Final Report on Phase Two of Muskrat Falls Project Potential Rate Mitigation Opportunities

Presented to:

The Board of Commissioners of Public Utilities
Newfoundland and Labrador

Presented by:

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A. Background and Work Scope

On September 5, 2018, the Government of Newfoundland and Labrador ("Government") issued a reference (the "Reference") directing the Board of Commissioners of Public Utilities of Newfoundland and Labrador (the "Board") to review and report on a number of matters, including options to reduce the impact of the Muskrat Falls Project ("MFP") on electricity rates through to the year 2030. The Board retained The Liberty Consulting Group ("Liberty") to assist with the review required for this Reference.

The Board asked us to perform the following tasks:

- Determine the total revenue requirements to recover the costs of the MFP with no rate mitigation options included ("Base Revenue Requirement")
- Examine the structure of Nalcor Energy Corporation, its subsidiaries and affiliates ("Nalcor") and identify cost savings opportunities associated with Nalcor activities
- Identify cost savings and opportunities related to the operations and maintenance of the MFP
- Identify the impacts on the Base Revenue Requirement of various alternative cost savings initiatives and rate mitigation approaches.

We conducted the work with a team of utility industry experts having decades of experience and industry knowledge in the areas they examined. We conducted our work in two phases.

B. Phase One

We issued a December 31, 2018 report addressing our Phase One work. That work relied upon extensive written information from Nalcor and Newfoundland and Labrador Hydro ("Hydro"), and meetings and discussions with management and executives designed to explore fully the areas under examination. We focused on costs of all functions typically performed by a vertically-integrated utility, given that moving oil and gas related business activities from Nalcor, as announced by the Government, would leave remaining Nalcor operations typical of what such utilities do. We examined the corporate entity structure, the organization of groups that carry out utility operations, their structure, and their staffing. We then examined historical and projected costs, both operating and maintenance ("O&M") and capital. We examined generation, transmission, distribution, customer service, corporate services, executive management and administrative services.

We also examined cost sources and opportunities involving outside entities. Financing arrangements for the Lower Churchill Project ("LCP") consisting of Muskrat Falls generation, the Labrador-Island Link ("LIL") and Labrador Transmission Assets ("LTA") involved more than $12.7 billion dollars in expenditures, which will create equity return, operating cost, debt service, and sinking fund payments beginning at about $725 million per year, growing to over $1.2 billion by 2039. Parties apart from Nalcor with substantial interests in those revenues include the Province and Emera who receive returns on the equity portion of that financing, and the federal government, which has provided loan guarantees, and requires interest and sinking fund payments under the LCP financing agreements.

Our Phase One work identified the potential for Newfoundland Power, the primary distribution utility in the province, to play a significant role in mitigation, given the nature and extent of its operations on the Island, and its expertise in providing service at the retail level.

We developed in Phase One a list of opportunities to examine in more detail in Phase Two and a plan for assessing them. We also completed an operating Revenue Requirements Model permitting the assessment of the revenue requirements and retail rate impacts of cost reduction opportunities. A series of opportunities that we generally identified as financially related presented by far the greatest opportunities for revenue requirements mitigation. Their sources included:

- Equity returns that the Province will receive from Nalcor on LCP equity investments, produced by the Purchased Power Agreement and the Transmission Funding Agreement obligating Hydro to pay for electricity from Muskrat Falls and transmission over the LIL
- Margins (revenues above costs) secured by Nalcor Energy Marketing ("NEM") on off-system sales of excess energy from Muskrat Falls
- Fees related to the use of water for generation at Churchill Falls and Muskrat Falls
- Dividends on Churchill Falls preferred shares
- Equity returns to Hydro on its investment in facilities used to serve its customers.

In Phase One we also identified a number of other financial options, related to the LCP financing agreements, that might be employed to design mitigation alternatives.

The financially-related mitigation sources grow substantially in magnitude over time. Their potential contributions are lower in early versus later years, when compared with the expected increases in revenue requirements. Thus, applying mitigation sources only as they naturally arise would produce a "camel's hump" in rates; *i.e.*, a significant increase followed by a decrease. The ability to capture mitigation sources earlier could produce a smoother rate path over time. However, the principal ways we considered would require federal government agreement. In April 2019, discussions between the federal and provincial governments about potential rate mitigation opportunities were announced. The Board decided to suspend our consideration of potential mitigation opportunities arising from the project financing agreements while the discussions are ongoing.

Apart from these financial measures, Phase One work also identified a series of operational measures warranting more detailed examination. They included a number of options:

- Integrating Nalcor Power Supply and Hydro into a single organization operating LCP, Churchill Falls, and Hydro generation, transmission, distribution, and customer service
- Transferring operation of functions, and perhaps, but not necessarily facilities, from Hydro to Newfoundland Power, to capture synergies from combined scope and scale

We also conducted a preliminary examination of changes in LCP O&M cost estimates in Phase One. We identified a plan for determining the reasons for those changes and the potential for securing reductions in the current estimate. We also committed to examining in Phase Two whether changes in depreciation rates might present an opportunity for revenue requirements mitigation.

C. Phase Two Approach

The same high level of cooperation we received from Nalcor, Hydro, and Newfoundland Power in Phase One continued in Phase Two. We informed stakeholders of our approach, processes, and expected interactions with them, and sought their input. We met individually with Nalcor, Hydro, Newfoundland Power, and the Consumer Advocate and his experts, jointly with Hydro and Nalcor, and jointly with Hydro and Newfoundland Power. We held discussions with the Island Industrial Customers. We also participated in technical conferences in March, June and August with all the parties involved in the Reference.

We continued throughout Phase Two to assess, develop, and fine-tune the analysis of financial opportunities.

The evaluation of operational cost reductions as sources of mitigation formed a major Phase Two focus. Like Phase One work, Phase Two relied upon extensive written information from Nalcor, Hydro, and Newfoundland Power. The work of this phase also relied heavily on meetings and working sessions with management and executives of all three. We found particularly helpful joint sessions between Hydro and Nalcor Power Supply and between Hydro and Newfoundland Power. These sessions explored the organizational structures of the companies, their resources, and operating changes that might be occasioned by transfers of responsibility for major functions and sectors of the Province's utility business.

In examining changes in operations responsibility, we carefully considered the need to ensure that Labrador and isolated-Island operations and customers now served by Hydro remain a focus in considering potential changes in responsibility for serving them, given that Newfoundland Power does not now serve isolated diesel customers or have operations in Labrador. We also evaluated the financial implications of a transfer of certain Hydro owned facilities and responsibilities to Newfoundland Power, to determine the consequences for electricity rates and mitigation opportunities of such a transfer.

Our Phase Two work examined two other issues that have a bearing on mitigation options:

- The Newfoundland and Labrador utility regulatory framework, particularly as it concerns LCP
- Utility industry practices and approaches to the marketing of excess energy.

D. Summary of Phase Two Results

1. *Financial Opportunities*

We reported in our Phase One report that financial opportunities can produce very steep reductions in revenue requirements. Combining the financial opportunities we examined in Phase Two produces a potential for reducing revenue requirements by an annual amount beginning at about $165 million in 2021, growing to over $500 million by 2030, and reaching more than $700 million by 2039. By 2039, these opportunities have the potential for reducing Hydro's currently forecasted all-in rate of 29.7 cents per kWh by somewhat more than 11.5 cents. As noted, producing this very sizeable offset will require the Province to consider the implications for its financial position and its ability to fund its operations without access to amounts identified in this report as available for rate mitigation to reduce the significant increase in electricity rates required to recover the MFP costs.

The principal contribution to these amounts comes from two sources related to the LCP: (a) equity returns, and (b) sales of "excess" Muskrat Falls power and energy. The Province provided $3.7 billion of the equity required to finance LCP. Contracts obliging Hydro to make purchases from Muskrat Falls and to pay for the rights to carry electricity over the LIL include equity returns for the asset owners. The Province is a principal provider of that equity, with Emera (the owner of Nova Scotia's electric utility) the other. Applying the Province's share of those equity-based returns to reduce electricity rates would generate revenue requirement reductions of $90 million per year in 2021, rapidly growing to $569 million by 2039.

Revenues from market sales of power and energy from Muskrat Falls comprises the next largest source. Like many major utility generating stations, Muskrat Falls will produce generation beyond what is needed to serve domestic load and other firm obligations (here, sales to Emera interests). Across North America, where customer rates recover the ownership and operating costs of such assets, those rates nearly universally are offset by the benefits of sales of power and energy beyond those requirements. Revenues from export sales by Hydro offset revenue requirements, but that is not the case for Muskrat Falls, where margins from revenues of excess sales by Nalcor in excess of costs inure to the benefit of the Province. Applying the Province's share of those Muskrat Falls export revenues (*i.e.*, to offset customer rates) can provide another $35-$45 million annually to customers, based on Nalcor's estimates.

These two LCP sources account for more than three-fourths of the financial sources of mitigation. While smaller, the remaining ones nevertheless prove substantial. The next largest source consists of the equity returns built into Hydro' current rates to its customers. These rates include an 8.5 percent return on the equity portion of the capital structure that funds the assets Hydro uses to serve customers. A significant portion of that return must remain available to sustain equity within Hydro at a level sufficient to permit the financial community to consider it as financially self-sustaining (*i.e.*, not reliant on government support to meet its financial needs). Maintaining a 25 percent equity level in Hydro's capital structure as a measure would require an increase from the current, approximately 19 percent level, but would still leave available substantial dividends to apply to reducing rates beginning in 2026 at a level of approximately $35 million.

Current uncertainties surrounding customer impacts from significant rate increases due to recovery of LCP costs raise the question of whether a more aggressive financial approach with respect to Hydro's equity target (*i.e.*, a low equity/debt ratio) is appropriate. We examined the consequences of using an equity target of 20 percent. Doing so would make another roughly $110 million available ~~annually~~ between 2021 and 2025, but later annual decreases would produce a net reduction of about $20 million in the cumulative total available by 2039. Earlier availability, however, even at the expense of a moderate total reduction, would help address the "camel hump," should the Province find the resulting financial community perception of Hydro self-sustainability consistent with overall Province financial goals and requirements.

Next in magnitude as a financial source of mitigation is the approximate $20 million in annual payments to the Province for water use for generation at Churchill Falls and Muskrat Falls,

Word "annually" removed by The Liberty Consulting Group from its Phase Two Final Report – September 3, 2019. See Transcript October 3, 2019 – page(s) 25, lines: 21-25 and 26, lines: 1-14.

followed by the $6 million per year in preferred dividends available from ownership of Churchill Falls. Ordinarily, one would expect larger returns for a project so large, but two factors limit them here: (a) a long-term, low-priced obligation to supply Hydro- Québec, and (b) an unusual, but entrenched approach of funding all capital work at the station with internally generated cash flow.

Our examination of the potential for reducing revenue requirements by changing depreciation lives found no substantial room for securing material reductions. We did, however, observe that the domestic customers of Hydro and Newfoundland Power will make more than $50 million per year in Harmonized Sales Tax payments (the Province's portion). We did not examine changes in provincial tax policy as part of our work, but do note that these payments do have a material connection to electricity usage and costs in the Province. In the past, the Government has provided a rebate of the provincial portion of HST on domestic electricity sales. Were it to do so again, it would provide another source of reducing electricity bill payments.

2. *Operational Opportunities*

We reviewed a number of opportunities to produce efficiencies by combining various activities and operations now conducted by multiple entities and organizations. First, we examined the integration of the two Nalcor operating entities: Power Supply and Hydro. Second, we examined various transfers of operational responsibility, with and without accompanying asset transfers, between Hydro and Newfoundland Power. Finally, we examined the potential to combine procurement and contracting among Nalcor, Hydro, and Newfoundland Power. We began Phase Two with an expectation of finding modest savings from such transfers, compared with those involving the financial sources of mitigation. Our Phase Two work proved them even somewhat more modest than expected.

We did find integration of Power Supply and Hydro beneficial in producing efficiencies and savings. While we found some savings achievable through combining some operating responsibilities of Hydro and Newfoundland Power, those options proved subject to execution risks and transition needs significant enough to rule them out as alternatives worth pursuing in this work for the Reference.

a. <u>Integrating Nalcor Power Supply and Hydro</u>

In 2016 Nalcor underwent a major change in organization structure, affecting all its resources. The reorganization led to a separate Nalcor Power Supply organization responsible for LCP completion and operation and for Churchill Falls operation. With LCP completion nearing, the need to provide a focus on the great challenges of doing so is nearing its end. We recognize the need for specialized skills to address LCP operating needs, like those that LIL high voltage, direct current ("HVdc") operation will entail, but we do not consider them sufficient to require organizations distinct from those that serve Hydro's system needs.

Nalcor also planned the reorganization on the basis of the "unregulated" nature of the assets for which Power Supply has responsibility. That split between Hydro for regulated assets and Power Supply for unregulated raises a number of issues. The very existence of a provincial focus on revenue requirements mitigation calls into question whether that designation will continue to have meaning in a financial sense if the Province makes decisions about applying the financial sources of revenue requirements mitigation like those discussed above to reduce rates. Second, and more importantly for our review, parallel organizations that perform similar functions for similar operations tend to produce duplication and resulting inefficiency, as our examination of current Hydro and Power Supply organizations confirmed.

We found no significant barrier to combining Power Supply and Hydro organizations to produce a unified operating entity. Doing so would eliminate duplication in technical and operating organizations, in corporate and other services that support them, and in the executive structure required to manage the technical, operating, corporate, and support services. We found that integrating the now-split Power Supply and Hydro organizations into one would produce material reductions in the personnel required to operate Nalcor as a comparatively small, vertically-integrated utility, after LCP completion and movement of Nalcor's oil and gas business to a separate Crown corporation.

A unified organization would allow reduction of 113 full-time-equivalent personnel, many of them at Nalcor and Hydro's higher compensation levels. We assumed a multi-year transition period that would consider factors like allowing a phase-in to steady-state LCP operation and a period to make the reduction in personnel effectively. The reductions can generate $12.7 million in annual savings initially, and $21 million beginning in 2023. These amounts include a change originally identified as part of a potential combination of responsibility for Hydro and Newfoundland Power's Island small hydro generating facilities. We did not ultimately find that combination worth pursuing, but found that significant savings can result from unilateral action by Hydro. These potential savings may prove small when compared to the potential amounts from the financial sources described earlier, but their pursuit nevertheless has a role to play in promoting the efficiency required to provide reliable service at optimum cost for customers. The pace of personnel reductions may cause some one-time transition costs to achieve sustained annual savings.

b. Combining Operations between Hydro and Newfoundland Power

Our Phase Two work continued examining scenarios combining utility operations and activities now performed by both Hydro and Newfoundland Power. These scenarios included transferring responsibility for Hydro's distribution and retail operations intact (*i.e.*, Island and Labrador, interconnected and isolated) and lower voltage (66 and 138 kV) transmission facilities. We eliminated consideration of transferring 230 kV and HVdc facilities, considering their criticality to overall system integrity and reliability, the need for allowing operation of LCP assets to reach a secure steady state, and the lack of Newfoundland Power operational experience with such facilities. We also examined whether efficiencies could be gained by combining operation of the Hydro and Newfoundland Power small hydro generating facilities under either entity.

Our analysis of the economic effects of asset transfers from Hydro to Newfoundland Power showed negative rate consequences for customers, even if we did not assume using Hydro's equity returns for mitigation. Hydro has significantly lower carrying costs for capital investments, even with the same rate of returns on the equity portion of its capital structure. Greater equity levels, higher debt costs, and taxation exemplify factors that make Newfoundland Power's costs higher. Transfer of Newfoundland Power's assets to Hydro would raise costs as well, assuming the acquisition premiums (to depreciated book value, the typical base to which return rates are applied) that have typified acquisitions involving investor-owned utility assets and businesses.

We then turned to consideration of transferring only operating responsibility. We found some apparent synergies that might enable resource reductions. The savings, however, were small, given significant uncertainty surrounding them, particularly as to future capital costs. The personnel resources required to support transferred operations had to assume similar network structure, configuration, and capability to the network of the entity acquiring the operations involved.

Insufficient time existed to conduct detailed facility examinations; therefore, future staffing assumptions assumed that the receiving utility would find facilities in a state allowing use of its typical metrics and ratios for projecting operating requirements. A second uncertainty arises from the need for a services agreement that defines the responsibilities of and provides appropriate compensation for the entity providing operational services - - a necessity absent an accompanying asset transfer. Third, labour bargaining agreements and working conditions would have to be rationalized, perhaps at some cost, and certainly at the time and expense of training. Fourth, while such operating agreements have precedent and can work well, they depend on a “partnering” mentality and approach, best executed in an environment and among peers with a more established pattern of cooperation and mutual confidence.

We found the potential savings that would arise with a transfer of operating responsibilities to Newfoundland Power modest, and subject to significant execution risks and limitations. That imbalance led us to conclude that greater potential lies in other directions; *e.g.*, pursuit by Hydro of a focused, comprehensive examination of its efficiency and effectiveness. We believe that undertaking such an examination promptly, objectively, and with a high level of transparency to the Board and stakeholders can produce results as or more substantial than those postulated by our Power Supply/Hydro integration.

In addition, we found striking the nearly $0.5 billion dollars in five-year capital spending Hydro and Newfoundland Power combined have identified. Reductions in the amount of capital spending will reduce revenue requirements as much or greater than those attainable through reorienting the long-standing division of responsibility that exists in the Province for providing electricity service.

3. LCP O&M Cost Estimates

Estimates of the future costs of operating the LCP have fluctuated significantly, and have occasioned substantial public interest in the factors driving the changes. We examined those changes and sought to identify potential sources for reducing future O&M costs. We found the latest, 2018 estimate sound in taking a conservative view of the requirements for operating a very large, reliability-critical, and (in some respects) new technology asset group. Nevertheless, we believe that, allowing for a suitably long phase-in to steady state operation, cost reductions can be obtained. We believe that the period assumed to reach such operation can be shortened from three to five years to between two and three years, and that a reduction of $12 million from the current $97.4 million estimate is realistic.

E. Overall Conclusion

The Reference called for an examination of alternatives for reducing revenue-requirements over the coming 10 years. We considered both a 10- and 20-year period, anticipating that results could differ substantially between them and that measures might exist for transferring sources of reduction to earlier years, where their application can help provide an optimum rate trajectory. Our work shows a dramatic difference between the first ten years and the decade following it. Across the full 20 years we reviewed, mitigation potential grows steadily and substantially, as Figure I.1 depicts.

Figure I.1: Annual Mitigation Potential

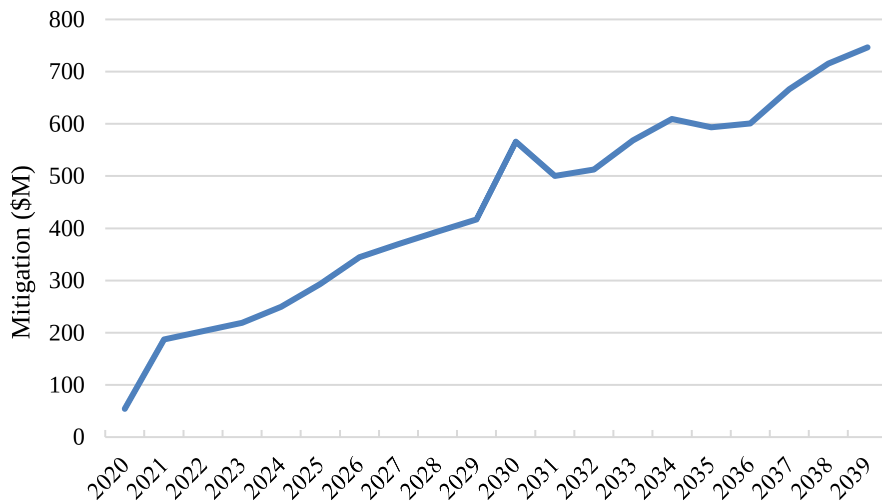
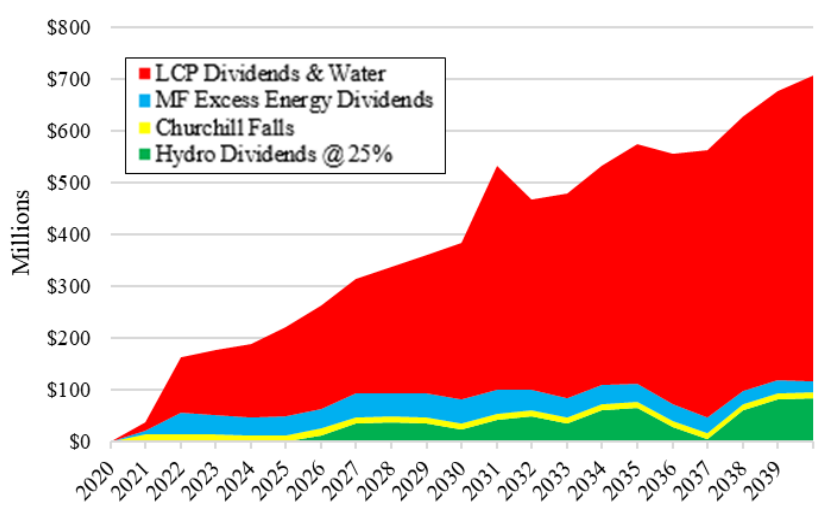


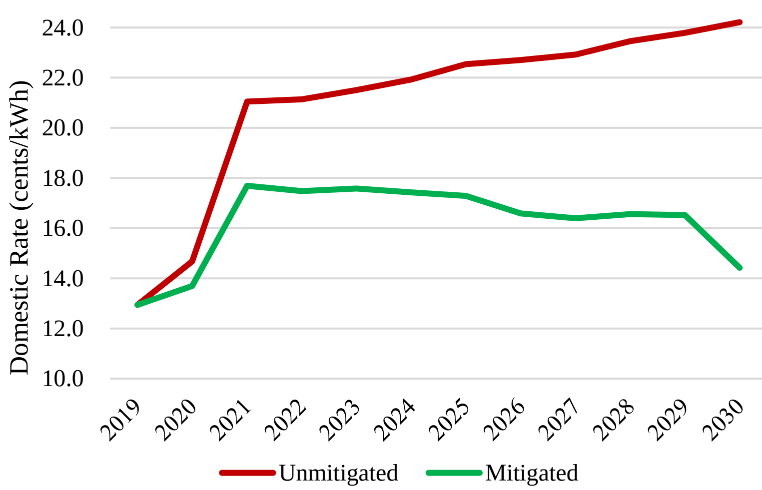
Figure I.2 shows that LCP-related sources dominate the potential reductions achievable, with notable contributions as well from off-system sales from Muskrat Falls and the equity returns built into Hydro's rates.

Figure I.2: Financial Sources of Potential Mitigation



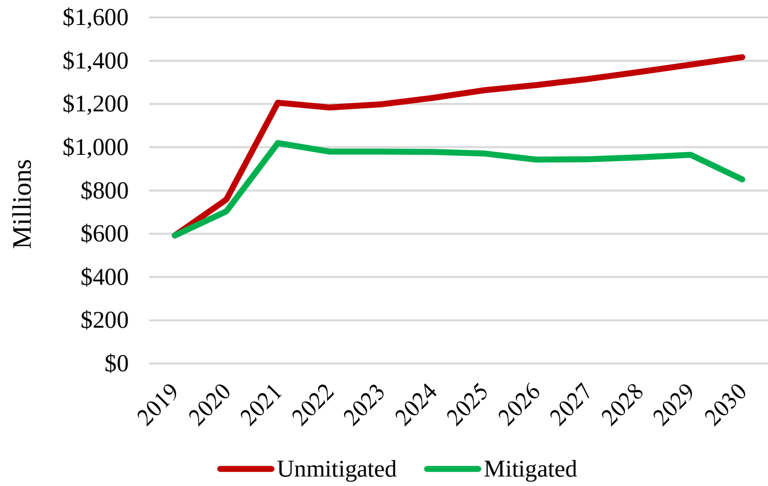
A consequence of this growth rate, insufficient revenue mitigation potential in the early years, keeps rates higher in the first decade following LCP operation than they can become in the second ten years. LCP financing requires significant payments (*e.g.*, sinking fund payments) in that first decade. They add to revenue requirements. Figure I.3 shows the limits in the first decade, leaving a significant initial jump even after mitigation, followed by stability, and ending with a reduction as the Reference's 10-year period comes to a close. The path shown by Figure I.3 underscores our reasons for examining in Phase One the means available under the project financing agreements for bringing forward some of the value that mitigation sources provide in greater measure in the second decade. We suspended examination of these measures pending continued discussions between provincial and federal authorities. It is clear that a still significant, approximately 35 percent increase, looms in 2021, even after applying all the mitigation potential identified in our report. Different mitigated rate paths have been presented, and are likely to change further as the Board continues to address the questions posed by the Reference. Our revenue requirements model has the capacity to employ any mitigated rate path put forth.

Figure I.3: Potentially Mitigated Rates through 2030



Not surprisingly, as Figure I.4 shows, growing revenue requirements, as compared with the first-decade mitigation sources available, limit rate-influencing ability through 2030.

Figure I.4: Hydro Revenue Requirements through 2030



F. Utility Regulatory Framework and Rate Mitigation Options

The Province's utility regulatory framework has a clear connection with the Reference Questions. One of the issues the Board was asked to consider was "forward-looking cost savings and opportunities for increased efficiency related to operating and maintenance of MFP." Ongoing LCP capital and operating expenses will have a large impact on future rates. Hydro and in turn its customers will pay for them in rates, but the Board, otherwise responsible for reviewing Hydro's costs, has no authority to examine them. Nalcor's incentives to generate revenues from off-system sales from Muskrat Falls compounds this departure from widely applicable regulatory norms. The margins from those sales do not, as is nearly universally the case, offset the costs of the assets to produce them, but flow in another direction - - to Nalcor. With no regulatory review of those costs, decisions about what and when to spend on the assets lies not within the jurisdiction of the agency responsible for optimizing utility reliability and costs. Instead, it rests with a Crown corporation making its own judgments about the importance of maximizing profitability from sales of power and energy in markets versus controlling costs to utility customers.

Empowering the Board to exercise with respect to LCP the same authority it has to review other ongoing utility capital and operating costs and operating and maintenance methods, practices, decisions, and actions will provide a more unified basis for ensuring optimization of costs and reliability. We do not, however, see similar justification for giving the Board authority to review LCP design and construction. Retroactively overlaying Board assessment of past performance of the LCP under a prudence and reasonableness standard, is logically strained. Moreover, the end result of failure to meet that standard generally involves cost disallowances. Hydro's LCP purchase agreement obligations, central to LCP financing structure, will not permit direct avoidance of Hydro's obligations to pay costs (judged imprudent or otherwise). A lengthy and painful prudence contest before the Board would complicate unnecessarily a process that can already be addressed through appropriate mitigation measures, as discussed in this report.

The Board was also asked to consider "industry best practices related to external market purchases and sales of electricity" and "sources of Nalcor income that could be put towards reducing rate increases." External sales from Muskrat Falls, as preceding section D. outlines, offer a material source of reducing rate increases. Nearly universal practice in both Canada and the U.S. would already apply this source to offset utility revenue requirements. That practice relies upon the principle that revenues obtained from use of assets that support utility service and whose costs utility revenue requirements include (as is the case for the LCP) should offset those costs. Thus, applying margins from off-system sales from Muskrat Falls to offset Hydro's utility revenue requirements would conform to sound, nearly universal North American practice, thereby conforming to what can fairly be described as best practice.

Nalcor's use of NEM to manage off-system transactions also has "best practice" implications. We do not question its establishment as a separate entity, but to whom it is responsible forms the more pertinent question. Prevailing North American practice makes organizations like NEM responsible to utility management, under the principle that cost optimization should be on the basis of total revenue requirements. What becomes available for off-system use should result from consideration of what optimizes reliability for system customers. Best practice also includes a comprehensive, well-structured risk program and controls to ensure transaction integrity. The utility industry has developed means for managing risk and transaction integrity in a manner that makes trading manageable in a reasonably conservative utility construct.

Contracting versus internally staffing a comparatively smaller marketing operation should be considered an option. Entities across North America have capabilities, experience, and market connections that it will take significant time and effort for NEM to develop. We believe it makes sense to determine through market outreach whether entities who would bring such assets to bear for Nalcor have substantial interest in performing on a fee basis what NEM does internally. If such interest is sufficiently broad, a formal solicitation will best determine whether NEM presents a better combination of performance and cost.

II. Financial Mitigation Opportunities

A. Background and Summary

This chapter addresses financial sources of potential revenue requirements mitigation. This area offers by far the largest such source. It has the potential to produce steadily-growing annual reductions in revenue requirements. By the 2039 end of our study period, those annual amounts can grow to about $700 million per year - - a level roughly equivalent to Hydro's total annual revenue requirements today. The principal sources of these potential reductions comprise amounts that will become available to the Province as its return for its vast investment made in the LCP and the use of the net profits from selling Muskrat Falls excess energy. Other opportunities include revenues available to the Province today - - equity returns built into Hydro's current rates to customers, payments related to water use to generate electricity (which will gain another source after Muskrat Falls begins operation), and preferred dividends paid from income generated by Churchill Falls.

LCP equity returns provide the biggest portion of the financial sources of mitigation. Separate contracts require Hydro to make purchases from Muskrat Falls and to pay for the rights to carry electricity over the LIL. These LCP assets were funded by a combination of equity and debt. The contracts obliging Hydro include equity returns for the asset owners (in the case of the LIL, an entity of Nova Scotia-based Emera Energy is a partner). Returning the Province's share of those equity based returns, which it will receive from Nalcor, would generate annual revenue requirement reductions beginning at $90 million in 2021, rapidly growing to $569 million by 2039.

Another major means for reducing customer rates would be to apply profits from Muskrat Falls "excess sales," as nearly all utility operations do with respect to generation and transmission sources whose costs they bear. Applying this normal approach would return to customers the margins from off-system sales from Muskrat Falls, rather than making them available to the Province. Doing so can be worth $35-$45 million annually to customers, subject to the more detailed work being performed for the Board on these forecast margins by Synapse Energy Economics ("Synapse").

As will be true for the LCP, Hydro's current electricity rates also include a return on equity that eventually becomes available to the Province. The Province needs to apply a significant portion of that return to ensuring that Hydro remains viable financially on its own, but even doing so leaves approximately $35 million available annually to apply to reducing customer rates.

Some smaller, but still substantial, opportunities to reduce revenue requirements fall into several other financially related areas we examined. They include $22 million in water related costs imposed by the Province for water use for generation at Churchill Falls and Muskrat Falls. They also include about $6 million yearly in preferred dividends available from ownership of Churchill Falls. This yearly amount is small for a project so large, but its operations labour under a long-term obligation to supply Hydro-Québec with very low-cost power, and an unusual, but entrenched approach of funding all capital work at the station with internally generated cash flow.

We also examined the potential for reducing revenue requirements by changing depreciation lives and found no substantial room for securing material reductions.

We halted work that we had begun in Phase 1 on a number of other financial options that have become topics of continuing discussion between the Province and the federal government.

B. Lower Churchill Project Dividends

Our Phase 1 work identified LCP dividends as a primary source of potential Hydro revenue requirements mitigation. LCP dividends come from two principal project components: Muskrat Falls and the Labrador Transmission Assets ("MFLTA") and the LIL. Two "take or pay" contracts between the LCP project entities and Hydro produce these dividends:

- The MFLTA Purchased Power Agreement ("PPA")
- The LIL Transmission Funding Agreement ("TFA").[1]

The PPA and the TFA provide the foundation for LCP equity and debt structures and the related guarantees and debt financing agreements established to fund the projects. This structure includes the Province's $3.7 billion equity investment in the LCP and $7.9 billion in federally-guaranteed debt. The PPA and TFA revenue streams assured from Hydro and recovered in its rates to customers provide the "revenue stream" required to support returns on the equity investment and the payment of principal and interest payments on the debt.

Revenue requirements driven by Hydro's PPA and TFA payments will exceed $700 million in 2021. Their inclusion in revenue requirements will essentially double Hydro's revenues from electricity sales, despite no material increase in sales to Hydro's customers.[2]

1. PPA and TFA Capital Cost Recovery Construct

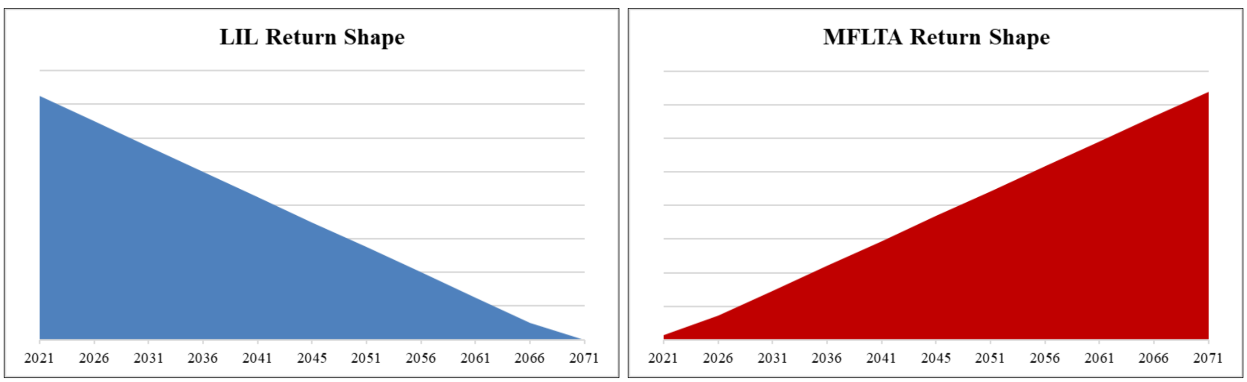
The PPA and the TFA seek to ensure full recovery of MFLTA and LIL costs from Hydro, but under different constructs. The TFA provides for the recovery of LIL costs using a cost-of-service ("COS") format traditionally used by utilities across North America. The reliance on depreciated book value under the COS approach produces maximum annual revenue requirements when cost recovery begins. The annual requirements fall each year as asset depreciation lowers the asset value that drives the return portion of cost recovery. The long lives of assets make the pace of reduction slow, but inexorable, and ultimately reduce the depreciation expense to zero after 50 years. The LIL therefore has the greatest annual impact on revenue requirements in 2021, the first full year of operation after its commissioning.

TFA pricing conforms to the most widespread model for setting the revenue requirements of regulated utility transmission and generation. However, the regulatory model for LIL pricing deviates very significantly from the usual regulatory model in at least one respect. Utility regulatory authorities who set revenue requirements for facilities paid for by customers also typically have the authority to examine initial justification for construction, and have ongoing authority to examine the reasonableness of annual capital and operating and maintenance expenses. We address this important distinction in Chapter III, *Utility Regulatory Framework and Mitigation Options*. Our goal in this chapter is limited to explaining the revenue-requirements mitigation opportunities built into TFA and PPA return requirements for the LCP - - declared unusually here to be "unregulated" despite captive utility customer responsibility for their costs.

TFA Section 3.9 (captioned *RROE*) defines the equity returns built into payments required of Hydro and benefitting the partnership that owns the LIL.[3] Two partners share ownership of this Labrador-Island Link Limited Partnership: (a) a wholly-owned Nalcor subsidiary (Labrador-Island Link Holding Corporation), and (b) an Emera entity (Emera Newfoundland and Labrador Island Link Inc.).

As we explain below, differences between TFA Section 3.9 and the PPA Schedule 1 cause the LIL and MFLTA equity returns to produce drastically different shapes over time. The LIL TFA returns begin high and decrease steadily and the MFLTA returns begin low and increase steadily over their 50-year service lives. Figure II.1 shows the "rough shapes" of equity returns produced by the difference in return recovery methods for the LIL (total, with a Nalcor share of about 43 percent) and MFLTA. The equity returns for the MFLTA are defined in Schedule 1 of the PPA titled "Base Block Capital Costs Recovery."[4]

Figure II.1: LIL and MFLTA Equity Return Shapes



These figures show diametrically opposed shapes for LCP equity returns through 2071. Revenue requirements "balancing" clearly lies at the heart of the different shape of the red, MFLTA portion. This back-loading of equity returns produced an Internal Rate of Return ("IRR") of 8.4 percent, measured in the 50th year. Use of the IRR as a return metric comprises a commonly used method for assessing the profitability of investments as part of capital project assessments. It calculates the discount rate resulting from making the net present value of all project cash flows equal to zero.

2. *Ensuring Cost Recovery through Hydro Energy Purchases*

PPA Schedule 2 locks in the volumes of energy ("Base Block Energy") for which Hydro must pay. A defined percentage of Hydro's "native load forecast" as of the signing of the PPA in 2013 drove the calculation of these volumes.[5] Fixing these Base Block Energy amounts and Hydro's obligation to pay for them, whether needed to serve customers or not, assures the revenues required to support MFLTA return, debt service and operating cost recovery. This PPA assurance and the requirement of Hydro to pay "rents" and operating cost recovery as defined in the TFA support the equity financing provided by the Province and by Emera (with respect to the LIL), as well as the $7.9

billion of debt issuances. The holders of that debt have the comfort of reliance on the federal guarantee, making the revenue assurance under the PPA and TFA agreements material to the federal government's willingness to provide that support.

The PPA and TFA also both address ongoing costs of LCP assets as well. Section 4.2 (b) of the PPA provides for the "flow through" of: (a) operating and maintenance costs, (b) Water Power Rentals, (c) Innu Impacts and Benefits Agreement payments, (d) "Sustaining Capital", and (e) as reduced by interest income. Sections 4, 5 and 8 of the PPA provide for recovery of debt service (principal and interest), sinking fund requirements, and debt guarantee payments. The TFA includes similar operating cost recovery clauses.[6]

Despite the obligation of Hydro (and in turn its utility customers) to pay for all LCP costs, the Board does not have authority to review or contest the reasonableness of these costs. We also address this significant regulatory anomaly in Chapter III of this report.

3. The Base for Calculating LCP Returns

LCP capital costs have grown very substantially since project sanctioning. The provisions of the PPA and TFA adjust for the recovery of those increases. Table II.2 summarizes currently-expected total LCP funding sources at commissioning, scheduled for 2020.

Table II.2: Lower Churchill Project Funding Sources (in Billions)

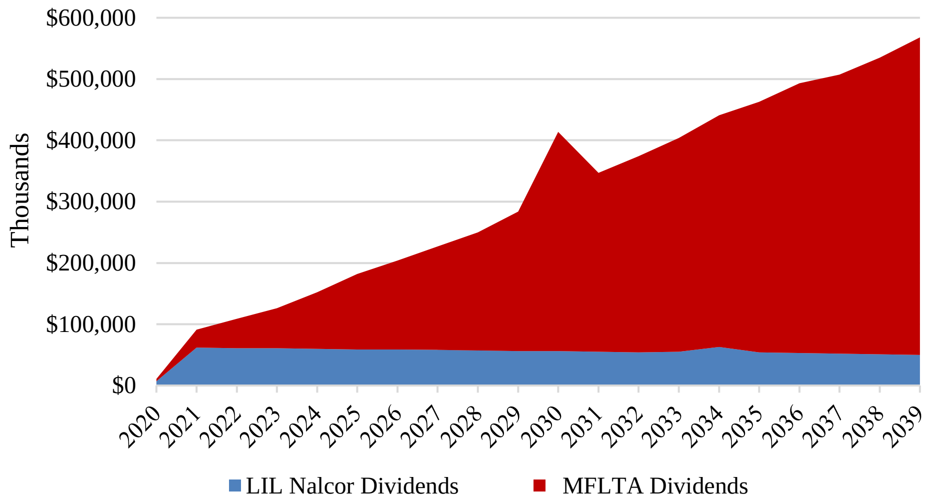
Component	MF	LTA	LIL	Total
FLG1 & FLG2 Debt	$3.7 billion	$0.7 billion	$3.5 billion	$7.9 billion
Nalcor/Province	$2.7 billion	$0.4 billion	$0.6 billion	$3.7 billion
Emera Equity	-0-	-0-	$0.6 billion	$0.6 billion
AFUDC	-0-	-0-	$0.4 billion	$0.4 billion
Total	$6.4 billion	$1.2 billion	$5.1 billion	$12.7 billion

4. Expected LCP Returns

Figure II.3 shows the returns on equity to Nalcor for the $3.7 billion in investments (the shaded row in the preceding table) made in the LCP. The PPA and TFA provide for return of and on that investment. The annual returns reach more than a half billion dollars per year late in our study period, which ends in 2039. The annual amounts begin at $90 million in 2021, and grow to more than $285 million by 2029. Continuing to grow thereafter, they reach $414 million in 2030 (the end of the study period called for by the Reference), and $569 million in 2039.[7] This later growth shows strikingly how limits on providing rate relief ease in the years following the end of the Reference's study period. Financial means for advancing those later year benefits have substantial importance in bringing pre-2029 rates into line with those lower ones achievable in succeeding years.

We examined revenue requirements for 2020 through 2039; Nalcor's equity returns total almost $6.2 billion through that period.[8] None of these amounts represent dollars currently available for Provincial use, because payments do not begin until the LCP is in service. The full $6.2 billion represents an opportunity, and by far the largest one available, to mitigate the revenue requirements impacts expected from inclusion of LCP costs into Hydro's rates.

Figure II.3: LCP Returns and Dividends



The "locks" provided by the PPA and TFA will cause LCP returns to remain as shown in the figure, absent a change in LCP capital costs. The required Hydro purchases from Muskrat Falls under the "Energy Sales" provisions of the PPA (see Schedule 2) increase over time, as does the price Hydro must pay for them.

5. Sensitivities to LCP Cost Changes

Risks exist for increases in capital expenditures at both MFLTA and LIL, both before and after project commissioning. We examined the impacts of increases of $1 billion in MFLTA and $0.5 billion in LIL capital costs on Hydro revenue requirements. We also examined the degree to which such increases would generate additions to returns and dividends, identified as the largest source of potential mitigation.

a. Capital Increases Before Commissioning

The analysis of pre-commissioning capital cost increases assumed an additional $1 billion in MFLTA capital expenditures, occurring pre-commissioning, with no change in commissioning date. The analysis assumed no further debt issuance, with funding entirely through equity provided from an in-Province source. An added $1 billion equity contribution would increase Hydro's revenue requirements by about $46 million in 2021 (escalating thereafter), based on the impact from PPA pricing requirements. Because this increase would come in the form of added equity return, it would produce a matching increase in the dividend amounts available for mitigation. Applying the full increase in returns to mitigation of Hydro's revenue requirements would therefore produce a net zero impact on Hydro's revenue requirements.

The analysis also assumed that the $0.5 billion increase in pre-commissioning LIL capital costs would also come from an in-Province equity infusion. The pricing mechanism of the TFA would cause such a pre-commissioning jump to increase Hydro's revenue requirements by about $53 million in 2021. The capital increase also increases the returns and dividends of the

Nalcor/Province equity share of LIL by the same $53 million, and the net effect on Hydro customer revenue requirements would again be zero.[9]

b. Post-Commissioning Capital Expenses

This analysis assumed an additional net $1 billion in capital expenditures for MFLTA in 2022, after commissioning and for a "Sustaining Activity" as defined in the PPA. Post-commissioning capital expenses for "Sustaining Activity" as defined in the PPA, become "flow-through" costs to Hydro. For MFLTA, the full $1 billion capital expenditure would be treated as a "flow through" item under the PPA, recoverable through Hydro payments entirely in the year incurred (2022). Such costs do not become adders to the MFLTA capital base; therefore producing no equity returns generated and available for offsetting Hydro's revenue requirements.

The TFA handles post-commissioning capital expenditures differently. The increased equity capital for LIL of $500 million would be depreciated over the remaining service life. Equity contributions to fund post-commissioning LIL capital expenditures generate TFA-established returns to the partners contributing to them. Like pre-commissioning equity, post-commissioning equity will also therefore generate a source of returns to reduce Hydro revenue requirements up to the amount of the Nalcor share of the equity contributed.[10]

c. O&M Expenses

Increases or decreases in operation and maintenance expenses are defined by the PPA and TFA as "O&M costs" that "flow-through" directly to the MFLTA and LIL costs borne by Hydro. Since flow-through expenses do not impact the MFLTA or LIL capital accounts, they produce no returns that would provide a source for revenue requirements mitigation.[11]

6. Water Power Rentals

The right to use the Lower Churchill River for power generation at Muskrat Falls requires payment each year to the Province as Water Power Rental payments. They too will form part of charges to Hydro. These rental payments, which commence after the Muskrat Falls commissioning, are expected to amount to about $16 million in 2021, escalating at an assumed 2 percent rate thereafter.[12] As payments to the Province, these annual sums also provide a potential source for offsetting Hydro's revenue requirements.

C. Churchill Falls

1. Churchill Falls Common Dividends

The 5,400 MW Churchill Falls hydroelectric plant in Labrador has for many years operated under the joint ownership of Hydro (65.8%) and Hydro-Québec (34.2%). At one time, but no longer, the Churchill Falls project produced common dividends to the owners, shared in these percentages.

Much of the station's output has since the early 1970s been sold under contract at very low prices to Hydro-Québec. Financed originally using a capital structure with more than 50 percent debt, Churchill Falls has since 2009 had a financial structure consisting entirely of equity. This occurred through payment of the original debt instruments and the subsequent funding of 100 percent of annual capital requirements with equity, using project cash flows.

Hydro and Hydro-Québec made in the late 1990s a number of changes affecting Churchill Falls revenue streams:

- Sale of Recall Power from Churchill Falls (300 MW) to Hydro at Hydro-Québec pricing
- Sales to Hydro-Québec under the Guaranteed Winter Availability Contract (682 MW) which produced a revenue stream that grew to more than $35 million annually by 2018
- Revision of Twin Block energy sales to Hydro for sale in Labrador.

Supported by earnings and cash flow from such sources, Churchill Falls produced dividends to its owners until about 2009. For several years prior to 2009, the Churchill Falls owners considered means for funding increasing capital expenditure needed to sustain Churchill Falls. They established in 2010 (and updated in 2012) a Long Term Asset Management Plan ("LTAMP"). This plan envisioned rebuilds and replacements over the very long term, leading to a fully re-built facility ready for operation by the two owners at the 2041 end of the Hydro-Québec contract. The LTAMP led to large capital expenditure increases from what had been very low annual levels.

The increase in capital needs produced a strategy to fund annual capital expenditures by managing such investment "to the cash flow." Based on forecasts of operating cash flows for the next few years, the highest priority LTAMP projects are selected; their costs would exhaust 100 percent of the available cash flow.[13] However, spending all available cash flow on capital expenditures left no funds available for payment of common dividends to the owners, while as a consequence, retained earnings and equity levels would grow. Projections show Churchill Falls with $855 million in equity capital and no debt at the end of 2019.[14]

We find an all equity structure very unusual in the electric industry, but understand it to be well understood and widely accepted for Churchill Falls.

We understand the Churchill Falls owners to be currently engaged in considering an updated LTAMP, perhaps to be completed in a year or two. Depending on the assessment of capital needs and expected cash flows, the funding of all capital improvements using operating cash flows may or may not remain feasible.[15]

2. Churchill Falls Preferred Dividends

While common dividends ended some time ago, preferred dividends, while small, continue. The four sources of Churchill Falls revenues are expected to produce steady enough cash flow (totaling $80-$85 million annually) to support their continuation. These sources are:

- Hydro- Québec energy sales (at $2/MWh)
- Recall/Recapture energy sales to Hydro (also at $2/MWh)
- Twin Block energy sales to Hydro
- Guaranteed Winter Availability capacity sales to Hydro-Québec.

Churchill Falls forecasts show preferred dividends from the Hydro "A" and "C" shares of $6-$7 million annually from 2020 through 2039. These moderate sums offer another source of utility-related revenue requirements mitigation.[16]

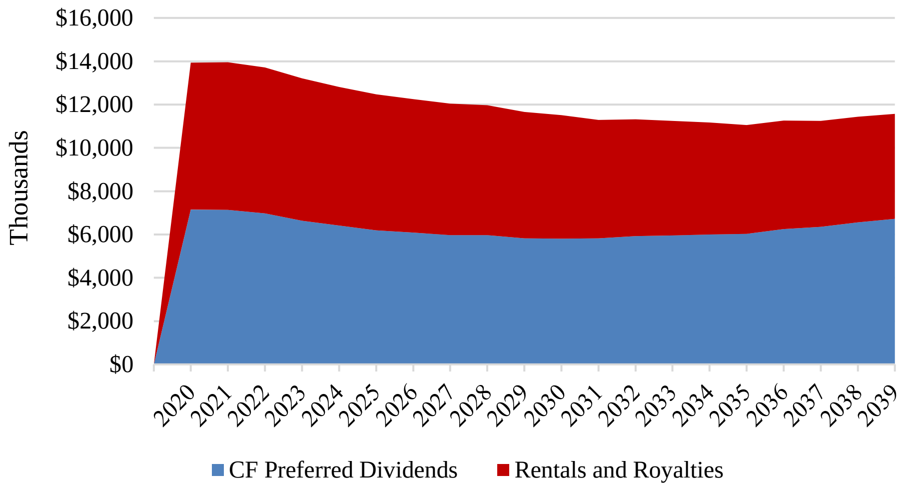
3. Water Rentals and Royalties

Churchill Falls pays a "rental royalty" to the Province in accordance with the 1961 Statutory Lease, understood to be for the use of water resources for power generation.[17] These payments totaled $6.7 million in 2018. Forecasts show these annual payments steadily declining to $5.7 million in 2030 and to $4.9 million by 2039.[18] Also moderate, these payments to the Province offer another source of utility-related revenue requirements mitigation.

4. Cumulative Sources of Churchill Falls-Related Mitigation Sources

Figure II.4 sums the potential Churchill Falls preferred dividends and water royalty sources from 2020-2039.

Figure II.4: Cumulative Churchill Falls Mitigation Sources



D. Nalcor Energy Marketing

1. "Unregulated" Margins from Customer-Funded Muskrat Falls

Nalcor formed NEM to market "excess energy" made available from operation of the Nalcor companies, seeking to maximize the benefits of such sales. Export sales of excess energy, particularly from Muskrat Falls, stand out as another large source of revenue requirements mitigation. The current plan calls for the margins that those sales produce to go directly to Nalcor. This approach is contrary to essentially universal North American practice for power supply facilities whose costs utilities include in their revenue requirements. Chapter III discusses this issue further.

Logic and practice dictate the application of off-system sales proceeds to offset revenue requirements for such facilities. As we explain in Chapter III, there is little if no disagreement in the industry that deregulating power supply facilities means much more than redirecting margins for off-system sales. It takes realigning the capital and operating risks of the units as well. Here, those risks remain with Hydro customers, who pay for all LCP costs. Large portions of the U.S. industry, and much smaller portions of its Canadian counterparts, have restructured the industry to make power supply competitive. In those cases, off-system margins do not inure to customer benefit simply because restructuring makes owners of supply sources in a competitive market responsible both for all the costs and risks of those sources, thereby making it sound to give them the benefit of the revenues as well.

Therefore, it is logical - - compelling one can contend on the basis of nearly universal experience - - to consider here the availability of margins from what NEM terms Muskrat Falls "excess energy" as an offset to Hydro's revenue requirements.

2. Forecasts of Off-System Sales, Prices, and Costs

Following the commissioning of Muskrat Falls, forecasts of total export sales (including both Muskrat Falls and Churchill Falls sources) begin at about 3.6 million MWh/year, gradually declining to under 3 million MWh/year in 2031 and after.[19] We have performed our analysis of the value of these sales using Nalcor's forecasts, deferring to the work of Synapse in addressing their likely magnitudes and margins in more depth.

Muskrat Falls excess energy is expected to support off-system sales of between 1.4 and 1.7 million MWh/year through 2031, declining thereafter. This energy source consists of Muskrat Falls generation in excess above the combined total of the "Hydro portion" (detailed in Schedule 2 of the PPA) plus the Emera share of energy. Churchill Falls will also provide a source of an expected 1.6 to over 2.1 million MWh/year, with the highest values in 2035. This energy will come from Hydro's right to purchase up to 300 MW of "Recall/Recapture energy." To the extent that these sources support profitable off-system sales, they can contribute significantly to mitigation of Hydro's revenue requirements.

As noted in the Churchill Falls section above, Hydro's purchase of Recall/Recapture energy is at the price of $2/MWH, and enters calculations of Hydro's revenue requirements with no markup and, to the extent it is supporting off-system sales by Hydro, is already providing in effect full benefits to customers.[20]

Nalcor has used fairly simple, uncomplicated modeling of the expected margins from export sales, using "net-back pricing" for sales in the northeastern United States, specifically into the New York and New England operating markets. The net-back pricing assumes spot and shorter-term energy sales in the northeast U.S. markets. It excludes sales longer than one year in duration. Net-back pricing subtracts transmission charges and losses and it targets the highest all-in spot market dollars available to optimize the sales.

Nalcor's forecasts also deduct expected NEM operating expenses in estimating margins from off-system sales. These costs include salaries and overheads, approximately $20 million for transmission of 265 MW across the Hydro-Québec transmission system and other variable transmission charges. These forecasts of export sales assume delivery at U.S. market hubs, specifically the Salisbury, Massachusetts or Phase 1/Phase 2 interfaces.

NEM forecasts include four key variables:

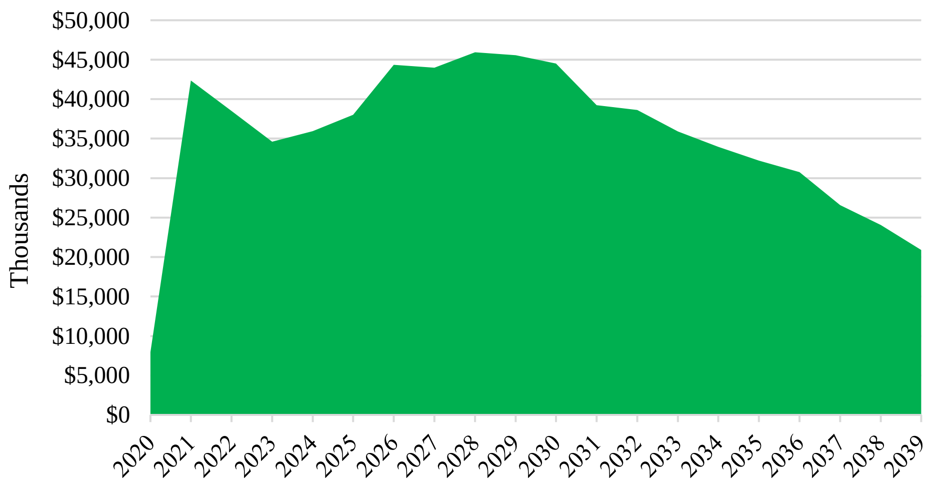
- Spot market pricing at U.S. hubs

- Hydro's electric loads in the Province
- Variable transmission costs
- NEM operating expenses.

3. Magnitude of Off-System Margins

Current Recall power pricing and regulatory treatment mean that no further mitigation can be gained from this source. Quite the opposite applies with respect to margins from Muskrat Falls export sales. Figure II.5 shows the very large reduction that would result from applying margins from Muskrat Falls off-system sales to revenue requirements, again using Nalcor's direct estimation method, and subject to the work performed by Synapse.[21]

Figure II.5: Savings Under Industry-Standard Approach to MF Off-Systems Sales



E. Hydro Equity Returns

1. Financial Implications of Hydro's Equity Levels

Accepted practice calls for a Hydro that the financial community views as self-sustaining. Doing so requires an ability to provide sufficient revenues to cover all costs and to maintain a capital structure with an equity portion sufficient to give comfort in the ability to deal with uncertainty about future conditions. Like other Canadian electric Crown Corporations, Hydro structures its financial policies to remain a self-sustaining entity, broadly perceived by the investment community as able to fund under a reasonable range of conditions its own operations and service its debt obligations without intervention and assistance from the Province. Hydro has been deemed self-supporting due to its ability to generate sufficient revenues to pay its own operating expenses and debt service, and to ensure it does not rely on any operating subsidies from the Province.

Equity returns built into Hydro's rates for service to its customers comprise a central element in remaining self-sustaining. What equity levels need to reach and how well rates support their doing so forms a central question in determining whether reductions to equity levels and returns built into Hydro's rates offer a significant opportunity for revenue requirements mitigation.

2. *Impacts of Hydro's Financial Condition on Provincial Financing*

Historically, the Province unconditionally guaranteed Hydro's short- and long-term debt, resulting in a "flow-through" of the Province's ratings. The guarantees gave Hydro debt the Province's credit ratings. As a result, Hydro achieved a lower interest rate than would have been available based on its own credit. The approach changed in December 2017, after which the Province, using debt issued in its own name, has in turn made loans to Hydro to fund additional debt required by the utility's operations. Hydro pays the Province's actual costs plus a guarantee fee for this "service."

Therefore, the question of whether Hydro is self-sustaining has Provincial implications as well. Financial concern about Hydro has implications for the Province's financial ratings and therefore for the costs of all its debt whose holders have general recourse to the Province for payment.

3. *Historical Hydro Equity Targets*

Their very high levels of capital intensity cause electric Crown Corporations and investor-owned utilities to share a high level of dependence on debt capital markets. Hydro's target capital structure sets the equity share at 25 percent and debt capital at 75 percent.

Ensuring the ability to provide cash flow required to pay utility operating expenses, debt service and ongoing funding requirements, plus a margin to address uncertainty, forms the basis for setting target equity percentages and equity returns. Rating agencies regularly monitor status against targets like these to inform capital market investors. A self-sufficient Hydro is material in avoiding adverse rating consequences for the Province. A self-sufficient Hydro keeps some $1.8 billion of Hydro debt and $7-$8 billion of "contingency debt" related to LCP off the Province's books.

Hydro's current financial policies became effective approximately 10 years ago, as it looked to enhance its regulated capital structure. The Province made a $100 million equity injection into Hydro in 2009, raising its equity level to approximately 25 percent. Hydro then clarified its dividend policy to call for re-investing retained earnings as required to maintain debt at about 75 percent of the regulated capital structure.[22] Hydro has not paid a dividend since 2012, instead retaining earnings to fund a portion of its substantial capital expenditure program. Retention of earnings has brought the equity component of Hydro's capital structure to 18.8 percent at the end of 2018.

Order in Council OC2009 – 063 established Hydro's capital structure and equity return ("ROE") in 2009. The Order stated that the capital structure approved for Hydro should permit a maximum proportion of equity equal to that most recently approved for Newfoundland Power (currently 45 percent). Hydro has maintained a target equity level of 25 percent since 2009. The Order in Council allowed Hydro the same return on equity as Newfoundland Power (currently 8.5 percent).[23]

The questions these standards raise for revenue requirements mitigation include the following:

- What equity level is required to keep Hydro self-sustaining
- What equity return levels are required to maintain sufficient equity
- How do impending rate increases and other uncertainties (like those involving the LCP) affect what is required for Hydro to be viewed, given its circumstances, as self-sustaining?

Another question looms as well. It is not one our work scope includes but it merits attention in that it implicates the degree to which the Province, effective holder of Hydro equity interests, is willing to risk change to its financial standing due to issues and uncertainties at and involving Hydro.

4. Comparative Crown Corporation Financial Targets

Each entity's status depends on its unique circumstances, but nevertheless it makes sense to begin looking at the questions posed above by comparing Hydro to other Canadian Crown Corporations that provide electricity service. Table II.6 shows Hydro's 25 percent equity target within, but at the low end of the range. We understand their Provinces generally guarantee their debt, with the exception of Ontario Power Generation. The lack of Provincial guarantees there makes its target equity an outlier. Hydro's situation, however, becomes much more typical in two other important respects: (a) all actual equity levels fall below targets, some by much more than Hydro, and (b) Hydro's 19 percent falls two percent below the median of the group (SaskPower at 21 percent).[24] There is much less variation in target equity returns; Hydro's can be considered representative.

Table II.6: Recent Canadian Crown Electric Utility Equity Metrics

Entity	Target Equity	Actual Equity	Target ROE
Ontario Power Generation	45%	25%	8.8%
New Brunswick Power	35%	5%	10.0%
Hydro Québec Distribution	35%	28%	8.2%
Hydro Québec Transenergie	30%	28%	8.2%
SaskPower	25-40%	21%	8.5%
BC Hydro	20-40%	16%	11.8%
Manitoba Hydro	25%	11%	n/a
Newfoundland and Labrador Hydro Regulated	25%	19%	8.5%

Hydro does face material uncertainties as questions about the consequences of a vast increase in rates, Provincial contributions to mitigating it, completion of the LCP, and the ability to operate Muskrat Falls and the LIL remain open. On the one hand, the circumstances and risks lend credence to maintaining a 25 percent target. On the other hand, equity-level performance to date lends weight to using a 20 percent target. If there were a third hand, it would be raised in favor of not pressing for a sustained level materially below 20 percent, given the open questions the Province faces and their implications for its credit standing.

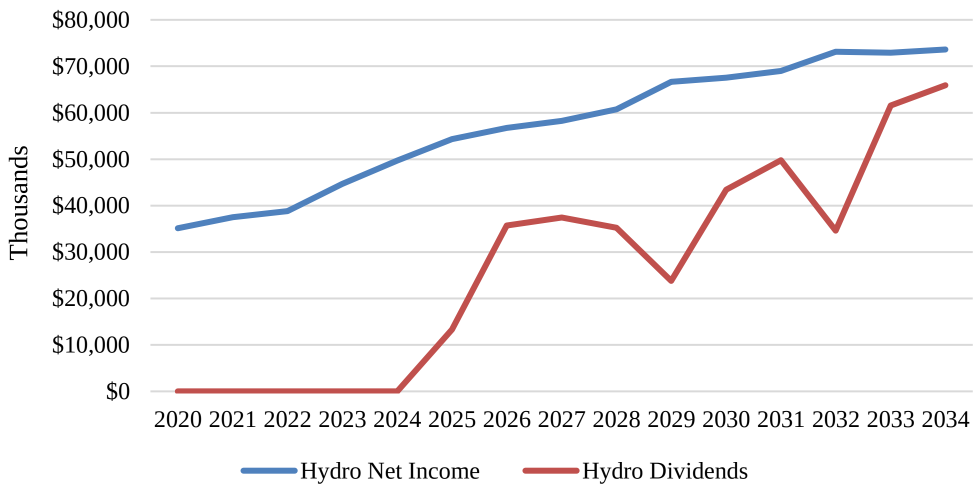
5. The Effect of Equity Levels on Amounts Available for Mitigation

A material question in determining equity levels, whether for the immediate term, or over the life of the 20-year period we examined, is how much they affect amounts available for revenue requirements mitigation.

a. Forecasted Dividend Levels

Hydro prepared forecasts for 2019 through 2039, using a 25/75 equity/debt ratio and an earned equity return for regulated operations of 8.5 percent. These analyses assume earnings retention until equity grows from the current 18.8 percent to a sustained 25 percent level. Figure II.7 shows the portion of net income amounts (the blue line) available for dividends (the red line) using these assumptions.[25] The red dividend line offers a measure of how much can be made available for revenue requirements mitigation, while allowing Hydro's equity to grow to 25 percent.

Figure II.7: Forecast of Hydro Regulated Net Income and Dividends

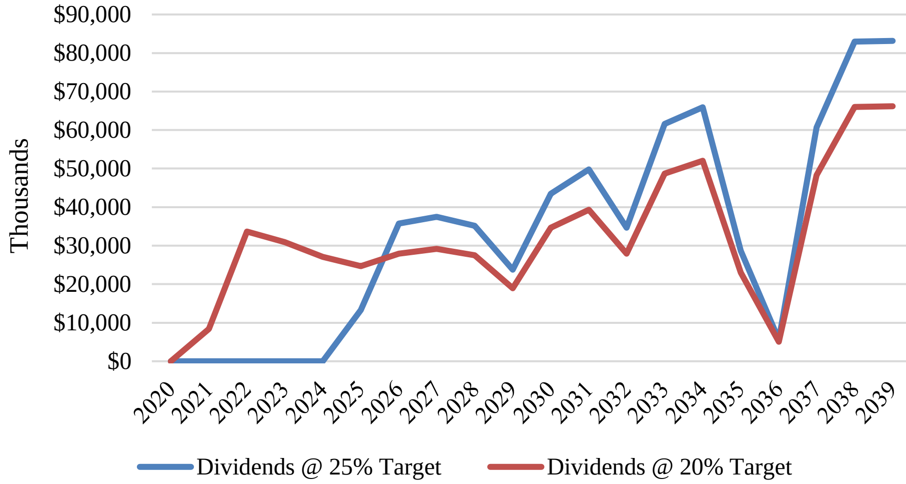


The dividends available for Hydro are generally equal to net income less the retained earnings required to fund capital expenditures and to build toward or maintain target equity levels. Permitting the 18.8 percent equity capital at year-end 2018 to grow to 25 percent bars dividends (or revenue requirements mitigation) until 2025. Beginning in 2026, Hydro could produce $35-$50 million of dividends annually. Dividends become erratic after 2034, dropping to $5 million in 2036 and rising to $83 million in 2039.

b. Adjusting for Different Equity Levels

Figure II.8 shows that changing the equity share in the capital structure from 25 percent to 20 percent would increase Hydro's dividends by about $111 million between 2021 and 2025, but reduce them in each year thereafter. The 20 percent equity target produces $22 million less in cumulative dividends through 2039.[26] Therefore, dividends based on 20 percent equity would produce a larger source of mitigation in earlier years, when other financial sources of mitigation are lower. The larger source in these earlier years would assist in producing a smoother future rate path, eliminating a temporary spike during that period.

Figure II.8: Dividends at 20 and 25 Percent Equity Maintenance Levels



6. Changes in Hydro Equity Returns

Hydro's achieved equity returns will drive the direction of its cash flow and equity percentage moves. Thus, while changing the equity return could provide one "lever" for reducing revenue requirements, how far to "pull" it requires consideration of its financial implications. For instance, a decrease in Hydro's return on equity to 5 percent would decrease Hydro revenue requirements (Island Interconnected only) by about $16 million in 2021, and by $551 million through 2039. However, it would also reduce Hydro earnings and cash flow by about one-half. The effect, should building equity to 25 percent remain a target, would be to eliminate all Hydro dividends available until 2039 (an equal amount of $551 million for Island Interconnected). From a Hydro sustainability point of view, the effect would be to decrease the cash flow "cushion" above debt service by 40 to 60 percent annually.[27]

F. Cumulative Sources of Financial Mitigation Opportunities

When combined, the sources of revenue requirements mitigation identified in this chapter not only overwhelm those obtainable through operational changes, but make a very large difference in rates post-LCP commissioning. Figure II.9 summarizes the potential impact on revenue requirements. The total Nalcor rate mitigation dollars grow from about $165 million in 2021 to more than $500 million in 2030, and to more than $700 million by 2039. Hydro's current total revenue requirements are in the range of $700 million per year.

Figures II.9 and II.10 combine the effect of the following revenue mitigation possibilities in 2039, and presents them on a total dollar basis and on a cents/kWh basis:

- Dividends that will become available to the Province from LCP equity returns built into PPA and TFA pricing ($569 million)
- Margins slated to go to the Province for Muskrat Falls excess energy ($20 million)
- Dividends now available to the Province from equity returns in Hydro's current rates ($83 million). A change in the equity target to 20 percent on a temporary basis would add additional dividends of about $111 million in the period 2021 to 2025, but later-year reductions would essentially match the values added in this earlier period

- Churchill Falls preferred dividends now available to the Province ($6-7 million)
- Water related fees now going to the Province for Churchill Falls ($6 million) and scheduled to go to the Province for Muskrat Falls ($22 million).

Figure II.9: Cumulative Financial Sources of Rate Mitigation

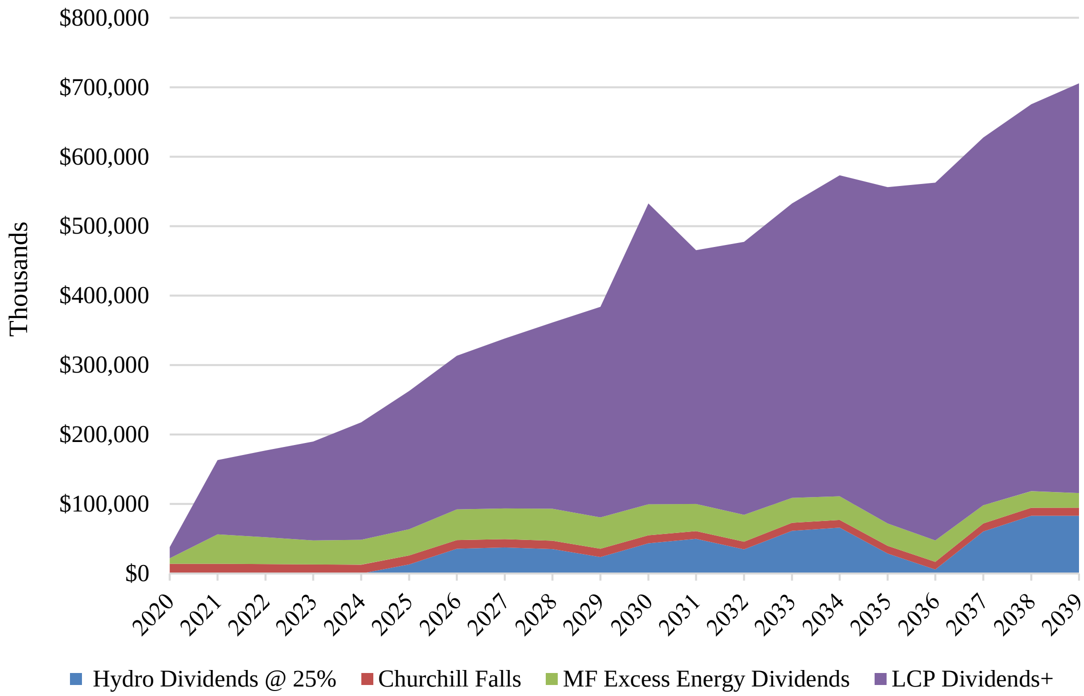
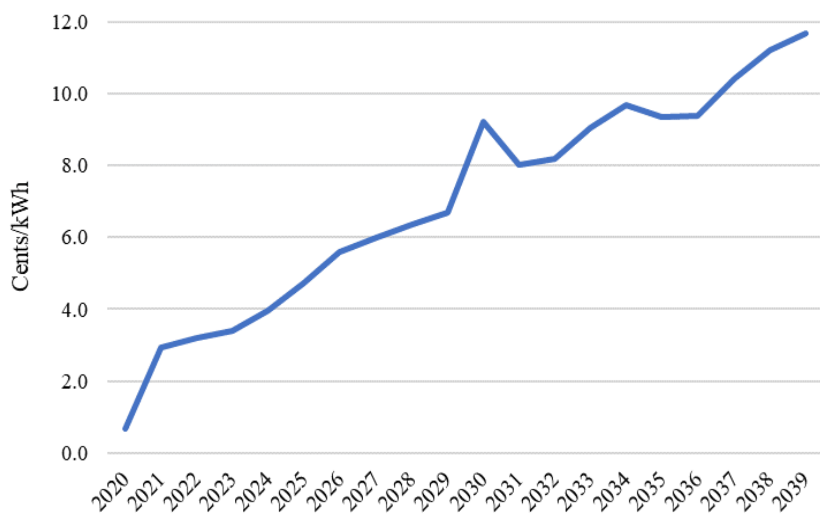


Figure II.10: Rate Impacts of Financial Mitigation Opportunities



The technical and accounting aspects of applying the various sources to rate mitigation for customers will require study by Nalcor and the Province to determine the most appropriate mechanism to effect such mitigation.

G. Provincial HST

Domestic customers of Hydro and Newfoundland Power pay Harmonized Sales Taxes ("HST"), a large portion of which goes to the Province. Hydro has estimated its HST payments to the Province at \$8.3 million in 2021, increasing to \$11.7 million by 2039.[28] Newfoundland Power estimates these payments at \$43.9 million in 2021, and remaining relatively steady at \$43.7 million in 2024.[29] Combined, this more than \$50 million per year has a direct relationship to electricity service provided in the Province. The Province in the past has rebated the provincial share of HST on domestic electricity sales to customers. If this were to be done again, it would reduce the amounts domestic customers pay for their electricity consumption.

H. Depreciation Issues

We also examined depreciation changes as a source of potential revenue requirements mitigation. We examined both existing Hydro and LCP assets and the depreciation methods and requirements applicable to each.

1. Hydro Depreciation

Hydro completed with the aid of a consultant an extensive 2016 depreciation study. It was considered in the 2017 General Rate Application, and resulted in a reduction in Hydro depreciation expense resulting from changes in depreciation methods. The reduction in depreciation expense came from lengthening previously approved average service life estimates and by amortizing gains and losses on asset retirements, rather than including them in current revenue requirements. Hydro's removal costs included in the depreciation expense were ordered to be at a rate of -5 percent, which also resulted in lower depreciation expense than Hydro's peers.

The resulting Hydro depreciation methods also incorporated the use of the Average Life Group ("ALG") procedure that results in lower depreciation expense than the Equal Life Group ("ELG") procedure generates.[30] The cumulative changes made produced lower depreciation expense than that of Canadian peers.[31]

Review of data used by other Canadian utilities confirmed that Hydro's new methods produced service lives longer than their Canadian peers for the largest asset categories; *e.g.*, Dams and Dykes.[32] Hydro and its consultant believe that the new depreciation expense employs average service lives extended to maximum levels. Our review did not find reason to believe that further extension offered material opportunity for additional rate mitigation.

2. LCP Depreciation

We also analyzed the potential for extending the depreciation lives of MFLTA and LIL assets. The terms of the PPA and the TFA pose fundamental obstacles to doing so. As we described earlier in this chapter, the pricing provisions of these agreements have been firmly fixed to support the financing that allowed the LCP to proceed. Each of the two specifies 50-year "service lives" for the MFLTA and LIL assets. Equity investments, including those by an outside Emera interest, and the debt financing guaranteed federally are entitled to rely on this and the other PPA and TFA terms.

Nevertheless, we did examine whether the unwinding of arrangements that may involve Emera, the federal government, and all bond investors might produce sufficient benefits to warrant pursuit. An analysis of extending LCP asset lives to 75 years showed a one-to-one correspondence between revenue requirements benefits from depreciation changes and dividends available for mitigation.[33]

I. Financing Alternatives

Our planned Phase 2 work plan included further exploration of several financing alternatives that could produce sources of revenue requirements mitigation, especially in the early years following LCP commissioning:

- Lower Churchill Project Sinking Funds
- Lower Churchill Project Capital Structure Optimization
- Churchill Falls Recapitalization Opportunities.

In April 2019, we suspended work on these financing opportunities, pending discussions between the Province and the federal government addressing measures that the latter might undertake or support to produce mitigation.

III. Utility Regulatory Framework and Rate Mitigation Options

A. Background

A primary goal of the Reference under which the Board engaged us is to examine options to reduce the impact of looming rate increases following LCP completion. Some of the options that may be available depend upon the Province's utility regulatory framework - - now and as it may change. For example, the LCP will continue to have impact well after its completion, as it continues to incur the capital and operating costs necessary to sustain reliable operation. We believe that the Board's ability to examine the reasonableness of such sustaining expenses can have a very large impact on both cost and reliability. Current limitations in the Province's utility framework preclude that role, as other limitations (see particularly Chapter II's discussion of the PPA and TFA and of NEM and the expected beneficiary of off-system sales from Muskrat Falls) preclude other forms. We have generally carried out our examination under the assumption that, while we should identify limitations (or "barriers" as we termed them), we should not assume that they are insurmountable.

This chapter addresses limits that the current utility regulatory framework of the Province may place on opportunities for lowering rates for customers. We also address how that framework bears on NEM's role, structure, scope, and generation of margins from off-system sales, and how those aspects of NEM may limit revenue requirements mitigation options.

The series of specific questions that the Province has designated for the Board's examination require consideration of the utility regulatory framework here. It has for example, asked for information addressing. "forward-looking cost savings and opportunities for increased efficiency related to operating and maintenance of MFP." As we explain in this chapter, we view the current lack of Board authority for addressing those costs as a direct threat to optimizing their efficiency and effectiveness.[34]

The Reference also specifically included revenues NEM is now slated to earn from Muskrat Falls sales among the "sources of Nalcor income that could be put towards reducing rate increases." It also specifically seeks an understanding of "industry best practices related to external market purchases and sales of electricity."[35] We do not think that question can be answered robustly without considering the means and best practices by which regulators across North America have addressed the operations, costs, and revenues of marketing entities that make off-system sales of power and energy from generating stations whose capital and operating costs are paid for by utility customers.

A jurisdiction's utility regulatory framework guides the determination of what customers will pay for electricity in the short run through rate proceedings, and in the longer term generally as well, through various forms of review of planned and actual expenditures on assets with a long life, like supply resources. It also determines how, in this most capital intensive business, planning for future needs occurs. That framework also serves to align risk between those who invest in and operate those facilities and those who use the electricity whose prices recover the costs of investment and operation.

The Board is expected to play a role classically defined throughout North America; *i.e.*, to balance customer interest in securing service that optimizes reliability and cost, on the one hand, with the need to permit the utility to recovery its reasonable costs and to give that provider an opportunity to earn a reasonable return on the investments it makes in providing that service.

A core principle that has served well across the long history of the business holds that a utility is entitled to a fair return on prudent and reasonable investment. This principle matured in an era dominated by monopoly providers. Competitive markets do not offer reward on the basis of the reasonableness of investments when made. Instead, those markets favor those who offer best prices (or values) at the time customers make purchasing decisions. Historical utility regulatory principles substituted prudence as a proxy for the disciplines and pressures of a competitive market.

B. Common Elements of U.S. and Canadian Regulatory Models

There has been significant recent convergence in many respects between the U.S. and Canadian electric utility industry regulatory models, but regulatory treatments in the countries have differed historically. The prevalence of Crown corporations, and particularly their ownership, have contributed significantly to those differences. There are fundamental exceptions, however. Alberta stands as one exception; there, ad hoc electrification by private enterprises first expanded electric utility service within the Province, and eventually produced ownership and regulatory models closer to the types that have come more frequently to characterize the U.S. industry, in particular, a competitive generation marketplace to price electricity supply. In general, the current Canadian models show more similarities than differences to the U.S. models.

In this Province the Board operates under the Public Utilities Act and the Electrical Power Control Act, 1994 ("EPCA"), which establish regulatory policy and the powers of the Board. The EPCA calls for Board application of tests consistent with sound public utility practice, thus making the range of industry experience a relevant consideration. Section 5 of the EPCA permits Government to exempt a project from the Board's jurisdiction, which occurred for the LCP. Government can also provide the Board direction on policies and procedures, which has occurred; *e.g.*, for rural rates and LCP O&M costs. This chapter provides the context that reference to other North American experience provides, while making observations about implications for the Province's regulatory policies (about which Government may direct change) as it considers opportunities for reducing rates.

More recently, Nova Scotia has replaced a Crown corporation structure with service from an investor-owned utility. While it continues to operate as a vertically-integrated electric utility, we found, across many years of engagement there by the provincial regulator, a utility operating structure and utility regulatory framework very similar to many in the U.S. Utilities there remain responsible not just for transmitting and delivering electricity, but generating it as well. The main difference we found is the use of formal proceedings for approving capital expenditures in advance. Despite the growth of filings and proceedings which either incorporate or at least approximate comprehensive Integrated Resource Planning, U.S. regulation of vertically-integrated utilities still generally provides for a review of the prudence and pricing of investment decisions after their completion.

Even those jurisdictions that employ Crown corporations apply many of the same regulatory concepts as do their U.S. counterparts. The Board here, for example, uses approaches and techniques familiar in the U.S. in areas such as: requiring a demonstration that planning and management of investments recovered in rates are prudent and reasonable, rate-of-return-based recovery of investment costs, use of test years to establish a pricing basis, offsetting revenue requirements with revenues from other sources, and earnings reporting.

Given such similarities, we begin with a comparison of the utility regulatory framework here with those typifying U.S. experience. With similarities more prevalent than differences in regulatory concepts and techniques, that approach will provide an overall perspective useful in focusing on the divergent aspects.

C. The U.S. Regulatory Model

Recent decades have witnessed major efforts, particularly in the United States, to introduce competition in the electricity industry. Those efforts began and still largely focus on segmenting what was a vertically integrated industry dominated by utilities that generated, transmitted, and delivered electricity to their customers. Usually retaining the monopoly status of electricity distribution, jurisdictions that have restructured their electric utility industry generally sought first to move generation to a competitive model, accomplished by divestiture or spin-off of generation assets, followed by what now has become substantially free entry and exit by competitive generation owners and operators. In those states, generators compete on price for customers who continue to be served by their monopoly distribution utilities that, for the most part, continue to provide transmission as well.

It is in this context that one best understands the term “unregulated” as it applies to generation facilities. That term involves two closely integrated and reciprocal concepts:

- Regulators do not set prices for generation, the market does
- Customers do not have responsibility for underwriting generation costs.

Curiously, the Province both does and does not follow a regulatory framework that balances risk and reward, as in the U.S. model. It does so with respect to the Hydro assets, ensuring the Crown Corporation the opportunity for a reasonable return on prudent investment and for the recovery of prudently incurred operating costs. The material variation is the use of a return on equity incorporating an investor-owned utility rate as a proxy for a rate based upon the costs of the owner (here, the Province) to compensate equity capital as in the American model.

The Province’s framework departs from this balance with respect to the assets of Power Supply. It splits cost responsibility (which falls on customers) and off-system benefits (which flow to ownership) for the very same assets. That concept is not in line with the U.S. model. We consider it appropriate to exclude Churchill Falls from those assets in discussing this immediate issue. The history and nature of its ownership and operating agreements, the commitment of the vast majority of its output to a single customer, the extraordinarily-long duration of the customer’s rights to that supply, and the immense mismatch between ownership shares and economic benefits as between the owners make Churchill Falls a true “one-off.” It is essentially unique.

Excluding Churchill Falls leaves us with the LCP. Chapter II explains how the PPA for Muskrat Falls output and the TFA for use of the LIL make Hydro's customers responsible for the residual costs. Those residual costs consist in major part of those not recovered through prices to Emera - - prices that provide material protection to those interests against LCP cost increases, past, present and future. The ability to use Hydro's customers as such a backstop - - with respect both to investment and operating costs by itself does not contravene the construct we have been addressing so far. Whether it ultimately does so depends on two other major factors:

- How does the prudence element of the construct apply?
- If there are benefits to be gained from the assets, where do they flow, considering the obligation of customers to bear investment and operating costs?

As explained below, neither of these reciprocal principles, both of them central to the utility regulatory framework on which have focused so far, apply to the LCP.

1. The Absence of a Prudence Standard

Unlike Hydro's investments, those of the LCP bring no investment risk to Nalcor, short of an essential collapse of Hydro's business, due to inability to pay PPA and TFA charges. The Board has had no authority to question the prudence of the decision to undertake the LCP, nor does it have the authority to examine the prudence of its design and construction. Moreover, it will have no authority to rule upon the reasonableness and prudence of future investment or operating costs. That authority lies with the owner. The magnitude of the difference between Hydro's other investments and the LCP underscores the practical significance of the exclusion of LCP from the regulatory framework. Hydro's current utility-service revenue requirements, regulated by the Board, amount to about $700 million per year. This amount includes costs associated with generation, transmission, distribution, and customer service. The LCP alone, however, will add an annual amount in the same range, but limited to additional generation and transmission, which, to add, will not be subject to Board scrutiny. Even more dramatic is the contrast between Hydro's current rate base (somewhat less than $2.5 billion) and LCP investment costs (now expected to be about $12.7 billion).

2. The Application of LCP Benefits

Chapter II of this report details the very large economic benefits expected to come from the sale and transport (through the LIL and the LTA - - LCP's other principal assets) of Muskrat Falls generation output above that sold to Hydro and Emera interests. Application of the margins (*i.e.*, revenues less costs) of those sales to offset revenue requirements stands, so far as we know after more than three decades in the industry, as a universal requirement for assets for which utility customers pay. The same is true for the natural gas business, which, like its electricity counterpart, depends on high-cost assets designed to serve customer needs reliably. Several factors common to both lie at the heart of this universal requirement:

- Electric and gas infrastructure design is based on the ability to meet peak loads, and justifies the charging of their costs to customers who contribute to those peaks
- At other than peak load periods, the infrastructure has some excess capacity to serve other customer bases in the industry profitably
- Reliably meeting peak demands and providing for long-term customer energy needs often produces "lumpy" investments, which can produce shorter-term excess that can find

profitable use even during some peak periods, while regularly contributing to off-peak opportunities.

As Chapter II explains, those off-system sales (subject to the analysis that Synapse has done) can be expected to generate for Nalcor margins of about $35 to 45 million per year. They do not, however, offset the revenue requirements of Hydro's customers, who directly bear both their direct share and residual responsibility for those LCP costs not recovered elsewhere. Instead, they flow to the Province, as owner.

3. Failure to Adhere to the Standard Model

It is clear that the current Newfoundland and Labrador utility regulatory framework does not meet the essential reciprocity principles underlying the standard model with respect to LCP revenues and costs. Ownership does not bear any responsibility to demonstrate the prudence and reasonableness of the LCP investment, and yet is assured of full investment and operating cost recovery. Ownership is not required to risk any portion of its investment in competitive markets but nevertheless receives the benefit of off-system power and energy transactions, rather than using them to offset utility-rate revenue requirements.

D. The Canadian Models

1. Alberta

Alberta's electricity development followed a pattern common in the U.S., with a variety of private and municipal entities largely responsible for initial electrification and its spread across the province. Therefore, there is no Crown corporation engaged broadly in the electricity business in the province.

Alberta some time ago employed a form of virtual generation to place generation effectively in a competitive market. This model is similar to that which has become widespread in the U.S. It has eliminated vertical integration. The province long ago restructured its industry to separate generation from transmission and distribution. Moreover, its industry participants are investor-owned. Generation, versus delivery, thus is no longer price regulated. Developers of these supply sources take investment risk, and operate without assurance of cost recovery through retail rates. Therefore, the Alberta Utilities Commission does not review supply resource capacity plans or set pricing for them in utility rates.

Given the competitive structure of the generation business in the province, margins (or losses) from transactions flow to the generation owners, who must also recover their costs from the market, not through regulated utility service rates.

2. British Columbia

The British Columbia Utilities Commission ("BCUC") regulates BC Hydro, a Crown Corporation. BC Hydro serves over 95 percent of the province as a vertically-integrated supply and delivery company. The Commission has substantial regulation authority, covering all aspects of BC Hydro's capital projects and revenue requirements.

In the summer of 2018, the province announced a comprehensive review of BC Hydro, designed in part to keep electricity rates affordable. A year-long review examined the business, with an emphasis on cost consciousness. Key outcomes included, according to BC Hydro, "enhanced regulatory oversight of BC Hydro and the development of a new five-year rates forecast that reflected cost and revenue strategies to keep rates affordable."[36] The review restored the authority of BC Utility Commission to review and decide on BC Hydro's costs, proposed rate increases, integrated resource planning and "almost all regulatory accounts, programs and capital projects."[37]

In addition to serving most of BC's native load, BC Hydro engages in export power sales when excess power is available. Margins from export sales offset retail electric rates and provide additional revenue to the province. The 2018/2019 trading revenues of Powerex, Corp., a wholly-owned BC Hydro subsidiary, amounted to $1.14 billion for the fiscal year ending in March 2019, for wholesale power, renewable energy credits or similar products, carbon-allowances, natural gas, ancillary services, and financial energy products. BC Hydro reported that:[38]

> *Powerex Corp.'s trade activities earn income to keep the Company's customer rates low and to help balance its system by being able to import energy to meet domestic demand when there is a supply shortage and exporting energy when there is a supply surplus. Exports are made only after ensuring domestic demand requirements are met.*

The Province has also recently directed annual reductions of $100 million in BC Hydro payments to the Province until they reach zero. The goal is to permit BC Hydro to reach a 60:40 debt to equity ratio, before these dividend-type payments resume.[39] The equity percentage was reported at 18 percent, falling from 21 percent the previous year.

3. Manitoba

Manitoba Hydro, a Crown Corporation, provides electricity on a vertically-integrated basis across Manitoba.[40] The Manitoba Public Utilities Board does not approve Manitoba Hydro's capital expenditures for generation or transmission. Manitoba Hydro does not have to justify such projects to the Board. However, the Board can exclude certain capital costs from revenue requirements in rate proceedings and it has been asked by the Province to provide recommendations about Manitoba Hydro's capital development plans.

Profits from export sales are used to offset the rates paid by domestic customers. Variances from forecasted export sales result in variances in net income. In special circumstances, through specific legislation, profits from export sales may be directed back to the provincial government, a scenario that last occurred in 2003. The company recently noted that:

> *Our export revenues brought in more than 23% of our total electric revenue over the 10-year period 2009–18. Without export revenues, all of the costs associated with the utility would need to be covered by our Manitoba customers.*[41]

4. New Brunswick

New Brunswick had for some time exempted the capital planning of the province's vertically integrated electric utility from review by its utility board. The Electricity Act, however, in 2013 gave the New Brunswick Energy and Utilities Board the power to regulate the rates charged by the provincially-owned electric utility, NB Power. Provincial legislation includes within the Board's mandate electricity generation and review of capital projects exceeding $50 million. Restructuring intended to bring generation within the scope of Board authority also eliminated the New Brunswick System Operator as a separate entity (beginning October 1, 2013). Most of the system operator's role moved back into NB Power operations and the Board has responsibility for ensuring compliance with reliability standards.

NB Power operates as a vertically integrated utility. Before generation moved back under the Board's responsibility, a marketing arm of NB Power managed external transactions, and resulting margins from external transactions did not offset revenue requirements. Now, however, margins from such transactions do offset utility revenue requirements. A separate marketing arm continues to conduct them, its costs of operation net against the margins produced. However, the Board does not exercise jurisdiction over the reasonableness of those costs.

5. Nova Scotia

Nova Scotia's vertically-integrated utility, Nova Scotia Power, operates as a subsidiary of investor-owned Emera. There is no Crown utility providing electricity service there. The province's Utility and Review Board does examine proposed capital expenditures and can review the reasonableness of capital and O&M costs generally. Emera's other operations include utility generation and engagement in wholesale electricity markets. The Board has the power to review, which it has done with regularity, the reasonableness, prudence, and arms'-length nature of transactions between Nova Scotia Power and its affiliates. However, in the case of the LCP and Maritime Link, the Board's powers of prior review were somewhat circumscribed by provincial legislation; *i.e.*, rather than a full review of the balance that existed between the Emera utility and non-utility interest, the Utility and Review Board's review concerned itself with whether, taking that structure as a given, the project offered the best solution to meeting customer needs.

6. Saskatchewan

The Saskatchewan Rate Review Panel advises the provincial government on rate applications by SaskPower. It does not have the authority to set rates or approve capital projects. SaskPower is a wholly-owned subsidiary of Crown Investments Corporation, a Crown Corporation, and is the primary electric provider in Saskatchewan. It is a vertically integrated electric utility, and its costs are subject to review by the Panel.

SaskPower is the primary electric utility in Saskatchewan, serving most of the province. Unlike neighboring provinces, Saskatchewan has only very limited low-cost hydroelectric generation. As such, export opportunities are limited. Export margins are used to lower rates, when available, but these represent limited contributions to the revenue requirement and retail rates.

7. Summary

The Canadian models differ in origin - - principally due to the common use of Crown corporations. Over time, however, there has been a clear trend toward support for utility regulatory commission review of the reasonableness of capital and operating expenditures, and, where vertical integration remains the model, application of export-sale margins to offset revenue requirements. Some jurisdictions, as discussed above, do not fully regulate the operations of the entities responsible for export sales (*e.g.*, their organization and operating costs), even where they apply margins produced to revenue requirements. That is not the case in the U.S. - - for strong reasons in our view. Regulatory oversight of these elements has the same public value in promoting cost efficiency through review by the province's presumably most expert authority on utility operations. It also has value in ensuring that off-system transactions are controlled in a manner that ensures service reliability.

E. The Planning Conundrum Created by the LCP's Dual Personality

Regardless of the model adopted, we consider it important to address the split personality of Nalcor's treatment of LCP. Use of the term "personality" seems odd for a corporation, but it has central relevance here because of what we see as an inherent conflict of interests with which Nalcor will have to struggle continuously. That struggle has particular consequence for the Board's ability to deal comprehensively with utility reliability and rate issues. The current focus of the Province on both highlights the importance of establishing clear, consistent authority and accountability for the public decisions and guidance that affect both.

The conundrum we suggest exists has relevance for both the planning and execution of assets like those of the LCP and for their long-term operation. Beginning with the latter will better crystalize these issues, so we begin there. The Board will have no role in reviewing either the capital costs needed to sustain the LCP assets over time or the operating costs to run them. This lack of authority denies a role for the regulator – the entity that the North American utility model very broadly considers the best capable and experienced to review and ensure optimization of the two most centrally relevant factors - - reliability versus cost. The Province appears to agree that the Board should have this essential role with respect to Hydro's assets.

The absence of such a role will tend to foster two negative consequences. First, the absence of Board review and approval authority for LCP capital and operating planning and execution will more likely than not result in higher spending. Second, the Board will effectively have to take Muskrat Falls and LIL reliability "as it finds them," because those capital and operating plans and their execution will strongly affect their reliability. Expecting the Board to exercise robust oversight of reliability becomes unrealistic with so large and important a set of assets outside its purview.

This inherent problem, already material in our view, will be exacerbated by the personality split woven into the current means of dealing with the LCP assets. When Power Supply makes decisions about plans, expenditures, and operations for the assets, it will do so in consideration of maximizing the value of off-system transactions. One should expect the size of the margins they produce to serve as the strongest influence on these performance definers and drivers. Importantly, however, what drives off-system margins may not be the same as what drives reliability.

We would expect a material level of reliability concern within Power Supply, but one inherently conflicting with margin producing incentives. The context here involves assets central to reliability and whose investment costs rest with utility customers. It also involves a Board charged with responsibility for the regulation of service and pricing of a vertically-integrated utility. This context offers the perspective that supports location in one place of accountability and responsibility for optimizing reliability and cost as the preferred option. Presently, with the areas delineated as beyond Board authority, integrating decisions are made by top Nalcor management, which operates under inherently conflicting margin optimization and its profit-biased judgment of how its "unregulated" assets should contribute to reliability.

The same arguments apply to planning, commitment to, and design and construction of assets like those comprising the LCP. Those assets will comprise the largest source of Hydro supply, investment levels dwarfing existing utility plant, and a source of perhaps $35 to $45 million dollars per year in margins for Nalcor from off-system transactions across the next ten years. The Board did not examine whether those assets and their planned operating profiles comprised an optimal solution to ensuring service adequacy and reliability. Had it done so, we can only speculate about whether it would have been able to consider the costs in the holistic manner usually employed by utility regulators; *i.e.*, applying margins against revenue requirements. Whether viewed narrowly, from the perspective of just costs of LCP operation after commissioning, or more broadly for what it implies about the Board's future role in examining major investments whose costs customers will bear, the issue remains the same - - can optimization of cost and reliability effectively occur when decisions are made, with no Board oversight, and by an entity charged by the Province with developing resources with significant market potential and building and operating facilities central to the long-term reliability of service to the residents, businesses, and institutions of Newfoundland and Labrador.

F. Crown Corporation Economic "Contributions" to their Provinces

Crown corporations operating in Canada generally make very large payments of numerous types to their provincial "shareowner." The following figure, from a recent decision by the Public Utilities Board of Manitoba,[42] summarizes the work in categorizing and measuring those payments. We have not sought to corroborate the individual entries, but overall, the figure clearly shows large contributions to be typical.

Figure III.1: Payments to Governments by Canadian Utilities

($ Millions)	Manitoba Hydro (Forecast 2018/19)	British Columbia Hydro (Forecast 2018/19)	Hydro-Quebec (2016 Actual, forecast not available)	Newfoundland Labrador Hydro (Forecast 2018/19)	SaskPower (Forecast 2018/19)	New Brunswick Power (Forecast 2018/19)
Water Rentals	103	350.1	667	0	21	0
Debt Guarantee Fee	185	0	218	2.2	0	31.8
Capital & Other Taxes	145	238.7	284	0	50	45.1
Other	0	0	0	0	35	0
Payments to Gov't	**433**	**588.8**	**1,169**	**2.2**	**106**	**76.9**
Gross Operations Revenue	2,246	4,836.8	13,339	696.5	2,697.6	1,705.5
Payments to Gov't as Percentage of Gross Revenue	***19.3%***	***12.2%***	***8.8%***	***0.3%***	***3.9%***	***4.5%***
Dividends	0	70.8*	2,146**	0	21	0
Total Payments to Gov't (with dividend)	**433**	**659.6**	**3,315**	**2.2**	**127**	**76.9**
Total Payments to Gov't (with dividend) as Percentage of Gross Revenue	*19.3%*	*13.6%*	*24.9%*	*0.3%*	*4.7%*	*4.5%*

Water rentals include fees for use of water resources for hydroelectric generation. Manitoba Hydro, for example, also pays rental fees for the use of Crown lands for water power purposes. Debt guarantee fees provide compensation to governments for providing utility debt guarantees or other assurances.

As the preceding figure shows, it is common in other provinces for the utilities to pay a variety of taxes (in many cases like other Crown, financial, and other corporations in the province); *e.g.*, a percentage of capital, taxes or payments in lieu of taxes on land and buildings, payroll taxes, business taxes, and payments to municipalities. Dividends comprise another source of payments from Canadian utilities to their provincial governments.

The preceding figure shows that current Hydro contributions to the provincial government are currently small, but, following LCP operation Nalcor and Hydro contributions will exceed all by far, measured as a percentage of total revenues.

The use of revenues from U.S. municipal and other publicly-owned utilities in excess of other "costs" has a long and strong history as well. We have not studied the amounts, but suspect that while they would be proportionately lower than Canadian Crown Corporation arrangements, the payments nevertheless would be significant in providing governments with revenues to use for non-utility purposes.

In any event, we believe that the basis for such amounts depends less on constructing definitions, like regulated versus "unregulated," and more on their affordability as adders to utility rates, in lieu of other revenue forms. Viewed from that perspective, we have no opinion on margins or other amounts related to utility operations that any government chooses to secure.

G. Conclusions

1. Aligning Risk and Reward

Viewed either from broad Canadian or U.S. perspectives, the current utility regulatory framework in the Province is anomalous. Electric service remains vertically integrated and lacks material competition at the wholesale generation and retail levels. It therefore creates a division between cost responsibility for LCP investment and operating costs (which fall on customers) and off-system benefits (which flow to ownership) respecting the very same assets. Having cost risk and profit opportunity reside with the same entity (an unregulated one) is a central element in a restructured industry; the same is true in a vertically integrated one (customers representing that entity). It is separating responsibility for investment and operating risk from margin-producing opportunity that creates the anomaly. A number of Canadian jurisdictions that had originally put cost risk on customers and profit opportunity on Provincial ownership have since moved in the prevailing direction of unifying them.

We believe that such a reversal here would remove structurally conflicting factors from the planning of resources that play important roles in providing reliable service. As do most jurisdictions operating vertically-integrated, monopoly utility operations, we consider the utility regulatory authority best positioned to judge how best to optimize costs and reliability in a joint process. It has a defined role and has the objectivity and expertise to do so more effectively and objectively to meet both customer and provincial economic interests that are placed in conflict by the treatment of large margins from off-system sales.

2. Review of Ongoing LCP Capital and O&M Expenditures

The same is true for managing ongoing capital and O&M expenses and asset operation. Maximizing reliability can sacrifice economy, as maximizing economy can sacrifice reliability. From a customer perspective, both should be optimized together. Giving the Board authority to review and approve capital and operating cost plans, and the reasonableness and prudence used in executing them, will most effectively optimize both reliability and operations.

We recognize the dependence of the LCP on the PPA and the TFA, which impose stringent requirements and limits on revenue-affecting matters. However, someone must have ultimate responsibility for overseeing the plans, budgets, and performance metrics designed to meet those intersecting requirements, limits, and other legitimate expectations (like reliability and economy for Hydro and its customers). We do not see barriers to investing the Board with that oversight role, including consideration of what the PPA and TFA require, with respect to management's plans and actions. Such a role will not deprive management of responsibility for planning and execution. It will only subject it to Board oversight consistent with reliability and cost protections for provincial customers, while remaining mindful of the need for the assets to operate in a way that will meet PPA and TFA requirements.

There is no longer an opportunity for a forward-looking review of commitment to, planning and design of, or construction management of LCP. Those activities have already occurred, and under a financial structure (as Chapter II details) that leaves no realistic "disallowance" option. Perhaps responsibility can be transferred from the residents, businesses, and institutions of the Province as "Customers" to that same general group as "Citizens." With the end result being that roughly the same subjects will pay the same amounts (perhaps divided differently), it is difficult to plot a course through a financing structure that will not, at least, add very large transaction, if not litigation, costs to an already heavy burden.

We thus have limited our examination to a forward-looking change in Board authority to review LCP ongoing capital and operating costs. Moreover, we have done so recognizing that residing that authority with the Board will take a clear change in established Government direction, making the question a policy decision for resolution at that level.

Making off-system margins, as they nearly universally are elsewhere, an offset to customer costs for the assets that produce those margins, should not be viewed in isolation with respect to their impacts on provincial revenue sources. The Province will necessarily be examining the level of current and expected utility-related revenues it can afford to apply to meet extremely challenging rate issues. The range of options it has to secure revenues from Nalcor or Hydro continue to include many that do not pose risk to that objective.

H. The Location and Nature of Nalcor Energy Marketing

The preceding sections addressed fully the treatment of margins produced by NEM. We examined a number of other issues that concern how Nalcor has structured and organized NEM compared to others in the industry, including:

- Existence as a separate entity
- Location of the marketing function in the corporate structure
- Market and other risks raised by trading operations
- Alternatives to performing the role internally.

1. Existence as a Separate Entity and Location

Nalcor cites a number of reasons for housing in a separate corporate entity the functions that NEM performs and that Nalcor plans for it to perform. Tax considerations are among them. Other Canadian Crown corporations employ separate marketing entities as well. Whether a department within a corporation or a separate corporate entity is structured for marketing export sales does not in our view affect how and for whose benefit it operates. Other Canadian electric Crown corporations with separate entities, unlike NEM, consider the margins produced as an offset to utility revenue requirements. Nalcor does not do so with LCP margins.

With respect to location within an organization, we consider the overriding issue to be from whom the marketing entity takes direction. Direction from outside the utility, Hydro in this case, raises material concerns when the marketing entity uses assets whose costs are borne by utility customers. The principal reason is that incentives to optimize margins from off-system sales can produce diseconomies if the marketing entity has the ability to override utility decisions, about dispatch for example. Power Supply, with NEM as its operating authority, has more than that ability with respect to off-system sales; it does not need to override utility decisions, it makes those decisions itself. This is not only true for LCP assets. Nalcor proposes to give it control over all external transactions. Moreover, Nalcor proposes for NEM a central role in "optimizing" Hydro's assets as well. NEM has taken into its organization a water management and hydro production scheduling group formerly operating as part of Hydro's power production resources.

The functions of this former Hydro group are important to making the optimum use of water resources for generation. However, since the change, the resources, analysis, and information to do so reside with an organization whose mission focuses on optimization from the perspective of off-system transactions. When Hydro had the group and its functions, optimization, as we have discussed earlier in this chapter, considered joint optimization of reliability and all-in costs (*i.e.*, direct costs to customers after off-system sales).

2. The Risks of Operating a Marketing Organization

Nalcor has cited the risks that participation in markets would bring to utility operations as a reason for structuring NEM as a separate entity outside of Hydro. We agree that risks exist, but so do means exist for mitigating them. U.S. electric and gas utilities have been trading in active, volatile energy markets for decades, developing strategies to minimize risk. The industry and its regulators there would find more concern with a utility's failure to use markets than with its active participation in them. Regulators certainly interest themselves in ensuring that utilities avoid high risk marketing activities and that they undertake measures to mitigate even lower risk activities. Examples include utilities with provider of last resort ("POLR") responsibilities entering into electricity and natural gas, as appropriate, hedging arrangements to mitigate potential future price volatility in those commodities. Naturally, hedges can prove to be profitable or unprofitable but risk mitigation, under properly developed and administered protocols, is a common feature of many companies.

Nalcor's point would take on more significance if it were to employ a higher risk appetite than is typical of a utility seeking highly controlled measures to gain value from portions of its resource portfolio that it can make available to markets without risk to serving domestic load and firm commitments to those with whom it deals on a wholesale basis. In restructured and competitive markets those who take ownership risk are free to take higher risks or to mitigate them less fully. Doing so generally does not, however, happen with even large, sophisticated vertically-integrated utilities. We would find surprising a high NEM marketing and trading risk appetite, but certainly concede that, under present circumstances, the Province and not the Board could direct otherwise.

3. Alternatives to an Internally Provided Marketing and Trading Function

Risk appetite was an important consideration of Nalcor in establishing and structuring NEM. Management considered the scope and size of the portfolio that NEM might operate. Early on, portfolio options included a very large and complex one in which NEM would have responsibility not just for marketing LCP excess, but also more than 2,000 MW at Gull Island and oil and gas market activities as well. That option far exceeds the several hundred megawatts at Muskrat Falls, a comparatively small portfolio by industry standards. The much larger scope and complexity among the options then had clear implications for risk tolerance, as they did for means of providing the capability to manage marketing and trading activity.

With a planned split of the oil and gas business from Nalcor and with no clear commitment to Gull Island on the horizon, a due regard for operational efficiency would appear to rule out NEM being organized to suit a large sized portfolio. While the potential exists for a significant future expansion involving Churchill Falls or the Lower Churchill, that possibility remains in the future. In the meantime, what remains available to market from Churchill Falls does not add enough to the Muskrat Falls excess to make NEM more than a fairly small market participant.

In fact, when considering a trading operation sized on the basis of Muskrat Falls, management should have considered a contracted solution to providing it. Primary difficulties in building a strong internal operation to manage a small portfolio of tradeable assets include acquiring a suitable group of highly capable resources, creating and operating the systems and controls to manage operations and risks effectively, and developing a reputation that encourages counterparty confidence and trust. Retaining an "asset manager" (what Nalcor termed an "agency") relationship has, as we believe management recognized, increasing merit as the size of the portfolio involved becomes smaller. And, returning to the question of risk, a small portfolio also tends to lead as well to the adoption of reasonably low risk tolerance; *i.e.,* limiting transaction types to low risk, highly hedged alternatives.

4. Nalcor Energy Marketing Conclusions

a. Board Oversight

We do not question the reasons for structuring NEM as a separate corporate entity. We do not, however, believe that the use of a subsidiary (a distinct corporate entity) has bearing on the source from which it should take direction or to where the margins it produces should flow. We believe that direction should come from Hydro in order to ensure that net customer costs (as opposed to marketing and trading margins) get optimized. Consistency with prevailing practice would subject its operations to the same forms of Board oversight that exists for other operations whose costs form part of Hydro's regulatory requirements. Providing that direction from Hydro also leaves control of important operating activities (like those of the water management and hydro production scheduling group moved to NEM) with the party responsible for generation operations.

Similarly, typical practice would make the reasonableness and prudence of its operations subject to Board review. Specifically, key facets of such operations warranting Board review include its structure and operating costs, the nature and extent of the transactions in which it engages, the controls it applies to ensure integrity in transacting, and the measures it takes to mitigate transaction risk. Board oversight of NEM would generate the regulatory oversight that has proven very valuable in ensuring the establishment of best operating practices:

- Definition of available transaction types consistent with a clearly established level of "risk appetite" appropriate for utility operations
- Credit limits intended to mitigate counterparty risk
- Organizations, systems, and controls to ensure transaction integrity, and where required, accounting to the proper entities.

Certainly, NEM will employ such measures, wherever located, or to whomever accountable. However, adding Board regulatory oversight will bring a benefit we have seen effective in dozens of instances in our work - - assurance of exposure to a broader set of best practices, and objective evaluation of sufficiency vis-à-vis utility customer interests.

b. An Internal versus External Marketing Function

Absent: (a) a determination that the potential rewards of a higher-risk range of transactions are in the Province's interests or (b) the inclusion of Gull Island in reasonably near-term plans for the Province's energy future, the energy marketing organization planned should anticipate a small portfolio under its management. Given the lack of experience in operating a marketing and trading organization and the costs of doing so with a small portfolio, the use of a contracted function becomes a realistic option.

There certainly exist providers with much more extensive experience than NEM will be able to offer, pending a reasonably long development period during which mixed results would not be surprising. How attractive those providers will find this market remains to be seen. Certainly, we have no predisposition with respect to how competitive internal, at-cost operation may prove relative to fee-based compensation to an asset manager, whose performance will require monitoring.

However, the use of a market solicitation would provide a qualitative and quantitative means to identify whether there exist alternatives better designed to manage NEM operating costs, transaction risks, and, most significantly, the size of margins produced to offset Hydro revenue requirements. Absent outreach to the market, it will not be possible to determine whether those with very substantial North American market experience (particularly in the continent's northeastern region) will find the Province sufficiently economically attractive.

Outreach efforts need to do more than create the impression that the expected result extends no further than developing cost-comparative information, while continuing to be wedded to an internally-provided option. Should sincere and concerted outreach efforts demonstrate that there is substantial interest among highly experienced market participants, Hydro may find greater levels of market experience, better operating costs, and larger margins available as compared with those of a new NEM operation operating on what appears likely to remain a comparatively small scale.

If outreach produces substantial interest, a formal, competitive market solicitation will provide a sound comparison basis for determining whether NEM offers the best alternative, experience, cost, and results combined.

Another potential advantage of the contracted model is the access it can offer to expertise that can support transition to an internal option if and as a tradeable portfolio builds.

IV. Hydro and Newfoundland Power Combination

A. Chapter Summary

This chapter addresses opportunities to reduce revenue requirements (without sacrificing customer service or reliability) through potential combinations among Hydro and Newfoundland Power in the performance of a number of areas:

- Transfer of Distribution and Customer Service for all Hydro Retail Customers to Newfoundland Power
- Transfer of Hydro's 66/138 kV Island Transmission Operations to Newfoundland Power
- Combine Island Small Hydro Generating Stations under either Hydro or Newfoundland Power
- Combine certain Hydro, Nalcor Power Supply, and Newfoundland Power Contracting and Procurement.

We had considered a transfer of Hydro's 230kV and Power Supply's HVdc transmission facilities as well. We eliminated it as an option to pursue because of the integral role of these facilities in providing reliable power supply across the Province and in the interconnection to the North American grid and Newfoundland Power's lack of experience in operating the higher voltage facilities.

We worked separately with Hydro and with Newfoundland Power to identify, categorize, and rationalize (*i.e.*, group in a way that permitted meaningful comparison) the resource changes that could occur on transfers. We sought to secure a sound, quantitative basis for determining the resources that the transferring entity would no longer need, and for determining the incremental resources the acquiring entity would need to meet the requirements added. After establishing that background, we conducted a series of common work sessions that engaged both Hydro and Newfoundland Power management. Those sessions addressed assumptions behind their staffing numbers and they allowed each to critique the data and analysis of the other, and to adjust their own numbers as means for making "apples-to-apples" comparisons became more clear.

We began Phase 2 with an open mind about the options of transferring both ownership and operation of assets or merely operating responsibility for assets without ownership transfer. When we analyzed the details, it turned out that transferring assets to Newfoundland Power would produce higher revenue requirements than Hydro's. It might seem that this conclusion suggests economy in transfers in the other direction. However, the multiples typical in investor-owned-utility acquisitions and asset transfers would, if applied here, also have a negative customer effect.

We discuss below each of the Hydro/Newfoundland Power combination possibilities we examined. One generally common theme surrounded the assumptions each had to make about future capital requirements for facilities whose operations they would acquire. Neither they nor we had the time to undertake an analysis of what physical changes to assets and their attendant costs would be required to permit them to operate new facilities in the manner and with the resource levels they applied already to their own network and systems.

The analysis of resource requirements, with some exceptions, assumed that resource needs for the types and quantities of networks, systems, and facilities to be operated after transfer could be based on an assumption that currently applicable needs and activities would suffice. Thus, the goal became, in effect, to determine whether we could identify large enough resource reductions to warrant the due diligence it would take to ensure that capital costs arising on transfer would not rise to a level that significantly threatened the potential resource reductions identified.

It has turned out that the savings identified, with one exception, do not justify the effort involved in undertaking the detailed analysis that would be required to determine these transition costs. Excluding that exception (common contracting) we identified savings of about $7 million annually, should Newfoundland Power assume operating responsibility for certain Hydro assets, broken down as follows:

- Transfer of all Distribution Operations to Newfoundland Power - - $2 to 2.5 million
- Transfer of Customer Service Operations to Newfoundland Power - - $1.5 million
- Transfer of 66/138 kV Transmission Operations to Newfoundland Power - - $1 million
- Transfer of Small Hydro Station Operations to Newfoundland Power - - $2.5 million.

This $7 million in potential savings will likely comprise something on the order of one-half of 1 percent of Hydro's revenue requirements following LCP operation. Moreover, we believe it is reasonable to expect Hydro to be able to produce savings in the range of at least $2 million, should its management diligently pursue operational savings.

There are significant barriers and execution risks to the achievement of the $7 million potential savings. These potential savings levels do not warrant the substantial effort it would take to address these risks. The execution risks and barriers include determining the revenue requirements effects of capital costs to implement the full transfer, reconciling labour agreements that produce different personnel costs and conditions of employment, integrating different corporate cultures, implementing a human resources transition plan, and compensating Newfoundland Power for providing operations services.

We did, however, find one area of common pursuit that may prove productive. A very modest 3.5 percent savings in categories where Hydro and Newfoundland Power both spend large sums could reduce total revenue requirements (the two entities combined) by $5 million. While significant barriers exist to implementing this option, we do recommend that it be further analyzed with the assistance of an independent party.

Despite the inability to find much in the way of combination savings, our work did, particularly late in Phase 2, disclose a number of instances where it may be possible for Hydro to operate more efficiently internally. We think that a comprehensive, structured, candid, and timely examination along those lines has significantly greater potential for producing revenue requirements reductions. Similarly, with Hydro and Newfoundland Power expecting to spend about $0.5 billion dollars on capital in the 2020 – 2024 period, it should be noted that only moderate reductions in those amounts will produce revenue requirements reductions equal to or greater than savings coming from combinations between the two companies.

B. The Cost of Asset Transfers

This chapter considers possible changes in responsibility for parts of the network and functions that Hydro and Newfoundland Power now combine to provide for most Island customers. Those changes raised the possibility of asset transfers. To the extent that a change in responsibility between Hydro and Newfoundland Power involves asset ownership transfer, it became relevant to examine how such transfer would add to or detract from Hydro's revenue requirements.

Such an analysis involves at least two major components:

- The difference in annual carrying costs for investments of the two entities
- Premiums or transfer costs that may be required to induce and effectuate asset transfers.

We began by addressing the first component. As we describe below, the clear answers it produced obviated the need for addressing the second.

We examined asset ownership differences between the two companies, focusing on a comparison of investment-related capital costs included in revenue requirements for customer rate setting. The principal areas that differ between Hydro and Newfoundland Power are factors like: (a) equity/debt ratio in their capital structures, (b) Newfoundland Power's 30 percent income tax obligation, and (c) embedded debt costs. Hydro enjoys a cost advantage in each of these three areas.

Figure IV.1 shows the results of our comparative analysis. It used the equity share of capital structure that each targets - - 25 percent for Hydro and 45 percent for Newfoundland Power - - and the debt cost components used in calculating Hydro and Newfoundland Power customer revenue requirements.[43] Hydro holds an approximately three percent baseline advantage for customers on distribution and transmission assets. Should Hydro dividends be employed for revenue requirements mitigation, that advantage grows to five percent. Moreover, as Chapter II has described, reductions in Hydro returns and changes in its capital structure could create significant revenue requirements mitigation opportunities that would increase Hydro's advantage.

Applying the resulting differential to the $313 million in distribution assets on Hydro's books at the end of 2018[44] would imply a customer penalty of $10 to $15 million dollars per year for assets transferred to Newfoundland Power, assuming no transfer costs or acquisition premium. Both are typical and often substantial in industry asset and business transfers. To achieve cost savings by transferring assets, Newfoundland Power would, therefore, have to produce savings in excess of these costs.

Figure IV.1: Revenue Requirement Cost of Capital Analysis

	Newfoundland and Labrador Hydro			Newfoundland Power		
	Capital Structure	**Cost of Capital**	**Weighted Average Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Weighted Average Cost of Capital**
Debt	72.18%	4.96%	3.58%	54.28%	5.84%	3.17%
Benefit and Retirement	3.76%	0.00%	0.00%	0.76%	6.19%	0.05%
Common Equity	24.06%	8.50%	2.05%	44.96%	8.50%	3.82%
	100.00%			100.00%	With Inc. Tax Factor @ 30%	5.46%
NL Hydro Revenue Requirement Cost of Capital			5.63%	**NP Revenue Requirement Cost of Capital**		8.68%
			3.06% Hydro Advantage			
Hydro Dividend Contribution						
Hydro Factor w/dividends for Rate Mitigation			**5.10% Hydro Advantage**			

C. Transfer of Retail and 66/138 kV Operations to Newfoundland Power

1. Background

We examined the transfer of responsibility for Hydro's current distribution operations and its Island 66 kV and 138 kV transmission systems to Newfoundland Power. This transfer of operating responsibility would change Hydro's management and operations focus to generation and 230 kV and HVdc transmission lines, and terminal and conversion stations. Hydro currently serves predominantly at wholesale, with the Island's distribution utility, Newfoundland Power, its largest customer by far. Newfoundland Power serves at retail the vast majority of retail customers on the Island, but Hydro does directly serve about 40,000 customers at retail, through distribution systems dispersed across the rural and isolated areas of Newfoundland and Labrador. Hydro serves some of its retail customers from the Island Interconnected System ("IIS"), but also serves 21 remote communities using small diesel generator plants and associated local distribution systems. All of Newfoundland Power's energy supply, save for the output of 23 very small hydro stations contributing less than 100 MW of capacity, comes from Hydro across the IIS.

2. Concepts and Assumptions Underlying our Analysis of Potential Reductions

We began Phase 2 with the intention of examining separately the transfer of Hydro's: (a) distribution system and retail customer service responsibilities, (b) 66/138 kV transmission, and (c) higher voltage transmission, including HVdc facilities. The major components of these three areas comprise:

- Hydro's Island interconnected distribution system
- Hydro's Labrador interconnected distribution system
- Hydro's isolated diesel distribution systems on the Island and in Labrador
- Hydro's radial transmission system that serves Newfoundland Power
- Hydro's Island 66 kV and 138 kV lines and terminal stations
- Hydro's entire Island transmission system.

We eliminated the higher voltage transmission and HVdc facilities because of the integral role in executing Hydro's mission and its accountability, and responsibility for power supply across the Province and its interconnection to the North American grid. We considered them and Hydro's large supply sources as central elements in carrying out Hydro's roles. Moreover, we did not find at Newfoundland Power the same degree of comfort or experience in operating the higher voltage facilities. In particular, we have significant concern about promoting stability while LCP completion work remains, and thereafter, for a temporary, short, but hard-to-define period of LIL phase-in and stabilization following completion.

Newfoundland Power expressed strong interest, however, in securing operational control of the lower-voltage, radial transmission facilities that serve its current retail customers and which would serve those added, if it becomes responsible for serving Hydro's retail customers. Doing so would encompass almost all Island 66 and 138 kV transmission facilities. We decided to proceed in Phase 2 by combining the second two transfer possibilities from Phase 1 - - distribution/retail and 66/138kV Island facilities. We did so because a transfer of transmission facility operation, in the absence of a distribution/retail transfer, did not appear likely to produce significant savings.

We began Phase 2 with an expectation that savings would prove substantial with the transfer of distribution/retail and 66/138 kV Island transmission operating responsibility. In the first place, it would enable combination of central office customer service systems and resources (*e.g.*, customer contact, billing, and collections). It would also align with Newfoundland Power's core strengths, and eliminate what, for Hydro, is a reasonably small part of its operations. Particularly when combining distribution and transmission networks, it would also present what we viewed at the time as a significant possibility for consolidating the employee and contractor resources who support those networks in the field. In short it appeared likely that Newfoundland Power could make more additions to field, engineering, support, and customer service work load marginal enough to secure significant savings when compared with the resources that Hydro dedicates to such functions.

The interconnected Hydro and Newfoundland Power distribution systems operate very differently (and are staffed differently) from the isolated diesel systems that Hydro serves. We also considered the implications of transferring the Labrador interconnected system to Newfoundland Power. These differences caused us to examine whether they would prove material in Newfoundland Power's assumption of responsibility for those systems, given that all of its provincial residential customers are supplied at wholesale by Hydro.

3. *Analysis*

Liberty examined Hydro[45] and Newfoundland Power[46] organization charts, operating locations, and operating territory maps. We compared job descriptions, functions, roles and responsibilities, and conducted interviews with engineering, operations and management personnel to identify likely redundant positions which would result from a transfer of operating responsibilities. We compared current Hydro Full Time Equivalent personnel ("FTE") counts with the equivalent FTE requirements generated by Newfoundland Power's distribution and transmission staffing models. We noted differences and we attempted to rationalize them. Our focus fell on Hydro resources that would appear no longer necessary after combination.

We found the comparison of Hydro's with Newfoundland Power's FTEs challenging, given differences in the capabilities of the networks they operate, the procedures under which they operate them, and terminology. We found nearly all distribution and transmission work functions performed by the companies were very similar, if not identical. However, the two entities organized those functions differently. Those differences produced more than locational distinctions for people having essentially comparable skills and responsibilities. We found skills and responsibilities often clustered in different working groups in the two companies.

We also worked with the two utilities to define lines of demarcation between the distribution feeders and the terminal stations serving distribution, and between the 230 kV system and its terminal station equipment and the 66 kV and 138 kV systems.

We believe that we have been able, with the cooperation of Hydro and Newfoundland Power, to resolve differences sufficiently to develop a model that allows us to account for and to compare all FTEs under meaningful classifications.

We have defined distribution/retail transfer to include Hydro's isolated Island diesel system customers and its Labrador customers (isolated or served from the network). Leaving them with Hydro after transfer of its Island Interconnected System customers would leave Hydro with too small a retail business either to be efficient or to ensure continuing focus on a much smaller group of customers. Moreover, retention of those customers would also require maintenance of central-office customer-service operations and costs that a full transfer to Newfoundland Power would avoid. Our analysis agreed with the views of Newfoundland Power that its unfamiliarity with the isolated diesel and Labrador customers would preclude any ability to identify resource reductions should Newfoundland Power become responsible for them. Moreover, we believe that a conservative approach to transfer of Labrador systems should be taken while the new operator learns enough about local conditions, systems, customers, and expectations. We decided that, should we find merit in the transfer at issue here, that a "stay calm" period of several years should precede any material actions to change costs for Labrador distribution/retail operations.

Working with Hydro and Newfoundland Power, we evaluated the current staffing levels of each, and discussed and tested them, in anticipation of a joint meeting between the two. We requested that each review classifications and personnel counts following that meeting and using a common structure for classifying them. We found Hydro's response, which refined its earlier numbers and classifications, complete and useful and we consider it as accurate as possible for assessing resources changes following a transfer of distribution/retail and 66/138kV operating responsibility.

Hydro's frequent use of fractional (10 percent to 90 percent) FTE counts to describe personnel with cross functional responsibilities did, however, complicate direct comparison. We understand fractionalization as a necessary consequence of assigning employees or groups of employees to any system of categorizing resources required by groups that make common use of some employees. However, we ultimately had to realize that, upon transfer of responsibilities, whole persons are moved or their positions eliminated.

As noted, Newfoundland Power also used the common FTE staffing model developed after the joint meeting. The Company needed to make assumptions about Hydro's network when examining how many incremental resources it would require for the operation of distribution/retail and transmission networks and systems. Newfoundland Power used the ratios that drive staffing for its network, thus effectively assuming that it would be operating Hydro facilities conformed to Newfoundland Power's network capabilities, configuration, and operating requirements. Understandably, this approach produces a substantial unknown - - how much cost and how long it would take to reach the "steady state" that would support operations based on typical Newfoundland Power's ratios.

For Hydro's IIS and Island's 66 kV and 138 kV lines, Newfoundland Power used a combination of its current ratios of line kilometers per FTE or customers served per FTE for extrapolating the incremental increase in line personnel. It then applied to them the ratio it uses between such employees and the required support personnel (such as supervisors, technology, engineering, and other). Recognizing the relatively more rural nature of the areas Hydro serves at retail on the IIS, Newfoundland Power used ratios taken from its low-density, remote Western region. Applying a combination of line kilometers per FTE and customers per FTE, Newfoundland Power calculated that it would need to add from 16 to 27 additional line personnel, settling on a final number of 24 FTEs. Our review found that projection reasonable for "steady state" operation of a network configured like that of Newfoundland Power's current system. We believe that adding between 24 and 27 FTEs would be appropriate.

Moving from distribution/retail to 66/138kV transmission line operation, Newfoundland Power estimated its anticipated FTE increment using the same kilometers per powerline technician. For operating and maintaining Hydro's 66 kV and 138 kV terminal station equipment, Newfoundland Power used a "weighted quantities" comparison method. It determined increased Electrical Maintenance FTEs by developing a table[47] that used "weighting factors." This method assigned labour hours required to maintain Newfoundland Power and Hydro 66kV and 138 kV substations and each of their major devices (*e.g.*, transformer, circuit breaker, recloser, and regulator). Adding the entries produced total expected operations and maintenance working hours for combined Hydro terminal stations and Newfoundland Power substations following transfer. Newfoundland Power then calculated the resulting, post-transfer estimate of Electrical Maintenance FTE's. We found this method appropriate.

Hydro's current Island isolated diesel system and Labrador interconnected and isolated diesel system requirements were then added without adjustment.

4. *Results*

Our analysis showed potential reduction (net of customer service, which we discuss separately below) of 9 to 12 FTEs. Savings associated with these reductions would be from $2 million to $2.5 million. Smaller reductions of 5 FTEs on transfer of Hydro's Island 66 kV and 138 kV transmission system could add another $1 million.

Significant barriers and transition requirements exist for this potential transfer to Newfoundland Power. For example, bargaining agreement and ancillary labour differences will require reconciliation, and may change the magnitude of savings achievable. Rationalization of work rules and necessary retraining to accommodate them and integration of different corporate cultures will also be required.

Moreover, Newfoundland Power provided its FTE data on the assumption that the Hydro network and systems are comparable to its own present ones. We understand the need to do so, given the lack of time during this study to undertake more detailed examination of networks and systems. The information available indicates that capital spending, perhaps significant, will be required to produce the "steady state" network and systems on which Newfoundland Power's estimates depend. Likely examples include Supervisory Control and Data Acquisition ("SCADA") and Geographic Information System ("GIS") upgrades.

If there is not an asset ownership transfer to Newfoundland Power, this transfer will require an operating agreement that leaves Hydro with control over planning and budgeting, while Newfoundland Power assumes operation, including submission of plans and budgets for Hydro's review as the owner. Implementation of such an agreement here entails significant risk. First, such agreements come with compensation, which would diminish savings. Second, a long-term "partnering" such as that at issue here requires mutually cooperative relationships and attitudes. Given the unfamiliarity with these types of operating agreements in this jurisdiction and the historical background of both utilities, execution risks make questionable the ability to achieve material savings.

D. Customer Service Operations

1. Background

Our examination of a transfer of distribution/retail operations from Hydro to Newfoundland Power addressed potential synergies from combining the customer service organizations. Combining customer service operations has the potential for both reducing costs through economies of scale and possibly improving service levels. We examined the following customer service functions:

- Call Center customer inquiry and support
- Meter Data Collection and Meter Reading
- Field Services and Collections
- Meter Testing and Meter Services
- Customer Billing – bill preparation, printing and mailing
- Customer Payment Processing
- Key Accounts billing and support
- Energy Efficiency Programs.

The following table presents Hydro's customers by class and region:[48]

Table IV.2: Hydro Distribution Customers

Region	Domestic	General Service	Total	% of Total
Interconnected Island	19,852	3,094	22,946	59%
Interconnected Labrador	9,838	1,427	11,265	29%
Isolated Island	684	105	789	2%
Isolated Labrador	2,918	755	3,673	10%
Total	**33,292**	**5,381**	**38,673**	

Hydro has centralized elements of its current organization. Hydro no longer offers walk-in service to customers, Hydro's call center in St. John's supports all customers regardless of their locations. Customer billing, including meter data collection, also operates from a centralized St. John's location. Hydro has, however, decentralized field and meter-related services. A large portion of customers served by Newfoundland Power reside on the Avalon Peninsula. Customers in Labrador and Isolated customers require a similar level of support were Hydro or Newfoundland Power serving them.

Hydro reads about 30 percent of its meters through advanced or automated metering technologies. Newfoundland Power has also deployed automated metering technology in almost all its meters. However, the companies do not use a common technology. Newfoundland Power would need to assume operation of Hydro's meter data collection technologies until it could standardize on its approach. Moreover, additional automation could be deployed to enable automated reading of Hydro's remaining manually-read meters.

Hydro completed deployment of a new Customer Information System in 2018. Supplemental resources were needed to support deployment and system stabilization however management expects these temporary resources will no longer be needed through the end of 2019. Newfoundland Power recently launched planning to replace its aging customer service system, anticipating presentation of a business case in 2020 for Board approval, with system implementation planned for 2022.

2. Concepts and Methods

To evaluate potential synergies and savings, we evaluated current state resource requirements, requested future state needs, and identified transition costs, risks, and considerations. We:

- Reviewed organizations, resources, and activities in discussions with both entities
- Requested data and reports to help us understand the current state resources and costs
- Discussed operational and systems similarities, supporting technologies, and customer service options and programs
- Defined scenario evaluation criteria
- Analyzed resource requirements of a combined operation
- Identified avoidable O&M costs (equipment and outside services)
- Facilitated joint discussions with Customer Service management from both utilities to understand current and projected resource levels, considerations, and risks.

3. Results

Economies of scale and other synergies can be realized through consolidation of Hydro's and Newfoundland Power's customer service operations. Largely consisting of resource reductions, the transfer can also produce marginal savings in avoidable non-labour O&M costs.

Our analysis evaluated future steady-state staffing levels from both companies,[49] following joint-party discussions, and in consideration of industry experience and best practices. Consolidation of customer service operations would reduce required resources by 12 to 14 FTEs, which would produce savings of $1.5 million at steady state. The consolidated operation would use a consolidated workforce for IIS-served customers, and maintain a consistent level of resources to serve Island isolated and Labrador interconnected and isolated customers. The meter shop would remain at current staffing. We assumed that transmission-voltage retail customers would be served by the entity operating transmission, which we believe would best remain with Hydro. Customer billing and support for Hydro's transmission-voltage customers is accomplished using MV90 meter data collection technology and a separate billing solution (MV-PBS), making it easy to separate these customers from all other retail customers who are billed by the Utility 360 CIS.

We expect that additional FTE savings could be achieved in future years through full deployment of Automated Metering technologies and higher customer utilization of digital customer service "self-service" options. With approximately 70 percent of Hydro's meters read manually, further automation can reduce the level of manual effort required to gather meter readings for billing. Additionally, the utility industry is trending towards higher levels of customer self-service through robust websites, mobile or phone-based apps thereby reducing the volume of representative-assisted customer contacts. Encouraging customer adoption of these options would reduce customer call volumes in the future and possibly FTEs.

Combining customer service operations would eliminate duplicate technologies and services supporting the Call Center, vendors providing after-hours answering services, third-party credit card processing, website account management features, and other equipment supporting customer billing and customer payment processing. Additional savings may also be achieved through the elimination of dedicated vehicles, workstations, and work reporting locations of redundant Customer Service personnel.

Some Hydro Customer Service technologies and systems[50] would be redundant upon the transfer, resulting in annual savings in future O&M costs:

- Utility 360 CIS
- IT or vendor resources supporting Utility 360, annual maintenance costs
- JD Edwards Work Order System (field services, collections)
- CISCO IVR & Telephony
- Telelink after-hours answering service
- Website (myNLhydro) supporting self-service and ebills (Smart Utility Systems)
- Third-party Credit Card processing
- Touch Logic Transactional Customer Satisfaction Measurement
- MQO Annual Customer Satisfaction Measurement
- Outside Collection Agency
- Dedicated work reporting locations for field personnel (Building Rental & Maintenance)
- Dedicated vehicles of other redundant Customer Service personnel
- Dedicated workstations of redundant Customer Service personnel
- Bill printing, stuffing and mailing equipment
- Envelope openers, remittance processing equipment

With 2018 Utility 360 CIS implementation, its costs and others incurred during the implementation of Hydro's automated and advanced metering technology would become stranded.

Successfully transitioning customers to Newfoundland Power would require significant effort to transfer and merge customer billing data. Newfoundland Power's CIS would first require modification to support Hydro's tariffs and rate structures. Getting to a "steady state" will involve transferring customer data, designing and incorporating Hydro's rate structure, and customer service representative and billing group training to enable billing and support customer inquiry.

Significant internal and external communications will be required to ensure a successful transition. Customers must be informed of the change as the monthly bill format will likely change as will their customer account number and web log-in. All customer communications channels will need to support the transition, including changes to the websites to direct Hydro web visitors to Newfoundland Power's customer portal and social media channels such as Facebook and Twitter. Published customer service contact phone numbers, including the toll-free 800 number will need to be redirected to Newfoundland Power's call center. A communications plan incorporating all these needs would be necessary.

The timing of Newfoundland Power's CIS replacement project provides both opportunity and risk as a Customer Service consolidation of the Companies would require Newfoundland Power's CIS to support Hydro's rates and billing practices. If the transition takes place following the implementation of its new CIS, Newfoundland Power will be required to operate dual CIS systems to support Hydro customers until rates can be designed into the new system. This would likely delay a CIS consolidation effort until after the new billing system is stable, sometime in 2023. Otherwise, Hydro's rate structures must be designed into the new CIS concurrently with Newfoundland Power's requirements. At a minimum, dual CIS operation will be required through 2022, requiring customer service representatives to be knowledgeable on both systems until the new system is deployed.

The transition would not be without risk, perhaps the biggest one arising from the need to harmonize CIS customer data. The transition timing issues described above detail a lengthy process. With any CIS transition there is the potential to disrupt or delay customer billing and customer inquiry for a number of months preceding and following the cutover. While it would be ideal if customers do not experience any impact, this is rarely the case. Significant planning and communications will be needed to ensure a smooth transition. If Hydro's system is not incorporated during Newfoundland Power's planned CIS transition, then two efforts will be required, both with risk.

Another technical challenge lies in homogenizing automated metering technologies between the companies. Newfoundland Power has fully deployed automated metering technology ("AMR") in which meter readings are gathered by a drive-by solution. Hydro has implemented several versions of automated or advanced meter reading technologies, with roughly 30 percent of meters read automatically. However, no common vendor serves both companies. The systems that support Hydro's automated meter reading would transition to Newfoundland Power and be incorporated into the daily meter data collection schedule. Additional training of Newfoundland Power metering personnel will be required to support the daily collection and ongoing support of these systems. At some point in the future Newfoundland Power may choose to replace Hydro's meter reading technologies with its current vendor solution and continue deployment on the remaining 70 percent of Hydro's meters that are not automated.

Significant potential FTE savings might occur from a combination of Hydro retail operations with those of Newfoundland Power, but the risks associated with the harmonization of systems and technology and associated transition costs are considerable. In addition, it does not make sense to consolidate Customer Service operations without also consolidating Distribution Operations.

Therefore, the risks and costs of consolidation for both functions must be weighed together against any FTE and O&M savings.

E. Combining Island Small Hydro Operations Under One Entity

1. Background

Hydro and Newfoundland operate hydroelectric generating facilities on the Island. Individual station sizes vary widely, as does their total capacity, with Hydro's dominant. Hydro's Island hydro generating stations range in size from the 0.4 to 613 MW in capacity, combining to give Hydro an Island hydroelectric capacity of 973 MW:[51]

- Bay d'Espoir: 613 MW
- Hinds Lake: 75 MW
- Paradise River: 8 MW
- Cat Arm: 134 MW
- Granite Canal: 40 MW
- Snooks Arm: 0.6 MW
- Venam's Bight: 0.4 MW
- Upper Salmon: 84 MW
- Star Lake: 18.4 MW
- Roddickton: 0.4 MW

Hydro's resources also include a related group of units ("Exploits"), that it does not own, but has since 2008 managed and operated on behalf of Province. These units, consisting of two designated groups, are related because they all operate in the Exploits river watershed. The two groups comprising Exploits, which bring Hydro's Island hydroelectric capacity to over 1,000 MW are:

- Six Grand Falls units of between 4 and 30 MW each, totaling 75 MW
- Nine Bishop Falls units of between 1 and 3 MW, totaling 22 MW.

A small unit at Buchans has not operated for a number of years and no plans exist to restart it.

Newfoundland Power operates 23 Island hydro stations, ranging in size from 0.3 MWs to 14.8 MW, and combining to produce total hydro capacity of 98 MW.[52]

Many of these stations make use of multiple turbine units, making individual units, at Exploits for example, sometimes quite small. Hydroelectric generation generally, and smaller units in particular, generate a reasonably common set of operating requirements, but differences in size or number of units can still have an impact on optimizing long-term operation. Other circumstances that can affect station operating needs include operation in a common watershed as is the case for Exploits, run-of-river or reservoir water supply, unique maintenance requirements or unique equipment for older units, environmental limits and requirements, wildlife considerations (*e.g.*, fish ladders), and control systems (*e.g.*, automated or manually operated), to name some.

We examined here, as we did in examining the distribution system potential transfers, whether a potential existed for significant synergies arising from assigning total or partial responsibility for operating or supporting Island small hydro generating stations, whether under Hydro or Newfoundland Power. The model for such combinations arises in what are accepted operating agreements in the industry. These arrangements bring together willing owners and expert, cooperative contractors. The logical "package" of responsibilities to transfer here under such a model include operations and asset management. The expert operator would propose short- and long-term operations, and capital and operations and maintenance plans for owner review and approval. The operator would then have responsibility for executing approved plans and for operating to established budgets and performance metrics.

We envisioned, should such a transfer option prove interesting, base and performance-based compensation to the operator sufficient to recover costs and risks of providing the contracted services encompassing these roles. Thus, any direct reductions in costs would be offset by the fees required to make the arrangement compensatory to the operating entity.

The industry provides substantial examples of use of the operating agreement model. PSEG-LI and the Long Island Power Authority ("LIPA") Operations Services agreement, Puget Sound Energy and Quanta Services, and numerous third parties that operate and maintain merchant power plants for non-strategic owners - - financial interests typically. A critique that Hydro has offered of the LIPA arrangement in our view, misapprehends its origins, the views of those who participate in it, and our own observations from direct experience.[53]

2. *Bounding the Stations Suitable for Change in Operating Responsibility*

We decided early in our examination not to consider options that would transfer operation of the largest stations to Newfoundland Power.

Smaller units, such as those at Exploits, also have materiality to Hydro's reliability planning, but much less so. We found them characteristically similar enough to include within the group of small hydro stations being considered as part of the option of combining Island small hydro stations under a single operator. Key to our thinking was a determination that Newfoundland Power has demonstrated the capability to reliably and efficiently operate and manage smaller hydro facilities that include those of the size that typify the individual Exploits units. We therefore set about determining where to draw the limits on "small," deferring but not rejecting the potential for other issues (like materiality to future reliability planning).

3. *Concepts and Assumptions Underlying our Analysis of Potential Reductions*

a. <u>Defining "Small" Hydro</u>

There is no universally accepted or standard means for classifying hydro facilities as "small" for present purposes. We view turbine unit size, as distinguished from total plant or facility capability, considering all units as the preferred basis for classification. We began with a subjectively determined, but generally supported by our cumulative experience guideline of <50 MW, but solicited input from Hydro and Newfoundland Power, based on their experience, familiarity, and local knowledge. Hydro responded with a very narrow definition, including only its stations $\leq$1 MW. This classification identified only three units: Venam's Bight at 0.4 MW, Roddickton at 0.4 MW, and Snook's Arm at 0.6 MW.

Hydro applied as a criterion for its selection the exclusion of facilities "directly included in capacity assessments for operational as well as long term system planning purposes."[54] This criterion did not use size as a controlling parameter, rather whether Hydro's planners included a unit when assessing the future reliability of supply resources. Exploits lies among those that Hydro would eliminate from consideration here due to its inclusion in supply planning. The fifteen units there (Grand Falls and Bishop Falls) are as small in capacity as 1 MW, none exceeds 30 MW, and they average less than 7 MW.

Newfoundland Power offered a list that included the same three very small Hydro-identified units, as well as Paradise River (8 MW), Star Lake (18 MW), and the Exploits units (Grand Falls at 75 MW and Bishop Falls at 22 MW).[55] Both agreed on the inclusion for analysis purposes of all of Newfoundland Power's generally very much smaller units.

We determined to continue the analysis of potential savings using our <50 MW criterion. We determined that, should it indicate potential savings, we could then measure them against the concern Hydro raised about significance for supply planning.

b. <u>The Impacts of Capital Expenditures</u>

The information we received about staffing requirements now and following potential combination began with current asset configuration, quality, approaches, methods, controls, and other features of how each of Hydro and Newfoundland Power currently operate their facilities. In effect, the base assumptions were that facilities transferred for operational purposes would, as required, be brought to whatever enhanced state might be required to make resource forecasts based on current circumstances realistic.

Neither the two entities nor we had time to undertake the more detailed examination of plant conditions, configurations, controls, environments, or special operating circumstances that might affect resource requirements. We did not have reason to expect differences requiring action to be extreme, but the more marginal any reduction in resources after transfer the more those unknowns could "turn" net results from positive to negative. Therefore, we looked for big enough differences to warrant the more detailed review needed to make final estimates of net cost changes after transfer. We also did not consider differences in bargaining unit agreements, again deciding that they only would become relevant if the base analysis showed promising resource reductions.

4. Analysis

We looked at the details of the organizations, staffing approaches of both, reviewed current staff levels at the facilities, discussed expectations for future changes in them, examined key operational and asset management functions, considered whether certain assets might operate under unique conditions or requirements, and attempted as best we could to ascertain whether capital expenditures might be notably different under either entity. Overriding all cost considerations, we also looked for any reason to expect a change in the quality of operations or in unit availability and reliability following a transfer of operations and asset management responsibilities.

Newfoundland Power does not break down its small hydro staffing of 27 FTEs by facility.[56] It controls its plants remotely and supports each with common engineering, asset management and maintenance resources. Moreover, supervision for Newfoundland Power's 23 plants, although small in size, resides with a single individual, and certain functions, such as maintenance, may be performed by multi-skilled individuals.

Hydro's staffing for small hydro of 38 (37 FTEs at Exploits plus an estimated one FTE associated with Star Lake and Paradise River) has some distinguishing characteristics.[57] Chief among them is the location of staffing at units in our "small" hydro classification. Hydro locates a high level of supervision, management, planning and maintenance staffing at Exploits. Conversely, Hydro assigns no full-time FTEs to Venam's Bight or Snook's Arm; a contractor operates them for less than $35,000 per year. Hydro operates Roddickton at a cost generally less than $20,000 per year. Star Lake and Paradise River are remotely operated with a small staff complement. Therefore, the overriding issue under the "to" Newfoundland Power transfer becomes what might change at Exploits.

5. Results

To evaluate the differential in costs if either entity assumes operational roles at the other's "small" hydro assets, it is necessary to identify the increase in FTEs that would occur at the new "controlling" entity and offset those increased FTEs by a commensurate decrease in FTEs at the entity relinquishing control. We found essentially no net change in resources under a transfer of Newfoundland Power hydro assets to Hydro. Hydro estimated that it would likely need to increase its operational resources by 18 FTEs if it were to assume responsibility for Newfoundland Power's hydro generation.[58] Newfoundland Power, on the other hand, projects an approximate decrease of some 16 FTEs, not its current complement of 27 FTEs, should Hydro assume operational control of its hydro facilities.[59] The increase in Hydro resources versus the decrease in Newfoundland Power resources (18 FTEs vs. 16 FTEs) equates to essentially no net change.

Newfoundland Power attributes the difference of 11 FTEs between its current hydro staffing total of 27 FTEs, and what would be reduced by Hydro assuming operational control of its hydro assets, to the need for those remaining FTEs to provide support for its emergency standby and mobile generators.[60] They would need to remain following transfer of generation operations to Hydro. While we find unusual so large a common assignment of responsibilities, we did not find reason to question Newfoundland Power's count. Even if some small portion of the 11 proved excess after transfer, their number would not make a difference material enough to disrupt current operations.

Therefore, savings from a transfer to Hydro would have to come from operating with a workforce smaller in size than Newfoundland Power's current complement. Again, the Newfoundland Power numbers are simply too small to suggest Hydro could operate 23 units with appreciably fewer than 16 additional FTEs.

We observed materially different results for a transfer to Newfoundland Power, but for a striking reason. There is a potential for increasing Newfoundland Power's FTEs by approximately 20, while reducing Hydro's by 38, producing a net change of 18.[61] The circumstance we found striking is the large size of the potential reduction of resources at Exploits. We concluded that transfer to Newfoundland Power might produce a reduction at Exploits of between 15 and 20 FTEs. We assumed for purposes of analysis a reduction of 17 FTEs.

We concluded that pursuit of operational efficiencies by Hydro for Exploits operations can produce essentially the same savings as a transfer of operating responsibility to Newfoundland Power - - and without the substantial barriers and execution risk. We recommend that Hydro commit to the development and execution of a plan to achieve efficiencies in Exploits operation of $2.5 million annually, with a goal to execute the plan within three years, subject to the degree of personnel dislocation required.

Should Hydro not find itself prepared to move along these lines, transferring small hydro operations to Newfoundland Power will require a number of steps:

- The identification of capital expenditures associated with installing remote operational capability at Exploits, as appropriate
- Development of an operations services agreement between Hydro and Newfoundland Power detailing the responsibilities of the respective organizations including the creation of an appropriate fee structure, communication protocols, and dispute resolution process
- Modifying control systems, as needed.
- Training of Exploits personnel in Newfoundland Power's operation and maintenance procedures and protocols
- Rationalization of bargaining unit compensation, work rules, and other affected "bargained for" items.

Should Hydro not decide to plan and secure reductions at Exploits, we consider the production of savings through transfer to Newfoundland Power worthy of pursuit through the more detailed examination that such transfer would require.

F. Efficiency and Effectiveness Gains

Assessing what can be done in cooperation with Newfoundland Power has made it appear less attractive economically and subject to significant barriers. Some of those barriers are hard ones, like fair treatment of bargaining unit positions. Other are softer, like the degree to which company interrelations are cooperative.

Alternatively, securing internal efficiency gains appears to have greater likelihood of producing material reductions in revenue requirements. Through discussions we had with Hydro throughout Phase 2, particularly as our work in that phase approached completion, we found a willingness by Hydro to pursue internal operating efficiencies. A detailed look at Hydro's and Power Supply's internal efficiency and effectiveness lay outside our scope, but we nevertheless did see indications that a concerted examination by Power Supply and Hydro will discover efficiencies and areas for resource reduction.

We think there should be an objective look at ways to achieve operational efficiencies. That look should be formal and structured in examining candidly and across the board how effectively Hydro is doing what it does. Certainly, the barriers to what can be done internally, after eliminating artificial barriers, like regulated/"unregulated" after LCP operation has phased-in will be reduced. Board and stakeholder engagement, encouragement, transparency, and Hydro accountability will all prove key to achievement of real results. Some of the areas where we saw gaps relative to best practices include:

- Work scheduling and execution - - management processes and central management
- Measurement of performance using specific goals and targets and key performance indicators
- Optimizing contractor and employee use jointly, rather than treating contractors as an adder, after loading internal resources
- Analyzing contractor use for a greater range of support services.

Similarly, in terms of comparing combinations with Newfoundland Power as a cost-saving measure, we found interesting the nearly $500 million in T&D capital the two companies plan to spend in the period from 2020 through 2024:[62]

- Distribution ($295 million)
- Transmission ($75 million)
- Substations ($120 million).

Decreases in planned capital expenditures by Hydro and Newfoundland Power would not have to be that great to produce similar savings.

G. Common Contracting and Procurement

1. Summary

We sought to examine the individual and combined dollars spent by Hydro and by Newfoundland Power in procuring goods, materials, and services in categories that typically involve significant expenditures by electric utilities. We did so to support an examination of the potential for producing economies through joint procurement by the Province's two utilities.

2. Work Activities

We generated the following list of ten major spending categories:

- Vegetation Management contractors
- Wood Pole purchases
- Wood Pole installation contractors
- Transmission and Distribution Construction and Maintenance contractors
- Distribution Transformer purchases
- Substation/Terminal Station Power Transformer purchases
- (Transmission and Distribution) Electrical Supplies purchases
- Engineering Services contractors
- Generation/Hydro Maintenance and Modification contractors
- Transmission and Distribution conductor purchases.

Hydro and Newfoundland Power provided summaries of 2018 annual dollars spent by vendor, supplier or contractor for both materials and services.[63] Both also provided high-level listings of units and quantities purchased in 2018 for the materials categories among those just listed.

We began with a comparison of the vendors for the two companies in each category. We reasoned that already common suppliers would present the most direct means for using the leverage of combined purchasing levels to secure better pricing. However, we also recognized that high combined purchase volumes would create two forms of potential reductions as well:

- Encouraging non-common suppliers to provide more attractive terms to achieve significant volume increases
- Encouraging suppliers not now competing for the separate volumes of Hydro or Newfoundland Power, but who might find the regional market more attractive with combined volumes at stake.

As these observations suggest, material volume increases produced by consolidation drive opportunities for potentially significant price movement. Categories where either Hydro or Newfoundland Power would add only small volumes to those procured by the other do not, in our view, offer potential worth pursuit. Increasing the annual spend of one in a particular category by adding only a marginal spend by the utility would not likely drive significantly better combined pricing.

Our plan was to use such preliminary comparisons as a basis for discussing in more particular terms categories showing greatest promise. A lack of common interest in pursuing savings through combined procurement prevented that step.

3. Summary of Results

Our initial assessment showed five of the ten procurement categories with:

- Significant annual spends by both
- A significant number of common suppliers in areas such as Vegetation Management contractors, Wood Pole Installation contractors, T&D Construction and Maintenance contractors, Distribution Transformer purchases, and Electrical Supplies purchases.

We consider these five categories worth specific pursuit with both existing vendor and supplier communities and those who may find the efforts to pursue business on the Island more attractive under combined volumes.

The additional category of Generation/Hydro Maintenance and Modifications contractors proved interesting for another reason. Combined, Hydro and Newfoundland Power have spent more in this category than in any of the others, but have no suppliers in common. Our survey efforts highlighted it as a high priority area to examine in a search for economy by combination. We recognize that work in these areas often represent, in and of themselves, “one-off” projects individually planned, budgeted, and executed (with completion often across short durations).

However, whether, one-off or not, a strong baseload of related work that continues from year to year can produce longer-term arrangements with contractors in ways that justify pricing concessions. Hydro and Newfoundland Power already award contracts within similar maintenance and modification disciplines on projects with similar scopes on similar facilities. Other utilities have used a “relationship” approach with key contractors to give them reasonable assurances of continuing work. The size of this category after combining the expenditures of the two utilities warrants further analysis.

We did not find promise that the four remaining categories are likely to generate significant combined purchasing savings. We concluded so for one of two reasons: one company’s annual spend adds too little to add significant purchasing or contracting additional leverage (Engineering Services Contractors, Wood Pole Purchases, T&D Conductor Purchases), or the combined annual spend of the two does not appear large enough to move pricing in the market place (Substation Power Transformer Purchases).

We did not find a large number of outside barriers, but one significant one, the different purchasing requirements that provincial legislation imposes on Hydro and Nalcor. Absent change in legislative and policy requirements and directives, savings from this opportunity are not likely. This and other barriers cited during discussions with the two entities prevented progress in gauging common procurement and contracting potential in the time available.

The potential magnitude of savings (although clearly requiring further study) is significant. For example, saving as little as 3.5 percent of 2018's $145,000,000 in combined expenditures in the six categories showing promise would save $5 million annually. We believe that there would be benefit in the completion of more analysis of the potential savings, which, if they prove significant, may lead to reconsideration of the current policy barrier to achieving them.

V. Hydro and Nalcor Power Supply Integration

A. Chapter Summary

In support of LCP activities, Nalcor has since 2016 managed LCP completion using an organization and support resources substantially separated from those employed by Hydro. With LCP completion pending, we found a review of that model timely. Nalcor also supports the broad, use of distinct organizations and resources on the basis that LCP assets are "unregulated." Despite substantially recreating in Power Supply functions, activities, and support similar to those with which Hydro conducts its operations, there have been efforts to share resources between Power Supply and Hydro where deemed effective.

Nalcor has urged retention of the regulated/"unregulated" distinction it makes between LCP and Churchill Falls assets, on the one hand, and the assets that Hydro operates, on the other hand. Chapter III explains why we consider that distinction artificial, and, in any event, not a barrier to the application of the returns and margins on LCP and Churchill Falls assets to offset Hydro's revenue requirements.

More significantly for this chapter, however, is the identification of whether the separation of Power Supply and Hydro produces greater costs than would occur without that separation. There is no sound operational reason for maintaining the distinction - - Power Supply and Hydro together have the characteristics of a reasonably small and vertically-integrated utility capable of effective management with a fairly straightforward and simple top management structure.

We found significant potential savings from combining Power Supply and Hydro engineering, smaller savings in transmission, and no current savings in generation. However, consolidating generation responsibility would promote accountability and provide a more solid foundation and basis for promoting best practices for the largest hydro units.

We found reasonably significant savings from combined resource reductions in areas like finance, accounting, human resources, communications, safety, health, environmental, sustainability and legal/governance. Table V.1 summarizes the sources of the approximately $17.6 million in annual savings potential we identified, after the FTE reductions reach a steady state. Initial, 2020 savings involve 66 FTEs and $12.7 million as determined by our model.

Chapter IV addressed our examination of combining small Island hydro generation under a single operator. We did not find that combination promising, but, as the chapter describes, we believe that Hydro can reduce hydro generation staffing by a number of FTEs in the range of 17 over a three-to-five-year period. Doing so will contribute approximately $2.5 million to the operational savings under a recombined Nalcor/Hydro. Note that the reductions in Chapter VI, which addresses LCP operating expenses, add to this amount.

Table V.1: Potential Savings from Hydro/Power Supply Combination

Functions	FTEs (#)	Costs
Engineering	21	$4,000,000
Transmission	5	$1,000,000
Generation	0	N/A
Finance	14	$2,200,000
Corporate Services	24	$3,600,000
Exec./Sr. Mgmt.	13	$4,300,000
Small Hydro Stations*	17	$2,500,000
Total	**94**	**$17,600,000**

* as derived in Chapter IV

Chapter IV also describes what we view as a promising opportunity for Hydro to reduce operating costs further, through a close and candid examination of its effectiveness and efficiency. As that chapter describes, we found as Phase 2 work proceeded, growing sentiment among Hydro's leadership for such an effort.

Achieving reductions in the range reported in this chapter will require a significant restructuring of Nalcor and Hydro. Some position eliminations may cause a need for increasing compensation for some position levels to provide for appropriate job scoping and compensation. Moreover, it is likely that the restructuring will permit combination of some positions below the management and supervisory level (*i.e.*, the "individual contributor" level). Thus, a number of different means for combining the functions and re-defining some of the boundaries of work group responsibilities and interfaces will present themselves. It is important that the change result from a comprehensive organizational review. While we are confident that this review will produce the level of reductions we have estimated, or more, the actual positions eventually consolidated, eliminated, and added may differ.

B. Introduction

The separation between Hydro and Power Supply came in 2016, driven by two principal factors: (a) a desire to increase the organizational focus on completion of the LCP, and (b) to make more transparent the separation between the regulated operations of Hydro, and the "unregulated" nature of the LCP and Churchill Falls assets. Prior to that time, the Hydro/Power Supply distinction did not exist. Hydro looked organizationally like the comparatively small, vertically-integrated utility it was, except for the lack of a single utility executive who integrated all of the functions required to provide planning and execution of the generation, transmission, distribution, customer service functions, and corporate and administrative services required by Hydro to serve its customers. Responsibility for many of the activities required to support LCP operation and Churchill Falls operation came from the Hydro organization. Separation of costs occurred through billings designed to ensure that Hydro's resources assigned and allocated costs appropriately to projects or activities supporting LCP or Churchill Falls, for example.

We observed in 2014 the anomaly presented by the lack of an integrating, top executive at Hydro. We recommended that Nalcor bring under a single Hydro top executive overall accountability for utility performance. Beneath the Nalcor CEO, executive responsibility was shared by Nalcor and Hydro officers. Nalcor created a unifying Hydro President position, and accountability and responsibility for LCP and Churchill Falls came to lie under two new organizations: (a) Power Development, and (b) Power Supply. The former took responsibility for managing LCP construction, and the latter for providing technical and operating support to Power Development, and managing the transition of the LCP assets to operation. Nalcor also intends it to manage operation of Nalcor's "unregulated" assets consisting of Churchill Falls and the LCP assets (Muskrat Falls, the LIL, and the Labrador Transmission Assets).

The Hydro organizations responsible for utility management and operations had provided much of the work that moved to Power Supply, which created a large organization dedicated to its "unregulated" assets. This organization thus had to duplicate a variety of management and technical groups performing similar functions for Hydro. While very similar from a broad perspective, some important differences existed; *e.g.*, the extraordinarily large and lagging LCP construction program, and novel (for Nalcor) technical factors such as HVdc facility design, construction, and operation.

This reorganization also led to a largely mirroring set of corporate and administrative support functions for the "unregulated" assets under Power Supply. The duplication occurred and continues today across a broad array of such services; *e.g.*, finance and accounting, human resources, communications, legal, and environmental, health, safety, and sustainability. The reorganization also produced an especially large executive and senior management team.

One of the principal reasons cited for splitting the organizations, completing LCP, will soon, it is hoped, pass into history. That leaves the transparency and separation that Nalcor has considered important to maintain between regulated and "unregulated" asset management and operation. We explain in Chapter III our views of how meaningful that distinction is, and the implications of redirecting returns and energy-sales margins to reducing Hydro's revenue requirements. We did not consider maintenance of the separation necessary, in fact finding it highly unusual in its justification and cumbersome in the organization and resource levels it will continue to impose when LCP construction ends and the assets phase-in to effective, continuous operation.

This chapter therefore examines what we describe as a re-integration of Hydro and Power Supply to produce an organization that reflects an industry-typical model for a small, vertically-integrated electric utility. It does so in anticipation of moving Nalcor's oil and gas business to a separate Crown corporation, as we understand still to be the intention of the Province. The next sections of this chapter describe our examination of each of the major elements that reintegration might affect:

- Engineering Services
- Transmission
- Large Hydro Generation Facilities
- Financial Services
- Corporate Services
- The Executive Organization.

The distinction between regulated and "unregulated" assets and operations may or may not continue indefinitely. To the extent it does in some form, we view a soundly constructed, well-controlled, carefully executed system of cost charging and allocation sufficient to address it. Experience across North America makes clear that optimizing overall organization for efficient and effective performance serves as the primary driver of structure and of the assignment of responsibilities for assets and activities. Separate organizations are generally not preferred in cases where they produce avoidable duplication and where, comprehensive, faithfully executed, and fully transparent charging controls, methods, practices, and documentation can provide confidence that costs spread among activities with different beneficiaries get spread according to causation. We did not urge organizational duplication here in 2014 or anywhere else in nearly 30 years of examining affiliate transactions and costs for utility regulators and for utility holding companies. When we addressed the need for restructuring in 2014, we believed, as we continue to believe now, that the primary issue was unified accountability and responsibility, not cost accounting for affiliate-type transactions.

C. Engineering Services

1. Background

Hydro and Power Supply employ separate engineering groups.[64] Hydro's group includes some 137 FTEs; Power Supply's companion group includes some 82 FTEs. A Vice President Engineering & Technology, who reports to the Hydro President, manages the individual groups that comprise Hydro's Engineering & Technology group. Hydro divides its engineering units by discipline (*e.g.*, mechanical, civil, electrical) and it includes specialized units addressing activities like protection and controls, support services, operating technology, project execution, and asset management.

The comparable Power Supply engineering organization reports to a Vice President. This officer reports to Power Supply's top executive, the Executive Vice President, Power Supply, who reports in turn, to the Nalcor CEO. Power Supply, however, organizes its engineering services resources differently - - largely by asset type (generation, transmission line, and terminal stations). Power Supply's Operations Support Group in the Engineering Services Group includes: (a) an AC Terminal Engineering and HVdc Specialists Group, (b) a Generation Engineering Group, and (c) a Transmission and Civil Engineering Group. Power Supply Engineering includes other sub-groups as well: (d) Project Execution, (e) Asset Management, and (f) Business Services.

We examined the combination of the parallel Power Supply and Hydro engineering organizations into one group designed to support all regulated and "unregulated" generation and transmission assets. We performed the examination under the assumption that a combined Engineering Group would report to a single Vice President, who in turn would report to Hydro's President. Note that Power Supply's responsibilities extend only to assets that Nalcor has declared "unregulated," thus excluding any distribution-related functions potentially subject to combination.

2. Concepts and Assumptions Underlying our Analysis of Potential Reductions

Our review of the functions performed by each showed no reason why the two groups could not be combined, subject to selection of an overall approach and with the appropriate focus on the specific needs of equipment that Power Supply now manages, but Hydro does not. We also began work under a number of other assumptions driven largely by prior experience. Our analysis of the organizations and our discussions with management bore out their propriety for use in our analysis here. We assumed that contractor personnel who primarily support capital projects, which produce variable costs from year-to-year, provide a weak basis for examining reductions in steady state costs. We excluded them from our analysis. We also excluded temporary personnel whose variability also make them difficult to analyze for steady-state reductions.

We did not find Nalcor's distinction between regulated and "non-regulated" assets, as opposed to the nature of the activities performed, meaningful in assessing the potential for resource reductions. What engineering services personnel need to do and how they need to do it do not vary based on that distinction. Long-term asset planning comprises a core engineering-services function. We did not find it logical to assume better performance based on location (*i.e.*, a central group versus groups dispersed among production groups). We also did not find work locations to be a material factor in assessing combination for engineering services.

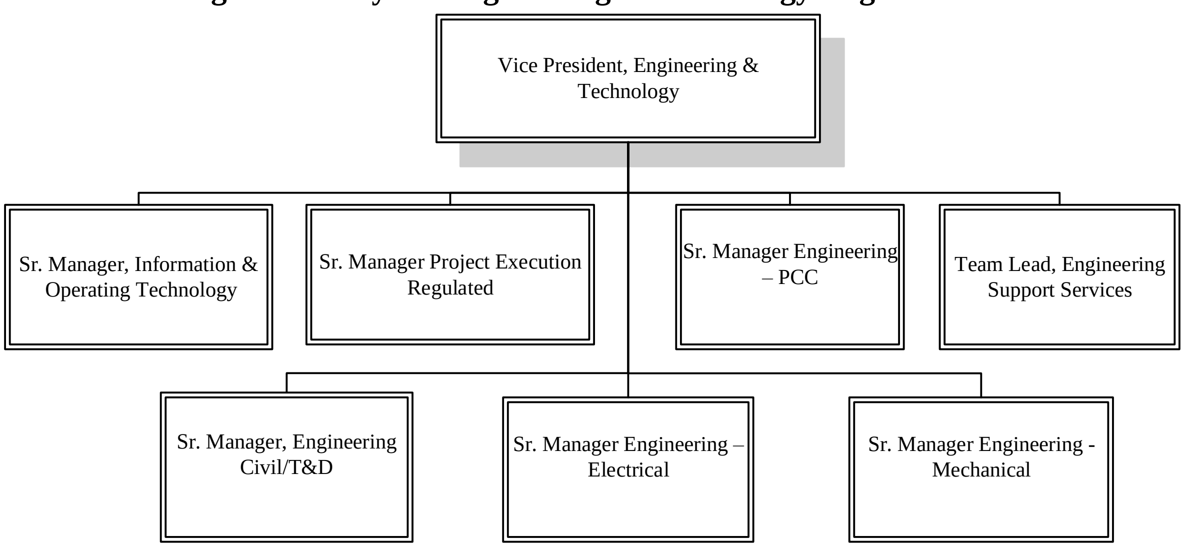
3. Analysis

a. Hydro's Engineering Support Group Structure and Resources

We examined the functions performed by the Power Supply and Hydro engineering organizations to determine the specific work of both groups. The discussion below describes the functions of the Hydro engineering organization.

The figure below depicts the organization structure of Hydro's engineering group.

Figure V.2: Hydro Engineering & Technology Organization



Hydro's Information and Operating Technology Group

This group, employing some 29 FTEs, provides network services, operational technology, and informational management services. Its Network Services sub-group manages and maintains all communications equipment at more than 150 Hydro sites that provide remote supervisory and control services that communicate with Hydro's energy control center. An Operational Technology sub-group has responsibility for the Energy Management Systems ("EMS"), used by the Newfoundland Labrador System Operator ("NLSO") in its role as Newfoundland Labrador's Transmission Operator. The Information Management sub-group ensures compliance with the

Management of Information Act within Hydro departments, and aligns Hydro's information management activities with corporate information management functions.

<u>Hydro's Projection Execution Group</u>

The 9-FTE Project Execution group provides program and project management services for approved capital projects.

<u>Hydro's Civil, Mechanical, and Electrical Engineering Groups</u>

These groups' 59 FTEs divide into discipline-oriented sub-groups that perform functions like the following: detailed engineering and technical support to the project execution personnel, technical and operating assistance to the Hydro Operations Division, and capital budget support. These groups can provide detailed engineering such as engineering analyses, design analyses, drawing reviews, technical specification review and development, and construction quality assurance. These group can also provide support as Project Managers for projects.

<u>Hydro's Project and Control and Communications Group ("PCC")</u>

The 23 members of PCC sub-group provide engineering related to system protection and control, including support for capital project planning and execution, and for the Hydro Operations Group.

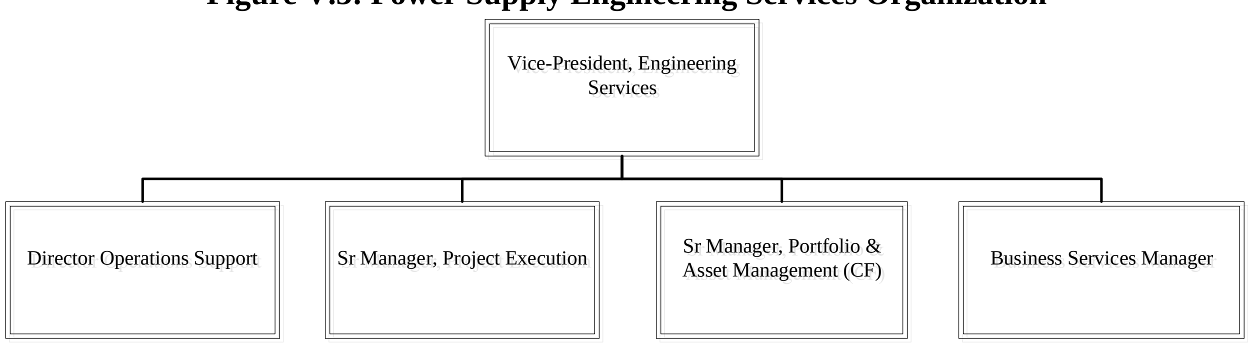
<u>Engineering Support Services</u>

This 17-person group performs activities such as project planning and scheduling, safety, project assistance, drafting and CAD support, and contract management and procurement.

b. <u>Power Supply's Engineering Support Group Structure and Resources</u>

Power Supply performs categorically similar functions to Hydro's, but in some respects focusing on different assets (like Power Supply's dc converter stations). Hydro organizes the engineering functions differently, using largely discipline-divided groups, while, as noted Power Supply provides support through an Operations Support Group. Apart from this difference, one finds largely parallel functions using industry-recognized specialties, such as project execution, asset management, and support services. The figure below depicts the current structure of Power Supply's engineering service group.

Figure V.3: Power Supply Engineering Services Organization



Power Supply's Operations Support

Power Supply's 21-person, multi-disciplined Power Supply Operations Support Group provides support services to three divisions of asset work; AC Terminals/HDVC, Generation, and Transmission. Hydro provides similar forms of engineering support through its discipline-based engineering groups, not a multi-disciplined group for an asset or asset group. At the engineer level, the functions remain similar.

Power Supply's Project Execution

Power Supply's 27-person Project Execution sub-group consists of discipline-based engineers plus project management personnel; by contrast, Hydro's Project Execution sub-group consists primarily of project personnel, with separate discipline-based sub-groups existing to support projects and other work requiring personnel expert in their disciplines. Hydro's more typical organization type provides engineering support through a matrix structure.

Power Supply's Asset Management

Power Supply's 8-person asset management personnel reside in its Asset Management Group. Hydro, instead, locates asset management personnel in its Production Groups. Again, the functions remain largely the same, but the personnel report to different groups.

Power Supply's Business Services

Power Supply's 26-person Business Support Group consists of planners, materials control, and warehousing personnel. These individuals primarily support the Churchill Falls unit.

c. Overall Summary of the Differences

It is primarily at the Manager/Director level that Power Supply and Hydro organize work differently. In the end, however, both Engineering Services Groups provide largely the following common services, albeit from within different groups:

- Detailed engineering services
- Project management services
- Asset management services
- Document control
- Safety and health specialists
- Project planning
- Cost control
- Drafting services.

4. Results

We believe that a savings of approximately 21 FTEs (15 now, and 6 additional within two years) can be accomplished through combination of the Power Supply and Hydro Engineering Support Services Groups under the leadership of an executive reporting to the President of Hydro. These reductions would generate annual savings in personnel costs of about $3 million in 2020, rising to $4 million per year after a two-year phase in, and increasing with inflation.

Both concepts surrounding their current organizational structures can and do function effectively, but we consider a discipline-focused organization more efficient and, in the long term, a more effective support organization. We apply these conclusions to steady-state operation of the LCP assets, which has yet to occur. We do not recommend changes to resources supporting LCP completion and startup.

We find a central engineering support services group typically more efficient and effective because it provides additional depth of engineering expertise, when compared with the more segmented grouping that Power Supply's organization employs. That is, engineers in a larger group can specialize more easily without threatening completion of required and desired work. A central engineering organization also provides greater career-path flexibility and upward mobility.

The end-state organization contemplated by the combination we see as cost reducing can use the existing structure of the present Hydro Engineering Services Group. Power Supply's personnel now located in the Operations Support and Project Execution groups would move into Hydro Engineering Services. The asset planning group personnel from Power Supply can move to the Hydro Asset Group to form a central asset management group. At present, Hydro's Asset Group functions in more of an oversight or governance capacity. The transfers from Power Supply would support broadening of the Hydro group's role, adding asset planning to its responsibilities.

In addition, the structure our vision of a combined organization contemplates would move asset management personnel from the Production groups in Hydro to this group. This change would essentially combine all asset management functions into one central group under Engineering Services. The remaining group, the Business Services Group in Power Supply can move altogether to Hydro or move to the large hydro units under a separate production group, but a decision on their location warrants further study to find the best organizational fit for this group.

We project the potential for a net reduction of 21 FTEs from combination, summarized as follows:

- 73 of the 82 FTEs in Power Supply move to Hydro provided, however, that the Business Services Group staff could move under the Hydro production organization depending on further study
- The net FTE reductions from movement from Power Supply to Hydro is thus 9
- 6 vacant positions are eliminated
- Combination of the organizations is likely to generate an additional 6 reductions as familiarity with combined operations permits work realignment at the individual contributor level.

5. Execution Barriers and Transition Needs

Study is required to determine the optimum location of two current organizational groupings: Long Term Asset Planning ("LTAP") and Business Services. We favor LTAP consolidation into one group operating across all asset types. The combination will make some Hydro Engineering Services groups larger, requiring an analysis of spans of control. Between 4 and 11 FTEs would be added to any single Hydro Engineering support group. Elevating some positions to "leads" may prove appropriate.

We also consider an assessment/inventory of skills important in ensuring application of required management and technical skills. Such an exercise makes sense even in the absence of organization change when massive projects produce both planned and unexpected dislocation. The need becomes greater with a reorganization that causes substantial movement and reduction. Ensuring the required HVdc skills and experience comprise an important focus here. Combining the organizations can produce individual responsibilities beyond reasonable expectations. Therefore, the combination will need to be accompanied by careful review of workloads below the management level, and rebalancing the work required of individual contributors where needed.

While the Power Supply/Hydro split has not been of long duration, we find it a fixed reference point in the minds of some personnel, more so, from our direct observations, at more senior levels. It will be important for a change such as that examined here to reflect strong support from the top. We would expect continued adherence to the regulated and "unregulated" split approach that now exists to be a major and likely insurmountable barrier to effective execution. Transitioning from an asset- to a discipline-focused engineering organization also will require focused change management. Moving to the more typical approach may ease that transition.

As compared with combinations involving Newfoundland Power or more directly implicating arrangements like those of CF(L)Co., this possibility faces fewer barriers that lie outside the direct control of Nalcor and Hydro.

D. Transmission

1. Background

Faced with the size and complexity of the challenge of LCP completion, Nalcor restructured its organization in 2016. That reorganization included transmission, with separate Power Supply resource groupings established to address LCP transmission assets - - the LTA and the LIL. Following completion, continuing to operate separate engineering and transmission functional organizations in both Power Supply and Hydro would perpetuate a split of normally integrated functions within what remains a small, vertically integrated utility. We examined opportunities for structural realignment that would, after LCP completion, bring together organizations now performing transmission-related functions.[65]

Both sets of assets are monitored and controlled by the NLSO and both systems are operated and maintained by Power Supply and Hydro engineers, managers, supervisors, vegetation management professionals, and craft workers possessing similar skills. We examined the ability to bring into one organization the transmission functions and resources of Hydro and Power Supply following LIL completion and phase-in.

2. Concepts and Assumptions Underlying our Analysis

We ruled out immediate reductions in craft workers and management/leadership teams with responsibilities associated with the LIL, pending a period designed to ensure stable operation and required training and skills development to support such operation. Our examination considered the potential need for some, post combination resources now engaged by Hydro to undergo HVdc training and skills development to permit integration of the groups responsible for LIL line and converter station work. While we addressed opportunities for reductions in ac transmission resources, we concluded that reductions in craft workers for those facilities should await Hydro's completion of a planned, internal staffing study shortly after the Nalcor/Hydro reintegration.[66] We recognized the existence of separate labour bargaining agreements, but proceeded under the assumption that, should material reductions appear possible, those agreements could be rationalized through negotiation.

3. *Analysis*

We examined detailed organization charts for Hydro's and Power Supply's transmission organizations, compared job descriptions, functions, roles and responsibilities, and positions that may not be necessary after integration. We identified supervisory and management positions with narrow spans of control. We undertook discussions with Hydro about potential changes post-combination and met with Nalcor and Hydro senior management to discuss preliminary indications of potential resource reductions.

4. *Results*

Moving LIL and LTA transmission management responsibilities from Power Supply to Hydro is feasible and it can reduce resource requirements moderately. The potential reductions include a net drop of one management position, resulting from elimination of a Power Supply director and manager, with the addition of a new senior manager position. Adding this reduction to four field positions would result in net FTE reductions of five positions, which appear feasible. We anticipate annual savings of just under $1 million after implementation.

Hydro anticipates a re-evaluation of transmission field resources within two to three years of re-integration of Power Supply and Hydro. We agree with the need for such analysis, but it need not wait that long. We anticipate that this analysis will identify further reductions. It should commence within two quarters of re-integration, with completion in approximately six months.

E. Common Production Organization for Large Hydro Stations

1. *Background*

Muskrat Falls and Churchill Falls operate under Power Supply management, while Hydro manages the remainder of the hydro stations. Hydro's thermal and hydro generating facilities fall under the direction of the Director of Operations, who reports to Hydro's Vice President of NLSO and Operations.[67] This vice president in turn reports to Hydro's President. A Senior Manager, Bay d'Espoir and Exploits Generation has responsibility for these stations.

Two very large hydro stations - - Churchill Falls and Muskrat Falls fall under the overall direction of the Power Supply's most senior officer, the Executive Vice President, Power Supply, reporting to Nalcor's CEO. Both of these generation assets are large hydraulic units. Power Supply's Vice President Production Power Supply and Energy Marketing has direct responsibility for Churchill Falls and Muskrat Falls, reporting to the Executive Vice President.

Churchill Falls, Muskrat Falls, and Bay D'Espoir far outsize the remaining units powered by water. Bay D'Espoir's 613 MW (the smallest of the preceding three) exceed those of the next largest station, Cat Arm at 134 MW, by a factor of 4.5. We examined the potential effects of combining the management of the largest three stations, which we found to be similarly structured, and therefore potentially duplicative in some respects.

2. Analysis

We examined the parallel Power Supply and Hydro organizations and resources, and we discussed with management of both the feasibility of combination. Not surprisingly, we confirmed that geographic distance has a very strong influence on the alternatives available. We also considered the existence of CF(L)Co., recognizing that Hydro-Québec's rights and its interests as a joint owner could be implicated by significant changes affecting Churchill Falls.

We did not find organizational differences, equipment types and operational requirements an obstacle to pursuing potential resource reductions. We confirmed that the major organizational difference lay in Hydro's location of asset management in the production organization versus Power Supply's use of its engineering services group. We did not find that difference material.

3. Concepts and Assumptions Underlying our Analysis of Potential Reductions

The interrelationship of water supply between Churchill Falls and Muskrat Falls raises important water management needs that cannot be underserved by combining hydro production resources. We paid particular attention to plant locations and the need for site-based and promptly site-accessible personnel, equipment, warehousing, and even worker housing. Such factors led us fairly early to rule out alternatives that would call for major levels of relocating of operations or maintenance personnel. No two of the units are close enough to support such an option. It is conceivable, however, that detailed analysis of required skills, especially maintenance-related, may result in small synergies among the resources for large hydro plants.

As in all our examinations of integration possibilities, we ruled out consideration of changes that might threaten operational excellence and reliability as a source for producing economies. The three stations encompassed in this review, Churchill Falls, Muskrat Falls, and Bay d'Espoir, comprise the most critical elements of the supply portfolio on which Hydro and its customers depend.

4. Results

We believe overall consolidation of Churchill Falls, Muskrat Falls, and Bay d'Espoir under a common organization to offer the best going-forward organizational concept. A single senior executive to provide overall direction for a vertically-integrated utility's supply portfolio comprises the typical approach. A similar approach applies as well to large operators of fleets operating in competitive markets. We do not expect more than a handful of net resource reductions; even a very moderate, $500,000 reduction lies at the top end of the expected range. Near-term savings from resource reduction do not form the basis of the change we envision here.

Two separate organizations are highly likely to work to separate and different standards, goals, priorities, and ultimately results. Even where common standards do exist, they remain subject to differing execution caused by a wide variety of factors. Our experience teaches that establishing operational excellence best comes under the direction of a single generation group operating under a single overall leader. Nalcor cited the need to finish the LCP and the "unregulated" nature of the assets consigned to Power Supply management. The first will hopefully soon become a legacy and the latter we view as a matter of semantics, not practical reality.

Apart from expecting combination to improve operational excellence, we do view a single production organization as enhancing operational effectiveness (productive of economy as well) over the long term, with the accompanying benefit of identifying means for efficiency gain as well. Separate organizations performing the same or similar functions tend to grow apart, diminishing incentives and opportunities to seek enhancements that can reduce costs. Long term, resource sharing opportunities will be less visible and less likely to occur -- two organizations will prove less efficient to some degree.

A simple consolidation of production organizations at the three large hydro sites raises span-of-control issues. Combination also needs to take special account of the common Churchill Falls and Muskrat Falls water sources, and of the need for avoiding any disruption at Churchill Falls. We consider enhanced operational excellence of benefit to both Churchill Falls owners, and it should not come at the expense of producing uncertainty on the part of the minority owner.

We therefore considered two combination scenarios:

- Integrate the Churchill/Muskrat Falls production organizations directly into the existing organization of the Director Operations, under which Hydro manages its hydro stations.
- Create a Hydraulic Production group headed by a vice president reporting to the President of Hydro, and place a director-level lead for Churchill Falls and Muskrat Falls, reporting to the head of this Hydraulic production group.

We consider the second alternative more appropriate, given the size and importance of these large hydro stations. We do not see insurmountable barriers to a combination arising from LCP or CF(L)Co commitments, agreements, or limitations, but recognize that a detailed legal review of them needs to take place to ensure that allowable avenues to combination are followed. Compliance with or changes to labour bargaining agreements must also be fully assured. A separate agreement covers workers at Muskrat Falls.

F. Hydro/Nalcor/Power Supply Financial Services

1. Background

Prior to 2016, all Nalcor traditional finance, accounting, planning, supply chain and information technology functions resided under the Nalcor Executive Vice President and CFO. Nalcor divided its finance organization in 2016. First, an organization under the Hydro President, eventually headed by a new Hydro Vice President, Financial Services position, assumed responsibility for accounting, reporting, budgeting, tax, and related areas for Hydro. Excluding the supply chain and Hydro internal audit functions reporting to this Hydro Vice President, Hydro Financial Services group consists of 27 positions:

- A Controller, whose Staff includes 23 positions
- A two-person commercial group responsible for addressing key accounts
- A Manager, Risk Controls and Planning.

Nalcor later created a financial function under the head of Power Supply to perform financial functions related to LCP and Churchill Falls. These resources reported to a Vice President Finance within Power Supply. This change left, in effect, a third, “holding company” finance organization.

Top-level reporting under the Nalcor CFO for finance and accounting functions now consists of three lead positions, under whom 58 positions exist:[68]

- Nalcor's Chief Accounting Officer (responsible for 18 positions, organized under two senior managers)
- Power Supply's Vice President Finance (responsible for 27 positions, organized under two controllers, two senior managers, and including a consultant position)
- Director, Financial Planning, Treasury and Risk Management (responsible for 13 positions organized under three senior managers).

A number of other functions moved as a result of these changes as well, currently located as follows:

- Supply Chain - - to Hydro's Vice President Financial Services
- Facilities Management - - to Hydro's Vice President Financial Services
- Regulatory Affairs - - to Hydro's President
- Internal Audit - - split between Nalcor's Chief Human Relations Officer & Senior Vice President, Corporate Services and Hydro's Vice President Financial Services
- Operations Technology - - moved from the head of corporate Information Technology to Hydro Engineering
- Commercial Management and Strategy - - to a director reporting to the Executive Vice President, Power Supply
- Financial Controls and Risk - - to a Manager reporting to a Power Supply Vice President.

The remaining organization under Nalcor's Chief Information Officer ("IT") also reports to the Nalcor CFO.

We examined the potential for recombining finance organizations back into the single financial organization that existed before the split.

2. *Concepts and Assumptions Underlying our Analysis*

We examined organization charts and staffing, and conducted a series of discussions with management of the functions involved. We also assumed for this analysis that the overall integration of Hydro and Power Supply would occur. That combination would restore Hydro's position as a moderately sized vertically-integrated utility. We applied our experience in the industry in examining utility organization structures to determine whether a combined financial services group could support operations of an integrated Hydro and Power Supply business.

Our work in Phase 2 confirmed that accounting, reporting, budgets, treasury, planning, IT, and other services performed for the Nalcor entities have a substantial similarity of purpose. We did not find Nalcor's regulated versus "unregulated" distinction a critical factor in analyzing financial services. A centrally organized set of functions traditionally located under a CFO is the preferred model absent specific reasons for not doing so. Nalcor identified a net reduction of 6 FTEs in financial services due to Muskrat Falls transitioning from construction to operating status in 2021; these reductions are not considered in this analysis.

3. *Analysis*

a. Accounting

Nalcor has divided its formerly unified accounting functions among three separate financial organizations, led by: (a) the Nalcor Chief Accounting Officer, (b) the Hydro Vice President Financial Services, and (c) the Vice President Finance, Power Supply. These three organizations perform the basic accounting support functions including accounting, financial reporting, budgets, and taxes.

The Nalcor Chief Accounting Officer's organization performs "corporate" accounting services, financial systems coordination, financial reporting, budgeting, and taxes and compliance for Nalcor Energy at the corporate level. The approved complement for the organization under the Chief Accounting Officer consists of 18 positions, eight of them managers.

A Hydro Controller, reporting to the Hydro Vice President, Financial Services has an authorized complement of 23, divided under four managers, to manage Hydro's accounts payable and general ledger accounting services, financial reporting, budgeting and forecasting, financial analysis, regulatory financial planning, and taxes. We added to the preceding complement of 23 the two-person team responsible for large customer accounts, which also reports to the vice president. Other non-accounting functions operate under the Vice President, Financial Services - - treasury, risk controls and planning, internal audit and supply chain.

The 25 accounting-related positions, organized under two controllers and one senior manager reporting to Power Supply's Vice President, Finance for Power Supply, perform financial accounting, financial reporting and compliance, budgeting and forecasting, financial analysis, and cost analysis for Churchill Falls and the Lower Churchill Project, each of which uses a separate Controller.[69]

We consider it feasible to consolidate these three organizations, whose complement, excluding top officers amounts to 68 into one organization reporting to a single Chief Accounting Officer.

b. Planning, Commercial/Strategy, Treasury and Risk Management Functions

Nalcor has spread planning, treasury, strategy, and risk management functions across four organizations whose complements total:

- The 13-position organization reporting to the Nalcor Director, Financial Planning and Risk Management
- 2 business and commercial positions reporting to Power Supply's Vice President Finance
- The Manager, Risk Controls and Planning reporting to Hydro's Vice President Financial Services.

We believe that all the strategy/planning/treasury/risk management functions can be consolidated into one organization reporting to a single executive, who in turn reports to the CFO.

c. Internal Audit

Internal audit activities fall under two groups, one reporting to the Nalcor Senior Vice President, Corporate Services (6 FTEs), and another reporting to the Hydro Vice President - Financial

Services (2 FTEs). These two groups have 2 Managers and 2 Team Leads that direct 4 non-management auditors. Internal audit functions can be consolidated under a single director. The reporting of the head of internal audit should also move to the President of Hydro. We found locating it under corporate services anomalous. Its independence, a critical element in ensuring its effectiveness, is better served by direct reporting administratively to the most senior corporate officer, accompanied by a substantive relationship with the board of directors. We did not find a basis for expecting a reduction in the current 8 FTE resource levels upon combination.

d. Supply Chain

An organization reporting to the Hydro Vice President - Financial Services has responsibility for procurement, materials and stores, facilities management and fleet functions across Nalcor. The supply chain functions are managed by eight management personnel (1 Manager, 2 Senior Supervisors, 3 Supervisors and 1 Transportation Officer), who direct 32 non-management FTEs, for a total of 40 FTEs. This group already reflects essential common functioning for Hydro and Power Supply. We did not find opportunity for combination-based reductions, but did assume elimination of the four vacant positions, which would reduce annual costs by about $400,000 per year.

e. Information Technology

A 47-position organization operating under the Nalcor Chief Information Officer has responsibility for Nalcor-wide IT operations, infrastructure, system security, system services, solution delivery and architecture, information management and corporate information systems. Responsibilities divide among three Senior Managers. This group already reflects essential common functioning for Hydro and Power Supply. We did not find opportunity for reductions. A separate Operations Technology ("OT") group in Hydro's Engineering Services organization has responsibility for management of technology that supports network operation and energy systems. Operating in Hydro's Engineering Services organization, the OT group includes 6 management personnel (1 Senior Manager, 1 Manager, 1 Team Lead, 1 Senior Supervisor, 1 Supervisor, and 1 Information Management Administrator) that direct 25 non-management FTEs. We did not see material opportunities for reductions through combination with the IT organization, but did assume elimination of the three vacant positions.

4. *Results*

We found that combining the accounting and other finance-related functions addressed in this section can result in material personnel reductions. The combination can reduce the need for 14 financial positions: two controllers, one senior manager, and 11 more junior positions. Savings from these reductions begin at about $2.2 million per year. We did not see a basis for reductions in internal audit, supply chain, facilities and fleet, or information technology other than the elimination of vacant positions that we outline above.

G. Corporate Services

1. *Background*

Hydro has a corporate service organization operating under its Vice President, Corporate Services. At the Nalcor level, the Chief Human Resources Officer and Senior Vice President, Corporate

Services heads a separate corporate services organization. The services provided by each include human resources, communications, and health, safety, and environmental. The Hydro Vice President, Corporate Services also manages customer service for Hydro. We examined combination of these organizations.

2. Concepts and Assumptions Underlying Our Analysis

We applied the same general assumptions to corporate services that we used to examine financial services.

3. Analysis

a. Communications

A Nalcor Director, Corporate Affairs manages a staff of 12, focusing primarily on communications, but with two positions (currently vacant) addressing corporate planning and shareholder and government relations. A communications organization internal to Hydro consists of three persons. Their commonality of functions permits a small resource reduction.[70]

b. Safety, Health, Environmental, and Sustainability

Between Nalcor and Hydro, a total of 39 FTEs work in the areas of safety, health, environmental, and sustainability. Hydro's Manager, Environment has a staff of 7 and its Manager, Safety has a staff of 6. At the Nalcor level, two senior managers address these functions:

- Safety and Health, with a staff of 14
- Environment and Sustainability, with a staff of 8.

Here too we found sufficient commonality of functions and activities to permit an opportunity for resource reductions.[71]

c. Human Resources

A Nalcor staff of 28 manages human resources, split between two Senior Managers, one for corporate and one for operations. Hydro employs a staff of 10, operating under a Manager, Human Resources and Labour Relations. Here too we found sufficient commonality of functions and activities to permit an opportunity for resource reductions.[72]

4. Results

Combination of communications functions will enable the elimination of two management positions and three vacant positions, producing a reduction in costs of about $800,000 per year. In the combined areas of safety, health, environmental, and sustainability, we believe that combination can cause a reduction of two mangers. Combining staffs of this size should also permit elimination of two additional positions, plus the one position now vacant. The savings from this reduction of five FTEs amount to about $800,000 per year.

Combination of the Human Resources organizations permits removal of management positions that become duplicative. Sufficient resources remain to permit reconfiguration of lower level management or supervisory roles, likely causing some compensation increases for those given increased roles. A number of human resources personnel appear dedicated to the LCP transition to operations, which should permit their elimination in the reasonably near term. We consider possible reductions of seven FTEs after phase-in of LCP through 2021, with annual savings of about $1.1 million per year.

We did not find a basis for combination-based reductions in required Supply Chain or IT resources, but, eliminating their seven vacant positions can reduce costs by approximately $900,000 per year.

H. Executive Organization

1. Background

An integration of Hydro and Power Supply has significant implications for the executive and senior management structure of both companies. Figure V.4 shows Hydro's and Nalcor's executive and senior management organizations. We did not consider the yellow-shaded portions of the structure as driving current staffing of a recombined Hydro and Power Supply. Power Development will not exist following LCP completion and the Government plans to make oil and gas a stand-alone Crown corporation. We understand the current development mission of Nalcor, but see no reason at this point to include in the combined Hydro/Power Supply organization resources dedicated to that part of the mission. Moreover, should that mission at some point take on a more definite or immediate focus, we consider large-scale development of generation sites proper for structuring on a merchant, rather than a utility-customer-funded basis. Integrating resources dedicated to this mission element does not appear logical for a utility-focused organization likely to remain in a low-growth mode for the foreseeable future.

The purple shaded sections show, in essence, three top-executives. The blue-shaded sections depict the principal technical and operating elements of Power Supply and Hydro. The Hydro organization also includes corporate services, such as legal and regulatory, finance and accounting, and corporate services. The latter, reporting to a single officer, includes human resources, communications, safety, health, and environmental groups. The orange-shaded portions of the figure show parallel Nalcor legal, finance, and corporate services functions. The corporate services functions under this Nalcor organization include those provided for Hydro by the groups under Hydro's Vice President, Corporate Services. That Vice President also manages customer service for Hydro's retail customers.

Figure V.4: Current Nalcor Energy Top-Level Organization Structure

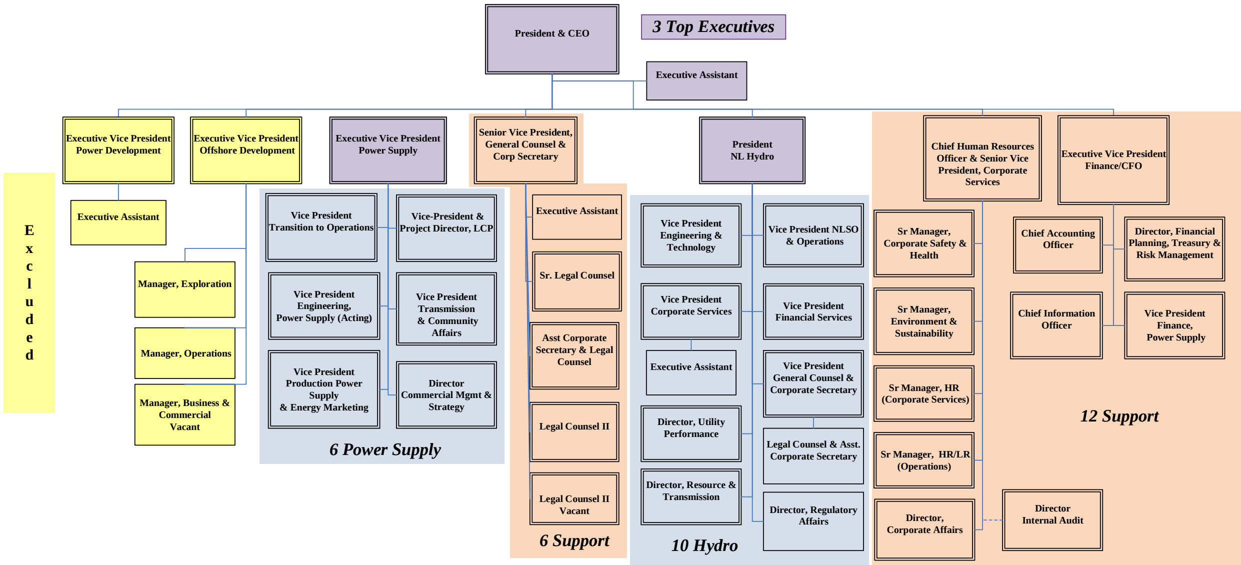


Table V.5 shows the combined Hydro and Nalcor-level resources providing the corporate and support services we examined. The numbers exclude the top officer responsible for the functions listed.

Table V.5: Combined Support Resources

Function	Nalcor	Hydro	Total
Accounting	44	26	70
Other Finance Related	15	1	16
Information Technology	47	0	47
Supply Chain	0	40	40
Human Resources	28	11	39
E, H, S, S*	24	15	39
Corp. Affairs, Communications	13	3	16
Legal	7	2	9
Internal Audit	6	2	8
Subtotal	***140***	***76***	***216***
Customer Service	0	37	37
Regulatory	0	12	12
Total	**140**	**125**	**265**

*E, H, S, S includes Environmental, Health, Safety, Sustainability

2. Analysis

Combination of Hydro and Power Supply operating and technical organizations (those shaded in light blue) will create a very substantial level of duplication at the executive level. It will also eliminate the need for separate Nalcor-level financial, corporate support, and legal organizations (shown in orange), again producing substantial overlap at the senior management level. Finally, integration will permit a reduction in the number of top executives as well. The resulting scope of operations, following LCP completion and separation of the oil and gas business, produces a scope and scale of operations typical of a small vertically-integrated utility.

The Hydro and Newfoundland Power split in responsibilities for serving the Province's electricity customers complicates a direct comparison of staffing metrics with other Crown corporations that provide vertically-integrated electricity service. We addressed that complication by adding Nalcor (including Hydro), and Newfoundland Power employees, executives, and customers. Doing so, as Table V.6 shows, leaves Newfoundland and Labrador with the smallest number of electric customers among Canadian peers. The table excludes the two Nalcor senior executives responsible for Power Development (LCP) and for Offshore Development (oil and gas). The table makes clear the unusually high number of executive positions versus Canadian peers, measured against customer numbers or employee numbers. While closer to the median, a combined Nalcor and Newfoundland Power still require more employees per customer to provide service.

We compared Nalcor employee and executive numbers with those of a Canadian peer group comprised of Crown corporations serving at least the vast majority of their province's residents, businesses, and institutions and on a vertically-integrated basis. SaskPower, NB Power, BC Power, and Manitoba Power comprise these peers. It takes a combination of Nalcor and Newfoundland Power to fit the model. To produce the combined Nalcor/Newfoundland Power values we summed a set of their operations expenses, customers, and employees. We used only Nalcor GWh sales for the combined value, in order not to double count sales to Newfoundland Power for resale to its customers. We summed officer numbers, but with two adjustments:

- Eliminating the two Nalcor officers shown as "excluded" in Figure V.4 above; the fact that the peer group members have functions like those performed by the two makes this a conservative approach
- Counting only two Newfoundland Power officers, under the assumption that only a customer service and a distribution operations officer would be likely were the Province served by only one retail utility.

The metrics we chose for comparing staffing and executive numbers consisted of our set of operating expenses, total sales of electricity, and numbers of customers. We used audited results from annual reports to collect an operating expenses set (the "Expenses" column of the following two tables) consisting of those costs that generally more directly drive personnel requirements. These categories included fuel, energy, materials, and contractors. We excluded expenses that influence resource requirements less directly; *e.g.*, depreciation and amortization, finances charges, taxes, and exploration. Table V.6 provides the base data for the four peers, their median and average values required to calculate our metrics, and how we combined the Nalcor and Newfoundland Power data.

Table V.6: Crown Electric Corporation Data Values

Company	Expenses (millions)	Sales (GWh)	Customers	Employees	Officers
SaskPower	$1,418	23,559	538,000	3,100	10
NB Power	$1,254	16,579	405,000	2,500	8
BC Hydro	$3,437	54,643	2,049,322	6,000	13
Manitoba Hydro	$1,038	22,505	862,000	6,000	8
Median	*$1,336*	*23,032*	*700,000*	*4,550*	*9*
Average	*$1,787*	*29,322*	*963,581*	*4,400*	*10*
Nalcor	$555	39,740	38,000	1,566	16
Newfoundland Power	$77	5,876	268,000	600	4
Nalcor + NP	$632	39,740	306,000	2,166	18

Table V.7 shows the calculation of our metrics. It makes clear that Nalcor, in terms of both employee and officer numbers has well above average and median peer values. The particularly large size of Churchill Falls comprises a notable feature of Nalcor staffing. We provided ratios for the GWh measure with and without including the output of Churchill Falls to bound the view of its staffing implications.

All of the circumstances that distinguish these peers, or any other selected for comparison, preclude direct conclusions. The large degree by which Nalcor exceeds the median and average values, however, does substantiate our direct analyses, which found significant efficiencies arising with integrating Power Supply and Hydro, and likely more from a comprehensive, structured, transparent examination by Nalcor of the efficiency and effectiveness of its utility operations.

Table V.7: Crown Electric Corporation Comparison Metrics

Ratios	Expenses		Customers		Employees	GWh	
	per Emp.	*per Off.*	*per Emp.*	*per Off.*	*per Off.*	*per Off.*	*per Off.*
Nalcor + NP vs. Median	164%	425%	119%	475%	322%	39%	117%
Nalcor + NP vs. Avg.	146%	493%	145%	544%	381%	37%	130%
Nalcor/NP vs. Median (w/o Churchill Falls GWh)						143%	432%
Nalcor/NP vs. Avg. (w/o Churchill Falls GWh)						136%	478%

Comparing it to U.S. experience confirms this observation. The combined customer numbers of Nalcor and Newfoundland Power would place it just above the fourth quartile (smallest) of electric utilities. Our experience with the U.S. industry confirms what our direct observation and analysis found here - - that the top-level Nalcor organization is unusually large and complex for such a comparatively small utility operation.

3. Results

Upon an integration of Power Supply and Hydro following LCP completion and relocation of the oil and gas business, a single top executive should prove sufficient, consistent with Nalcor's existence at that stage as essentially a small, vertically-integrated utility. It would also be possible to eliminate a significant number of top-level executive positions required by the separate Power Supply, Nalcor corporate services, and Nalcor legal groups.

The potential exists for the elimination of 9 executive positions (8 net, with the addition of a regulatory affairs executive), 3 senior management positions and 2 support positions. Beginning in 2021, annual cost reductions would amount to about $4.3 million per year. We consider the addition of a regulatory affairs executive reporting to Hydro's President important in providing an executive team member who can provide a broad view of the implications of regulatory requirements and policies that bear on important executive-level decisions. Effective execution of regulatory affairs takes more than the technical and quantitative analysis that underlie major regulatory requests and proceedings. Our view of Hydro since we began working for the Board has been that the utility does not see focus on regulatory requirements and stakeholders as requiring strategic thinking. This view remains unchanged. We believe that it does and that providing it through a senior-level position will make for better executive decisions at Hydro, and will enhance the utility's ability to structure and support its regulatory positions, filings, and presentations.

VI. LCP O&M Costs

A. Chapter Summary

Estimates of LCP O&M costs prepared in March and in October of 2018 provide sound, well-developed baselines for projecting those costs. They take an appropriately conservative view of staffing needs, given the significant size of the project, new technology (*i.e.*, HVdc), and most importantly, a several-year performance-stabilization period that commencement of LCP operations will require. Despite the propriety of beginning from this conservative approach, we believe that the period for moving from early to sustaining needs requiring fewer resources can be shortened from three-to-five years to between two and three years.

We believe that the complement of certain Nalcor and contractor operations-related personnel can be reduced by 19 FTEs within that period. This reduction in FTEs will reduce LCP O&M costs, when fully realized by 2023, by about $3.1 million each year. Reductions in two major service areas (Corporate Support and in Engineering Services) should cause a further reduction of about $1.4 million per year, starting in 2021. This reduction in Corporate Support and Engineering Services is real in terms of its impact on LCP O&M costs, but is not additive to the costs saved by the potential reductions described in Chapter V (See the *Engineering* and *Corporate Services* sections). They should, however, happen not later than the projected first full year of commercial operation of the LCP in 2021. We foresee the potential for another two or three personnel that are additive, but they will not produce a large additional reduction and the feasibility of those reductions will depend on the organizational changes discussed in those chapters.

Contingency amounts fall as projects like LCP near completion. We found contingency in forecasted LCP O&M costs high by about $5 million. Making that reduction will lower the LCP O&M "estimate" in a real way, but should not be interpreted as lowering future costs. The reason is that the basis for the elimination is the lack of substantial expectation that the contingency funds will need to be spent in the future. SEM-related (other than contractor related SEM costs previously identified) and Administration and Other costs associated with the LCP represent a significant portion of total estimated annual O&M expenditures. We believe that those costs can be reduced by approximately $2.5 million per year, as discussed later in this chapter.

In summary, we believe it is reasonable over time to reduce the current $97.4 million estimate of annual LCP O&M costs by about $12 million, consisting of the following elements:

- $3.1 million for operations related FTE reductions,
- $1.4 million in Corporate Support and Engineering Services charged to LCP O&M
- $4.8 million in reduced O&M Contingency allowance
- $2.5 million in reduced SEM and Administration costs

Some of these reductions can occur now (Contingency) or in the next year or so (Corporate Support and Engineering Services). However, the reductions related to operations-related personnel will take from two to three years post full commercial operation of the LCP. While shorter than the period anticipated by management, we still consider a period of up to three years necessary to ensure that full operation of the LCP assets allows for a sufficient period to reach stabilization, permit transition from contractor to employee control, develop and gain experience with performance metrics and their implications, and for personnel to become familiar with the equipment and systems for which they have accountability and responsibility.

B. Background

The Provincial government sanctioned the LCP in 2012, with construction beginning in 2013. Five formal estimates of annual LCP O&M costs have issued:

- July 2012:[73] $28.4 million
- October 2013:[74] $34.4 million
- June 2017:[75] $109 million
- March 2018:[76] $106.3 million
- October 2018:[77] $97.4 million

These estimates, however, do not have identical scopes. For example, those produced in 2018 include estimates for Water Power Rental ("WPR") and Impacts and Benefits Agreement ("IBA") payments of more than $20 million in total. The three earlier estimates do not include those charges. Even apart from these additions, however, substantial increases have occurred in estimated LCP O&M projections since sanction. They have more recently trended downward, and will likely see further reductions due, at minimum, to the recent Provincial mandate requiring Nalcor to identify $12 million in LCP O&M reductions from those presented in its March 2018 estimate.[78] The mandate references cost reductions in "Muskrat Falls" but the estimate cited encompasses the LIL and LTA portions of the LCP as well. In any event, both the nearly 400 percent increase between the October 2013 and June 2017 estimates and the almost $100 million absolute value of the latest estimate justify examination of the estimates and determination of whether significant potential exists for a material reduction in the current forecast.

We did not examine the detailed sources of changes between LCP O&M forecasts over time, except insofar as they might provide insight into potential consequence for future estimates. We did ask Nalcor to explain the significant increase in the forecast from 2012 to 2017. Nalcor advised that it based the increase in the estimate on a number of factors including, among others, a reassessment of the basis of the estimate considering industry benchmarks of O&M costs as a percentage of asset base, HVdc staffing models, the decision to create Power Supply as a separate organization, an operating philosophy consistent with a high degree of LCP reliability, and the need for experienced HVdc contractor personnel in the early years of operation.[79] We focused primarily on the details of the October 2018 estimate as best representative of the reasonableness of the LCP annual O&M estimate and whether opportunities for material reductions in those costs may exist.

C. LCP O&M Forecast Costs by Category

Our first step in understanding whether potential annual O&M cost reductions may exist was to understand the organization of O&M estimates and the level of detail underlying the cost and personnel (FTEs) categories presented. Both forecasts prepared in 2018 identified four cost categories common to the LIL, the LTA and MF. Only two categories (OL&S and C&ESL, described below) include FTE forecasts. The other categories do not forecast labour (FTE) costs. The four categories of costs common to all LCP operations were:

- *Operating Labour and Salaries ("OL&S")*: Salary, benefits and overtime for LCP operations personnel
- *Corporate & Engineering Support Labor and Salaries ("C&ESL")*: Costs associated with corporate support and engineering services
- *System Equipment Maintenance ("SEM"):* Various contracts associated with the Stations, Transmission, Facilities, SOBI, Reservoir, Powerhouse, and others
- *Administration and Other Costs ("Admin"):* Costs for items such as insurance, travel, equipment rentals, professional services, North American Electric Reliability Corporation ("NERC") membership, safety supplies, etc.

Three additional cost categories apply only to Muskrat Falls:

- *Environmental ("Environ."):* Associated with environmental monitoring, particularly of methylmercury water quality monitoring
- *Water Power Rental ("WPR"):* Unit payments for water use
- *Impacts and Benefits Agreement ("IBA")*: Fixed annual payments

The following table provides a breakdown of cost and FTE projections from the October 2018 estimate for 2021, the expected first full year of LCP operation. We found these projections reasonably similar to those of the March 2018 estimate.

Table VI.1: October 2018 LCP Estimate: O&M Costs and FTEs

Category	Cost ($)	Cost (%)	FTEs (#)	FTEs (%)
OL&S	$14.7mm	15.1%	96	54.3%
SEM	$29.3mm	30.1%	-	-
C&ESL	$12.8mm	13.1%	80.8	45.7%
Administration	$15.0mm	15.4%	-	-
Subtotal	*$71.8mm*	*73.7%*	*176.8*	*100%*
Environmental	$4.2mm	4.3%	-	-
Water Power Rental	$15.6mm	16.0%	-	-
Impacts and Benefits Agreement	$5.8mm	*6.0%*	-	-
Subtotal	*$25.6mm*	*26.3%*	*0*	*0%*
Total	**$97.4mm**	**100%**	**176.8**	**100%**

The SEM category includes $8.2 million in contingency dollars - - approximately 12 percent of the combined OL&S, SEM, C&ESL, Administration and Environmental categories. Excluding contingency brings 2021 estimated SEM costs to about $21.1 million. We made a number of observations about the data shown in Table VI.1:

- Operating-related labour represents only about 15 percent of total annual forecasted costs so even significant reductions in this category will, at best, produce only a marginal impact on overall O&M costs
- SEM comprises the largest cost category - - before and after excluding contingency
- The contingency level (included in SEM) appears high for a project so late in its completion process
- Administration comprises the second largest cost category; combined with C&ESL it represents over 28 percent of total annual O&M costs.

- Corporate support and engineering services FTEs, many of whose costs hit LCP O&M through direct assignment or time charges to LCP, represent over 45 percent of the total identified FTEs associated with the project.

The following table breaks down the FTEs expected to be assigned or to charge time to LCP operations. It does not include contractors, who will play a major role in the early years of LCP operation. For example, Muskrat Falls anticipated more than 50 contractor FTEs at commercial operation, with reductions over the subsequent four years to approximately 34 FTEs.[80]

Table VI.2: LCP FTE Breakdown by Major Component

Category	FTEs (#)	FTEs (%)
LIL	53	30%
LTA	12	6.8%
MF	31	17.5%
Subtotal	*96*	*54.3%*
Corporate Support	38.4	21.7%
Engineering		
Engineering/Technology	28.5	16.1%
Management/Administration	13.9	7.9%
Subtotal	*80.8*	*45.7%*
Total	**176.8**	**100%**

The largest groups of Corporate Support FTEs come in the sub-categories of Finance, Investment Evaluation & Treasury (13.8); Human Resources, (4.0), Environmental (5.0), Executive (3.1), and Supply (3.0). We noted that the 80.8 FTEs charged to the LCP total 90 percent of the total FTEs (90.2) charged to Churchill Falls.[81]

D. Concepts and Assumptions Underlying our Analysis of Potential Reductions

We took a conservative approach in identifying reductions, given the core principle of avoiding risk to the reliable operation of the LCP assets. In particular, this principle led us to conclude that immediate reductions to FTEs or to contracted resources for operations and maintenance staff should not occur until the assets proceed far enough into early operation to ensure that they have reached a sound steady state. First-year staffing assumptions do appear conservative, but we accept that approach, given the high reliability expected, the lack of experience with HVdc operations, and, particularly, the difficulties in recruiting necessary additions and in providing training. We have been dealing and quantifying those challenges for many quarters in our regular monitoring reports addressing Nalcor's preparation for operations of LCP assets.

While patience is required here as contract resources give way to internal personnel in key roles and knowledge transfer is successfully realized, we do, however, believe that management can reduce the transition period it expects to be required to develop a leaner organization. At present, formal identification of personnel requirements (FTEs) extend only to 2021, but plans exist to include five-year FTE projections in the next formal LCP O&M cost estimate due later this year. Nalcor advised us that it expects fewer required FTEs upon reaching steady-state operations; therefore, we would anticipate seeing those reductions in that next estimate.

SEM and Administration cost estimates make up nearly half of annual LCP O&M estimated costs. Those categories present a significant cost-savings opportunity. Similarly, contingency is too high for the LCP, which is nearing completion. Lowering contingency, while appropriate, will not per se avoid costs, but rather make the estimate of annual costs more realistic.

Chapter II's discussion of financial sources of revenue requirements mitigation addressed the water-use-related fees as one such source of cost reduction. Should the Province elect to apply that source to mitigation, it would have the practical effect of eliminating the $15.6 million annual cost shown in Table VI.1 or would make the fees available for rate mitigation to offset the revenue requirement. We did not examine the Impacts and Benefits Agreement as a source of reducing LCP O&M costs. Growing out of discussions and negotiations involving the Innu Nation, Innu Band Councils, the Provincial government and Nalcor Energy, we took changes to the landmark agreement as a matter for the parties who worked hard to put it in place.

The near equality of LCP and Churchill Falls costs for personnel providing Corporate Support and Engineering Services made these categories an important part of our examination. Muskrat Falls has a resource capacity about 15 percent that of Churchill Falls, but almost 90 percent of the FTEs that Churchill Falls has for these services.

E. Analysis

We performed a number of analyses in evaluating whether reasonable prospects exist for reducing LCP O&M cost estimates. Our initial review of the five formal LCP O&M cost estimates developed an understanding of how Nalcor estimated LCP costs and of how and in what categories those costs changed over time. We discussed with Nalcor management its operational and maintenance structures and approaches, which underlie its estimates of personnel requirements. For example, expectations about developing the staffing of operator shifts has changed over time, as did the anticipated use of contractors. We sought to determine how Nalcor approached these topics and whether plans do or should exist to make changes in the future.

We also examined studies and reports Nalcor used in modeling staffing structure and resource numbers. Two specific reports, a LIL-focused study prepared by TransGrid Solutions in 2016,[82] and a 2018 Navigant study[83] examining potential staffing models at Muskrat Falls, substantially informed Nalcor's development of staffing estimates. We also reviewed a number of the larger LIL-related SEM contracts.

Intercompany charges for personnel comprise a not insignificant portion (approximately 13 percent) of LCP O&M costs. We did not examine time-recording and cross-charging methods, systems, and tools underlying the portion of costs that LCP O&M will bear for personnel who serve multiple Nalcor entities (generally Power Supply and Hydro). The Board has reviewed intercompany cost-recovery methods and reviews them periodically in general rate application proceedings.[84] While we accepted the resulting FTE numbers as a valid output of charging as it will be applied, the level of cross-charging FTEs can be reduced. We also surveyed Administration related estimates, and requested support for certain charges (*e.g.*, NERC costs) but, similarly, did not validate support for each Administration related cost category.

F. Conclusions

Our analysis of potential LCP cost reductions led to a number of major conclusions:

1. The LCP O&M cost estimates, particularly the most recent March 2018 and October 2018 versions display a comprehensive presentation of the varied elements that make up LCP estimated O&M costs, showing increasing levels of detail and variance analysis. However, while Liberty reviewed some specifics of the estimates, it did not examine most of the supporting detail due to the practicalities of project time constraints. Estimates of annual O&M charges for projects such as the LCP, which total nearly $100 million, typically reflect, among other considerations: the results of input from scores of internal and external personnel; development, review and updating of numerous individual and focused analyses; application of corporate protocols and standards (*e.g.*, cross charging); ascertaining the relevance (or not) of changing commercial and technical conditions; and a keen understanding of and appreciation for organizational capabilities. The time frame under which we conducted our work allowed us to develop a sufficient level of understanding of costs, cost trends, cost categories and justification(s) to make considered recommendations, but not enough to delve deeply into estimate details.
2. First year (2021) FTE staff levels appear appropriately conservative, given the goal of high LCP reliability and lack of experience with HVdc operations.
3. Nalcor should target operational-related reductions (including contractors) of 19 FTEs from projected first-year levels, primarily in the operations and support areas of MF. (Contractor FTE reductions for the LIL would be reflected in additional SEM reductions, described below). Such reductions would reflect operational shift changes, reduced environmental monitoring, and reduced FTEs for waterway and dam maintenance post-LCP completion.
4. These reductions should be accomplished post-commissioning after successfully reaching a stable and predictable operating environment, but should be accelerated, where possible, to accomplish reductions within two to three years.
5. Material Corporate Support and Engineering Services reductions should occur. We understand that the LCP operates under operating conditions and technologies, and contractual arrangements that require significant management attention, although the separation of Hydro and Power Supply responsibilities (addressed in Chapter V) adds to the staffing requirements for doing so. Factors like these make determining support personnel requirements more than simply a matter of facility size, but they do not make it irrelevant. A reduction of just 8 FTEs (approximately 10 percent) from an estimated total of 80.8 will still leave the LCP with more than three quarters of the numbers that support Churchill Falls (90.2).
6. We do not see a reason to defer these Corporate Support and Engineering Services reductions until post commissioning; they can be made by 2021. The analysis of corporate support staff and of combining Hydro and Power Supply functions (Chapter V), pick up most of these reductions. Perhaps an additional two or three reductions may be possible, but we hesitate to estimate them because they depend on any organizational changes that may occur as a result of recommendations made in Chapter V. Thus, while it is appropriate to remove their costs from LCP O&M estimates, these reductions should not be considered additive to the reductions described in that chapter.

7. The current 12 percent ($8.2 million) contingency allowance should be reduced to, in our opinion, a more reasonable level of 5 percent, or $3.4 million. This reduction of $4.8 million can be accomplished immediately.
8. Estimated SEM costs for 2021 amount to $21.1, excluding contingency. However, because SEM-related contractor cost reductions of $2.4 million (of the $3.1 million in operations-related personnel) have already been identified, remaining SEM costs total $18.7 million (*i.e.*, $21.1 million - $2.4 million). Estimated Administration costs for 2021 amount to $15.0 million. We consider the combined remaining SEM costs (*i.e.*, $18.7 million) and Administration costs ($15.0 million) of $33.7 million reducible by 5 to 10 percent (between $1.7 and $3.4 million). We have approximated the savings at $2.5 million. We did not ground this estimate on a detailed review of all SEM contracts and their status, nor a review of the 15 categories of Administration and Other costs. However, not all SEM contracts have been executed, which provides opportunity for negotiated reductions in scope and cost, particularly given the scale of the project, and Administration-related costs (*e.g.*, travel, rentals, transportation, advertising, training) are largely within the purview of management and can be moderated to reflect extant financial circumstances.

G. Transition Needs and Barriers to Execution

Implementing the reductions we have recommended imposes a number of transition needs. First is to pace the reductions as required to meet the main priority of ensuring safe and reliable operation of facilities that bring major size and technological change to the organizations who will operate them. Lack of experience within Nalcor in HVdc operations, reliance on outside resources for early operations, and the physical environment in which the LIL will operate, support the need for measured resource reduction and transfer from contract to employee performance of key roles. Nalcor will need to monitor asset performance especially closely in the first phase of LCP operation and seek to develop a sufficiently nuanced understanding of asset operations. At the same time, we do not consider it appropriate to extend the glide path to sound and permanent LCP operation and staffing levels, absent well-founded justification. Careful monitoring of projected reductions in contingency allowance, SEM costs, and Support FTEs will also be required to minimize any jeopardy to operational reliability.

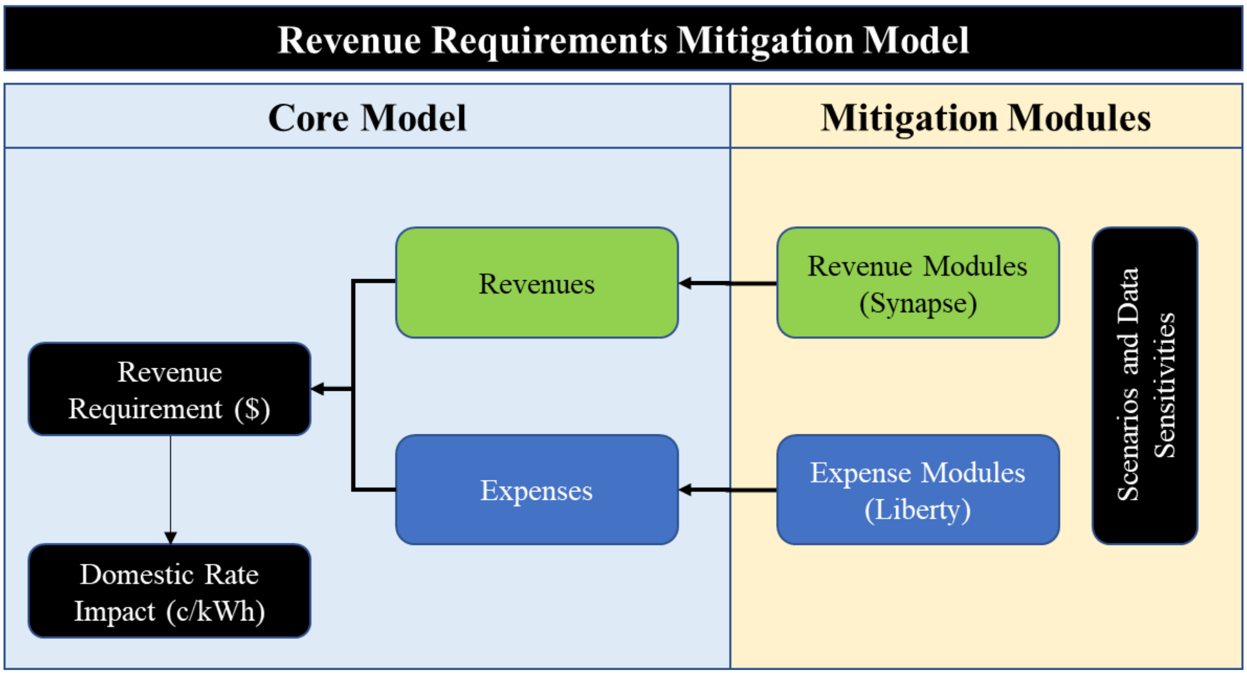
In summary, LCP reliability must remain paramount and resource reductions, although reasonable over time, should not add reliability risk. Performance of the LCP post commercial operation, therefore, will guide the timing of reductions, but management should seek to make its transition to that state more expeditious.

VII. Revenue Requirements Model

A. Model Purpose

We developed a Revenue Requirements Mitigation Model ("RRMM") to manage, organize, and interpret revenue and cost data developed in our examination of revenue requirements mitigation opportunities. We designed the RRMM to convert mitigation scenarios into the two fundamental parameters of the Muskrat Falls cost mitigation initiative: (a) reductions in the annual revenue requirement in dollars per year and (b) reductions in the domestic rate in ¢/kWh. Figure VII.1 provides a high-level view of mitigation initiatives and their impact on Revenue Requirements and the domestic rate[1]. The RRMM includes a Rate Module that estimates the impact of mitigation measures on the domestic rate.

Figure VII.1: Revenue Requirements Mitigation Module Process Flow



B. Model Design

We designed the RRMM to convert all mitigation scenarios into annual economic impacts. For the operational mitigation work that we performed, the Labour Module proved the key one. We designed this module to convert labour (FTE and contractor) reductions from headcounts into dollars (revenue requirements) and ¢/kWh (the domestic rate). We required a tool to link personnel reductions to fully loaded labour rates for each. This required linking the positions and labour rates through a common denominator - - pay grades.

We designed the Labour Module to capture both increases and decreases in positions by year, for

[1] The "Domestic Rate" is the retail electric rate paid by Newfoundland Power's residential customers based on revenue requirements that include both purchases from Hydro and Newfoundland Power's costs.

both Nalcor/Hydro and Newfoundland Power employees and contractors. The module enabled our team examining mitigation opportunities to determine the specific areas in which resource adjustments could occur. It also supported the modeling of compensation differences between Nalcor to Newfoundland Power for positions that might move between the two in certain scenarios. For example, a scenario might show a Hydro work group realizing a reduction of three FTEs in an area where transfer of responsibility to Newfoundland Power would require it to add two. The model would net the three reductions at Hydro's fully-loaded compensation rates and the two additions at Newfoundland Power, using the corresponding labour rate of each.

We mapped Nalcor/Hydro positions to labour rates employing a table (provided by Nalcor) of positions mapped to pay grades,[85] and linked this to a table (also provided by Nalcor) of fully loaded labour rates[86] by pay grade. Fully loaded labour rates include Job Rate (base salary), Benefit Burden, Overtime, Allowances & Other Salary, and Other O&M. Overtime, Allowances & Other Salary includes short term incentive for non-union pay grades 10-11 and executive grades, and vehicle allowance of $12,740 for executive grades. The Benefit Burden includes employer costs for group insurance, Canada Pension Plan, employment insurance, workers compensation, registered pension plan contributions, and employee future benefits. The Benefit Burden represents 31 percent of base salary. Other O&M includes training and associated travel expenses.

We mapped Newfoundland Power positions to labour rates using a company table of job titles mapped to band/grade,[87] and linked this to a table (also provided by Newfoundland Power) of fully loaded labour rates[88] by band/grade. The Newfoundland Power fully-loaded labour rates include Job Rate (base salary), Fringe Costs, Pension Costs, Pay for Performance, Labour Allowances, Overtime, and Non-Labour Allowances. Fringe Costs add approximately 16 percent to base salary, and consist of the company portion of Employment Insurance and Canadian Pension Plan, life and health insurance, Workplace Health, Safety and Compensation premiums, payroll tax, and current service cost of other post-employment benefits. Pension Costs add approximately 11 percent of base salary. Combined, these two items total 27 percent, as compared to the 31 percent for the Nalcor/Hydro Benefit Burden. Labour Allowances account for shift-differential and standby pay. Non-Labour Allowances account for travel, meals, and clothing allowances.

We escalated the loaded labour rates by two percent across our study period (2019-39), using Newfoundland Power's assumption. Nalcor/Hydro did not provide clear guidance on expected labour escalation rates.

This mapping process produced lists of hundreds of positions aligned by dozens of pay grades. The linkage that the Labour Module created permitted our team members to enter FTE adjustments by position, by year, for each company, making it possible to observe and chart resulting annual and cumulative revenue requirement reductions and impacts to the domestic rate.

C. Financial Sources of Mitigation

As Chapter II of this report makes clear, financial sources of revenue requirements mitigation offer by far the largest opportunities. We calculated the mitigation contributions from a number of financial sources:

- Hydro Dividends - - Application of Hydro earnings achievable while maintaining a 25 percent equity level (assumed to be realized in 2025 and beyond).
- Churchill Falls Preferred Dividends and Water-Related Payments to the Province
- Margins from Off-System Sales from Muskrat Falls - - excess energy above the requirements to supply Hydro and Emera interests
- LCP Earnings and Water-Related Payments - - Expected equity returns under the PPA and TFA and water-related payments to the Province.

We input values for each of these elements into the RRMM to produce mitigation contributions. Figure VII.2 shows the results in terms of millions of dollars of annual revenue requirements mitigation. Figure VII. 3 shows the impacts on Hydro's rates in ¢/kWh. We used Hydro's estimates of margins from sales of Muskrat Falls excess energy.

We also calculated (see Chapter II) the effects of applying a 20 percent equity level for Hydro. Doing so would increase Hydro's dividends by about $111 million between 2021 and 2025, reductions each year thereafter would produce $22 million less in cumulative dividends through 2039.[89] Directly reducing Hydro's return on equity to five percent would decrease its IIS revenue requirements by about $16 million in 2021 ($551 million in total through 2039). Doing so while retaining a 25 percent equity target would eliminate all Hydro dividends through 2039.[90]

Figure VII.2: Potential Annual Mitigation from Financial Opportunities

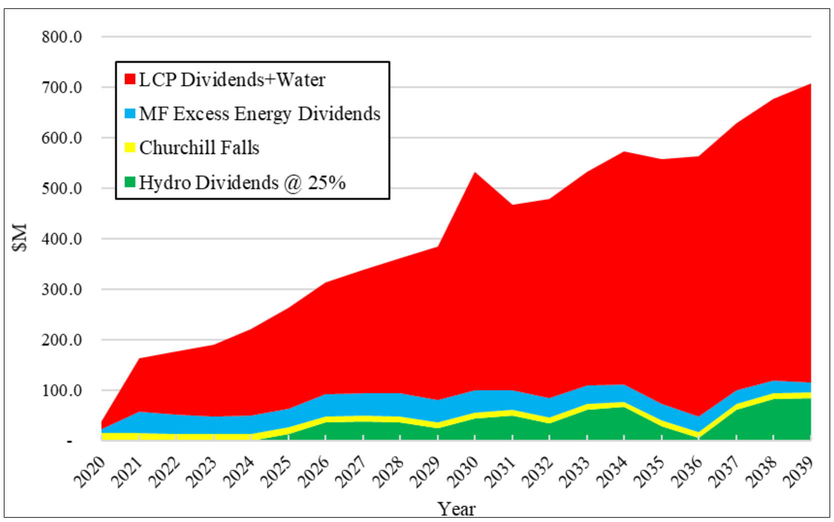
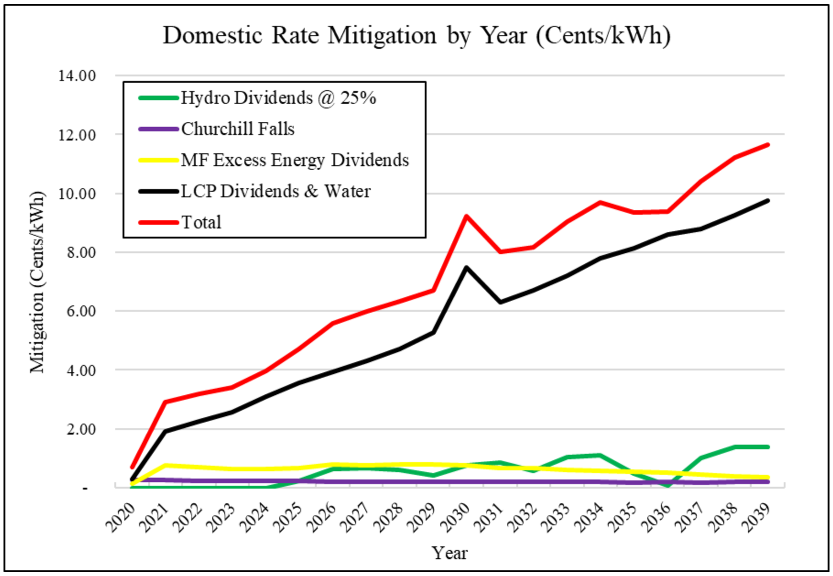


Figure VII.3: Rate Impacts of Financial Mitigation Opportunities



D. Operational Sources of Mitigation

Liberty categorized operational sources of mitigation under the following functional/organizational alignment:

- Hydro and Newfoundland Power Combinations
- Hydro and Nalcor Power Supply Integration
- LCP O&M Costs.

1. Combining Hydro and Newfoundland Power Operations

Our examination of combining Hydro and Newfoundland operations addressed distribution/retail operations, 66 and 138 kV Island transmission, customer service, and small Island hydro generation. That work found a potential for reduction in approximately 45 positions at a possible $7 million in annual costs. However, we did not model them because we found them too uncertain in terms of successful execution. However, the savings we identified for small hydro stations are, in our view, capable of execution under Hydro management. We therefore did include reductions of approximately 17 FTEs and $2.5 million in annual savings for them. We assumed a three-year implementation period.

2. Hydro and Nalcor Power Supply Integration

Our team members addressing each functional area or organization, used the Labour Module to input potential staff changes. Figure VII.4 below shows the resulting annual revenue requirements impacts. Figure VII.5 accumulates the annual results over our full study period. Figure VII.6 shows impacts on the domestic rate by year on a ¢/kWh basis. Figure VII.7 displays the sum of mitigation by functional area/organization for the entire assessment period (2020-39) in a pie chart.

Figure VII.4: Annual Mitigation from Potential Labour Reductions

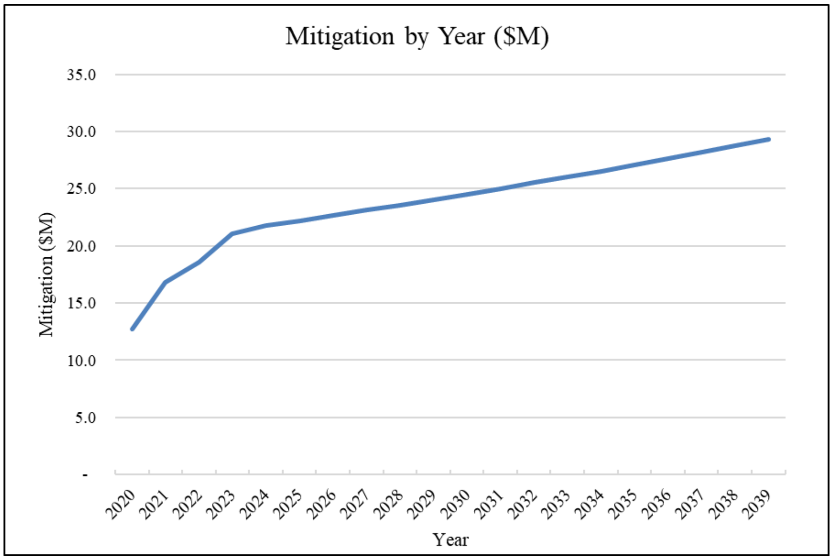


Figure VII.5: Cumulative Mitigation from Potential Labour Reductions

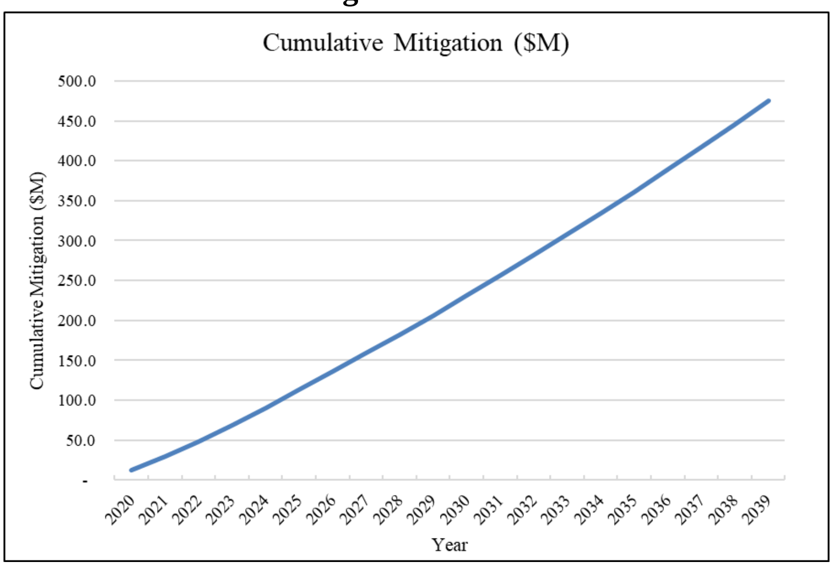


Figure VII.6: Annual Domestic Rate Impact (¢/kWh)

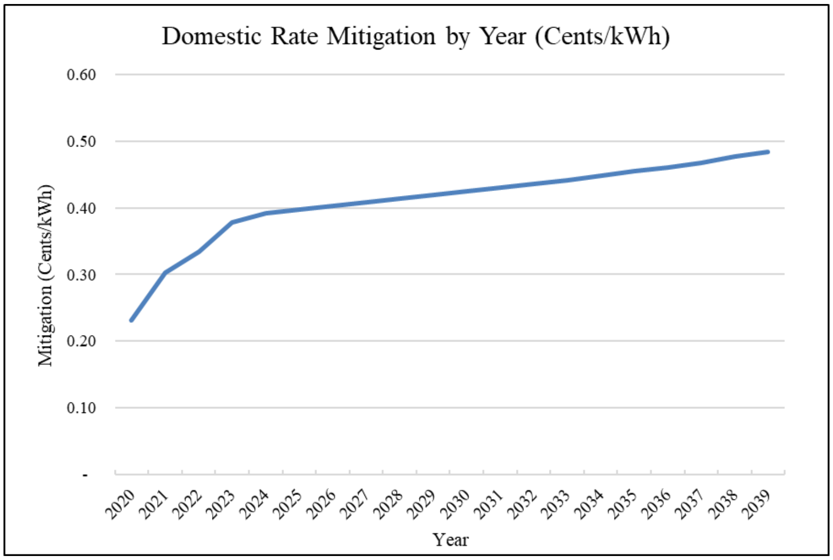
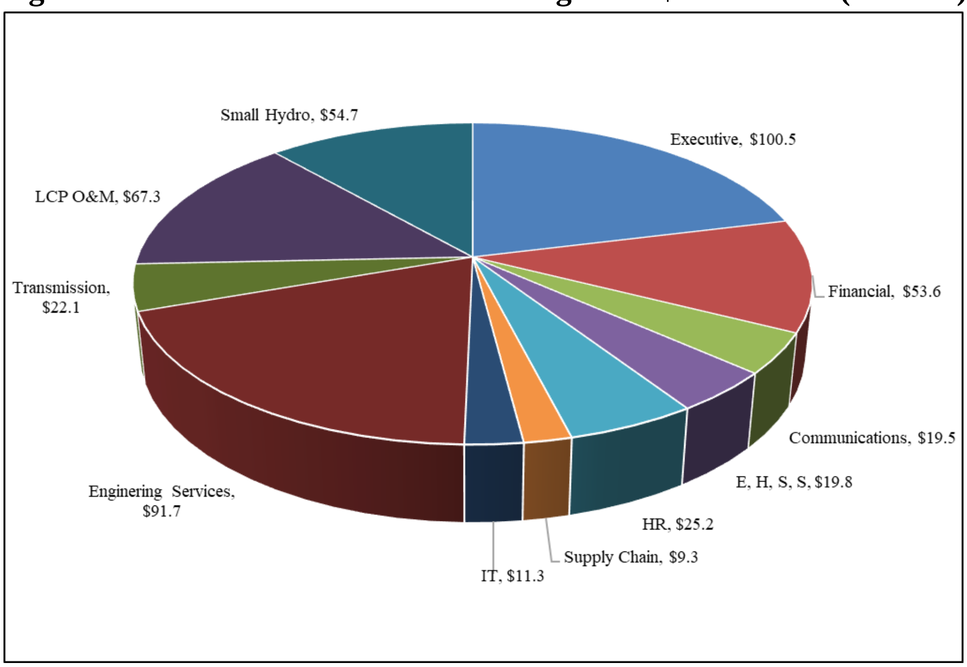


Figure VII.7: Total Labour-Related Mitigation: $475 Million (2020-39)



E. Non-Labour O&M Expense Reductions

In addition to the potential labour-related expense reductions described above, we found it appropriate to reduce the current size of contingency incorporated into estimates of future LCP operations costs. A reduction in contingency from the current 2021 budget of $8.2 million per year to what we view as a more appropriate $3.4 million (given the late stage of LCP completion) would reduce revenue requirements by $4.8 million per year. That reduction would lower rates by just under 0.1 ¢/kWh.

Additionally, Liberty projects a reduction in O&M expenses due to savings in SEM and administrative costs as described in the Chapter VI of this report. This change will reduce O&M by $2.5 million per year, beginning in 2021, escalated by 2 percent thereafter. This reduction will have a 0.05 ¢/kWh impact on the domestic rate. Combined, the two non-labour mitigation items total $7.3 million in 2021, escalating as displayed in Figure VII.8. Cumulative savings from 2020-2039 total $170 million (Figure VII.9). Figure VII.10 plots savings to the domestic rate from the non-labour O&M expense reductions, which begin at 0.13 ¢/kWh in 2021. Figure VII.11 displays the relative contributions of each component of non-labour O&M to the cumulative total.

Figure VII.8: Annual Mitigation from Non-Labour O&M Reductions

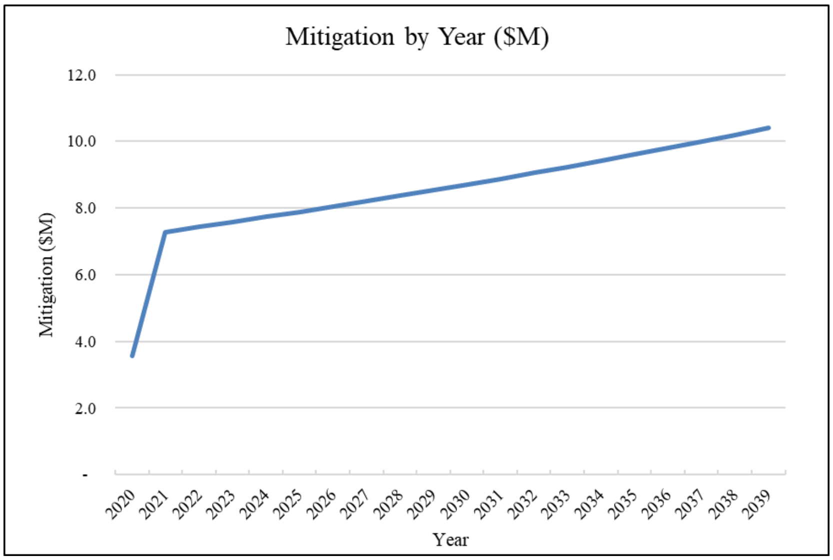


Figure VII.9: Cumulative Mitigation from Non-Labour O&M Reductions

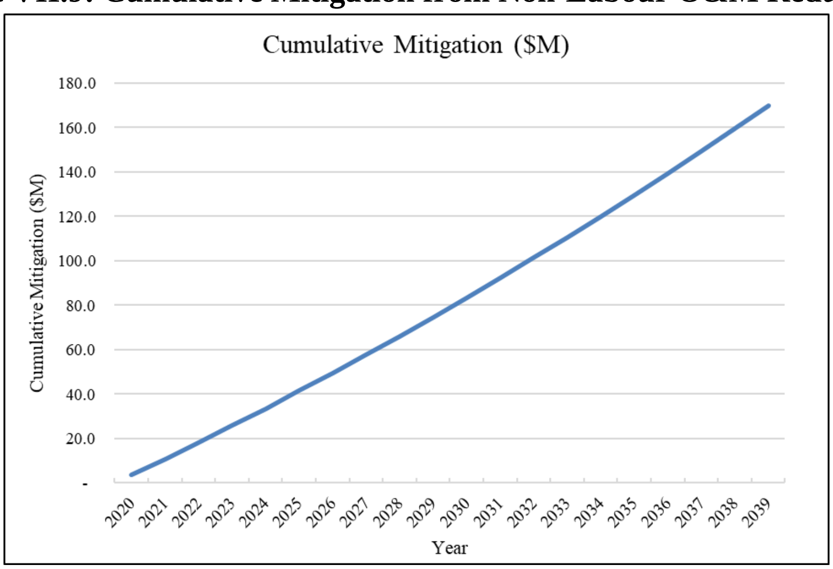


Figure VII.10: Annual Domestic Rate Impact of Non-Labour O&M Mitigation (¢/kWh)

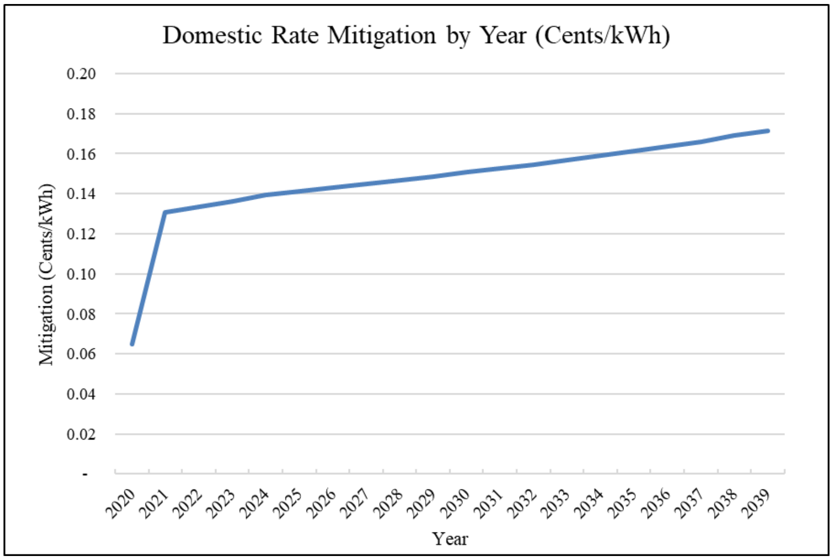
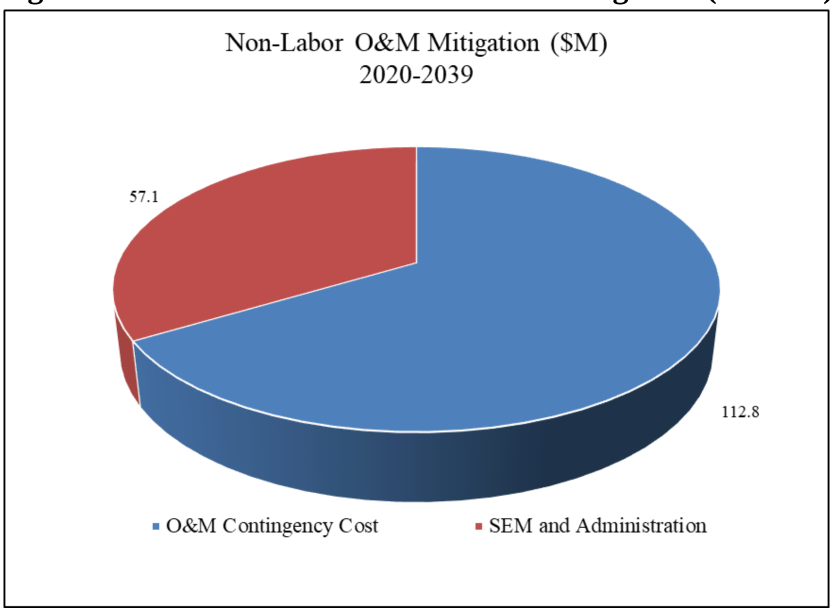


Figure VII.11: Total Non-Labour O&M Mitigation (2020-39)



F. Mitigation from Market Opportunities

Our design of the RRMM included the ability to address the work performed by Synapse. The Revenue Module allows the overlay of outputs from Synapse scenarios onto the cost savings scenarios, thereby providing a depiction of combined revenue requirements mitigation potential resulting from our work and theirs. This work can be done, if necessary, to show the implications of various scenarios.

G. Summary

The RRMM calculates the total impact to Hydro's revenue requirement and domestic rate resulting from mitigation measures. The RRMM acts as a central repository of all mitigation measures, serving as a key project management tool that enables an organized process for collecting and managing mitigation data. The RRMM, a live model, can be adjusted at any time, in real time, to assess the impact of sensitivities such as position headcounts. It provides an easy user interface that enables testing of individual mitigation measures and combinations of mitigation measures where applicable. When combined, the cost savings related with Financial mitigation sources, Labour sources, and Non-Labour O&M sources amount to a substantial reduction in the revenue requirement and domestic rate. This is displayed graphically on an annual basis below in Figure VII.12, and cumulatively in Figure VII.13.

Figure VII.12: Total Mitigation (2020-39)

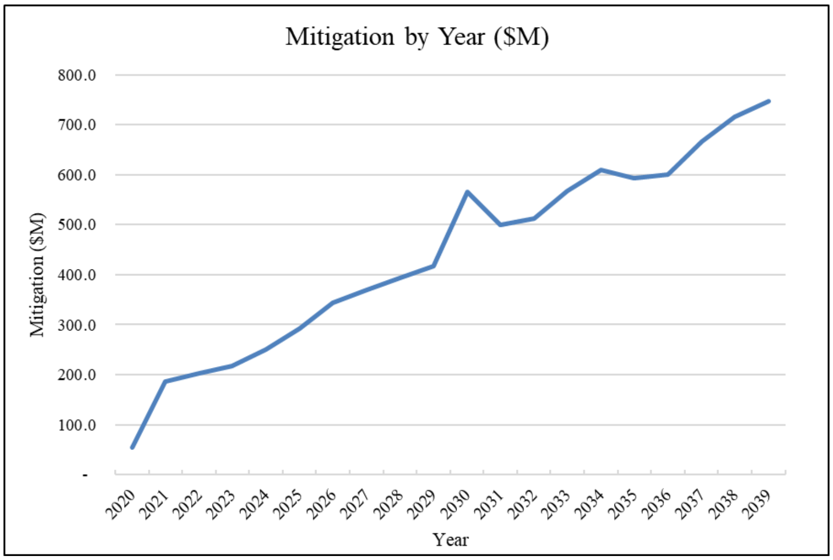


Figure VII.13: Total Cumulative Mitigation (2020-39)

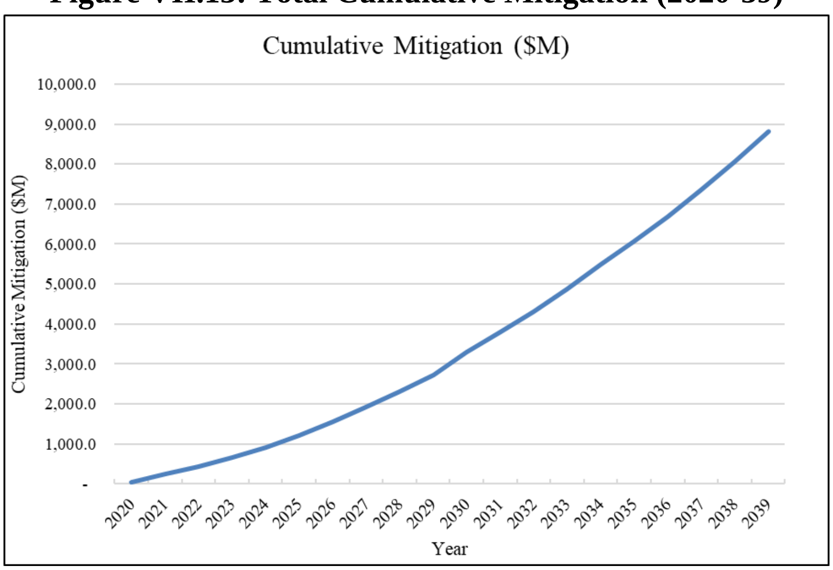
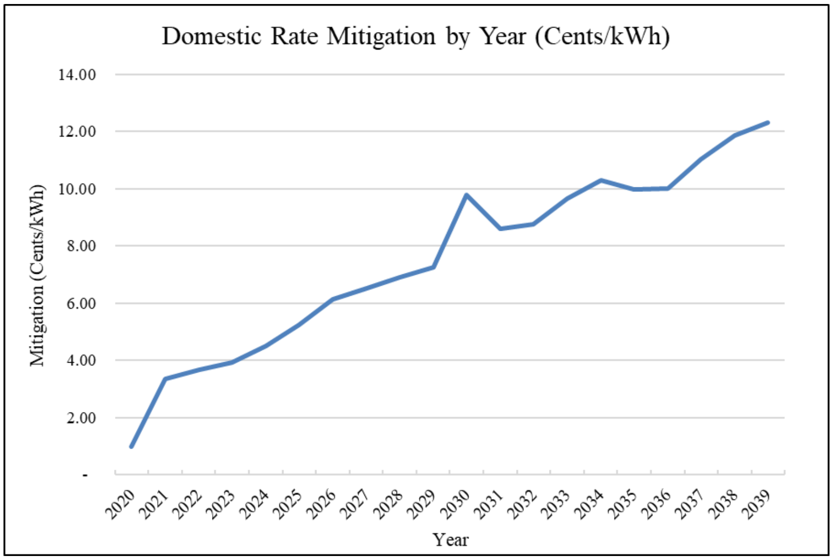


Figure VII.14 shows the total of rate mitigation sources. The mitigation measures start at about one cent reduction in early years, rising to more than a twelve-cent reduction in 2039 when the dividend values from LCP are at their highest levels.

Figure VII.14: Total Mitigation (2020-39)



The result of the mitigation efforts in their entirety are to reduce the domestic rate path as shown in Figure VII.15. The blue area represents the rate after mitigation. The top of the red area represents the unmitigated rate. The red area displays the sum of all recommended mitigation initiatives. Figure VII.16 displays the relative contributions of the sources of mitigation. The lion's share of contribution comes from financial/dividend-related sources, most notably from LCP dividends and water usage fee retention.

Figure VII.15: Rate Path (2019-39)

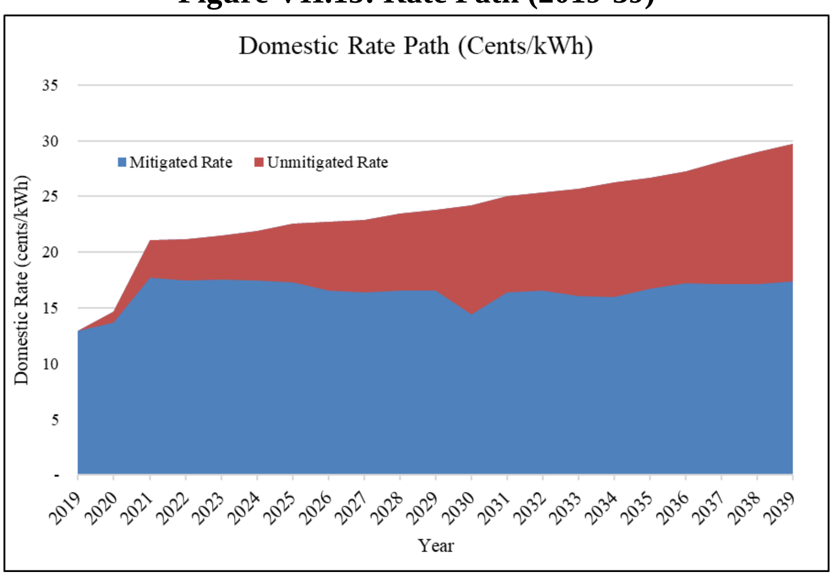
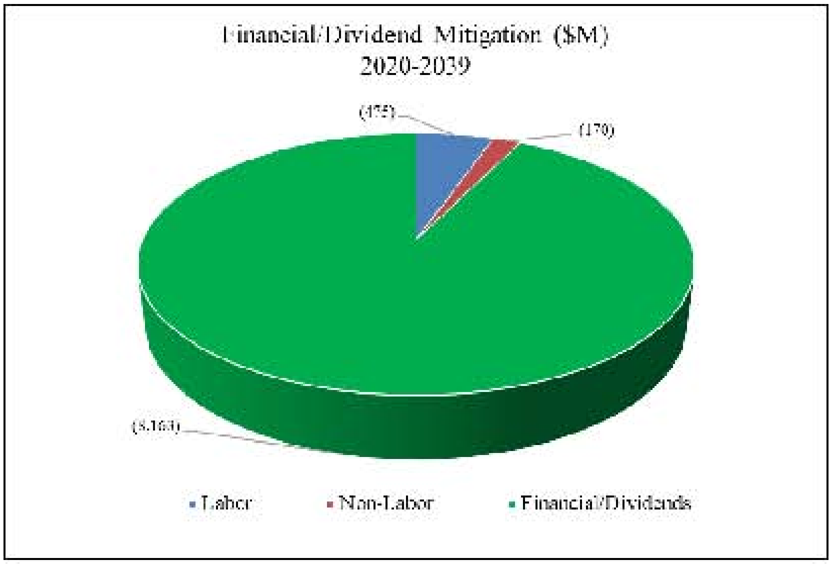


Figure VII.16: Total Mitigation by Source (2020-39)



End Notes

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[1] PUB-Nalcor-016
[2] PUB-Nalcor 046 and PUB-Nalcor-143, Attachment 1,p.4
[3] PUB-Nalcor-16
[4] Ibid
[5] PUB-Nalcor-016, Schedule 2
[6] PUB-Nalcor- 201-204
[7] PUB-Nalcor-30
[8] PUB-Nalcor-30
[9] PUB-Nalcor-258 and 260.
[10] PUB-Nalcor-259 and 261
[11] PUB_Nalcor-262
[12] PUB-Nalcor-263 and 201
[13] PUB-Nalcor-181, 182 and 144
[14] PUB-Nalcor-144
[15] PUB-Nalcor-182
[16] PUB-Nalcor-144
[17] PUB-Nalcor-184
[18] PUB-Nalcor-144
[19] PUB-Nalcor-63
[20] PUB-Nalcor-34
[21] PUB-Nalcor- 34 and 35
[22] PUB-Nalcor-213, DBRS report on Newfoundland and Labrador Hydro, dated December 11, 2008, and PUB-Nalcor-214
[23] PUB-Nalcor-214
[24] PUB-Nalcor-251 and various annual reports
[25] PUB-Nalcor-255
[26] PUB-Nalcor-255
[27] PUB-Nalcor-255
[28] Request PUB-Nalcor-281
[29] Request PUB-NP-101
[30] PUB-Nalcor-267
[31] PUB-Nalcor-267, Attachment 5
[32] PUB-Nalcor-267, Attachment 2
[33] PUB-Nalcor-264
[34] Reference Questions to the Board of Commissioners of Public Utilities Rate Mitigation Options and Impacts, September 5, 2018, at page 2
[35] Reference Questions to the Board of Commissioners of Public Utilities Rate Mitigation Options and Impacts, September 5, 2018, at page 2
[36] BC Hydro 2018/19 Annual Service Plan Report, at page 7
[37] BC Hydro 2018/19 Annual Service Plan Report, at page 14
[38] BC Hydro 2018/19 Annual Service Plan Report, at page 24
[39] BC Hydro 2018/19 Annual Service Plan Report, at page 31
[40] https://www.hydro.mb.ca/corporate/ "About Us"
[41] https://www.hydro.mb.ca/corporate/ "Value of Electricity Exports"
[42] Order No. 59/18 May 1, 2018, at page 178 of 316
[43] Formal Requests PUB-Nalcor-199 and 200, PUB-NP-075
[44] PUB-Nalcor-280, pp 17-21
[45] PUB-Nalcor-129 and 225,
[46] PUB-NP-033 and 050

[47] PUB-NP-084
[48] PUB-Nalcor-011
[49] PUB-NP-084 and PUB-Nalcor-221, 222, 223
[50] PUB-Nalcor-188
[51] https://nlhydro.com/operations/hydro-generation/ ; Note that Star Lake (18.4 MW) is not shown on the cited page.
[52] PUB- Newfoundland Power-094, page A-1
[53] PUB-Nalcor -280, Attachment 1
[54] PUB-Nalcor-238
[55] PUB- Newfoundland Power-094
[56] PUB-NP-097
[57] PUB-Nalcor-129, page 8 of 11
[58] PUB-Nalcor-240
[59] PUB-NP-097
[60] PUB-NP-097
[61] PUB_NP-094, Attachment A, pages 8 and 9
[62] PUB-Nalcor-279 and PUB-NP-100
[63] ***Confidential*** PUB-Nalcor-237 and PUB-NP-093
[64] See generally, PUB-Nalcor-225, Revision 1, Charts D1 through D8 and H1 through H1.4
[65] See generally, PUB-Nalcor-225, Revision 1, Charts E1 through E3, E3.5 through E4, H2, and H2.1
[66] PUB-Nalcor-234
[67] PUB-Nalcor-225, Revision 1, Charts E3 through E3.4
[68] PUB-Nalcor-225, Revision 1, Chart C1
[69] See generally PUB-Nalcor-225, Attachment 1, Revision 1, Charts C1 through C3.1 for organization charts under Nalcor and Hydro finance
[70] See generally, PUB-Nalcor-225, Revision 1, Charts B4 and F1
[71] See generally, PUB-Nalcor-225, Revision 1, Charts and B1 and F3
[72] See generally, PUB-Nalcor-225, Revision 1, Charts B2, B3, and F3
[73] PUB-Nalcor-268, page 1
[74] Ibid, page 2 (Note that PUB-Nalcor-081, page 2, indicates that the estimate - $34 million – was prepared in 2012)
[75] PUB-Nalcor-026, Attachment 1, page 15
[76] PUB-Nalcor-050, Attachment 1, page 14
[77] PUB-Nalcor-050, Attachment 2, page 5
[78] *Protecting You from the Cost Impacts of Muskrat Falls,"* April 2019, pages 5, 6 and 10.
[79] PUB-Nalcor-051
[80] PUB-Nalcor-247, Attachment 1, page 9
[81] PUB-Nalcor-243
[82] PUB-Nalcor-175, Attachment 1, page 17
[83] PUB-Nalcor-174, Attachment 10
[84] PUB-Nalcor-165
[85] PUB-Nalcor-272
[86] PUB-Nalcor-142
[87] PUB-NP-099-C
[88] PUB-NP-098-C
[89] PUB-Nalcor-255
[90] PUB-Nalcor-255