be engaged" (November 2, 2018, transcript, p. 27).

Ms. Dunderdale spoke of the public concern and the PUB referral in her testimony (December 18, 2018, transcript):

> [D]ebate was happening vigorously in the public arena through open-line shows and so on and questions being put forward in the House of Assembly and so on.

> And to—there was so much conflicting information around those two questions, and for me and for the Cabinet, they were the two critical questions: do we need the power, and what is the least-cost option?
>
> And in my own thinking, having that put to somebody independent of government wasn't a bad thing. So I made the recommendation to Cabinet that we have a limited referral to the PUB to answer those two questions based on the information we have to date. (p. 51)

THE REFERENCE QUESTION PARAMETERS: MAY 2011

May 16: GNL informed the PUB that it would receive a Reference Question that would involve a review of the Project. The same day, Maureen Greene, legal counsel for the PUB, met with Charles Bown and Paul Scott of the Department of Natural Resources to discuss the process and schedule for responding to the question, as it was outlined in an early draft of the proposed Terms of Reference for a PUB Review (Review).

The PUB learned that it would be asked to determine which of Nalcor's proposed two options was the least-cost option, and that the PUB report would be due by December 30, 2011. From the start, the PUB was concerned about the short time frame specified by GNL. Throughout the process of addressing the work, the PUB consistently articulated and documented the requirement for Nalcor to provide full and timely disclosure of information so that it could complete the Review in the time allotted.

May 17: Opposition Leader Yvonne Jones (Liberal) challenged the Premier in the House of Assembly, asking why the Project would not be subject to the full scrutiny of the PUB. Premier Dunderdale (Conservative) replied that the exemption order was issued by a Liberal Government in 2000. Premier Dunderdale then announced that there would be a Review by the PUB that would consider whether the Project was the least-cost option (P-00533, p. 13).

May 18: Mr. Bown wrote to Mr. Thompson asking, "Will we be limited to 2 supply options or 5? If we want to meet the schedule we should limit to isolated island and MF" (P-01094).

May 19: Nalcor and GNL collaborated to prepare the final form of the Reference Question. An evaluation of "the reasonableness of the screening process used by NLH in identifying feasible options for Island Interconnected Customer power requirements" was removed from the scope of the Review by GNL (P-01095, p. 3).

Mr. Bown provided a comment on this deletion in his testimony: “If we are asking for an evaluation of two options, then why is it necessary to also ask for a reasonableness test of how NLH did its analysis; is this required and does it impact time?” (P-01095, p. 3). From this response, as in other instances throughout the Project decision-making process, it appears that meeting the schedule proposed by Nalcor was a high priority for GNL.

Mr. Bown was also concerned about the optics of the Reference Question, writing in his review of it: “I’d also like to consider how to phrase some of the more negative statements so that they don’t appear so limiting” (P-01095, p. 1).

May 20: Mr. Thompson sent a draft of the core Reference Question to Premier Dunderdale. It proposed that the PUB consider whether the Project or the Isolated Island Option was the lowest-cost option for power supply, as well as the following matters (P-01096):

- The screening process used by NLH in identifying feasible options for the Island Interconnected Customer power requirements;
- The Island load forecasts used by NLH in comparing the two options;
- The system planning assumptions and process used by NLH in comparing the two options; and
- The assumptions used by NLH and Nalcor for developing and comparing the estimated costs for delivery of power to NLH from the two options. (p. 1)

May 24: GNL sent another draft of the Reference Question to Nalcor, from which the reference to the screening process had been removed and the scope narrowed to two options. In an email, Nalcor’s David Harris provided the following comment on this draft (P-01390):

> This started as comparison between infeed and isolated island, and then went to review of all options, and now seems to be back to the original. The concern with the original comparison was the exposure to criticism that all reasonable options are not shown to be inferior to the infeed. (p. 2)

This shows that at least some people within Nalcor were willing to address how the two options were selected. However, GNL decided to exclude from the scope anything outside the binary choice.

May 25: Minister Skinner approved the final Reference Question (P-00845). In the Direction Note prepared for the Minister by the Department of Natural Resources, the pros and cons for recommending that the PUB address the Reference Question were primarily focused on the time frame for the Review and the potential for public criticism. They were stated as follows (P-00845):

Pros:

- Fulfills commitment to have the Board involved
- A Consumer Advocate will represent consumer interests and reduce the number of potential Intervenors
- The referral can require an appropriate deadline for reporting back

Cons:

- Timeframe will be very challenging for the Board
- Could be criticized as not allowing sufficient time for adequate review
- Requires the Board to hold a public hearing
- Either Government or Nalcor will need to pay the costs of the referral (p. 2)

May 26: Cabinet gave its approval to issue Orders in Council to send the Reference Question to the PUB. The Orders in Council were not made effective until June 9, 2011 (P-00846).

The Reference Question Process: June to November 10, 2011

June 2011 to January 2012 was a challenging period for the PUB. Nalcor did not fulfill the PUB's requests to provide detailed and current information in an expedient manner. The PUB and its consultants were frustrated, believing that Nalcor would already have substantially prepared such information when the Project passed through DG2.

In her meeting with Mr. Bown on May 16, 2011, and thereafter, Ms. Greene had registered her concerns about the tight timeline for the PUB to perform its work and the need to begin as soon as possible if it was to be completed by December 30, 2011.

The PUB engaged Fred Martin as a consultant to provide engineering and technical advice for its Review. He was to work closely with the PUB and liaise with the firm that would carry out the technical review. Ms. Greene recommended the engagement of Fred Martin because she had worked with him at NLH (P-00534). Mr. Martin assisted the PUB in preparing the request for proposals for the technical review (P-00536). What follows is the next series of key events.

June 8: Mr. Bown advised Ms. Greene that there had been a system delay, which prevented the Reference Question from being officially released. Ms. Greene emphasized the PUB's concerns about the urgency of beginning work as soon as possible, especially since two weeks of the schedule contemplated at the first meeting had by then been lost (P-00535).

June 17: Shawn Skinner, Minister of Natural Resources, sent the Reference Question to Andy Wells, Chair of the PUB. The same day, the PUB and Nalcor representatives met to discuss matters related to the Reference Question. As the minutes of that meeting indicate, Nalcor advised that it had most of the information the PUB required, although it may not have been in the format requested, and that it would deliver a "comprehensive/meaningful package" of documents by June 30, 2011 (P-00539, p. 2). The PUB then sent its initial information request to Nalcor. It contained a substantive list of items to have been provided no later than June 30.

Ms. Greene testified that Gilbert Bennett led the PUB to understand that it should expect to receive a "truckload" of documents by June 30 (October 24, 2018, transcript, p. 33).

June 30: The PUB received the first delivery of documents.

Ms. Greene testified that many of these documents were about Gull Island, not the Project, and that her reaction was "disappointment that we were not getting off to a good start" (October 24, 2018 transcript, p. 34). Describing his expectations about Nalcor's document production (October 25, 2018, transcript), Fred Martin testified that he understood from the initial meeting that

> there was lots of documentation available and it would be forthcoming. The other thing was that we had not been advised, in advance of arrival of this information, that it wasn't going to be what we expected, that it wasn't going to be anywhere near complete, what we had been advised would be coming, and it was disappointing. (p. 4)

July 4: The PUB retained Manitoba Hydro International to:

- Review Nalcor's work on the two options
- Review the CPW analysis
- Produce a final report

MHI was asked to prepare its final report by September 15, 2011, to allow the PUB sufficient time to prepare its own report by December 30, 2011 (P-00547, p. 6).

July 8: The PUB met with Nalcor and subsequently advised Nalcor that it was crucial that all relevant information be filed as soon as possible. Nalcor agreed to file a full submission explaining both options (Interconnected Island and Isolated Island) by the end of July.

July 15: Geoffrey Young, Nalcor's legal counsel, responded to a July 12 letter from the PUB stating that "much of the information that has been requested by Board staff is not organized and held by Nalcor in the format that the Board appears to have expected" and that collecting the information from a variety of sources will be time-consuming (P-00546, p. 2).

July 21: In a letter, the PUB acknowledged Nalcor's filing of further documentation on July 15, but noted that gaps and deficiencies remained. This was because Nalcor had identified some reports as containing proprietary or "commercially sensitive" information and had withheld this information subject to further review. The PUB's position was that it was entitled to see and expected to receive all such information, which did not necessarily need to be released to the public (P-00548).

July 27: By this date, Nalcor had responded to only 10 of the 63 requests for information (RFIs) MHI has sent; it advised that its main submission would be delayed until mid-August.

July 29: Fred Martin met with Gilbert Bennett and Paul Harrington and communicated the PUB's frustration with the delays in receiving the necessary information from Nalcor. He noted, in particular, the lack of detailed cost estimates for the Project. Mr. Bennett stated that cost estimates will be given at "structure level" and in more detail later, if required, citing commercial sensitivity. Nalcor agreed to provide the PUB with various documents that the PUB had requested. In an email to Maureen Greene and Sam Banfield, Fred Martin said he felt that the meeting had been "very positive" (P-00551, p. 2).

August 1: In preparation for meeting with the MHI team, Fred Martin asked for the Muskrat Falls layout documents, which some reports had referred to but were not yet provided to the PUB. Nalcor suggested that these were immaterial to the PUB Review. Fred Martin stated that some of the bigger remaining gaps were "technical and cost data related to the Strait of Belle Isle cable, cost estimates for the Muskrat Falls development, and HVdc link, and reports related to specific and overall risk assessments" (P-00552, p. 2).

August 16: In a report of this date, under "Technical Status Report," MHI stated (P-00558):

> From all indications, Nalcor has been fast tracking the Muskrat Falls LIL HVDC Link Option and as the project definition has only changed from Gull to Muskrat in the last year, a great deal of information is in process or not yet available.
>
> MHI's request for detail technical information on the Muskrat Falls LIL system has been slow to come or not made available. For example, the detailed HVDC Specifications and Estimates are only now being finalized for DG3. To overcome this deficiency, a new detailed IR has been drafted.
>
> The Isolated Island Option has suffered from a lack of data and filings. Details on the Holyrood life extension, and estimates for CT and CCCT were only made available this week. This material has now been forwarded to the Thermal assessment team in preparation for the visit next week. (p. 6)

August 31: Before August ended, MHI requested that the PUB grant an extension for the filing of its final report from September 15 to October 31, 2011, because of non-receipt of Nalcor responses to certain RFIs.

September 12: Cheryl Blundon and Maureen Greene of the PUB met with Geoffrey Young, David Harris and Gilbert Bennett of Nalcor. At this meeting, Nalcor expressed concerns that some of the recently issued RFIs were outside the scope of the Terms of Reference.

According to Ms. Greene's testimony, this was the first time Nalcor had raised this issue (October 24, 2018, transcript, p. 76). The RFIs that Nalcor disputed fell into two categories:

1. RFIs in which Nalcor was asked to perform CPW analyses of scenarios different from those described in Schedules A and B of the Reference Question. For example, the PUB requested that Nalcor evaluate a scenario in which Holyrood would operate until 2041 with low-sulphur fuel instead of the carbon scrubbers and precipitators, to be followed in 2041 by the HVdc link to bring power from Churchill Falls to the Island.

2. RFIs related to Nalcor updating information and cost estimates beyond DG2. Nalcor's position was that the review was intended to

> answer the question of least cost based on the DG2 estimates. PUB counsel pointed out that there was nothing in the Terms of Reference that required the PUB to limit its review to DG2 estimates. The PUB and Nalcor concluded that there was "a disconnect in their interpretation of the context of the review, especially with respect to timing" and that it would be discussed further.

Other topics of discussion at the meeting on September 12 included ongoing problems of information flow and the failure by Nalcor to file its submission to the PUB. As one record of this meeting shows, Ms. Greene's conclusion was that "Nalcor wasn't ready for this review as very little substantive information was provided until early to mid August" (P-00564, p. 3).

At the meeting, Mr. Bennett defended Nalcor's performance, stating that Nalcor had given priority to answering technical questions from MHI before responding to other RFIs, and then finally to preparing its submission required for the Review, which outlined the two options. He said that some of the detailed questions were unnecessary and "added little value to the process." The PUB's record of this meeting attributed the following statements to Mr. Bennett (P-00564):

> [S]ome of the information that has been asked for doesn't exist, because their reporting process is not in the same process contemplated by the Board's questions. Nalcor doesn't require the type of final reports (for example, the feasibility report on the proposed Muskrat Falls Project) as requested. Nalcor never contemplated that it would have to provide information and reports in the comprehensive manner that the Board has requested and expects. (p. 3)

September 14: The PUB wrote to Nalcor, expressing concern about the schedule for delivering its response to GNL, given the lack of information that Nalcor had filed to date. It was particularly concerned that Nalcor's submission, which should have been filed at the commencement of the PUB Review period, had not yet been received. In closing, the PUB stated: "We reiterate that the requested information is critical to allow a review of the proposed schedule for the Review" (P-00566, p. 2).

September 22: PUB Chair Andy Wells wrote Minister Skinner informing him that the PUB would not be able to complete the Review by the end of the year due to insufficient information having been supplied by Nalcor. The PUB was not formally requesting an extension at the time, however, because it could not give a realistic alternate date until it knew when Nalcor would file its submission and respond to the outstanding RFIs.

October 11: A provincial election was held and the Conservative Government was returned to power.

October 18: By this date, Nalcor had not responded to 144 of 268 requests for information. MHI could not complete its report until the outstanding RFIs and Nalcor's submission were filed. In a Briefing Note to the PUB written on this date, Ms. Greene stated (P-00570):

> **Action Plan and Recommendations:**
>
> Nalcor's failure to respond to the Board's request for information on the filing date for its submission and the responses to requests for information should be addressed.
>
> It is recommended that Nalcor be written to advise that it has stymied the Board in moving forward with the review and that Government will be advised that the Board cannot move forward with the review at this time in light of Nalcor's failure to respond.
>
> It is also recommended that a media statement be issued regarding the delay in the review. (p. 3)

October 20: Mr. Geoffrey Young wrote the PUB and defended Nalcor's efforts to provide information to it and to MHI (P-00571):

> These efforts have been complicated by both the volume of material included in the review as well as the format and organization of material requested. These were recognized early by Nalcor and this concern was communicated to Ms. Maureen Greene by letter on July 15, 2011. (p. 1)

In this letter, Nalcor also denied that it had committed to filing its submission by the end of July, adding that there had been a "collective decision" made by the PUB and Nalcor staff that Nalcor would focus efforts on providing MHI with the information it had requested before making a formal submission. Mr. Young indicated that Nalcor would give priority to the remaining RFIs and file its submission by November 10, 2011.

October 25: The PUB responded to Mr. Young's letter, alleging that it "contains a number of inaccuracies which must be corrected for the record." It lists seven (P-00572):

1. At a meeting on June 17th Nalcor stated its Submission would be filed by the end of July. This was confirmed in our letter of July 12th and at a meeting attended by a Nalcor representative on July 20th. We are therefore surprised to read in your letter that Nalcor "*had not committed to that date*".

2. The Board was not involved in any "*collective decision*" that the Submission would be delayed until the completion by Nalcor of requests for information from Manitoba Hydro International Ltd. ("MHI").

3. As confirmed at the meetings on July 20th and September 12th it was always contemplated that the MHI report would be finalized and filed after Nalcor's Submission.

4. Nalcor had not provided a list of confidential exhibits to the Consumer Advocate as stated on October 20th, the date of your letter. We understand that this list was provided late on October 21st, after it had been brought to your attention that such list had not been provided as stated.

5. The Review was initiated in mid-June, which is more than four months ago, not three as stated.

6. While the numbers are continually changing as new information is filed, Nalcor had, as of October 20th, (the date of your letter) filed answers to 166 requests for information and not 187 as stated.

7. There were responses to six requests for information (not five) outstanding for MHI as of October 20th. (pp. 1–2)

October 26: The PUB issued a media release advising that, because it had not yet received Nalcor's submission nor answers to several outstanding RFIs, it was not possible to determine when its Review would be completed.

October 28: Cheryl Blundon, Fred Martin and Maureen Greene met with Gilbert Bennett and Paul Humphries of Nalcor. Ms. Blundon's handwritten notes indicate that the various topics that were discussed included specific RFIs, a number of which the PUB believed did not respond to the questions asked and to which Nalcor agreed to file revised responses. The PUB also sought clarification on the timeline of events and, specifically, when Nalcor had decided to defer Gull Island in favour of Muskrat Falls. Mr. Bennett indicated that Nalcor would respond to the PUB's letter the following week.

Also on this date, Jerome Kennedy was appointed Minister of Natural Resources.

November 7: Mr. Bennett replied to the PUB's October 25 letter. His note was conciliatory in tone and acknowledged the PUB's requirement that a complete record of information be filed in a timely fashion, stating: "Nalcor has been unable to meet the Board's expectations in this regard and we accept responsibility for any delays, misunderstandings and incorrect information provided to the Board in the letter of October 20, 2011" (P-00576, p. 1). Mr. Bennett also provided an update on the outstanding RFIs, saying that they would all be submitted by November 24, 2011. He added: "I would like to personally emphasize that Nalcor Energy respects the Board's responsibility and oversight on this matter, and welcomes the Board's questions and analysis of the reference question" (p. 2).

November 10: The PUB finally received Nalcor's two-volume submission (P-00077):

- The 158-page first volume summarized the system planning process that had established the two alternatives and provided an analysis that concluded that the Muskrat Falls Project was the least-cost option
- The 92-page second volume gave an overview of the basis of design for the Interconnected Island Option, Nalcor's project delivery approach and cost and schedule at DG2

THE MANITOBA HYDRO INTERNATIONAL INTERIM REPORT

November 16: MHI provided an interim draft report to the PUB (P-00577). In the following days, PUB staff made extensive comments on the draft.

November 29: The PUB sent its comments, summarized in a 56-item table, to MHI's representative, Paul Wilson (P-00578).

Fred Martin's handwritten notes about the MHI draft report, which were provided to the Commission, included a list of points he had noted on various dates to discuss with Mr. Wilson (P-00605). His comments reflected frustration on the part of PUB staff with MHI's efforts on the report, for example: "extremely disappointed and concerned with apparent lack of effort and product to date," "no respect for our comments" and "focus/efforts seem to have gone off this project" (p. 12). Fred Martin testified that, although he did not have any problem with the findings in MHI's report, the writing quality was uneven in some sections. The report had obviously been drafted by different people and as a result did not flow well (October 25, 2018, transcript, pp. 11–12).

Some of Fred Martin's noted concerns were substantive, however. For example, his notes of December 21, 2011, state: "Feeling is that the report is too glowing of Nalcor, especially in light of some 'shortcomings'" (P-00605, p. 10). He also questioned MHI's praise of Nalcor's "good environmental stewardship" and "good alignment with Government's energy policy" (p. 10).

Fred Martin and Maureen Greene continued to review the draft in January 2012, providing comments and edits and engaging in extensive discussion with representatives of MHI. By the time the MHI report was finalized, it appears that the PUB representatives felt that they had put much more work into its preparation than should have been required, considering that they had paid MHI to write it. On February 21, 2012, Fred Martin noted that the PUB had been "concerned regarding the time and effort required of its staff in assisting the finalization of MHI's report" (P-00605, p. 1).

PUB Request for Extension: December 2011 to January 2012

December 5: Maureen Greene provided a Briefing Note to the PUB Commissioners in which she advised (P-00580):

- Nalcor had responded to all 297 RFIs by November 25, 2011
- More than a third of the responses (115) had been filed between November 14 and November 25; this material contained substantial information not previously available
- The PUB, MHI and the Consumer Advocate were in the process of preparing new RFIs, including questions about the recently filed information
- Given the significance of some of these questions, a final draft of the MHI report could not reasonably be completed until mid-January
- The planned activities included a technical conference as well as public consultations
- A realistic (but optimistic) date for filing the PUB's final report would be June 29, 2012

- The PUB should request an extension for filing its report to June 29, 2012, notwithstanding that it was already aware, from discussions with Mr. Bown, that GNL was considering March 30 as the deadline

December 12: To allow the Project to be debated in the House of Assembly's spring session, Minister Jerome Kennedy advised the PUB that its Review must be completed by March 31, 2012. He stated: "It is imperative that we receive the report by March 31, 2012 to ensure that Members of the House of Assembly are not constrained in their ability to examine and debate the report" (P-00045, p. 1). Mr. Kennedy added that GNL was committed to assisting the PUB in meeting the deadline of March 31, 2012 (P-00045).

December 16: Andy Wells replied to Mr. Kennedy, formally requesting an extension to June 30, 2012, with this justification (P-00046):

> The reason this extension is necessary is Nalcor's failure to provide the required information in a timely fashion. This review began in June but as of late November Nalcor was still filing significant new information. Between November 10 and November 24, 2011 Nalcor filed its submission as required by the Terms of Reference, a detailed study in relation to reliability, responses to 115 requests for information and 12 additional exhibits. This new information is now being reviewed and assessed and additional requests for information will be issued so that Manitoba Hydro International Ltd. ("MHI") can finalize its report and we can begin the public consultation process. (p. 1)

December 23: Mr. Kennedy replied, insisting that because GNL had announced its intention to table the report of the PUB in the spring session of the House of Assembly, it was of "critical importance that the Board's report be received not later than March 31, 2012, so as to allow Government to meet its commitment to the people of the Province" (P-00047, p. 1). Mr. Kennedy also questioned whether all the processes proposed by the PUB were necessary.

Mr. Kennedy also wrote the Consumer Advocate to inform him of the March 31 deadline and advised him that GNL did not want him to hold "public sessions around the Province in order to receive customer input directly on matters engaged in the review" (P-00583, p. 1). Finally, Mr. Kennedy advised the Consumer Advocate: "It was not contemplated that the Consumer Advocate would complete its own independent analysis of the project" (p. 2).

January 6, 2012: Mr. Wells wrote GNL, advising that the PUB would endeavour to meet the March 31 deadline, even though it believed that the earliest possible date for completion of the Review was June 29, 2012. This letter stated that some activities would have to be dropped because of the abridged schedule (P-00590). These included RFIs in relation to the MHI report, technical evidence from other parties, the contemplated technical conference and public hearings outside of St. John's. He also noted that the PUB expected that the truncated Review might result in several issues remaining outstanding at the conclusion of the PUB's work, which GNL might want to address in the future. The letter concluded with (P-00590):

> While I appreciate your offer of additional resources to assist the Board in meeting the deadline I can advise that the Board has had the necessary resources in place since June 2011 to complete this review. The only difficulty has, from the beginning, been Nalcor's inability to provide the required information. In fact I can advise that, even at this late date, with a completion deadline less than three months away, Nalcor has not answered a number of outstanding requests for information that were issued in mid-December. (p. 2)

OBSERVATIONS ON THE PUB REVIEW PROCESS

Based on my consideration of all the evidence about the involvement of the PUB and the directions given to it by GNL, I have reached the following conclusions:

- The PUB Review should have been high on Nalcor's list of priorities, but it was not—particularly with regard to the information requests and the filing of Nalcor's submission
- Nalcor was well aware of the short time frame the PUB had been given to answer the Reference Question; I find that Nalcor's actions clearly indicate its opposition to having any review by the PUB and also reflect its view that Nalcor had complete control over the information that the PUB would receive
- Nalcor's position that some "commercially sensitive" documentation should not be provided to the PUB is surprising, based on the PUB's mandate and its quasi-judicial status; this position, however, appears to be consistent with its attitude toward any external review of its work on the Project

- It was important that Nalcor file its formal submission with the PUB at or near the commencement of the PUB Review process and Nalcor knew this, or ought to have known it; the evidence clearly establishes, however, that Nalcor deliberately delayed filing its formal submission, thereby, in effect, undermining the PUB Review process
- It is unacceptable that Nalcor justified its delay in providing timely disclosure to the PUB on the basis that some of its documents were not in the format that the PUB and MHI required. Nalcor's actions, inaction and general conduct frustrated and undermined the PUB's efforts to discharge its important responsibility in a timely and efficient manner
- The importance of this work by the PUB for the public was either not understood or intentionally frustrated by the actions of Nalcor

Additional Complications: Andy Wells' Media Comments/Meetings

Some actions of the Chair of the PUB, Andy Wells, gave rise to concerns about the objectivity of the PUB's response to the Reference Question.

Throughout the PUB Review process, Mr. Wells had several meetings and conversations with politicians and civil servants. As noted earlier, within two weeks of receiving the Reference Question, the PUB had become concerned about the flow of documentation and the lack of co-operation from Nalcor. At the hearings, Mr. Wells reported that he had read statements in the newspaper attributed to Finance Minister Thomas Marshall in which the Minister extolled the virtues of the Project. He went on to relate what he said when he encountered Mr. Marshall one morning soon after (October 25, 2018, transcript):

> I just stopped him, I said, Tom, b'y, look, from—look, just to let you know, I saw your—I heard you or saw you, and I said, if I were you, I wouldn't be singing the praises of Muskrat Falls. From what we're seeing—from what I'm seeing it doesn't look that good, that's all. And he just looked at me and walked on. (p. 71)

In the fall of 2011, Mr. Wells had been called to the Confederation Building for a "very short meeting" with Robert Thompson, Brian Taylor from the Premier's Office, and a lawyer for the Department of Natural Resources. Mr. Wells recalled Mr. Thompson saying:

"I am not satisfied with some of the questions that your lawyers are asking of Nalcor," to which Mr. Wells replied, "It is not for you or me or for anyone else to question our lawyers with respect to any questions they may ask of Nalcor" (October 25, 2018, transcript, p. 67).

At the hearings, Mr. Wells recalled that he then turned to Mr. Taylor and asked him, "Are you concerned about the cost of this project?" According to Mr. Wells, Mr. Taylor's response was that he "laughed at me insanely" and said: "No b'y, of course not, we're not concerned about the cost of this project, we are only concerned about the optics." At this point, Mr. Wells recalled that he said, "Thank you very much," and walked out of the meeting. Mr. Wells stated that he was deeply offended by the comments of Mr. Thompson and Mr. Taylor, and he characterized the meeting as "an attempt at intimidation of a regulatory tribunal." He also indicated that he felt that the meeting's subject matter was "extremely improper" (October 25, 2018, transcript, p. 67).

Mr. Thompson testified that he recalled that the inquiries made during this meeting were entirely proper and that Mr. Wells said that "[i]t was none of government's business what questions that the lawyers may ask." Mr. Thompson testified that he had no recollection of Mr. Taylor "laughing insanely" or saying that GNL was only concerned about the optics (November 14, 2018, transcript, p. 59).

In 2012, more meetings and interactions with Mr. Wells were notable.

January 4: Mr. Wells met with Jerome Kennedy and Mr. Kennedy took handwritten notes of this meeting (P-00586). Mr. Wells attended this meeting alone and he discussed the challenges that the PUB was experiencing.

At the hearings, Mr. Kennedy characterized the tone of this meeting as "very amicable" and added: "He was raising legitimate issues that he was—in his own way—some of his terminology was a bit harsh perhaps—but he was very clear in terms of the way he saw the failure of Nalcor to provide information" (December 3, 2018, transcript, pp. 70–71).

January 5: As a result of the January 4 meeting, the PUB Commissioners asked Ms. Greene to attend a second meeting with Mr. Wells and Minister Kennedy, scheduled for January 5. The PUB Commissioners agreed that it was appropriate for counsel to accompany the Chair to such meetings. Ms. Greene testified that the purpose of this meeting was to discuss changes in the process and schedule that the PUB would need in order to meet the March 30 deadline that GNL had stipulated. Mr. Kennedy's notes confirm there was a discussion about the procedural difficulties experienced by the PUB, which included a "lack of timely response from Nalcor" and "lack of current info[rmation]" (P-00588, p. 2).

January 10: *The Telegram* reported Mr. Wells' observations about the schedule for the PUB Review. Mr. Wells was quoted as saying that the PUB had made clear to Nalcor in 2011 that it was four months behind schedule because of Nalcor's failure to provide the comprehensive information that the PUB required to properly complete its work (P-00591).

When asked at the hearings why he thought it was appropriate for him, the Chair of a quasi-judicial tribunal, to make these kind of comments to the media, Mr. Wells indicated that the nature of a Reference Question was different than that of a normal regulatory process (October 25, 2018, transcript):

> [H]ad this matter been a regulatory matter where we would have been rendering a decision, I would have had absolutely no comment whatsoever to anybody, but we were rendering—we were giving an opinion here.
>
> So, I took a bit more of a relaxed approach to it and what I was expressing here, finally, after what, this was probably six months, close to six months probably seven months because it's expressing extreme procedural frustration. (p. 65)

January 11: Edmund Martin wrote the PUB in response to Mr. Wells statements in *The Telegram*. Mr. Martin defended the efforts that Nalcor had made in the PUB Review process, while acknowledging that Nalcor did not clearly communicate to the PUB that some of its deadlines were unachievable. He explained that "the reasons were due solely to an underestimation of the volume of requests and the time required to compile the answers, and should in no way be interpreted as a lack of commitment to the process" (P-00592, p. 1).

This letter was signed by Mr. Martin, but it was written collaboratively by Nalcor and GNL. In an email chain marked "URGENT," Dawn Dalley (Nalcor VP of Corporate Relations) had sent a draft of the letter to Deputy Minister of Justice Donald Burrage, to Nalcor counsel Thomas O'Reilly and to Robert Thompson. All three recipients provided extensive edits (P-01106) and a closing paragraph was added that expressed concern about the comments made by Mr. Wells in the media. That paragraph reads (P-01217):

> We would be remiss, however, if we did not express our concern about your comments in the media yesterday. They do not provide a balanced view on the extraordinary efforts we have made to supply information to the Board. Nalcor wants to ensure that the process and final Board report is both balanced and a fair representation of the information presented. We trust that the foregoing

> will provide a better understanding of Nalcor's firm commitment to the review process by the Board. (p. 1)

February 12: Mr. Wells met alone with Charles Bown, despite having been advised not to attend any meetings with GNL representatives unless accompanied by legal counsel.

Mr. Wells testified that, at this meeting, Mr. Bown asked him how the Review work was going and he replied, "It's not going anywhere, Charles. We're spinning our wheels. We're not getting any co-operation from Nalcor. It looks terrible. And I said, I'm deeply concerned that, you know, this is not a good thing for the province, this project, from what we've been seeing" (October 25, 2018, transcript, p. 70).

Mr. Wells also recalled that Mr. Bown then asked, "Based on what you have observed to date, would you recommend to the government that the Muskrat Falls Project be shut down?" Mr. Wells stated that he replied, "Based on what I have observed to date, I would call the Premier's Office and I would tell her to call Ed Martin and I would say, 'Mr. Martin, shut this project down right now.'" Mr. Wells recalled that Mr. Bown thanked him and the meeting ended (p. 70).

In his testimony, Charles Bown flatly denied Mr. Wells' account of this meeting and said, "I would never ever pose a question like that. That's not in my nature." Mr. Bown characterized the meeting as "a very cordial meeting" to "ask him how things were going" (December 7, 2018, transcript, p. 98).

In addition, Mr. Wells testified that he had at least two conversations with former Premier Danny Williams while the Reference Question was before the PUB (October 25, 2018, transcript, p. 72). By his account, the first meeting was in 2011 in Mr. Williams' office in St. John's. He described the meeting like this: "Well, he wanted to know how it was going and I said: 'It's not going, Danny.' I said: 'We're not getting anywhere with this. It's terrible what Nalcor and the government were doing with respect to this'" (p. 72).

The second conversation Mr. Wells referred to took place after he made the comments complaining about Nalcor in *The Telegram*. He said that Mr. Williams "called me up and said that he didn't think that it was right that I was criticizing Nalcor like that. 'Well,' I said: 'That's too bad.' I said: 'We're fed up with the way this is going, it's not fair'" (p. 72).

The only evidence about the discussions that Mr. Wells claims to have had with Mr. Williams was the evidence of Mr. Wells. Mr. Williams was not questioned on these alleged statements.

COMPLETING THE PUB REVIEW: JANUARY TO MARCH 2012

January 31: MHI filed its final report with the PUB (P-00048). In his covering letter, Paul Wilson noted challenges that MHI had encountered during the Review process that made a comprehensive analysis difficult and time-consuming (P-00594). The challenges included the piecemeal and late receipt of information and the unavailability of some important documents, such as the AC integration studies and transmission line design criteria.

February 13 through 23: The PUB held public hearings on the Reference Question in St. John's, at which presentations were made and witnesses were examined and cross-examined. Maureen Greene testified that the hearings were followed by a period of "very intense effort" by the PUB Commissioners as they worked "night and day" to meet GNL's March 30 deadline for filing the final report (October 24, 2018, transcript, p. 63).

On February 17, while the Reference Question was still before the PUB, Nalcor made a presentation to Cabinet in which it stated its interpretation of the MHI report (P-01616). While highlighting the positive findings of the report, it failed to note MHI's concerns, including making no mention of questions related to the reliability of the transmission line.

March 30: At 10 p.m. on the deadline date, the PUB delivered to GNL its report answering the Reference Question (P-00052). The 115-page report—*Review of Two Generation Expansion Options for the Least-Cost Supply of Power to the Island Interconnected Customers for the Period 2011–2067*—was signed by all four PUB Commissioners.

As the title of its report reflects, the PUB had been asked to determine whether the Interconnected Island Option or the Isolated Island Option, as described by Nalcor, represented the least-cost option for the supply of power to customers on the Island up to the year 2067. The PUB's conclusion was that the information provided by Nalcor was not detailed, complete or current enough to make a determination.

The PUB gave several reasons why it had reached this conclusion:

- It did not believe that it was possible to use DG2 cost estimates to make a determination on least cost, as those figures were based on a high-level conceptual project definition of approximately 5% to 10% with a range of accuracy of +50% to -30%; the PUB made it clear that it was aware that Nalcor had completed much work since the DG2 cost estimates were prepared in order to better define the Project and its cost estimates, but Nalcor had not provided this additional work to the PUB
- The gaps in Nalcor's analysis that MHI identified in its report had the potential to significantly impact the cost of the Project
- The load forecast did not justify an immediate need for the large amount of power that the Project would generate
- The cost preference for Muskrat Falls, which was the result of fuel savings over the forecast period from the closure of Holyrood, was highly sensitive to changes in assumptions about fuel prices, load and capital costs

Part One of the PUB report described the background, processes and context of the Review, including the information delays and extension requests. The Board noted that its review did not focus on non-controversial aspects of the process and that the majority of the work done by Nalcor for DG2 was found by MHI to be reasonable and consistent with good utility practice. Part Two of the report focused on the Reference Question.

The PUB Report: Important Findings

The PUB report:

- Outlined the two power-supply options Nalcor was considering and commented at length on the scope of the Review, quoting from various intervenors in the hearing process on the exclusion of other supply sources from Nalcor's review
- Identified various arguments that proposed that Churchill Falls power might be a better long-term power source, as well as Nalcor's

reasons why it believed Churchill Falls power would not be a realistic option

- Noted the exclusion of the Maritime Link from the parameters of the PUB Review, which was significant from a reliability perspective
- Discussed pollution control upgrades to Holyrood, which some people believed were not necessary; the PUB declined to comment on this
- Noted that there was controversy about the exclusion of other supply options but that the PUB had not reviewed any other options because that was outside its Terms of Reference; it added that there was insufficient information on the record to make any determination about these other supply options
- Described Nalcor's Decision Gate process and listed the documents provided to the PUB that were major inputs into the DG2 analysis
- Stated that Nalcor had advised that it had been working intensely since DG2 but could not provide updated information because it was not complete
- Commented that the Reference Question did not state that the PUB Review was limited to information available at DG2
- Described the load forecast in detail and noted that, given the importance of the load forecast to the least-cost aspect of the Reference Question, the PUB had three main concerns:
    - Nalcor had elected not to prepare a 2011 planning load forecast and simply used the planning load forecast for 2010 in its analysis; this meant that this forecast was two years old by the time of the PUB's Review (the Board also found that Nalcor's explanation for this dated information was unconvincing)
    - It would have been advisable for Nalcor to adopt non-utility modelling for the load forecast before making such a large increase in capacity, given that this would be best practice and could potentially better address issues

    such as changing demographics and the impact of CDM programs

    - Nalcor had failed to take any steps outside the normal load forecasting process to obtain additional reassurance from industrial customers; Nalcor did not develop contingency plans to address the implications of reduced industrial loads despite the fact that Corner Brook Pulp and Paper, which made up 50% of the industrial load, was facing challenges

- Concluded that the load forecast did not demonstrate an immediate need for a very large incremental increase in generation capability and that the Isolated Island Option offered "what might be considered a less risky approach," in which capacity and energy would be added in smaller increments more closely matching the load forecast
- Described the CPW methodology for determining least cost and inputs into the Strategist software that performed the analysis of the options; it also commented that:
    - The fuel price forecast was the main factor in the CPW preference for the Interconnected Island Option and that fuel cost was volatile and difficult to forecast; the volatility of fuel cost had been one of the reasons Nalcor had given for its selection of the Interconnected Island Option, which reduced reliance on fossil fuels
    - The Board believed that there were significant risks that had to be recognized in forecasting 57 years into the future and that it was beyond a reasonable expectation to predict fuel price escalation beyond 2025
- Described Nalcor's cost estimating methodology and the Association for the Advancement of Cost Engineering definitions of cost estimate maturity; the DG2 estimate was said to be a Class 4 estimate, meaning that it had a concept study level, or feasibility level, of

definition of 1% to 15%, which is associated with a cost accuracy range of +50% to -30%

  - Nalcor had estimated that the level of definition for the Interconnected Island Option was between 5% to 10% and that it was less than 5% for the Isolated Island Option

- Noted several issues that could cause upward pressure on the cost of the Interconnected Island Option, including low estimates for the transmission line, the potential requirement to increase the reliability level of the transmission line, the cost of observing North American Electric Reliability Corporation (NERC) standards and possible costs associated with the conditions of environmental approval
- Noted that Nalcor had declined to create a reserve for strategic risk contrary to its consultant's recommendation, arguing that risks had been reduced and would be offset by the benefits of the FLG, which had not been included in the DG2 analysis
  - Despite saying they would revisit this recommendation at DG3, Nalcor did not include a strategic risk reserve
- Described Nalcor's Power Purchase Agreement model, and its use for repayment of the cost of the Project instead of the normal utility approach, which is the Cost of Service model
  - As noted earlier, Nalcor chose the PPA model in order to avoid the shock caused by a sudden drastic increase in rates—estimated at the time to be $214 per MWh with COS, versus $76 per MWh with the PPA—which would lead to a rapid reduction in electricity use
- Noted that some presenters raised issues at the PUB hearings about the decision to use the PPA model, including about its "take or pay" nature
  - As discussed earlier in this Report, using the PPA required NLH to buy the energy from Muskrat Falls regardless of whether customers needed it or not, which

could pose risks to customers in the event that the load proves to be significantly lower than forecasted

- Stated that MHI found that the Interconnected Island Option had a lower CPW value than the Isolated Island Option, based on the feasibility level of the information and notwithstanding the gaps that were identified; the PUB did not disagree with this conclusion but was of the view that the DG2 CPW analysis did not form an adequate basis upon which a determination could be made about which was the least-cost option
- Listed sensitivities performed for the PUB Review and quoted from various presenters about the risks of the Project and Nalcor's efforts to mitigate them
- Commented that risk is a factor in any generation planning decision, which is magnified in this case by the large scale of the Project and the long forecast period
- Found that Nalcor was able to demonstrate that it had undertaken a comprehensive assessment of the risks associated with the Interconnected Island Option and was putting the necessary processes in place to mitigate them
- Found that the sensitivity analyses, however, demonstrated significant risks still existed in relation to load, fuel and cost estimates
- Noted that the preference for the Interconnected Island Option would be eliminated by any of the following circumstances: 44% lower fuel costs, 50% increased capital cost, or 10% increased capital cost plus the closure of the Corner Brook Pulp and Paper mill
- Recognized Nalcor's ongoing work to enhance Project definition from DG2 to DG3, noting that $82.8 million had been spent from November 2010 to December 2011, and that a further $12 million to $15 million per month was forecasted to be spent until DG3; the plan was that all the studies, forecasts and inputs into the CPW analysis would be updated by June 2012 for DG3

- Cited Cabot Martin, David Vardy and Ronald Penney, who believed that it was not possible to provide a least-cost recommendation based on DG2 cost estimates and a Class 4 AACE estimate
- Recognized that NLH's industrial customers, who jointly presented to the PUB, were also of the view that the areas of concern raised by MHI in its report should be addressed in a transparent and accountable manner before DG3
- Provided greater detail on some of the gaps and risks in Nalcor's work that MHI had identified, particularly Nalcor's rejection of MHI's recommendation that a 1:50-year return period for the transmission line reliability was inadequate and should be upgraded to at least 1:150-year; the PUB stated that the deficiencies related to power system reliability needed to be addressed by Nalcor in a meaningful way if the Project was to be sanctioned

GNL Criticism of the PUB Review

GNL was critical of the PUB's response to the Reference Question. On April 2, 2012, it issued a press release expressing its disappointment with the PUB Review and announcing that GNL had retained MHI to provide an external and independent analysis of the DG3 information prior to any decision on whether to sanction the Project. In this press release (P-00727), Premier Dunderdale is quoted as saying:

> I am disappointed that after nine months, in excess of $2 million spent, and the PUB having access to thousands and thousands of pages of documentation, that they have chosen not to fulfill their responsibility as it relates to the terms of reference for their review to determine whether Muskrat Falls is the least-cost option to respond to our future power needs. This is especially puzzling given that others have been able to use the same information available to the PUB to assess whether or not the development represents the least-cost option. (p. 1)

In the House of Assembly, Premier Dunderdale stated that she was puzzled and disappointed by the Review, and that the PUB had "walked away from its responsibility." She also asserted that the PUB's mandate had always been to conduct its work for the Review based on DG2 estimates and that it did not communicate to anyone that it required DG3 numbers to answer the Reference Question.

I find that the Reference Question did not make specific reference to the time period or level of detail of the cost estimates. The PUB had advised Nalcor that it required the most up-to-date estimates available in order to adequately respond to the Reference Question.

Ms. Dunderdale has acknowledged that her attitude toward the PUB was influenced by the public and private comments of Mr. Wells. In her testimony, she said: “There were hearsay being reported back about political discussions that the chair was engaged in. And, you know, I did take some of that into account because they were reliable sources” (December 18, 2018, transcript, pp. 60–61).

Mr. Wells’ negative comments about the Project, made directly to politicians and civil servants, may have given GNL some reason to believe that the PUB process was prejudiced, and they also may have provided a basis to reject the conclusions and concerns in the PUB Review. This is unfortunate, for the PUB report contained valuable commentary on the risks associated with the Project that GNL should have taken into account even if it had already decided to continue toward sanction.

In a press release issued on April 3, 2012, Danny Williams, who had resigned as premier 17 months earlier, stated that he was deeply disappointed by the indecisive nature of the PUB’s Review and that prejudicial comments made by the Board Chair during the Review work showed that the PUB was biased against the Project (P-00232). He stated:

> I have never before seen a quasi-judicial body make such negative and prejudicial statements in the middle of a review. It concerned me greatly at the time, but I had hoped those careless comments would not have carried over to the final report. Clearly, those opinions formed the basis of the final document as the board had backed itself into a corner several months ago with such strong statements. (p. 1)

This release also conveyed Mr. Williams’ concern that the PUB had given great weight to “the personal opinions of former bureaucrats and academia, while ignoring the world-class experts at Nalcor.”

In an interview on CBC television on April 7, 2012 (P-00728, p. 1), Minister Jerome Kennedy was asked if the PUB Review had come back to bite the Government. Minister Kennedy replied, “I think it came back to bite them.” In the CBC report about the interview, he is said to have “chided the PUB for not understanding what it [had] been asked to do, including working with cost estimates that it knew would not be final projections.” The report also quotes Minister Kennedy as saying: "It just showed a lack of respect for the process on their part, a failure to comply with their statutory mandate."

When Maureen Greene was asked at the hearings whether, in her view, the PUB failed to comply with its statutory mandate, she replied: "Absolutely not. They struggled to the very best of their ability based on the information that they had to conduct a fair and impartial, transparent process and to provide a report that would adequately address the question" (October 24, 2018, transcript, p. 64).

In her testimony, Darlene Whalen, a PUB Commissioner at the time, stated that she interpreted the public comments of Jerome Kennedy as a public expression of non-confidence in the PUB. After hearing these comments, Ms. Whalen testified that she packed up her office in expectation of being fired. She described it as "a really low point in my time at the Board" (October 25, 2018, transcript, p. 41).

Mr. Wells provided the following comment on the response of GNL: "I think they expected us to somehow give them the Public Utilities Board Housekeeping Good Seal of Approval. That's what they expected we would do. And when we did not do it, they got nasty" (October 25, 2018, transcript, p. 75).

I accept that Mr. Wells' public comments on the Project during the PUB Review process were ill-advised and ill-timed. However, after reviewing the testimony of Darlene Whalen and Maureen Greene, I am satisfied that Mr. Wells' public comments did not lead to a biased report. I find that it was entirely reasonable for the Board to conclude that it lacked the necessary information and details required to appropriately respond to the Reference Question. If GNL had wanted a proper review, it should have recognized this.

Although GNL had stated that it was crucial that the PUB review be completed in time for the spring session of the House of Assembly, it is important to note that the debate did not actually take place until December 5, 2012, at which time there was a two-hour debate on a private member's resolution in support of the Project. GNL was aware that the PUB needed more time to properly complete its work, but it denied the PUB its reasonable request for a further three-month extension. I find that GNL's sense of urgency was based primarily on pressure from Nalcor, which was pushing for Project sanction. It is clear that GNL succumbed to Nalcor's pressure.

If GNL had been committed to discharging its oversight role in a responsible manner, as was expected by the public, it would have recognized the importance of insisting that

Nalcor have substantially more design work completed and more accurate cost and risk estimates prepared before sending the Reference Question to the PUB.

Furthermore, Nalcor's insistence that it would not provide any information on cost and schedule beyond DG2 estimates eliminated any real possibility that the PUB would be able to answer the Reference Question.

In my view, the PUB's decision on the Reference Question was reasonable and justified in the circumstances. I conclude that GNL believed that the PUB should have simply rubber-stamped GNL's preference for the Interconnected Island Option.

THE MHI REPORTS

As already noted, both the PUB and GNL, in separate contracts, retained Manitoba Hydro International to provide expert advice on various aspects of the Project. MHI produced two reports: the first (delivered to the PUB on January 31, 2012) was based on DG2 information; the second (delivered to GNL on October 26, 2012) was based on DG3 information.

The PUB considered the first MHI report when it concluded that it could not determine, on the basis of the information provided by Nalcor, whether the Project represented the least-cost option when compared to the Isolated Island Option (P-00052).

MHI's second report, delivered to GNL just under eight months after its first report was prepared, was based on more up-to-date information. It was presented as a cornerstone for GNL's decision to sanction the Project. A press release issued on December 17, 2012, by the Executive Council and the Department of Natural Resources stated that the Project had been "endorsed" by MHI (P-00066):

> Muskrat Falls has been endorsed by a series of renowned independent energy experts including Manitoba Hydro International (MHI), Navigant Consulting, Dr. Wade Locke, and Ziff Energy Group of Calgary. In October 2012, the province released the project's Decision Gate 3 cost estimate and the findings of a report conducted by MHI. The report confirmed the engineering, costs, and project planning completed by Nalcor and affirmed Muskrat Falls as the least-cost option for electricity generation in the province. The report included the most up-to-date information on load forecasts and cost estimates including capital costs, operating costs, financing costs, fuel and interest. (p. 1)

MHI's work for the PUB was limited by time constraints and delays in document disclosure by Nalcor. Delivered on January 31, 2012, the first MHI report assessed only the work that had been completed by Nalcor for DG2. In the report for GNL of October 26, 2012, however, MHI stated (P-00058):

> MHI completed its analysis of both the Muskrat Falls and Labrador-Island HVdc Link, identified as the Interconnected Island option and the development of the various power units on the Island, identified as the Isolated Island option. MHI has found Nalcor's work to be skilled, well founded and in accordance with industry practices. Both options have increased substantially in cost from prior estimates released in November 2010, however, the Interconnected Island option continues to have a lower present value cost given the full range of sensitivity analysis and inputs provided by Nalcor to MHI.
>
> . . .
>
> **MHI Recommends**
>
> Given the analysis that MHI has conducted based on the data and reports provided by Nalcor, MHI recommends that Nalcor pursue the Interconnected Island option as the least cost alternative to meet future generation requirements to meet the expected electrical load in Newfoundland and Labrador. (pp. 80, 83)

The scope of MHI's review for GNL that resulted in that October 26 report was significantly narrower than was communicated to the public by GNL. Further, the execution of that narrow scope of work by MHI was not as thorough as I would have expected, given the risks that MHI itself had highlighted in its report for the PUB. The public was informed that MHI had been retained to provide a thorough and objective review. This is not what happened.

For its first report, MHI was hired by the PUB as an expert advisor. MHI's scope of work, described in its contract with the PUB (P-00547), was:

> (a) A review of all previous work performed by consultants and others related to the Projects and the Isolated Island Option which are necessary for the Consultant to perform the Services. . . . ;
>
> (b) A comprehensive review of the Cumulative Present Worth (CPW) analysis of the Projects and the Isolated Island Option to enable the Board to identify the least-cost alternative;
>
> (c) Preparation of a final report . . . ;

> (d) Provision of ongoing support to the Board in the preparation of its report to the Government of Newfoundland and Labrador… (pp. 5–6)

As set out earlier, MHI's report for the PUB was initially scheduled to be completed by September 15, 2011. MHI was unable to meet this deadline in large part because Nalcor's disclosure of documents to MHI was occurring more slowly than had been expected within the time constraints for the PUB Review. MHI expressed frustration with this delay.

In its final report for the PUB, dated January 31, 2012, MHI stated that "Nalcor's work and that of the consultants they engaged is well-founded and generally in accordance with industry practices as of DG2 with certain significant exceptions as noted in these key findings" (P-00048, p. 10).

The qualifications in MHI's report are worthy of consideration, in light of later events. In particular, the points discussed below are significant.

Although MHI noted that "a detailed analysis . . . confirms that the load forecast has been performed with due diligence and care," it added the following qualifications (P-00048):

> - The domestic forecast methodology chosen was acceptable but consistently under-predicted future energy needs at a rate of 1% per future year
> - The best utility practices for forecasting future energy needs would incorporate end-use modelling techniques rather than econometric modelling techniques
> - Any large changes in the load would have a significant impact on the CPW (pp. 10, 17)

On the issue of reliability, MHI observed that "a probabilistic adequacy study that includes transmission considerations for comparison of the reliability of the two options has not been performed by Nalcor" (P-00048, p. 51). In its view, such a study would have made risk analysis more understandable.

As referred to earlier, on the reliability return of the transmission lines MHI reported (P-00048):

> ***Design Loading Criteria –*** Nalcor has selected a 1:50-year reliability return period (basis for design loading criteria) for the HVdc transmission line, which

> is inconsistent with the recommended 1:500-year reliability return period outlined in the International Standard CEI/IEC 60826:2003 with Canadian deviations in CSA Standard CAN/CSA-C22.3 No. 60826:06, for this class of transmission line without an alternate supply. In the case where an alternate supply is available, the 1:150-year reliability return period is acceptable. In this latter scenario, Nalcor should also give consideration to an even higher reliability return period in the remote alpine regions. MHI considers this a major issue and strongly recommends that Nalcor adhere to these criteria for the HVdc transmission line design. The additional cost to build the line to a 1:150 year return period is approximately $150 million" (pp. 13–14).

In summary, MHI's January 2012 report for the PUB supported the view that the Project was the least-cost option, but not in a definitive or absolute manner. In its subsequent report to GNL, delivered in March 2012, the PUB commented that "the gaps identified by MHI in Nalcor's analysis as set out above have the potential to significantly impact the project definition and costs for the Interconnected Option," and that "the information which was made available during the review was considerably less detailed and comprehensive than the information that Nalcor has today and will have at Decision Gate 3" (P-00052, p. 5). I would have been surprised if the PUB had concluded that MHI's findings provided an adequate and reasonable basis for deciding that the Interconnected Island Option was the least-cost option.

The PUB delivered its report to GNL at 10 p.m. on Friday, March 30, 2012. Premier Dunderdale, Minister Kennedy, GNL officials and Edmund Martin met the following Sunday morning, April 1, 2012, to discuss it. At this meeting, it was decided that GNL would approach MHI to discuss a review of the DG3 cost estimates and other information. Minister Kennedy's notes from that meeting indicate that "we decided to hire the same experts PUB went to" (P-01237, p. 1). This proposed review by MHI was initiated without a competitive process.

Charles Bown and Jerome Kennedy did not express any reservations or concerns during the April 1 meeting about the advisability of hiring MHI. At the hearings, Mr. Bown testified (December 5, 2018, transcript):

> The context of any discussion that we would have had is that, given the time pressure that was presented to us, that if we were going to do a review of DG3—which was necessary, because work on DG2 had been done, it would be—it wouldn't—I guess the view of the government would be that it's incomplete if you only had it—sanction work done on DG2 and not on DG3.

> And that the most appropriate consultant to do that is one who was fully—well-versed in the project and could—after having done all the background work and done the due diligence and have an understanding—is one who is best suited to do the next piece of work. (p. 107)

It is clear that both GNL and Nalcor felt that they were under a time pressure to have the review completed in order to meet the Project's schedule targets. Mr. Bown testified that the message from the Premier's Office on April 1 was to ensure that the proposed review by MHI was "a process whereby whatever you're going to do you get it done on that time" (December 5, 2018, transcript, p. 114).

After the April 1 meeting, Mr. Bown emailed Paul Wilson of MHI stating: "I am interested in a conversation with you to discuss next steps on Muskrat Falls" (P-00259, p. 2). Not having received a reply, Mr. Bown asked Gilbert Bennett if he could contact Mr. Wilson and put them in touch. Mr. Wilson contacted Mr. Bown the same evening (April 1), stating that they would speak the following day. Mr. Wilson testified that he had no prior knowledge that MHI would receive any further requests for work on the Project.

When the PUB learned that MHI had been contacted by GNL to discuss another proposed review, it had concerns about the professional ethics of that action, since the PUB and MHI had not yet formally ended their own engagement. Darlene Whalen, who is a registered Professional Engineer, testified that "from a professional ethics concern, you just don't leave one client and go work for another client and do the same work" (October 25, 2018, transcript, p. 38).

After intervention by GNL, Paul Wilson wrote to the PUB on April 4, 2012, requesting permission for MHI to enter into a contract with GNL. He acknowledged that "any contractual engagement with a third party on a related study may be construed as a conflict of interest with the Board" (P-00602, p. 1). On the same day, Premier Dunderdale contacted PUB Chair Andy Wells, whose handwritten version of the conversation is as follows (P-01619):

> Dunderdale warned me that "I am fed up with the Board. I have had enough." Fred Martin was trying to interfere with govt's decision to hire MHI. She warned me to put a stop to it right away. I advised her that this was in our opinion—an ethical issue arising from MHI decision to enter into a contract re: Muskrat Falls without informing the Board which has initially engaged MHI on the issue—that this involved Professional Ethics for Professional engineers in Manitoba/Nfld. She told me that there were no ethical issues and for the Board to cease interfering in. I told her that I would deal with it. (p. 1)

Ms. Dunderdale testified that while it was unusual for her, as Premier, to make a request like this, she did so because she was asked to get the letter released from the PUB as soon as possible so that the DG3 review could begin. In his testimony, Mr. Wells characterized Ms. Dunderdale's tone in this telephone conversation as menacing, threatening and angry. When she testified, Ms. Dunderdale denied Mr. Wells' description of her tone and stated: "I am not going to become part of Andy Wells' parade" (December 18, 2018, transcript, p. 64).

On or before April 10, 2012, the PUB sent an undated letter to MHI that officially concluded its engagement by the PUB and granted MHI permission to enter into a new contract with GNL. This letter also stipulated that MHI was to observe its ongoing professional ethical obligations to the PUB.

Determining MHI's Scope of Work

The development of MHI's scope of work for its report for GNL is worthy of consideration.

On April 2, 2012, Mr. Bown prepared a draft scope of work for the proposed engagement. He sent it to Gilbert Bennett and to Donald Burrage, Deputy Minister of Justice. Mr. Bown's draft scope included a comparison of the Isolated Island and Interconnected Island options. Mr. Burrage replied, "The Minister did indicate (and brian [Brian Taylor, the Premier's Chief of Staff] agreed) that we have "moved on" from the least-cost option question, so item 1 may not be where gov is. Rather a due diligence on the DG3 numbers" (P-00259, p. 1).

On April 3, 2012, MHI's Paul Wilson sent Mr. Bown his own draft of the scope of work that MHI would perform (P-00741). His proposal was that MHI would review all work completed for DG3 and provide a "reasonableness" assessment of all inputs into the CPW analysis. It also contained an option for a review of the following: the integrated financial forecast (including sensitivity analysis for cost overruns and fuel prices), the impact of sales of excess electricity and the FLG. Furthermore, his draft listed these other items:

> xi. Risk Analysis review. Review Nalcor most recent risk analysis assessment for gaps, suitability to task, and appropriateness of reserve margins for cost estimate contingency.

Information required:

- Strategic Risk Assessment Updated Report, and Westney update if available. (p. 5)

Mr. Bown sent this draft scope to Nalcor for comment. On April 4, Paul Harrington, Project Director, sent back the following comments (P-01178):

> In order for this to be performed in the time available it has to be focussed on what is needed, we do not want to have MHI tell us about reliability and NERC adn [*sic*] return periods, the Basis of Design is fixed and we should not invite commentary on that—MHI should focus on the updated CPW analysis using updated numbers. This has to be an apples to apples comparison so the expansion plan used in this review has also to exclude the Maritime Link as per the DG2 review. This will make this review more straightforward and achievable in the timeframe-
>
> The DG3 review will be later when the expansion plan is complete and all other DG3 inputs available.
>
> We must get MHI here in St John's to do the work and not have IR's flying back and forth—these will only go public. MHI should work directly with us thereby avoiding a lot of papaerwork [*sic*] and we should compress the schedule to a couple of weeks when we have the data. Unless this scope is controlled we will have a repeat performance with the same "experts" with the same opinions. (p. 1)

Later, on April 4, 2012, Brian Crawley of Nalcor emailed Mr. Bown about the proposed scope of work. He stated: "I understand Ed was trying to reach you on this. We are still working it but do have major concerns with what has been proposed. Will be in touch" (P-01236).

On April 6, 2012, Edmund Martin, Brian Taylor, Robert Thompson, Glenda Power, Charles Bown and Jerome Kennedy met to discuss MHI's scope of work for the DG3 review. Mr. Bown produced Mr. Wilson's draft. Mr. Bown testified that Nalcor's position was that, for time reasons, a risk review could not be done.

GNL wanted to have the MHI review done in time for a June debate in the House of Assembly. Mr. Bown testified that "the view that would have been coming from Nalcor at the time was that we can provide you with the DG3 numbers but we won't be able to have the risk assessment done by that time" (December 5, 2018, transcript, p. 117). This view was accepted by Minister Kennedy and the GNL officials who were present at the April 6 meeting. In order to meet GNL's timeline, it was agreed that assessing strategic risk would be removed from MHI's scope of work.

Ms. Dunderdale testified that she could not recall whether Brian Taylor or Glenda Power, her Director of Communications at the time, had briefed her about the April 6 meeting and the decision to delete any review of strategic risk from MHI's scope of work. Ms. Dunderdale was asked whether she felt the same way as Jerome Kennedy, who had testified that he considered it alarming that MHI had not completed a review of strategic risk. She responded with this testimony (December 17, 2018, transcript):

> I don't find it alarming per se; I wish that they would have included strategic risk—absolutely. But I have to tell you, Mr. Learmonth, I had confidence in Nalcor. And I still have confidence in Nalcor. I'm under oath here; I'm gonna speak the truth.
>
> So somebody is gonna have to show me that, you know, that the contingent risk hasn't been tested, at least within Nalcor. And, you know, contingent risk is included. And they've come to me and told me that risk is mitigated. And I know that I have a scale that I can work with in my own head in terms of if we have overruns—what they might look like. And I also have the assurance of what the total benefits are in terms of Nalcor—what we're gonna spend, what we're gonna earn, relatively speaking. And can we afford this project, and can ratepayers afford this project, and can I go forward and say that, as honestly as I'm saying it here today, to the people of the province?
>
> And the answer was yes to all of it. (pp. 86–87)

Robert Thompson, who attended the April 6 meeting, testified that he had no recollection about why strategic risk was removed from MHI's scope of work. He stated that he first learned about the issue when reading the report prepared for the Commission by Grant Thornton (November 14, 2018, transcript, p. 67).

Mr. Kennedy testified that he was surprised that a group as professional as MHI did not bring the significance of the review of strategic risk to GNL's attention, if it was something that was very important (December 3, 2018, transcript, p. 32). Regarding the removal of strategic risk from MHI's scope of work, Mr. Kennedy said: "[I]t's not consistent with what I was attempting to do but I do accept that it was done and that Mr. Bown—there's reference to the notes which indicated it was—it appears to have been discussed with various ministers and/or officials. Yeah" (December 5, 2018, transcript, p. 49).

The removal of an assessment of strategic risk from MHI's scope of work was of great significance, because this risk category represented the potential for cost overruns of hundreds of millions of dollars, which GNL would be responsible for covering.

The significance of this is further amplified by Edmund Martin's decision not to allow any quantification of strategic risk in the Project cost estimate.

I conclude that no one in GNL understood the significance or consequences of allowing the review of strategic risk to be removed from MHI's scope of work. Nalcor, however, was fully aware of the consequences of the removal of the assessment of strategic risk from the MHI scope of work, but it did nothing to ensure that GNL was aware of these consequences. Based on Edmund Martin's evidence regarding the funding of strategic risk for the Project, I conclude that he was of the view that it was not necessary for GNL to understand the significance of this removal. This was a breach of the duty that Nalcor owed to GNL.

GNL made additional changes to MHI's scope of work beyond this deletion.

By April 9, 2012, the PMT had not received an update on MHI's scope of work. Brian Crawley of Nalcor wrote the following to Gilbert Bennett: "Ed asked us to hold off on the MHI's scope of work while he worked it with the Province. Have you heard anything on this since? Can we touch base with him today to see if there has been any progress? If we don't help progress the scope it will be done in isolation of us, which might result in the review reflecting MHI's original proposal as opposed to what is actually needed" (P-01179).

On April 12, Mr. Crawley sent Mr. Harrington's April 4 edited scope of work to Charles Bown, stating: "I understand you have been discussing this with Ed. Paul and I discussed it earlier today. We understand this is to be essentially a validation of the least-cost alternative and a due diligence update from the work they have already conducted. Pls. advise" (P-01180, p. 1).

Later that day, Mr. Wilson sent his revisions to the scope of work to Mr. Bown. This version was similar to his first draft but the level of detail for each item was condensed. In addition, a bullet for "new material related to wind farms" was added. It appears that the inclusion or deletion of strategic risk had not yet been discussed with MHI because a strategic risk review remained part of this draft. As well, the option of reviewing Nalcor's Integrated Financial Forecast was mentioned (P-01527, p. 6).

MHI's Paul Wilson and Allen Snyder travelled to St. John's to attend an April 17 meeting with Nalcor representatives as well as Mr. Bown and Walter Parsons of the Department of Natural Resources (P-00261). Following two days of meetings, Mr. Wilson sent Mr. Bown a revised draft scope of work on April 19, writing (P-00742):

> Hello Charles, it was a pleasure to meet with you and Walter over the last two days. As a result, we have gained a better understanding of the project constraints, goals, and inputs for this important review project. Al and I have revised the scope of work which now captures all the important elements required and factors in the data availability and schedule. We have also removed the items that do not require our involvement, in particular the power system reliability review, Muskrat Falls Hydrology review, and the detailed HVdc converter station review. (p. 1)

Although not noted in the cover letter quoted above, the proposed review of strategic risk had also been removed from the scope of work. In addition to the revisions in MHI's April 19 scope, the proposed deadline for completion of MHI's final report was changed to July 31, 2012.

In a news report by radio station VOCM on April 26, 2012, the following statement was attributed to Premier Dunderdale: "She says MHI's work on Decision Gate Three numbers will not be completed until July or August. That information needs to go into the hands of the opposition, and that's when the debate in the House will happen" (P-01246).

The April 19 draft scope of work was received by Nalcor on April 20, 2012. Even though the proposed review of strategic risk had been removed, Mr. Harrington was still not satisfied and felt that the proposed scope was too invasive. He also expressed concern about the process MHI would follow (P-01181):

> My first reaction is they still do not understand.
>
> The critical issue for me is the MHI requirement for information to be provoided [*sic*] to them. This is wrong, and is an IR in reality MHI should meet with our team and review the data and documentation not have it all sent to them They are in auidit [*sic*] mode and not review mode. (p. 1)

At the hearings, Mr. Harrington testified about these points (November 20, 2018, transcript):

> Well, my concerns were we—you know, the project team was under a lot of, you know, pressure at that point in time to get deliverables done. I'd seen how it worked previously under the PUB requirement, and you know, that was a long drawn out effort. Information requests were submitted, they would be dealt with within the team and given back to the PUB and then back to MHI. In this situation, what I wanted to do is try and short circuit that type of review so that we would do it, basically, across the table with each other. So we'd have the documentation available to them, so they could be presented with it so that we'd cut out all of that long, drawn out, backwards and forwards with information request, because information requests can sometimes get

> misunderstood and misinterpreted. So my view at that point in time was this will be more efficient if we do it face to face. (p. 10)

Mr. Harrington made edits to the April 19 scope of work and sent them to Brian Crawley on April 26, 2012. In his comments, Mr. Harrington was emphatic that MHI's work should be considered a review, not a technical audit (P-00813). He further expressed that MHI should not be allowed to "walk away" with drawings, data and information. Mr. Harrington changed all listings of "information required" to "information to be made available during the review which is to be carried out in St. John's." He also deleted most of MHI's listed outcomes including, for example, identification of material gaps in design documents. These items were replaced by specifying that MHI report on the "reasonableness" of the information about each component used as an input into the CPW analysis.

Mr. Harrington's proposed revisions, which further limited MHI's scope of work, were accepted by Mr. Bown. This is demonstrated by a further draft scope of work that Mr. Bown sent to Mr. Wilson on April 30 (P-00743).

> A high level review will focus on the reasonableness of existing engineering or financial documents used in the development of the CPW analysis including design documents, design studies, material and equipment specifications, cost estimates and schedules. (p. 3)

On May 8, Robert Thompson commented on the April 30 draft scope of work, highlighting wording that he thought "would raise uncertainties about the process" (P-01115). His highlights included these sections:

> The Request for Information process will not be implemented as part of these services, nor will any preparation for public hearings be taken into consideration.
>
> . . .
>
> No new information, data or reports are to be developed by Nalcor for this review to proceed except those already scheduled by Nalcor to meet its prior commitments for Decision Gate 3.
>
> . . .
>
> Information to be made available during meetings with Nalcor to be carried out in St. John's. (pp. 3, 5)

It is apparent that Mr. Thompson was concerned about the optics of this scope of work, given that some of its wording placed significant limitations on how MHI would conduct its review.

On May 14, 2012, Mr. Bown sent the latest draft of the scope of work with his own edits to Gilbert Bennett (P-01528). Mr. Bown had reinstated "information required" and removed some of the phrases that had caused Mr. Thompson concern. Once again, Mr. Harrington pushed back strongly. He was adamantly opposed to giving MHI any authority to request information or to require Nalcor to produce any new documentation for the review. In a May 14 email to Gilbert Bennett, Brian Crawley and Edmund Martin, Mr. Harrington wrote (P-00814):

> I recommend that the wording is put back to as last proposed.
>
> My reasoning being that we should not be preparing specific documentation just for MHI—the review should be performed across the table with us, using the project documents and data in the format they currently exist in. If we go with the wording that MHI have proposed in this last go around it will be similar to the last time with us compiling and producing documentation specific to respond to MHI IR's. I would like to avoid that and get back to a review similar to an IPR where the MHI team meet with our team and have a dialogue, not an audit. (p. 1)

It is clear that there was a conflict between the constraints Nalcor wanted to place on MHI's scope of work and Mr. Thompson's concerns. Ultimately, it was decided that the wording that was preferred by Mr. Bown and Mr. Thompson for the scope of work would be maintained. However, Nalcor's concerns would be addressed by supplementing the scope of work with a letter to MHI outlining the "understandings" that would govern its work, in order to meet the timelines in the contract of services. As a result, a supplementary letter was sent to Mr. Wilson on May 16, 2012 (P-00746). It outlined limitations on the MHI review to ensure that it would not be an arduous process. In accordance with Mr. Harrington's request, it included stipulations that there would be no RFI process, Nalcor would not be required to produce any new reports, and the MHI representatives would meet face-to-face with Nalcor officials to be briefed on certain data.

As can be seen by this sequence of events, Nalcor was successful in pressuring GNL officials to significantly limit MHI's scope of work as well as the authority MHI was given to produce its report—a report that ultimately supported the decision to sanction the Project. The pressure applied by Nalcor was accepted without significant resistance by

GNL, and in particular by Mr. Bown. In fairness to Mr. Bown, it should be noted that his passive acceptance of Nalcor's proposed revisions to the scope of work was in accordance with the mandate that he had received from the Premier. However, delaying the schedule of when the Project would be considered by the House of Assembly—moving it from spring 2012 to December 2012—provided GNL with an opportunity to have MHI conduct a more thorough review including a review of strategic risk, as MHI had first proposed. GNL witnesses offered no reasonable explanation about why it did not take advantage of this opportunity.

The contract with MHI was approved on May 31, 2012 (P-01522). The contract was signed on June 5, 2012, by Minister of Natural Resources Jerome Kennedy and MHI's Paul Wilson (P-00770).

The final scope of work stated that MHI was to review work done by Nalcor since DG2 in preparation for DG3 and assess the reasonableness of the inputs into the CPW analysis for the Isolated Island and Interconnected Island options. "Reasonableness" was defined as following "good project management and execution practices" as well as "good utility practices," recognizing the uniqueness of the isolated system on the Island of Newfoundland (P-00770, p. 8). The level of the review was to be "sufficient for the Consultant to report on whether Nalcor has performed work with the degree of skill, care and diligence required by customarily accepted professional practices and procedures completed in the performance of similar work" (p. 8). It was to be done through an examination of documents and a summary of the documentation reviewed was to be provided in the report. The work would also be carried out through meetings and working sessions with Nalcor, the meeting notes of which were also to be summarized in the report.

MHI was also specifically asked to:

- Review the 2012 load forecasts and report on their reasonableness as a basis for the development of the generation expansion plans and subsequent CPW analysis
- Review the AC integration studies and report on the reasonableness of the results as an input into the CPW analysis
- Review the design, costs and schedule estimates for the Muskrat Falls generating station, the HVdc converter stations and AC switchyards, the transmission line and the SOBI crossing, as well as other changes

to both the Isolated Island and the Interconnected Island options since DG2, and also to provide a report on the reasonableness of each as an input into the CPW analysis

- Validate the CPW analysis results for the base case of both options, and assess and comment on the sensitivity analysis done in connection with the CPW
- Prepare a final report that included: an executive summary, a description of the consultant's review team, a description of the methodology MHI used and a summary of the results of the review that included a discussion of the materiality of MHI's observations, recommendations, and steps taken by Nalcor to address such matters

The work done by MHI was not to be a high-level review, certainly not from the expectations of the politicians involved as expressed to the public. However, MHI's approach may well have been different. In an email Paul Wilson sent to Charles Bown dated June 25, 2012, he provided an update on meetings with Nalcor the previous week (P-00750). That email stated: "I believe we have sufficient information for an opinion with a **high level** review." This email went on to report that meetings on load forecast went well and that Nalcor had provided us with "summary documents, Single Line Diagrams, Mini specifications, schedules and **high level** cost estimates when we requested them" (emphasis added in both quotes).

In a later email on August 10, 2012, Mack Kast, on behalf of MHI, prepared several questions for discussion for upcoming meetings with Nalcor that were to begin on August 15 (P-00819). These questions included the following:

> Please provide a high level reconciliation of the CPW for each of the two Options between DG2 (prior report) and DG3 (current update).
>
> Please identify a likely range by which you believe the Newfoundland/Labrador Load Forecast could vary looking into the future and conduct a CPW sensitivity around these ranges.
>
> Please provide the source document for the Fuel Forecast (#2 and #6 fuels).
>
> What is the basis for the change in unit fuel prices extending from the end of PIRA forecast to 2067?

> Recognizing the probability spread for AACE Class 3 is +30% and -20%, please conduct a CPW sensitivity run for each of the two spreads for the Infeed Option (MF and LIL).
>
> Have the Isolated Island costs been identified to a DG3 level?
>
> Relative to DG2, to what extent were the capex cost estimate increases for MF and LIL for DG3 offset by a reduced level of contingency allowance?
>
> Please provide the derivation of the $65.38/MWh (2010 $) to be paid for power purchases from MF for DG3. Please reconcile this amount to the $76.00/MWh (2010 $) used for DG2.
>
> Please comment on the revised discount rate of 7.0% used for DG3 relative to the 8.0% used for DG2.
>
> Please provide rationale for the 2.0% inflation factor applied to the power purchase cost for the Infeed Option.
>
> Please comment on the reduced Rate of Return on Rate Base from 8.0% (DG2) relative to 7.0% (DG3). Please comment on the impact of the reduced RORB for DG3.
>
> Please comment on the extent to which the Infeed Option contemplates the purchase of power from the Upper Churchill Falls power facility. (pp. 4–5)

In an internal Nalcor email, Paul Humphries commented on Mr. Kast's list of questions as follows: "I guess nobody told Mack that there wasn't an RFI process. There's a couple of weeks work here and I don't think much of [*sic*] has anything to do with their scope of work. I am not in today but I think we need to shut this one down" (P-00819, p. 1).

These comments reflect both the level of work MHI attempted to do, even after the limiting of its scope, to complete its report, as well as the information it was requesting and receiving from Nalcor.

I find that the MHI review was another lost opportunity for GNL to complete a fully independent analysis of Nalcor's work, one that would include a full review of both cost estimates and schedule. It is shocking that GNL did not comprehend that it was absolutely necessary to have a fully independent analysis done, especially considering the conclusions submitted by the Joint Review Panel and the PUB in their reports.

The MHI Report to GNL

On October 26, 2012, MHI submitted its final report: *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options* (P-00058). At the hearings, MHI took the position that its actions in preparing and delivering this report to GNL were proper and appropriate in the circumstances and in accordance with its scope of work. Below is my consideration of this position.

In its final report, MHI recommended that Nalcor pursue the Interconnected Island Option as the least-cost alternative to meet Newfoundland and Labrador's future generation requirements. With the caveat that all of MHI's findings were based on data and reports provided by Nalcor, it found that (P-00058):

- Nalcor's work was skilled, well-founded and in accordance with industry practices
- The load forecasts for the Interconnected Island Option were well-founded and appropriate as an input for the DG3 process
- The AC integration studies had been done in accordance with good utility practice, although opportunities were suggested to enhance system reliability during the detailed design
- The cost estimates and the system estimates identified for the HVdc converter stations, switchyards and electrodes were reasonable as inputs into the CPW analysis
- The structures and routes for the transmission facilities were "cost-effective considering the terrain, route and climactic loading expected" (p. 52) and that the cost estimates for the transmission line were within AACE Class 3 accuracy range
- The cost of the SOBI crossing was reasonable and equally likely to decrease as to increase
- The Project schedule, which planned to achieve first power in July 2017, was reasonable and consistent with best practice; MHI noted that a few areas would be challenging but that the discussions with the members of the PMT made it apparent that they were well aware of these risks and were taking measures to manage them
- The cost estimate for the Muskrat Falls generating station was a Class 3 estimate and therefore reasonable for DG3, noting that a contingency of 9% was reasonable because there was fixed pricing in place for approximately 25% of the work

- The Labrador Transmission Assets cost estimate was reasonable and consistent with best practice and that its contingency of 9.1% was reasonable "when combined with conservative inputs on labour and indirect costs" (p. 59)
- The overall Lower Churchill Project design schedule and cost estimates were consistent with good utility practice and sufficiently detailed to input into a CPW analysis and to support Project sanction
- The load forecasts and updated cost estimates for each of the components of the Isolated Island Option were reasonable and suitable to be used as inputs into the CPW analysis
- Nalcor's CPW analysis indicated a strong preference for the Interconnected Island Option ($2.4 billion) based on the inputs and sensitivity analysis presented by Nalcor; MHI noted that a 25% cost overrun would still result in a strong preference for the Project and that "there is an equal probability the capital costs would decrease as well as increase" (p. 79)
- The monetization of excess power would generally improve the preference for the Project, as would the connection with the North American grid, although MHI noted that these topics were outside its scope of work

Examining the sequence of draft reports leading to the final version reveals two tendencies: the removal of statements expressing concerns about various aspects of Nalcor's work, and the inclusion of statements perceived to be agreeable to Nalcor, even on points that MHI (or some of its employees) disagreed with. For example, a September 19 draft report reveals significant revisions in tracked changes, most notably the complete removal of the bibliography and references to specific documents provided by Nalcor, despite the fact that MHI's final scope of work required a summary of the documents that it reviewed (P-00773). On this point, Mr. Wilson testified that Nalcor had raised objections because some of the documents were confidential or commercially sensitive and so should not be mentioned in the MHI report. Mr. Wilson testified that he discussed this with Charles Bown, who agreed that the issue could be resolved by simply removing the bibliography and that the suggestion to do so came "probably from Nalcor" (October 29, 2018, transcript, pp. 65–66).

Another notable example in the September 19 draft report is this (P-00773):

> MHI also recommends that Nalcor be cautioned regarding the contingency levels in their estimated costs as there are opportunities for unexpected increases. Nalcor has current contingency levels in their estimate for the Labrador Island HVdc converter stations that are below industry norms and therefore should be re-evaluated. Any additional contingency allocated for . . . HVdc converter stations at levels following industry norms would not alter the outcome of the Interconnected Island option in favour of the Isolated Island option. (p. 14)

Mr. Wilson testified that he did not know why or who had deleted this paragraph from subsequent drafts of the report (October 29, 2018, transcript, p. 64).

Generally, when asked about other changes to the draft reports, Mr. Wilson and the other MHI witnesses were unable to offer any convincing explanations for the changes. They testified that, for the most part, they could not recall why such changes had been made nor who authorized them.

There were also significant changes in the draft MHI reports that were related to the critical matters of contingency and cost estimates. The first draft report, sent on August 2, 2012, stated that "consideration should be given to the relatively low contingency remaining in the estimate" and that the cost and schedule were sufficiently detailed and comprehensive to support a DG3 decision "other than the contingency factor" (P-00754, p. 59). These phrases were removed and did not appear in any subsequent drafts.

As another example, MHI wrote in its September 21 draft that a contingency allowance of 9% for the generating station was on the low side (P-00774, p. 65). The email that accompanied the next draft, which was sent by Mr. Wilson to Mr. Bown on September 25, contained the following notation (P-00761):

> Hello Charles, as requested here is a version marked draft with today's date. All markups have been removed and the copy is clean. The following revisions to pages 55 and 56 items are
>
> "The Muskrat Falls Generating Station project contingency in the Decision Gate 3 estimate is 9.0%, but maybe higher with allowances if required. This has been discussed with the Nalcor project team, and the Nalcor project team believes that the current Decision Gate 3 estimates input detail and conservative assumptions justify the chosen contingency amount. Nalcor has noted that there is fixed pricing in place for approximately 25% of the project value, thus the 9% contingency is reasonable for Muskrat Falls Generating Station."

> and
>
> "The LTA Decision Gate 3 estimate includes a 9.1% contingency which is reasonable when combined with conservative inputs on labour and indirect costs."
>
> Good luck! (p. 1)

Evidently, Mr. Wilson had discussed these changes with Mr. Bown and one or more Nalcor representatives, and it had been agreed that MHI would change the wording to reflect more favourably on Nalcor's work.

A further blatant example of MHI's willingness to accommodate Nalcor's requests was the removal of cautionary comments about the 6.7% ($368 million) contingency for the overall Project. Sometime in the period between the preparation of the drafts dated September 19 and September 21, the shaded text (shown below) was removed from the MHI report. It did not appear in the final version.

> **Capital Cost Projections for Muskrat Falls and Labrador Island Link**
>
> Scenarios numbered 5, 6 and 7 reflect variances of capital costs in the order of magnitude of plus 10%, plus 25% and minus 10%. According to an Estimate Accuracy Analysis Report ~~prepared by the Westney Consulting Group, Inc. on June 4, 2012~~ provided by Nalcor to MHI, the engineering and detailed design of the Lower Churchill Project was approximately 40% complete in April 2012. ~~To reach a P50 value of probability, a~~ A contingency of $368 million was ~~required~~ specified for purposes of attaining a P50 probability rating. Accordingly, Nalcor included a contingency allowance of 7% which equates to the required $368 million increment. ~~The projected capital costs, including a contingency and escalation allowance, for the Lower Churchill facility are $6.2 billion.~~ A P50 value implies there is an equal 50% probability the project estimated costs will increase as well as decrease. Given a project level of definition of approximately 40%, the project falls within the range of a Class 2 to Class 3 level according to the AACE Classification System. A mid-range amount of 25% level was applied for purposes of setting an appropriate level for the sensitivity capex variance in the CPW analysis. (markup of deletions in original, P-00773, pp. 93–94)

I conclude that this discussion of contingency and P values was important information that most certainly should have been included in MHI's final report. Based on the testimony of the MHI witnesses, I also conclude that MHI knew the contingency amounts were inadequate. As in earlier examples, however, Mr. Wilson's memory as to why these changes were made was very limited. He testified, however, that Mr. Bown knew that these changes had been made.

A review of each of the drafts of MHI's report culminating with the final version reveals further material edits that resulted in the description of contingency allowances being changed. In the draft report of August 2, 2012, prepared by MHI (P-00754), the following is stated:

> It is noted that the overall Muskrat Falls project contingency in the Decision Gate 3 estimate is 6.7%, which in MHI's experience, is low for this level of estimate. This has been discussed with the Nalcor project team, and the Nalcor project team believes that the current Decision Gate 3 estimates input detail and conservative assumptions justify the chosen contingency amount. (p. 58)

However, in subsequent drafts the wording changed and in its final report, there is no reference to the 6.7% contingency level or that it was low for that level of estimate.

Assessing Transmission Line Reliability

MHI knowingly removed wording that would have reflected negatively on Nalcor's work on the reliability return period for the transmission line. As discussed earlier, in MHI's DG2 report for the PUB, it had considered Nalcor's application of a 1:50-year reliability return period to be "a major issue and it is contrary to best practices carried out by utilities in Canada for transmission line design." In that report, MHI strongly recommended the use of at least a 1:150-year return period (P-00048, p. 66).

In its DG3 report, MHI retained this recommendation but softened the language, stating the upgraded reliability return period was something MHI simply "continues to support" (P-00058, p. 52). This change was intentional and made for political reasons, as confirmed by a draft of the report dated July 2012 (internal to MHI), in which Mr. Wilson commented that "these two paragraphs need to be reworded to be more politically astute and palatable" (P-00752). The paragraphs in question were:

> Nalcor is aware of these additional reliability recommendations, and the decisions made in other provinces considering similar HVdc projects such as in Alberta and Manitoba; however, through its own internal design policy, it has elected to not incorporate them in this project.
>
> By selecting a 1:50-year climatic return, Nalcor only meets the <u>minimum</u> reliability requirements outlined in CAN/CSA C22.3 for high voltage transmission lines. (emphasis in original, p. 12)

It is clear from the evidence that considerations of political astuteness and palatability were always taken into account by MHI in the writing and editing of its drafts and final DG3 report.

MHI concluded that the Project would be the better option "given the full range of sensitivity analysis and inputs provided by Nalcor to MHI" (P-00058, p. 80). This implies that Nalcor's sensitivity analysis was thorough and robust and was endorsed by MHI as reliable. I find, however, that the number of sensitivities performed by Nalcor for DG3 was very limited, and that they were even fewer than Nalcor had considered at DG2. MHI relied on only 10 sensitivities, which had all been prepared by Nalcor. None of them included a combination of multiple variables, such as a decrease in both load and fuel prices (P-00058, p. 75).

Not one of the sensitivities presented in the MHI report came close to showing the cost of the Project exceeding the cost of the Isolated Island Option. However, even the best possible project will have worst-case scenarios that demonstrate how things can go wrong. Pelino Colaiacovo, an expert witness, conveyed this fact in the report he prepared for the Commission (P-04445):

> 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 [to] 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. (emphasis in original, p. 69)

MHI's mandate did not give it the authority to request additional sensitivity analyses, but there is no reason why it should not have communicated to GNL that the range of possible outcomes as presented was remarkably narrow and therefore insufficient. Rather, the MHI report stated that the preference for the Interconnected Island Option was tested by a "full range" of sensitivities—when clearly it was not. In his report, Mr. Colaiacovo stated that: "Good practice for this type of analysis would have included systematic review of all variables critical to the outcomes of each plan, including financial modelling of an extensive number of combinations of those variables, or scenarios. This work was not completed" (P-04445, p. 3).

In his testimony at the hearings, Mr. Colaiacovo pointed out the following (July 17, 2019, transcript):

> What I find curious is that Manitoba Hydro, in the NFAT process, which came about a year after this, themselves ran quite a few scenarios. They started with 81 when they first presented their report, and then developed even more after that. In this instance, in that list that you pointed to just a minute ago, there was only less than 10. There was only about a dozen that were prepared in the Nalcor process. So Manitoba Hydro itself—now this was Manitoba Hydro International, which is the consulting arm of that company as opposed to the corporate arm of the company. But they didn't follow their own consulting arm's practice because they did a heck of a lot more when they ran their own NFAT process. (p. 55)

I agree with Mr. Colaiacovo that it is curious why MHI employed much lower standards for its review of the Project than Manitoba Hydro would normally employ for its own programs. Moreover, stating that a "full range" of sensitivities had been tested indicates that MHI played a part in creating an unwarranted sense of confidence in the Project.

It is clear that the scope of MHI's review for DG3 was significantly more limited than one might expect for a review that would be used to justify, or at least support, a decision as important as proceeding with the Project. A robust analysis of the business case was not performed, since in reality only an unsophisticated and high-level CPW analysis was conducted. The risks of the Project were not examined—particularly strategic risks, which were hidden entirely from the view of both MHI and GNL. I recognize that in April 2012, when the early drafts of MHI's scope of work were being prepared, it was apparent that Westney's work on strategic risk had not been finalized, meaning that MHI could not have carried out a review of strategic risk before the spring session of the House of Assembly. However, after the decision had been made to postpone the House of Assembly's consideration of the Project to the fall of 2012, it should have been readily apparent that there was plenty of time for MHI to conduct a full review of strategic risk.

I find that the review performed by MHI for DG3 was more limited than its review for the PUB with the DG2 estimates. I would have expected a much more thorough review at this stage of the Project's development.

I conclude that if GNL had been serious about obtaining an in-depth review of Nalcor's DG3 work, it would have given MHI full authority to request whatever information it required from Nalcor so that MHI could do a complete and comprehensive review and analysis. It is evident that GNL did not believe that a comprehensive review and analysis was required. It had prioritized expedience far ahead of due diligence and had total faith and confidence that Nalcor's work was as expert and as thorough as it could possibly be.

As for Nalcor's approach to this review by MHI, on June 15, 2012, Paul Harrington emailed other Nalcor personnel with suggestions about how they ought to approach their participation in the MHI review process (P-00816). Mr. Harrington wrote that the desired outcome should be: "A report on the reasonableness of the MF cap cost estimate and schedule as inputs to the CPW—keep this in mind we do not have to go down to a detailed level to pass this test of reasonableness, so avoid going into the weeds on our work" (p. 3). He concluded with:

> We should be respectful, helpful but we should not offer anything outside of the Terms of Reference and Scope of work without internal agreement, if they ask for something then Gilbert, Brian or I will step in if needed. We can let them look at most things at the high level and if they want to burrow down deeper then we shall have to caucus on that. We can play it by ear in the meeting and take the lead as shown above. So only bring along high level documents as indicated above. (p. 3)

Paul Wilson was asked to comment on this statement by Mr. Harrington. He testified: "Nothing really that surprising." He elaborated by saying: "Our scope of work had been reduced from our original submission of scope of work to elements that the Government of Newfoundland would agree with, like between their decision or discussion they've had with Nalcor or their internal needs" (October 29, 2018, transcript, p. 7).

Allen Snyder of MHI testified that Nalcor had indicated that it had received bids for certain parts of the Project and that these bids were favourable. However, he also stated (October 29, 2018, transcript):

> There was certainly some—some work had actually been bid—there were bids in—and Nalcor made note of the fact that the bids were in and that they had a very good idea of the projected costs, and our people were not given the opportunity to review those bids because those were deemed to be confidential to the utility itself. (p. 8)

Mr. Snyder acknowledged that even though MHI had signed a confidentiality agreement, it was refused access to detailed documents and instead accepted verbal summaries by Nalcor representatives. Even so, all three MHI witnesses who testified at the hearings, indicated that they were not troubled by Nalcor's refusal to provide access to some source documents.

I find that Nalcor's efforts to restrict MHI's inquiries and knowledge of relevant information on the Project to a "high level" and MHI's acquiescence to this approach to be improper and indefensible.

The MHI witnesses also confirmed that they had no knowledge of the Westney report, which contained the recommendation that $497 million be added to the cost estimates to cover strategic risk (P-00821, p. 6). Nalcor received the final version of this report on September 20, 2012, more than a month before MHI delivered its final report to GNL. Nevertheless, even after he was shown a copy of Westney's strategic risk report at the hearings, Mack Kast of MHI testified: "I have total confidence in what was put forward, and what we used in the CPW" (October 29, 2018, transcript, p. 12). When asked whether Westney's strategic risk recommendation was relevant to MHI's scope of work, Mr. Kast responded: "It's not for me to decide." Mr. Kast stressed the importance of making a fair comparison between the Interconnected Island and Isolated Island options. I find, however, that a correct and accurate cost estimate was required as an input to the CPW analysis. For this reason, I fail to understand why strategic risk would not have been relevant to the CPW analysis.

Generally, I found MHI witnesses Paul Wilson, Mack Kast and Allen Snyder to be conveniently forgetful and evasive in their answers. On one occasion, Mr. Wilson stated (October 29, 2018):

> We were engaged to review base cost estimates and contingencies in inputs into the CPW analysis, and management and strategic reserves were an

> additional (inaudible) to that, not in our scope of work or study, and that was in the agreement with the Government of Newfoundland in our scope. (p. 10)

He went on to acknowledge that:

> If we had seen this document [the Westney Strategic Risk Report] . . . we would've probably taken a note of it and addressed it in our report at some level. . . . So the government would've been informed. And we—maybe that would've been taken out in the final draft because it is a risk analysis area that wasn't in our scope, but we would've mentioned it. (p. 10)

When pressed in cross-examination, Mr. Wilson admitted that he was angry at Nalcor for failing to disclose certain information.

In an internal MHI email chain, Mr. Kast stated, "I am trying to rein in what the CPW review will be but at the same time, protect our professional approach etc." (P-00744, p. 3). This is one of the factors that supports my conclusion that MHI was aware that its review was anything but thorough or that it provided an adequate basis on which to base a sanction decision.

I conclude that MHI's review of the DG3 information was conducted at a very high level and was superficial in many respects.

MHI knew that its scope of work excluded areas that it had previously identified as being reasonably required for a DG3 review (P-00740). MHI was not obliged to accept the contract with GNL and should not have done so if it thought the scope of work was so restrictive that it would be unable to provide a meaningful review. Assuming that it was reasonable for MHI to accept such a limited mandate, MHI should have made it clear in the text of its report that the review was limited. It did not, and any lay reader of the report would be left with the erroneous impression that the MHI review was comprehensive. It is clear, however, that MHI knew, or ought reasonably to have known, that this was not the case.

During their testimony, the three MHI witnesses were asked to comment on the impact of excluding the presence or absence of strategic risk in their review. Specifically, when asked about whether the $497 million in strategic risk should have been included in the cost estimate, they drew a strong distinction between a cost estimate and the CPW analysis, which they said was the focus of MHI's engagement. Furthermore, they testified that it would be unfair to include strategic risk in an apples-to-apples comparison between the two options, because the Isolated Island Option did not contain anything for strategic risk. They also declined to comment on whether the $497 million for strategic risk should have been reported to GNL.

MHI was not given the time-risk analysis that Westney completed for Nalcor, which estimated that the likelihood of the Project achieving full power in 2017 was a P1, later upgraded to a P3. The MHI witnesses agreed that this information would have been "good" to include in the MHI report but they would not say that they were disappointed that this information had not been provided to them or that it should have been provided to GNL. Mr. Snyder testified that the information given to MHI was provided with good intentions and that the people at Nalcor with whom they had been meeting "would have done their 'darndest' to try to achieve that date [full power by 2017]" (October 29, 2018, transcript, p. 19).

The MHI review was not an analysis of the business case for the Project. Mr. Snyder testified that he assumed GNL or Nalcor would have examined the business aspect of the Project. Maybe so, but MHI did not make its recommendation to sanction the Project conditional on the completion of a business case or on any other analysis.

MHI's position that its mandate was limited to a CPW analysis is inconsistent with its inclusion of positive comments about the benefits of the Project, which were also outside the scope of its work. If MHI believed its scope of work was restricted to the CPW analysis, it should have done only that and also properly qualified its conclusions on all other matters. In reality, the MHI report contained few words of caution about the Interconnected Island Option and nothing in favour of the Isolated Island Option. I conclude that the MHI report was plainly and obviously biased in favour of the Project.

Nalcor's Involvement in the Content of the MHI Report

I am concerned about the level of Nalcor's involvement in the writing of the MHI report and, in particular, about the changes that Nalcor proposed in drafts of the report. I am also concerned about the willingness of MHI to make changes to satisfy Nalcor's requests. I accept that it is not unusual for a proponent such as Nalcor to be given an opportunity to review a draft report to ensure factual accuracy. However, I question the propriety of an independent consultant asking a proponent whether the contents of a report contained "wording acceptable," as Paul Wilson wrote in a communication to Charles Bown when the draft report was being finalized (P-00873, p. 1).

As well, it appears to me that on many occasions, MHI was acting as if it had been retained by Nalcor, not by GNL. It also appears that these practices were condoned by Mr. Bown, who was GNL's main contact person for MHI's DG3 review.

MHI was aware that GNL would rely on its report as a key input in its sanction decision. MHI deliberately avoided making certain statements and findings in the report that could have prompted questions or cast doubt on the adequacy of Nalcor's work, or on the Project budget and schedule.

I conclude, based on the evidence, that MHI's DG3 report was inadequate and lacked independence. While MHI's work on DG3 can be faulted from a professional point of view, I find that the deficiencies in its work were not solely the fault of MHI. GNL and Nalcor approached this review as a means of securing support for the sanction of the Project. They were not interested in obtaining a comprehensive, independent analysis of the Project, its costs or its associated risks, although this is what the public was being told that they were getting.

CHAPTER 8: OTHER ISSUES

THE FEDERAL LOAN GUARANTEE

At the time of Nalcor's negotiations with Emera, which resulted in the signing of the Term Sheet on November 18, 2010, GNL began to develop a strategy for its approach to Canada to secure a loan guarantee that would cover part of the financing costs of the Project. A Briefing Note prepared by GNL's Department of Finance and dated October 7, 2010, stated (P-00970): "There is no formal loan guarantee program available to public authorities within the federal government. Any request for financing assistance through a loan guarantee by a public authority would be *ad hoc*" (p. 2).

On November 12, 2010, Premier Danny Williams wrote to Peter MacKay, a Nova Scotia Member of Parliament who was then Minister of National Defence and also the regional Cabinet member for Atlantic Canada. The letter contained a request for a federal loan guarantee and outlined the case for the Project, its carbon benefits and its significant borrowing requirements. The letter stated, in part (P-00224):

> Due to the significant borrowing requirement necessary to move this phase of the project forward, I am seeking the support of the Government of Canada through the form of a loan guarantee for the generation facilities at Muskrat Falls and the Labrador–Newfoundland transmission link. Given that the federal government's tax revenue will be more than double that of the Government of Newfoundland and Labrador, and the extraordinary benefits that will be created for the entire country, the business case for a loan guarantee is sound.
>
> Following his public commitments in December, 2005, and again in a letter to me in January 2006, I have discussed the matter of a loan guarantee with the Prime Minister on numerous occasions. He has stated his willingness to entertain the loan guarantee provided the Province provides an appropriate level of financial documentation. My government is prepared to provide full access to our economic analysis as soon as an agreement is finalized, which could be any day now. (p. 3)

As stated earlier, Mr. Williams stepped down as Newfoundland and Labrador's premier on November 25, 2010, seven days after the signing of the Term Sheet with Emera, and Kathy Dunderdale assumed the office.

On December 2, 2010, representatives of GNL, Nalcor, Nova Scotia and Emera met with representatives of the Prime Minister's Office in Ottawa. Further meetings were held there on December 14 and 16, 2010. The purpose of these meetings was to explain the concept behind the Project, the Nalcor-Emera deal and the Project's potential national benefits. On December 17, federal Finance Minister Jim Flaherty came to St. John's to meet with Premier Kathy Dunderdale, Natural Resources Minister Shawn Skinner and Finance Minister Thomas Marshall (P-01378).

On March 26, 2011, a federal election was called. At a March 31 campaign rally in St. John's, Prime Minister Stephen Harper announced that a re-elected Conservative Government would provide a loan guarantee for the Lower Churchill Project. Mr. Harper described the Project as "unprecedented." As part of this announcement, Mr. Harper stated that the Project would have to meet three conditions. As reported in the media, the development would be required to (P-01598):

- Be of national and regional importance
- Have economic and financial merit
- Significantly reduce greenhouse gases

On April 4, 2011, Minister Thomas Marshall stated in the House of Assembly (P-00912): "I would like to be friends with the only Prime Minister in fifty years of Confederation that has taken Newfoundland and Labrador's side on a hydro dispute with the province of Québec."[8]

Throughout the spring and summer of 2011, discussions continued among officials from Newfoundland and Labrador, Nova Scotia, Canada, Nalcor and Emera about formalizing an agreement for an FLG. These discussions culminated in a meeting of all parties in Ottawa in August 2011. The representatives at that meeting from Newfoundland and Labrador were Edmund Martin, Charles Bown, Robert Thompson, Derrick Sturge and Auburn Warren (October 31, 2018, transcript, pp. 25–26).

At the hearings, Mr. Sturge testified that Nalcor's vision had been to finalize a Term Sheet for the Project by the summer of 2011. However, discussions stayed at a high level because Canada had not yet engaged a financial advisor or legal counsel and it was unwilling to discuss details until that occurred (October 31, 2018, transcript, pp. 25–26).

On August 19, 2011, the terms and conditions of a Memorandum of Agreement (Memorandum) were signed by representatives of Canada and the governments of Nova

[8] On May 2, 2011, the federal Conservative Government was returned to power with a majority.

Scotia and Newfoundland and Labrador (P-00040). The Memorandum stated that Canada would provide or purchase a loan guarantee for the Lower Churchill River Hydroelectric Projects, namely Muskrat Falls, the Labrador Transmission Assets, the Labrador-Island Link and the Maritime Link.

The Memorandum was brief but significant. It was the first formalized step toward the finalization of the FLG. Mr. Sturge testified (October 31, 2018, transcript):

> So I think this would probably—you know, probably the most important thing that came out of this is Canada set three criteria for the loan guarantee. And you'll see in there in the second paragraph of this page, said: "The Government of Canada confirms the projects collectively"—and the word collectively became—would become very important on this— "collectively have national and regional significance"—so that was now pointing to the—collectively, the projects as a regional thing, not just individually, have "economic and financial merit"—and I'll come back to that one—"and will significantly reduce greenhouse gas emissions."
>
> So there was three key criteria Canada had set, and while they look benign there, they would ultimately shape how the next 18 months would play out on this from here on in. And—you know, and it also sort of described the guarantee, but at that point, it was pretty high level. There was a lot of work yet to be done before we could finalize the guarantee. (p. 26)

A news release announcing the signing of the Memorandum was issued on August 19, 2011 (P-00848). Minister Skinner was quoted as saying:

> Today's signing is a testament to Premier Dunderdale's leadership in getting us to this point with the Lower Churchill Project. . . . This Memorandum of Agreement represents yet another important milestone, and a federal endorsement of the project as we move towards project sanction of the Muskrat Falls development. (p. 1)

On October 18, 2011, Premier Dunderdale, with the approval of Cabinet, provided a commitment letter to Nalcor (P-00868). It stated, in part:

> The government is committed to supporting the development of the Projects as a matter of Government policy of the highest importance, consistent with its *2007 Energy Plan.* To that end, upon the final sanctioning of the Projects, Government's policy will be to revise the framework governing the electricity industry in the Province to align that framework with the requirements of this successful completion of the Projects. (pp. 1–2)

The letter went on to list the commitments that GNL would make, in order to ensure that the Project would be built. They were:

1. Approve the creation of those subsidiaries or entities controlled by Nalcor which are required in order to facilitate the development and operation of MF, the LIL and the LTA, and to ensure Nalcor and existing and new subsidiaries or entities have the authorized borrowing powers required to implement the Projects and meet any related contractual or reliability obligations.

2. Provide the base level and contingent equity support that will be required by Nalcor to support successful achievement of in-service for MF, the LTA and the LIL, in cases with and without the participation of Emera.

3. Ensure that, upon MF achieving in-service, the regulated rates for Newfoundland and Labrador Hydro ("NLH") will allow it to collect sufficient revenue in each year to enable NLH to recover those amounts incurred for the purchase and delivery of energy from MF, including those costs incurred by NLH pursuant to any applicable power purchase agreement ("PPA") between NLH and the relevant Nalcor subsidiary or entity controlled by Nalcor that will provide for a recovery of costs over the term of the PPA and relate to:

    (a) initial and sustaining capital costs and related financing costs (on both debt and equity), including all debt service costs and a defined internal rate of return on equity over the term of the PPA;

    (b) operating and maintenance costs , including those costs associated with transmission service for delivery of MF power over the LTA (as described further in 5 below);

    (c) applicable taxes and fees;

    (d) payments pursuant to any applicable Impact & Benefit agreements;

    (e) payments pursuant to the water lease and water management agreements; and

    (f) extraordinary or emergency repairs.

4. Ensure that, upon the LIL achieving in-service, the regulated rates for NLH will allow it to collect sufficient revenue in each year to enable NLH to recover those amounts incurred for transmission services, including those costs incurred by NLH pursuant to any applicable agreements between NLH, the LIL operating entity and/or the entity holding ownership in the LIL assets, that

will provide for a recovery of costs over the service life of the LIL and relate to:

(a) initial and sustaining capital costs of the LIL and related financing and debt service costs, including a specified capital structure and regulated rate of return on equity equal to, at least, a minimum value required to achieve the debt service coverage ratio agreed to in lending agreements by the LIL borrowing entity;

(b) operating and maintenance costs;

(c) applicable taxes and fees; and

(d) extraordinary or emergency repairs;

and that any entity which is associated with the investment of Emera in the LIL will be treated as a "public utility" under the Public Utilities Act and the Electrical Power Control Act, 1994;

5. Ensure that, upon LTA achieving in-service, the regulated rates for the provision of transmission service over the LTA will provide for a recovery of costs over the service life of the LTA including initial and sustaining capital costs, operating and maintenance costs, extraordinary or emergency repairs, applicable taxes and fees and financing costs (on both debt and equity), including all debt service costs and a defined internal rate of return on equity over the term of any applicable agreement. (pp. 2–3)

The letter concluded with: "The means undertaken to implement these policies and objectives will be at the sole discretion of the Government, but may include legislative amendments, regulatory rulings, and orders under current legislation" (p. 3).

The commitment letter was approved by Cabinet pursuant to a Cabinet paper dated August 31, 2011 (P-00043). The Cabinet paper explained the purpose of the commitment letter, which had been requested by Nalcor to assure Canada, credit rating agencies and potential lenders that GNL would take actions to ensure that the Project proceeded and would generate sufficient cash flow to service the debt involved. The letter was eventually provided to credit rating agencies, Canada and other potential lenders on a confidential basis.

The commitment letter was a key component of the financing process that Nalcor required in order to provide assurance that the Project would be completed and that all Project costs would be covered. It was also needed so that Nalcor could obtain a "shadow credit rating," a confidential unofficial rating that would be given by credit rating agencies.

The support provided by GNL in the commitment letter assisted Nalcor in obtaining an "investment-grade" shadow credit rating, which was necessary to advance discussions with Canada and lenders. Later, for debt financing to be approved, a formal credit rating would be required. Nalcor's plan was to obtain non-recourse loans for the Project serviced entirely by Project cash flows and secured only by the Project assets. This would mean that the lenders would have no recourse against GNL and Nalcor's other assets in the event of default.

James Meaney of Nalcor's Finance division led the process of obtaining a commitment letter from GNL. That process had begun in April 2011 after the announcement by Stephen Harper that Canada intended to back the Project and the Maritime Link with a loan guarantee. One of the conditions formalized in the August 19 Memorandum of Agreement was that the economic and financial merit of the Project and the ML had to be demonstrated. Nalcor's plan to fulfill this condition was to obtain a shadow investment-grade credit rating in the absence of a federal loan guarantee, thus demonstrating that the Project was economically viable on its own merits. In order to secure both the shadow and the formal credit ratings, it was necessary for there to be a guaranteed revenue stream and a commitment that the Project would be funded to completion.

At the hearings, Mr. Sturge testified that without the commitment letter, "We wouldn't have been able to categorically answer 'how's the cost recovery going to work?' and 'where's the equity going to come from?' we needed—so the strength of this letter was really powerful for rating agencies" (October 31, 2018, transcript, p. 27).

Although the commitment letter may not have been a legally binding document, it was nevertheless a promise by GNL that it would provide additional equity to cover any Project cost overruns and that it would structure the province's electricity system in a way that ensured that the cost of the Project would be fully recovered through electricity rates. In particular, the clause committing GNL to providing "contingent equity support that would be required by Nalcor to support successful achievement of in-service MF, the LTA and the LIL" (P-00868, p. 2) has been characterized as a completion guarantee for the Project or even as a "blank cheque" for Nalcor—a phrase that Terry Paddon, who was Deputy Minister of Finance at the time, conceded in his testimony was a fair description (November 5, 2018, transcript, p. 53).

The August 31 Cabinet paper was prepared by the Department of Natural Resources in consultation with the Department of Finance, the Department of Justice and Nalcor. The "financial considerations" section of the paper described, in general terms, the impact of the Province's equity contribution to the Project, which at the time was estimated to be approximately $1.52 billion. Because the Project was classified as an asset, borrowing money funded by the asset was not considered to be an increase in the Province's net debt. However, it could potentially decrease the Province's liquidity, increase debt servicing costs and put a strain on the Province's credit rating, especially in the event of an increase in capital cost and schedule delays.

GNL knew that funding the Project could have a negative impact on its liquidity and credit rating and that it was making a commitment to fund the Project on an unconditional and unlimited basis. Despite knowing this, GNL did not conduct any financial analysis to determine the effects of the increased contingency equity payments on the fiscal position of the Province or the maximum exposure to cost overruns that the Province could afford. Nor did it put in place any system that would have required Nalcor to report Project cost overruns to GNL.

On these points, Mr. Bown testified (December 6, 2018, transcript):

> As others have said here, there was always an understanding that there could likely be cost overruns. But, to the extent of what they would be, I don't think there was—I wouldn't say there wasn't a discussion on it, but there wasn't an assessment done to determine what the outside framework, or outside riverbank, of that would be. (p. 60)

During his testimony, Mr. Skinner was asked what the Department of Natural Resources did to assess the potential for cost overruns. Mr. Skinner's answer was: "I would've assumed that the Department of Finance would've looked at that from their perspective. They would've had the expertise, from my perspective to be able to look at that and make that determination" (November 2, 2018, transcript, p. 25). However, Mr. Skinner later testified that he did not have any communications with the Minister of Finance to confirm his assumption.

The reality is that the Department of Finance did not conduct any such review, so there was no basis for Mr. Skinner's assumption. When Thomas Marshall was questioned about GNL's exposure to contingency equity payments, he stated his confidence in the fiscal position of the Province at the time (November 6, 2018, transcript, p. 52). He also testified: "We had a strong cash position. I think we had enough cash we could have paid it ourselves" (p. 35). When asked whether GNL's exposure to such risks was discussed with Nalcor, he replied: "We would discuss that. That would come up very often as part of general discussion, you know. What do you think? How's it going? How does it look? And Mr. Martin would tell us, you know, about how—what they're doing to try to de-risk the situation" (p. 36).

Similarly, Mr. Bown cited presentations from Nalcor as providing sufficient assurance and certainty about Project costs to allow GNL and its officials to feel comfortable about issuing the commitment letter (December 6, 2018, transcript, p. 23). He further testified: "And they would have given the assurance—trust, again, that, based on the work they had done, based on the amount of engineering they had done—that they had certainty in the costs that they had, and that we were ok to go ahead and issue this commitment letter" (pp. 60–61). It should be noted that at that time, very little engineering and design work had actually been completed for the Project.

The commitment letter did not create an immediate legal or financial obligation for GNL, and for this reason it was perceived as a necessary step toward realizing the Project and as a formalization of plans, not as a risk. Robert Thompson testified: "The signing of this letter was not regarded as a new element of risk, because we saw that it was a part of the overall strategy that we anticipated executing" (November 14, 2018, transcript, p. 52).

In November 2011, with the commitment letter in hand, a delegation from Nalcor and GNL that included Terry Paddon and Charles Bown gave the "Lower Churchill Phase I: Indicative Rating Presentation" to rating agencies DBRS, Standard & Poor's and Moody's (P-00881). In December 2011, these three rating agencies gave the Project positive indicative credit ratings, which were then provided to Canada. The three rating agencies also provided a dozen "core principles" that all parties were required to agree to and incorporate into the Term Sheet for any proposed federal loan guarantee. The core principles were (P-01614):

1. Maximize Ratepayer Benefit
2. Irrevocable and Unconditional
3. Full and Timely Payment
4. Payment not Collection Guarantee
5. Waiver of Defenses from Guarantor
6. FLG Term Matches Term of Loan

7. Enforceable against Canada as Crown
8. No impact on FLG Assignment/Transfer
9. Effective Governing Law Jurisdiction
10. Guarantee Amount
11. Applicable to "Claw Back" Amounts
12. No Fees (p. 8)

The Term Sheet for the FLG was signed on November 30, 2012. This led to sanctioning of the Project in the following month. The Financial Close documents of the FLG were signed on November 29, 2013.

Early Works by Nalcor

At DG2, the target date for Project sanction was October 2011 and the start of early works was scheduled for February 15, 2012. By the fall of 2011, however, the target date for Project sanction had been moved to May 1, 2012, at the earliest, which increased pressure on Nalcor to meet its Project schedule. At the hearings, Jerome Kennedy, who was Minister of Natural Resources during that period, testified that "at that point we were told that Nalcor . . . had to be in there by February 2012 to start early works. That they had to be in there by the summer, that June was the latest in order not to lose a construction year" (December 3, 2018, transcript, p. 23).

In his testimony, Edmund Martin stated:

> So, the project team came to me with the message the schedule's achievable . . . stressed that so that they could identify the key areas; and the key areas they came up with, that we needed to be conscious of and focusing our mitigation efforts on, was weather windows—missing weather windows; . . . the primary thing was the approval to expend, prior to sanction, on key things, and what was recommended . . . they wanted to progress . . . the access roads; power installation; they wanted to put a 300-person temporary camp in early; and they wanted . . . [to] cut the bulk excavation out of one of the main contract packages and award that early so that they could get that awarded and potentially get that work started prior to sanction. (December 11, 2018, transcript, p. 51)
>
> . . .

> And then, and as I mentioned earlier, at the board level we were still certainly recognizing strategic risk . . . we would have been having discussions around schedule and such, because we wanted early works to start and fund. So, those types of things were being discussed. Productivity was obviously a key discussion and the risks around that. (December 13, 2018, transcript, p. 9)

And so, in anticipation of Project sanction and in the interests of maintaining the Project schedule, Nalcor made plans to commence early infrastructure work for the Muskrat Falls site following the Project's Environmental Assessment release and commencement of permitting.

Nalcor's Project Execution Plan dated September 22, 2011, stated (P-01966):

> During Gateway Phase 2, NE-LCP had already undertaken the detailed engineering for selective site infrastructure facilities referred to as Early Works (e.g. accommodations, access roads, communications and construction power).
>
> . . .
>
> This includes site roads, accommodations infrastructure and installation/erection, communications and construction power infrastructure, potable & sanitary water supplies, septic infrastructure, etc., . . .[and] a starter camp to facilitate the initial works. (pp. 35–36, 50)

The "early works" consisted of five contracts:

- CH-0002: Supply and Install Accommodations Complex Buildings
- CH-0003: Supply and Install Administrative Buildings
- CH-0004: Construction of South Side Access Road
- CH-0005: Supply and Install of Accommodation Utilities Site, which eventually was combined with CH-0002
- CH-0006: Construction of Bulk Excavation Works and Associated Civil Works

The consideration of early works was reviewed by Nalcor's board of directors. The minutes of a Nalcor board meeting on April 18, 2012, include the following (P-00659):

> Mr. Martin advised that there is ongoing engineering work and that the decision to proceed with the construction of the road in Labrador has a cost of approximately $20 to $25 million. If the Project is not sanctioned, the road would need to be remediated or could be used as forestry purposes. Board members confirmed that they were in agreement with proceeding with the early works. (p. 2)

At the same time, the Nalcor executive was seeking approval from GNL for the commencement of the early works. An email from Robert Thompson to Premier Kathy Dunderdale and Mr. Kennedy on April 13, 2012, summarized "the issues around the House of Assembly debate and Early Works" (P-01244, p. 1). Mr. Thompson recommended that a debate be held in the House of Assembly during the last week of July 2012. He also noted that Nalcor was "satisfied with the probability that the federal loan guarantee will proceed as promised" and that "Nalcor advises that the first contract for road-clearing needs to be let on Monday, April 16 in order to maintain the May 1 schedule" (p. 2). When questioned about this at the hearings, Ms. Dunderdale made several comments:

> [W]e were expecting to go to sanction, middle–late summer, July, August. And I wanted to have the debate with as much information as we could possibly get to the Members of the House of Assembly. (December 17, 2018, transcript, p. 88)
>
> And so the need for early works would have become much more intense once we . . . knew that wasn't going to happen in July . . . so now we're under threat of losing the full year. (December 18, 2018, transcript, p. 22)
>
> . . .
>
> [T]he sanction date was getting pushed out because I wouldn't go to sanction without a loan guarantee. . . . So the project kept getting pushed further out. And this was creating risk in terms of schedule particularly. And Mr. Martin and Mr. Bennett felt strongly that we needed to spend significant money before sanction in order to mitigate that risk so we didn't lose a whole year of construction. (December 17, 2018, transcript, p. 50)
>
> . . .
>
> I remember giving our approval for the building of the tote road, the camp—there were a number of things done . . . costing hundreds of millions of dollars. I was very aware of that because it was pre-sanction. And all of that was done in order to mitigate risk on schedule. (December 17, 2018, transcript, p. 50)

Ms. Dunderdale was further asked whether it was her understanding from Mr. Martin that approval of early works before sanction would mitigate the schedule risk and preserve the reliability of the July 2017 schedule for first power. Ms. Dunderdale agreed, stating: "Yes . . . absolutely mitigated risk . . . that's correct" (December 17, 2018, transcript, p. 56).

The minutes of Nalcor's board meeting on April 27, 2012 (P-00660), state that Mr. Martin

> advised that some early works have commenced with regard to the construction of a road and further early works, including site clearing, will be

> commenced in the coming months. He advised that the Project personnel continue to progress and have RFPs ready with respect to long lead procurement. (p. 4)

In a timeline of events prepared for the Commission by the PMT (P-00862, pp. 23–24), early works construction was highlighted as commencing on April 25, 2012. The April 2012 monthly progress report included the statement: "Delay in start of South Side Access Road construction is having a 'knock on effect' for other early works packages" (p. 24). At this time the bids for Contract CH-0002 for the supply and installation of the accommodations complex had been received, and the Request for Proposals issued for Contract CH-0006 for the bulk excavation and associated civil works. On May 25, 2012, Contract CH-0004 for the south side access road was awarded.

The Independent Project Review final report dated August 31, 2012, highlighted the early works mobilization as a provision to "protect schedule milestones and gain early on-site experience" (P-00504, p. 13).

It is clear that the PMT was well aware of the need to meet the Project schedule if costs were to be contained, and that it was loath to acknowledge that the schedule was not achievable. As we have seen, in an email on August 31, 2012, Paul Harrington wrote the following to Derek Owen (P-00505):

> It was most unfortunate that you used the P1 characterization of the schedule in the meeting this PM. . . . We very recently stressed the importance with Ed of allowing the bulk excavation contract to be awarded prior to sanction and with your statement that causes him to doubt the value of making that step now. The schedule risk model is a simplified activity schedule and some work is needed and the critical path assumed earlier regarding sanction being a prerequisite to bulk excavation award is one such change that is necessary and contributed to the low probability result.
>
> So we need to meet and get this back on track so that we are not alarming Ed on dated information and analysis. (p. 1)

On September 5, 2012, Jason Kean emailed Jack Evans of Westney Consulting Group asking that Westney rerun the time model for the risk analysis. Mr. Kean wrote (P-00130):

> [T]he key areas we have the knowledge upon that may influence the results of the analysis is the timing for award of the mass excavation and (2) relaxing the river closure window. These two areas, combined with the accommodations complex ready for use and risk related to concreting drive the overall completion timeline. (p. 327)

His fundamental question was: "'Does our current knowledge of the Project, increase the PXX of our base planning Schedule?' I believe the answer is yes, however are we now at P20 or P30?" (p. 326).

As discussed earlier, Westney reran the time model and concluded that the schedule had improved from a P1 to a P3. At the hearings, Mr. Kean stated:

> [T]he DG3 QRA clearly identifies that the early works work was a schedule risk. And that was one of the items that became of concern to allow the bulk excavation contractor to start. (May 7, 2019, transcript, p. 25)
>
> . . .
>
> I think that was evident in . . . July of 2012 with the first risk analysis. . . . The schedule did come with challenges, despite the good work that had been done. So we got some agreement to do some things to help improve that in terms of camp, the access road, early award of bulk excavation, but the subsequent analysis still showed that the probability was on the low end. (May 6, 2019, transcript, p. 49)

On November 6, 2012, Contract CH-0006 was awarded to IKC-ONE Earth Works Constructors Partnership. This was the first major civil package awarded for the Project and was within the DG3 estimate. There were limitations placed on the contractor. At the hearings, Jason Kean noted (November 8, 2018, transcript):

> So what we did get is we got approval to award the contract to—and we introduced several milestones there. We could allow the contractor to mobilize; however, we wouldn't allow the contractor to do—and we'd allow him to set up a site, but not start physical rock removal. Because in the event sanction wouldn't occur, of course, you can't replace the rock, unlike some trees and overburden. (p. 33)

The DG3 "Capital Costs Overview" presentation for the Independent Engineer dated October 22, 2012 (P-02161, p. 16), provided the progress update on the early works that is reproduced in Figure 2.27 on the following page.

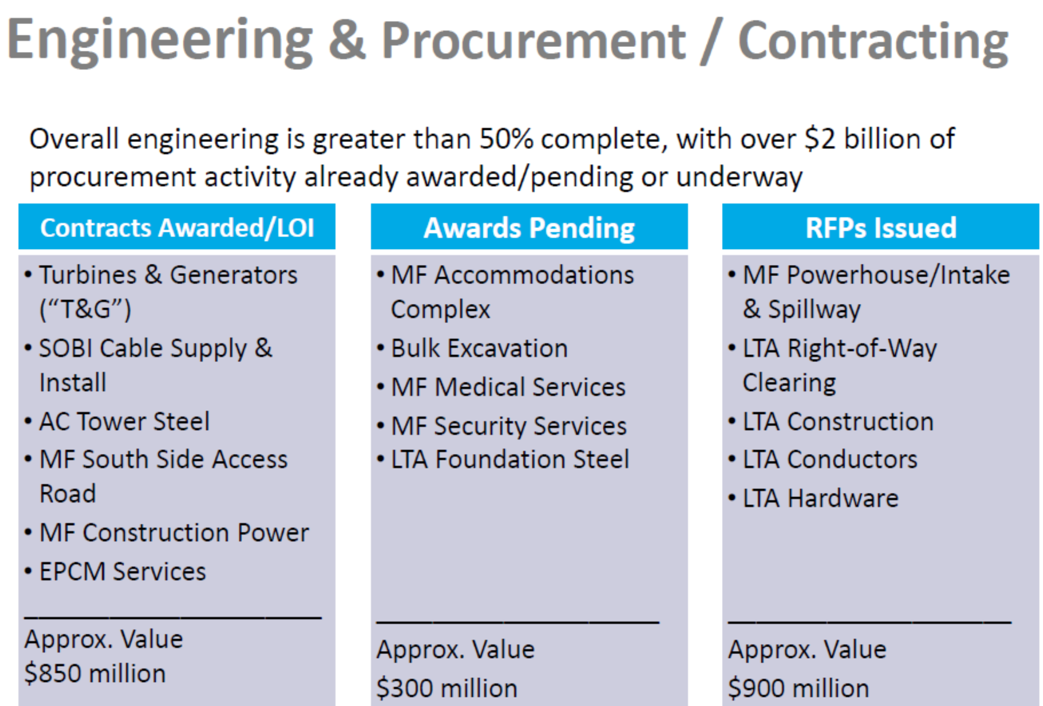

Figure 2.27: Nalcor Overview of Engineering, Procurement and Contracting

The presentation also noted that the construction of the south side access road was nearing completion and that early work on the accommodations complex was underway.

At this time, the transition from the EPCM model of Project management to the Integrated Management Team model was also in progress. Mark Turpin of Nalcor testified (April 3, 2019, transcript):

> As the estimating coordinator and pulling the DG3 estimate together, I was then asked would I go to look after the . . . CH-0006 . . . bulk excavation contract package. . . . Again, this was the beginning of the integrated team. It was a very challenging environment. . . . Nalcor was taking the work away from SNC, so it was a very difficult time.
>
> We had a very competent contractor. . . . But it was a very difficult time with Nalcor just starting and everybody finding their ground. (p. 110)

In October 2012, bids were received and evaluated for Contract CH-0002 for the accommodation complex. These bids were significantly higher than budgeted and that prompted Nalcor to secure alternate accommodations. Jason Kean testified (November 8, 2018, transcript):

> We also made a decision—because after receiving the bids for the main accommodations complex, prices were a bit higher than anticipated, the delivery times were out. We knew we needed to have beds to support the bulk excavation contractor, so we secured—made the decision, based upon the risk analysis showing the main camp would not be available, we acquired Manitoba Hydro's Wuskwatim camp for 300 persons. (p. 33)

Scott O'Brien also testified about the delays in finalizing arrangements for the accommodations complex (May 30, 2019, transcript):

> The delivery of the primary camp was delayed, that is correct. There were mitigating strategies put in place in order to address that. A temporary camp, as we called it, was purchased from Manitoba Hydro and was installed at the Muskrat Falls site during the time of bulk excavation. The bulk excavation contractor was staying in the base in Goose Bay up to that point, which was always part of the plan, that they would house themselves within the community.
>
> As the challenges manifested with the delivery of the primary camp, we saw a need to mitigate the risk of lack of accommodation for the larger workforce that was coming and purchased a temporary camp, which we then installed at Muskrat Falls in 2013; bulk excavation contractor then moved into that camp for the remainder of their work until they demobilized at the end of 2013. (p. 73)

The contract for the accommodations complex (CH-0002) was signed on December 1, 2012, with a cost growth of $45.1 million. On May 24, 2013, the scope of work under this contract was expanded to include site utilities.

The temporary accommodations complex became available for use in mid-April 2013 (P-00862, p. 35). The effect of the late availability of the on-site accommodations resulted in an August 2013 claim from the bulk excavation contractor (P-02745).

As noted earlier, the delay in Project sanction raised concerns about meeting the schedule. In February 2013, Nalcor rebaselined the Project schedule (P-00862, p. 34). On April 2, 2013, Nalcor directed the bulk excavation contractor to accelerate its schedule to meet a powerhouse excavation target completion date of October 25, 2013 (P-02745, p. 10).

On November 30, 2013, the bulk excavation for the powerhouse and spillway structures was completed (P-00862, p. 39). However, issues with over-excavation for this work led to knock-on effects for other contracts.

The total cost incurred for early works as of Financial Close was approximately $900 million.

REVIEWS CONDUCTED WITHIN GNL

As discussed earlier, GNL relied largely on Nalcor to provide it with information about the Muskrat Falls Project. This included reliance on the analyses Nalcor conducted on costs, schedule and risks, whether the Project was viable, whether the Project was the least-cost option for Island ratepayers and whether the business case supported the Project.

While I would have expected GNL to have conducted more thorough analyses of the Project, particularly on costs, risks and whether it was the least-cost option, the evidence establishes that GNL did conduct some assessments of the Project. However, these assessments were limited by a lack of expertise, knowledge and capacity within GNL. Furthermore, any analysis completed by GNL civil servants relied significantly on the assumptions and forecasts that had been provided by Nalcor.

In October 2010, Robert Thompson, then Deputy Minister of Natural Resources, directed a group of economists in that department to conduct a review of "the data, assumptions and modelling techniques being used by Nalcor to determine whether the analysis was sound" (P-01060). This review was to consider the options open to the Province for the supply of electricity to Island ratepayers.

In his testimony, Robert Thompson stated that the review conducted was not meant to test the assumptions underlying the engineering or the capital cost estimates, because "that would've not been a capacity we had in the department" (November 14, 2018, transcript, p. 21). Rather, the review was to be a reasonableness assessment of Nalcor's assumptions for load, oil prices, exchange rates and the CPW analysis that Nalcor had prepared.

The GNL officials who conducted this assessment made inquiries of Nalcor's staff and, using the information provided, accepted the reasonableness of much of Nalcor's work and its assumptions and forecasts.

A 2010 internal GNL review entitled "Future Island Electricity Supply" presented to Charles Bown (P-01069) contained an overview of the following topics:

- Electricity Forecast
- Island Supply – Options & Considerations
- Economic Assumptions
- Generation Expansion (focus scenarios)
- Island Revenue Requirement (focus scenarios)

- Oil Price Outlook
- Fuel Costs
- Summary Considerations
- Appendix - Generation Expansion Scenarios
- Follow Up:
  - CPW Definition
  - Economic Assumptions/Consideration
  - Island Revenue Requirement ($/MWh)
  - Oil to Gas Fuel Switching
  - Holyrood (LNG Fuel Option)
  - 2002 Pricing Terms Revisited (p. 3)

The summary considerations of the review were:

- Timeline on Lab HVdc consideration linked to timing of decision for environmental upgrades at Holyrood.
- Island electricity forecast appears reasonable – consistent with July 2010 PUB capital plan filing.
- Economic assumptions appear reasonable.
- Capital cost estimate risks.
- Isolated Island scenario presented as an oil-fueled thermal generation expansion scenario.
- Oil prices and hence fuel costs can be volatile variables and difficult to forecast.
- Generally, long term outlook horizon makes forecasting more difficult. (p. 14)

It is unclear whether GNL placed reliance on this review in reaching a decision on Project sanction.

The officials involved in the review were aware that the capital cost estimates, a key component of any CPW analysis, might not have been completely accurate and they allowed for a variance in Nalcor's cost estimate at that time of +/-10% to +/-25%. NLH informed them that this was the same level of variance used by NLH in its generation and expansion planning.

As discussed earlier, the departments of Finance and Natural Resources identified the need for an independent analysis of the Project's estimated costs and its impact on the Province's finances (P-00807). A May 2011 Decision/Direction Note prepared by Terry Paddon and Charles Bown, which was approved by their respective ministers, Thomas Marshall and Shawn Skinner, recommended a thorough review of the Project by an international management consulting firm. This recommendation was not accepted by Premier Dunderdale. However, it did lead to GNL deciding to send a limited Reference Question to the PUB.

In January 2012, three civil servants in the Department of Finance—W. Tymchak, M. O'Reilly and K. Hicks—recommended that the Project's business case and the possible impact of the Project on the Province's finances be subjected to a thorough analysis. They suggested that the review by the PUB in response to the Reference Question was far too limited in scope and that the PUB should be given more time to complete a full review of the Project (P-00922). These recommendations were not accepted by GNL.

In 2012, prior to Project sanction, the Department of Natural Resources prepared a series of discussion papers, which were released to the public, that addressed such questions as "Why not develop Gull Island first?" (P-00062), "Do We Need the Power?" (P-00070) and "Upper Churchill: Can we wait until 2041?" (P-00061). In addition, other papers were prepared on topics such as the environmental benefits of closing Holyrood (P-00073). All of these papers relied heavily on data and information provided by Nalcor and appear to have been influenced by GNL's early commitment to the Project.

At the hearings, there was evidence that suggested that there was confusion between the Department of Finance and the Department of Natural Resources as to which department was responsible for conducting analyses regarding the Project.

In summary, while GNL's civil servants made some attempts to conduct analyses and assessment of the Project, they were minimal and superficial considering the size and cost of the Project and its potential impact on the Province's finances.

THE NALCOR BOARD AND GNL: INFORMATION FROM NALCOR

Information about Project planning, activities and progress flowed to the Nalcor board and to GNL primarily from Nalcor's CEO, Edmund Martin, sometimes with the involvement of Gilbert Bennett and others on the Nalcor executive.

Much of the information that flowed from Nalcor to GNL went through Charles Bown, the Deputy Minister of Natural Resources at the time of Project sanction. Based on the evidence, I conclude that Mr. Bown was the main conduit for information from Nalcor. It was his responsibility to notify his Minister, the Premier and/or the Clerk of the Executive Council of any important information he received. Mr. Bown was seen as the point person within GNL for the Project. As a result, within Nalcor, he was often referred to as the "shareholder."

However, Mr. Martin also had a direct line of communication to the Premier and to the Minister of Natural Resources. He had frequent conversations with Premiers Williams and Dunderdale. Ms. Dunderdale testified that, except for one occasion unrelated to the Project, she only met with Mr. Martin when others were present, usually Mr. Bown, the Minister of Natural Resources, the Premier's Chief of Staff and/or the Clerk of the Executive Council. In addition to such meetings, Mr. Martin had numerous telephone calls with the Premier and the Minister of Natural Resources.

Based on the significance of the Project, it is understandable that there was a direct line of communication between Mr. Martin and the Premier's Office. However, its existence also created problems within the civil service, as was apparent from the evidence of Todd Stanley, senior legal counsel with GNL. I find that, on occasion, approvals were given by the Premier to Nalcor without either the input or knowledge of the civil service.

When making presentations to its board of directors and to GNL, Nalcor management usually used presentation decks (PowerPoint). Most of these presentations tended to accentuate the positives of the Project, sometimes to the point of not presenting what I would consider full and accurate information.

Edmund Martin assumed full responsibility for providing GNL with any new and/or material information on cost estimates, schedule and risks. Because there was no protocol defining the communication expectations between GNL and Nalcor, it was left to Mr. Martin to decide what information on cost estimates, schedule and risks would be communicated to them. Based on the evidence given by politicians and civil servants who were asked to describe the disclosure they expected, I am satisfied that GNL expected much more information than it received.

Mr. Martin's control of information was also clear within Nalcor. Derrick Sturge, Gilbert Bennett and James Meaney all testified that they had no authority to discuss updates or new information on cost or schedule with the Nalcor board or GNL without first obtaining Mr. Martin's authorization. This was an absolute rule, which Mr. Martin confirmed in his testimony (June 12, 2019, transcript, p. 58).

The relationships between Mr. Martin and the Premier and the Minister of Natural Resources were important. Mr. Martin and many of the GNL witnesses described these relationships as positive. Similarly, all of the GNL witnesses who interacted with Mr. Martin felt that he was always available to answer questions and to discuss matters when needed, and that he was knowledgeable, reliable, convincing and confident when he presented information to them. They expressed a strong sense of trust in what was conveyed—they believed that Mr. Martin was providing them with complete and accurate information. Nalcor board members clearly also placed a lot of faith and trust in the information they received from Mr. Martin.

In his testimony, Robert Thompson described GNL's relationship with Nalcor as being "an integrated team" (November 14, 2018, transcript, p. 24). Mr. Thompson said that the work on development of the Energy Plan in 2007 had been "an integrated effort" (p. 12) by GNL (in particular, the Department of Natural Resources) and Nalcor. He acknowledged that after the Energy Plan was released, in September 2007, GNL and Nalcor continued to work in many senses as "an integrated team."

This integrated-team approach applied to work on the Project and it also extended into other related areas, such as communications and public relations, even including work on the 2011 Reference Question for the PUB. A striking example of the high level of collaboration and cohesion of the integrated team was demonstrated by the evidence presented in relation to the GNL-initiated review of the natural gas energy supply option in the spring of 2012.

Charles Bown went even further than Mr. Thompson in his description of the high degree of collaboration and cohesion that characterized the work of this "integrated team." When asked whether it was integrated in every respect, Mr. Bown replied "absolutely" (December 5, 2018, transcript, p. 79).

It is noteworthy that Mr. Thompson and Mr. Bown did not believe that this integrated-team approach compromised GNL's oversight of Nalcor's work on the Project. GNL officials and politicians accepted the information provided by Nalcor without any meaningful challenge. They trusted Nalcor's representatives without any reservations. They believed that Nalcor's representatives, and in particular Edmund Martin, were at all times providing GNL with all relevant information on cost estimates, contingencies and risk assessments for the Project. I find that they were naive in this belief and they accepted Nalcor's repeated assurances that the DG3 cost estimates were reliable and of high quality without any detailed and independent review of these assurances. GNL deferred to Nalcor and allowed Nalcor to operate with autonomy.

At the hearings, Todd Stanley testified that at certain times, some GNL officials believed that Nalcor was a "fiefdom" and "a runaway train" (October 22, 2018, transcript, pp. 8, 4). The evidence at the hearings confirmed to me that these descriptions of Nalcor had merit.

It is surprising to me that there was never a written protocol or policy statement defining how and when Nalcor was required to report to GNL officials and politicians, and outlining what needed to be reported. In February 2011, the Department of Natural Resources prepared two draft documents: "A Shareholder's Letter of Expectations" and "A Shareholder's Handbook" (P-01168). The documents' purpose was to define the roles, responsibilities, policy directions and performance expectations for Nalcor, and to enhance the communications between GNL and Nalcor. Originally, the Department of Natural Resources intended to send the final versions of the documents to Mr. Thompson for review. Mr. Bown testified that he was unable to provide any explanation as to what happened to this initiative. He stated that he had no memory of what happened to these draft documents and had "lost track" of them (December 6, 2018, transcript, p. 43). In any event, these documents were never circulated or signed. Mr. Bown testified that his failure to pursue this initiative was the one area that he regretted about his work on the Project.

Internal Communications: Information Transfer from Nalcor's Executive to Its Board

I am satisfied that a significant volume of documentation was provided to Nalcor's board of directors prior to Project sanction. However, quantity is not the same as quality, and repercussions flow from that difference.

In November 2012, Nalcor prepared a 525-page document entitled "Decision Gate 3 Support Package" (P-00121). This document was delivered to Nalcor directors before the board meeting on December 5, 2012, at which the resolutions in support of sanction were to be considered.

The Nalcor board of directors approved the sanction of the Project at that December 5 meeting, the twelfth meeting that the board had convened since June 28, 2012. The board minutes from this series of meetings indicate that, while there had been some discussion of the Project's cost estimates, contingencies and risks, there had been no mention of either the recommendation for a $497 million management reserve for strategic risk or the P3 value for the Project schedule.

The critical information that Mr. Martin chose to withhold from the Nalcor board was similar in many respects to critical information that he also withheld from GNL before Cabinet's vote to approve Project sanction on December 6, 2012.

The Nalcor board members were hardworking and intelligent, but they had no specialized experience in megaproject construction. As a result, they required full and accurate information to properly execute their duties on behalf of GNL, the owner of Nalcor. It is clear that Mr. Martin had a duty to fully, frankly and accurately disclose to the board all relevant information on cost estimates, risk, contingencies and schedule before the directors decided to consider the sanction of the Project. I conclude that Mr. Martin failed to discharge this duty.

In their testimony, Nalcor directors Terry Styles, Ken Marshall, Gerry Shortall and Tom Clift all stated that before the board's vote on Project sanction (December 5, 2012), they were satisfied that Mr. Martin and the Nalcor executive had fully disclosed to them all relevant information that they required to make an informed decision. I accept that this was an honest belief on their part. The problem is that they were mistaken in their honest belief. The evidence clearly shows that Mr. Martin had material information on matters such as strategic risk, schedule risk and P values that he was obligated to disclose but did not.

Even if Mr. Martin and the Nalcor executive believed that all strategic and schedule risks had been, or would be, fully mitigated, they were required to disclose all relevant information and explanations in support of their assessment and mitigation plans. This information was important and would have assisted the board.

As referred to earlier, the Nalcor board could have retained an expert to provide it with independent advice and analysis. I am surprised that it did not do this, since the directors recognized deficiencies in their ability to properly assess the information provided to them. The board had previously retained experts on matters such as board governance, but it did not see fit to do the same for this major and significant project. The high level of trust and reliance they placed in Nalcor's executive, and particularly Edmund Martin, was a mistake. The Nalcor board was incapable of making an informed decision on Project sanction because its directors lacked the full skill set necessary to properly assess and challenge the information they received from Mr. Martin.

It is difficult for me to understand how Mr. Martin could determine that matters such as risk contingency and schedule would not be fully communicated to the board members in a way that allowed them to appreciate the significance of these issues.

External Communications: Information Transfer from Nalcor to GNL

Before Project sanction, Mr. Martin had many meetings and discussions with Premier Dunderdale and Jerome Kennedy, then Minister of Natural Resources. As well, he made several presentations to the Premier and to Cabinet as they proceeded toward the sanction decision. The test that Mr. Martin applied to determine whether information should be communicated to government was whether, in his judgment, the information could be seen as having a significant impact on Nalcor or on the Province (December 10, 2018, transcript, p. 21).

On December 17, 2012, Nalcor and GNL jointly announced sanction of the Muskrat Falls Project. Premier Dunderdale referred to the expected benefits of the Project with enthusiasm, including the expectation that it would generate excess revenues of more than $20 billion over 50 years. Edmund Martin added that "with Muskrat Falls, generations of Newfoundlanders and Labradorians will benefit from clean, renewable, low-cost hydropower providing long-term rate stability" (P-00066, p. 1).

Cabinet had given its approval to Nalcor to sanction and proceed with the development of the Project on December 6, 2012. Cabinet's sanction decision was based on information contained in a Memorandum prepared by the Department of Natural Resources and signed by Minister Kennedy on December 5, 2012. This Memorandum contained detailed information about the background of the Project, as well as financial and other relevant considerations (P-00067).

Included in the Memorandum were reviews of reports and assessments that Nalcor and GNL had commissioned or obtained for the purpose of demonstrating that the Project was the correct and least-cost choice for meeting the present and future energy needs of the province. The reports and assessments covered by the Memorandum had been prepared by different sources, including Navigant Consulting, Manitoba Hydro International, Knight Piesold Consulting, Natural Resources Canada, Wade Locke and Ziff Energy.

According to the Memorandum, the Project's $6.2 billion DG3 cost estimate "represents the total cost to the Province and Nalcor and excludes interest during construction and financing costs" (p. 10). It also stated that the financial analysis showed that the free cash flow that would be returned to the Province through dividends from the Project would be more than sufficient to meet the debt servicing requirements.

As found earlier, GNL did not perform any detailed analysis of the impact of the Project on the finances of the Province, nor did it—or specifically the Department of Finance—perform any detailed assessment or review of Nalcor's DG3 cost estimates before sanction. Finance officials did not have the expertise or resources to carry out such a review. Officials at the Department of Natural Resources did conduct a limited review of the CPW calculations, but they did not have the expertise or resources to carry out an in-depth assessment of the DG3 cost estimates (P-01069). What had led GNL to this point?

Lost Opportunity: The Decision/Direction Note

In May 2011, Ministers Shawn Skinner and Thomas Marshall approved a Decision/Direction Note (Note) prepared by senior officials of their respective departments, Natural Resources and Finance (P-00846). The Note identified the need for GNL to retain an independent consultant to conduct a review of risk associated with the Project, specifically in areas such as design and engineering risk, construction risk, generation/technical risk, market risk, financial risk and contractual risk. The Note pointed out the need for GNL to conduct its own due diligence with complete independence from Nalcor because of the real possibility that there could be issues of an overriding provincial nature or concern that might not be relevant to Nalcor's considerations and to its internal due diligence. Recognizing the complexity of the proposed independent review, the Note suggested that the ideal consultant for this work would be a large international management consulting firm with deep expertise and experience. The successful candidate would have to be entirely independent of Nalcor, with no existing or prior relationship that could create a conflict of interest.

The Note was presented to Premier Dunderdale for her consideration, but it was never presented to Cabinet. The Premier did not accept the recommendations contained in the Note. She did not see this type of independent review as necessary, given that GNL had decided to refer the matter to the PUB for a limited review.

I find that the PUB Review (the Reference Question) that followed was not a reasonable substitute for the independent review recommended in the Note. The recommendations in the Note were compelling and should have been accepted. This was an important opportunity that was missed because of Premier Dunderdale's decision, which was made at a time when the Province was proceeding with the most expensive and riskiest project it had ever undertaken.

The Note also indicated that Nalcor had informed GNL that it planned to undertake further due diligence by retaining Independent Project Analysis to complete a project cost analysis. In addition, the Note stated that Nalcor had informed GNL that it planned to complete a thorough review and commentary on Project readiness by commissioning an Independent Project Review for DG3.

Nalcor did not ask IPA to conduct its Project cost analysis before the date of Project sanction or Financial Close of the FLG. In my opinion, if IPA had conducted such an analysis, it would have, at the least, identified that there was nothing in the DG3 cost estimate to cover strategic risks. It is remarkable that, according to testimony, no one in GNL ever asked, or followed up with anyone at Nalcor, about the proposed review by IPA.

Nalcor's Independent Project Review team delivered its report on August 31, 2012. One of its recommendations was to include an amount for strategic risk in the DG3 cost estimate. Nalcor did not accept this recommendation. If someone in GNL had obtained a copy of the report, an inquiry could have been made as to why there was nothing in the DG3 cost estimates to cover strategic risks.

These events and inaction are further examples of the unjustifiable faith and trust that GNL had placed in Nalcor.

GNL had a duty to ensure that the DG3 cost estimate and schedule were reliable, and that all financial risks had been properly costed and included in the estimate. Because GNL officials did not have the expertise or experience to carry out an independent review, the only reasonable course of action was to accept the recommendations in the Note and retain an international management consulting firm to conduct an in-depth review.

In the PUB's report of March 30, 2012, which responded to the Reference Question, the Board refused to endorse the Project as being the least-cost alternative. The Joint Review Panel had also suggested commissioning an independent analysis to determine whether the Project was the least-cost alternative. As we have seen, GNL retained MHI in June 2012 to carry out a review of the DG3 cost estimates and schedule. The scope of the MHI review was limited because Nalcor persuaded GNL to remove a strategic risk review from MHI's mandate, and also to place additional limitations on the scope of work that MHI had proposed. Without such a risk review and a larger scope for its review, it was not possible for MHI to carry out a complete and thorough assessment of the DG3 cost estimate.

Based on the information that Nalcor had provided to GNL before December 6, 2012, it is probable that GNL officials such as Jerome Kennedy held an honest belief that the Nalcor cost estimate and schedule were accurate and reliable. After he was appointed Minister of Natural Resources on October 11, 2011, Mr. Kennedy gave considerable attention to cost estimates and contingencies for the Project, as well as to the impact that potential cost overruns could have on the cost of electricity for ratepayers. Between October 11, 2011, and December 6, 2012, Mr. Kennedy met with Mr. Martin on several occasions to discuss cost estimates, contingencies and other matters related to the Project. In meetings held in September and October 2012, Mr. Martin assured Mr. Kennedy, with conviction and confidence, that the DG3 cost estimates were reliable and of high quality and that cost overruns were unlikely. Mr. Kennedy's evidence on these meetings is credible and it is corroborated by his handwritten notes. As described earlier, the cost estimates prepared were deficient in certain areas and, importantly, had never been subjected to an independent review.

Mr. Kennedy and other members of Cabinet did not know that Nalcor, on the direction of Mr. Martin, had intentionally concealed critical information and had failed to disclose to GNL known risks that were certain to increase the cost of the Project well beyond the $6.2 billion DG3 estimate. The critical information that Mr. Martin failed to disclose to GNL in the months leading up to the sanction decision is covered, in part, in Grant Thornton's *Sanctioning Phase* report (P-00014, pp. 66–68), prepared for the Commission. The most important parts of the unshared critical information are summarized below:

- Nalcor did not include $497 million of strategic risk exposure in the DG3 capital cost estimate
- On August 31, 2012, Nalcor received a DG3 IPR report in which the IPR team recommended that adequate provisions for management reserve and schedule reserve be included in the Project sanction costs and schedule, and expressed the opinion that the targeted schedule was a P1 (later increased to P3); Nalcor never disclosed this report to either GNL or its own board of directors, and it did not follow all of the recommendations of the IPR report

- Nalcor selected a P50 value from the results of the Monte Carlo simulation prepared by its consultant, Westney; GNL was made aware of the fact that Westney had conducted a risk analysis, but it was never provided with full information related to that analysis
    - The evidence establishes that neither Mr. Martin nor anyone else at Nalcor provided GNL officials, the Premier or members of Cabinet with any meaningful information on P values; specifically, no information was provided on the significance of selecting, for example, a P50 value as opposed to a P75 value for strategic risk
    - Since the DG3 cost estimate made no mention of strategic risk, the receipt of any such information by GNL would probably have led to inquiries about strategic risk for the Project—a topic that Mr. Martin did not want to advise GNL about; by not providing information on P values, GNL was denied the opportunity to determine its risk appetite

Strategic risk is a factor for all megaprojects. In reaching this conclusion, I find strong support in the expert evidence of Professor Bent Flyvbjerg, Professor George Jergeas, Professor Ole Jonny Klakegg and others. The fact that there was nothing in the DG3 cost estimate for strategic risk meant that cost overruns were inevitable. Mr. Martin and the PMT knew this very well.

Before Project sanction, Nalcor was of the view that full power from Muskrat Falls could be achieved by December 2017. In the opinion of Westney, the December 2017 schedule was a P1, meaning that there was only a 1% chance that this schedule could be achieved. After receiving this opinion about the schedule in June 2012, Jason Kean of Nalcor sent additional information to Westney with the objective of convincing it that the P1 for schedule was too low, and that a P20 to P30 for schedule was more appropriate. Westney reviewed that information and revised its schedule estimate to a P3 value. Neither the P1 nor the P3 schedule was ever disclosed to GNL. It is clear that any schedule delay inevitably means increased costs.

At the time of sanction, it was well known to the PMT that the Project schedule was unrealistic. In a letter sent in June 2016 by Paul Harrington (on behalf of the PMT) to

Stan Marshall (Edmund Martin's replacement at Nalcor), Mr. Harrington stated that Mr. Martin had given the PMT a direction to set a very aggressive schedule for first power (P-01962). He went on to state that it was well known at the time of Project sanction that the schedule was in the range of P5 to P10.

In his testimony, Mr. Martin was unable to provide a reasonable explanation for his failure to advise GNL of this critical information related to the schedule before sanction. Mr. Martin did not agree that he had instructed the PMT to set a very aggressive schedule for first power, nor did he agree that the work carried out by Westney on the schedule risk, which resulted in a P3 value, was a full and reliable risk analysis. Rather, he suggested that Westney's work on the schedule was nothing more than a stress test of four key areas of risk that could affect the schedule and that Westney's work did not take into account the many opportunities that existed to mitigate these four risks.

Mr. Martin testified that he found it "immensely frustrating" that Westney's work on schedule risk had been interpreted as providing a basis for the conclusion that a P3 value should have been assigned to schedule. He stated emphatically that this conclusion was "absolutely incorrect" (June 12, 2019, transcript, p. 37). Mr. Martin expressed the view that all risks for schedule delay had been fully mitigated at the time of Project sanction, and for that reason he did not share the P1 or P3 advice of Westney with any GNL representatives.

I find that Mr. Martin's explanation that all strategic or schedule risks had been mitigated is implausible. If Mr. Martin had believed that Westney's work on risk was simply a stress test on four areas of risk and not a reliable analysis, why did he not ensure that his counsel put his position to Richard Westney and Keith Dodson when they testified? I also question why, if this was true, Nalcor would not have obtained a complete risk analysis regarding the schedule, as such was a reasonable requirement prior to any sanction decision.

Mr. Dodson testified that at DG2, 36[9] areas of risk had been identified for the Project (February 25, 2019, transcript, p. 11). At DG3, Nalcor instructed Westney to provide advice on only four areas of risk. The remaining risks included such things as foreign exchange risk, protests by Indigenous Peoples and environmental groups, and other political risks. These remaining risks should have been quantified. If they had been, a P50 value for strategic risk, if used, would have been much higher than $497 million. It is in this sense only that Mr. Martin is correct when he stated that Westney did not carry out a full risk assessment.

[9] This appears to be an error. The correct number of risks identified in the risk report was 33.

I conclude that at the time of Project sanction Mr. Martin knew that the Project schedule was extremely aggressive and unrealistic and that he was fully aware that Paul Harrington and other members of the PMT were of the view that achieving the schedule was somewhere between a P5 and a P10—a long shot, at best. I do not accept Mr. Martin's evidence that the reason he did not include anything in the DG3 cost estimate for strategic risk was that he had an honest belief that all strategic risks had been fully mitigated before sanction. He knew, or should have known, that there were unmitigated strategic risks, as is the case for all megaprojects.

I find that Mr. Martin placed great reliance on the fact that GNL had provided an unlimited Project completion guarantee to the federal government and financiers, meaning that GNL was fully committed to cover any cost overruns. Mr. Martin may have felt that the approval of an FLG and a change in the HVdc transmission line construction provided some level of mitigation. In my view, this fell short of providing full mitigation of all potential strategic risks.

Mr. Martin's thought process on cost overruns was consistent with an observation made by Ernst and Young during the course of its review of Project costs, schedule and related risks, which commenced in January 2016. At a meeting with Premier Ball, the Minister of Natural Resources and GNL officials on February 25, 2016, representatives of EY reported that there was no sense of responsibility at Nalcor for cost escalation, and that Nalcor's focus was on completing the Project regardless of cost, with GNL providing unlimited funds. In his testimony, Michael Kennedy of EY identified Nalcor's James Meaney as the source of this observation.

Not one of the GNL officials or politicians who testified at the hearings accepted that Mr. Martin was justified in keeping critical information to himself. Furthermore, all of the GNL officials and politicians who testified stated that they first learned of critical information when they read Grant Thornton's *Sanctioning Phase* audit report (P-00014), which was prepared for the Commission in 2018. They all agreed that this information should have been disclosed to Cabinet before Project sanction. Many of them expressed surprise, shock and even anger when they realized that they had been deprived of critical information before sanction. None of them supported Mr. Martin's decision to withhold such critical information.

As noted above, GNL and Nalcor jointly announced the sanctioning of the Project to the public on December 17, 2012. At that time, the public was advised that the Province's share of the total cost of the Project was $6.2 billion, excluding interest and financing charges. GNL officials confidently assured the public that the $6.2 billion total cost estimate was reliable and that it had been independently tested and verified by MHI. I conclude that this assurance was ill-founded.

The review of the cost estimate undertaken by MHI was deficient because GNL had limited MHI's ability to conduct its review and, importantly, had removed the review of strategic risk from MHI's scope of work, at the request of Nalcor. The result of this was that at no time before sanction had the DG3 cost estimate been subjected to any robust and independent review. As acknowledged by Jerome Kennedy during his testimony, this reality was "alarming." Other weaknesses in the MHI assessment were also apparent.

In my view, the flow of information between Nalcor and GNL was loose, unstructured and informal. There was no reporting protocol or policy directive. GNL did not have the necessary capability or resources to meaningfully challenge, test or evaluate the information that it was receiving from Nalcor. The obvious solution to this lack of capability and resources would have been to retain independent experts, as was recommended in the May 2011 Decision/Direction Note.

No one in GNL appears to have bothered to carry out any research on megaprojects, even though well before 2012 there were textbooks, articles, reports and other online information available on this subject. It has been common knowledge for decades that megaprojects have a history of substantial cost overruns. This observation is confirmed by the expert evidence and publications of Professor Flyvbjerg and Professor Jergeas. However, no one in GNL appears to have been concerned about this.

GNL's oversight of Nalcor was weak, at best. GNL was the owner of Nalcor but nevertheless allowed Nalcor to be the dominant player in the relationship. In some ways, the evidence of Todd Stanley is confirmed—in the sense that Nalcor was operating similar to the "runaway train" or "fiefdom" that Mr. Stanley described.

I reject the suggestion that if information was available publicly, Nalcor had no duty to provide full and complete disclosure of this information. For instance, during the hearings Nalcor's counsel pointed to its 259-page submission to the PUB on the Reference Question (P-00077) and to comments in the PUB's 115-page report at DG2 (P-00052) to show that Nalcor had disclosed that neither strategic risk nor management reserve was included in the DG2 cost estimate. Robert Thompson provided testimony on this point at the hearings, noting (November 15, 2018, transcript):

> Well, we wouldn't expect Nalcor to rely upon the department to ferret out that detail and bring it up for discussion. If it's an important issue we would rely upon Nalcor to frame it up for us in one of these briefings. That's not to deny that the—that that information existed in that report. (p. 46)

I agree with Mr. Thompson's position on this point. This information was buried in both documents without any meaningful explanation. Such a position on the part of Nalcor highlights an apparent lack of appreciation of the duty its officials had to bring relevant information to the Nalcor board and to GNL.

Nalcor officials knew that the GNL officials and politicians who worked on the Project were considerably over their heads and unqualified to evaluate cost estimates, schedule and risks. Nalcor officials took full advantage of this serious and glaring weakness when they should have recognized that this imposed on them an even greater duty to ensure that GNL was fully informed and understood the cost estimates, schedule and risks.

Premier Dunderdale testified that sometime before Project sanction (she did not know when) Mr. Martin had verbally advised her that in a worst-case scenario there could be cost overruns up to $500 million over the $6.2 billion DG3 estimate. This information was provided to her in a very informal way—so informal that Premier Dunderdale had no recollection of ever sharing it with GNL officials or members of her Cabinet.

There is no doubt that Nalcor, and in particular Mr. Martin, must be faulted for intentionally failing to disclose to GNL relevant information on costs, schedule and risks before Project sanction. If GNL had received full disclosure from Nalcor before sanction, it would have been in a position to properly evaluate the Project and provide the public with truthful and accurate information on Project cost estimates, schedule and risks. There is also no doubt that GNL politicians and officials must be faulted for failing to provide a reasonable level of oversight of Nalcor, for placing an unjustified amount of trust and blind faith in that corporation, and for the naivety that they demonstrated in accepting, without a comprehensive independent review, Nalcor's DG3 cost estimates, schedule and risks.

The Project Charter, issued by Nalcor in December 2011, contains the following "Community Goal" (P-01481):

> Demonstrate Nalcor Energy's openness and accountability to the people of Newfoundland and Labrador and other stakeholders on the development of NE-LCP Phase I (p. 17)

It is also noteworthy at this point to refer to Nalcor's statement of its core values, which it included in many internal and external communications, often as shown below.

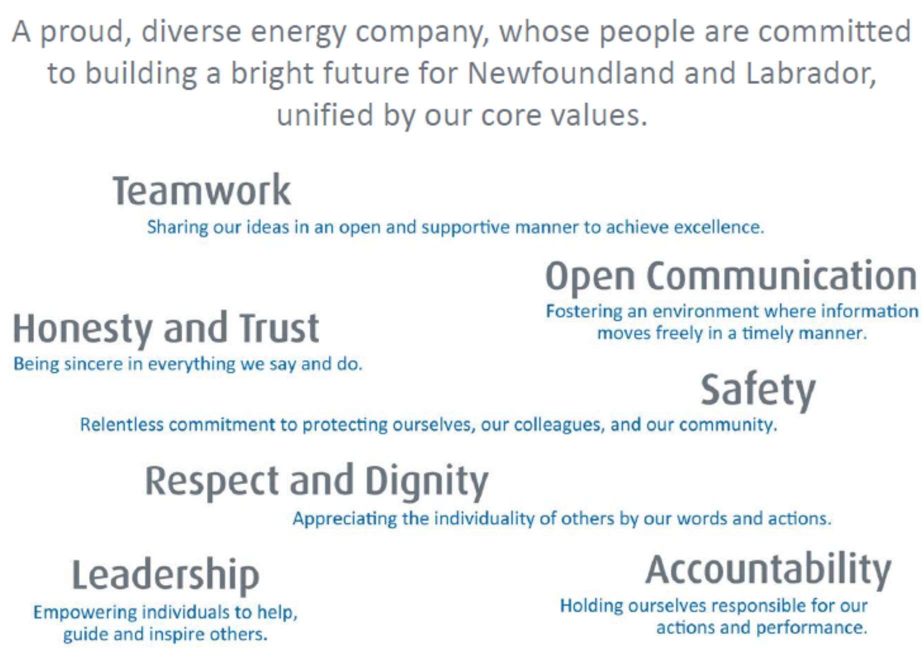

Figure 2.28: Nalcor's Core Values

Considering the evidence presented at the hearings, I find it ironic that Nalcor continued to espouse these core values while at the same time failing to properly discharge its disclosure obligations to GNL and to its own board of directors. The evidence clearly establishes that many people within Nalcor, and Edmund Martin in particular, did not adhere to the core values of open communication, honesty and trust, or accountability in their discussions and communications with GNL and Nalcor's board of directors. This failure continued after Project sanction.

GLOSSARY

This list includes terms and their meanings as used in this Report.

Term	Meaning
alternating current (AC)	An electric current that periodically reverses direction. Alternating current power is typically the form of power delivered to households and businesses.
base estimate	An estimate that reflects the most likely costs for known and defined scope associated with the Project's specifications and execution plan.
bifurcation	A separation into two parts. When used in the context of the Project, it describes the establishment of distinct management teams for the generation and transmission components, as implemented in June 2016.
bipole (operations)	A bipole HVdc system has two conductors and allows for greater reliability for transmission than a single-conductor or monopole system. If one line goes down, the system immediately reconfigures itself to monopole operation to avoid power outages.
capacity	The maximum power that a generating unit, generating station or other electrical apparatus can supply. Common units for measuring capacity include kilowatt (kW) and megawatt (MW).
cofferdam	A temporary enclosure built within (or in pairs across) a body of water to allow the enclosed area to be pumped dry. This pumping creates a dry work environment so that the main dam (or other) work can be carried out safely. Commonly used for construction or repair of permanent dams, oil platforms and bridge piers built in or over water.
Conservation and Demand Management (CDM)	A range of programs and initiatives to encourage energy consumers to conserve electricity and use it more efficiently. It also includes efforts to decrease peak demand for electricity.
contingency	In an estimate, the provision made for probable variations in estimates of time or cost that cannot be specifically identified at the time the estimate is prepared.

Term	Meaning
converter station	Equipment used to convert alternating current to direct current (or direct current to alternating current).
critical path	A project management term for the entire sequence of steps or activities between the start and completion of a target, milestone or project.
Cumulative Present Worth (CPW)	The present value of all incremental utility capital and operating costs expected to be incurred to reliably meet a specified load forecast, given a prescribed set of reliability criteria. CPW is used for comparative purposes, as a measure of the total costs of a supply option.
DarkNL	A series of widespread and significant power outages that occurred on the Island of Newfoundland in January 2014.
Decision Gate (DG)	In the development of a project, a pre-defined moment when the Gatekeeper (see below) has to make appropriate decisions about whether to move a project to the next stage, to place a temporary hold or to terminate it.
direct current (DC)	An electric current that flows in only one direction. Direct current is used to transport power over long distances. Direct current has to be converted to alternating current before it can be used by homes and businesses.
dispatchable power generation	Sources of electricity that can be used on demand at the request of power grid operators, according to market needs. Dispatchable power generators can be turned on or off, or can adjust their output according to an order.
electrostatic scrubbers and precipitators	Pollution abatement equipment that reduces particulate emissions from thermal generating plants, such as Holyrood.
energy	The total amount of electricity that a utility supplies or a customer uses over a period of time. The energy supplied to electricity consumers is usually recorded as kilowatt hours, megawatt hours, gigawatt hours or terawatt hours.
Engineering, Procurement and Construction Management (EPCM)	A contracting model in which the EPCM contractor, acting as the owner's representative, is responsible for the engineering, procurement and construction management of suppliers and contractors.

Term	Meaning
escalation	In estimating, the provision for changes in price levels driven by economic conditions. Escalation includes inflation.
Federal Loan Guarantee (FLG)	The guarantee by Canada on a portion of the debt borrowed by Nalcor and Emera, enabling them to borrow at a lower interest rate than they would otherwise have been given.
Financial Close	The execution and delivery of several financing documents, the issuance of bonds and the advance of funds for the Project, pursuant to the Federal Loan Guarantee which took place in late 2013.
firm energy	Energy intended to be available throughout a specified period of time.
first power	The point at which power is first transmitted to the grid from a generating system.
force majeure	An event, condition or circumstance beyond the reasonable control of a party, and without fault or negligence of that party. Examples of *force majeure* events are natural disasters, environmental conditions, acts of war, court orders and strikes or lockouts.
full power	The first time the full capacity of a generating station is transmitted to the electrical grid.
Gatekeeper	The individual responsible for making decisions at each Decision Gate of a project's Gateway process. On the Muskrat Falls Project at DG2 and DG3, this was Nalcor CEO and President Edmund Martin.
Gateway process	A staged or phased decision-assurance process used to guide the planning and execution of the business opportunity presented by the development of the lower Churchill River.
geotechnical engineering	The study of the behaviour of soils under the influence of loading forces and soil-water interactions.
glaze ice	A smooth, transparent and homogeneous ice coating caused by freezing rain or drizzle.
grid	The layout of an electrical transmission or distribution system.

Term	Meaning
Integrated Resource Planning (IRP)	A method of least-cost planning that aims to properly compare the economic and environmental implications of alternative solutions for providing reliable electric power.
Interconnected Option	One of two options presented by Nalcor for the supply of electricity to Island ratepayers. It consists mainly of the Muskrat Falls Project and Labrador-Island Link, with thermal combustion providing reliability support.
Isolated Island Option	One of two options presented by Nalcor for the supply of electricity to Island ratepayers. It consists of a combination of thermal, small-scale hydro and wind generation projects on the Island.
Labrador Transmission Assets (LTA)	High-voltage cables transmitting power between Muskrat Falls and the Churchill Falls generating station.
Labrador-Island Link (LIL)	High-voltage cables transmitting 900 MW of power from Muskrat Falls through Labrador, across the Strait of Belle Isle and the Island to Soldiers Pond on the Avalon Peninsula.
Limited Notice to Proceed (LNTP)	A written notice that gives a contractor the go-ahead to begin work in a limited manner prior to the signing of a final contract.
LMAX	"Labour maximum cost," or the maximum value of the reimbursable cost of labour that an owner will provide to a contractor. The intention of an LMAX is to make the contractor responsible for labour costs above the LMAX value.
load	The amount of electric power delivered at any specific point or at specific locations on a grid system.
Maritime Link (ML)	The 500 MW high voltage connection from Granite Canal, Newfoundland, to Woodbine, Nova Scotia.
Mass Hub Price	A measure of current market prices for electricity in New England.

Term	Meaning
methylmercury	A toxic organic form of mercury formed when inorganic mercury combines with a methyl group, which is composed of carbon and hydrogen. It can be absorbed by fish and marine mammals and, as mercury poisoning, affect the health of humans who the eat contaminated species.
mitigation	The adoption of special measures or techniques to minimize or neutralize the negative impacts of a particular event.
monopole	An HVdc transmission system with one conductor.
Monte Carlo simulation	A mathematical method using random sampling that can simulate the probability of various outcomes. It is used in engineering and construction as a tool for quantitative risk analysis, to help determine a range of likely cost outcomes.
non-dispatchable power generation	Sources of electricity that cannot be used on demand at the request of power grid operators, according to market needs. Examples are wind and solar generation, because their energy is not always available.
non-firm energy	A source of energy that is not guaranteed to be a continuous flow and reliably available.
North Spur	A feature of the landscape at Muskrat Falls that forms a natural dam.
optimism bias	The demonstrated tendency for people to be overly optimistic about the outcome of planned actions.
peak demand	The highest level of electricity consumption that a utility has to meet at any one time.
penetration (wind)	The amount of wind energy supplied to a power grid, often expressed as a percentage.
powerhouse	The structure that contains the turbine(s) and generator(s) of a power project.
price elasticity	An index or measure of consumers' responsiveness to a price changes. Simply put, more product will be bought when the price of a commodity is cheaper and less will be bought when the product is more expensive.

Term	Meaning
P value	The statistical confidence level of achieving specific cost and schedule forecasts. For example, a cost estimate with a P value of 75 indicates a 75% chance the predicted cost will be achieved.
Quantitative Risk Analysis (QRA)	A process that attempts to determine the probability of various cost and schedule outcomes. The cost risks can be separated into strategic and tactical risks.
Recall Block	The 300 MW block of power that can be recalled from Churchill Falls, under the existing power contract between Hydro-Québec and CF(L)Co. Also "recall power."
reliability	The extent to which equipment, systems and facilities can be counted on to perform as intended.
rime ice	Opaque ice that forms when airborne drops of water freeze on contact with an object.
sanction	The milestone event at which a project's scope, budget and schedule are authorized. Sanction for the Project occurred on December 17, 2012, marking the start of the execution phase.
S-Curve	A diagram that has an S-shaped curve, which in a cost analysis simulates the likelihood of achieving a capital cost. In a time risk analysis, the curve simulates the likelihood of achieving project completion at given times.
sensitivity analysis	Analysis of the impact on a project's overall costs caused by variations in the key input parameters.
spilling water	Allowing water to pass through or over a dam, rather than using it to generate electricity.
Strait of Belle Isle (SOBI) crossing	A 30-kilometre underwater cable between Labrador and Newfoundland.
strategic misrepresentation	The planned, systematic distortion or misstatement of fact (lying) in response to incentives in a budget process.
strategic risk	Identified background risks that are outside of the control of the project team and that typically pertain to external issues.
Strategist	A software program that calculates and minimizes the cost of meeting anticipated energy demand for every hour of every year, suggesting which new generation assets should be built and when.

Term	Meaning
substation	A component of an electrical generation, transmission and distribution system where electricity passes through switchyards that transform it from high- to low-voltage electricity or vice versa.
synchronous condenser	A specialized machine, the unattached shaft of which spins freely. Its purpose is to assist in the voltage control of the transmission system to which it is connected.
tactical risk	The risk amounts associated with the base capital cost estimate and that result from uncertainties with the four components of that estimate: (1) project definition and scope omission, (2) construction methodology and schedule, (3) performance factors, and (4) price.
thermal generation	Electricity generated through the conversion of heat to electricity. Common thermal generating station types are coal, petroleum, geothermal, solar and natural gas.
watt	The base unit of electrical power used to measure the generating capacity of an electrical system, or the maximum demand of electricity consumers. Equivalencies: 1 kilowatt (kW) = 1,000 watts 1 megawatt (MW) = 1,000,000 watts 1 gigawatt (GW) = 1,000,000,000 watts 1 terawatt (TW) = 1,000,000,000,000 watts

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ACRONYMS

Acronym	Expansion
AACE	Association for the Advancement of Cost Engineering International
AC	alternating current
AFE	Authorization for Expenditure
ATIPPA	*Access to Information and Protection of Privacy Act*
CDM	Conservation and Demand Management
CEAA	Canadian Environmental Assessment Agency
CEO	Chief Executive Officer
CF(L)Co	Churchill Falls (Labrador) Corporation Limited
CFO	Chief Financial Officer
COREA	Cost Overrun Escrow Account
CPW	Cumulative Present Worth
COS	Cost of Service
CSA	Canadian Standards Association
DG	Decision Gate
EA	Environmental Assessment
EAA	Energy Access Agreement
EIS	Environmental Impact Statement
EOI	Expression of Interest
EPCA	*Electrical Power Control Act*
EPC	Engineer, Procure and Construct
EPCM	Engineering, Procurement and Construction Management
EY	Ernst & Young LLP
FFC	Final Forecast Cost / Forecast Final Cost
FLG	Federal Loan Guarantee
GDP	gross domestic product

Acronym	Expansion
GHG, GHGs	greenhouse gas(es)
GIS	gas insulated switchgear
GNL	Government of Newfoundland and Labrador
GWh	gigawatt hour
HHRAP	Human Health Risk Assessment Plan
HVac	high-voltage alternating current
HVdc	high-voltage direct current
IBA	Impacts and Benefits Agreement
IBEW	International Brotherhood of Electrical Workers
ICS	integrated cover system
IE	Independent Engineer
IEAC	Independent Expert Advisory Committee
IMT	Integrated Management Team
IPR	Independent Project Review
IRP	Integrated Resource Planning
JRP	Joint Review Panel
kV	kilovolt
kWh	kilowatt hour
LCC	line commutated converter
LCMC	Lower Churchill Management Corporation
LCP	Lower Churchill Project
LiDAR	light detection and ranging
LIL	Labrador–Island Link
LMAX	labour maximum cost
LNG	liquefied natural gas
LNTP	Limited Notice to Proceed
LTA	Labrador Transmission Assets

Acronym	Expansion
MF	Muskrat Falls
MFC	Muskrat Falls Corporation
MFEA	Muskrat Falls Employers Association
MHI	Manitoba Hydro International
ML	Maritime Link
MOU	Memorandum of Understanding
MW	megawatt
MWH	MWH Canada Inc.
MWh	megawatt hour
NCC	NunatuKavut Community Council
NERC	North American Electric Reliability Council
NG	Nunatsiavut Government
NLH	Newfoundland and Labrador Hydro
NSPI	Nova Scotia Power Inc.
O&M	operating and maintenance
P&C	protection and control (software)
PAA	Project Assignment Authorization
PBR	Performance-Based Regulation
PMT	Project Management Team
PPA	Power Purchase Agreement
PPE	personal protective equipment
PUB	Public Utilities Board
QRA	Quantitative Risk Assessment
RCC	roller-compacted concrete
RDTC	Resource Development Trades Council
RFI	Request for Information
RFP	Request for Proposals
ROW	right-of-way

Acronym	Expansion
SNC, SLI	SNC-Lavalin Group Inc.
SOBI	Strait of Belle Isle
SPO	Special Project Order
TWh	terawatt hour
UARB	Utility and Review Board (Nova Scotia)

NAMES AND AFFILIATIONS

This list includes the names and affiliations (as it pertains to the content of this Report) of people frequently referenced in this Report.

Last Name	First Name	Organization
Alteen	Peter	Newfoundland Power
Argirov	Nik	Independent Engineer
Bader	Georges	Astaldi
Ball	Dwight	Government of Newfoundland and Labrador
Béchard	Normand	SNC-Lavalin
Benefiel	Roberta	Grand Riverkeeper Labrador/ Labrador Land Protectors
Bennett	Gilbert	Nalcor
Blidook	Kelly	Memorial University
Bown	Charles	Government of Newfoundland and Labrador
Brewer	Donna	Government of Newfoundland and Labrador
Brockway	Tom	Grant Thornton, Expert Witness
Browne	Dennis	Consumer Advocate
Bruneau	Stephen	Memorial University
Cappe	Mel	University of Toronto, Expert Witness
Card	Bob	SNC-Lavalin
Chebab	George	Nalcor
Chippett	Jamie	Government of Newfoundland and Labrador
Clark	David	Nalcor
Chryssolor	Ken	Astaldi
Churchill	Jason	Cleo Research, Expert Witness
Clarke	Lance	Nalcor
Clift	Tom	Nalcor board of directors
Coady	Siobhan	Government of Newfoundland and Labrador
Colaiacovo	Pelino	Morrison Park Advisors, Expert Witness
Crawley	Brian	Nalcor
Dalley	Derrick	Government of Newfoundland and Labrador
Davis	Paul	Government of Newfoundland and Labrador
DeBourke	Darren	Nalcor
Delarosbil	Don	Astaldi

Last Name	First Name	Organization
Dodson	Keith	Westney Consulting
Ducey	BJ	Valard
Dunderdale	Kathy	Government of Newfoundland and Labrador
Evans	Jack	Westney Consulting
Fagan	Kevin	Nalcor
Feehan	James	Memorial University
Fleming	Greg	Nalcor
Flowers	Marjorie	Grand Riverkeeper Labrador/ Labrador Land Protectors
Flyvbjerg	Bent	Oxford University, Expert Witness
Goebel	Martin	Government of Newfoundland and Labrador
Goulding	A.J.	London Economics International, Expert Witness
Gover	Aubrey	Government of Newfoundland and Labrador
Greene	Maureen	Public Utilities Board
Hancock	Bernice	Community Education Network
Hanrahan	Denise	Government of Newfoundland and Labrador
Harrington	Paul	Nalcor
Harrington	Tim	Cahill-Ganotec
Hokenson	Rey	Independent Engineer
Holburn	Guy	Western University, Expert Witness
Hollmann	John	Validation Estimating
Humphries	Paul	Nalcor
Huskilson	Chris	Emera
Hussey	Patrick (Pat)	Nalcor
Jergeas	George	University of Calgary, Expert Witness
Kast	Mack	Manitoba Hydro International
Kean	Jason	Nalcor
Keating	James	Nalcor
Kennedy	Jerome	Government of Newfoundland and Labrador
Kennedy	Michael	Ernst & Young
Klakegg	Ole Jonny	Norway University of Science and Technology, Expert Witness
Knox	Leonard	H.J. O'Connell
Lemay	Paul	SNC-Lavalin
Leopold	Tim	Independent Project Review Team

Last Name	First Name	Organization
Lewis	Roy	Nalcor
Loucks	James	Independent Engineer
MacIsaac	John	Nalcor
Mallam	John	Nalcor
Manzer	Alison	Cassels Brock & Blackwell (legal counsel for Canada)
Marshall	Stan	Nalcor
Marshall	Ken	Nalcor board of directors
Marshall	Thomas	Government of Newfoundland and Labrador
Martin	Craig	Government of Newfoundland and Labrador
Martin	Edmund	Nalcor
Martin	Fred	Public Utilities Board
Martin	Thierry	General Electric
Mavromatis	Bill	Andritz
McClintock	Ken	Nalcor
McCormick	Patrick	Resource Development Trades Council
McLean	Carl	Nunatsiavut Government
Meaney	James	Nalcor
Michael	Lorraine	Retired, Member of the House of Assembly
Molloy	Donovan	Government of Newfoundland and Labrador
Morris	Paul	Government of Newfoundland and Labrador
Mulcahy	John	Nalcor
Mullaley	Julia	Government of Newfoundland and Labrador
Myrden	Paul	Government of Newfoundland and Labrador
Noble	Richard	Ernst & Young
O'Brien	Scott	Nalcor
Over	Ed	SNC-Lavalin
Owen	Derek	Independent Project Review Team
Paddon	Terry	Government of Newfoundland and Labrador
Palumbo	Mauro	Astaldi
Penney	Ronald	Muskrat Falls Concerned Citizens Coalition
Piétacho	Jean-Charles	Innu of Ekuanshit
Power	Ronald (Ron)	Nalcor
Power	Tanya	Nalcor
Raphals	Philip	Helios Centre, Expert Witness

Last Name	First Name	Organization
Rietveld	Aaron	Barnard-Pennecon
Russell	Todd	NunatuKavut Community Council
Schaufele	Brandon	Western University, Expert Witness
Shaffer	Scott	Grant Thornton, Expert Witness
Shortall	Gerry	Nalcor Board
Skinner	Shawn	Government of Newfoundland and Labrador
Snyder	Allen	Manitoba Hydro International
Snyder	Greg	SNC-Lavalin
Stanley	Todd	Government of Newfoundland and Labrador
Sturge	Derrick	Nalcor
Styles	Terry	Nalcor Board
Taylor	Brian	Government of Newfoundland and Labrador
Thompson	Robert	Government of Newfoundland and Labrador
Thon	Scott	SNC-Lavalin
Tisdel	Derek	Barnard-Pennecon
Tranquilla	Desmond	Nalcor
Tremblay	Jean-Daniel (J.D.)	SNC-Lavalin
Turpin	Mark	Nalcor
Vardy	David	Muskrat Falls Concerned Citizens Coalition
von Lazar	Laszlo	General Electric
Wade	David	Resource Development Trades Council
Walsh	Tom	Resource Development Trades Council
Warren	Auburn	Nalcor
Wells	Andy	Public Utilities Board
Westney	Richard	Westney Consulting
Williams	Danny	Government of Newfoundland and Labrador
Williams	Kelly	Valard
Wilson	Paul	Manitoba Hydro International
Young	Geoffrey	Nalcor