2013 **NSUARB-ML-2013-01**
Matter No. M05419

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: **IN THE MATTER OF THE MARITIME LINK ACT**

- and -

IN THE MATTER OF: **AN APPLICATION** by **NOVA SCOTIA POWER MARITIME LINK INCORPORATED** for approval of the Maritime Link Project

Evidence of MPA Morrison Park Advisors Inc.

Review of the Fairness, from a Financial Perspective,
of the Maritime Link Project to the Ratepayers of Nova Scotia

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1. Introduction, Summary, and Opinion

A. The Project

MPA Morrison Park Advisors Inc. ("MPA") understands that NSP Maritime Link Incorporated ("NSPML" or the "Applicant"), an indirect wholly owned subsidiary of Emera Inc. ("Emera"), and an affiliate company of Nova Scotia Power Inc. ("NS Power"), has filed an application (the "Application") dated January 28, 2013 to the Nova Scotia Utility and Review Board ("UARB" or "Board") for approval of the Maritime Link Project (the "Project" or "ML") and a plan to recover all Project Costs, including those related to building and operating the Maritime Link, pursuant to the *Maritime Link Act* and the Maritime Link Cost Recovery Process Regulations made under Section 6 of the *Act*. NSPML is the Applicant and the entity through which the Maritime Link Project will be developed and constructed. The Project is designed in such a manner as to allow Nova Scotia, among other things, to satisfy a number of environmental obligations, including Nova Scotia's Renewable Electricity Standards (the "Renewable Requirements"), and new Federal regulatory requirements focused on greenhouse gas emission reductions.

The Project will be constructed, financed, owned and operated pursuant to a series of commercial agreements among and between a number of stakeholders, including NSPML, Emera, Nalcor Energy, the Government of Nova Scotia and the Government of Newfoundland and Labrador. These agreements, taken together, provide for, among other things, the following:

i. The development of the Maritime Link by Emera,
ii. the provision to Emera of energy equivalent to 20% of the estimated capacity of the Muskrat Falls Generating Station,
iii. the provision to Nalcor Energy of certain transmission rights through the Province of Nova Scotia,
iv. the granting of transmission rights over the Maritime Link,
v. the responsibility for operating and maintaining the Maritime Link, and

vi. the transfer of the Maritime Link to Nalcor Energy following a period of 35 years after energy is first delivered to Emera.

These agreements are described in detail in the Application and the agreements themselves are a matter of public record. The foregoing description is subject in its entirety to those documents. For the purposes of this report, MPA considered the totality of the agreements, taken together, in assessing the fairness, from a financial point of view, of the Project to Nova Scotia ratepayers.

B. Engagement of MPA

MPA has been retained by the Board to assist Board Counsel to understand the evidence and to assist in ensuring the Board is provided with impartial, objective analysis which will permit it to make the best decision possible under the law. Pursuant to MPA's role, Board Counsel have requested MPA to provide an opinion as to the fairness, from a financial point of view, of the Project to ratepayers in Nova Scotia (the "Opinion").

Pursuant to an engagement letter dated January 23, 2013, MPA was engaged by the Board and will receive fees for its services. No portion of MPA's fees is contingent upon the outcome of the regulatory approval process.

C. Credentials of MPA

MPA is an independent, employee-owned, Canadian investment banking advisory firm which specializes in providing financial advisory services to corporations and governments. MPA focuses on several industry sectors, including the regulated utility/energy infrastructure sector, in which it has substantial background and expertise. MPA and its professionals have participated in a variety of capacities in many major transactions involving the valuation, acquisition or financing of regulated utilities and other large, complex energy projects in North America. As such, MPA is very familiar with the approach to value taken by major regulated utility acquirers in Canada and the key drivers of value in the regulated utility business.

MPA and its professionals have extensive experience in preparing valuations and fairness opinions and in transactions involving utilities such as the Applicant.

The Opinion expressed herein represents the opinion of MPA as of the date hereof and the form and content herein have been approved by a group of MPA's directors and officers, each of whom is experienced in mergers and acquisitions, divestitures, valuations and fairness opinions.

D. Independence of MPA

MPA confirms that:

i. neither MPA nor any of its affiliated entities is an associated entity or affiliated entity or insider of any of the Project proponents;
ii. prior to the date hereof, MPA has not been engaged as financial advisor to any of the Project proponents; and
iii. during the term of its engagement, MPA will not be engaged by the Project proponents as a financial advisor in respect of the Project.

As an independent investment banking advisory firm, MPA does not act as a trader or underwriter of securities or as a lender. In the future, in the ordinary course of its business, MPA may provide investment banking services to the Project proponents or their respective associates or affiliates, as MPA has a practice advising utility clients from time to time. Except as expressed herein, there are no understandings, agreements or commitments between MPA and the Project proponents or any of their respective associates or affiliates with respect to any future business dealings.

E. Scope of Review

In connection with the Opinion, MPA reviewed, considered and relied upon (without attempting to verify independently the completeness, accuracy or fair presentation thereof) or carried out, amongst other things, the following:

- The Application and all Appendices;
- Information requests ("IRs") to NSPML by MPA and other intervenors, and the responses thereto;
- Participation in technical sessions held by NSPML in respect of the Project;
- Other public information regarding the Project, including public information provided by Emera and Nalcor Energy on their respective websites;
- Filings related to the Project made with the Newfoundland and Labrador Board of Commissioners of Public Utilities;
- Numerous discussions with Board Counsel and staff and other experts and advisors retained by the Board;
- Public information regarding public market trading and other statistics for Emera and comparable companies; and
- such other corporate, industry and financial market information, investigations and analyses as MPA considered relevant in the circumstances.
- MPA had full access to and the cooperation of the Board Counsel and staff and was not, to the best of its knowledge, denied access to any information requested by MPA.

F. Assumptions and Limitations

In accordance with the terms of its engagement, MPA has relied upon, and has assumed the completeness, accuracy and fair presentation of, all financial and other information, data, advice, opinions and representations obtained by it from public sources or provided by the Applicant or any of its subsidiaries or their respective directors, officers, employees, consultants, advisors and representatives (collectively, the "Information"). The Opinion is conditional upon the completeness, accuracy and fair presentation of the Information. Subject to the exercise of its professional judgment, MPA has not attempted to verify independently the completeness, accuracy or fair presentation of the Information.

MPA has assumed that the forecasts, projections, estimates and budgets regarding the Project provided to us and used in our analyses have been reasonably prepared on bases reflecting the best currently available estimates and judgments of the relevant personnel as to matters covered thereby.

The Opinion is rendered on the basis of securities markets, economic, financial and general business conditions prevailing as of the date hereof and the condition and prospects, financial and otherwise, of the Project, the Applicant and other Project stakeholders, their subsidiaries, affiliates and other material interests as they were reflected in the Information reviewed by MPA. In its analyses and in preparing the Opinion, MPA made numerous judgments with respect to industry performance, general business, market and economic conditions and other matters, many of which are beyond the control of any party involved in the Project. All financial figures herein are expressed in Canadian dollars except where otherwise noted.

The Project is subject to a number of conditions outside the control of the Applicant and MPA has assumed that all conditions precedent to the completion of the Project can be satisfied in due course and in a reasonable amount of time and all consents, permissions, exemptions or orders of regulatory authorities will be obtained, without adverse conditions or qualifications. In rendering the Opinion, MPA expresses no views as to the likelihood that the conditions with respect to the Project will be satisfied or waived or that the Project will be completed within the timeframe indicated in the Application.

The Opinion does not constitute a recommendation as to whether the Board should approve the Project.

The Opinion is provided as of the date hereof, and MPA disclaims any undertaking or obligation to advise any person of any change in any fact or matter affecting the Opinion of which it may become aware after the date hereof. Without limiting the foregoing, in the event that there is any material change in any fact or matter affecting the Opinion after the date hereof, MPA reserves the right to change, modify or withdraw the Opinion.

The Opinion has been prepared and provided solely for the use of the Board, and may not be used or relied upon by any other person without the prior approval of MPA.

Although MPA conducted such financial analyses as it believed was appropriate in the circumstances in order to arrive at its Opinion, the Opinion should not be construed as a formal valuation of the Project or any of its assets.

MPA is not a legal, tax or accounting expert and MPA expresses no opinion concerning any of these matters regarding the Project. The Opinion should also not be construed as an opinion by MPA of the strategic merits of pursuing the Project or any alternative business strategy.

MPA has based the Opinion upon a variety of factors. Accordingly, MPA believes that its analyses must be considered as a whole. Selecting portions of its analyses or the factors considered by MPA, without considering all factors and analyses together, could create a misleading view of the process underlying the Opinion. The preparation of a fairness opinion is a complex process and is not necessarily susceptible to partial analysis or summary description. Any attempt to do so could lead to undue emphasis on any particular factor or analysis.

G. Summary of Fairness Considerations

In arriving at its Opinion as to the fairness, from a financial point of view, of the Project to ratepayers of Nova Scotia, MPA did not attribute any particular weight to any consideration, but rather made qualitative judgments based upon its experience in rendering such opinions and on prevailing circumstances, including current market conditions, as to the significance and relevance of each methodology and overall financial analyses.

MPA considered the ratepayers of Nova Scotia as a homogenous group and made no attempt to distinguish between different classes of ratepayers or between ratepayers at different points in time over the economic life of the Project.

The assessment of fairness, from a financial point of view, must be determined in the context of the particular transaction. In arriving at its Opinion, MPA considered, among other things, the following:

- MPA considered the levelized unit electricity cost ("LUEC") of the amount of power required to satisfy Nova Scotia's Renewables Requirement for the foreseeable future.
    - MPA considered specifically the LUEC of the Renewables Requirement when the power to satisfy that Requirement was delivered through the ML, under a variety of load scenarios. In arriving at that LUEC, MPA considered a variety of system related effects of the Project, including, among others, the ability to buy surplus energy at a potentially lower price than would otherwise be available to Nova Scotia ratepayers absent the Project.
    - MPA also considered the LUEC for the amount of power required to satisfy the Renewable Requirements under a variety of load forecast scenarios for the Status Quo option. In arriving at the Status Quo LUEC, MPA also considered a variety of system related effects, including the range of potential requirements to upgrade the Nova Scotia electricity system to support additional wind resources. These analyses are described in detail below.
    - MPA found the range of Project LUECs to be comparable to the range of Status Quo LUECs.
- MPA considered the qualitative benefits to ratepayers of Nova Scotia of the Project relative to the Status Quo option.

- MPA considered the relative financial and other benefits to the various Project proponents, and in particular Emera and Nalcor Energy, and found these financial and other benefits to be commensurate with the contributions being made and the risks being taken by such parties.
- MPA considered certain of the financial arrangements in the Project, and found no indication that these were commercially unreasonable.

H. Opinion

Based upon and subject to the foregoing, MPA is of the opinion that the Project is fair, from a financial point of view, to ratepayers of Nova Scotia.

2. Review Structure and Methodology

A. Organization of this Review

The Project is a complex transaction, consisting of multiple commercial agreements, many direct and indirect impacts on the Nova Scotia electricity system, and complex interrelationships with multiple surrounding electricity markets and commodity markets. In order to gain insight into the Project, and ultimately to be confident in rendering an Opinion on the fairness, from a financial point of view, of the Project to the Ratepayers of Nova Scotia, we have organized the remainder of this document as follows:

Section 3	Description of the Project	• Summary of features critical to the analysis
Section 4	Nova Scotia Electricity Needs	• Focus on legislative and reliability requirements: renewable energy, emissions, capacity
Section 5	ML and Nova Scotia Electricity Needs	• Project impacts, both direct and indirect
Section 6	Description of Alternatives	• Consideration of the further development of the Status Quo, and other options
Section 7	Analysis of Alternatives	• Use of LUEC analysis to consider financial impacts
Section 8	Consideration of Relative Fairness	• Distribution of costs, risks and benefits between the parties to the Project
Section 9	Consideration of Financial Aspects of the Project	• Debt arrangements, equity rate, tax risks, incentives for completion
Section 10	Conclusions	

B. Note on the Use of Projections and Models

In conducting our review of the Project, we have made use of the following:

- Information that was made available by the Applicant through this regulatory process, both in the form of the Application and supporting evidence admitted, and in response to all information requests;
- Information that was publicly available, whether from the Applicant, other Project stakeholders, from public authorities such as electricity system and market operators, or from general corporate, economic and financial sources;
- Financial information available through paid subscription services;
- Information, advice and opinions of other experts participating in this regulatory process on behalf of the Board, in the form of discussions and meetings;
- Our general experience, qualifications and skills in financial analysis and the preparation of valuations and opinions on fairness from a financial point of view.

A very significant component of the work of this Review involved the use of forecasts, projections and estimates, and in particular those provided by the Applicant in evidence and in response to information requests. We have not passed any judgment on the validity or reliability of these projections and estimates, but rather have assumed that they were prepared with all due care based on the professional qualifications of those responsible for them. It is critical to point out, however, the fundamental uncertainty that underlies many of the projections in question, particularly as they extend out not only years, but decades. 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. The development of hydraulic fracturing in the natural gas industry over the past decade is only a recent example of expectations about future market conditions being totally undermined: widespread expectations a decade ago were that North America would by now be supply constrained and increasingly reliant on expensive imports of natural gas from elsewhere, yet now there is a rush to find ways to export an overabundant commodity that has dropped dramatically in price.

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

It is commonplace that commercial transactions are analyzed using mathematical models, often providing a degree of precision measured in decimal points, which sometimes gives the illusion of accuracy or predictive power. We have used such models in this Review. 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 case, 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.

3. Description of the Project

The Maritime Link Project will be, if approved, a transmission connection between the Nova Scotia electricity system and the Newfoundland island electricity system. Financially and operationally it is related to the Lower Churchill Project (comprising the Labrador Transmission Assets, or "LTA", the Muskrat Falls hydroelectric generating station, or "MF", and the Labrador Island Link, or "LIL") that Nalcor and Emera are undertaking, but physically the ML is not connected to that project. Physically in between the Maritime Link and Labrador Island Link are parts of the existing Newfoundland island transmission grid.

The parties to the Maritime Link are NSPML and its parent company Emera and other related companies, Nalcor, and Nova Scotia ratepayers. The Government of Canada may also be considered a party to the agreement because of the loan guarantees being provided to support the debt obligations of the Project.

The ML is a unique arrangement, considered from the perspective of power systems. It is not a typical power purchase agreement, where an independent power producer agrees to supply a fixed amount of power or generating capacity to a customer for a known (or calculable) price over a fixed period of time. It is also not a traditional regulated generation asset, where a utility builds, owns and operates an electricity generating station at cost plus a regulated return. In either of these cases, there are multiple examples and benchmarks against which a new project can be compared.

Instead, the ML has some features of a variety of different arrangements:

- It is a power supply arrangement, since it includes the supply of an estimated 895 GWh of power per year for 35 years from in-service, plus an additional 220 GWh of power for the first five years;
- It is a capacity arrangement, since Nova Scotia will be able to rely on 153 MW of firm power supply for 35 years on a 7 day by 16 hour basis;

- It provides a new option to buy additional power at competitive market prices, since the capacity of the connection is 500 MW, and Nova Scotia will be in an intermediate position between a major seller of power in Newfoundland, and a potential buyer of power in New England; and
- It is a transmission project which strengthens the province's grid by adding two parallel 250 MW interconnections to a neighbouring market to which there has never been a connection before.

As a commercial agreement, the ML is also not easily characterized:

- The ML will be financed, constructed and operated by one company, NSPML;
- The only "user" of the ML will be Nalcor, since it will have exclusive rights to send its power across the connection;
- Nova Scotia ratepayers will pay the full construction and operating cost of the ML over the course of 35 years, as if it were a regulated transmission asset, but instead of just receiving transmission services they will in turn receive a specific amount of power provided by Nalcor at no additional cost;
- At the end of 35 years, the ML will be "sold" to Nalcor for the nominal price of $1, and Nalcor will be free to continue to use the asset for the remainder of its useful life, expected to be another 15 years, so the asset will cease to be a regulated asset and turn into a merchant asset owned and operated by Nalcor.

The ML is neither a simple purchase and sale, nor a lease, nor any other typical commercial transaction. It is a complex arrangement, governed by a number of highly detailed contracts, and as a result is both challenging to understand fully and bears the closest scrutiny.

From the perspective of understanding the value of the ML to Nova Scotia ratepayers, three of its features are critical, and will underpin much of the discussion in the rest of this Review:

- Ratepayers would be taking on the full capital and operating costs of the Project for 35 years in exchange for a fixed amount of power; therefore, it is possible to place a financial value on that power, based on the budgets and estimates pertaining to the Project;
- The nature of the power being provided to Nova Scotia ratepayers is such that it can be relied upon as a system resource in Nova Scotia, and hence has additional value;
- The size of the interconnection between Nova Scotia and Newfoundland would be such that substantial additional power beyond what has been committed could be transmitted, if market conditions warrant and the power is available. This feature is potentially valuable, but is much more difficult to quantify financially owing to the number of factors at play in determining value at any given point in time.

4. Nova Scotia Electricity Needs

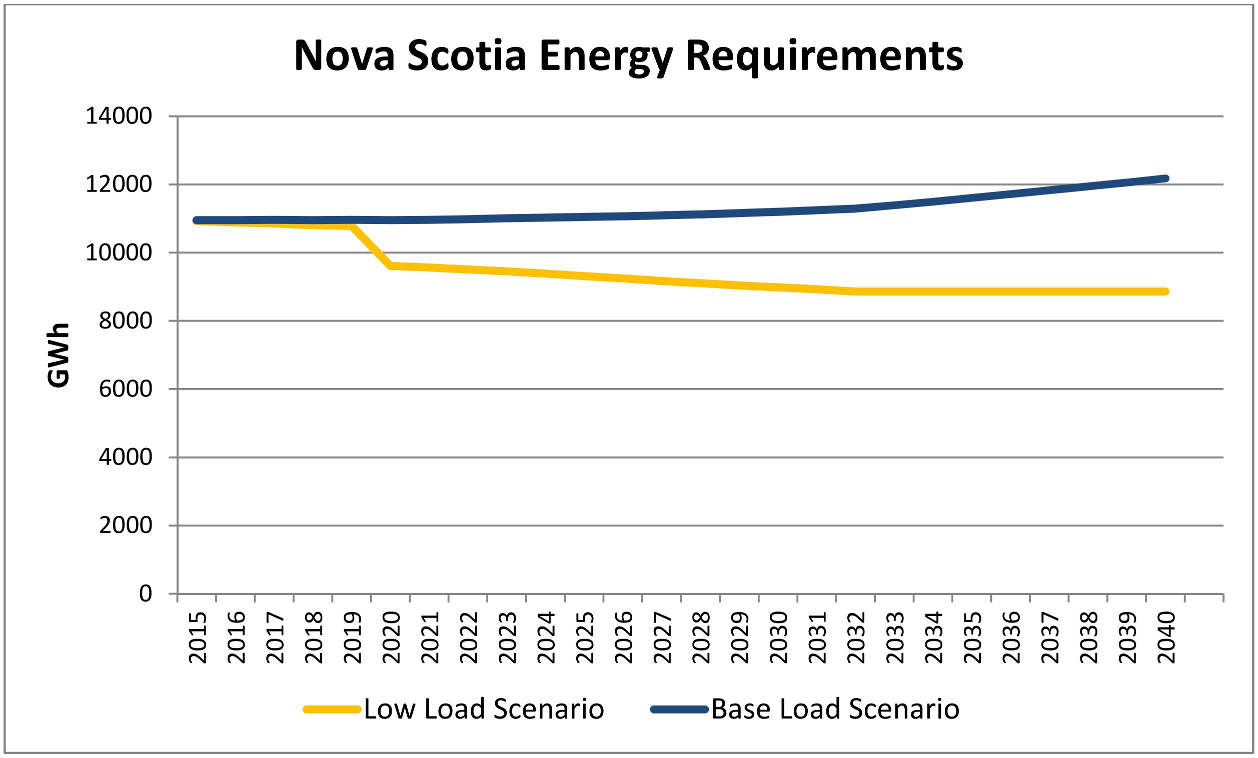
Nova Scotia ratepayers, like ratepayers everywhere else, want reliable, safe, environmentally sustainable and cost effective power.

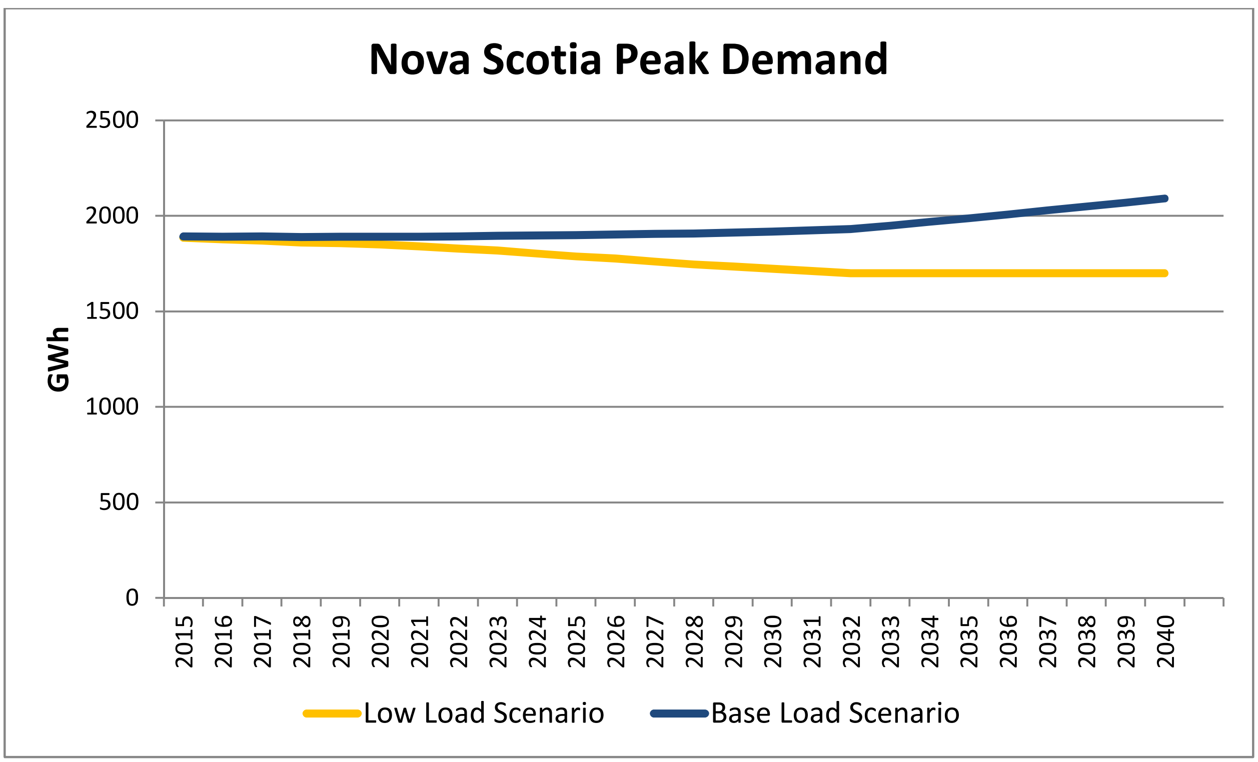
The existing electricity system in Nova Scotia meets these needs, but like all other systems faces the stresses of ageing assets that must be replaced, environmental restrictions that must be met, and a constantly changing economic and technological environment.

The ML, if approved and constructed, will be only one small part of a much larger system and collection of electricity assets. It is not being developed or constructed in a vacuum, but should be examined from the perspective of the system it will be part of, and the needs of that system.

Fundamentally, electricity systems must generate and deliver the amount of electricity that ratepayers require. This is measured both in terms of the total energy that is delivered and the instantaneous availability of needed power when it is most in demand.

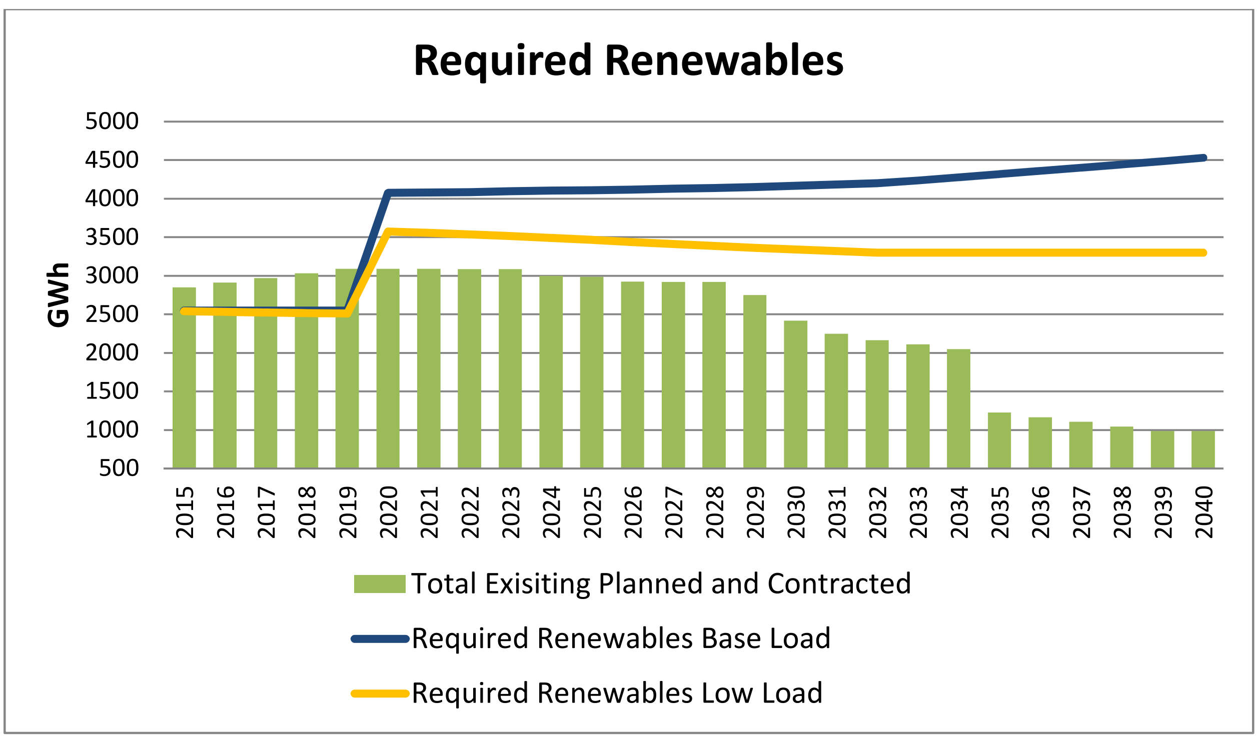
The Applicant has provided a load projection and peak demand projection extending to 2040, based on their analysis of economic drivers, and assumptions about the success of the province's demand side management programs. Two versions were provided, one a Base Load assumption, and the other a Low Load case.





It should be noted that the ML is a proposed 35 year arrangement from its in-service date, and the transmission asset itself is expected to have a life of approximately 50 years. Assuming in-service in 2017, this means that the ML will last until 2052, and the asset itself until 2067. The load forecasts do not reach out that far, however they do cover a substantial portion of the life of the ML, and are helpful in analyzing at least the nearer term impacts of the project.

The Government of Nova Scotia and the Government of Canada have placed restrictions on the nature of the supply which can serve customers. As noted by the Applicant, a specific portion of customer load is required to be served by “renewable energy”, as per Nova Scotia’s legislation. Nova Scotia is not starting from a zero base in considering the ML, however, since there are already a number of facilities which qualify as renewable energy, and in addition a number of new facilities have been planned or contracted. The following chart compares the available resources with the Base Load and Low Load renewable requirements.[1]



[1] Note that all existing hydroelectric plants have been assumed to be permanent (subject to periodic reinvestment), and all other renewable facilities are assumed to have useful lives of 20 years. Note also that this table does NOT assume reinvestment in any facility that reaches the end of its useful life, hence the declines in Existing and Planned resources over time.

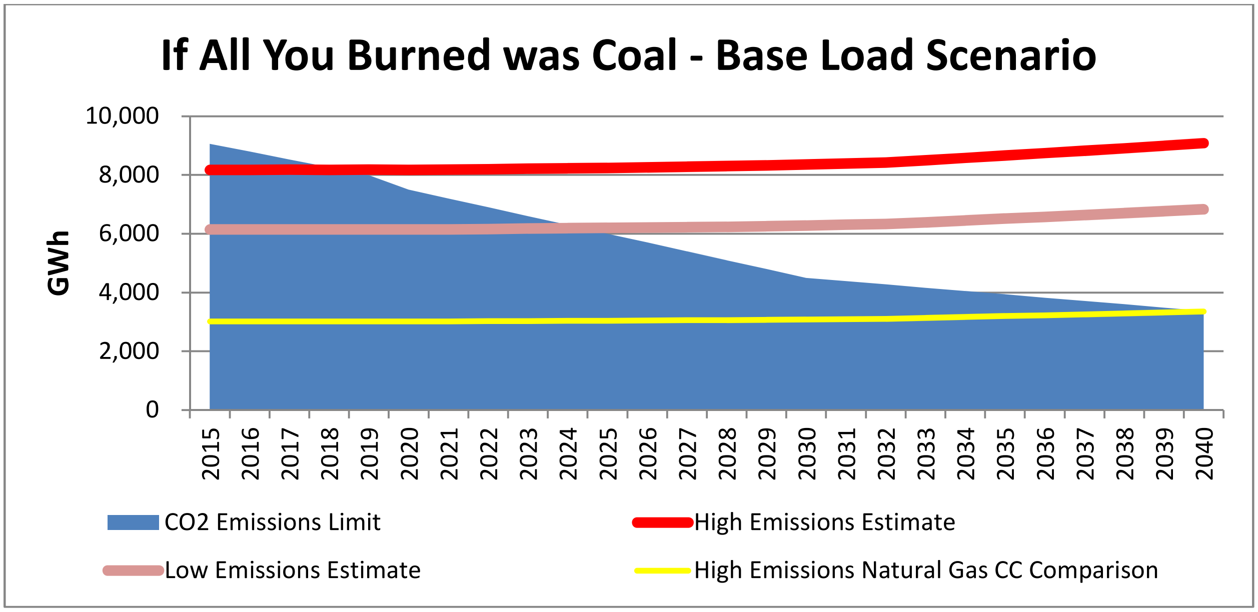
It should be apparent that Nova Scotia has a currently expected deficit in renewable energy resources, particularly in the Base Load scenario. In both scenarios the eventual end of life of existing facilities (which is the reason for the decline over time of the green bars representing existing and planned generation), will either require reinvestment in those facilities, construction of new renewable energy facilities, or import of qualified renewable energy.

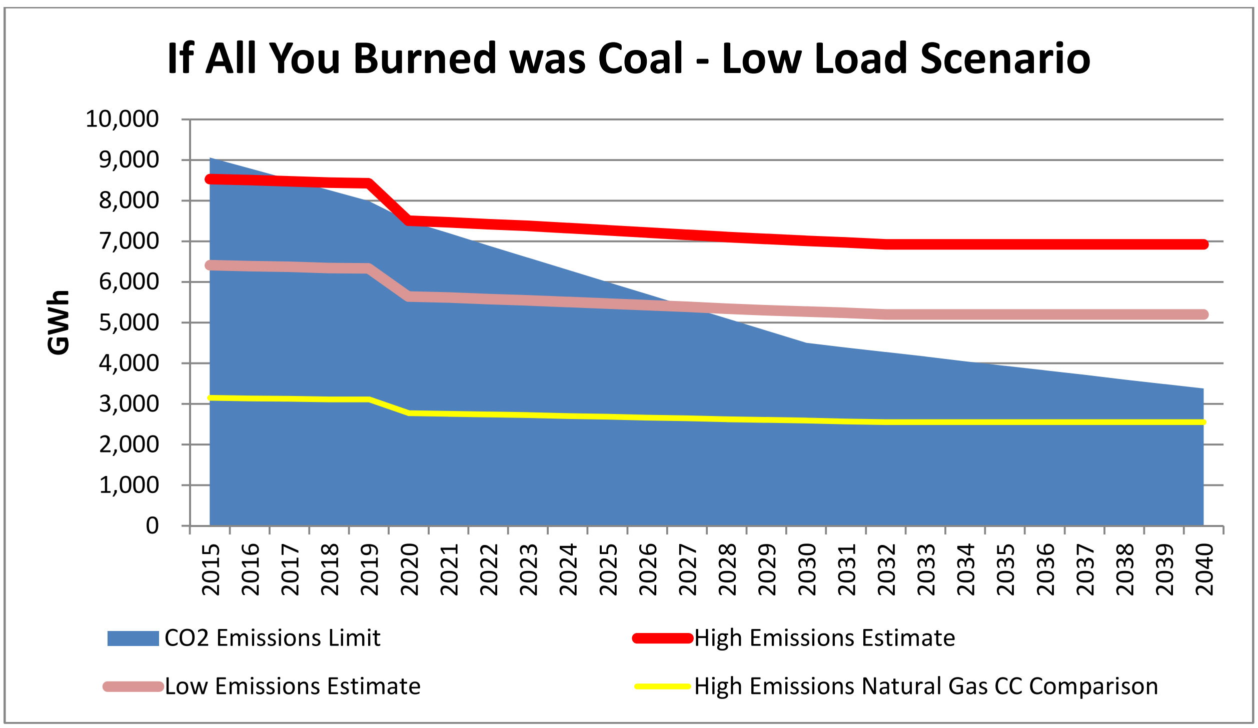
Filling this projected gap in renewable energy, whatever it may ultimately be, is the primary need that the ML addresses.

The portion of projected load that is not required to be served by renewable resources should presumably be served at the lowest cost possible, in order to keep the total cost of power for ratepayers as low as it can be. However, CO2 emissions from electricity generation will be limited by the agreement on equivalency of greenhouse gas emissions regulations between the Government of Nova Scotia and the Government of Canada, so it may not be possible to simply choose the lowest cost form of energy.[2] Historically, coal has been a cheap and readily available fuel for electricity generation. As a result, Nova Scotia over the years has built a sizeable fleet of coal-fired electricity generating stations. The following charts show the relationship between the imposed CO2 limits, and the consequences of generating all of Nova Scotia's electricity, except for that coming from renewable energy facilities, from coal-fired generators. [3]

[2] Other emissions are also regulated, including Oxides of Nitrogen, Mercury, Particulates, etc., however there are technologies available to manage most of these emissions. To date the technologies available to limit CO2 emissions are prohibitively expensive and as of yet uncertain in their long term performance. A technological innovation with respect to carbon capture and storage is one example of how technology could upend forecasts and future options.

[3] Note that figures are based on: coal with a range of 93.5 to 103.6 kg CO2 per MMBTU; coal plant heat rate between 10 and 12 MMBTU/MWh; pipeline natural gas with a range of 52.9 and 54.0 kg CO2 per MMBTU; gas plant heat rate between 7 and 8.5 MMBTU/MWh.





As can be noted, coal-fired power plants,[4] using current technology, could not be used exclusively to provide non-renewable power in Nova Scotia beginning likely in the mid to

[4] Similar constraints apply to fuel oil and petroleum coke, which can be substituted for coal in some Nova Scotia facilities.

late 2020s, under either scenario. This assumes, of course, that coal-fired power is cheaper than other sources, and would be preferred absent the CO2 restrictions.

It is also notable that natural gas-fired combined cycle plants do not face the same constraint: if Nova Scotia were to have a fleet consisting of only relatively efficient gas plants, the emissions target would not be problematic.[5] However, closing coal plants which are not at end of life in order to buil new combined cycle gas plants would be a very expensive proposition. As coal plants age, it would make sense to retire them and replace them with gas or some other available technology that will not suffer from the same emissions

The current lineup of generation facilities in Nova Scotia includes a substantial reliance on coal, so the CO2 target is indeed a real constraint that must be managed. Total existing non-renewable capacity, as measured by the nameplate of facilities is as follows:

	MW
Coal	1242
Natural Gas Single Cycle	419
Natural Gas Combined Cycle	150
Diesel/Fuel Oil	223
Total	2034

From this listing, it appears that coal is about 60% of the province's total fossil fuel electricity generating capacity, and so the constraint appears manageable. However, the single cycle natural gas facilities and the diesel/fuel oil facilities are peaking facilities specifically designed to run only a fraction of every year. While it is clear that Nova

[5] This is consistent with the intent of the federal regulations, which place an emphasis on the electricity industry meeting a gas plant based standard.

Scotia does not currently generate all of its non-renewable energy from coal, coal does make up a very substantial portion of the current output, and reliance on the fuel will have to be reduced in the future, no matter the prevailing prices.

This is the second energy need that the ML is to address; namely, that reliance on coal power in the future must be reduced, and preferably the new substitute should be as low cost as possible.

The final need involves Nova Scotia's peak capacity requirement. Nova Scotia must maintain a fleet of electricity generating units which are capable of meeting its projected needs. This involves projecting what the peak capacity requirement might be, based on all normal planning expectations and weather analysis, and then adding a safety margin to ensure that outages or accidents do not become barriers to reliably providing power to consumer.

A special feature of peak capacity analysis is that units must be counted upon only for the capacity that should be reasonably available when peak capacity is required, having regard to the unpredictable nature of the time of day or the season of a peak capacity event. This means that, for example, variable sources of generation such as hydroelectric and wind facilities cannot be counted upon to deliver their "nameplate" generation size. Instead, they must be discounted to a lower level, based on a number of factors that system operators take into account. Also, transmission interconnects with other jurisdictions can be counted on for support during peak events, but only to the extent that those lines are fully reliable, and not subject to congestion or other limitations.

The Applicant provided evidence on current capacity, expected changes to that capacity over the next few years, and the resulting target for 2020 and beyond. Summarized in the following table is the projected situation to 2020, when the renewables requirement described above must also be met:6

[6] Information from CA-SBA IR243 Att 2.

Peak Capacity Balance to 2020

Existing Resources		2340
Changes to 2020	Add Burnside #4	+ 33
	Add COMFIT projects	+ 16
	Add REA projects	+ 23
	Add Biomass project	+ 55
	Remove Lingan #1 and #2	- 306
Net Resources		2161
Required Resources	Low Load Scenario	2218
(including safety margin)	*Deficit*	- 57
	Base Load Scenario	2267
	Deficit	- 106

The planned retirements include two coal-fired units at the Lingan facility, both of which have been in-service for more than 30 years. While Nova Scotia has other coal plants that are as old, or even older, it has been determined that these plants should be retired.

Given this changing capacity picture it can be noted that the province will be short capacity by 2020 if there is not some addition of new facilities or firm import arrangements.

To summarize the needs of the existing Nova Scotia electricity system that the ML is expected to address:

A. *There is a near-term and ongoing requirement for additional renewable energy in the province, given Nova Scotia's renewable energy mandate; the size of this need depends on the actual load of the province, and whether it develops as seen in the Low Load or Base Load projections;*

B. *There is a longer-term need to reduce the province's reliance on coal/oil/petcoke, given the restrictions on Nova Scotia electricity sector CO2 emissions that have been agreed upon by the Federal and Provincial governments, but at the same time it is crucial for ratepayers that the total non-renewable energy supply be as low-cost as possible;and*

C. *There is a need for a relatively small amount of near-term firm capacity to ensure that the province can meet its expected system peaks after the planned retirement of two coal facilities.*

5. ML and Nova Scotia Electricity Needs

The ML, as planned, is designed to meet all three of Nova Scotia's electricity sector needs:

A. The guaranteed annual delivery of power from Nalcor through the ML will qualify as renewable energy, as confirmed by government regulation, meeting a substantial portion, if not all, of the incremental renewable energy required in the near term as per the load projections; in addition, if more energy is purchased from Nalcor and delivered on the ML, then that too may also qualify as renewable, and will assist in meeting the targets;

B. The ability to purchase additional power from Nalcor through the ML reduces the need to generate energy from coal, oil, natural gas or petcoke, and hence helps to reduce emissions, assuming that the additional power is competitively priced as against other options; and

C. The firm energy element of the ML appears to meet the need for firm capacity that results from the retirement of the two Lingan units.

Before considering alternative ways to meet Nova Scotia's needs, it is useful to address some issues that arise from the way the ML meets Nova Scotia's needs.

A. Meeting Renewable Energy Requirements

First, with respect to meeting renewable energy requirements, it should be noted that in the Low Load projection, the ML actually provides substantially more renewable energy than is required by legislation for many years of the projection, until existing facilities begin retiring in 2030. In fact, the ML would still provide excess renewable energy in the 2020s even if actual provincial load were 1000 GWh higher than the low load projection, or about midway between the two.

This raises a critical issue of the relative likelihood of the various load projections. If the Low Load projection is the more likely of the two, or if the probability favours the lower end between these two load projections, then the ML is oversized for this requirement.

There appear to be a few variables that underlie the different scenarios:

- Base Load assumes more robust economic growth;
- Base Load assumes that industrial load is at least maintained, rather than declining significantly around 2020; and
- Base Load assumes some growth in demand due to electric vehicles.

Our qualifications do not extend to the ability to question these assumptions, but at a minimum it should be recognized that these two projections may simply represent extreme possibilities bracketing what may occur.

On the other hand existing renewable resources, with the exception of hydroelectric facilities, have limited lives and will almost all require substantial reinvestment or outright replacement beginning around 2030. Given that the ML's 35-year term extends to 2052, and the expected life of the actual transmission connection extends to 2067, it may be possible that future investments in renewable energy to replace retiring assets could simply be avoided. An oversupply problem in the 2020s under the Low Load projection could in turn become an advantageous abundance under the same scenario, in the longer term.

B. Meeting Capacity Requirements

The ability of the ML to provide firm capacity for the Nova Scotia electricity system depends on two critical factors: the committed 150 MW of 7 day x 16 hour energy that comes from Nalcor to the ML, and the physical design of the ML.

Notionally, the power that is to be delivered to Nova Scotia will come from the Muskrat Falls hydroelectric facility. MF is being developed as an 824 MW station, with an annual capacity factor of approximately 65%, which suggests that on average it will deliver over 500 MW of power every hour of the year. In fact, annual snowmelt and rainfall patterns have a significant impact on the seasonal availability of water to run the facility, so the average does not represent the typical output of any hour. At the same time, however, the facility will benefit from substantial impoundment capacity, meaning that at lower water times of the year its available resources can be managed to ensure availability at peak requirement times. Given that the Nova Scotia block of power is to be delivered in only 16 hours of the day, the ability to shape power delivery from MF provides comfort that the firm power will be available when required. Of course, MF may be unavailable for certain periods for regular maintenance, or in the event of a forced outage. Hydroelectric plants, however, are among the most reliable types of electricity generation facilities, with typical forced outage rates below 1%.[7]

In reality, the ML is a transmission link, connected not directly to the MF facility, but to the Newfoundland island transmission system. As such, the availability of the guaranteed block of power depends not only on MF, but on the whole health and capacity of the Newfoundland and Labrador electricity system, as it will be once the Lower Churchill Project is completed. This means that the Nova Scotia block is subject to potential outages in the Newfoundland AC Transmission System, as well as on the LIL and at MF. To some degree, the risk of lost capacity from MF or through the LIL is somewhat mitigated by the fact that Newfoundland will have additional resources to call upon on the island itself. It is conceivable that if power were unavailable from MF because of an outage there, or an outage on the LIL, it might still be possible for Newfoundland to provide the Nova Scotia block based on island resources.

After the power reaches Bottom Brook in Newfoundland, it must actually traverse the ML in order to reach Nova Scotia. Like any other transmission infrastructure, the ML itself will face the need for regular maintenance, and the risk of forced outages. Unlike terrestrial systems, the ML faces unique challenges because of its undersea nature (like one segment of the LIL between Labrador and Newfoundland as well). The greatest risk

[7] See NLH, Exhibit 12 in the Muskrat Falls Review at the Newfoundland Public Utilities Board.

is that the undersea cable itself breaks or is otherwise damaged. Repairs to underwater cables are subject to potentially long waits for the customized ships and equipment that are necessary for repairs. To mitigate this risk, the ML has been designed as two parallel 250 MW cables, so that there is a high degree of probability that at least one cable will always be in service.

Ultimately, it should be noted that the 150 MW of firm capacity that is provided by the ML is less than half of the required reserve above maximum projected peak demand that must be maintained in Nova Scotia for safe operation of the system. Like all resources that contribute to Nova Scotia's required capacity, the Nova Scotia block of firm energy should be assumed to face a similar level of unavailability during the course of any given year.[8]

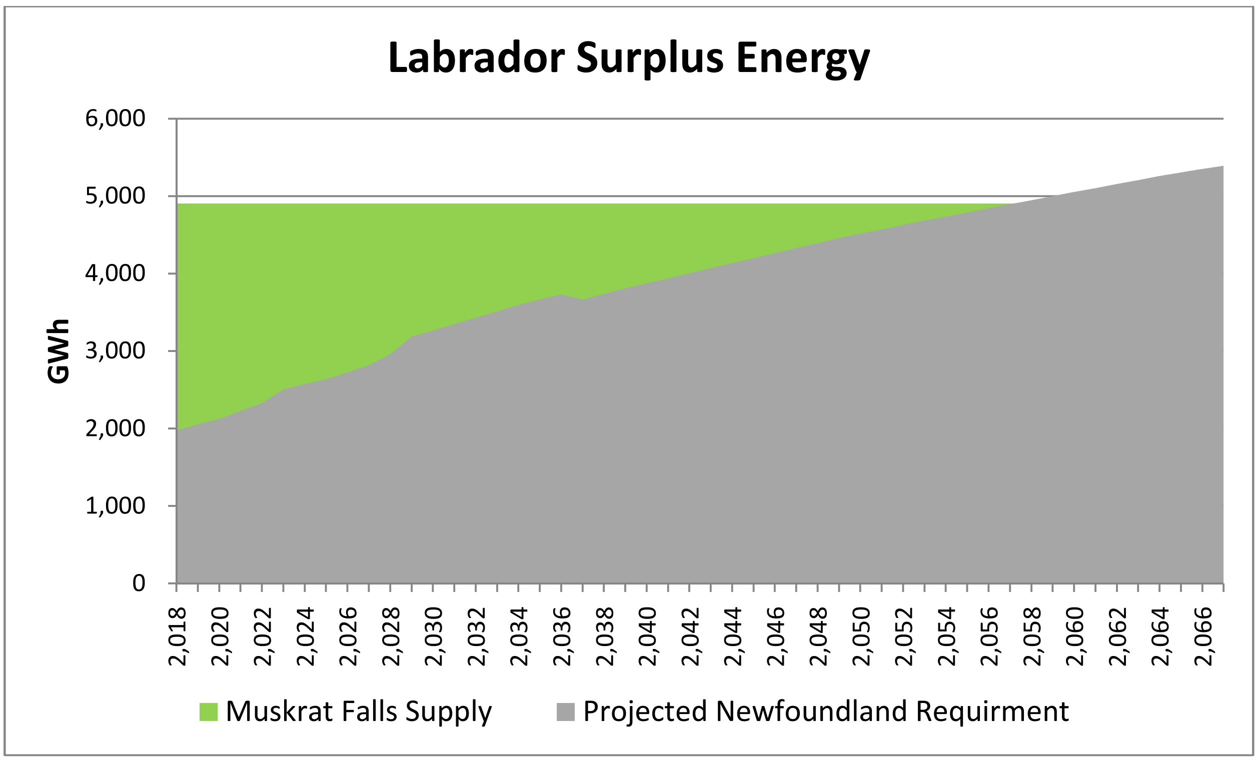
C. Availability of Low Cost Power from Newfoundland and Labrador

In addition to the fixed amounts of power that must be delivered as part of the ML, Nova Scotia ratepayers will also have access to additional non-firm power that can be purchased from Nalcor. On an annual basis, the ML is capable of transmitting more than 4 TWh of power, while the Nova Scotia block of firm power is less than 1 TWh. As noted above, the ML is physically just an interconnection between the Nova Scotia and Newfoundland electricity systems. As such, it can carry power that is available in Newfoundland, regardless of whether it happens to qualify as renewable or not. Assuming that Nova Scotia's renewable energy requirements have already been met, then the question becomes whether Newfoundland is a potentially good source of low cost power. In order to sell to Nova Scotia, Newfoundland must have available some "surplus" power that it does not itself need, and it should be competitively priced.

[8] Note that forced outage rates for single cycle gas turbines, combined cycle gas turbines and coal plants are much higher than hydro plants. The combined expected forced outage rate for MF, LIL, and ML would have to be substantially worse that typical forced outage rates for fossil fuel plants in order to deem the 150 MW from the ML as a suspect capacity resource.

The first issue to address is how much surplus power from Newfoundland and Labrador is expected to be available over the life of the ML. This is actually an issue of substantial uncertainty because of the longer term future of the Newfoundland and Labrador electricity system.

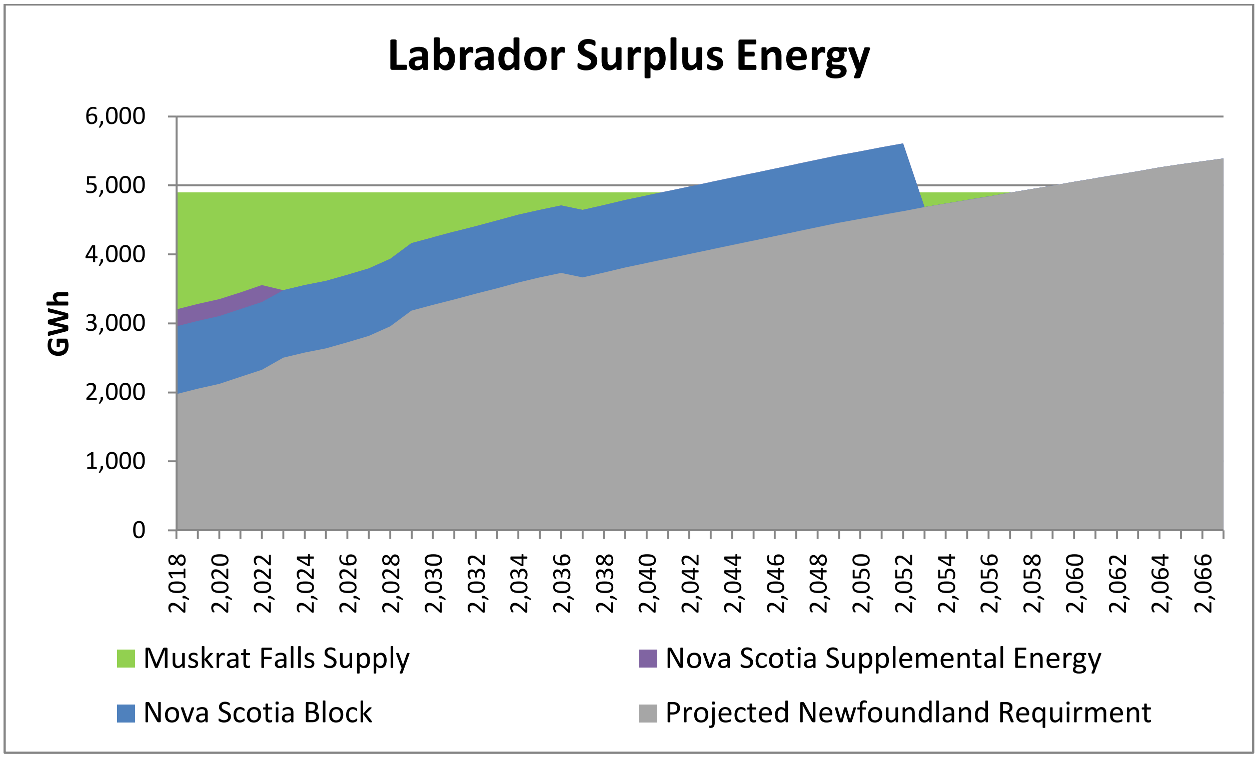
According to projections filed by Nalcor in regulatory hearings before the Newfoundland Public Utilities Board, load in Newfoundland is expected to grow over time, and consume a progressively larger portion of the available supply from Muskrat Falls. The following table shows the amount of power that is projected to be required to be transmitted from sources in Labrador to the island of Newfoundland in order to support projected load.[9]



As is clear from the above graph, MF by itself will not be able to support this projected Newfoundland load in the future (bearing in mind the extreme uncertainty of projections that stretch out decades). Note that this table does not include the requirement to sell

[9] Source: Exhibit 6.6b, Newfoundland PUB Review of Muskrat Falls.

power to Nova Scotia under the ML. If those commitments are added it should be obvious that "surplus" power from the MF will be limited in the much nearer, and perhaps more predictable future.



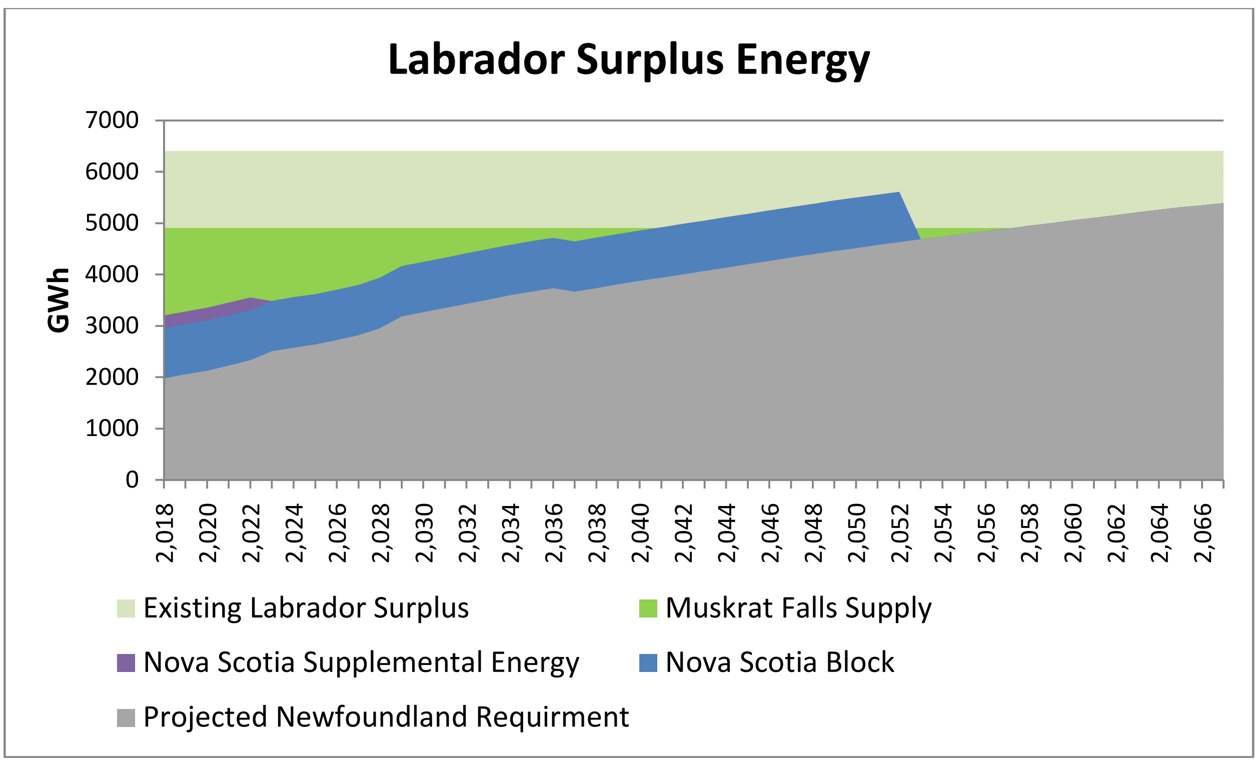
However, Labrador currently enjoys a surplus of supply, given the 525 MW of power available from Churchill Falls in the form of the "Twin Falls" and "Recall Power" arrangements.[10] The full supply of power is not currently being consumed in Labrador, and as a result, Nalcor has been able to sell the available surplus. Over the past five years, Nalcor has sold approximately 1500 GWh per year of power to export markets in New York.[11] The path for these exports is a 265 MW firm transmission agreement with Hydro Quebec on the existing 735 KV network that leads from the Churchill Falls Generating station down to interconnects with New York and Vermont. The

[10] The Recall Block of power – 300 MW at a maximum 90% load factor – was a term of the original Churchill Falls contract with Hydro Quebec, and lasts until 2041. The Twin Falls block is 225 MW at a maximum 90% load factor, fully subscribed and sold to mining concerns in Western Labrador. When the contract expires in 2014, the block will be made available to Nalcor at "market prices", presumably to be resold to the same customers. Together, the two blocks of power amount to approximately 4.2 TWh per year.

[11] Source: Nalcor 2011 Annual Report.

transmission service arrangement costs $19 million per year, and expires in 2014, but is renewable at Nalcor's option.[12] Transmission losses on the Hydro Quebec 735 KV network average approximately 5%, making this a relatively efficient way for Nalcor to sell its surplus power to export markets further south.

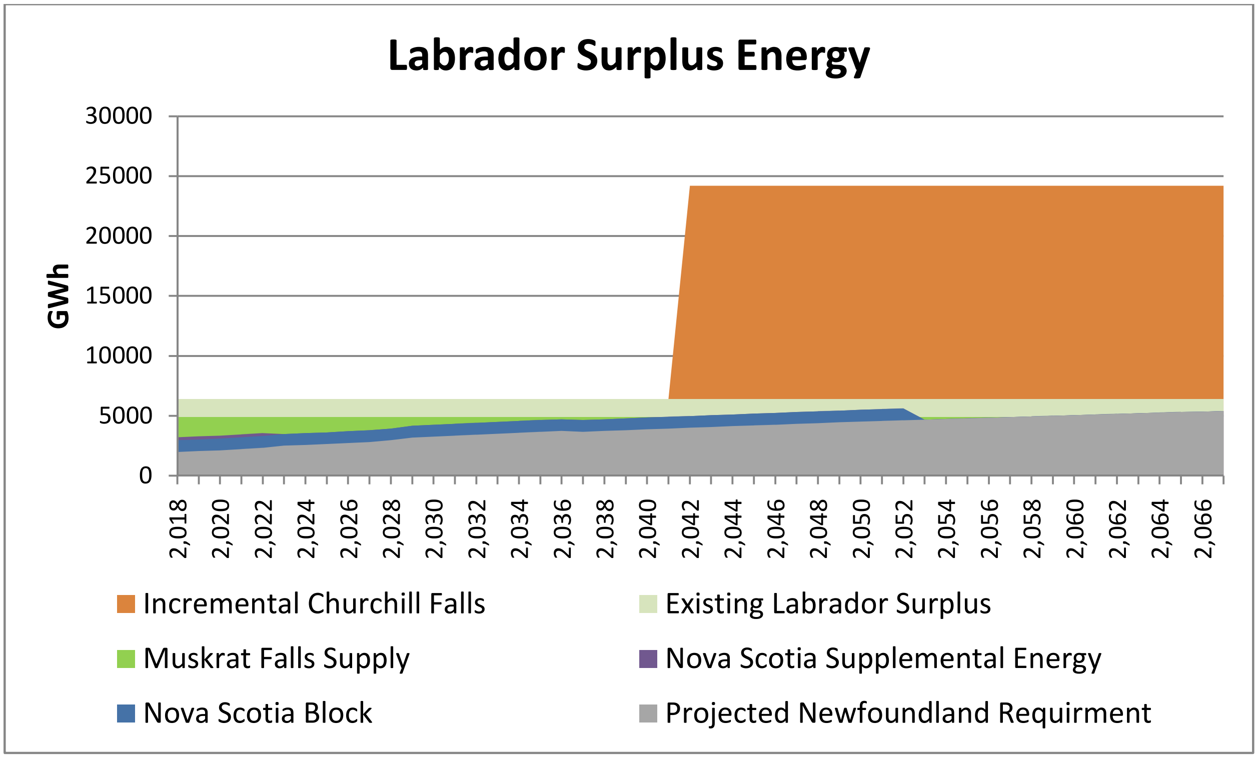
Power demand in Labrador from existing customers is not expected to grow very much over time, so this existing 1500 GWh of surplus power can be considered approximately reliable going forward. However, there is the potential for substantial expansion of mining activity in Newfoundland over the next 20 years, with an unpredictable impact on the existing Labrador surplus. According to the Government of Newfoundland, it is possible that the existing Labrador surplus could be entirely consumed by new mining activity, at least in a high growth scenario. As such, including the existing Labrador surplus to what was shown above would be a maximal expectation of available surplus in Newfoundland. The reality of surplus supply in Labrador is likely to be between the table shown above, and the following table.



[12] Ibid.

This is not the complete story, however. In 2041, the existing contract between the Churchill Falls Corporation and Hydro Quebec will expire, as will the contractual arrangements applying to the Twin Falls and Recall Blocks of power. Under its contract, Hydro Quebec is currently supplied with approximately 30 TWh of power per year, or about 90% of the output of the Churchill Falls facility. When that contract expires, some other arrangement will be required to determine the future sale of power from the facility.[13] Nalcor owns 65.8% of Churchill Falls Corporation, and Hydro Quebec owns 34.2%. At a minimum, it can be assumed that Nalcor will be free to make choices about the disposition of 65.8% of the power output of the facility, which over the past five years averaged approximately 33 TWh per year (Nalcor's share would therefore be approximately 22 TWh; note that this would be a net increase of about 17.8 TWh over the existing 4.2 TWh that Nalcor controls from the Recall and Twin Falls blocks). This supply should be expected to be available to fulfill any and all Newfoundland load, and any obligations to Nova Scotia.

[13] Note that the three 735 KV lines from the Churchill Falls station connecting to southern Quebec and from there into New York, Maine and New Brunswick are *physically* capable of carrying the full generating capacity of the station, at 5428 MW. The state of the Quebec transmission system at the other end of the lines in southern Quebec may be an issue, and the commercial arrangements for transmission access are another issue altogether.



A final issue concerning the availability of surplus power in Newfoundland and Labrador is the potential for development of the Gull Island hydroelectric site. Nalcor has estimated the supply potential at approximately 12 TWh per year, if a facility were to be developed. However, existing transmission infrastructure, including the ML if built, would not support this additional power supply, so the Gull Island facility could only be built in conjunction with new transmission facilities.

In summary, Newfoundland and Labrador is expected to have a substantial amount of surplus power immediately following construction of the MF facility, but will have declining supplies of surplus power until 2041. The speed of that decline will depend on the growth of the mining industry in Labrador, and its demand for power, as well as the accuracy of Nalcor's estimate of the growth in demand for power on the island of Newfoundland. In the most aggressive scenario, it is possible that Labrador may have no surplus energy by 2041, or alternatively there may be abundant supplies throughout the period. When the expiry of the Hydro Quebec contract arrives in 2041, Newfoundland will have

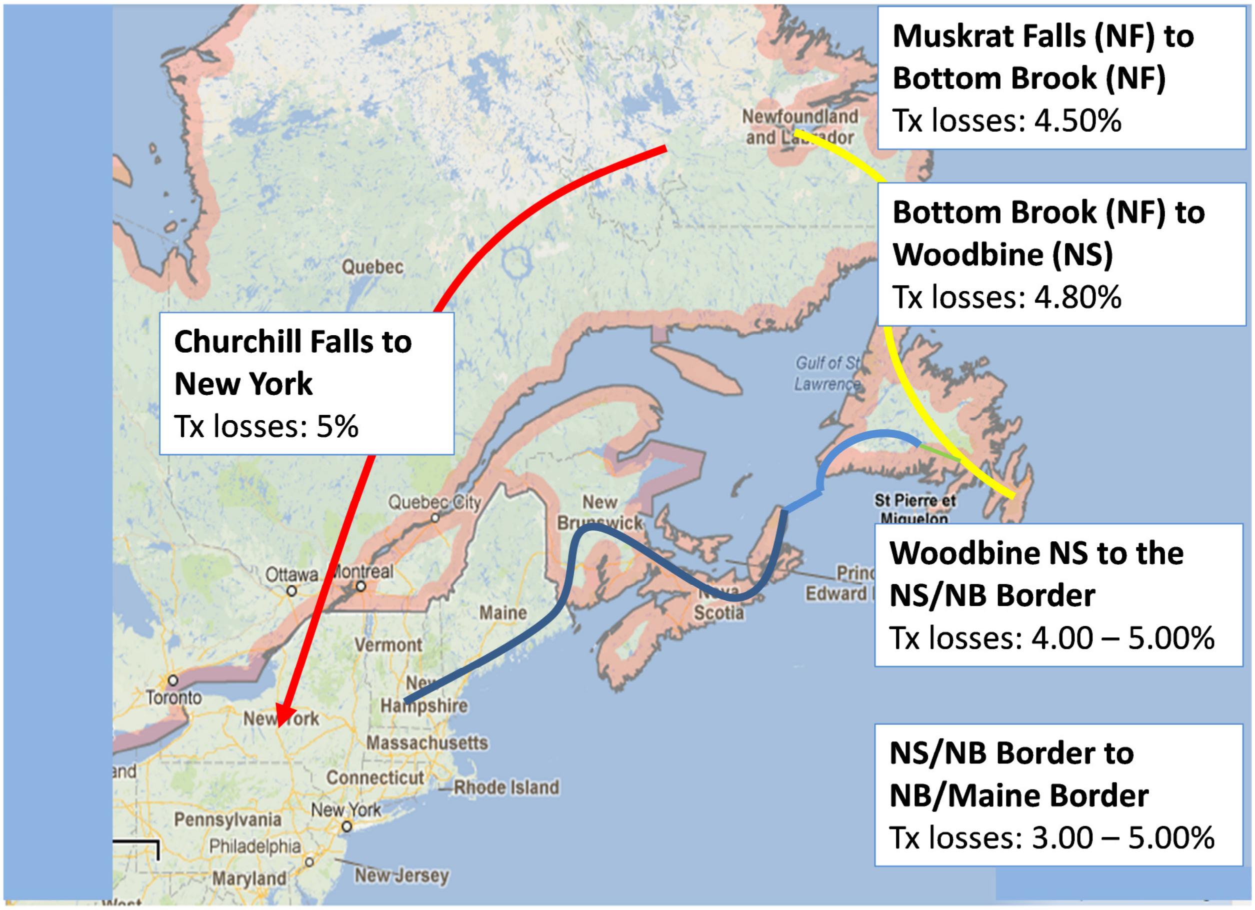
access to an abundant supply of surplus power. Moreover, the potential for construction of the Gull Island facility would mean another massive injection of surplus power into the Newfoundland and Labrador system.

Price of Labrador Surplus Power

The next issue, after confirming that there will indeed be surplus power available in Newfoundland and Labrador over the life of the ML, is whether that surplus will be made available to Nova Scotia, and if so at what price?

Existing surplus power in Labrador only has one outlet: the 265 MW of transmission capacity being purchased from Hydro Quebec that leads down to New York. After the Lower Churchill and Maritime Link Projects are complete, Newfoundland will have a second route to export power, namely to Nova Scotia and beyond into New Brunswick and from there to Maine and the rest of New England.

Routes For Surplus Power



The cost of the transmission through Quebec is currently $19 million annually. In addition, Newfoundland must factor in approximately 5% loss of power through the transmission connection before reaching the New York market at the border between Quebec and New York.

Reaching Nova Scotia from Muskrat Falls through the Maritime Link (and the LIL and Newfoundland AC transmission system before that) will be financially costless to Nalcor under the ML arrangements, however it does entail approximately 9% in losses to transmission.

If Nalcor wishes to sell its surplus power to New England markets, then it will have to pass through Nova Scotia and New Brunswick, which means even more transmission losses and costs. Surplus power from Labrador will suffer approximately 17% losses before it reaches New England, and Nalcor will have to pay transmission tariffs in both Nova Scotia and New Brunswick before selling its power.

Surplus Power Route Comparison

Route	Transmission Losses	Transmission Costs	Capacity (before losses)
Labrador to New York	Approx. 5%	Quebec Tariff	2300 GWh/year
Labrador to Nova Scotia	Approx. 9%	No cost	4300 GWh/year
Labrador to New England	Approx. 17%	Nova Scotia Tariff & New Brunswick Tariff	4300 GWh/year

Nalcor currently exports about 1500 GWh of power to New York per year, but the maximum capacity of the transmission link would be about 2300 GWh. Newfoundland should be economically indifferent between selling surplus power to New York and selling it to Nova Scotia when:

New York Power Price * (Surplus Export – 5%) - $19 million = Nova Scotia Price * (Surplus Export – 9%)

Assuming the Surplus is 2300 GWh and the New York price is $50/MWh, then the Nova Scotia price would have to be $43.12/MWh in order for Newfoundland to be economically indifferent. In other words, Nova Scotia, owing to the existence and structure of the ML, would have an economic price advantage over any New York buyer of Newfoundland surplus power of a bit less than $7, in this example. Another way of saying this is that Nova Scotia would be able to purchase power at its end of the ML at a price approximately $7 *less than* the price at the New York/Quebec border, at least in this scenario. To the extent that Nova Scotia was willing to pay more than $43.12/MWh, then Newfoundland would actually be unequivocally better off selling to Nova Scotia than New York.

There is a caveat to this story, however: it is unlikely that Nalcor would be willing to relinquish the contract it has for 265 MW of transmission access through Quebec, under almost any circumstances.[14] The relationship between Newfoundland and Quebec has been so tumultuous because of the Churchill Falls-Hydro Quebec contract, and because of disputes over Newfoundland's desire to increase its transmission access through Quebec and Quebec's refusal to accommodate that request, that to relinquish the only available block of transmission access would be very unlikely. If this is assumed to be true, then the $19 million annual transmission cost, escalating at whatever rate over time until 2041, should be assumed to be a "sunk" cost for Nalcor. In that event, the transmission paths through Quebec and the ML should be compared on the basis of no transmission cost for the Quebec path, at least for the first 2300 GWh of surplus power. In that case, Nova Scotia would be required to pay a cost of New York prices at the border *plus* 4%, because of the higher transmission losses on the ML.[15] However, for any surplus power in Labrador above 2300 GWh, the ML would be the only conceivable outlet and so New York prices are not relevant. As shown in the graphs in the preceding section, between the in-service date and about 2030 it should be expected that the Labrador surplus will exceed 2300 GWh, unless new mining development in Labrador erodes the surplus substantially, as discussed above.

For any power above the 2300 GWh of transmission availability through Quebec (or in the event that the Quebec transmission path is for some reason no longer available to Labrador surplus power), the value of power at the end of the ML at Woodbine, Nova Scotia is measured differently. Nalcor's option would be to sell power to Nova Scotia at that point, or else sell the power further along the transmission grid, to customers in

[14] Note however that it is possible that Hydro Quebec may at some point argue that it can no longer offer the transmission path to Nalcor because of congestion on the 735 KV system, in which case the ML would be Nalcor's only route to market for its surplus energy. From Nalcor's perspective, this is a critical benefit of the ML, which will be discussed below.

[15] Note that sending power from Muskrat Falls to Churchill Falls on the LTA would incur some transmission losses, so the spread would likely be slightly less than 4%.

New Brunswick, in Maine, or elsewhere in New England. Each step along the way entails costs, however, since transmission losses and transmission tariffs are incurred at each step. For example, crossing Nova Scotia from Woodbine to the New Brunswick border entails a transmission loss of approximately 4%, and crossing New Brunswick to the Maine border another 3 - 5%, depending on various circumstances. At the same time, both Nova Scotia and New Brunswick have Open Access Transmission Tariffs that would be paid before the power reached the Maine border. It should be expected, therefore, that the price for Nova Scotia of “true” Labrador surplus power at Woodbine would be:

Woodbine price = (Maine border price – 8%) – (cost of transmission through NS and NB)

This is a substantial price difference, and of enormous significance for Nova Scotia ratepayers.

In sum, the price of Labrador surplus power at the Woodbine station in Nova Scotia should be assumed to be one of either of three prices:

- New York/Quebec border price plus 3% to 4% (because of transmission losses), less the cost of transmission through Quebec (if Nalcor were indifferent to giving up its Quebec transmission access, which is highly unlikely)
- New York/Quebec border price plus 3% to 4% (if Nalcor insisted on keeping its Quebec transmission access regardless of economics, which is both likely and commercially sound, as will be discussed below)
- Maine/New Brunswick border price less 8% (for transmission losses) less the cost of NS and NB transmission (for any surplus power that could not access the Quebec transmission grid for any reason)

A final subtlety is that the price for surplus power at Woodbine will actually be the highest of these three price points, at least for the first 2300 GWh of Labrador surplus power, since Nalcor would retain the option of using either transmission route.

Technical Note:

For the sake of simplicity, the explanation so far of prices has assumed that there is a simple "New York" price for power, and a "New England" price for power. In fact this is not the case. Both New York and New England have complex electricity markets with different prices for power at different points within their market territory, and these prices are changing every hour of the day. Comparing the options that Nalcor would face in deciding where to sell its power would also require an understanding of the spread in prices between the Northern New York "node" where the New York system interconnects with Quebec, and the Northern Maine "node" where New Brunswick connects to the New England electricity system. Prices will be changing in each market independently of each other because of local demand and supply pressures and transmission constraints, so the spread between them will not be simple to estimate. This is a level of complexity that requires detailed knowledge of each market to address, and is beyond the scope of this Review.

From this analysis, it appears that the price of surplus power from Newfoundland is competitive with sources that are outside the province (since all potential sources of power will base their prices either on New York or New England market prices, as the benchmark prices within reach of Nova Scotia). The only remaining question is whether these prices are competitive with the cost of generation in Nova Scotia itself.

Comparison of Labrador Surplus to Domestic Generation in Nova Scotia

It is clear that Labrador will have surplus power at various times, and it is clear that Nova Scotia is a potential market for at least some of that power. But will Nova Scotia want that power? Obviously, if Nova Scotia were in a state of short supply, then it would pay the required price, however Nova Scotia is not in short supply, since it has a fleet of power plants of its own. Nova Scotia will therefore only want to buy surplus power from Labrador if the price of that power were cheaper than generating power locally.

Existing non-renewable generation in Nova Scotia consists of the following:

Existing Fossil Fuel Plants in Nova Scotia

Coal		Natural Gas		Natural Gas CC		Diesel	
Plant	**MW**	**Plant**	**MW**	**Plant**	**MW**	**Plant**	**MW**
Lingan #1	153	Tufts Cove #1	81	Tufts Cove #6	150	Burnside #1	33
Lingan #2	153	Tufts Cove #2	93			Burnside #2	33
Lingan #3	153	Tufts Cove #3	147			Burnside #3	33
Lingan #4	153	Tufts Cove #4	49			Burnside #4	33
Pt Aconi #1	171	Tufts Cove #5	49			Tusket #1 CT	25
Pt Tupper #2	152					Victoria Junction #1	33
Trenton #5	150					Victoria Junction #2	33
Trenton #6	157						
Total	**1242**	**Total**	**419**	**Total**	**150**	**Total**	**223**

With the exception of Lingan #1 and #2, which are projected to be retired by 2020 at the latest, all of these facilities are required to ensure that the province has sufficient capacity to serve ratepayers during peak demand periods. Capital and fixed O&M costs must therefore be spent regardless of the price of alternative energy supplies, from Labrador or elsewhere.

The principal variable cost for all of these plants is fuel, so it is the marginal cost of fuel per MWh of power produced which could be displaced by surplus power from Labrador, if the price were attractive, and the Nova Scotia facilities in question were not needed to maintain safe operation of the electricity system.[16] Normally, the efficiency of a fossil fuel plant is measured in "mmbtu/MWh", and is called the "heat rate". This is a measure of the heat value of the fossil fuel required to produce 1 MWh of power. A coal plant requiring 10 mmbtu of coal would be more efficient than another coal plant which requires 12 mmbtu of coal for the same MWh. Gas plants also measure their fuel in mmbtu. The marginal cost of operating a fossil fuel electricity plant is therefore the cost of the fuel, measured in mmbtu (whether coal or gas), multiplied by the specific heat rate of the plant: e.g., coal for $6/mmbtu * 10 mmbtu/MWh = $60 per MWh.

[16] Note that there will be some variable cost for every MWh of power produced at any of these facilities, but it will only be a small fraction of the cost of fuel, so it is being ignored here for simplicity. If anything, addition of such a factor only makes imports more attractive.

Only the coal plants and the combined cycle gas plant in Nova Scotia need be considered, since the single cycle gas plants and diesel plants are far more expensive to operate than imported power prices given their very high heat rates and operating costs.

Assuming that the price of power at the end of the Maritime Link is based on the New England market price (as was described above, this would be equal to the New England price less at least 8% for transmission losses), then Nova Scotia would want to buy surplus power from Nalcor if the cost of operating plants in Nova Scotia was higher than the cost of New England power less 8%. Not all plants in Nova Scotia are the same, however, so this calculation would have to be made on a plant by plant basis, to determine how much power Nova Scotia would really want to buy.

The relative prices of coal and gas are important in this calculation, because the New England market price is largely set by the gas-fired plants located throughout the New England area, while Nova Scotia is mostly dependent on coal plants. If gas is relatively cheaper than coal, then New England prices will tend to be lower, and since power from Nalcor will be priced 8% lower than New England, it will be very cheap for Nova Scotia to buy. However, if gas prices are high, then the New England power price will tend to be high, and the price of Nalcor power will also be less attractive.

Based on the range of coal and gas price projections provided by the Applicant, the fuel cost for Nova Scotia's coal plants will be higher than the cost of Labrador surplus power in all but the highest market price forecasts.

This suggests that the surplus power available on the ML will indeed be an attractive option for Nova Scotia at many times.

6. Description of Alternatives

Based on the three Nova Scotia electricity needs identified above, some alternative solutions to the ML can be considered.

Renewable Energy Deficit: The obvious solution is to build renewable energy generation facilities in Nova Scotia; another alternative is to procure renewable energy from a supplier outside of Nova Scotia other than Nalcor.

Low Cost Energy Constrained by Emissions Limits: build low cost generating facilities in Nova Scotia that produce relatively low emissions (such as combined cycle gas plants), or procure sufficient imported power to minimize Nova Scotia emissions, and do so at lower cost than existing or new generation.

Capacity Requirement: To the extent that new renewable energy does not satisfy the need for capacity, then build additional capacity in Nova Scotia, or procure additional firm energy from outside of Nova Scotia.

The applicant constructed two hypothetical alternatives that would meet these criteria:

- An Indigenous Wind solution that would see renewable energy needs met by significantly increasing Nova Scotia's renewable energy production, supplemented by new gas-fired plants to fulfill capacity needs;
- An Other Import solution where a renewable energy supply contract with an external provider would be facilitated by a major build-out of transmission capacity through New Brunswick, and where the additional transmission capacity would provide the opportunity to purchase additional power that may be competitive with indigenous supply options while assisting with meeting longer-term emissions targets

Commercial Reasonableness of Other Options

Nova Scotia is currently facing the option of buying power from Nalcor through the proposed Maritime Link. This is a real, fully negotiated commercial agreement, which is actionable now.

Nova Scotia also has another option that is definitely actionable, which is to continue on its current path of building renewable energy facilities in Nova Scotia: essentially the Status Quo. This is akin to what the Applicant has termed the Indigenous Wind option, but it is important to note that Nova Scotia retains much more flexibility than the Applicant has allowed in describing the Indigenous Wind option. At some point in the future, for example, Nova Scotia could decide to build a new transmission line to bolster its capacity to import power, from somewhere, and therefore blend imports along with domestic renewable energy to satisfy its needs.

It is also apparent, however, that what the Applicant has called the Import Option is not actionable at this time. There is no commercial agreement in place with an alternative provider, nor have there been any discussions about the terms and conditions of such an import solution.

The fundamental feature of the Other Import option is that the imports would satisfy the need for renewable energy, in the same fashion that building renewable energy generation facilities in Nova Scotia would. The value of such an option would presumably be that it would be cheaper than a plan based on indigenous renewable resources.

The difficulty is that there is no liquid commodity market for “renewable energy” in Northeastern North America. There are many markets for electricity, but these do not satisfy the Nova Scotia requirements for renewable energy. Renewable energy, up until today, is typically purchased through direct bilateral contracts between buyers and sellers. Often, these contracts are agreed to after competitive requests for proposals

("RFPs"), which are a means for buyers to get the lowest price possible for what they are buying, *in the absence of an open, liquid and competitive market*. This presumes that there are multiple sellers who would actually qualify for and compete to satisfy the terms of an RFP. In the absence of a liquid market, and in the absence of a group of competitive suppliers who would be expected to participate in an RFP, there is little basis upon which to assumptions about the price of a bilateral renewable energy contract.

Given that Nova Scotia's primary electricity requirement is for renewable energy, and this requirement is large (somewhere between 500 and 1000 GWh per year, according to the projections provided by the Applicant), and it would require substantial upgrade to the existing transmission system, it is not reasonable to simply assume that it could be commercially achieved, and especially at a price that would be cheaper than Nova Scotia's domestic option.

Any potential seller of renewable energy to Nova Scotia, assuming there are any who could satisfy the requirement, would know that the other alternative is local production in Nova Scotia, and would be free to set its price accordingly. The result is that the import option cannot be assumed to be cheaper.

The only alternative would be for Nova Scotia to build its transmission improvements without first negotiating a purchase of renewable energy, and only then seek to buy power through an RFP or similar competitive process. Again assuming there were several potential suppliers, then Nova Scotia could hope for some competitive market discipline to hold prices down. However, given the time constraints to meet Nova Scotia's 2020 renewable energy requirements, it does not appear that this option is open.

From a commercial perspective, the Other Import option effectively does not exist as an independent economic possibility distinct from the Status Quo. Analysis of its features is pointless, except potentially to demonstrate that it is technically feasible (which the

Applicant appears to have done), since it can be assumed that the economic result would be the same.

The Status Quo Option

For 2020, load projections suggest that Nova Scotia will require somewhere between 500 and 1000 GWh of renewable energy resources beyond what is currently in place or planned. Assuming this could be provided by wind farms with a 35% capacity factor, and assuming that all energy produced can be accepted by the transmission system, this suggests that between 165 MW and 330 MW of new wind resources are required.

The Applicant has argued that in fact additional resources will be required, to a total of between 250 MW and 425 MW, because some of the currently planned generation may not materialize, and because integrating this quantity of variable wind power into the Nova Scotia grid will require frequent rejections and curtailments, effectively reducing the output of the new facilities below the intended capacity factor.

In future years, in addition to replacing all existing renewable facilities when they reach end of life, additional wind facilities may be required if load grows as per the Base Load scenario.

In addition, the Applicant has argued that wind facilities should only be recognized as providing a 20% contribution to peak capacity, therefore between 50 MW and 85 MW of capacity resources, short of what will be required to meet that need. As a result, the wind scenario is described as also requiring the construction of a 50 MW simple cycle natural gas fired peaking facility. This would contribute very little energy to the system, but would be available on the few days per year when peak demand is in sight or when other units are unavailable for whatever reason.

Eventually, when emissions constraints and age require the retirement of existing coal facilities, new combined cycle gas-fired facilities could be built to replace them (on the assumption that they will be the most efficient and lowest cost means of delivering non-renewable energy in the province).

A by-product of the over-production of wind resources in this scenario is that Nova Scotia may ultimately have surplus power events, and therefore be forced to export power to New Brunswick or beyond, taking market price for the exported power at the time (whether that market price is sufficient to cover the cost of the energy or not).

Another consideration raised by the Applicant with respect to this scenario is the potential need to spend considerable resources on integration of this wind capacity. As described, when the total wind fleet of a jurisdiction reaches a high proportion of total capacity, the operating characteristics of wind generators create challenges for successful operation of the grid. The considerable and not-very-predictable swings in output of wind facilities mean that grid operators have challenges with ramping, with maintaining other units operationally available, ensuring the stability of frequency, and managing reactive power and voltage. These technical considerations are well beyond our scope of our expertise. However, the Applicant's evidence argues that considerable capital and operating expenditures will be required in reverse proportion to the amount of wind capacity ultimately added to the system.

Notes and Questions

The Applicant has made the case that relying on Nova Scotia wind resources is far more expensive than the ML. Given the above description it is not hard to see why:

- Planned generation capacity from the COMFIT was discounted, increasing the incremental amount of wind required;
- Wind generation firm peak coincident capacity was minimized (at 20%), resulting in the need for additional peaking gas-fired capacity;
- Incremental wind generation was oversized because it was deemed that it would not be practically able to deliver a designed capacity factor of 35%; and

- Substantial additional expenditure on grid support – whether in the form of transmission upgrades, additional simple cycle gas generators, or electrical storage – was deemed to be required.

Relaxing any or all of these assumptions would result in a reduction in the total cost of the Indigenous Wind option.

With respect to the COMFIT program, it is not clear why this was specifically identified as not contributing to meet the renewable energy targets of the province.17 Other procurements, including the REA, entail completion risk as well, but they were not discounted. Moreover, all of the modeling undertaken includes the assumption that existing renewable facilities will be rebuilt or otherwise replaced at the end of their life, regardless of the practical difficulties in doing so successfully that are assumed away.

It is a commonplace that wind generation is notoriously unreliable because of its variability. Power is literally generated only when the wind blows. However, wind patterns have now been recorded for many years, and are much better understood than in the early days of development of the wind generation industry. For a winter-peaking jurisdiction like Nova Scotia, it is arguable that wind capacity is actually admirably suitable, because of the tendency for the wind to blow stronger at night, and harder in the winter rather than the summer. However, it should be noted that other jurisdictions with different characteristics place an even lower peaking capacity factor on wind, so this issue should be subject to the scrutiny of experts.

The last two points, oversizing to compensate for poor capacity factor performance and the need to spend additional sums on integration, appear to at least partly be duplicate solutions to the same problem. The risk with wind is clearly its potential negative impact on the overall transmission grid. This risk could be managed in a variety of different ways, and potentially with action in many different directions simultaneously. However, it appears to be an over-compensation for the problem to assume that an oversized wind

[17] See note 41 of the Application, on page 113.

fleet is required because of curtailment expectations, and then to assume substantial grid effects because of an oversized fleet which can only be met by further additional investments.

Comparison of the Maritime Link and the Status Quo Option

The Following table summarizes the features of the two options with respect to the three needs of the electricity system.

	Maritime Link Project	**Status Quo**
Renewable Energy	• Meets the target in 2020 and beyond under the Base scenario because of delivery of 895 GWh of Nova Scotia block, plus approximately 250 GWh of Supplemental energy for first five years • May be oversized if load is closer to the Low scenario • If renewable requirement grows, additional targets can be met through purchase of surplus power from Nalcor • Surplus power could also be an alternative to reinvestment in existing assets when the begin retiring in 2030	• Can be sized more closely to observed load conditions, within the constraint of about three years' lead time to construction for wind farms • Future increases in renewable energy needs, whether through load growth or higher government mandated targets, can be met through incremental construction
Capacity	• Meets the need resulting from the retirement of two coal units by 2020 • Future retirements of coal units will require new gas-fired or other capacity	• Wind alone will not meet the capacity requirement in 2020 based on a 20% deemed capacity factor • Additional gas-fired peaking capacity must be built and maintained • Future retirements will require new capacity additions

	Maritime Link Project	Status Quo
Low Cost Energy	• Surplus energy from Labrador is expected to be available at competitive prices because of the position of Nova Scotia along the electrical route from Newfoundland to New England. This energy may be cheaper than the variable cost of power from existing units, immediately reducing the net cost of supply for non-renewable energy. • The availability of surplus energy will influence future decisions on capacity additions, in terms of whether they will be, for example, combined cycle vs. lower cost single cycle gas-fired units	• Depending on the specific suite of grid support improvements pursued upon the addition of wind capacity, there will be impacts on the net cost of non-renewable energy • For example, improved transmission capacity with New Brunswick and beyond will increase the availability of market priced power in Nova Scotia; however, the price of this power will be at New England market plus transmission costs and losses, and hence may not be competitive with indigenous sources

It should be clear from this summary comparison that the Status Quo option is far more modular and cumulative than the ML. The ML is an overall solution to the three challenges, and is largely fixed in both size and duration. While the ML includes the potential for added benefits because of access to surplus energy, it is not scalable downwards. When scaled upwards in terms of imports because of growth, or because of access to low cost energy, the ML actually becomes more cost effective (since surplus energy from Labrador is assumed to be cheaper than domestic energy, and simultaneously solves potential challenges in meeting emissions restrictions).

The Indigenous Wind option on the other hand is scalable, and can be more accurately sized to meet renewable requirements. However, it would appear that this option suffers from diseconomies of scale, since the larger the build of the province's wind fleet, the more likely and more severe the impact on the transmission grid that must be managed.

7. Analysis of Alternatives

MPA has reviewed the two principal alternatives – the ML and the Status Quo – using mathematical modeling of costs of energy. The results were calculated as Levelized Unit Energy Costs ("LUEC"), which provides a single price for energy that is meant to be provided over a long period of time, under various conditions. In order to make the calculations useful, the object of the analysis was to determine what the LUEC would be for the renewable energy that Nova Scotia would be buying to satisfy its legislated requirement.

One immediate issue is that it is uncertain how much renewable energy is required. Depending on the growth (or decline) in electricity demand, Nova Scotia will need more or less renewable energy to satisfy the legislation. Cost analysis therefore has to cover a range of possible futures.

At the same time, prices of coal, gas, and future transmission system upgrades are also uncertain, as are the relative prices between the New York and New England electricity markets. As was discussed previously, there is a wide range of estimates about what prices could be in the future. This means that LUECs resulting from calculations must necessarily be ranges, rather than specific numbers.

A further source of uncertainty is the cost of the ML itself. The LUEC of the ML Project itself depends the project being on time and on budget, and with all of the other commercial parameters as described in the application. If this is not the case, then the all of the assumptions about the ultimate LUEC of renewable energy for Nova Scotia will change as well.

It is important that the two LUEC analyses be kept distinct: the LUEC for the ML, and the LUEC for renewable energy ultimately relevant to Nova Scotia ratepayers.

Costs of the ML

The cost of the ML is relatively well known, within the range of certainty that could be expected for any massive infrastructure project that is still pre-construction.

Assuming the estimates provided by the Applicant are accurate, then the ML results in the provision of 35 years of 895 GWh of power per year, plus five years of 220 GWh of supplemental power, for a Project LUEC (Levelized Unit Energy Cost) of approximately $150/MWh for the total amount.

In order to calculate a renewable energy LUEC, however, there are some additional calculations that must be made. First, there are very minor expenditures that are required to upgrade certain parts of the Nova Scotia transmission grid, on the order of $30 million according to the Applicant. Much more importantly, the overall impact of this expenditure is access to low cost energy. The Applicant has estimated that between 1750 and 2500+ GWh of energy could be purchased each year for 35 years at prices that are below the variable cost of producing the power in Nova Scotia. Obviously, the economic impact of this low cost energy depends on the amount purchased and its specific price in relation to what would otherwise be available to Nova Scotia.

In addition, after the expiry of the 35 year contract, there will be an additional period of approximately 15 years when all energy imports through the ML can be expected to be competitively priced, and will be far below the ML Project LUEC.

Finally, at each event of end of life of an existing facility, whether renewable or otherwise, a decision would have to be made whether reinvestment would be required in the retiring unit, or whether imported energy could be substituted as a cheaper option.

ML Project Cost Sensitivities

We have built and tested an ML project cost model to better understand the drivers for the LUEC calculation, which was approximately $150/MWh (in 2013 dollars) in the base case. Some of the sensitivities are as follows, bearing in mind that each sensitivity was calculated in an isolated manner, as compared to the base case:

Variable	**Change in Variable**	**Change in Project LUEC**	**Notes**
Capital Cost	+/- $100 million	+/- $7.50	The Applicant has asked for flexibility in the event that capital costs of the ML are up to $60 million higher than the base case, which would add approximately $4 to the LUEC of the project Note that the base case cost of $1.52 billion is the P90 estimate. If capital cost were to be less than that, a similar benefit would be achieved. Also, because of the cost sharing formula with Nalcor, Nova Scotia will only be responsible for 20% of the variance from the base case cost
Completion Delay	1 year	+ $13.00	The ML cannot become operational until not only it is completed, but also not until the MF facility, LIL and upgrades to the Newfoundland transmission system are all operational. The impact of delay is very significant to the cost of the project, because AFUDC will accumulate over time.
Debt Interest Rate	+1%	+ $13.00	Long-term debt rates are historically low, with government of Canada 30-year bond rates at less than 2.5%. The Applicant's estimate of 4% for the project, given the federal loan guarantee, provides flexibility for interest rates to rise by more than 100 basis points over the next two to three years, until debt capital is actually secured. If long term debt costs rise beyond 4%, then the impact on the cost of the project becomes significant, and is locked in given the expectation that long-term debt will be used to finance the project.
Equity Rate	+/- 1%	+/- $7.00	The applicant has requested a rate of equity to be committed for the construction period. Following that, the

Variable	Change in Variable	Change in Project LUEC	Notes
			model assumes a fixed rate of equity return for the life of the project. In reality, the Applicant has requested that the equity rate be adjusted from time to time, as per the case with regulated ratebase assets (and unlike the case with power purchase agreements, which have an implied fixed rate of return built into the price). If the rate is increased by 1% for the full 35 year life of the ML, then the impact on LUEC is significant. This should be taken into account when considering the disposition of the project. It should be noted that equity rates for regulated utilities often are related to prevailing medium and long-term interest rates, and in this case the applicant has asked for a similar formula. As a result, if interest rates rise, then equity rates would rise, and there is the potential for both sensitivities to accumulate. However, if the project is financed with long term fixed rate debt during construction, as is anticipated, then the fluctuation of equity rates over time – which are largely driven by interest rates – will be independent of the debt in the project.
Debt Ratio	80/20 instead of 70/30	- $14.00	The ML will benefit from a Federal Loan Guarantee which provides support for lower interest rates, but which requires that a debt-equity ratio of 70/30 be maintained. If it were possible to increase the amount of debt in the project to 80% of total capital, then the impact on LUEC would be dramatic. However, it should be noted that doing so might mean the loss of the Federal loan guarantee, and potentially a higher interest rate on debt. The benefit of a higher debt ratio would be more than negated by a likely cost of debt.
Operations and Maintenance	+/- 10%	+/- 2.50	The model includes the Applicant's estimate of operations and maintenance costs for the ML for its full life. Modeling shows that an increase or decrease in operations and

Variable	Change in Variable	Change in Project LUEC	Notes
			maintenance has a modest impact.
Delivery Failure	No power for 6 months in either the 7th, 17th or 27th year; Makeup power in following year	+ $1.00	A significant concern with the ML, and perhaps even more so with the LIL, is the potential difficulty of repairing a break in the underwater cables. It may take up to six months to repair one of these lines, particularly if the break were to occur at inopportune times of the year. In the event a break in the line, it might not be possible to effect delivery of power (this assumes that both ML lines fail or that two of the three LIL lines fail). In this case, power would not be delivered, but could be made up in the following year. Under this scenario, which was modelled to occur in three different years after construction, the impact on LUEC would be modest, as long as the missing power was actually made up when transmission was restored.
Corporate Income Tax Rate	+/- 1%	+/- $0.50	Corporate income tax rates were included in the model at 31%. Changes in the tax rate have modest impact on the LUEC.

Calculating the Value to Nova Scotia of Buying Surplus Energy From Labrador

Buying surplus energy from Labrador is a critical feature of the ML, but also perhaps the most uncertain variable.

Surplus power will have value to Nova Scotia only if it is cheaper than the cost of electricity production in Nova Scotia itself. Otherwise, Nova Scotia would simply allow the power to flow across its transmission lines for sale in New England. As has been noted, prices fluctuate constantly, on an hourly basis. In any given year, buying surplus energy could be attractive in some days or months, and not in others. At the same time, Nova Scotia is limited in terms of the maximum amount it can buy, because some of its plants must always be running to maintain system reliability. Calculating the benefit of the surplus energy to Nova Scotia therefore means making assumptions both about prices, and about the quantity of energy that Nova Scotia would be interested in buying.

If we assumed that Nova Scotia purchased 1000 GWh of power per year for 35 years, at a nominal price advantage against other options of $1/MWh, the impact on the ML Project LUEC is a reduction of approximately $1. In other words, if Nova Scotia were to import an average of 2000 GWh per year for 35 years, and the typical savings against other options were $5/MWh, then the effective LUEC of the ML would fall by approximately $10, making the LUEC of the ML $140/MWh instead of $150/MWh.

Since the Applicant is forecasting approximately 1500 GWh of imports per year in the Low Load scenario, and approximately 2200 GWh of imports in the Base Load scenario, this would mean a reduction in the LUEC of the ML of between $1.50 and $2.20 for each nominal dollar of discount to all other options achieved by imports.

A similar analysis was undertaken with respect to the value of savings through imports in the years 35 to 50 of the life of the asset. Given the impact of discount factors on goods being purchased so far in the future, the ML LUEC impact for each nominal dollar savings per MWh, assuming import of at least 1000 GWh per year, is $0.10. In other words, if 2000 GWh of power were imported at Woodbine at a discount to market of $10/MWh every year for those final 15 years, then the 2013 ML LUEC would fall by only approximately $2.

To illustrate how this might work in the nearer term, consider a situation in 2020, when the facility is fully operational:

- A Nova Scotia coal plant has a heat rate of 10.5 mmbtu/MWh

- The cost of coal at the facility, according to the estimates provided by the Applicant, is expected to be in the range of $5 to $6 per mmbtu[18]
- The resulting marginal cost of power from this facility would therefore be $52 to $63/MWh, plus a small additional amount for variable O&M; note that there would be no difference in this cost regardless of whether the plant operated on-peak or off-peak
- The New England market cost of power at that time, according to the forecasts provided, could be anywhere from $50 to $80/MWh on peak, or $40 to $60/MWh off-peak
- Import power at Woodbine, however, should be assumed to be at an 8% discount to the New England price (as an offset to transmission losses), plus an additional discount for transmission tariffs that would otherwise accrue to Nalcor to get its power to market: for simplicity, assume the price is therefore at a 10% discount to the market, making it $45 to $72/MWh on peak, or $36 to $54 offpeak
- In this case, using the mid-points of all the ranges, import power would have an advantage of $12.50 during off-peak hours ($45 vs. $57.50), and a disadvantage of $1 during on peak hours ($58.50 to $57.50)
- Presumably, Nova Scotia would choose to import as much power as possible during off peak hours, and save its coal plants for operation during on peak hours, when it is both economically advantageous, and the plants would have to be available for grid support in any case
- If this import price advantage were durable over time, then the LUEC of the ML would be reduced by between $18 and $27, depending on the demand scenario

While this illustration is meant to help clarify how the savings mechanism might work, and why the narrow ML LUEC should not be considered in isolation, it MUST be emphasized that the actual economic value of the ML will simply not be knowable in advance. As noted at the outset of this review, prices fluctuate constantly, both for individual commodities, and for commodities relative to each other. The price advantage of imports as against domestic production will fluctuate constantly, based on the relative

[18] Note that more recent estimates than those filed as evidence actually predict higher coal prices.

costs of coal and natural gas, the cost of transmission, changes made to the transmission grid that make it more or less efficient in terms of loss factors, upheavals that may occur in the broader electricity market, the progress of the general economy, etc.

It can, however, be fairly said that if construction and financing of the ML is in accord with the plan presented by the applicant, then the ML LUEC of $150/MWh should be considered the extreme upper bound, and the benefits of access to low cost imports as an unquantifiable, but likely very significant counterbalancing value.

The final element to the analysis is the renewable energy demand in the province. In the Low Load scenario, the ML would actually be providing more renewable energy than necessary in the near term. This means that the “extra” renewable energy from the ML would be displacing what would otherwise be lower cost non-renewable power. In later years of the Low Load scenario, Nova Scotia might choose not to rebuild retiring plants, however, making all of the ML energy useful. Of course, in the Base Load scenario all of the ML energy is required to meet the renewable requirements.

Status Quo Cost

The cost of basic wind power according to the Applicant, is a LUEC of approximately $80/MWh. On its face, this is a reasonable assessment, based on the capital cost of $2.3 million/MW installed, 35% capacity factor, and 7.25% pre-tax weighted average cost of capital. This is clearly assumed to be regulated assets, given that the return on equity (9.4%) included is below market for independent power producers bidding on power purchase agreements.

This LUEC is enormously advantageous as compared to the ML. If the story did not proceed further, then a comparison between the two options would be no contest. However, as was noted above, there is considerable complexity to be addressed.

First, if it is assumed that a gas-fired peaking facility of 50 MW were required in order to satisfy capacity constraints in 2020, then the combined LUEC of the wind and gas facilities rises. Nova Scotia ratepayers effectively have to pay for both facilities in order to meet their renewable energy requirements.

On a pure energy basis, the shortfall in renewable energy in the Low Load scenario could be addressed by approximately 160 MW of 35% capacity factor wind facilities. For the Base Load scenario 330 MW would be required. A 50 MW peaking facility would increase the LUEC in these two cases by anywhere from \$5 to \$13, depending on projected gas prices and the frequency the peaking facility was required to run over its life. This raises the LUEC of the status quo option into the range of \$85 to \$93.

If, as the Applicant argues, the wind facilities will need to be oversized and face situations where they will be constrained off, resulting in energy production below the 35% capacity factor, then LUECs rise again. For example, if the 325 MW is oversized by approximately 10% to 360 MW, but the capacity factor is assumed to be reduced to 32% so that it produces the same energy, then the LUEC of the system rises a further \$7. At the proposed size of 425 MW and a capacity factor of 30%, the LUEC has risen more than \$13/MWh.

The critical issue for calculating the cost of the Indigenous Wind option is the assumption that upgrades will be required in the form of transmission, storage, reactive power assets, etc., as discussed in the evidence submitted by the Applicant. For every \$100 million of capital upgrades added to the Indigenous wind option, LUEC rises by approximately \$5 to \$10, depending on the expected life of the new assets, and without considering the possibility that these new assets will also increase operational costs on the system. The Applicant's evidence suggests that this expenditure could be anywhere in the range of \$200 million to \$600 million, depending on the scenario, which could mean increasing LUEC by anywhere from \$10 to \$60/MWh. When added to the base LUEC of \$80, the need for peaking gas support costing between \$5 and \$13, oversizing of facilities adding potentially \$7 to \$13, and an unknown amount of system upgrades potentially costing between $10 and $60, the net LUEC could be anywhere from $102 to $165.

Finally, in the Indigenous wind scenario, there is no additional low cost energy being purchased to reduce the output of Nova Scotia coal plants. Nova Scotia's non-renewable energy will continue to depend solely on its existing fleet, and will face emissions constraints as early as the mid-2020s. This will require additional investments in new combined cycle gas plants to replace coal plants that will need to be retired (in the case of ML, coal plant retirement can be delayed because low cost energy imports will result in the plants running less often and therefore emitting less, but still providing critical system support during peak times). The exact timing of these subsequent investments is unknown, and depends largely on the future of demand in the province, but under the Indigenous Wind scenario they appear to be inevitable.

Comparing the ML and Indigenous Wind Scenario Costs

Both options can only be analyzed by making a host of assumptions and projections about the future. Both options contain significant uncertainties that will not be resolved until long after the directional decision has been made. The various sensitivities and scenarios analyzed suggest that the range of potential outcomes for the two projects overlap. Unquestionably, the Indigenous Wind scenario has a lower bottom bound than the ML, but by the same token potentially has a higher upper bound.

The ML is best characterized as a large, fixed cost asset of significant size. It will address most of the challenges that the Nova Scotia electricity system will have for the foreseeable future, and in some cases may turn out to be a very valuable and advantageous asset. However, in other scenarios, particularly if load in Nova Scotia falls dramatically, then it will appear to have been an over-sized investment. In many respects, it can be compared to buying a rugged off-road vehicle: if all you are ever called on to do is drive on paved roads in the city, then it will appear to be expensive overkill, but if you find the need to traverse rough country, it will be up to the challenge.

The Indigenous Wind option is basically the opposite in many respects. It is modular, and entails making smaller investments on a more “as-needed” basis. Nova Scotia would have the option to watch load growth more closely, and match it with wind investment in stages. Given that wind projects can be procured and built in three years, Nova Scotia would have the option of tracking demand for a few more years before committing to a build. Additional study could be carried out to determine exactly what system investments would be required to support additional wind facilities on the grid, and whether they would indeed need to be oversized and periodically curtailed. However, based on experience from elsewhere, there is the real possibility that significant investments might be required, making this an expensive and challenging future to manage. To continue with the automobile analogy, the Indigenous Wind option is akin to buying a small city car, and retaining the option to buy up to a larger and more feature laden vehicle in the future, with more capacity. If the increase is not required, then savings could be significant, but if an upgrade is required soon, then the two car strategy could become very expensive.

Both of these are reasonable commercial points of view to take. It does not appear to us that either option is clearly and unequivocally superior to the other. In both cases, assumptions and sensitivities can be manipulated to show one option being less expensive than the other, but it does not appear that there can be any legitimate probability weighting of these possible outcomes, given the fundamental unknowability of the future prices in question. Making decisions on the basis of the arithmetic mean of calculated ranges is no more legitimate than making decisions on the basis of risk aversion. To make another colloquial analogy: a majority of Canadians chose to buy a 5-year mortgage for their house rather than a variable rate mortgage, even though it is widely known that in a majority of 5-year periods a variable rate mortgage is cheaper. However, in those times when variable rate mortgages prove to be more expensive, the financial pain can be severe, and many Canadians are risk averse and prefer not to be exposed to that potential. The choice cannot be gainsaid. In this case, the ML appears to have the higher certain cost, with the potential of the net cost being reduced over time by access to potentially lower cost power, at uncertain but probably reasonably significant volumes. The Indigenous Wind option appears to have a lower certain cost, but scale effects are perverse, and if more facilities have to be erected the increasing impact on the electricity system as a whole will require additional investments potentially leading to a much higher cost. Risk aversion is a critical deciding factor.

8. Distribution of Costs, Risks and Benefits Between the Parties

As noted in the introduction, another question in terms of commercial fairness is the relative position of the parties. Each is bearing various costs, accepting certain risks, and being compensated in different ways. The appearance of commercial unfairness in any of these relationships between the parties would be a cause for concern.

The following chart summarizes the distribution of commercial impacts among the parties:

Participant	Contribution	Benefit	Risk
Nalcor	Muskrat site and opportunity Capital (100% Generaton; 51% of overall Transmission, including the LTA, LIL and ML)	Strategic leverage with respect to Quebec transmission issues Value of surplus Labrador power that would be otherwise stranded Return on capital deployed Access to excess transmission in NS/NB/NE Ownership of ML post year 35	Non-recoverable cost overruns on LTA/MF/LIL Merchant risk on surplus Labrador power Federal break-up fee
Emera	Capital (49% of overall Transmission, in the form of ML plus a fraction of LIL) Bayside transmission rights and equivalent after 2026 Option on NB transmission build Maine transmission rights	Opportunity to fund regulated transmission at ratebase cost Potential lead order for NB transmission build in 2026 Secures business plan for several years	Non-recoverable cost overruns or failures on ML/LIL Requirement for post-2026 transmission rights or equivalent capacity in NB may be expensive Federal break-up fee

Participant	Contribution	Benefit	Risk
NS Ratepayer	Full cost of ML over 35 years Modest transmission upgrades in NS Guaranteed transmission capacity through NS (at OATT price)	1.1 TWh for 5yrs; 0.9 TWh for 30 more Option to purchase surplus Labrador power at competitive and potentially lower than market price Possibility of future transmission lines from NL OATT revenue on existing excess transmission capacity (reducing transmission cost for NS ratepayers) Reliability benefits	Prudent cost overruns will be paid by ratepayers Cost of certain operational failures (uninsurable repairs, plus backup power) Potential transmission congestion in NS
Feds	Loan guarantee (which has the effect of minor debt capacity crowding)	Regional economic development Emissions reductions in Nova Scotia by use of Labrador power instead of coal	Catastrophic failure of the project leading to payment of guaranteed debt
NL Ratepayer (technically not party to ML, but party to the broader set of agreements)	Full cost of LTA/ MF/LIL over 50 years (however at a lower than typical equity return for Nalcor) Transmission upgrades in NF	2 TWh/yr of emission-free power in first year, growing after that for 50 years Eliminate NF dependence on oil-fired electricity Added reliability for the Island because of LTA/LIL/ML transmission interconnects	Prudent cost overruns will be paid by ratepayers Cost of certain operational failures (uninsurable repairs, plus backup power)

Impact Upon and Strategic Benefits for Nalcor

Nalcor is a provincially owned company in Newfoundland and Labrador that generates and delivers electricity, develops and manages oil and gas resources on behalf of the province, and includes other related business such as fabrication. As of the end of 2011, the company reported $2.5 billion in capital assets at book value, and a strong five year track record in return on capital employed.

Nalcor's fundamental mission is to develop energy resources in Newfoundland and Labrador for the benefit of the people of the province. As a result, constructing the Muskrat Falls facility and associated transmission is central to its purpose. However, the energy resources available in Labrador in particular far outstrip the needs of the people of the province, so export capacity is a necessary precondition to successful development.

Exporting electricity from Labrador has been historically controversial. The Churchill Falls generating station, jointly owned with Hydro Quebec, exports its production to Quebec through high capacity transmission lines. The commercial arrangements facilitating this export are bound up with the very difficult history of that generating station. Currently, Nalcor only has access to 265 MW of firm transmission capacity for its own use, which represents a maximum of 2300 GWh per year of exported power, compared to total available surplus after the Muskrat Falls facility is completed of approximately 3100 GWh.

For some time, Nalcor has been trying to secure additional transmission capacity through Quebec, but has been unable to do so, either through purchase of Quebec capacity, or agreement to construct additional capacity. This has been the subject of difficult negotiation, regulatory hearings, and now legal action.

In the background are two issues: Nalcor would like to develop both Muskrat Falls and Gull Island, which combined represent nearly 3,000 MW of electricity generation potential, and some 17,000 GWh of production per year; and in 2041 when the existing Churchill Falls arrangements expire, Nalcor presumably would like to be in a strong commercial position to negotiate a new and more satisfactory arrangement to export its surplus power.

The Maritime Link Project, in conjunction with the Labrador Transmission Assets and Labrador Island Link, represents a critical strategic asset for Nalcor in its future dealings with Hydro Quebec and related Quebec electricity institutions. It will be a practical demonstration of the alternate path to market that Nalcor will need to strengthen its position in future negotiations with Quebec.

On a practical level, the development of these transmission assets expands Newfoundland and Labrador's export capacity from 2300 GWh to approximately 6600 GWh, and it allows the island of Newfoundland to benefit from the clean, emissions free power available in Labrador. The transmission route through the ML to Nova Scotia and beyond also acts as insurance against any failure or unavailability of the 265 MW transmission route through Quebec.

From a strictly financial perspective, the benefit of the ML to Nalcor is the ability to sell, at market competitive prices, its entire expected surplus above the existing 2300 GWh of transmission capacity it now has access to. As shown in the graph presented in an earlier chapter of this review, this amounts to approximately 900 GWh in 2018, dwindling to 0 in 2029, assuming the validity of current projections, and the lack of considerable new mining demand for power in Labrador over that time. However, this sale of energy should be taken in the context of a capital investment in excess of $6 billion, $1.8 billion of which will be equity. The revenue streams from the otherwise stranded power that will be sold through the ML does not amount to a significant portion of the return that Nalcor will earn on its investment in the Lower Churchill Project.

The bulk of Nalcor's capital investment in the Lower Churchill Project will be funded by the electricity purchases of Newfoundland ratepayers over the course of 50 years. As per Nalcor's regulatory application to the Newfoundland Public Utilities Board, the company will ultimately be accepting a lower return on equity than would be typical for a regulated investment in recognition of the fact that it will be able to earn revenues through merchant export sales of its power. This further reduces the net financial value of the ML export option to the company, since it will not in effect be earning above normal profits from the combined regulated and merchant revenue streams.

It would appear that the fundamental benefit for Nalcor of the ML is strategic and future oriented, while its costs – and risks related to construction execution and operating performance over time - are very real and immediate.

Impact Upon and Strategic Benefits for Emera

Emera Inc. is a widely held company with investments in regulated utility and other energy businesses. Its common shares are traded on the Toronto Stock Exchange with a current market capitalization of approximately $5 billion and a total enterprise value including debt of approximately $9 billion. According to Emera, approximately 85% of its business comes from regulated assets, of which 50% is represented by Nova Scotia Power.

Emera will contribute approximately $450 million in equity to the Maritime Link as well as approximately $390 million for its share of the Labrador Island Link, for a total of approximately $840 million in total equity. A substantial portion of this would likely have to be externally funded, meaning that Emera would issue new securities (equity and/or corporate level debt) to third party investors. In order to induce investors to buy these securities, returns on these securities will have to be competitive with other comparable investments.

MPA therefore considered the impact of the Project upon Emera by assessing the pro forma impact on the key financial metrics considered important by investors in publicly traded regulated utilities, including earnings per share, dividends, rate base and book value, and growth rates in these types of metrics. MPA assessed these impacts over the five year investment period for the Project and the implied range of returns for shareholders, using a range of assumed normalized trading multiples appropriate for regulated investments of this nature. MPA found that the range of total shareholder returns to be consistent with the regulated returns on equity being considered in the application.

In our view, returns of these levels will be necessary in order to attract the required funding for the Project. Returns at a lower level would mean that it would be difficult for Emera to raise the required capital, and make their participation difficult. Since they are expected to merely meet market demands for returns on new capital, rather than exceed them, we consider their planned returns to be commercially reasonable.

Beyond the financial returns, however, Emera will see broader strategic benefits from participation. The Project is a large, significant growth opportunity for Emera. As such it assists the company in further establishing itself as one of a small number of premier, large capitalization, high growth regulated utility businesses in Canada. This enhanced positioning provides Emera with even greater funding capability and flexibility, and enables it to pursue further growth opportunities in the future. The Project also enhances Emera's status as a national champion headquartered in Halifax. These benefits are largely strategic, rather than quantifiably financial. In exchange, Emera is giving up valuable transmission rights in New Brunswick and Maine, accepting all of the normal construction and operating risks associated with major new developments, and undertaking the risk of managing a complex and long term agreement with Nalcor.

Impact Upon and Strategic Benefits for Nova Scotia Ratepayers

The financial value of the ML for ratepayers was discussed in the previous chapter concerning the comparison between the ML and the Indigenous Wind option. MPA's view is that the two options are comparable, given the level of risk variety of potential scenarios involved, and as a result it would be inappropriate to ascribe substantial net financial value to the ML for ratepayers.

From a strategic perspective, Nova Scotia will, through the ML, gain an intermediate position in electricity flows in Northeastern North America, rather than being on the periphery. Currently, Nova Scotia is tenuously connected through a single 300 MW tie to New Brunswick. The ML will add a 500 MW connection to Newfoundland and Labrador, while at the same time rendering its existing tie to New Brunswick more useful. Assuming the successful construction and operation of the ML, future construction of additional transmission lines leading ultimately to Labrador becomes a possibility, and a potential value.

Ratepayers are of course accepting the potential for higher than expected costs for the ML through construction delays or operational failure. However, this kind of risk is currently accepted with respect to all other generation and transmission facilities as well, and is as a result not abnormal. On the other hand increased interconnection capacity is a practical benefit from reliability and transmission management perspectives.

Comparison of the Relative Distributions

As between Nalcor, Emera and Nova Scotia ratepayers, MPA does not see anything in our review of the ML which gives rise to concerns with respect to commercial fairness.

Nalcor is contributing the greatest capital to the project, and taking the most significant financial risks, including merchant risk on a portion of the output of the Muskrat Falls facility. Emera is contributing significant capital, but does not appear to be likely to earn returns that are above market expectations for regulated investments. Nova Scotia ratepayers are accepting normal risks associated with any new regulated asset, and in our view at a price that is consistent with the other main option available.

From a strategic perspective, all three stakeholder are making gains. Nalcor, which again is contributing the most and taking the most risk, is gaining a very significant strategic benefit with respect to its future dealings with Quebec on transmission-related issues, and it receives an immediate alternate route to the limited transmission capacity it currently enjoys. Emera, again contributing significant capital and accepting financial risk, is supporting its long term business plan, and bolstering its position in the market as a major player in the utilities sector. Nova Scotia ratepayers, while the risk that the ultimate price of the ML in comparison to other options will not be known except in hindsight, will benefit immediately upon construction by a fundamentally changed position in the electricity market, and an immediate improvement in its system reliability.

9. Commentary on Specific Features of the Arrangements

Review of Debt Arrangements

Project debt will be issued as and when needed over the course of the expected construction period to fund necessary ML capital expenditures. The debt will be issued in separate tranches under the terms of a federal loan guarantee (FLG) regulating the issuance of ML project debt between the federal government of Canada, the province of Nova Scotia and Emera.

ML project debt is subject to issuance constraints and may not exceed the lessor of i) a maximum debt service coverage ratio of 1.40x, ii) a maximum debt-equity ratio of 70% (subject to some exception) and iii) a fixed dollar amount of up to $1.3 billion.

Constraints under a loan guarantee/credit substitution agreement are common and the terms of the FLG with respect to the amount of debt that NSPML may issue under it are not unreasonable and appear fair, and consistent with market practice.

The debt of a regulated utility is typically rated from BBB- through to A+. However the FLG will support a AAA credit rating and ML project debt will be priced relative to the cost of debt available to a AAA rated entity, and at a slight premium to that value. The yield on Government of Canada 30-year debt is approximately 2.40% at current rates, and it is our expectation that ML project debt will be issued under the FLG at a spread of 0.25-0.50%, for a total debt financing cost of approximately 2.65-2.90% (given current market conditions, which remain subject to change at all times).

NSPML has assumed a rate of 4.00% for the cost of debt in their project modelling, which we feel is not an unreasonable assumption given the debt capital markets and the current cost of borrowing available to a AAA-rated credit.

ML project costs will be reduced significantly given the existence of the FLG. The FLG will buy-down the cost of debt financing by effectively substituting a AAA credit rating for that of Emera or a wholly owned subsidiary thereof. This credit rating would not be available in the absence of the FLG. The FLG is a direct benefit to the ratepayers of Nova Scotia, as interest savings in the form of a lower cost of debt are passed directly to the ratepayer in the form of a reduced NSPML revenue requirement.

The debt arrangements between the federal government of Canada, the province of Nova Scotia, and Emera, with respect to the FLG and the financing of the ML in general, and the specific terms of the FLG, are not unreasonable, are reflective of typical market practices, and are reflective of commercially reasonable relationships.

Equity Rate

The Applicant has requested that an equity rate of return be confirmed for the purposes of use during construction of the project, with future rates determined by formula for the years of operation of the Project.

The initial equity rate requested appears to be consistent with the rates of return currently in place for other regulated utilities across Canada.

The issue of the relationship between the regulated rate of return and debt instruments is a complex one, and different regulators have opted for a range of formulas. This is an issue upon which MPA is not qualified to comment in detail, however, we would note that the formula requested, a simple lift above prevailing interest rates, appears to be an over-simplification of models in use, and bears closer scrutiny.

Completion Risk Apportionment

From the terms of the agreements it would appear that the Nova Scotia ratepayer is responsible for completion risk in the ML. Completion risk would include both time and budget risk, in other words, the risk of overruns with respect to both time and money. The 20 percent true-up (through cash or energy compensation) arrangement largely protects the ratepayer from exposure to cost changes that occur between a potential regulatory approval and the Decision Gate 3 confirmation of the cost of the ML, but the ratepayer remains solely responsible for any delay in COD, and solely responsible for cost overruns over that DG3 estimate, whether as a result of the ML itself or an independent delay in generation in MF and/or in transmission over the LIL, and other Newfoundland and Labrador transmission assets.

The question arises as to whether or not it is fair for the ratepayer to be solely responsible for COD risk, and whether or not it would be unreasonable to apportion the cost of this risk among both the ratepayer and NSPML. In our opinion, there is scope for the Applicant to bear some measure of COD risk through a risk sharing mechanism. Such a mechanism could be structured in the form of an equity holdback, where NSPML's regulated return on equity (i.e. profits) are held back from the revenue requirement placed on the ratepayer. Such a holdback could start from a relatively modest base and escalate with time as appropriate. The idea would not be to transfer all COD risk to the Applicant, but to apportion the risk among both the Applicant and the ratepayer in a manner that reflects, as best it can, the interests of both.

10. Conclusions

In arriving at its Opinion as to the fairness, from a financial point of view, of the Project to ratepayers of Nova Scotia, MPA did not attribute any particular weight to any consideration, but rather made qualitative judgments based upon its experience in rendering such opinions and on prevailing circumstances, including current market conditions, as to the significance and relevance of each methodology and overall financial analyses.

MPA considered the ratepayers of Nova Scotia as a homogenous group and made no attempt to distinguish between different classes of ratepayers or between ratepayers at different points in time over the economic life of the Project.

The assessment of fairness, from a financial point of view, must be determined in the context of the particular transaction. In arriving at its Opinion, MPA considered, among other things, the following:

- MPA considered the levelized unit electricity cost ("LUEC") of the amount of power required to satisfy Nova Scotia's Renewables Requirement for the foreseeable future.
  - MPA considered specifically the LUEC of the Renewables Requirement when the power to satisfy that Requirement was delivered through the ML, under a variety of load scenarios. In arriving at that LUEC, MPA considered a variety of system related effects of the Project, including, among others, the ability to buy surplus energy at a potentially lower price than would otherwise be available to Nova Scotia ratepayers absent the Project.
  - MPA also considered the LUEC for the amount of power required to satisfy the Renewable Requirements under a variety of load forecast scenarios for the Status Quo option. In arriving at the Status Quo LUEC, MPA also considered a variety of system related effects, including the range of potential requirements to upgrade the Nova Scotia electricity system to support additional wind resources. These analyses are described in detail below.

  - MPA found the range of Project LUECs to be comparable to the range of Status Quo LUECs.
- MPA considered the qualitative benefits to ratepayers of Nova Scotia of the Project relative to the Status Quo option.
- MPA considered the relative financial and other benefits to the various Project proponents, and in particular Emera and Nalcor Energy, and found these financial and other benefits to be commensurate with the contributions being made and the risks being taken by such parties.
- MPA considered certain of the financial arrangements in the Project, and found no indication that these were commercially unreasonable.

Based upon and subject to the foregoing, MPA is of the opinion that the Project is fair, from a financial point of view, to ratepayers of Nova Scotia.

Appendix

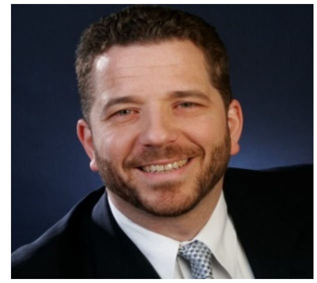
Biographies of MPA Team

Brent Walker

Managing Director

- A native Nova Scotian, Brent is a co-founder of MPA, with more than 20 years of experience in investment banking and the financial industry
- From 1996 to 2004 a Managing Director in Scotia Capital's Mergers and Acquisitions Group, and the senior M&A specialist in a number of sectors including power and infrastructure, pipelines, energy and real estate
- Began career in investment banking at Lancaster Financial, Canada's foremost independent M&A boutique which was acquired by TD Bank in 1994
- Brent has a B.Sc. from Dalhousie University and received his M.B.A. from McMaster University's DeGroote School of Business.

Pelino Colaiacovo



Managing Director

- Pelino brings to the firm 15 years of wide ranging experience in consulting, government and financial services
- From 2003 to 2005 was Chief of Staff to the Ontario Minister of Energy
- During that time, assisted in significant restructuring of the Ontario electricity sector, including the drafting and implementation of new legislation, the creation of the Ontario Power Authority, and significant procurements of new electricity generation capacity for the province
- Previously, ten years in management, policy and communications consulting in Canada and the United States, advising clients across a wide range of sectors, including energy, transportation, telecommunications, and healthcare
- Pelino has a B.A. and LL.B., both from the University of Toronto

Benjamin Kinder

Vice President

- Ben joined MPA in 2009
- Previously spent two years in Scotia Capital's Investment Banking and Equity Capital Markets Groups, and focused primarily on advising clients on capital markets and mergers, acquisitions and divestiture transactions
- More recently received a degree in law at the University of Cambridge and spent three years living abroad in the United Kingdom
- Ben has a B.B.A. from York University's Schulich School of Business and a B.A. in law from the University of Cambridge