R.B.B.

Management of Muskrat Falls' Excess Costs Using Future Electricity sales from Churchill Falls after 2041

SUMMARY

NALCOR and the government of Newfoundland & Labrador (NL) will be facing major financial stresses resulting from delays and cost overruns on the Muskrat Falls project and associated power lines. This text describes three methods to ease those financial stresses from now and up to year 2041. The methods used all convert the future value of electricity produced at Churchill Falls (CF) after 2041.

The first method would involve the delayed exchange of electricity with NALCOR receiving electricity from Churchill Falls once the Labrador Link (LIL) is operational in mid 2018. Before Muskrat Falls (MF) operates, an estimated 6.2 TWh could be supplied to the LIL at no immediate cost to NALCOR. Once Muskrat Falls enters operation in 2020, up to 1.3 TWh could also be supplied on the LIL annually. The accumulated quantities of electricity transferred over the years would be accrued with a mutually agreed interest rate. The electricity owed would be returned after 2041. This method is calculated to bring an average value of a maximum of approximately $100 millions per year to NALCOR. The electricity received would power Newfoundland Island at lower cost, help close some units of Holyrood earlier, optimize (fill up) the water levels in hydraulic reservoirs and potentially start sending contractual quantities of electricity to Nova-Scotia using the recently operational Maritime Link. This resolves the winter peaking of Muskrat Falls and water management issues.

The second and principal method involves HQ purchasing future electricity produced at Churchill Falls with deliveries made only after 2041, but with payments made immediately to NALCOR. The accumulated quantities of electricity purchased over the years would be accrued with a mutually agreed interest rate. This method can be applied quickly, even before the LIL is operational. Large revenues to NALCOR of typically up to $200 millions to $300 millions per year can be generated. The magnitude of those revenues is mainly limited by the number of years required to return the electricity after 2041. For the above revenues and the above quantities of electricity exchanged, approximately 10 years of Churchill Falls' production would be necessary. For more funds, the borrowed energy can be increased and the return period increased accordingly.

The third method would involve selling some equity in the CF facilities that would take effect only starting September 01, 2041. With full use of the first two methods described above, selling of equity may not be necessary. Selling equity in CF can generate large immediate revenues to the province and would be used mainly to remove a specific higher interest debt. Selling assets or shares is a broadly accepted method of generating revenues for companies encountering short term financial difficulties. However, the difficult historic negotiations between the two provinces may make this option politically sensitive compared to exchanging or selling electricity. Selling of equity in Muskrat Falls or the LIL may not be as appealing to a buyer, compared to Churchill Falls's assets.

The value of the future CF's production after 2041 is very significant. Using this asset, NALCOR and the province of NL can elegantly resolve the current financial difficulties generated by MF. This would mitigate hardship to the population and industry. It would also demonstrate the Newfoundland & Labrador' government capability to elegantly resolve an acute financial situation.

TABLE OF CONTENTS

FOREWORD

This report was written by [redacted], a retired physicist and electrical engineer residing in Québec that worked in the nuclear energy domain for 36 years. The idea of financing the Muskrat Falls' debt using the future value of Churchill Falls after 2041 first evolved in 2012 as means to finance the development of Gulls Island. It further evolved in spring 2017 towards Muskrat Falls, once informed about the major financial burden caused by large cost increases in the Muskrat Falls project's costs. The idea centers from the fact that Newfoundland will finally dispose of a large portion of the Churchill Falls electricity production after August 31, 2041. This enables the potential to return some of that future electricity production to Hydro-Québec over several years against funds that Hydro-Québec would provide during the 2022 to 2041 period. The first concept has Hydro-Québec purchasing electricity regularly over the years so that NALCOR obtains those funds to pay some of the Muskrat Falls debt. As Hydro-Québec does not need power now, its delivery can be delayed and only made after 2041 when NALCOR will own a large portion of Churchill Falls' production. A preliminary description written in French was first made in spring 2017 using data from a spreadsheet (also written in French) to document the concept, analyze several scenarios and determine the principal parameters involved. Private verifications indicated that such a scheme did not seem to be contemplated by the involved corporations. A subsequent report in English was finalized on August 11, 2017. It provided a more in-depth review, further development of the spreadsheet and re-write of a more comprehensive descriptive text/report in English. This version was based on a low and fixed selling price (Hydro-Québec patrimonial price) and a high interest rate (Hydro-Québec borrowing rate plus 2% profit) over the years. This report was then reviewed and commented privately. A large number of editorial, technical and economics modifications were called. The main comments pertained to the lack of an escalation system for the assumed cost of electricity and the high interest rate used to accrue the energy debt. The report was modified to include editorial comments, a progressively increasing electricity rate and a 3% escalation on the energy due.

During that period, the Labrador Link capabilities were reviewed. The review of the energy transfer capabilities of the LIL resulted in the development of a new financing scheme for NALCOR. In supplement to the Muskrat Falls' energy, the LIL can transport approximately 3 TWh of electricity from Churchill Falls to Newfoundland over and above the production from Muskrat Falls. This extra energy can be partially supplied from the recall power and from the 1/3 ownership of the Twin Falls' replacement power that can total up to 1.7 TWh of energy. This power can be returned to Newfoundland Island as soon as the LIL is commissioned in mid 2018. Before Muskrat Falls operates, the line is only partially used and Hydro-Québec could possibly transfer up to 6.2 TWh to NALCOR. The electricity would normally be purchased at commercial costs but the idea is to have it supplied at no immediate charge. When not immediately paid for, much more electricity would be wheeled to the Newfoundland Island and ultimately Nova-Scotia. The total quantity of electricity accumulated (owed) would be accrued using an agreed interest rate up to 2041 at which time it would be returned to Hydro-Québec. The August 11 report was thus further modified to document this development.

On October 05, 2017, the federal Parliamentary Budget Office (PBO) issued its yearly budgetary financial assessment of provinces and Canada titled "Program Sustainability Report". This report generally used data provided by provinces. The financial statements from NALCOR and from the government of Newfoundland & Labrador were reviewed earlier by the author. No specific modifications to revenues were found in those statements in 2041 when a significant portion of the Churchill Falls' production will finally revert to NALCOR. With a 21 TWh increase in production reverting to NALCOR, supplementary annual revenues of the order of 1.2 billions would result with a future electricity price of $0.06 per kWh. Such extra revenue is very large for Newfoundland & Labrador. For the province, those extra revenues would significantly change the long term debt prospects from problematic to positive. In order to comment on this absence of revenues in the PBO document related to future revenues from Churchill Falls, an E-mail was sent to the Parliamentary Budget Office on October 16, 2017. The E-mail also indicated that there is a potential to also minimise the current financial difficulties of the province during the 2018 to 2041 period by using the scheme of delayed sales of electricity. The subsequent day, on October 17, 2017, a short E-mail was received from its director, Mr. Jean-Denis Fréchette. It indicated its organization's interest in the future revenues of Newfoundland (presumably to help ensure the two Federal Loan Guarantees will be honoured) and in receiving this current report when completed.

The revision of the August 11 report was finalized on February 15 2018. This version includes previous comments and introduces a progressive pricing of electricity over the years, further develops the concept of delayed exchange of electricity using the LIL residual capacity and documents a number of supplementary opportunities. This revision also considers the fact that EMERA's bid to supply Massachusetts with the proposed Atlantic Link was not retained and that the power from Muskrat Falls allocated for this project and their eventual revenues will not materialize through this project. The February 15, 2018 report was then privately overviewed and some further editorial modifications made to obtain the current March 08, 2018 revision.

The commercial opportunities described in this report are solely the opinion of the writer. Those financial schemes have not yet been specifically discussed with NALCOR or Hydro-Québec. Completion of a comprehensive and reviewed document is made first to ensure it can stand the scrutiny of Utility's specialists and Parliamentary Budget Office personnel, before its contents are used for discussions with involved corporations. Such discussions are expected to be made during 2018.

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1 The Financial Consequences of the Muskrat Falls Project

General Structure of report

This section 1 reviews the financial situation created by the Muskrat Falls project cost overruns. A review of the elements of the plant and associated power delivery system is then made along the energy availability situation in Labrador. A review is then made of adjacent electricity markets, electricity transportation and of competition from other industry players that may affect the capability to repay the basic cost and interests incurred from the Muskrat Falls project.

Section 2 reviews the development of the Churchill Fall project, the markets available at that time, the fundamental difficulties of exporting its electricity and the responsibilities of organizations involved. Section 3 reviews the value of Churchill Falls' facilities for Newfoundland & Labrador. The possibilities to generate sufficient value from Churchill Falls in order to repay a sizable portion of the Muskrat Falls' interest and debt for the next three decades are reviewed.

The sections 1, 2 and 3 are quite long and contain basic information that provides a general background underlying the technical and economical situation in which the Muskrat Falls project is embedded. Some readers may already be familiar with the Newfoundland & Labrador grid, with the Muskrat Falls project, with the Churchill Falls project history, the resulting contractual arrangements and with the structure of competing electricity markets. Those first three sections may possibly be skipped in favour of reading from section 3.3 and subsequent ones while reading the earlier sections would be made at a later time. There may thus be some overlapping of information between the first three sections that provides background information and the subsequent sections that covers the analyses.

Section 4 represents the hearth of the document and describes the methodology and parameters involved in developing the future value of Churchill Falls to resolve the Muskrat Falls financial difficulties. Section 5 reviews the methodology and parameters involved for the delayed exchange of electricity using the Labrador Island Link (LIL). Section 6 reviews the delayed sales of future electricity from Churchill Falls. It provides a parametric analysis for a range of funding levels, determines the quantities of electricity involved and the periods required to return the owed electricity after 2041. The delayed sales method is then combined with the delayed exchange of electricity to determine the quantities of electricity involved and the periods required to return the electricity after 2041. Section 7 reviews the various equities that could contribute to help resolve the Muskrat Falls financial difficulties. This section also review possible energy exchanges on the LIL that can have their effectiveness increased when the electricity is supplied at no immediate cost to NALCOR and with its return planned after 2041. This section also reviews two other longer term projects that could generate revenues for NALCOR. Section 8 provides conclusion and recommendations.

A list of acronyms is provided at the end of the report along the list of Tables and Figures used in the report.

1.1 Financial Situation of NALCOR Resulting from the Muskrat Falls Project

The Muskrat Falls project is meant as a replacement for the aging 490 MW oil fired Holyrood station on the Newfoundland Island but was slightly too large for Newfoundland alone. As Nova-Scotia is also dependant on thermal plants for its electricity both joined to realize the project. Muskrat Falls is large enough to supply both Newfoundland & Labrador and Nova-Scotia with clean energy. It can replace approximately 2 to 2.5 TWh of production from Holyrood and also replace approximately 3 TWh of coal and gas fired plant production in Nova-Scotia. As this project directly reduced Canada's greenhouse gas emissions, the federal government has supported it by directly providing a large portion of its funding at the low interest rate it can get on markets. During its implementation, most of the project elements unfortunately suffered from very large cost overruns and delays on the construction of the plant and associated power lines. Those cost overruns will significantly increase the cost of electricity on the Newfoundland Island and severely stress the province's finances.

The initial cost estimate for the Muskrat Falls hydroelectric facilities was slightly optimistic with respect to a similar project such as La Romaine. For the hydraulic facilities alone, the Muskrat Falls estimate of 2.9 billions in 2012 represented a unit cost of $3,520 per kW installed. The current estimate for La Romaine hydraulic facilities (excluding lines) has climbed slightly to $7.2 B in 2017 representing a unit cost of $4,590 per kW installed. The Muskrat Falls initial estimate thus represented approximately 77% of La Romaine's near final costs. The initial estimate for Muskrat Falls can thus be termed as slightly low even considering that the MF plant has a single site, few roads to build and benefited from some economy of scale with respect to the four sites necessary to build the La Romaine facilities. In retrospect, the importance of common risks involved in constructing large facilities such as a hydro dam, DC lines, cables and converting stations was clearly underestimated.

The latest project cost estimate for Muskrat Falls and related DC and AC power lines facilities, released in June 2017, is of $12.7 billions. This number may be subject to further variations when the project will be finalized and the contractors' claims resolved. It also assumes that the North Spur performance as an effective dam does not require further modifications following reservoir fill up and that soil performance around the reservoir will not generate landslides that would demand remedial actions. The difficult project cash flow situation has already resulted in NALCOR having to let go a sizeable portion of the Labrador Island Link (LIL) to EMERA and to larger supplies of electricity to Nova-Scotia over the years (see Table 1.1). This reduces revenues from electricity transfer due to the reduced ownership of the line system. To enable start up of this low greenhouse gas project, the federal government has also been called on to guarantee a large portion of the money ($6.3 billions maximum at a rate of 3.9%) to be borrowed. Approximately $5 billions of that initial loan have currently been used. Following cost increases during project construction, a second Federal Loan Guarantee of $2.9 billions at a rate of the order of 2.9% has also been granted, enabling project's completion. This has reduced the average debt interest rate on the two Federal Loan Guarantees to a compounded interest rate of approximately 3.5%. Such a large financial support is rarely required in the Canadian Utilities' business. Other support to Canadian Utilities has however occurred in the past such as for the construction of the Nelson River dipole in Manitoba and for the development of nuclear energy in Québec

(Gentilly 1 and Laprade), New Brunswick (Point Lepreau) and to a much larger extent in Ontario (Chalk River Laboratories, Douglas Point, Pickering). The federal government has also invested in one form or another in the development of other forms of energy such as oil and gas, wind and other emergent technologies.

The Muskrat Falls project requires of the order of $280 millions per year ($5 billions at 3.9% and $2.9 billons at 2.9%) solely meant to service the debt covered by the money already taken from the Federal Load Guarantees. Overall, this project will generate severe stresses in the financial health of the province over several decades. Increased operating costs of the Direct Current (DC) lines and converters used for the Labrador Link and decreased ownership will also partly reduce the expected revenues from the project. Once Muskrat Falls is in operation, overall debt repayments by NALCOR are expected to require significant electricity cost increases to residential, commercial and industrial customers. Those extra costs may result in customer's electricity price increase from the current $0.11 cents per kWh, up to $0.23 cents per kWh, assuming nothing would be made to mitigate those increases. This possible doubling of rates represents an unbearable burden for the population and the industry that would have severe social consequences. Due to elasticity of demand those increased electricity prices should somewhat reduce electricity consumption and therefore indirectly limit revenues to NALCOR. This power environment may make Newfoundland & Labrador less appealing for possibly two decades until Churchill Falls's production comes back to NALCOR and enable significant electricity cost decreases. In practice, the rate increase will be made less severe (such as $0.17 per kWh) with some of the debt transferred to the provincial government and the interest paid for as income and sales taxes. Also, the provincial government can ask that NALCOR reduces the dividend that is to be returned to the province, enabling some reduction in electricity rates. At the end, either through electricity rates or taxes, the people of Newfoundland will financially and socially suffer from Muskrat Falls' cost increases.

The Muskrat Falls project is not a straightforward hydro project encompassing the construction of hydraulic facilities and tying it using medium voltage Alternating Current (AC) power line to carry electricity to one specific local area over a short distance. The use of an AC line is simply not possible over such long distances and is also not possible even for a short underwater cable. The power line portion is significantly more complex compared to other projects. The project has to join three land masses: Labrador, the Newfoundland Island and Nova-Scotia as it would provide a too large quantity of electricity for only Newfoundland. Also, the involvement of Hydro-Québec in the Gull Island or Muskrat Falls projects was not found cost effective following negotiations. Hydro-Québec preferred building the La Romaine project in Québec without having to negotiate trade-off with a third party. Nova-Scotia was very interested in reducing its greenhouse gas emission and was thus significantly more interested in the project. Following negotiations, the participation of Nova-Scotia was obtained. The project's configuration needed 2 main power line systems that each required DC lines with an AC/DC converter at their extremities and an undersea cable system. Those two DC systems also needed to be supplemented by two auxiliary AC power lines, one in Labrador connecting to Québec and one between the Avalon Peninsula and the Bay d'Espoir hydraulic facilities supplying the Bottom Brook converter. The complex power line system was necessary to manage the normal and abnormal power flows in order to generate the operational flexibility and the mandatory reliability required when interconnected with other North American Utilities.

The early cost estimate at Decision Gate 3 (DG 2) at $2.9 billons for the Muskrat Falls hydraulic facilities correspond to a unit cost of slightly more than $3500 per kW installed. The more recent and hopefully more final cost for La Romaine is of $7.2 billions corresponding to a unit cost of $4,600 per kW installed. The DG 3 estimate represents 76% of the final La Romaine costs. This indicates a low initial estimate even if Muskrat Falls benefited from some economy of scale compared to La Romaine. The Muskrat Falls hydraulic facilities are currently expected to result in a unit cost neighbouring $7,000 per kW installed, 53% higher than La Romaine. The source of cost increases is thus a combination of a low initial estimate followed, in one form or another, by a number of the project difficulties. Even if the Muskrat Falls' costs are 53% higher, the project allows Newfoundland to unlock a supplementary 3 TWh of energy from the Churchill Falls contract. This represents an increase of approximately 60% of the energy that can be obtained from Labrador. All in all, the Muskrat Falls hydraulic facilities have a final unit cost that is comparable to the final La Romaine costs when the extra power from Churchill Falls is considered.

In order to transport the Labrador (Churchill Falls and Muskrat Falls) energy to its markets and obtain the required reliability, the design consists in four power line systems:

- First, the Labrador Island Link (LIL). It the principal power delivery system consisting of a 900 MW DC terminal station at Muskrat Falls, a long DC land line crossing Labrador eastward, an underwater set of cables crossing the Belle-Isle Detroit, a long DC land line crossing the Island of Newfoundland from West to East and a second terminal station at Soldiers' Pond near St-John. The Soldiers' Pond facilities include a DC line grounding system to the Holyrood bay. They also includes new synchronous condensers that are required to stabilize the power flow from the 1,100 km long LIL lines and electrical connections to Holyrood to enable operation of its alternators as synchronous condensers. Those quite complex systems are required to deliver LIL's full capacity to Avalon Peninsula and mitigate transients and short duration power line failures. Delivery is made to the Avalon peninsula instead of a delivery to Bottom Brook as a DC line is more efficient compared to an AC line to cross Newfoundland from West to East. The maritime Link will mostly use power from the hydraulic facilities found near the Granite Canal and Baie d'Espoir area.

- Second, the Maritime Link. It is required to connect to Nova-Scotia for export of (indirect) power from Muskrat Falls' and Labrador that cannot be consumed in Newfoundland and for supply reliability purposes. Once units of the Holyrood station are shutdown, this line can be used as a backup in case of partial or total failure of the Labrador Island Link, with power coming from Newfoundland Island hydro Facilities and from Nova-Scotia during the period. The Maritime link starts with a 500 MW DC terminal station at Bottom Brook in western Newfoundland. Then, a DC land line carries the power towards Cape Ray in South-Western Newfoundland and towards an underwater set of DC cables to Nova-Scotia crossing the Cabot Detroit. A DC land line in NS, a DC terminal station in NS complete with its grounding system and finally a number of AC connections to the Nova Scotia electric grid complete the system. The connection is made at Bottom Brook in order to more directly tap the hydro stations at the nearby Granite Canal complex. The Maritime Link is paid for by EMERA in return of blocks of power from Newfoundland that is derived from Labrador facilities for a specific number of years. The commercial blocks of power dedicated by contract to Nova-Scotia and their durations are provided in Table 1.1

- Third. An AC line connection and sub-stations are required between the Muskrat Falls' sub-station and Churchill Falls to complete the Labrador system. This AC line supplies the recall Power and the Twin Falls electricity. The line will also increase supply reliability to the converters in case of Muskrat Falls' line failure or partial/complete power plant outage. It will also generate the capability to export to the continent during an outage of the Labrador Island Link or if market conditions indicate this generates larger revenues from non-committed power. This line will soon allow Newfoundland to be supplied with significant quantities of less expensive power than Holyrood up to operation of Muskrat Falls. As a very important fringe benefit, this line will allow an average of approximately 3 TWh of supplementary energy to be moved from Churchill Falls to Newfoundland and potentially Nova-Scotia resulting in a delivered energy of the order of 2.6 TWh considering line losses and reliability. This transfer of energy is possible as Muskrat Falls will not always use the line at its full capacity, allowing significantly more power to be moved over a year.

- Fourth. An AC line from the western Avalon Peninsula to the Bay d'Espoir hydraulic facilities, supplying the Bottom Brook converter. It will facilitate power interchanges between those two areas enabling partial energy flow from Labrador to Nova-Scotia. It will also allow energy flow from Nova-Scotia to the Avalon Peninsula during single or dual line failure of the Labrador Island Link.

The units of the 490 MW Holyrood oil fired thermal station are mainly used to produce peak winter power and help stabilize the grid. It should no longer be required to produce significant quantities of power within a few years. The facility may however continue to be used as a synchronous condenser to locally stabilize the grid during grid upsets and line outage. The yearly usage of the recently installed thermal plant as a cost effective power peaker will be reviewed over the short future.

1.2 The Muskrat Falls Project Cost Increases

Cost overruns on a complex and diverse construction project are not uncommon. All large Hydro and nuclear projects in Canada have suffered from some form of cost overruns, except for most of the recent hydro projects made by Hydro-Québec. Costs overruns come from a number of sources such as: insufficiently detailed initial scope of work resulting in unaccounted cost elements; insufficiently detailed and precise initial cost estimation resulting in low initial estimates; insufficient inclusion of the probable cost of risks factors, political pressure to keep cost estimates and cost allocations for risks to a minimum, increases in the scope of work forced by external organizations or pressure groups; environmental reviews or demands from jurisdiction authorities; difficulties of finding enough skilled labour (partly due to the concurrent construction of the nearby La Romaine project and other petroleum related investments); technical difficulties and technical changes; organisational difficulties; labour disputes; complexities of controlling contracts and manufacture in foreign countries, abnormal weather events; political interference; variations in financing conditions; internal or external pressure for acceptance of a low cost or partly compliant bid; insufficiently experienced subcontractors, claims from subcontractors for scope and cost increases; reorganization of sub-contractors, unforeseen project scope increase, hardship claims from contractors, project delays that increase interests during construction, etc.

In practice, the Muskrat Falls' project most likely had to deal with several if not most of those project stresses in one form or another. The systems and components required for construction of a hydro dam and power lines are now generally well within the capabilities of suppliers. The exception is perhaps the Belle-Isle crossing with high voltage DC cables that required iterative engineering to converge towards its final design due to the specific risks from icebergs. The sea crossings did not generate fundamental technological difficulties as suitable cable design, on shore connections and laying systems were available from worldwide suppliers. Finally, generally speaking, the Muskrat Falls project benefited from not being generally plagued by a high inflation rate during construction and did not suffer from technological risks from the use of insufficiently proven technologies.

Once Muskrat Falls reaches its in-service date around 2020 / 2021, large sums will be needed to pay for yearly interests on the debt, debt repayment and for power plant and line operating and maintenance costs. The electricity rates to customers are expected to increase significantly. Over time, expensive electricity rates may decrease residential and industrial consumption. Consumers can be expected to minimize the daily use of electrical power, enhance thermal insulation of houses and buildings, switch to more efficient industrial processes, move to non-electric processes, use of lower energy consuming lighting (cities), install air or geothermal heat pumps, increase wood burning in winter and increase the general use of oil, propane, natural gas and coal for a number of applications. As a result, the quantities of electricity sold to clients may diminish somewhat, exacerbating the revenue crisis for Newfoundland & Labrador.

1.3 Strength of Expected Revenues from Muskrat Falls and Competition on the Export Markets

A major portion of electricity produced from Muskrat Falls and from repatriated Churchill Falls energy is destined for use in Newfoundland & Labrador in order to replace Holyrood and other thermal plants. Specific blocks of power are however dedicated by contract to EMERA to compensate for the construction of the Maritime Link and for its financial participation into Muskrat Falls and the Labrador Island Link projects. This power will be used by Nova-Scotia customers for a number of years as indicated in Table 1.1. The quantity of energy to Nova-Scotia will total from 2.42 TWh to 3.02 TWh. From 55% to 70% of the energy destined for Nova-Scotia can be supplied from energy recovered from Churchill Falls and owned by NALCOR. The Labrador energy can start to be delivered once the LIL is in operation (mid 2018). It can be subsequently delivered to Nova-Scotia as the Maritime Link can carry power since December 2017. It can be said that the residual energy (Recall Power and a portion of Twin Falls) from the old Churchill Falls contract are now used much more efficiently. The power will partly pay for the Maritime Link project and other costs related to Muskrat Falls' project at little real supplementary cost to Newfoundland as this energy was not providing much revenue when fed to Hydro-Québec or U.S. markets. Table 4.2 provides the quantities of energy involved. It is thus principally Hydro-Québec that receives slightly less very low cost energy from Churchill Falls. With the scheme proposed in this report, a good portion of Churchill Falls' production after 2041 can also be put to work to pay for a significant portion of Muskrat Falls, demonstrating a supplementary benefit from this old contract. When the NALCOR owned portion of the Labrador power is added to the extra power what Hydro-Québec can deliver for free, the ~ 3 TWh available can supply the entire commercial commitments to EMERA. This would leave the entire Muskrat Falls capacity for the Newfoundland Island.

Type	Quantity of energy (TWh) (Total of 2.42 TWh to 3.02 TWh)	Period of Supply (years)
Nova Scotia Block	0.98	35
Supplementary energy	0.24	5
Market priced energy	1.2 to 1.8	24

Table 1.1 Energy Dedicated by Contract to Nova-Scotia

The Nova Scotia block is electricity supplied to Nova-Scotia in order to pay for the Maritime Link as a Built Operate Transfer (BOT) scheme that will return the ML to Newfoundland & Labrador's ownership after 35 years. The supplementary energy is to cover for extra funds from EMERA to help cover for some of the LIL's extra costs. The market priced energy is owned by EMERA from its participation in the Muskrat Falls project. It can use it or sell it to markets such as New Brunswick and New England states. The rest of electricity not used on the Newfoundland Island will need to be sold on commercial markets through Nova-Scotia. This quantity is estimated at approximately 1.1 TWh per year when Muskrat Falls is in operation. It was allotted as the participation of Newfoundland to the Atlantic Link project to supply Massachusetts. This power is now available for the spot market. The Muskrat Falls project includes electrical connections to Nova-Scotia and Québec. The remaining electricity could thus be sold either to New-Brunswick and North Eastern United States markets at commercial rates through the Maritime Link or to the province of Québec via the line to Churchill Falls to export towards those markets. Hydro-Québec may be called to supply Newfoundland before Muskrat Falls enters production and thus generate a debt of energy for Newfoundland. The 1.1 TWh of non-allotted energy from Muskrat Falls that cannot be used in Newfoundland could be used to repay / return the ~12 TWh of owed energy to Hydro-Québec (from the pre-operation period of Muskrat Falls) in a decade.

Electricity sales to Nova-Scotia would have the environmental advantage of reducing greenhouse gas emission in Nova-Scotia, reduce importation of coal and allow retirement of one or more coal fired units without having to incur the high refurbishment or upgrades (scrubbers) cost on old units. With fuel costs in excess of $500 millions per year, Nova-Scotia can take a significant amount of low carbon energy. The current average production cost of electricity in Nova-Scotia is of the order of $0.05 to $0.06 per kWh. The value that

Newfoundland can obtain on this specific market should be slightly lower than this. This market is limited by the ML residual capacity once the committed power is on the line.

The three existing 735 kV lines from Churchill Falls to Québec have a very large capacity of the order of 5,150 MW and are used to serve Churchill Falls. Sales of energy are still possible year around and in winter using the remaining capacity of the lines. Even during maximum use of the lines, less water flow can be run through turbines at Churchill Falls to allow for Muskrat Falls' electricity to be added on the lines. Line limitations towards the main Hydro-Québec grid will not necessarily add more power to that grid, but can add significant energy. The drawback with sales or supply of electricity to Hydro-Québec is that this Utility is both in a power and in an energy surplus situation. It may thus have little appetite for more power during non-winter months or more energy year around, specifically if the winter peak power capability is not increased. A market however exists as Hydro-Québec does purchases several hundred MW of excess power from Ontario almost every night and week-end when Ontario bulk power prices are lowest. The price paid for this energy is relatively low but the benefits of this short term "storage of electricity" are usually split between the Utilities involved.

Since 2016, the Recall Power is no longer included in the Churchill Falls contract. A portion of it is since exported to U.S. markets using Hydro-Québec's grid instead of being sold at the low price of $0.002 (2 mills) per kWh. This power currently provides small net revenues of the order of $0.01 per kWh. Those revenues have some potential to increase if U.S. electricity and gas prices firm up in the incoming years. Generally, slightly higher net revenues are expected with sales to Nova-Scotia as their cost base is in the range of $0.05 per kWh to $0.06 per kWh. Nova-Scotia currently purchases power from New Brunswick at an average cost $0.062 per kWh, indicating the general production costs that prevail in Nova-Scotia would be slightly higher than this value. The quantity of supplementary electricity that can be sold to Nova-Scotia is however limited to slightly more than 1 TWh as the ML is already used to carry committed power.

The commercial rates for electricity on the North-eastern United States spot market are currently very low during non peak periods. Such low prices are expected to continue for a decade or so due to the availability of low cost shale gas. Summertime sees more electricity consumption due to the use of air conditioning units that increase demand. During summer of 2017, this has however not resulted in significant price increases and prices remained low. This last winter (2017 to 2018), the New England demand peaked and generated significant price increases over most to the cold periods. During those periods, electricity produced from thermal plants burning oil and gas prevailed. During cold weather conditions that are below minus 10°C, heat pumps stops and heating reverts to other means such as gas heating, oil or electricity. Gas consumption for heating draws a larger portion of the gas pipeline capacity. This results in the use of more gas that is pre-stored in Liquefied Natural Gas tanks that carries a higher price. This increases the price of electricity generated from natural gas during cold weather conditions. The high demand also forces the use of oil fired plants and coal fired plants that may have an even higher production cost depending on their yearly usage.

For sales towards United States, sustained low average costs can also be expected due to the availability of low cost electricity from shale gas that can be burned in efficient combined cycle gas turbines. With the new leadership change in United States in early 2017, the production of green house gases, Mercury, NOx and SOx does not carry a significant penalty while little or no benefit for clean hydroelectric power is accounted for.

The North Eastern states however seem to be trying to not significantly increase their use of fossil fuel. There is a specific interest for local wind power and local solar power production. The imminent closure of the two Indian Point reactors north of New-York has triggered an eventual demand for about 2,000 MW of power in the 2020/22 horizon. More recently, the planned closure of the 685 MW Pilgrim nuclear plant in Massachusetts has triggered in 2017, a request for tenders for the long term supply of non-fossil replacement power from renewable sources. The call is for a large quantity of 9.45 TWh of electricity representing about 1½ times Pilgrim's average production. This energy demand also represents (at a 100% capacity factor) more than twice the overall yearly production of Muskrat Falls (4.9 TWh at source, 4.3 TWh at delivery). Once Newfoundland and Nova-Scotia are supplied, there will be between 1.2 TWh and 1.8 TWh of remaining energy available on average. To enable the export of this power, EMERA is planning, if it becomes the successful bidder, to construct the Atlantic Link project. This project consists in the laying of a set of undersea cables between Coleson Cove (St-John, NB) and the Pilgrim plant in Massachusetts and construction of a converter station at each of its endpoints. For this project, only 1.09 TWh of energy (11% of the supply) is earmarked to be supplied by NALCOR. The strength of this project is its delivery point. It is located in southern Massachusetts and close to Rhode Island and Connecticut states, directly in the hearth where power is needed. One of its weaknesses is that the supplied power has a strong wind source and is thus not guaranteed all year around. DC lines are expensive and require a high capacity factor to increase their cost effectiveness which is not the case for that proposal. Most eventual suppliers have either the production or the transportation facilities to build. Local New England wind and solar producers are close to the load and do not require construction of significant transportation facilities, only production facilities. Such energy sources unfortunately cannot guarantee the supply of power when necessary. The capital cost of wind power has recently been reducing yearly due to low cost blade and turbine suppliers from low-cost countries (China). On the other hand, Hydro-Québec has the necessary electricity production facilities already in operation and only has the land transportation facilities to build over a relatively short distance. Also, a very strong competition exists from Québec in the form of 3 sets of projects that can supply a guaranteed, all hydraulic supply, year around or a partial wind component with full back-up from hydraulic, year around. Those projects can use one of three paths: through New Hampshire (Northern Pass), through southern Maine or through southern Vermont via DC cables laid in Lake Champlain. Those 6 proposals from Québec along with 39 others proposals are in direct competition with the Atlantic Link project that has to build both the production and transportation facilities.

To support the 2017 Massachusetts renewable power bid, one of three paths in Vermont, New Hampshire or Maine could be used. Those are sized at a typical capacity of 1090 MW and can supply from 8.5 TWh to 9.4 TWh of renewable energy. On January 25, the Northern Pass project that uses Hydro-Québec's energy has been selected for further negotiations by the Massachusetts bid management. This project is still affected by opposition in New-Hampshire and the supply may simply be shifted towards one of two other configurations through Vermont or Maine. Thus, chances are now remote to have the Maritime Link project realized quickly.

Currently, Hydro-Québec sends between 700 MW and 950 MW to New Brunswick. Most of this power is redirected through Maine towards the remaining New England States. It is a long route of medium voltage and medium power lines that start in Lévis (Québec) continue toward Rivière du Loup and Edmonton where the power is passed through a back to back AC to DC to AC converter at Madawaska to adjust the phase and frequency. A third of the power goes farther north and is similarly converted at Eel River near Campbelton New Brunswick and then goes south. Power is then flowed south through New Brunswick and finally reach northern Maine. This path was meant to serve New Brunswick and Maine but now serves also PEI, and now predominantly Maine with about 2/3 of the load. The Massachusetts bids included the New England Clean Energy Connect project. It takes power from the Sherbrooke area and brings it through a relatively short route of 350 km to Lewiston in southern Maine, where it can connect more directly to the other New England grid. This path requires half the distance compared to the New Brunswick path. This project would separately allow the availability of 1080 MW to New England and potentially free some of the Madawaska and Eel River converters. This would make available approximately 500 MW to 700 MW of extra power in the Maritimes allowing timely closure of Nova-Scotia coal fired plants. The federal government is, amongst other avenues, looking for reductions in Canadian greenhouse gas emission from Alberta, Saskatchewan, Ontario, New Brunswick and Nova-Scotia to meet targets in the electricity energy field. It supports the idea of a Canadian power corridor to achieve this goal and may help finance such projects in a similar manner as was done of the Labrador Island and Maritime Links. Instead of creating a 1000 km long power corridor from Lévis (Québec) to Halifax, the simpler and more direct construction of a line to southern Maine would achieve a similar objective at lower cost. Alternatively, the power level of the converters could be increased over the capacity required to service the Massachusetts bid. Also, the DC lines could continue past Lewiston toward the sea and supply Boston and/or New-York using undersea cables in a similar manner as the Atlantic link. That configuration could be more cost effective and simpler to realise than the Champlain Hudson Power Express.

In supplement and external to the Massachusetts bid, there is another power delivery system under study towards downtown New York: the Champlain Hudson Power Express. The project would carry 1,000 MW of power from La Prairie south of Montréal, to downtown New York using very long DC cables. The cables would principally run in Lake Champlain and Hudson River and under roads and along railways. At 1000 MW, this project would cover for half of the 2000 MW that will be lost from closure of the two Indian Point reactors north of New York. The remaining replacement power would most likely come from other sources and preferably from the South to maintain diversity of supply, similar to the Neptune DC cable system. The Champlain Hudson Power Express line could feed even more clean power into the New England States. This project would directly benefit from the very high prices that can be obtained for power delivered downtown New-York.

With the low potential of sales using the Atlantic Link, those possible revenues may not be available from the Massachusetts bid to help finance the extra (stranded) debt. Sales may have to be made on the spot market possibly generating less revenue than previously anticipated. Essentially, most sales on the Maritime link will be used by Nova-Scotia. Thus the amount of funds required to resolve the current financial crisis may be larger than initially anticipated in 2012 and 2017.

1.4 Competition on the Export Markets

The actual power flow, sales volumes and net revenues (after paying for transportation out of the Newfoundland Island) will only be known during the 2018 to 2020 period and will vary somewhat over time. From those numbers, a significant gap will most likely emerge between the necessary yearly spending for the Muskrat Falls' project and revenues. Similarly to HQ, both NALCOR and EMERA will most likely need to sell excess electricity at low cost on the same markets. In 2016, the average selling price on the New England market was \$0.028 (U.S.), corresponding to \$0.035 (Can.). Unfortunately for NALCOR, Hydro-Québec currently tolerates exports at such low prices because its patrimonial rate is slightly below \$0.03 per kWh (exact figure is \$0.0288 per kWh for 2017). Currently, with normal yearly rainfall, the Hydro-Québec's production capacity is too large by several thousands MW and by about 30 TWh per year for energy. This is a large amount of power and to put it in perspective, it is more than 6 times the overall yearly production that Muskrat Falls can deliver in the Avalon Peninsula. The reservoirs currently store a large quantity of water that are quite full and contain typically more than 100 TWh of energy. It is generally better to turbine water and sell electricity at a low price on markets compared to just passing water over the spillways without revenue, as long as the revenues are larger than the incremental transportation costs. This availability of low cost power also limits the selling price of Muskrat Falls' electricity in the New England states on a day to day basis. Hydro-Québec already feeds New Brunswick (NB) through the Madawaska and Eel River converters. Those are rated at a minimum summer capacity of 700 MW. Also, up to 295 MW of power can be sold through Alternating Current (AC) lines powering a northern portion of New Brunswick that can be isolated from the New Brunswick grid and synchronized to the Québec grid. Those AC lines and DC converters are commonly used at close to their maximum capacity on a day to day basis and year along. Coupled with AC lines directly supplying northern New Brunswick, between 800 MW to 900 MW is delivered to New Brunswick, PEI, Nova-Scotia and more importantly to Maine and New-England states. Non wind power requirements for Prince Edward Island (PEI) are contracted from those sources. The energy is delivered via a set of recently refurbished under sea cables tying PEI to the New Brunswick grid. The PEI market is thus not achievable for Newfoundland. The largest portion of power through the Madawaska and Eel River converters is generally sent to Maine and New England states via AC lines through New Brunswick. Bulk power prices at the Maine border are low at typically \$0.02 to \$0.04 cents (U.S.) per kWh but occasionally rise significantly during specific peak demand periods. Those low prices can be expected to remain this low for a number of years, except during peak demand periods or during outage of major equipment.

Hydro-Québec, in collaboration with the New England Utilities, has progressively developed since the 90's, a 1,800 MW direct current line to Sandy Pond, 45 kilometres northwest of downtown Boston. It also has a back to back converter at Beauharnois for export of 1,800

MW to New-York state. An export capacity of 220 MW is also operating at full capacity and year around to supply the back to back DC converter of Comeford in Vermont. Another back to back DC converter in Masson and rated at 1250 MW also connects with the Hawthorne substation East of Ottawa city. This link is sometimes used to redirect some power to New York State at Massena and is often used to exchange electricity between nighttimes and daytime to mutually help balance the two grids. Other interconnections with Ontario are smaller and mostly tied to the Ottawa valley hydro plants and the Beauharnois and Rapide des Cèdres facilities that have turbine loads switched from one province to another depending on demand. An eventual participation of Muskrat Falls' production into the Ontario market would be made through the Masson interconnection. Existing lines and planned ones (see next paragraphs) would be in direct competition with power from Muskrat Falls sent through the Maritime Link, Nova-Scotia and New Brunswick or through Churchill Falls. From Nova-Scotia, delivery of power to Boston could be contemplated using underwater DC lines from New Brunswick, Maine or Nova-Scotia. Undersea lines have the distinct advantage of having less opposition from residents living near their path, compared to land lines using AC or DC towers or even buried DC cables that have little environmental impact. The drawback of a DC line is that it nearly always requires a long term contract to ensure enough revenues are available to realize the project. The likelihood that such an option quickly materializes has vanished in January 2018.

Hydro-Québec is currently completing the La Romaine complex with an installed capacity of 1550 MW. It has a projected average energy production at the facilities of 8 TWh per year corresponding to a nominal capacity factor of 58%. As of October 2017, the first three units at La Romaine are in operation with an installed capacity of 1325 MW. The fourth unit rated at 245 MW, is planned for completion 2020/21 as its construction has been somewhat delayed due to the excess power situation. This delay may help make more specialist personnel available for Muskrat Falls' completion. The current estimate for La Romaine has climbed 11% to $7.2 B in 2017 following a re-estimation to complete using a delayed construction of La Romaine 4. This project most likely includes interests during construction for each production unit. This should represent the final costs. Similarly to Muskrat Falls, the La Romaine facilities were planned slightly before the 2008 economic downturn and during the deployment of less expensive electricity from combined cycle gas fired stations. The energy produced from HQ's existing facilities is currently sufficient to power its needs and produce and average 15% excess margin (30 TWh), while the normal excess margin is planned to be closer to 10% (20 TWh). This makes the power from La Romaine redundant for a number of years. The already large excess energy from Hydro-Québec will thus further increase and remain large for a decade or more if no increases in internal province consumption or increases in exportations occur.

The cost of natural gas remains low in United States and keeps the cost of electricity down when demand is normal. Other production facilities and short underwater DC power lines similar to the Neptune project can also bring supplementary power to downtown New-York. On the other hand, the demand for new sources of electrical power can be expected to increase somewhat in the next decade, as several nuclear plants totalling several thousands MW are expected to be shutdown along other coal and oil fired facilities. The Gentilly 2 and Vermont Yankee plants are examples of those permanently shutdowns nuclear plants that have occurred. The Indian Point reactors near New York, Pilgrim in Massachusetts and perhaps Seabrook in New-Hampshire are also expected to follow a similar path in a few years. With the present U.S. leadership, there is little chance that a carbon emission fee becomes a reality.

With low electricity prices all across North Eastern U.S., there are thus few short term options available for deriving significant revenues from Muskrat Falls except for selling more power into Nova-Scotia, replacing the power produced by its thermal plants. Significant rate hikes to Newfoundland customers will thus remain the main revenue source. The return on equity demanded by NALCOR on its operations can be reduced along with dividends returned to the government. This could reduce the price of electricity charged to clients. Such a practice would not represent a true source of long term income for the province as money is simply shifted from one debt account to another. The project's costs that are over the initial cost estimate represents a stranded debt for which little revenue can be found to repay the debt. Solutions require thinking outside the box of rate increases. As explained below, other solutions are however possible to help repay the extra debt, but they are outside the direct scope of the Muskrat Falls project. Solutions mainly involve tapping the future value of Churchill Falls' electricity production after September 01, 2041 as described in the following section.

2 The development of the Churchill Falls Project

This section evaluates the development of the Churchill Falls project, and its capability to help finance the Muskrat Falls debt without equity being lost in either facility. A large portion of Churchill Falls' production will be owned by NALCOR after 2041. It can be used to return electricity that has been "borrowed" from now and until 2041. When a reasonable return period of 10 years (from 2041 to 2051) is contemplated, a very large quantity of the order of 190 TWh of owed energy can be returned during the 2041 to 2051 period at a rate of 18.9 TWh per year. Considering interests during the return period, a maximum of approximately 160 TWh of owed energy can be accumulated in 2041 for return during the following 10 years. This electricity owed can be worth several $billions in current Canadian dollars depending on price. This large energy borrowing capability can be used to obtain immediate electricity and funds from Hydro-Québec during now and 2041 in exchange of future electricity from Churchill Falls. That energy debt labelled in TWh would not undermine the financial debt situation of NALCOR labelled in dollars as there are separate assets to repay this energy owed. The energy owed can also be used to receive some electricity from Churchill Falls through the LIL before Muskrat Falls starts producing, reaping the full benefits of the line at an earlier date. The quantity of energy owed is accrued over the period using an agreed interest rate.

The principal future asset of Newfoundland & Labrador is that by September 01, 2041, the Churchill Falls contract will finally expire after 65 years. This facility was only made possible in the 60's by the negotiation of a long term sales contract for its energy. It enabled the sales of its electricity providing the revenues necessary to service the debt incurred during construction of that project. By September 01, the Newfoundland share of the 34 TWh yearly electricity production will revert to Newfoundland & Labrador. The Newfoundland ownership of the CF(L)Co is 65.8% and approximately 21 TWh of supplementary energy will be available to Newfoundland. This electrical energy represents more than 4 times the annual production of Muskrat Falls. At a present value of between $0.03 per kWh and $0.06 per kWh in 2041, this production is worth between $630 millions and $1.2 billions per year and perhaps more. Churchill Falls has been rightly called the golden goose of Newfoundland and Labrador. This will be similar to inheriting more than four projects like Muskrat Falls in one shot, all paid for, all reliably operating. The facilities also come with the possibility to use an excellent set of land AC power lines capable of serving the immense markets of Québec, Ontario and North-Eastern United States. The Churchill Falls contract will thus be very beneficial to Newfoundland & Labrador but only upon its expiry. This contract has historically been termed as not very beneficial to Newfoundland & Labrador during its application. However, it will become very beneficial when it ends. It will provide the capability to transform the province of Newfoundland & Labrador from a relatively poor to a relatively rich province.

Churchill Falls was a very difficult project to realize partly due to its large size and remoteness. In order to launch the Churchill Falls project, Newfoundland, British partners, industrials partners and Shawinigan Engineering gather in BRINCO to provide the initial project momentum. With the purchase of Shawinigan Water and Power's assets in 1962, Hydro-Québec acquired a 20% portion of the planned project. During the six years from 1963 to the contract signature in 1969, a number of commercial negotiations were held between the above organizations. Those are best described in the Document "*The Origins of a Coming Crisis: Renewal of the Churchill Falls Contract*" written by James P. Feehan and Melvin Baker.

At some point during the project, major delays and cost increases were encountered by CF(L)Co and supplementary money could not be borrowed due to high risks related to power lines and risks of not completing the project. Hydro-Québec supplied (by borrowing at the high interest rates prevailing at that time) the funding necessary to complete the project. Those funds were converted into an increase in the project's participation from 20% to 34.2%, a participation that still remains as of today. A similar arrangement was made between NALCOR and EMERA for the Labrador Island Link's project.

The Churchill Falls Labrador Company (CFLCo) was comprised of very capable partners that took the initial lead to develop the project. After trying for years, the group was however not able to obtain a long term contracts with United States (Consolidated Edison) or from Ontario (Ontario-Hydro, now Ontario Power Generation) that were necessary to borrow the money required. A "power corridor" through Québec was envisaged. The Québec grid was and is still not synchronized with the rest of the North American grid. This is due to the electrical characteristics of reactive power for long power lines and the near absence of large generators having sufficient rotating inertia in the southern portion of the province that make control of voltage and frequency much more difficult. The fluctuating Québec grid cannot be economically synchronized with the much more stable Ontario or New-York grids that have an abundant number of large rotating inertia turbo-alternators at thermal stations. In the 60's, the Hydro-Québec grid was specifically viewed by U.S. Utilities and Ontario as unstable and unreliable and would be more so with its large generators away from load centers. The power corridor idea would have required avoiding the non-synchronized Alternating Current (AC) grid in Québec to enable electrical synchronization with the New England and Ontario grids. That configuration would have removed Hydro-Québec as a partner in this project. The long AC lines from Churchill Falls to south of the U.S. border that would have been required to achieve this were and still would not be economically feasible. This is due to the too low line power factor that makes the efficiency of long lines to diminish rapidly below economical levels when distances are longer than several hundred km depending on configurations. To become possible the power corridor would have required the use of Direct Current technology that is much less affected by long distances. The power corridor would also have required offloading some of the power in Québec, requiring a multi-terminal HVDC system that was not thinkable at that time. Even with large technological developments in this field since the 60's, only 2 such multi-terminal systems are now in operation worldwide, one being the HVDC Radisson to Nicolet to Sandy Pond line and the other one serving the Italy-Corsica and Sardaigna Islands. HVDC technology in the 60's was then in its infancy and used mercury arc technology. As an example, the Nelson River dipole at 1850 MW used mercury arc relay technology and at that time, was the largest in the world with respect to power, voltage and distance. It was operational only in the mid 70's and would have only carried one third of the required Churchill Falls' capacity. Compared to the LIL, the required system for Churchill Falls would have been 6.6 times larger. None existed at that time that had the necessary voltage, length or the capacity to handle 5,400 MW. Knowing the difficulties encountered with the 900 MW HVDC system used for Muskrat Falls, a 5,400 MW mercury arc HVDC system would have taken a lot of time to successfully implement, would have generated large cost overruns and would have suffered from a low initial reliability. Utilities do not favour a project configuration where the large technical and financial risks of supplying electricity to its clients are managed by external organizations for which they may have an insufficient control. The resulting financial disaster would have been much larger than the Muskrat Falls one. Alternating Current (AC) technology requires a number of substations with synchronous condensers and other inductive and capacitive equipment along the path to readjust the voltages and rebalance the power factor so that power can flow correctly to meet the demand.

It is only since the 80's that DC technologies started using more reliable high power solid state technologies and since the 90's that their power level became sufficient to move power at the level of more than 5,000 MW that was required for Churchill Falls. Even if the energy could have been transported through a power corridor and without using the non-synchronized Hydro-Québec grid, the very large amounts of power from Churchill Falls could simply not be absorbed at one delivery point by either the U.S. or Ontario markets or both. In retrospect, a hybrid option of having some of the power directly sent outside Québec using DC lines and some destined to Québec sent via AC lines could have reduced the overall risk. However, negotiations with respect to scope of work, power distribution between parties, delivery points for the power, responsibilities, risk management and other matters would have been found too lengthy and difficult. Following their internal assessment, Ontario and U.S. Utilities separately refused the technical and financial risks of investing in the Churchill Falls project and in the necessary power lines. In United States, there was also a severe objection to import such large amounts of electricity from one foreign source when it could be produced locally in the United States. Those Utilities have historically built plants near their loads, a scheme that does not require much electricity transportation over long distances. U.S. and Ontario Utilities knew very well that expensive back to back DC converters, multi-terminal HVDC or complex AC lines and sub-stations would have been necessary between Québec, Ontario and U.S. as the Québec grid is not synchronized with theirs.

A power corridor through Québec can shortly be termed as a quasi impossible and hugely expensive political dream that did not stand simple engineering, cost or market reality at that time. The Ontario and U.S. Utilities simply found simpler, more economical and less risky to meet their internal demand in an incremental way using the minimum number of thermal stations required for their grids as demand increased. Those technologies had generally controllable technical and financial risks that such Utilities felt capable of resolving themselves. Ontario opted to implement several medium size nuclear reactors that were then relatively inexpensive at $900 millions for the four Pickering A reactors providing more than 2,000 MW of capacity with no long power lines. Consolidated Edison opted for a combination of thermal and nuclear plants that provided significantly less risks with in-house technology available.

Only Hydro-Québec showed some interest as it felt capable of transporting that level of power using their recently developed very high capacity 735 kV AC lines in a cost effective manner without the use of expensive and (then relatively unproven) mercury arc DC technology. This was somewhat facilitated, as the power could be diffused into the grid at a number of points. The hydro plant and line construction was still not without risks. The financial markets were not satisfied that CF(L)Co and Hydro-Québec had enough capabilities to efficiently deliver the project. In order to minimize its financial risks, the U.S. financial markets also forced the utilization of the large engineering capabilities of the largest worldwide engineering firm at the time: Bechtel. The financial markets, evaluated that both Hydro-Québec and CFLCo required an increased engineering capability to ensure strong project management and cost control for such a large project. Also, the financial markets refused lending money to CFLCo unless a long term sales contract was available with a Utility with deep pockets and that was backed by its provincial government.

Hydro-Québec was thus the only Utility that:

- Was willing and technically capable of ensuring project completion with the help of Bechtel. Ontario-Hydro and Consolidated Edison opted for more local projects;
- Had sufficient financial strength to borrow large amounts of funds on the U.S. markets for this project. Risks also had to be taken for possible variations in the Canadian / U.S. currency exchange rate in order to repay the interests, as the Canadian financial markets were not capable of absorbing such a large debt alone;
- Had developed and put in operation a sufficiently reliable very high voltage 735 kV line technology capable of transporting such a large amount of electricity over the long distance required to reach the southern Québec markets;
- Could absorb the energy without immediately having to build a large number of DC converters for export to United States, Ontario or Maritimes. Only a medium power mercury arc DC converter rated at 320 MW was initially built to serve New-Brunswick, representing about 5% of the Churchill Falls overall power. Over a 30 years period, more converters were built to export power from James

Bay and finally reach a capacity similar to the one that would have been required for Churchill Falls;

- Could minimize the size of the right of way for the power lines and interconnect with existing and necessary electrical high voltage sub-stations along the path;
- Could obtain governmental and population acceptance for the right of way required for those lines;
- Had a large enough grid, a large expanding industrial base such the Aluminium smelting business and a large commercial and residential client base to eventually absorb the power over a reasonable period;
- Did not require DC technologies to reach it customers.

The initial investment made by CF(L)Co finally resulted in a project that got constructed mainly due to the signature of a long term power purchase agreement. This ensured that loans would be repaid to the lenders even in times of very high inflation and high interest rates of 10% and more, which were typical during this period.

The Churchill Falls' contract brought a number of benefits but also some drawbacks to Newfoundland:

- It allowed CF(L)Co to not loose the large sums of money initially invested in the project. This money initially invested in the 60's by the partners in CF(L)Co was not lost and was used to maintain a large majority ownership portion (65.8%) of the facilities by the Newfoundland & Labrador government that still remains today;
- The technological risks from the generating station and power lines, the risks of not completing the project, the risks of paying for cost extras and the risks of paying interests during high inflation times were removed from CFLCo and were carried by Hydro-Québec. Without the sales contract, the Churchill Falls project construction would have most likely been stopped at some point with large losses to Newfoundland. If stopped during an advanced stage of construction, it would have undeniably bankrupted Newfoundland at the time. Churchill Falls was a project more than six times larger than Muskrat Falls, which is a project that has a finite possibility of bankrupting the province within a few years if nothing is made to generate sufficient revenues to pay the project's debt;
- CF(L)Co has received a small but stable payback from sales of electricity. Those sums are however not comparable to the revenues that Hydro-Québec can now make with the purchased electricity. This reality has brought the sense by Newfoundlanders and its government of having been steeled of those revenues even when risks were finally taken by other organizations. Reality indicates that it would have been a financial disaster for Newfoundland to continue to try to complete this project alone. At that time, even Hydro-Québec alone was not judged by the financial community to be able to fully minimize project's risk. Muskrat Falls is there to remind the harsh reality of such mega projects;
- The plant can supply Labrador's electricity loads at low cost using the recall power. This has allowed industries to develop and made populations to settle across the territory. Some of the recall power is now sold to continental markets bringing small amounts of revenues to Newfoundland.

- The Twin falls water could be redirected and reused more efficiently at Churchill Falls, producing more value from the natural resource;
- The contract, with its 25 years extension starting in 2016, now extends over a period that comes too late for Newfoundland to quickly reap the benefits of the plant after the initial period of 40 years. This represents the most important drawback of the contract for Newfoundland: its very long duration;
- The ultimate, largest and mostly forgotten benefit is that ownership of a large portion of the electricity produced will revert to Newfoundland & Labrador for free at the end of the contract on September 01, 2041.

Thus by that date, Newfoundland will inherit its portion of assets worth over $15 billions (see next section). Churchill Falls will then supply sustained revenues of typically $1 billion per year to Newfoundland in today's money, depending on the price of electricity at that time. This is more than enough to change Newfoundland from a relatively poor province to a relatively rich one.

3 Exploiting the Future Value of Churchill Falls after 2041

3.1 The Value of Churchill Falls Facilities

This section tries to estimate the value of the Churchill Falls plant in 2041, when a large portion of its production will revert to Newfoundland. The value in 2041 should be larger than the current value calculated on commercial price of electricity as the price of electricity should increase over time. At that time, the price obtained for its electricity will change from a contractually defined price to a commercially agreed price. The first estimation method would be to calculate the net present value of the facility. It is made by evaluating the future revenues and expenses from the facility and discounting the net revenues over the years using a discount rate. The second method is to compare the facility to the cost of similar commercial facilities for which the cost is known.

The discount rate will remove the foreseen inflation rates and the value of money over the years to estimate the present value of goods. Each yearly revenue is reduced by the factor 1 / $(1+ \text{discount rate})^{\text{year number}}$ and summed up over the years to obtain the present value. The operating costs of the Churchill Falls facilities is currently less than $0.002 per kWh (0.2 cents per kWh) as enough revenues are obtained to pay for operating costs. For a typical sales price of $0.05 per kWh, such operating costs would represent about 4% of revenues and can be considered non-significant. The current cost of replacement power from La Romaine is of the order of $0.07 per kWh and the construction of similar replacement facilities can be expected to be even higher in 2041. The average internal production cost at Hydro-Québec should currently be between $0.03 per kWh to $0.04 per kWh and would be expected to rise further in 2041. The selling price of Churchill Falls' electricity in 2041 can be expected to correspond to a commercial trade-off between the future internal supply cost at Hydro-Québec and the replacement cost for new equivalent production facilities in 2041.

In order to determine the potential value of Churchill Falls, a range of net sales price from $0.04 per kWh to $0.08 per kWh (corresponding to $40 millions per TWh to $80 millions per TWh) has been used. The discount rate is varied from 4% to 8% and significantly alters the value of the facility. The number of years for which the value is added is limited to a conservative time horizon of 50 years. Typical results are provided in Figure 3.1. For realistic net energy prices of $0.06 per kWh, the total value of the Churchill Falls facilities is larger than $30 billions with a discount rate of 6%. With a 65.8% ownership, the value of the Churchill Falls facilities to be received in 2041 at the end of the contract would most likely be a gift that exceeds $20 billions. As this value uses current electricity value, it also represents the current value of the plant that does not need to be reduced to cover inflation.

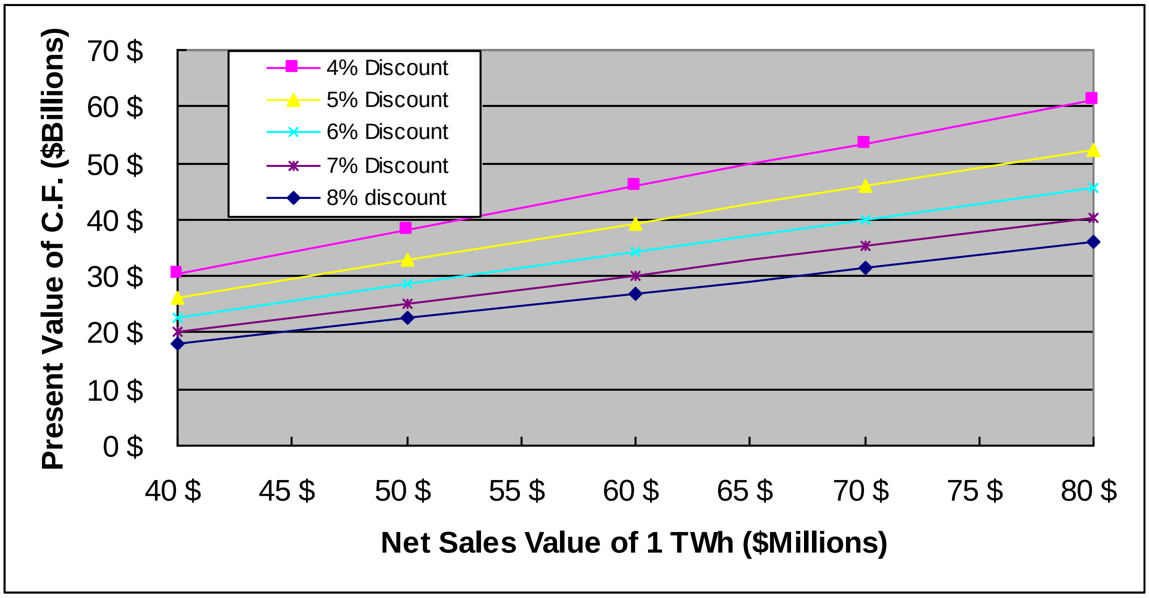

Figure 3.1 Net Present Value of Churchill Falls Facilities for Various Discount Rates

The second estimation method would use the current La Romaine project value that is still under construction. This project is located only a few hundred kilometres South-East from Muskrat Falls and Churchill Falls and has also been built far away from major population centers during its construction. Using the construction cost for an existing recent parallel project that (like Muskrat Falls) is still under construction can provide a good indication of the typical value of a hydraulic plant in this area. The cost of La Romaine represents how much money a Utility like Hydro-Québec has been recently (or would be) willing to pay to obtain the future power and energy produced by a new hydroelectric facility of similar size as Muskrat Falls.

The La Romaine project covers 4 different sites located over a 200 km distance along the river with a total installed capacity of 1550 MW. Generally, construction at four different sites is more expensive compared to a single site as the economy of scale is not fully obtained. The project had a current initial budget of $6.5 billions for the hydroelectric facilities only, the long transport lines to southern loads being excluded from that number. The latest summer 2017 estimate is of $7.2 billions, an 11% increase. This latter value should contain most of extra costs from contractors. The costs of power lines, transformer stations and other grid modifications to carry the power to southern loads are estimated at $1.3 billions. The cost of the lines is less than 20% of the total project costs. For Muskrat Falls, the cost of power lines is predominant and forms slightly less than half of the overall project expenses. The La Romaine lines have been sized at 735 kV to eventually accommodate the future production of the Petit Mecatina River (around 1500 MW) and were thus more expensive than required for this project only. Being nearly complete, the final project should not significantly surpass the latest project estimate. Using $6.5 billions is thus conservative and gives a rounded unit cost of $4,200 per kW installed. Using this value, the Churchill Falls facilities would be valued at approximately $22.5 billions (5,429 MW x $4,200 per kW = $22.5 B). Using the latest project cost estimate and a $4500 per kW installed, a value of $25 billions is obtained. With a 65.8% participation, NALCOR's portion of the facilities can thus be estimated to be worth up to approximately $15 billions to $16 billions. In 20 years or so, the commercial value of clean hydro power should be even higher as prices for natural gas and oil should then be higher due to depletion of the resource. Another not too well known asset of Churchill Falls is that one or potentially two supplementary turbines of 493 MW each can also be cost effectively added. This would increase its installed capacity by 987 MW (for two turbines) to 6,415 MW. Added line capacity would normally be required for the upgrade. However, the La Romaine power lines were built with a 1,500 MW spare capacity to handle the future four hydroelectric plants planned for the Petit Mecatina River. The La Romaine power lines are approximately two hundred kilometres South of Churchill Falls and could carry the load at little extra cost. The commercial value of the upgraded Churchill Falls plant would then increase above $25 billions. It can be concluded that the value of the Newfoundland & Labrador portion of Churchill Falls now easily exceeds $15 billions and should be even higher in 2041.

When ownership of a valuable asset that can generate revenues is to be obtained in the "near" future, banks or investment markets may accept to lend money based on those future revenues or against a portion of this future asset. Specifically, money could be borrowed from the future value of the plant or from the future value of the electricity produced by Churchill Falls. It is possible that such a scheme with Canadian, U.S. or other international financial institutions could be realized within a few years. It is however likely that no acceptable settlement can be reached in time with such financial institutions. The financial markets' familiarity with respect to the future value of a power plant is marginal and such arrangements may be labelled as risky and thus call for a larger profit margin to cover risks. Financial institutions cannot really accept electricity as a form of payment and will most likely prefer equity in the plant in order to resell it to a buyer when necessary. The likelihood of reaching a simple and rapid arrangement with a financial institution that would bring immediate revenues to NALCOR in time for paying its debts in 2020 is quite uncertain. Selling a large portion of the future Churchill Falls assets may also be politically difficult and unwise. An example is the recent possibility of a purchase of a large portion of New Brunswick Power by Hydro-Québec, as initially sought by premiers of both provinces. It was principally aimed at resolving some of NB Power financial difficulties generated by the high cost of the Point Lepreau refurbishment project and anticipated repairs to the Mactaquac hydro plant that is plagued with alkali aggregate reaction of its concrete. It ultimately resulted in a veto from provincial's elites and the population. Although their Utility was in trouble with significant debts and risks, the population still preferred to keep New Brunswick Power within ownership of the province, even if it meant paying a bit more for their electricity. A similar reaction may be expected for Newfoundland & Labrador, making the selling of a significant portion of Churchill Falls to Hydro-Québec more difficult.

A simple solution that allows putting to use the future value of Churchill Falls, without loosing property rights, is to obtain an immediate payment for the sale of electricity that will not be delivered at the time of the transaction, but only after 2041. This scheme is reviewed in more details in the next section. The pro and cons of a similar scheme that would involve selling incremental portions of the Churchill Falls facilities during the 2020 to 2041 period is also discussed in Section 7.1.1.

An alternate solution involves delayed exchanges of electrical energy over a long period of time. That scheme has technical limitations due to the maximum of approximately 3 TWh that can be carried on the LIL when Muskrat Falls is in operation. Part of this capacity will be used to return all available power from the Recall Energy and of the NALCOR's portion of the Twin falls portion of Churchill Falls. This Recall and Twin Falls Power can be used in Labrador, Newfoundland or exported to Nova-Scotia to start delivering a portion of NALCOR's commitments to EMERA. During the period where the LIL operates and Muskrat Falls does not yet supply electricity, the line is only used at a relatively low power. It could carry up to 6.2 TWh capacity per year, for approximately 2 years and perhaps more until start-up. With an estimated commercial value for this ~12 TWh of electricity of $0.05 per kWh, this represents a gross value of the order of $600 millions to which the LIL transportation costs must be subtracted. The resulting funds can surely be used by NALCOR to ease its short term financial position.

The quantity of energy initially transferred could increase somewhat if the Muskrat Falls turbines take longer to start up or if there are soil difficulties with the North Spur or the reservoir. During operation of the LIL, there will be periods where power could not be sent to Newfoundland. The production at Muskrat Falls can be partly curtailed for short periods without spilling large quantities of water but the electricity produced will eventually need to be sent towards the Hydro-Québec grid. Modern DC converters are quite reliable at typically 97%. However, when associated with two long power lines running through harsh and isolated landscape (that increases the time necessary to repair damages) and an undersea cable, the combined line capacity factor will most likely not exceed a yearly average of 95%. The non-delivered power from Muskrat Falls could average 5% or more of the 4.9 TWh production and account for approximately 5 TWh up to 2041. This energy returned over the years would compensate for about half the energy sent during the 2018 to Muskrat Falls' start-up.

Although limited in value for NALCOR, it may be much simpler to initially implement the delayed electricity exchange method, because it only involves an exchange of TWh that would not fuel public sensitivity. This represents a simple negotiation that is centered in the determination of the interest rate to apply to the owed energy. Once this is accomplished and confidence builds up between parties, the scheme of having delayed sales of electricity will be tackled. It involves negotiations centered on the sales price as the interest rate to be applied would have been negotiated earlier. The long term electricity exchange scheme could be implemented quickly as it is already built-in the Churchill Falls / NALCOR operation that allow such electricity exchanges, but at a smaller scale and for short periods. The long term energy exchange scheme could have NALCOR to immediately receive power from Hydro-

Québec in mid 2018 at no immediate cost. The energy is returned from either Muskrat Falls' current production that cannot be sent to the Newfoundland Island from time to time, or from future Churchill Falls' production after 2041.

3.2 Revenues from Churchill Falls

This section describes how future revenues from Churchill Falls can be used to resolve the current Muskrat Falls financial difficulties.

One of the main assets of Newfoundland & Labrador is its share of the Churchill Falls hydroelectric plant and specifically the value of its production after 2041, the pre-2041 production being already committed. The plant's average yearly production of 34 TWh of electricity is several times the entire Newfoundland Island actual consumption of approximately 7 TWh. NALCOR owns 65.8% of the CF(L)Co. Of the total production, 2 TWh is earmarked for Twin Falls. Of the remaining 32 TWh, NALCOR will thus benefit from 21.1 TWh of energy to which the 1/3 ownership of Twin Falls can be added for a total of 21.9 TWh. The energy ownership of Churchill Falls' production is depicted in Figure 3.2. At that time, replacement energy should be valued at approximately $0.06 or more per kWh, possibly generating about $1.3 billions of revenues from sales. To those revenues, maintenance costs have to be subtracted. That increased rate of revenues should help resolve the Newfoundland & Labrador debt on Muskrat Falls in less than a decade and the overall provincial government debt a few years later. This should be the start of long awaited and hopefully permanent prosperity for the province.

The Churchill Falls generating station has been operating for decades and important repairs such as changing turbo-alternator groups may be expected over the next two decades and continue over the years. Plants are normally run with some turbines planned to operate more often while other operates less often in order to generate a spread in the number of operating hours. Turbine refurbishment can then be made over a number of years. The design of the plant is relatively simple and mainly consists of its large underground powerhouse as it has no principal dam or dyke of significant height. The facilities mainly consist of long but relatively low height dikes, of the power plant, switchyard, lines to Québec and of its services. The power plant maintenance involves repairing/changing gates, penstocks, turbines, alternators, transformers, insulators, instrumentation and power lines. Maintenance on one of the 11 turbo alternator group is normally made during times of low production. It will therefore not significantly affect the required production that can be maintained by the remaining 10 turbines. Repairs to a turbine do not necessarily result in a loss of power during most of the year, but may reduce the plant's peak power capability if repairs extend into the winter period. Maintenance to lines is also staged and made during lower demand periods, preventing a loss of energy delivery capacity.

Legal actions have been undertaken by the province of Newfoundland over the years to obtain more money from the Churchill Falls electricity sales contract. None has been obtained over the last 40 years. Those efforts have only turned into a loss of large sums of money spent for legal fees. A positive outcome of recent actions that would quickly generate even a small portion of the massive incomes necessary to pay for Muskrat Falls by 2020 is not assured.

NALCOR and the current government of Newfoundland & Labrador have to find and implement alternative solutions to large rate increases due to Muskrat Falls. If no solutions are found, the population that expects some relief may simply consider a change of government for lack of finding a solution.

3.3 The Use of Future Production from Churchill Falls to Mitigate Foreseen Electricity Rate Increases

This section describes how the future production of Churchill Falls can be used to generate immediate funding to Newfoundland & Labrador. This would help mitigate electricity rate increases to rate payers and industry and reduce the eventual tax increases to Newfoundlanders. The economy of Newfoundland & Labrador would have more chances of flourishing with stabilized rates. With manageable electricity rates, the industry may decline less and the unemployment rate decrease over time.

The schemes consist in the following three principal avenues that will be used in parallel as necessary to generate the required revenues to serve the Muskrat Falls' debt:

1. **Delayed exchange of power with Hydro-Québec.** For NALCOR, this scheme consists in receiving electricity from Hydro-Québec at no immediate cost to NALCOR. The electricity is returned at a later date, most of it after 2041. Before Muskrat Falls start up, Hydro-Québec would provide at no immediate cost, a quantity of up to 6.23 TWh of energy per year onto the Labrador Island Link to supply Newfoundland and Nova-Scotia's obligations. This is depicted in the overall energy flow diagram provided in Figure 4.1. The loaned energy, accrued over the years, would be returned to Hydro-Québec after 2041 or during short periods when power cannot transit towards the Newfoundland Island due to maintenance of failure of the line. This scheme is simple and in order to be implemented, requires relatively simple negotiations related to the interest rate to be applied to the owed energy. Once Muskrat Falls starts-up, some remaining capacity on the LIL may allow the transfer of smaller quantities of energy to Newfoundland, further helping NALCOR to reduce its costs.

2. **Sell future power to Hydro-Québec.** In this arrangement, Hydro-Québec would immediately provide funds to NALCOR for electricity assumed to be sold at the time of transaction. Using a mutually agreed selling price, the fund transfer would be equated to a specific quantity of energy (TWh). The sold energy would be accumulated over time and the energy owed would be accrued over the years using an agreed interest rate. The owed energy will ultimately be returned to Hydro-Québec after 2041.

3. **Selling small portions of Churchill Falls' equity** on a yearly basis with the ownership acquired after 2041. This method may also require to be accrued using a mutually agreed interest rate as the "goods" exchanged against the money are only producing revenues much later than the date of purchase. Selling some equity will

reduce the rate at which energy can be returned when the two previous methods are used.

It is very well known by Hydro-Québec's management that by 2041, it will no longer benefit from the inexpensive power obtained from their investment in the Churchill Falls' project made in the 60's. After 2041, Hydro-Québec will have to manage the loss of approximately 19.5 TWh of low cost electricity from Churchill Falls. This currently represents approximately 10% of its entire present production of 200 TWh in Québec. The end of the contract should result in a financial stress of the order of 20% of expenses (currently at $8 billions) assuming a present replacement value for the electricity of $0.09 per kWh for construction in 2041. This predictable financial stress should be managed by Hydro-Québec well in advance of 2041. The management of this financial stress can be accomplished in a number of technical ways such as reduction of sales to other grids and increases in night and week-end purchases on adjacent grids. It can also be managed financially by changing the debt to equity ratio on new capital expenses (more short term borrowing) and obviously, in increasing rates to customers over a few years. A number of other methods will likely be contemplated. Senior management of Hydro-Québec will certainly listen to the commercial schemes described in this document, as long as reasonable benefits can be obtained and that risks are reasonable compared to other investments. The quantities of energy involved in this report are of the order of 190 TWh when a limit of time of 10 years is set to return the owed electricity. This quantity of electricity is similar to the energy planned to be supplied to Massachusetts over 20 years which is estimated to be worth approximately $10 billions. The project of electricity sales to Massachusetts has risks associated to the difficult task of permitting a new power line and risks related to construction costs. The schemes described in this document are not constrained by construction or permitting risks as no construction is involved, the LIL being built by NALCOR and EMERA. The main cost for Hydro-Québec is very small and pertains to the labour required to review the financial characteristics of the schemes and to the management time necessary to negotiate with NALCOR. The profit margin achievable for the schemes described in this report should be similar to the ones contemplated for the Massachusetts bid. Thus generally speaking, the management effort put in the schemes developed in this report should at most be a small fraction of the effort put for the Massachusetts bid.

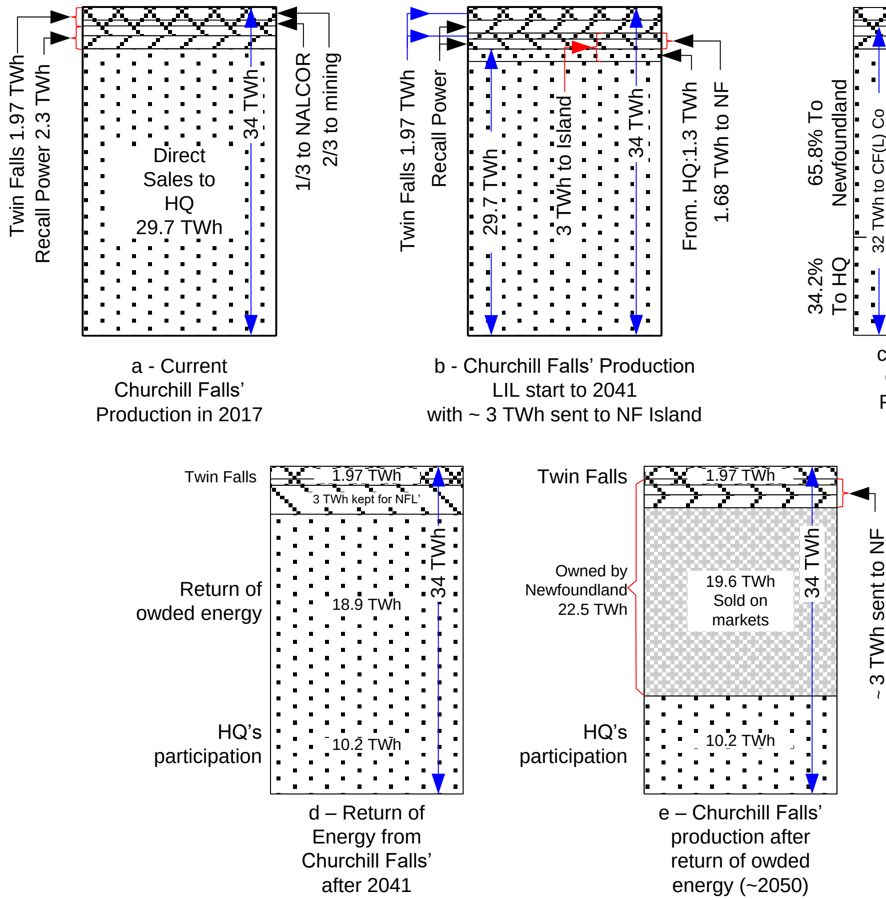

Figure 3.2 Diagrams of Energy Ownership Over Time

The production from Churchill Falls available to NALCOR after 2041 should be around 22.5 TWh. During the period when the energy is returned, NALCOR will still require continued revenues. The entire quantity of yearly energy then owned by NALCOR cannot be entirely used for return of owed energy. During several years after 2041, Hydro-Québec is assumed to continue to supply Newfoundland with funds in exchange for a nominal quantity of 3 TWh purchased at market prices. Refer to diagram d) from Figure 3.2. This would generate a range of revenues to Newfoundland of $200 to $250 millions, assuming a power replacement value of ~$0.06 to $0.09 per kWh in 2041. This will result in the capability to reimburse owed power at a yearly rate of 18.9 TWh. The exact value may change upwards or downwards due to power demands in Labrador but is representative of the achievable electricity return rate. Figure 3.2 provides a diagram that depicts the energy ownership over time, from the current situation to when all the owed energy would have been returned. NALCOR has contractual obligations with EMERA for the supply of 1.2 TWh to 1.8 TWh of energy. Those obligations would expire in mid 2042, if the LIL can be used in mid 2018 to start delivering this commitment to EMERA or in 2044 as currently planned. This electricity can add from $70 millions to $100 of revenues to NALCOR and help maintain its financial health.

4 Methodology to Develop the Delayed Exchanges and the Delayed Sales of Electricity

The exact numbers to be used for calculations, such as electricity selling price, quantity of funds required, interest rate, rate of power return, etc., will be jointly determined by both organizations in order to obtain a fair commercial exchange of electricity. Both organizations are expected to set up a strong team composed of a number of economists, engineers, accountants, contract lawyers and management personnel as necessary. That team would review and most likely improve the processes suggested in this report. The team would determine requirements and demands from involved parties, determine acceptable numbers to be used and generate the documentation necessary to obtain board's approval of the processes in their respective organizations. Communications with the political leadership and the population would be made once the terms are agreeable to the parties involved.

In order to implement the delayed exchange of electricity on the LIL and the delayed sale of electricity, the following general steps are expected to be necessary:

a. A management team is formed.

b. Both parties <u>define the quantities of electricity that can be exchanged</u> to Newfoundland using the residual Labrador Island Link capacity. This number is expected to be from 4.9 TWh to 6.2 TWh before the start of Muskrat Falls and smaller thereafter.

c. NALCOR and the government of Newfoundland & Labrador <u>determines the amount of yearly funds</u> they wish to obtain to reduce the financial burden of the Muskrat Falls' project on the population, industry and province's finances. The level of funding does not need to be immediately fixed and may simply be provided as pre-specified limits. The yearly level of fund transfers would then be adjusted as needed. This subject has been reviewed in section 1.3

d. Both parties <u>negotiate the yearly effective selling price</u> for electricity exchanged against the funds provided yearly to NALCOR. This will determine the equivalent number of TWh assumed to have been sold in exchange of the funds received. This represents the hearth of negotiations and a number of escalation methods may be used. This report will assume that the value of electricity linearly ramps from an initial value close to current average prices of bulk electricity on large grids to a higher value in 2041 that is closer to the value currently paid by Utilities for replacement production facilities.

e. <u>The interest rate is determined</u> for the quantities of TWh of energy due, in order to compensate for the fact that there is a long period required before the electricity is returned.

f. <u>The general conditions for return of electricity after 2041 are determined</u> such as the post 2041 level of funding still required by NALCOR and the government of Newfoundland & Labrador, the rate at which the energy is delivered and the interest rate to be applied on the remaining energy to be delivered.

Those steps are further reviewed in the next sections.

4.1 Determine the Level of Funding Required by NALCOR

The purpose of this section is to estimate the level of funding that may be required by NALCOR during the 2020 to 2041 period. The level of extra funding should be between $200 and possibly up to $400 millions per year.

Before NALCOR proceeded with the Muskrat Falls project, some form of review of expected costs to implement the project was made. It included the expected revenues from consumers and partners, savings from the curtailment of Holyrood and of other parameters. At that time, the cost of the Muskrat Falls' project and lines was estimated to be between $6.2 and $7.6 billions. At those cost levels, the project most probably did not projected a very significant cost increase to clients. With a current estimate of $12.7 billions, there is an added shortfall to the entire project of approximately $5 billions. NALCOR is financially responsible for the plant, the Alternative Current (AC) link to Churchill Falls and the AC line between the Avalon Peninsula and the Bay d'Espoir dam. It is however only partly responsible for extra costs on the Labrador Island Link while construction of the Maritime Link is EMERA's responsibility. Some elements of the project had more extra costs (Labrador Link) while some other part had less cost increases. This assessment will thus consider that a level of $4.5 billions of unfunded cost overruns is to be managed by NALCOR and the Newfoundland & Labrador government in one form or another.

Some of the cost increases will most likely be passed on to electricity ratepayers and / or taxpayers. However, it is unlikely that all extra costs will. The rate increase for a full payment by customers is expected to move the rate from $0.11 per kWh to $0.23 per kWh if nothing is made about reducing the rates. This would make Newfoundland & Labrador's electricity one of the most expensive in North America and similar to the costs found in large American cities such as Boston and New-York. The government is also not warm at such increases and would prefer to limit increases halfway to a maximum closer to $0.17 per kWh. It is most likely that any rate hike will occur progressively over a few years and stabilize at a fraction of the total required rate increase of $0.12 per kWh. Elasticity of demand will most likely play a role and may reduce electricity consumption in the province over time. Using the scheme developed in this report, the money required to limit electricity cost increases towards excessive values would come from funds provided annually by Hydro-Québec in exchange of future deliveries of electricity. The funding process would start only once negotiations are complete and contractual arrangements made. Those may take several months or years. This report covers a 2 years period potentially starting in 2018 (for energy exchange) and ending in 2041. Energy sales are assumed to start in 2020.

For debts incurred for assets that can generate continued fixed revenues over long periods of time, the interest payments are likely to drive the need for revenue, compared to capital repayments. If we consider that NALCOR needs to pay the interests on an extra sum of $4.5 billions and that the average borrowing rate guaranteed by the federal government averages 3.5%, then $160 M would be needed annually to just repay the interest rate. Operating costs have also increased from their initial estimates. If the stranded debt ends up being higher than the above number, the revenues required would further increase. Also some form of compensation may be required to cover for electricity cost increases for low income persons. Repayment of the debt itself will also add to the necessary funds. The funds necessary for

NALCOR would be slightly reduced after 5 years when the Supplementary Energy of 0.24 TWh will no longer be required to be delivered to Nova-Scotia. This small change in revenues has conservatively not been considered in the report.

The exact financial requirements to cover for interest and debt repayment are presently difficult to evaluate with sufficient accuracy and are also expected to evolve with time. Thus, for simplification, this report considers that NALCOR needs a yearly sum between $150 millions and perhaps up to $400 millions.

This assessment considers a fixed yearly level of funding to NALCOR. In practice, the level of rate increases to customers that can be achieved will mostly determine the level of initial funding required. The selling price of remaining power not used in NL or by EMERA may vary whether it can be part of a bulk sale or has to be sold on the spot market, itself quite volatile. Gross revenue from electricity sales outside Newfoundland will need to be reduced by the transportation costs through NS and beyond, through the Maritime Link and through the Labrador Island link. All in all, the rate of funding required will vary with time. Those fluctuations can be generally managed by modifying the funding level in the process.

4.2 Define the Quantities of Electricity that can be Exchanged

The first method of solving NALCOR's financial difficulties consists in the delayed exchange of electricity over the LIL. With the implementation of the Labrador Island Link (LIL) electricity can be exchanged between Newfoundland and Québec. The LIL is sized at a 900 MW capacity. At this level a maximum 7.88 TWh of energy can be inputted, assuming a 100% line capacity factor. Muskrat Falls can produce an average of 4.9 TWh and is only expected to use 62% of the LIL over the years. There is a remaining capacity of 2.98 TWh of energy that can be carried on the LIL. Approximately 1.34 TWh of the total 2.36 TWh Recall Power is consumed in Labrador, leaving approximately 1 TWh available for sending towards Newfoundland Island. NALCOR also disposes of approximately 0.68 TWh from ownership of a portion of the capacity allotted to cover Twin Falls' replacement power. The rest is owned by mining companies that use this power. Thus NALCOR can forward approximately 1.68 TWh (1 TWh plus 0.68 TWh) onto the LIL. This leaves 1.3 TWh (2.98 TWh minus 1.68 TWh) of remaining capacity that could be supplied by Hydro-Québec onto the LIL. However, before Muskrat Falls starts, its 4.9 TWh production could also be supplied annually by Hydro-Québec (HQ) at commercial cost or against future deliveries for a total of 6.23 TWh. Table 4.2 provides a summary of energy available from Recall Power and Twin Falls.

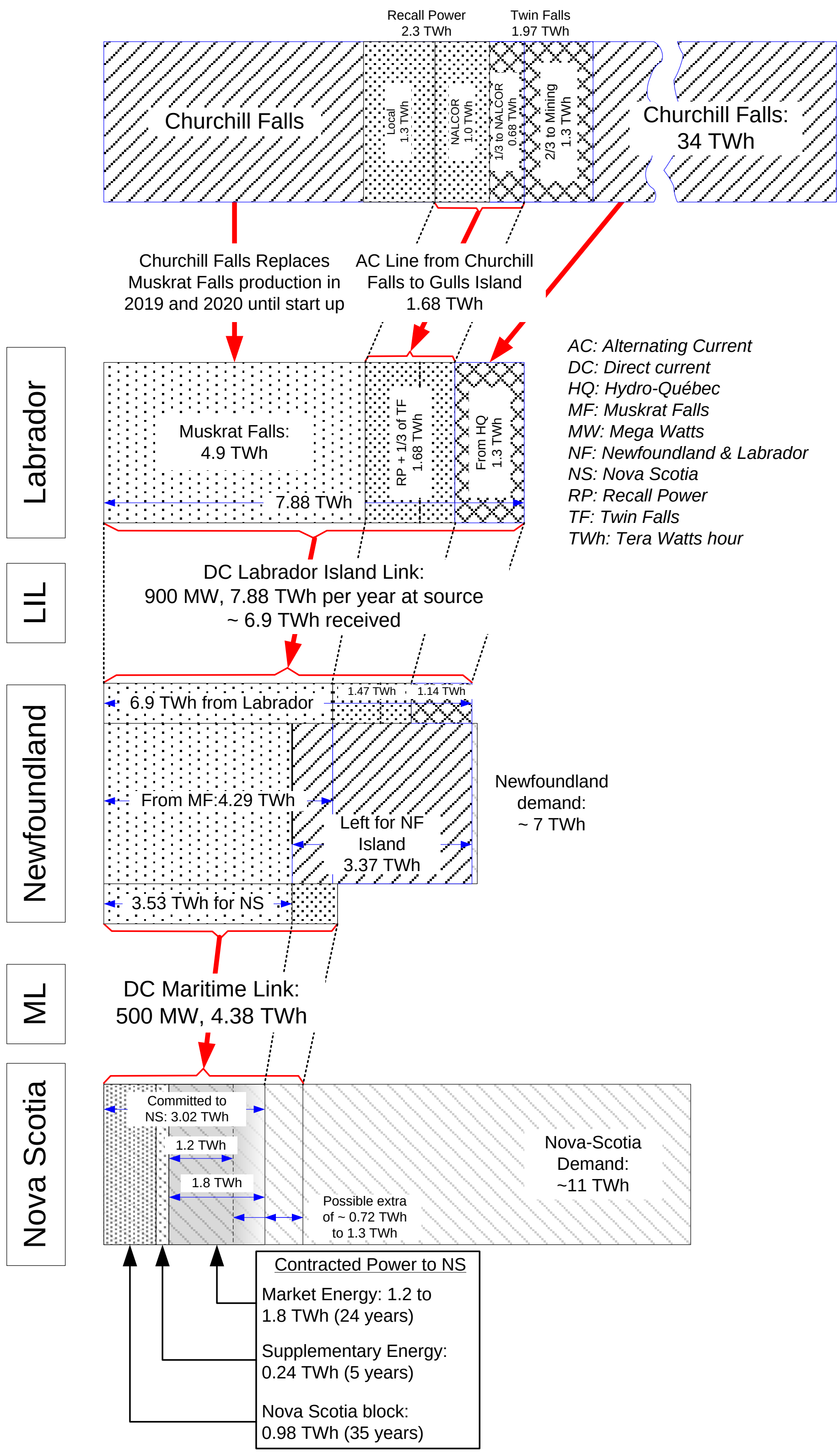

Figure 4.1 Diagram of expected Power Flows from Churchill Falls, the Labrador Island Link and the Maritime Link

	Recall Power (TWh)	Twin Falls (TWh)	Total (TWh)
Power	300 MW	225 MW	525 MW
Production	2.36	1.97	4.33
Owned by mining companies	-	1.31	1.31
Owned by NALCOR	2.36	0.66	3.02
Used in Labrador	1.34	1.31	2.65
Available for use on Newfoundland Island	1.02	0.66	1.68

Table 4.2 Energy Available from Recall Power and Twin Falls

The LIL is expected to have power line and conversion losses of the order of 70 MW (7.8 %), when operating at full power, thus delivering 830 MW. Over time, the LIL would be expected to reach a capacity factor of the order of 95% due to converter's reliability, line reliability with respect to line faults, isolator failures, icing, cable or tower failures and maintenance requirements. Overall, the LIL is assumed to effectively transport approximately 87% of its nominal capacity, representing 6.9 TWh of power to the Avalon Peninsula, with some of it forwarded to Nova-Scotia. The 5% power that cannot be carried due to its capacity factor would not be lost but simply used to return electricity to the Hydro-Québec grid, reducing the energy debt accordingly.

Figure 4.1 provides a diagram of expected power flows from Churchill Falls, the Labrador Island Link and the Maritime Link and provides the ownership assumed in this report. The numbers provided in these diagrams may require revision to fully represent the agreed contractual terms of supply and final equipment performance. Thus the negotiating team will need to verify and adjust inputs as necessary.

4.3 Determine the Effective Selling Price

The second method that can be used to materialize the future value of Churchill Falls is to assume that future electricity is sold at the current commercial value of electricity over time. It does not require the return of electricity sold before 2041. The effective selling price, similarly to any transaction is very important for both parties and must represent a fair commercial price. The effective selling price would be initially negotiated between both parties and reviewed on a regular basis of a few years.

The first English version of this assessment used a fixed value over the entire 2018 to 2041 period. It used a representative value of Churchill Falls' electricity close to the industrial rate to which some transportation costs were removed. As this was close to the patrimonial value of Québec's electricity, this latter value was instead used for simplifications. Also for simplification, this low initial value was kept over the entire period up to 2041. This method did not cover for the fact that in 2041 the value of this electricity should be closer to the construction and operating costs of facilities aimed at replacing retiring production facilities. Those replacement facilities will have a total unit energy cost that can only be much higher than the patrimonial cost. This revision of the report is made assuming that electricity costs are linearly ramped from an initial low value now prevailing on electricity markets to a higher value in 2041 that better reflects the current cost of replacement energy. The negotiation team will certainly modify this methodology a number of times but this method and the numbers used are believed to represent a fair value of electricity over the period.

The value of electricity is expressed in dollars per kilo Watt-hours (kWh) in this text. The reader must understand that the cost of electricity varies significantly along the delivery path from a power plant far from load centers. It varies along the high voltage and high power line up to its delivery due to line costs and electrical losses. It varies also as a function of the distribution to specific industrial, commercial or residential load located in rural areas and cities. Electricity cost may also vary as a function of the power level, consumption, time of year, time of day, reliability requirements, neighbouring market costs and a number of other commercial and technological parameters. For a large production center far away from load centers such as James Bay, Manicouagan or Churchill Falls, the value of electricity is close to the average production cost. A large quantity of energy delivered from a high voltage power transformer station to a single customer represents the industrial rate. It is based on the production cost plus the transportation cost and losses on high power lines to industrial centers. It thus excludes distribution that can be particularly quite expensive in large cities. The commercial and residential rates are based on electricity that is distributed to rural areas and into cities. This distribution involves a number of transformer stations and several lower power and lower voltage lines and sub-stations. The cost of electricity also depends on the quantity received and is highest for small residential customer loads. Overall, the cost of electricity delivered to residential customers is typically 2 to 3 times the production costs. This cost structure of delivered electricity is well understood by management personnel of Utilities, but is often misunderstood by the general population, the media and politicians.

As an example, the 2017 commercial selling price of bulk electricity for industrial high power clients (Tariff L - *grande puissance*) was \$0.0327 per kWh in Québec. At the other limit, a residential customer in Québec currently pays an average that is between \$0.08 and \$0.09 per kWh including taxes and connection fees depending on its actual monthly consumption. The commercial rates (shopping centers, apartment blocks) are slightly lower but include a number of cost elements pertaining to the load that makes the final cost of electricity also significantly higher that Tariff L. In Québec, the average cost of electricity delivered to clients is of the order of \$0.06 per kWh and is generally higher for other jurisdictions. The value of Churchill Falls' production is supplied from large power lines and would thus need to be compared to the industrial Tariff L rate.

In order to more directly apply the Tariff L value as the initial effective selling price, the transportation cost from Churchill Falls to southern industrial loads has to be considered. The cost of using power lines (from their construction and maintenance costs) and the cost of electrical line losses must also be removed from the industrial Tariff L. The number from that subtraction would provide a commercial value of electricity from Churchill Falls at the delivery point south-west of the plant. This price will be lower than Tariff L in the neighbourhood of 10% of more to cover for line cost, maintenance and line losses. The cost of transporting power on high voltage lines and the line loses are well known by Utilities and will be easily determined and agreed by the personnel affected to work on this scheme.

A well known value of electricity used in Québec is the patrimonial cost of electricity of $0.0288 per kWh. This is the blended cost of most hydroelectric stations in the province, including Churchill Falls. This value represents 88% of the Tariff L rate. By using 12% as an estimate of the transport cost, the cost of electricity would revert to the patrimonial value of $0.0288 per kWh: ($0.0327 per kWh x 0.88 % ~ $0.0288 per kWh). Using the patrimonial rate would be easier to understand as this is the cost of a blend of generating stations. For simplification of this report, the initial value of electricity is rounded at $0.03 per kWh, close to the average between the Tariff L and the patrimonial cost of power. The current cost of power from La Romaine is of the order of $0.07 per kWh for the production facilities. The line cost would represent approximately $0.02 per kWh (for U.S. exports) for a total delivered cost of $0.09 per kWh. That amount would thus well represent the actual cost for replacement hydraulic power delivered in southern Québec. This level of production and delivery costs is also similar (but slightly higher) to the most recent large commercial wind generating facilities that delivers power to the grid at approximately $0.08 per kWh. The average value of $0.09 per kWh can thus be taken as a representative present value of bulk electricity in 2041.

Although historically difficult, negotiations between NALCOR and Hydro-Québec are possible. Recently, NALCOR and Hydro-Québec have successfully negotiated an electricity contract with Hydro-Québec that is valued at more than $40 millions a year. It involves the sale and transportation of 1.6 TWh of electricity from Churchill Falls for ultimate sales on the US markets. The basic price of electricity for this transaction was of $0.02718 per kW. This price is nearly identical to the patrimonial electricity cost in Québec discussed above. This indicates that the current commercial value of electricity from Churchill Falls is close to this value. The cost for transportation of the electricity to southern Québec and its conversion on an AC/DC/Ac converter has to be subtracted from the above value. The contract to be negotiated in order to realize the scheme described in this report would thus initially use similar values but involve larger sales volumes.

However, much before 2041, Hydro-Québec will have to generally decide if it will construct further facilities, reduce its exports or/and continue to purchase electricity from Churchill Falls to fulfill the demand of its customers. Each of those options has its specific cost structure and will be used to some extent depending on evolution of electricity prices (oil and gas prices, closure of nuclear plants), future market demand (larger population, electric cars), the construction of new facilities, the retirement of older units, carbon taxes for thermal plants, the value of exports, evolution of wind and solar energy prices and ultimately the price that is asked by NALCOR for Churchill Falls' electricity. The current cost for construction of the next new hydraulic facilities can now be expected to be of the order of $0.07 to $0.10 per kWh including transportation to southern Québec, more if exportation on DC converters is required. Also, the average yearly export price may increase from the current $0.04 (Can.) per kWh to $0.10 per kWh or more in two decades. Such prices are not unheard of as export prices averaged close to $0.09 (Can.) per kWh just before the 2008 recession. The commercial value of electricity from Churchill Falls will thus be compared to those options over the years. In practice the price will probably evolve from the current ~$0.03 per kWh and increase slowly towards the above high end values of the order of $0.09

per kWh reached in 2006-2008 era. The effective selling price is expected to be renegotiated at fixed intervals of a few years in order to represent a fair commercial value for both parties. The quantity of electricity sold will also vary as necessary between both parties.

4.4 Determine the Interest Rate to Apply during the 2018 to 2041 Period

The interest rate to be applied to quantities of electricity owed is quite important as it becomes compounded over the years and little or no payback is feasible before 2041. This section reviews how the interest rate is selected for this assessment. The rate will certainly be revised by the negotiation committee but the number obtained from this assessment should reasonably depict the financial possibilities of the scheme. The two current Federal Loan Guarantees provides funding at an average level of 3.5 %. The methods described in this report imply a large quantity of borrowed electricity that will be due to Hydro-Québec over three decades. Similarly to money due to a lender, the quantity of electricity due has to be accrued over the years and thus has to bear an interest rate to be of some interest to the lender compared to other investments. The value of money depreciates every year due to inflation. Electrical energy on the other hand can be expected to maintain its value over time and increase at least as inflation does, if not more. The interest rate for lending goods that are not significantly affected by inflation may be somewhat reduced.

Utilities have a large debt that is made from a number of debts of various sizes contracted at different times. Each debt title bears a specific interest rate determined at the time of the loan and extends for a specific number of years that is attached to each debt title. When the total amount of interest paid by a Utility is divided by the total debt, a rough estimate of the average borrowing interest rate is obtained. Other specialized methods may be devised by economists to determine an acceptable average borrowing rate for specific conditions. The Hydro-Québec's 2016 annual report indicates a total debt of $55.46 billions and interests amounting to $2.51 billions, resulting in an average 4.526% interest rate. The average borrowing rate for Newfoundland & Labrador is similar at 4.6%. The recent borrowing rate obtained for Hydro-Québec's debt titles is even lower. Such an interest rate fundamentally contains inflation and lender's commercial return on investment. It should be financially neutral for Hydro-Québec to either invest $1 in a project that will accrue at that rate or repay $1 of its debt, as long as there are no risks in the investment. When TWh that have a value that keeps up with inflation is used for repayment of the debt, the inflation need not be included as it is already included in the value of the goods received.

In the previous version of the present report, estimations for the maximum quantity of TWh due and the time taken to return the electricity after 2041 were calculated using a nominal rate of 6.5 % in this report. This was obtained from the 4.526% average borrowing rate, to which a profit premium of approximately 2 % (1.974%) was added to obtain a rounded value of 6.5%. The logic was to obtain a value higher than obtained from repayment of a debt. The resulting commercial interest rate is higher than the ones paid for by federal or provincial governments, by large Utilities and for the FLG. Such a rate is however more common in industry. For example, accounts payable between NALCOR and Hydro-Québec bear a 7% interest rate for electricity exchanged as part of the upper Churchill contract. This rate has been set at this relatively high value to force the return of electricity and debt repayment as quickly as possible. If electricity would be involved, the inflation rate could have been subtracted.

Similarly, electricity exchanges between Newfoundland and Nova-Scotia on the Maritime Link have already been negotiated. When a surplus of energy is owed, it bears an interest rate of 3%. As the value of electricity would increase similarly with inflation that is currently of the order of 1.5% to 3%, a 3% rate would correspond to an interest rate of approximately 4.5% to 6%, should money be owed instead of electricity.

For this assessment a rounded value of 3% is used, the same value that ended up to be negotiated between NALCOR and EMERA for the Maritime Link. A similar value can be expected to result from negotiations between NALCOR and Hydro-Québec. Each party to the negotiation team will certainly hope to have this number increased or decreased but the final negotiated rate should be quite close to this number and remains close to this value for several years.

4.5 Determine Modalities for Return of Electricity after 2041

At the end of the contract on September 1st 2041, Newfoundland & Labrador should dispose of the electricity set by its share in CF(L)Co. The diagrams a), b), and c) from Figure 3.2 describes the ownership of the production that is assumed in this report. The real contractual split of the energy may slightly differ and slightly affect the numbers of this report. The available energy for return of electricity is the actual Churchill Falls production minus the Twin Falls energy allocation of 2 TWh that does not change with time. In supplement 2.3 TWh is allocated to NALCOR as Recall Power. This leaves 29.7 TWh to be split between Nalcor and Hydro-Québec. The Recall Energy is reserved for Newfoundland, except that since completion of the first 40 years of the contract, the NALCOR owned energy is no longer priced at $0.002 but can be sold to markets at a higher price. Since 2016, that power is sold to U.S. markets with at export prices (about $0.03 to $0.04 per kWh) minus transportation costs of typically $0.02 per kWh for transport and DC conversion. After 2041, the 29.7 TWh is split 65.8% / 34.2%, resulting in 19.5 TWh of supplementary energy for NALCOR. When considering its participation in Twin Falls and the energy for the Recall Power, NALCOR disposes of 21.9 TWh, plus its 0.65 TWh from its participation in Twin Falls that is necessary for mining corporations. Of the 21.9 TWh available to NALCOR, 3 TWh are retained to generate continued funds, resulting in 18.9 TWh available for return of energy in 2041.

Once the LIL enters operation, the portion of the Recall Power that can be dispatched is sent to the Newfoundland Island instead or being sold to markets at U.S. export prices minus transportation. This is made to decrease the Holyrood fuel costs that are higher than the net value that can be obtained from the U.S. market. This still maintains 29.7 TWh for Hydro-Québec up to year 2041.

The Market Energy portion of the supply to Nova-Scotia is required to be derived over a 24 years period. If this delivery can start in mid 2018, it would end in mid 2042. NALCOR will then benefit from the sale of this electricity. Using a range of $0.06 to $0.09 for this energy, a value of $180 to $270 millions would be generated for consumption by NALCOR. This would add to the revenue from the delivery of 3 TWh of energy to Hydro-Québec. Those revenues after 2042 should be more than sufficient for NALCOR. If more money is necessary, slightly less electricity can be send back to Hydro-Québec, with the effect of slightly increasing the period required to entirely return the owed electricity. After 2041, NALCOR will thus be able to return 18.9 TWh to Hydro-Québec for the necessary period without undue financial stress, maintaining reasonable rates to its clients.

5 Parameters for Delayed Electricity Exchanges Using the Labrador Island Link

This section reviews the parameters to be expected from the process of supplying electricity from Churchill Falls to Newfoundland and Nova-Scotia and having it returned after 2041. The parameters used for the assessment are summarized in Table 5.1. The electricity is assumed to be delivered as soon as the LIL can deliver power and reduces/stops when Muskrat Falls operates. For simplifications, a period of 2 years is used starting in mid 2018. A quantity of up to 6.2 TWh per year could be sent, knowing that capacity will be necessary to carry the Recall Power.

PARAMETERS For Energy Exchange	VALUE
Labrador Island Link nominal capacity	900 MW
Labrador Island Link nominal energy input capacity	7.88 TWh per year
Nominal energy produced at Muskrat Falls	4.9 TWh per year
Remaining LIL capacity with Muskrat Falls in operation	2.98 TWh per year
Energy from Recall Power and Twin Falls inputted to Labrador Island Link	1.68 TWh per year (1.02 TWh from Recall Power and 0.66 TWh from Twin Falls)
Remaining quantity of energy that can be inputted on the LIL before start of Muskrat Falls (7.88 TWh - 1.68 TWh)	6.2 TWh per year
Remaining quantity of energy that can be supplied by HQ on the LIL when Muskrat Falls and NALCOR's owed energy is transported (6.23 TWh - 4.9 TWh)	1.3 TWh per year
Labrador Island Link line losses (efficiency)	7.8% (92.2%)
Labrador Island Link capacity factor	95% (estimated)
Interest rate on supplied (owed) electricity	3 %

Table 5.1 General Parameters used for Energy Transfers from Churchill Falls to Newfoundland Using the Labrador Island Link

In practice those deliveries may extend for a longer or a shorter period and may use only a fraction of the LIL capacity as the Muskrat Falls turbines comes on line. For the remaining 21 years, extra energy supply would be much smaller due to Muskrat Falls' production, except during maintenance of equipment.

With electricity rates of $0.12 per kWh to residential customers, the production cost of electricity on the Newfoundland Island should be higher than $0.05 per kWh, as this would imply a high value of $0.07 per kWh for distribution. Before Muskrat Falls starts, approximately 12.5 TWh (2 x 6.2 TWh) of extra energy would have been transferred from Hydro-Québec onto the LIL, resulting in a delivery of 8.5 TWh of energy that bear no immediate costs. For subsequent years when Muskrat Falls is in operation, less energy (1.3 TWh) is delivered. The energy inputted into the LIL would accumulate and, with interests, would reach up to 61.8 TWh in 2041. Although very large from the Newfoundland Island grid perspective this energy can be returned in less than 4 years using the energy that NALCOR will dispose from Churchill Falls after august 31, 2041. Table 5.2 provides a summary of results for delayed energy transfers of energy from Churchill Falls.

In practice, the LIL will not be able to deliver energy all the time due to required maintenance and momentary failure of equipment. During that period the power is returned to Hydro-Québec, reducing the quantity of energy owned. Over time, possibly up to 5 TWh of energy could be returned during those periods. For simplifications, this type of smaller scale energy transaction has not been included in calculations made for this report. Energy exchange adds flexibility as the Muskrat Falls facilities may produce less for specific periods due to equipment failure or low water conditions. Energy would be supplied by Hydro-Québec during such events and added to the owed energy. If Muskrat Falls' production is larger due to abnormally high precipitations, the quantity of owed energy would be correspondingly reduced. Such exchanges would resolve the water management rights issue.

Summary of results for energy exchange through the LIL	VALUE
Energy inputted to the LIL from 2018 to 2041	40 TWh
Energy received on the Newfoundland Island from 2018 to 2041	33 TWh
Maximum energy owed with interest	62 TWh
Increase in energy owed due to interests and line losses	90%
Rate of energy return	18.9 TWh per year
Total energy returned	65 TWh
Years to return owed energy	3.4 years

Table 5.2 Summary of results for delayed energy transfers from Churchill Falls to Newfoundland using the Labrador Island Link

It can be seen that the supply of significant quantities of energy that accumulates to 33 TWh over the years can be made. This roughly corresponds to 6 years of Muskrat Falls' production and can help resolve a portion of NALCOR's financial difficulties.

Figure 5.1 provides the evolution of the total quantity of energy that would be owed as a function of time using the parameters provided in Table 5.1. The key parameters of Figure 5.1 are summarized in Table 5.2.

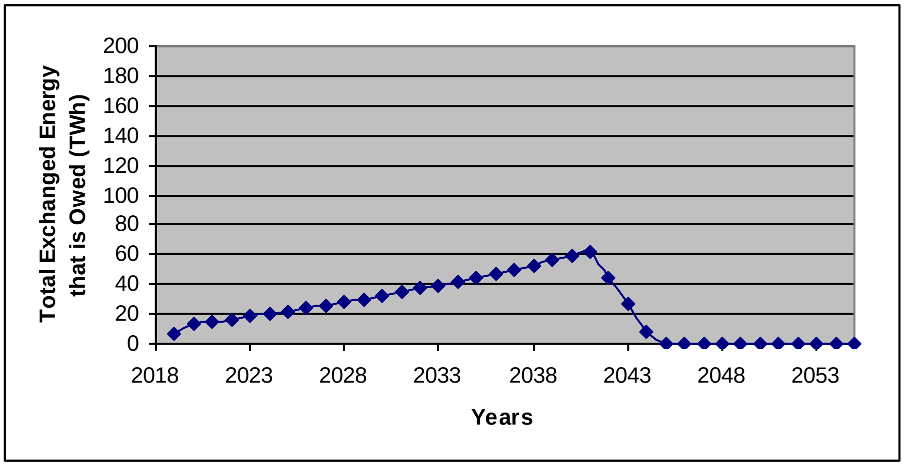

Figure 5.1 Quantity of Energy Owed with Energy Exchange Method Only

This simple method is however not expected to be sufficient to resolve NALCOR's financial difficulties. Thus, the delayed sale of electricity will most likely need to be implemented.

6 Typical Parameters Obtained from Delayed Energy Sales

This section analyses the delayed sales of energy with five different funding levels. The general parameters used for assessment of delayed sales of electricity are provided in Table 6.1.

PARAMETER	VALUE
Period of fund transfers	2020 to 2041
Assumed initial selling price of electricity in 2020	\$0.03 per kWh
Assumed final selling price of electricity in 2041	\$0.09 per kWh
Level of yearly fund transfers:	\$100 M \$150 M \$200 M \$250 M \$300 M
Interest rate on owed energy	3 %
Churchill Falls' energy retained (not returned) for sales against funds	3 TWh per year
Rate of return of energy after 2041	18.9 TWh per year

Table 6.1 General Parameters Used for Assessment of Delayed Sales of Electricity

The funding level is varied from \$100 millions per year to \$300 millions per year using increments of \$50 millions. Two specific assessments are made. The first covers the case where only funds would be transferred to NALCOR using the above yearly rates. The second assessment covers the more probable option which has the maximum quantity of electricity that can be delivered on the LIL used <u>and</u> funds are transferred to NALCOR using the above funding levels.

The selection process for those parameters has been extensively described in previous sections. For the first two years, no funds are transferred because a large quantity of electricity is transferred to the Newfoundland Island that has a value of several hundred $millions. Funds could be transferred but because extensive negotiations are necessary, the earlier start is assumed to be 2020. The transfer of funds continues at the same level for the next 21 years until 2041. As described previously, the assumed sale value for electricity equivalent to the funds transferred is varied linearly from $0.03 per kWh to $0.09 per kWh along the period. The owed quantity of electricity is accrued at a rate of 3%.

Table 6.2 provides typical results for the purchase of energy with delayed delivery. The second column provides the quantity of energy purchased in exchange for the funding provided to NALCOR. The third column provides the maximum quantity of energy owed in year 2041. The fourth column provides the final quantity of energy required to be returned after 2041. Those numbers represents very large quantities of energy that are from 6 to 16 times larger than the annual energy consumption on the Island of Newfoundland. However, as Churchill Falls produces very large quantities of electricity, the owed energy can be returned relatively quickly. The fifth column provides the number of years necessary to return the energy owed. It can be seen that if only funds are involved (no transfer of electricity), the objective of taking less than 10 years to return the owed energy can be achieved with a funding level as high as $300 millions per year.

Rate of fund transfers ($millions per year)	Quantity of energy initially purchased by HQ (TWh)	Maximum quantity of energy owed in 2041 (TWh)	Quantity of energy to be returned after 2041 (TWh)	Time needed to return owed energy after 2041 (Years)
100 $	36	53	55	2,9
150 $	54	79	84	4,5
200 $	72	105	115	6,1
250 $	90	132	147	7,8
300 $	108	158	181	9,6

Table 6.2 Result of Assessments Considering Only Direct Funding

In practice, transfers of energy into the LIL will be used to the maximum extend possible. This is because the cost of producing power on the Newfoundland Island and in Nova-Scotia is larger than the value of energy for Hydro-Québec, particularly when large surplus prevails in Québec. Table 6.3 provides the results of the assessment considering the maximum supply of electricity to the Newfoundland Island is made over the years <u>and</u> that various levels of direct funding are made. It can be seen that in order to reach the target of returning the energy within a 10 years period, a maximum supply of funds of $200 millions per year should be used. This indirectly indicates that the exchange of electricity into the LIL at the rate and cost assumed in this assessment is generally equivalent to an average funding level of $100 millions per year.

Rate of fund transfers ($millions per year)	Quantity of energy supplied over the years plus purchased by HQ (TWh)	Maximum quantity of energy owed in 2041 (TWh)	Quantity of energy to be returned after 2041 (TWh)	Time needed to return owed energy after 2041 (Years)
100 $	76	114	126	6,7
150 $	94	141	159	8,4
200 $	112	167	194	10,3
250 $	130	193	230	12,2
300 $	148	220	269	14,3

Table 6.3 Result of Assessments Considering Both Exchange of Electricity and Direct Funding

Figure 6.1 provides an illustration of the total quantity of energy owed as a function of time. Similarly to Table 6.3, it describes the case where both the maximum electricity supply and a number of rates of fund transfers are made concurrently. The graphic thus displays how the owed energy accumulates up to 2041 and diminishes thereafter as power is returned.

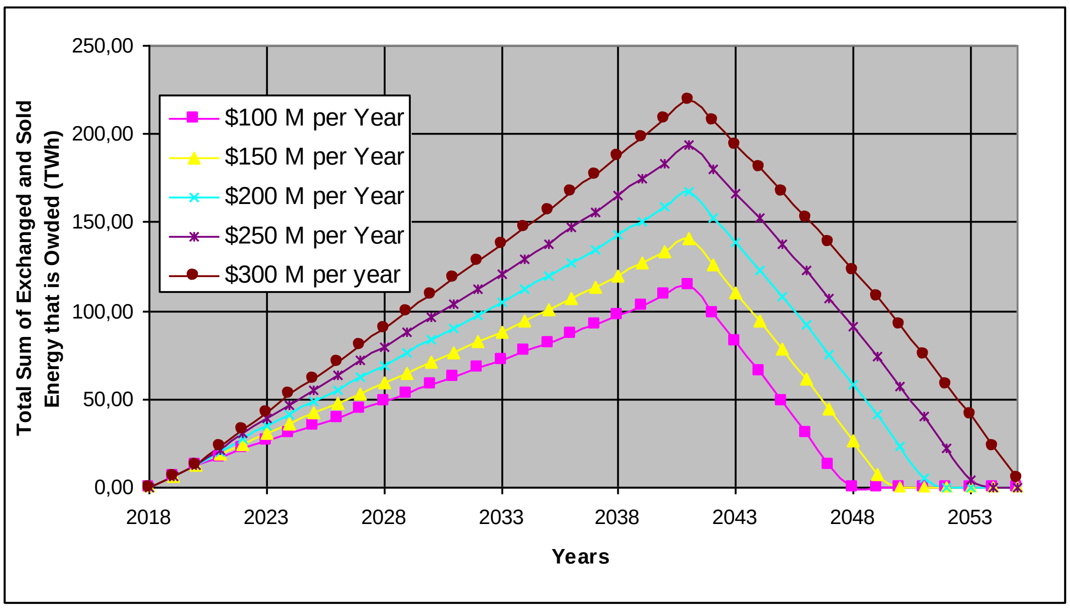

Figure 6.1 Variations of energy owed (TWh) over time for different funding levels assuming a maximum of energy exchanged via the LIL

Figure 6.2 concerns solely the situation where various levels of direct funding are made to NALCOR. It does not include the effect of the supply of power onto the LIL. The figure provides in a graphical form the total quantity of energy purchased; the maximum quantity of energy owed in 2041 and the total quantity of energy required to be delivered after 2041.

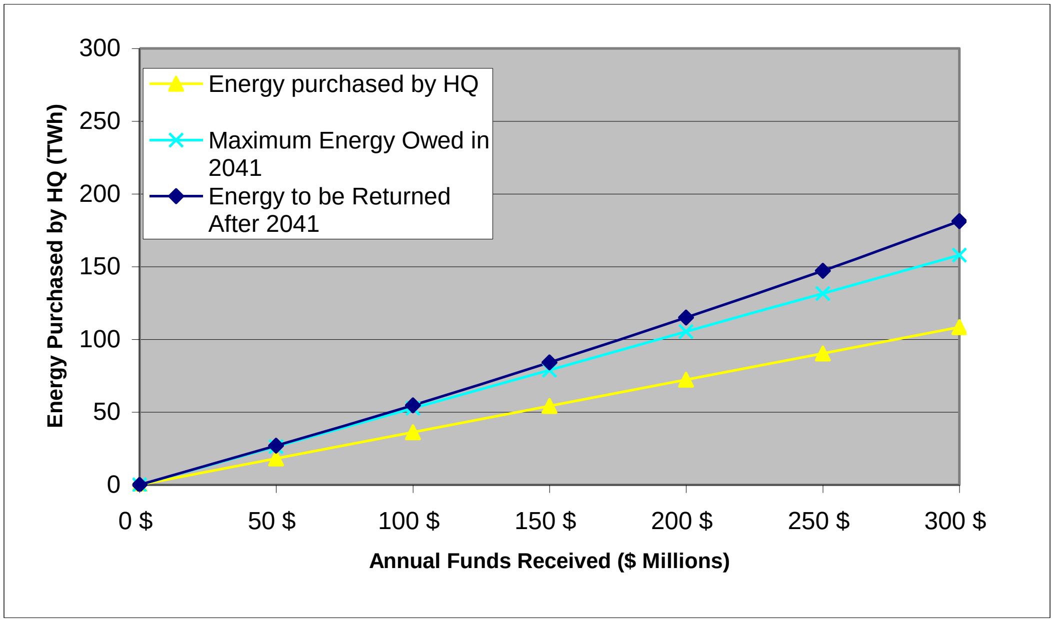

Figure 6.2 Direct Funding Only – Quantities of Energy

Figure 6.3 concerns the cases where energy would have been supplied by HQ on the LIL over the years and various levels of direct funding are made to NALCOR. The figure provides in a graphical form the total quantity of energy purchased; the maximum quantity of energy owed in 2041 and the total quantity of energy required to be delivered after 2041.

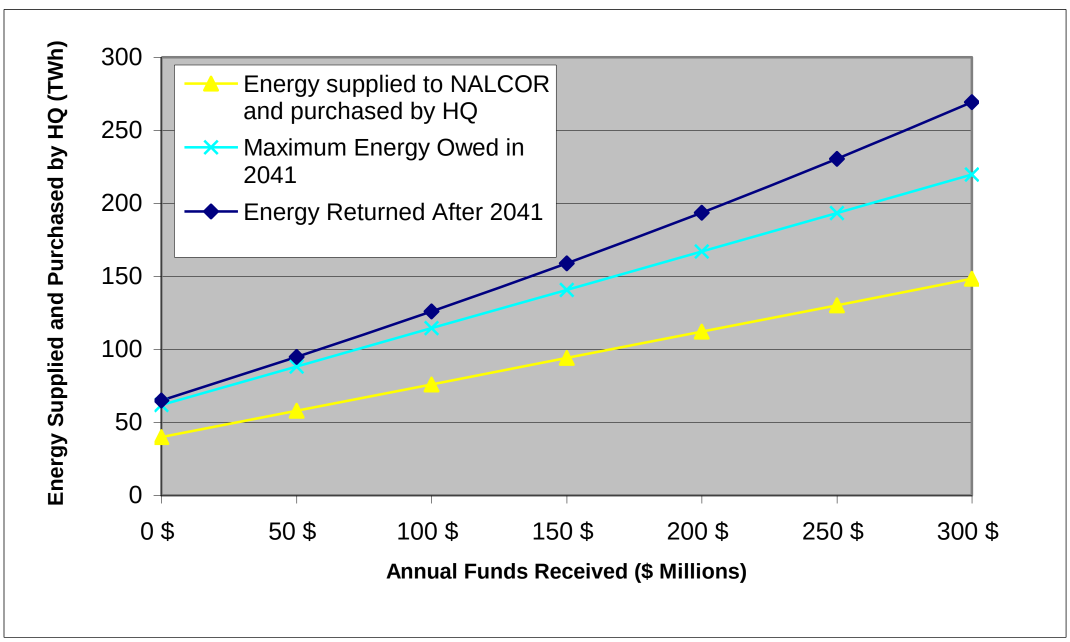

Figure 6.3 Energy Supply on LIL and Direct Funding– Quantities of Energy

Figure 6.4 provides in a graphical form, the number of years required to return the owed energy for two cases. One covers for various levels of fund transfers to NALCOR. The other more likely case has Hydro-Québec to supply a maximum of energy onto the LIL, in supplement to fund transfers. It can be seen that a funding level of $300 millions per year can be obtained while maintaining a period of less than 10 years to return the electricity. When the maximum quantity of electricity is fed onto the LIL, a funding level of up to $200 millions per year can be obtained while maintaining a period of less than 10 years to return the electricity

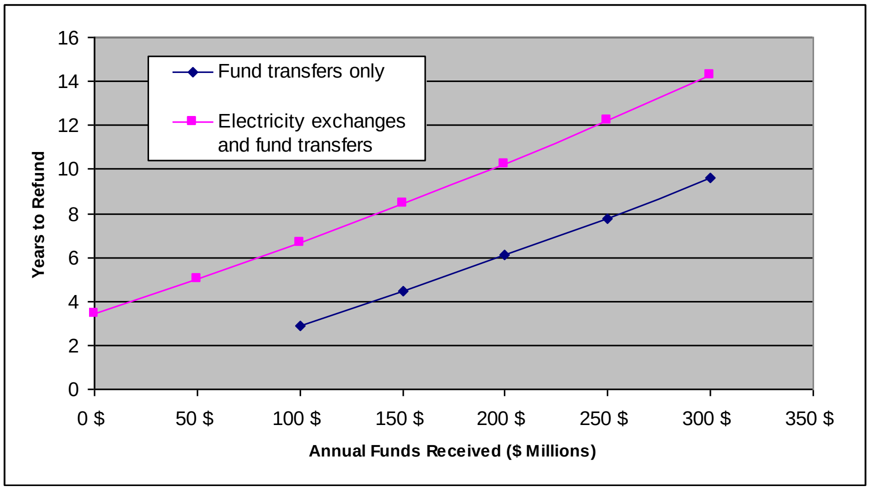

Figure 6.4 Number of Years Required to Return the Owed Energy

Figure 6.5 provides the estimated yearly value of electricity supplied from Churchill Falls to which fund transfers of $200 millions per year are added.

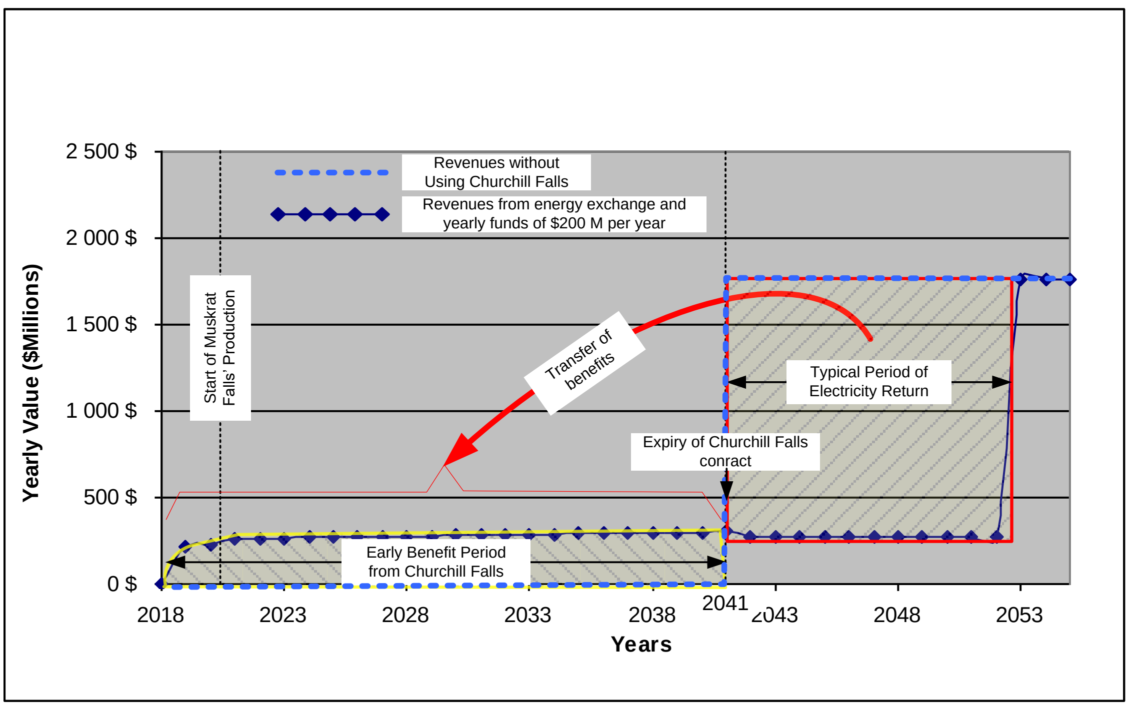

Figure 6.5 Estimated yearly value of revenues from Churchill Falls

This level allows full return of electricity by 2051. After 2041 and up to full return of owed energy, a yearly quantity of 3 TWh of electricity is purchased by Hydro-Québec at market prices. The remaining 18.9 TWh supplied is used to repay the owed energy that has already been paid for over the years. After 2042, the 24 years supply of Market Energy to EMERA will be completed and NALCOR will be able to receive the commercial value of this electricity. Those 1.2 TWh to 1.8 TWh of energy in 2041 can be worth between $100 millions and $170 millions par year assuming a value of electricity of $0.09 per kWh on markets during that period. Those extra revenues are not illustrated in Figure 6.3, but would maintain revenues close to $400 millions per year. Once the owed electricity is paid, NALCOR's revenues from Churchill Falls will exceed $1.5 billions per year, ending Newfoundland & Labrador's financial difficulties.

7 Other Options to Generate Short to Medium Term Revenues for NALCOR

This section reviews a few other opportunities to generate revenues for NALCOR in the short to medium term. The options described in this section are known to NALCOR and are listed mainly for information to the reader.

7.1 Selling of Equity from Current Assets to Pay for Muskrat Falls

Selling future renewable electricity produced at Churchill Falls is the best option for NALCOR because ownership is maintained in assets that can provide revenues for a long period. It however has some limit and if more substantial funds are required, selling of equity in specific facilities may need to be evaluated. The principal equities owned by NALCOR are Muskrat Falls, the Labrador Island Link and its interests in Churchill Falls. Being too far from its grid, the assets on the Newfoundland Island such as power lines or hydraulic facilities may not create a sufficient interest for Newfoundland to obtain a fair value from Hydro-Québec.

7.1.1 Selling Partial Ownership of Churchill Falls after 2041

A large portion of the Muskrat Falls' debt has been made at the very low rate obtained with the Federal Loan Guarantee (FLG) 1 and FLG 2. A direct sale of a large portion of equity in Churchill Falls in order to directly repay the capital of those low interest debts may not be the best financial or political decision as long as the necessary interest and capital payments can be made over the years. The two other funding methods described in this report should cover for most yearly financial requirements. If selling of equity is necessary, a yearly selling of a small fraction of equity is preferable as the yearly funds necessary will vary with time. This progressive approach may be more effective particularly if oil prices rise significantly or if the fisheries business gets better. Only time will determine the best combination for sourcing revenues.

The acquisition of an increased ownership would not immediately benefit HQ and would not do so before 2041. The purchase should thus be made in 2041 only. In order to make the purchase effective at an earlier date, an interest rate has to be applied. Normally, the purchaser of a good requires that the benefits become available immediately. To transfer that value in time, an interest rate may be considered during each year until the benefits from the goods are obtained or a larger portion of the facility obtained in the transaction. The number representing the interest should not include inflation as the value of the plant in the future will also increase with inflation. The percentage ownership would be accrued yearly to obtain the final increase in ownership in 2041.

Assuming a commercial value of the plant at $25 billions, a $125 millions fund transfer per year would correspond to a 0.5% purchase of the plant. After 22 years, 11% of the plant would have been sold while the rest would remain with Newfoundland & Labrador if no interest is required on this scheme. The resulting ownership split would be close to 55% for Newfoundland and 45% for Québec, maintaining a majority share. If the % ownership purchased over time is accrued with a specific interest rate, the final ownership ratio would evolve accordingly and closer to a 50% / 50% split when the interest rate is around 3%. If NALCOR would accept a reduction of its share to 50.1%, approximately $125 millions per year over 22 years could be obtained, which is worth approximately $2.7 billions over time to NALCOR. NALCOR has already proceeded recently with a partial sale of the LIL to EMERA. Sale of shares of a corporation is a very common way of generating money for corporations. As long as majority ownership is maintained, the sales of a further portion of the Churchill Falls facilities would most likely be tolerable to Newfoundlanders and to its political leadership. A loss of 10% equity in Churchill Falls represents a loss of revenues from 540 MW of hydraulic production. Such an equity loss in Churchill Falls is not efficient to payback the 824 MW Muskrat Falls facilities. A 15% loss of equity in Churchill Falls would be equivalent to loosing Muskrat Falls altogether! Thus this method should not be heavily used.

Currently, Hydro-Québec is ready to invest both inside and outside Canada in future or existing power projects, power lines or other technologies tied to its core business of electricity. An investment in the Churchill Falls project in the form of equity or electricity production or a mix of both would represent a low risk purchase for Hydro-Québec. It would bring a much desired extra production after 2041, thus compensating for the contractual loss of a large portion of the Churchill Falls production at that date.

Overall, selling future electricity from Churchill Falls seems to be the most practical solution to resolve Muskrat Falls' financial difficulties. The choice may be difficult between exchanging electricity, selling electricity or selling equity, or selling a mix of those, but at least there are some choices available on how to resolve current NALCOR's financial difficulties.

7.1.2 Selling of Equity in Muskrat Falls

Selling of equity in Muskrat Falls is not envisaged in this assessment. The principal reason is that its final construction cost will be too high, that a large portion of its production is currently earmarked for EMERA and that a potential investor may find that geotechnical risks are too high. Those impediments would prevent the owner to obtain a fair price for the facilities. Specifically, the long term performance of the North Spur that contains some quantities of quick clays generates geotechnical risks that would require a thorough review. The current North Spur is planned to operate solely with the specific reinforcements made up to now. The long term capability of the North Spur as a dam capable of resisting the pressure from initial reservoir filling, resisting the effects from small or large seismic events that may occur in the future and the risk of waves or level increases from potentially large upstream landslides may not be adequate for an investor such as Hydro-Québec. The consequences from a dam failure outside its jurisdiction are too large. Events occurring with a low probability of typically one in 1000 years or less must be considered to minimize risks.

Soil quality is important for dams. For the southern James Bay Rivers, namely the Nottaway, Broadback and Rupert (the NBR project) more than 5,000 MW of hydraulic projects were not made in the 70's and are still not developed until now, partly due to the widespread presence of sensitive clays. The James Bay developments were finally made in the northern portion for the La Grande River basin. It provided more power and had a generally higher elevation. It flowed primarily on rocky terrain, resulting in construction of dams and dykes that were much less affected by sensitive soil conditions. Construction of a dam normally requires full excavation of in-situ materials and rock sealing. The dam body includes a water tight inner zone and several other zones built with controlled materials. There are few exceptions such as the Peribonka dam that did not had all the soil excavated. Bentonite was injected down to rock and the rock injected to seal it. Large quantities of bentonite were then injected to generate a solid volume into which excavation for the diaphragm wall could take place. Sophisticated, stare of the art, custom built, trench cutters are then used to dig into the bentonite down to below rock level, replacing the bentonite with concrete in order to perform the diaphragm wall construction and to have it properly keyed to the underlying rock. At the Peribonka dam, the rock was 116 m (380 ft) deep making it one of the deepest one built worldwide for such application. Construction on deep sensitive clays without removing uncontrolled material would only be contemplated for a low height dyke using a very conservative and robust design involving a very wide base, low angle slopes and the use of controlled materials deposited over the in-situ materials. For the North Spur, unconfirmed data indicate that the rock depth may extend down to 260 m (850 feet). Such a large number seems suspect and may instead be only 260 ft (80 m) deep. Even at such depths, the construction of a diaphragm wall would be difficult, time consuming and onerous. Perhaps filling with rock the deep pool slightly below the spur would be simpler along other geotechnical reinforcements.

Generally speaking, an investment in Muskrat Falls may not be of sufficient quality compared to other energy investment that can be made in Canada, North America or elsewhere. Specifically, an investor would be far more interested in the Churchill Falls' facilities that have known technical and historical performance characteristics.

7.1.3 Selling Equity in the Labrador Island Link

The Labrador Island Link is co-financed and co-owned by NALCOR and EMERA and is currently expected to cost $3.7 billions. The EMERA's ownership has generally shifted from an initial 20% to nearly 60% in exchange of supplementary funding made to cover some of the extra project costs. This has left NALCOR with an equity representing approximately 40% of the line's commercial value. This corresponds to $1.5 billions when the entire above construction cost is assumed at its face value. In practice, its commercial value may be much smaller. Such a line may represent a valuable asset for an electric Utility such as Hydro-Québec that owns several of the DC export lines and converters within and close to the

Québec's borders. The line can be expected to run at full capacity, generating steady revenues. Lines and converters located in other jurisdictions have often been paid for by Utilities that need those facilities. There may be a small interest by Hydro-Québec to purchase some equity in this line. Selling of the remaining ownership in the line would only provide a partial relief to NALCOR. Generally, if more money is required by NALCOR, it would be best to simply increase the energy debt, say beyond 160 TWh that takes 10 years to refund and take a few more months to return Churchill Falls's electricity over more than 10 years, compared with permanently losing equity in the LIL.

7.2 Revenues from Transfers of Energy on the LIL

During operation of the LIL, a number of opportunities exist for NALCOR.

7.2.1 Powering Newfoundland Island before Muskrat Falls Operation

This option is very well known to NALCOR and is summarized mainly for information to the reader in order to ensure a relatively complete review of options is made.

The Labrador Island Link will be commissioned before Muskrat Falls starts production due to the supplementary delays encountered. Up to when Muskrat Falls starts producing power, some of the Newfoundland Island power can be supplied from Churchill Falls through the Labrador Island Link.

Hydro-Québec can easily supply the remaining line capacity of 6.2 TWh resulting in approximately 5.4 TWh delivered into the Avalon Peninsula. The price that can be offered will be lower than what EMERA can provide to close off Holyrood. The Labrador power, even when purchased, could be used to supply power throughout the year to the Newfoundland Island and remove the need to operate Holyrood altogether. The Maritime Link would principally act as a back-up supply in case of partial or complete LIL failure during peak demand periods. If electricity is purchased from Hydro-Québec, a commercial selling price close to Tariff L could be negotiated. For Hydro-Québec, the Newfoundland Island load can be seen as a large industrial load serviced from Churchill Falls. This power would normally be paid for by NALCOR when purchased and would still be less expensive than power from fossil fuels. With the supplementary 5.4 TWh available, NALCOR could start delivering the power necessary to meet all its commitments to EMERA at an earlier date. Even when EMERA's commitments are fulfilled, some power would still be available to supply Nova-Scotia and possibly New Brunswick.

Investigations along those avenues are most likely underway. Those investigations most likely assume that the supplied power is paid for at a rate of approximately $0.03 per kWh. The LIL wheeling cost will have to be added bringing the cost of delivered power closer to $0.05 per kWh, further reducing profits to NALCOR. Even using such a price, it is most likely possible for NALCOR to reduce its costs and make some profits on sales towards Nova-Scotia. It is obvious that significantly more cost reductions and revenues can be generated when the energy is provided at no immediate cost. There is little doubt that the schemes described in this report will prevail compared to schemes where NALCOR has to immediately pay for the energy delivered.

7.2.2 Selling Non Committed Power from Muskrat Falls

On a day to day basis, Newfoundland & Labrador will require a variable amount of power. Also, Nova-Scotia will also require a variable amount of power, some of it already contracted for with EMERA. On average, the remaining power from Muskrat Falls will be approximately one third of the overall power produced by the plant as depicted in Figure 3.2. That power could be sold to Hydro-Québec or most likely to EMERA depending on prices and contracts. As a large portion of Nova-Scotia is supplied from coal fired plants, the supply of clean electricity from Muskrat Falls would be environmentally welcomed. However, price will most likely determine what happens and the value of electricity may resume to the incremental cost of the sea coal saved at EMERA's power plants. The typical average production cost of electricity in Nova-Scotia is of the order of $0.05 to $0.07 per kWh. The average cost of electricity imported into Nova-Scotia from NB is of $0.062 per kWh, indicating the general value of electricity in Nova-Scotia. The revenues from such sales have long been included as revenue to pay for the initial Muskrat Falls project. Assuming that power is obtained at no immediate cost at the LIL starting point, more revenues can be obtained by NALCOR. Even with such increased revenues more funds will still be required to be called using the scheme described in this report.

7.2.3 Selling or Returning Power during Labrador Island Link Outage

The direct current Labrador Island Link system is relatively complex and may require shutdown for maintenance or may partly or totally trip from a system's fault. During such a period, some power can be sold to Hydro-Québec at an agreed price. Most of the time, the total capacity of the three 735 kV lines is not totally used and the power can simply be added on the lines. However, if the lines are used at full power or near full power, the production from Churchill Falls may be reduced to receive the Muskrat Falls production using the 3 existing 735 kV lines. There should be little penalty for this as water remains stored in the Smallwood reservoir and can be produced at another time. In practice the energy supplied is returned within a short period. It would most likely be cost effective for NALCOR to reduce the amount of owed energy compared to selling the electricity because of the compounded effects of interest on the owed energy.

7.3 Other Medium Term Projects

Aside from the direct selling of assets, there are a number of other alternatives to generate revenues over the medium term. Those are projects that require the necessary market opportunities, availability of funds and the effort of constructing new facilities.

7.3.1 Installing Extra Peaking Capacity at Churchill Falls

The Churchill Falls facilities were initially designed to have a high capacity factor of 71%. This configuration was chosen in the 60's to minimize the cost of extra turbines and, more importantly the cost of the extra long power lines to carry the peak winter power. The plant capacity resulted being the capacity of three high voltage 735 kV lines. This resulting capacity factor means the plant configuration was designed to provide a peak winter capacity of approximately 40% (1 ÷ 0.71% – 1). More recent hydroelectric facilities, even located far from markets, are designed with a lower capacity factor of approximately 60 % depending on their distance from load centers. This allows the facilities to produce during short peak winter periods at a level approximately 2/3rd higher than the average yearly power.

The Churchill Falls turbines are very powerful at a 493.5 MW each, resulting in a relatively large power increase per turbine. Peak power increase is made by adding a discrete number of turbines in a separate power hall or into an extension of the existing one. Table 7.1 provides the capacity factor decrease as the number of turbines is increased. The installed capacity can most likely be economically increased by adding two turbines and possibly a third one using the same turbine capacity. It is not mandatory to use the same turbine power or design as interchangeability with the old turbines is not critical; a number of solutions and power levels thus exist.

Number of existing turbines	**Power (MW)**	**Capacity factor (%)**
11	5 429	71%
Number of added Turbines	**Resulting peak power capability (MW)**	**Resulting capacity factor (%)**
1	5 922 (+493)	65.5%
2	**6 416 (+987)**	**60.5%**
3	6 909 (+1,480)	56.1%

Table 7.1 Addition of power and capacity factor at Churchill Falls

The cost of adding those turbines and the associated power lines have to be determined and compared with other means of achieving a similar result. Using this revised power and the La Romaine construction costs, the value of the Churchill Falls plant would increase significantly as indicated in section 2. The installation of extra capacity at Churchill Falls cannot be made over the short term as the electricity markets are too unfavourable. The earliest time horizon for this upgrade would be in a decade or two as HQ is already paying for a nearly unused peaking gas-fired plant at Bécancour. The difficult question of ownership of turbines and water use would also have to be resolved as it would affect the available water flow at Muskrat Falls and its production. The cost of delivered power may be quite reasonable as the La Romaine power complex was built with two 735 kV lines that are now operated at only 315 kV. This has been planned ahead to allow the addition of the ~1200 MW Petit Mécatina project in a decade or more. The added power to Churchill Falls could initially use the La Romaine lines that are not located far from Churchill Falls, further reducing the cost of the project.

This indirect asset will require time to be needed and to be cost effective on the grid, require a number of years to negotiate and also a number of years to build. Power addition to Churchill Falls thus cannot be used to generate short term revenues for NALCOR.

7.3.2 Royalties from the Gulls Island Hydroelectric Facilities

Newfoundland & Labrador could have the Gulls Island project developed by other partners without investing significant money or take substantial risks in building the power plant and lines, while obtaining royalties from it. NL would essentially supply the site over a long period against royalties. This would be similar to a mining operation where a province typically does not invest in the project but takes royalties for using the resource.

With the supply of electricity from Muskrat Falls, Newfoundland & Labrador will not require significantly more electricity for years to come. The Gulls Island project has a potential capacity of 2,250 MW, which is 2.7 times the capacity of Muskrat Falls. This project has a water flow slightly smaller than Muskrat Falls but its hydraulic head is much higher, increasing the output accordingly. This project is unfortunately expected to lay dormant for at least one decade or two until market conditions change or that NALCOR starts to try to make some money out of it. It is sad that such a renewable asset is not producing any value for Newfoundland and is not replacing other more polluting sources of electricity. If the construction costs can be controlled and power lines built economically, this project may be one of the most cost-effective large hydroelectric projects in North America. This does not insure its cost effectiveness against wind, gas turbines or other power sources. The site benefits from a configuration that maximizes the economy of scale, as only one diversion canal, one dam, one spillway, one powerhouse and one switchyard have to be constructed. Good roads are even already available up to the construction site, representing a rare bonus. The flow from Churchill Falls may even be controlled to facilitate construction and to minimise the likelihood of large spring overflow during construction.

The dam site is located upstream of the Gull Islands, at the end of a narrow valley that has relatively steep sides made of rock. Soils conditions downstream of the dam and closer to the actual geographic position of the downstream Islands may be affected by the presence of sensitive clays. Because the dam is built before the end of the gorge, sound rock should generally prevail at a shallow depth under the thalweg. The valley upstream of the dam may have been geologically created by a fissure in the earth's crust that may extend to a certain depth into the earth before solid rock is encountered, similarly to the Muskrat Falls site. The ease at which the bottom of the dam can be sealed is quite important for Gulls Island due to the high head. From review of the available sections of the river at Gull Island, it can be expected that rock can be found at shallow depths perpendicular to the river. All non solid materials under the dam require excavation to enable construction on solid rock. Loose rock is removed, loose materials washed away and the remaining rock is injected with high pressure concrete to seal it. Extensive geotechnical studies will need to be completed to fully define the materials capabilities and determine how the dam base will be sealed. Ample rock is available locally to supply good quality materials for the dam. The rest of the facilities are of common type and should be technologically controllable as long as experienced organizations are involved.

Similarly to Churchill Falls and Muskrat Falls, getting the electricity out of the Gulls Island site and into the available markets of Québec, Ontario, Maritimes and New England states will not be straightforward. Similarly to Churchill Falls, AC lines may be built from Gull Island and integrated to Hydro-Québec's grid. Those lines would follow the North Shore and should avoid crossing the St-Lawrence River downstream of Québec or even downstream of Montreal due to the large width of the river downstream of those cities. To meet environmental objectives, the Radisson-Nicolet-Sandy Pond line had to be run using DC cables under the St-Lawrence River. The cables were laid in a small accessible tunnel running across the St-Lawrence River to enable access to the cables. A similar solution may be required if a DC cable has to cross the River. Adding Gulls Island represents the addition of approximately 5% to HQ's grid. That energy may be partially added to consumption or exported. Depending on future conditions, exportations could be made using existing and future back to back converters feeding Ontario, NY, Vermont and NB, made using the existing Nicolet terminal or the DC line that feeds Massachusetts or made using future ones such as the one planned towards southern Maine. Alternatively to AC lines, a long DC line that carries full plant capacity or partial capacity may be built to bring the energy south. With a DC line from the plant, it is best to not connect such a line to Hydro-Québec's grid but to connect it to the other grids that are synchronized. A power delivery system similar to the Radisson-Nicolet-Sandy Pond multi-terminal DC line system could also be built from Gulls Island to a location in Québec and continued south of the Canadian border to Boston, New-York or Toronto. The DC terminal station could be in the La Tuque area where other AC lines could use the corridor of existing 230 kV lines to reach the St-Laurence River and cross it. Connections could then be made to the future Des Cantons converter station that will export to southern Maine.

Over the medium term, some of the Pickering nuclear Units will be shutdown by 2028-2030 and could be replaced by increased use of existing gas fired stations or hydraulic or new nuclear. Toronto has a set of existing power lines to Chat Falls, 200 km west of Ottawa on the Ottawa River. This path may represent the simplest option to input Gulls Island power into the Toronto area. The lines in Québec would go North of Lac Saint-Jean and north of La Tuque to Chat Falls avoiding much of the populated area. The length of the DC line to Toronto would be approximately 1,700 km long. This distance is slightly longer (13%) than the 1,480 km Radisson-Sandy Pond DC line that carries 2250 MW. The power level needed for Gulls Island is approximately the same as the Radisson-Nicolet portion of that HVDC line. The longer line length is not significant for a DC line and would simply increase construction costs as more pylons are required and slightly increase operating costs due to larger ohmic losses. A very similar line design could thus be implemented, even one that would use the multi terminal configuration, thus minimizing design novelties. This supply to Toronto would be of comparable length to the planned Copanawa hydro facilities on the Nelson River in northern Manitoba. At that location, there is an amount of power similar to Gull Island that is available from Copanawa and other sites along the Nelson River. The HVDC line from Churchill Falls to Toronto could be jointly owned by Hydro One (Ontario), Hydro-Québec and potentially by NALCOR, ensuring that all parties receive revenues from the line. Ownership of the line portions in Québec and Ontario would be necessary to obtain its local acceptance. Also, only a portion of the power may be sent to Toronto via a DC line, while the rest would enter Hydro-Québec's grid using AC lines. The DC power line to Toronto could be built before Gulls Island if the converter is built at Churchill Falls. The Gulls Island power would be carried by AC lines to Churchill Falls. There is a number of ways to configure and finance the Gulls Island project and associated power lines. Those HVDC lines may form the backbone of a Canadian East-West electricity grid contemplated by the Federal Government spanning from Manitoba to Newfoundland. Some financing could thus potentially be obtained from Ottawa to reduce the Canadian greenhouse gas emissions. As NALCOR owns the site and hydraulic rights, significant royalties could be obtained from that project during the mid 30's.

The schemes of delayed delivery of electricity described in this report would have Churchill Falls' electricity booked up to year 2051. Thus receiving revenues from Gulls Island should help during 20 years to 25 years before the large influx of revenues from Churchill Falls starts to be received. If desired, a process starting around 2050 could be implemented where NALCOR would be allowed to purchase the remaining Gulls Island debt from the other partners in exchange of ownership. The Gulls Island facilities can produce of the order of 13 TWh of energy per year representing potential revenues of $700 to $800 millions per year at $0.06 per kWh. As NALCOR brings access to the site at the table, a reasonable level of royalties of 15%, representing about $100 millions per year should be obtainable. This would bring more revenues to Newfoundland within two decades, helping resolve its financial difficulties.

The Gulls Island project would have an installed capacity 2.7 times larger than Muskrat Falls. The final construction unit cost from the La Romaine project, for the power plants is of the order of $4,600 per kW installed. This is to be compared to Muskrat Falls at $7,100 per kW installed, excluding the lines. Using the same unit cost of $4,600 per kW installed for Gulls Island case, a linear extrapolation would result in project cost for Gull Island of the order of $10 billions. The plant layout for Gull Island is generally similar to Muskrat Falls except that it has a higher water head. The principal difference between an installation with a higher head (for a run of the river configuration) is that the dam height is higher. The dam will thus require more materials to be emplaced resulting in a larger construction cost. Most of the other plant parameters will be of similar cost. The derivation canal, spillway, water intake, tail race system and a number of other elements will have a similar capacity and design as Muskrat Falls and thus similar overall costs. It is principally the turbo alternator groups that will be more powerful, slightly increasing the cost of those components. All in all, the construction of Gull Island should not be significantly larger than the Muskrat Falls hydraulic facilities. The above linear extrapolation of costs should thus be conservative and Gulls Island should be able to produce energy at less than $0.06 per kWh to which the line cost will need to be added.

Similarly to the Churchill Falls and Muskrat Falls case, the Gulls Island project is too large for the Newfoundland & Labrador grid. It is also a large project for a Utility the size of NALCOR. A time span of about 10 years to obtain favourable market conditions and a 5 years period for its construction would be required for such a project. This brings the completion of Gull Island in the early to mid 2030's at best, much too late to have any short term effect on NALCOR's financial conditions. The cost effectiveness of such a plant still needs to be demonstrated in the current market conditions as the projected delivered electricity from La Romaine is around $0.09 to $0.10 per kWh, including transportation. To become a reality, the Gulls Island project will require a strengthening of the Ontario and U.S. market electricity or a desire to reduce greenhouse gas emissions.

A multi provincial project this size will need to be managed by a very capable utility or most likely by a group of utilities with adequate technical and financial capabilities. Since two decades, the electricity markets have entered an era of low increases in electricity demand and sometimes of decreases in demand such as in 2008. Large step increases in supply power are now even more risky and Utilities tend to increase their supply using addition of small power increments whenever possible. These realities have increased the risk of large hydroelectric projects and the construction of Gulls Island will have to wait better market conditions as discussed above and in Section 1.3.

All the construction schemes related to Gulls Island take too much time to permit the resolution of the immediate financial constraints that will hit NALCOR in 2020 and is thus mostly academic with respect to solving that exact short term problem.

Even if Gulls Island represents one of the best hydraulic projects to feed Québec and Ontario, it has competition from other technologies aside from natural gas. The installation cost of windmills has decreased below $2,500 per kW or less. A recent commercial wind energy project had costs as low as $0.076 per kWh (including transportation to main grid) for the Nicolas Rioux project in Rimouski (Québec) with full project amortisation and debt payback within a 25 years period. This project corresponds to a unit cost of $2,230 per kW for wind. When the wind and hydraulic capacity factors are considered, the windmill unit cost is equivalent to a hydraulic unit cost of $3,900 per kW. This initial unit cost is lower than current hydraulic projects to which little additional cost is required for power lines. Over time, hydraulic projects generally have lower maintenance costs (amortized over 60 years) compared to windmills that are amortized in 25 years. The initial construction cost is less expensive than La Romaine and possibly less expensive than Gulls Island. Much lower unit costs have been obtained in 2017 in Alberta for commercial wind facilities. After the 25 years amortization period, the debt should be repaid resulting in much lower financial costs. Maintenance costs would increase with time but remain manageable as a large proportion of equipment is expected to last for more than 25 years. There is no doubt that wind can now compete with several large hydro projects. The Gull Island project may also have to first wait for the addition of turbines at Churchill Falls or the completion of the Petit Mécatina project to be cost effective.

8 Conclusion

This report has reviewed two principal schemes that can immediately help NALCOR. Those do not require construction of new facilities or loss of equity in its current assets. One scheme has electricity delivered from Churchill Falls and into the LIL at no immediate cost to NALCOR with the power inputted into the LIL returned after 2041. The second scheme considers selling electricity from Churchill Falls over the years but with a delivery also delayed after 2041. Those two schemes can bring a sufficiently large amount of cost reductions and supplementary funds to NALCOR to pay for all interest costs necessary to honour the various debts that were required for the Muskrat Falls project. Those two schemes can provide combined revenue of the order of $300 millions per year to NALCOR with a 10 years return period. Proportionally more funds could be obtained by extending the return period beyond 10 years. This should be sufficient to mitigate rate increase, prevent tax increases and prevent a cash flow and debt crisis in Newfoundland & Labrador.

The general possibilities to implement the relatively complex contractual scheme between Nalcor and Hydro-Québec were discussed during private communications with Dr. J. Feehan of Memorial University (St-John, NL). He is, amongst other subjects, a specialist of the Churchill Falls contract and of provincial energy policies. The general feedback obtained was that although theoretically feasible, it would be unlikely that those two corporations would be able to quickly agree to such long term contractual arrangements that contain a number of commercial risks. It is also unlikely partly due the low confidence level stemming from the historical contractual difficulties between the two parties with respect to the Churchill Falls contract.

However, with some good will of parties, the detailed configuration of a win-win process can be polished with an adequate team of economists, accountants, engineers, contract lawyers and management personnel from NALCOR and Hydro-Québec. Once acceptable to both parties, the process can be readily understood and accepted by politicians and the public. As this process maintains current ownership of the Churchill Falls plant after 2041, its acceptance would be much simpler. It could be implemented quickly enough to be in place before the Muskrat Falls' plant in service date, when interest payments would start to be due. For Hydro-Québec, the maximum quantities of electricity to be returned (194 TWh) are comparable to the 190 TWh of electricity involved in the Massachusetts bid. Both schemes can probably provide a similar return on investment for Hydro-Québec. The difference is that this investment related to Muskrat Falls and Churchill Falls does not require any construction and solely requires the successful negotiation of two key numbers in a contract. It will allow Hydro-Québec to quickly dispose of 12 TWh from its surpluses of energy within the next two years and of up to a total of perhaps 60 TWh up to year 2041. This will ease the power surplus immediately until the Massachusetts supply project can be implemented in 2022. With the large quantities of power to be returned after 2041, it will ease the transition period required by the completion of the Churchill Falls contract that provides low cost power to Québec.

If larger fund transfers are sought by NALCOR, more funds can be transferred to NALCOR, increasing the period of return of electricity beyond 2051. Alternatively, if further funding is required by NALCOR, a yearly purchase of equity in the Churchill Falls plant could be also be developed quickly as Hydro-Québec is looking into investments in electrical technology and electrical assets. The political and social acceptance of this scheme would be more questionable and may take more time to develop. The approach would then be to start with the delayed electricity exchange process for 2 years that will supply large savings to NALCOR until Muskrat Falls starts. Once Muskrat Falls operates, much less electricity can be supplied and the direct supply of funds to NALCOR would then be started. Should the level of funding still needs to be increased, the selling of a small percentage of plant's equity may be considered.

The schemes described in this report will certainly help resolve the financial difficulties from the Muskrat Falls's project and restore the financial viability of Newfoundland & Labrador, avoiding its possible default on loans.

9 List of Acronyms

The following table provides a list of acronyms used in the text and their definition.

AC	Alternating Current
BOT	Newfoundland & Labrador
CFLCO	Churchill Falls (Labrador) Company
DC	Direct Current
FLG	Federal Loan Guarantee
HVDC	High Voltage Direct Current
HQ	Hydro-Québec
kV	kilo Volt
kWh	kilo Watt hour
LIL	Labrador Island Link
ML	Maritime Link
MF	Muskrat Falls
MW	Mega Watts
NB	New Brunswick
NBR	Nottaway, Broadback and Rupert
NY	New York
NL	Newfoundland & Labrador
NOx	Nitric oxides such as NO_2 and NO_3
NS	Nova-Scotia
OH	Ontario-Hydro
OPG	Ontario Power Generation
PBO	Parliamentary Budget Officer
PEI	Prince Edward Island
RP	Recall power
SOx	Sulphuric oxides (SO_2; SO_3)
TF	Twin Falls
TWh	Tera Watts hours
US	United States

10 **List of Tables and Figures**

List of Tables.

List of Figures.