January 24, 2013

Cheryl Blundon
Secretary to the Board
Board of Commissioners of Public Utilities
120 Torbay Road
P. O. Box 21040
St. John's NL
A1A 5B2

Dear Ms. Blundon

The undersigned would like to formally request that the Public Utilities Board, as part of the recently announced inquiry, perform a complete review of Newfoundland and Labrador Hydro methodology used in the forecasting of peak demand.

As documented within the January 8 presentation to the Board, the actual demand realized on January 3rd was 1532 MW, compared to a forecast of 1453 MW. This occurred while conservation measures were allegedly in place. The events of early January has provided evidence that NLH's forecasting methods have the propensity for the under prediction of peak load in winter. Furthermore, there is evidence that the shape of the hourly demand profile has changed from what has been assumed by Newfoundland and Labrador Hydro (NLH) in their long term planning.

The Public Utilities Board is respectfully reminded that during the Muskrat Falls review the Board consultants, Manitoba Hydro, recommended that although Nalcor's use of econometric models were acceptable, they did not meet best utility practice. There was specific concern raised by MHI that the increasing percentage of electric space heaters, may lead to increased error in the peak demand forecast. Manitoba Hydro recommended that to meet utility best practice that Nalcor should[1]:

1) Develop an end use forecasting model for the domestic sector. The best utility practice for preparing a domestic energy forecast is the combination of regression and end use modelling techniques.
2) Nalcor should develop a process to integrate the energy and peak forecasting methodologies.

The undersigned would like to request that the Board inquire as to the status of MHI's key recommendations on load forecasting, specifically the recommendation to adopt end use modelling. In the absence of implementing these earlier 'best practice' recommendations, Nalcor should be obligated to verify the accuracy of their current forecasting of peak demand, particularly for colder than average winter days.

The undersigned also remains deeply concerned that if Nalcor's econometric models do have a propensity to under predict peak loads, this may have far reaching implications on long term planning, even after the commissioning of Muskrat Falls. Attachment 1 provides further

[1] Section 1.11 of Volume II of Manitoba Hydro's report to the Public Utilities Board.
http://www.pub.nl.ca/applications/MuskratFalls2011/files/mhi/MHI-Report-VolumeII-Load.pdf

background on how a small adjustment in peak load could result in continued, unplanned, reliance on thermal generation in the winter months.

Section 5.1 of the Pre-Filed evidence to the PUB during the 2009 Water Management Hearings[2] stated "The WMA will not impose any obligation upon CFL(Co) to produce energy for Nalcor which exceeds the amount of energy Nalcor previously banked, nor to produce at a **rate** for Nalcor in excess of Nalcor's facilities capabilities". This implies that the maximum output available to the Province in the winter months will be a maximum of 824 MW from Muskrat Falls, in addition to the 80 MW remaining of Recall power from the Upper Churchill[3].

Once transmission losses are accounted for, and the deliveries to Emera are made, the Labrador Island Link will contribute 645 MW at peak to the island grid at Soldiers Pond[4]. However, if Nalcor commit 70 MW to Alderon, this will be reduced to about ~580 MW of peak delivery at Soldiers Pond. Following the decommissioning of Holyrood there will only be a net increase of about 120 MW available to the island grid.

During the Muskrat Falls hearings the Maritime Link, and subsequent deliveries were omitted from the Terms of Reference. It is unclear if the Strategist results presented in the Muskrat Falls review included, as a minimum, the 167 MW peak delivery to Emera?[5] Therefore, in addition to the status on MHI's recommendations concerning forecasting techniques, the undersigned would request that the PUB seek clarification on:

1) Confirmation from Nalcor as to the nature of the Power Purchase Agreement (PPA) between Nalcor and NLH for Muskrat Falls. Specifically what Capacity (in terms of MW) will be available to the NLH at Soldiers Pond in the months of January – May respectfully, and how does this compare to the Strategist calculations performed by Nalcor in support of the Muskrat Falls decision as the lowest cost option for ratepayers.
2) Is Nalcor's PPA with NLH based on the Average Annual Energy, or Firm Annual Energy supplied from Muskrat Falls? How does this compare to the Strategist calculations in support of the Muskrat Falls decision?
3) Does Nalcor's obligations to Emera (the peak delivery of 167 MW, or sales of any surplus energy under the Energy Access Agreement) potentially compromise the delivery to NLH? What recourse (ie; damages in PPA) does NLH have against Nalcor in the event of non-delivery? Would any such damages be used to offset the rates payable by the NL rate payer in the regulated rate base?
4) Contractually does Nalcor have a priority to deliver the 167 MW to Emera, or to NLH in the event of a shortfall in domestic generation?
5) Could Section 8 of the EPCA-1994 be used by the Board to direct the 167 MW Emera delivery to NL consumers in the event of a winter shortfall of capacity? Would the Board be willing to undertake such action as a preference to rolling blackouts?

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[2] http://www.pub.nl.ca/applications/Nalcor2009Water/files/applic/Application-VolumeI.pdf

[3] Page 94; http://www.pub.nl.ca/applications/MuskratFalls2011/files/submission/Nalcor-Submission-Nov10-11.pdf

[4] Page 14 http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit106.pdf

[5] This was specifically asked by the undersigned in RFI's CA/KPL-Nalcor-175 and 175 during the Muskrat Falls hearing. There was no response by Nalcor at the time as they were deemed outside the Terms of Reference

6) If the EPCA is used to redirect the Emera delivery to Newfoundland, would any penalties incurred upon Nalcor be in included within the NLH rate base? If so, what is the estimated magnitude of any such damages which Nalcor must pay Emera?
7) Without the ability to take more than 525 MW (Recall + Twinco blocks) from the Upper Churchill facility, it is likely that Nalcor will depend on the reservoir storage at Muskrat Falls to ensure the plant can meet 824 MW peak delivery[6]. All submissions made by Nalcor to the CEAA, or the PUB, have referenced the reservoir elevation remaining constant through operation. In light of the recent frazil ice issues at the Grand Falls run of the river hydroelectric facility, Nalcor are requested to confirm that **daily** fluctuations in reservoir elevation, of 0.5 meters, can be accommodated at Muskrat Falls in periods of ice cover.
8) Attachment 2 provides information from Nalcor, which suggest that if the reservoir elevation cannot change, and Hydro Quebec request full output from the Upper Churchill, the maximum capacity from Muskrat Falls is 630 MW. Considering the Alderon and Emera deliveries, this would limit the delivery to Soldiers Pond to approximately 435 MW (less than Holyrood). Nalcor are requested to confirm the Firm Winter Capacity of the HVDC link in the event Hydro Quebec exercise their contractual right to take full production from the Upper Churchill plant for short periods of time (excluding Recall and Twinco Blocks).
9) The PUB is requested to clarify why Nalcor have recently completed revised numerical modelling of the hydrology of the Churchill river system?[7] Nalcor is requested to clarify the firm capacity, firm energy and the average annual energy as calculated by Hatch within the most recent work. What impact does this have on the availability of energy and capacity to NL ratepayers.
10) Can Nalcor provide a status regarding the supply of backup power from Nova Scotia? In the 15 legal agreements between Nalcor and Emera, has access and a rate been agreed for this back up power? If the island deficiency is due to failure of the LIL, would the cost of any back up imports from Nova Scotia be excluded from the NL rate base?
11) Nalcor are to confirm that their current expansion planning is consistent with what was presented in DG2/DG3 documentation[8]:
    i. Holyrood is planned for decommissioning in 2022 (-466 MW),
    ii. Hardwoods CT decommissioned in 2022 (-50 MW),
    iii. Stephenville CT decommissioned in 2024 (-50 MW)
    iv. 2 x 27 MW windfarms decommissioned in 2028 (-54 MW)
    v. No additional generation until a new 50 MW CT in 2032.
12) If the DG2 strategist analysis presented by Nalcor to the Board does not include the Emera delivery of 167 MW, then it is requested that the following be updated with all current and future energy/capacity delivery obligations included. These should be based on the most current load forecast, cost estimates, and an expansion plan meeting similar design standards:
    i. RFI-MHI-Nalcor 13: Energy Balance and LOLH calculations
    ii. RFI-MHI-Nalcor 49.1(b): Fuel Expense Details
    iii. PUB-Nalcor-5: Hydro's Wholesale and Retail Estimates

[6] http://www.scribd.com/doc/114943485/The-Water-Management-Agreement
[7] http://www.hatch.ca/News_Publications/Vista_DSS/November_2013/nalcor.htm
[8] http://www.pub.nl.ca/applications/MuskratFalls2011/files/rfi/MHI-Nalcor-13.pdf

13) Nalcor are requested to provide clarity as to how the winter island demand will be met if any additional power sales are committed to Labrador industrial customers?

To conclude higher than predicted demand, combined with lower generation available from Muskrat Falls, could have a substantial impact on the reliability of the island generation system. Although the Maritime Link was excluded from the terms of reference of the original Muskrat Falls hearing, the undersigned considers it essential that the Board fully review the implications of the Emera peak period delivery. Any additional requirements for alternate generation sources earlier than 2032, or the life extension of existing thermal assets, will potentially have an impact on the rate structure. In light of the recent inability of Nalcor to meet peak demand, it is considered prudent for the Board to investigate these points.

Finally, the undersigned would like the Board to investigate if CAPEX expenditures on the island isolated system (New 50 MW CT unit, Third Line, or other maintenance items) were intentionally delayed to increase rates in the years prior to the Muskrat Falls facility being commissioned. Reference is made to RFI-PUB-Nalcor-87[9] in which Nalcor stated a clear policy objective to ensure that rates for the interconnected alternative would be no higher than the isolated option during the early years of the Muskrat Falls project. With declining oil costs, was there a decision by Nalcor to delay key projects to inflate rates in the 2015-2018 period, thereby reducing 'rate shock' upon the completion of Muskrat Falls?

Although these issues may expand the current scope of the inquiry, it is continued essential to verify the long term reliability of the island system following the decommissioning of the Holyrood plant. The rate payers of the Province deserve full transparency on these issues.

Respectfully Submitted,

JM

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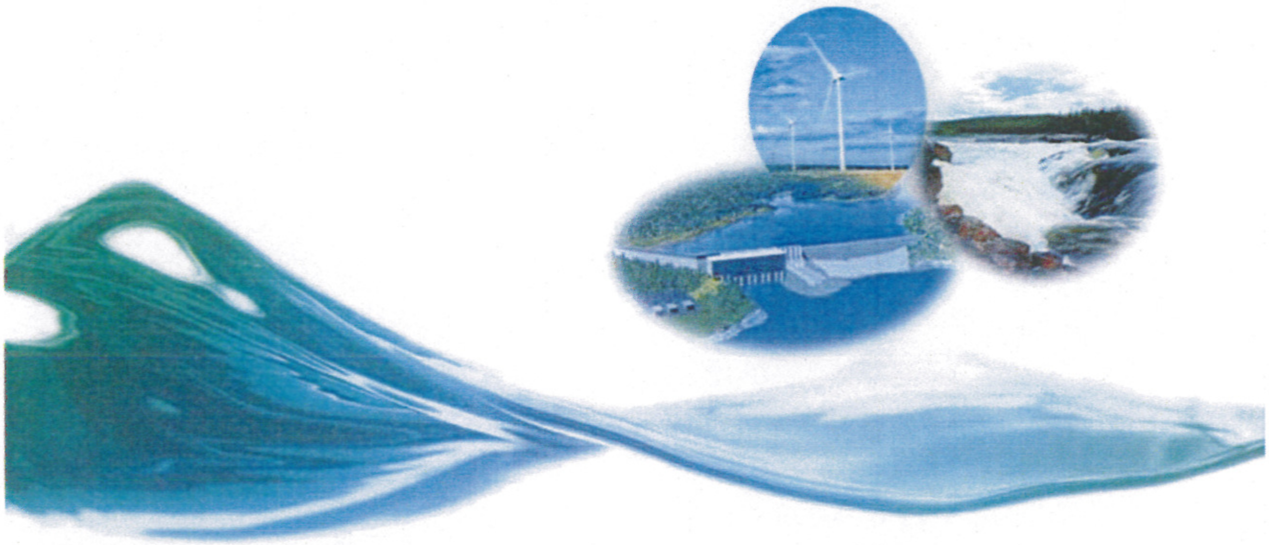
[9] http://www.pub.nl.ca/applications/MuskratFalls2011/files/rfi/PUB-Nalcor-87.pdf

Attachment 1

Underestimating Peak Load and the Potential Impact on the Muskrat Falls Solution



Underestimating Peak Load and the Potential Impact on the Muskrat Falls Solution

A Discussion Paper on Muskrat Falls

Volume X

January 2014

Introduction

Over the past 20 years, there has been a clear shift in the way people heat homes; away from oil and wood to electrical heating. We are now much less likely to have a neighbor who has a wood stove or a parent with an oil burner. Independent rural communities that once could accommodate a week-long power outage must now organize 'warming centers' to shelter the elderly and those without alternative heating. We are now completely dependent on the black wire which connects to our homes.

The rolling blackouts of January 2014 clearly demonstrate our collective dependence on electricity. It is no longer an issue of lights and comfort. Extended power outages in the dead of winter are a safety issue. It is therefore essential that we fully investigate the root cause of the recent set of blackouts that led to 70% of the population of the province without power in temperatures of minus 15 degrees. Why were we in this situation?

People will rightly focus on why three of Nalcor's generators were out of service. Are there structural deficiencies in Nalcor's asset management process that would allow essential generation to be under maintenance during the peak period?

Why were key upgrades to the island generation and transmission system delayed? This includes a new 50 MW CT unit that was supposed to be in service in 2014 and a third line from Bay D'Espoir that was supposed to commence in 2011 to reduce the oil burned in Holyrood, and increase the firm capacity of the island generation system [Ref. 13]. What is of great concern is that both of these upgrades are also required for Muskrat Falls .

If Nalcor had advance warning of these deficiencies, why was there not better communication to the people of the province? When Ed Martin discussed the litany of issues like lack of spare parts and untested fuel hoses [Ref. 1], one cannot help but think that these are merely symptoms of a broken system. There are fundamental questions which must be properly answered by Nalcor to the people of the province.

The most alarming observation from the recent blackouts was not that generation was offline. This can be explained with root cause analysis. What is more alarming is why demand was so much higher than expected by Nalcor.[1] Why were Nalcor caught flat footed, by cold temperatures, in the middle of winter? This is less likely to be addressed in any report which may be filled by Nalcor to the Public Utilities Board on this failure. But the rate payers of the province should be concerned about the potential under prediction of peak load, and the impact on Nalcor's future generation planning.

This essay will attempt to further explore these concepts.

[1] Within the presentation to the PUB made on January 8 [Ref. 15] Nalcor indicated that the forecast for the Nalcor system was 1454 MW. (Readers should note this is the Nalcor system on the island, and not the entire Island load which also includes Corner Brook Pulp and Paper, and NF Power generation). The demand on December 14th was 1501 MW (3%) and on January 3 reached 1532 MW with conservation measures in place. This was 5% over the peak load. Dawn Dalley tweeted on January 5 that the peak Nalcor demand was 1550 MW and the total island demand was 1720 MW.

Our Changing Energy Requirements

As part of the January 5th press conference, Ed Martin effectively acknowledged the role of residential base board heating in explaining the very high demand levels which were experienced leading up to the blackout. Planning engineers at Nalcor normally use complex econometric models to assess the demand, based on previous electrical consumption correlated to current economic indicators. They should be able to estimate the demand with a reasonable level of accuracy[2]. Nalcor analysts should be able to properly account for the increase in electrical heating, and cold temperatures.

We must consider whether this first "colder than average" winter in over five years has revealed an unknown deficiency in Nalcor's forecast modeling techniques. A continual under-prediction of the peak load may have a serious impact on Nalcor's planning to meet our electrical needs. A systematic under prediction of forecast load would mean that Nalcor customers will potentially face rolling blackouts until Muskrat Falls is brought online, if not beyond that time. That remains a serious question: what will happen after the commissioning of Muskrat Falls, if Nalcor's forecast of peak winter demand over the 50 year life of the project is consistently too low?

Readers who followed the PUB review of Muskrat Falls may remember much discussion regarding the estimated growth in demand on the island demand which justified the expensive Muskrat Falls solution. In their review for the PUB, Manitoba Hydro International raised specific, and major concerns with Nalcor's dependence on econometric models for predicting peak power requirements. They noted that best utility practice would be to use "end use modelling" to forecast the peak loads. MHI's concerns and recommendations are recapped from their final report submitted to the PUB [Ref. 2].

[2] Within Section 1.1 of Volume II of Manitoba Hydro's report to the Public Utilities Board it was concluded that "The domestic forecast methodology is acceptable, but does not meet the requirement of best utility practice for this sector". MHI also concluded that there was a likelihood that Nalcor's models would under predict into the future.

The electric space heat end-use has a very low load factor (probably in the range of 35-40% in Newfoundland), so the system load factor should decrease as electric space heating represents a larger proportion of the total island energy requirements. Since 1990, the overall system load factor has changed very little, fluctuating around 60%, even though the number of electric space heating customers has risen dramatically and the high load factor industrial load has declined sharply.

The peak forecasting adjustment assumes that the rate of technological change will continue at a rate of 30% lower in the future. This may not be enough of a reduction. If future efficiency gains from the existing building stock shell improvements (e.g. insulation upgrades, EE windows, caulking, etc.) become even more difficult to achieve, then the rate of future technological change could diminish more than 30%. This would have the effect of increasing the peak forecast (i.e. technological improvements reduce peak requirements). The key point is that the continued addition of electric space heating load should have the effect of lowering the future system load factor more than the current forecasted level of 58%.

The main concern with this methodology is that the system peak is being calculated separately from the energy portion of the forecast. This makes it necessary to calculate adjustments to the peak in order to ensure consistency with the energy growth and produce a smooth load factor for the island. The system peak forecasting methodology could be improved by incorporating domestic, general service, industrial and end-use (e.g. space heating) load research information into the forecasting process to develop an integrated energy and peak forecasting methodology. NLH staff should partner with Newfoundland Power to develop a coordinated load research program that is designed to develop load shape information by sector and by end-use. Sector or end-use energy forecasts could be distributed on an hourly basis throughout the year, using the hourly load shape profiles developed from the load research information. These hourly load forecasts could then be added together to produce an hourly forecast model for the interconnected system.

MHI noted that "electric space heat end-use has a very low load factor ...in Newfoundland.... Since 1990, the overall system load factor has changed very little, ..., even though the number of electric space heating customers has risen dramatically and the high load factor industrial use has declined sharply."[3]

MHI's main concern with Nalcor's forecasting method was "that the system peak is being calculated separately from the energy portion of the forecast." While MHI used language that might be hard for some to understand, the ideas are actually quite easy to see if we use a simple description of what has actually happened in Newfoundland over the past decade.

It has been well documented by Nalcor that energy once used by the two Abitibi paper mills have been utilized by new home construction. The new homes are larger in size, with 90% using electrical heating. Although the total annual energy has remained essentially the same, the "load demand profile" – that is, when we use the energy - has changed.

A large industrial customer like a paper mill requires energy evenly over the year. This is illustrated within the following figure.

[3] Section 1.6.3 of Volume II of Manitoba Hydro Report to the Public Utilities Board as part of the Muskrat Falls Review [Ref. 2]

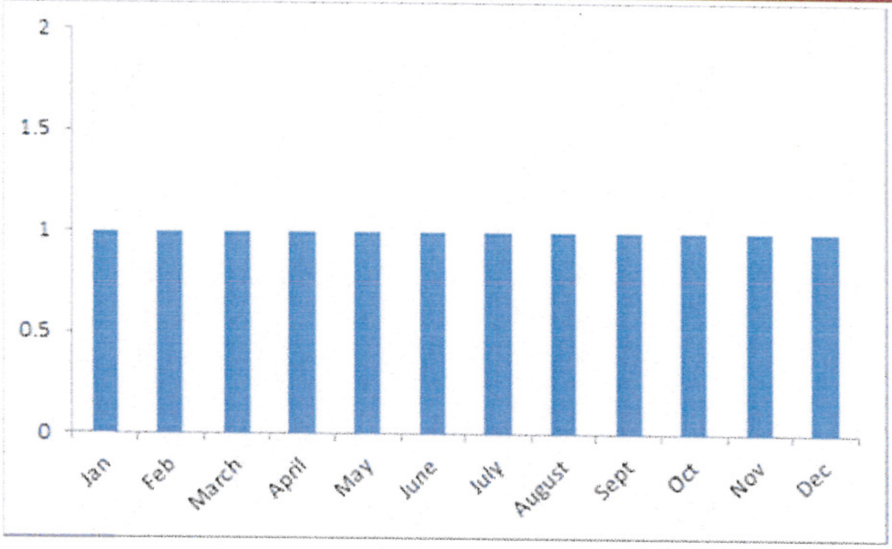


Figure 1

Now consider if this power was required by a 3000 square foot house heated with base board heating. Consumption in winter is going to be much higher in the coldest months than in the summer months. Figure 2 shows a typical home in such a situation: it uses twice as much power in January than in July.

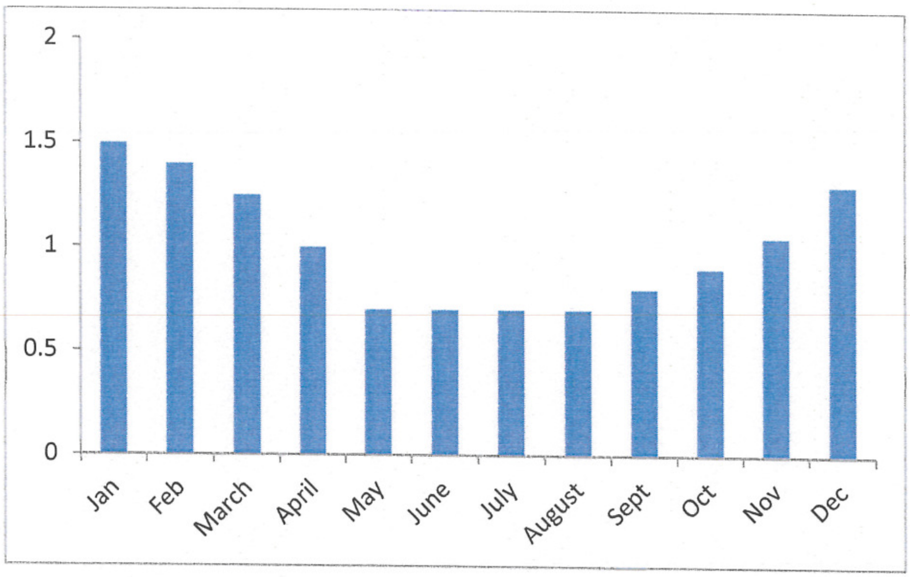


Figure 2

As with the industrial user in Figure 1, there are there are 12 (monthly) units of energy used over the entire year. However there are 1.5 units in January and 0.75 units in July. The ratio of total energy to Peak has changed from 12:1 for an industrial customer, to 8:1 for a residential customer.

What that means in simplest terms is that with the change from an electrical market with a heavy industrial load to one that is dominated by electrical home heating, the peak demand (MW) should grow at a faster rate than the total annual energy (MWhr). This is what MHI identified as a potential shortcoming in Nalcor's forecasting methodology. To deal with this fundamental change in the island's electricity market, MHI recommended that Nalcor change the forecasting method to the one used by used by most major utilities, but not employed by Nalcor.

During the PUB review of the Muskrat Falls project, and independent of MHI's assessment, the Author also questioned Nalcor's forecasting of the peak load over the 50 year duration of the Muskrat Falls project [Ref. 3]. In an earlier paper, the Author compared the ratio of total energy (GWhr) to the Peak Demand (MW) from the period of 1970 to 2067. The resulting graph showed that there has been a clear historical decrease in this ratio. In other words, over the past 40 years, peak demand has been growing at a faster rate than total annual energy.

Figure 3 shows the ratio of total energy to peak demand. The flat line from 2010 to 2067 is the ratio of total energy, to peak, as determined by Nalcor within their future 57 year forecast. The flat line implies that Nalcor assumed that the Peak (MW) was growing at the same rate as the overall annual energy requirement (GWh). This is verified within Exhibit 1 submitted to the PUB, during the Muskrat Falls hearing, and contained within Appendix A.

The trend evident in Figure 3 for the period of 1970 to 2010 is what MHI described. A market that is increasingly dominated by domestic base board heating should result in peak load increasing at a faster rate that the total annual energy consumed. Nalcor's future assumption of a constant ratio (ie; flat line) seems to counter what has been reasoned by MHI and correlated with historical trends.

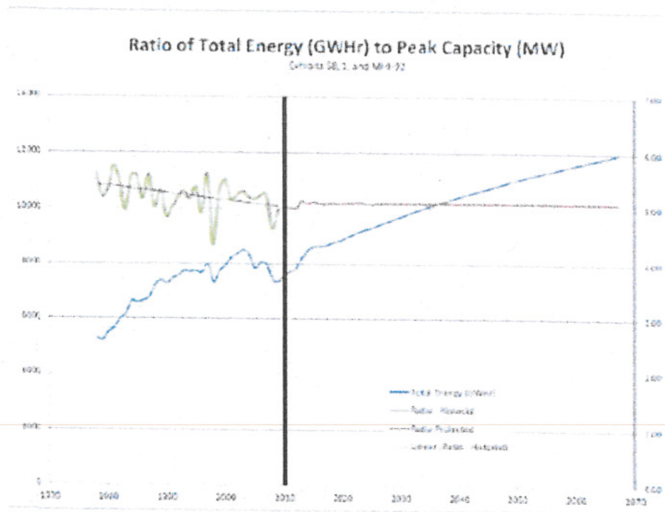


Figure 3: Ratio of Total Energy to Peak Load

If Nalcor has been under-estimating the peak load, then what is the impact of that on Nalcor's long term planning? What is the potential impact when Muskrat Falls comes online? If the peak loads are higher than expected, will Nalcor be able to take Holyrood offline in 2021, as is the current plan. Nalcor's analysis provided to the Public Utilities Board [Ref. 4] assumed that Nalcor will be able to decommission Holyrood in 2021. Nalcor does not plan to add new thermal (CT) generation to handle peak loads until 2032 when the company has included a new 50 MW CT unit within their analysis[5].

Most importantly is the peak load now much more sensitive to cold temperatures than what it was even 10 years ago?

[5] This is from the DG3 analysis presented as part of MHI's report completed for Nalcor as part of the DG3 review [Ref. 16]. Nalcor planning also has the co-generation unit at Corner Brook and the Hardwoods CT (gas turbine generators) coming offline in 2022. The Stephenville CT unit (two gas turbines) will come offline in 2024 and the current wind units will be taken offline in 2027 [Ref. 3]

Peak Load and the Muskrat Falls Solution

If Nalcor's peak forecasting is deficient, then Nalcor may not be able to take Holyrood out of service and/or decommission other thermal generation. The requirement to put the expensive retrofit costs into Holyrood or to immediately build new thermal generation to replace Holyrood's existing plant would wipe out any argument that Muskrat Falls is the lowest-cost way to meet Newfoundland's future electricity needs. Any forecast of future electricity costs for consumers would also be invalid.

Nalcor's Winter Peak Demand Model

Historically, the island of Newfoundland had a much higher requirement for energy and capacity in the winter than compare in the summer. There can be as much as a 700 MW swing in demand between the winter peak and summer average. Figure 4 shows the load profile for 2010. The winter peak (just to the left of the word "March") is clearly visible. [Ref. 5]:

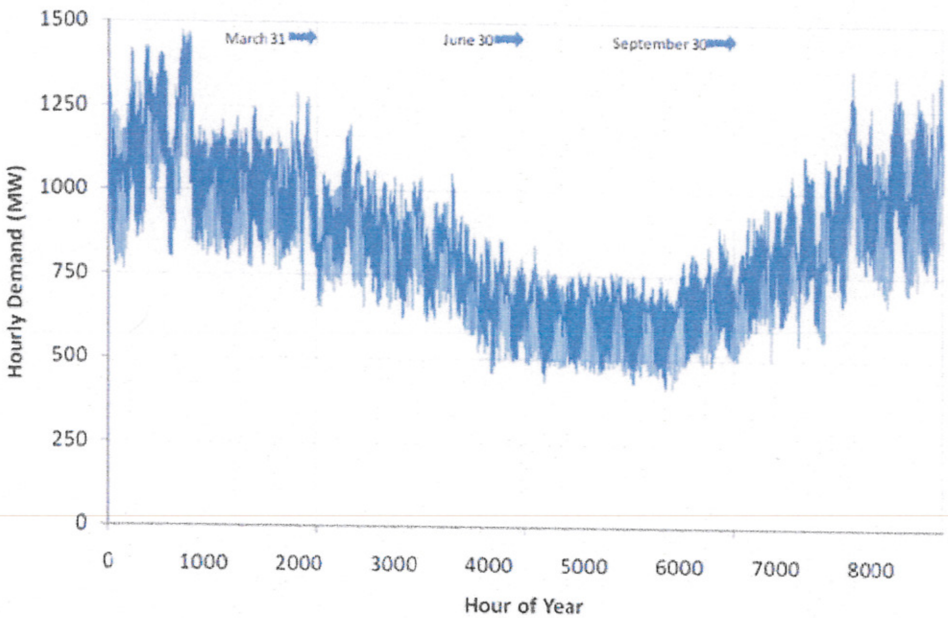


Figure 4: 2010 Demand Profile

During the Muskrat Falls PUB review, Nalcor submitted considerable amounts of data about the island's load profile to support their submission. Exhibit 1 [Ref. 6] provided the forecasted peak load for the 20 year PLF. The loads from the DG2 assessment are provided below.

	Energy GWh	Peak Load MW
2010	7,585	1,519
2011	7,709	1,538
2012	7,850	1,571
2013	8,214	1,601
2014	***8,488***	***1,666***
2015	8,608	1,683
2016	8,626	1,695
2017	8,666	1,704
2018	8,735	1,714
2019	8,806	1,729
2020	8,872	1,744
2021	8,967	1,757
2022	9,065	1,776
2023	9,171	1,794
2024	9,235	1,813

Nalcor Exhibit 2 [Ref. 7] submitted to the PUB provided an hourly profile of the demand for each month of the year. Based on Nalcor's information the peak load occurred in January, with a slightly reduced peak load occurring in December and February.

Figure 5 provides a typical weekly demand profile for January, based on Nalcor's data for 2014, 2021, and 2032. There is a clear increase in the peak energy into the future. When reviewing Figure 5 the reader is reminded that 2021 is when it is planned to convert Holyrood from a generating unit, and 2032 is when the next 50 MW CT unit is added to the system after Muskrat Falls coming on line.

Figure 5 clearly shows that in 2014 that Nalcor should have been prepared for a total island load of 1666 MW in January.

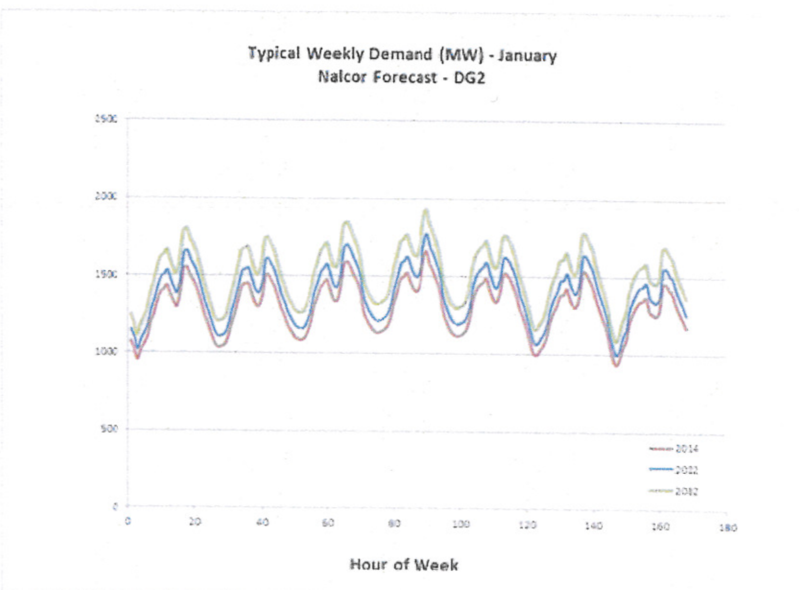


Figure 5: Typical Weekly Profile (MW)

Muskrat Falls Decision Gate 2 Assessment

Within the DG2 comparison of Muskrat Falls versus the isolated alternative, Nalcor treated the Labrador Island Link as if it was a 900 MW CT unit [Ref. 8]. As described by Nalcor "this transmission interconnection has a capacity to supply 900 MW of power and energy from Labrador to the Island and is treated by Strategist as an unrestricted thermal supply source".

This was a key part of Nalcor's analysis because it assumed that there was 900 MW available when needed to meet the island demand. Thermal generators (CT units) can provide electricity whenever it is as needed, up to the maximum output of the generator. Hydro-electric generators cannot because the water needed to make electricity is not always available at the maximum. The only limit Nalcor imposed in their model was the annual energy, which included both the firm energy from Muskrat Falls (4500 GWhr) and the remaining firm energy from RECALL (1400 GWhr) [Ref. 9].

Nalcor's DG2 assessment also used a number of other key assumptions:

1. There was no delivery of 167 MW to Emera (980 GWH of energy) during peak hours.
2. There is no delivery to Alderon (estimated as 80 MW)
3. The WMA is considered effective, and Nalcor do not need to "chase the flows". The full output of 900 MW is available at any time from the combination of the Muskrat Falls, and Churchill Falls plant.

With the benefit of the full output from Muskrat Falls there was no requirement to burn oil in the cold winter months to meet the peak load. Exhibit 99 [Ref. 10] documents that although there were added costs for the new CT units to provide back up support, Nalcor did not allow for any significant oil costs to actually generate electricity[6]. <u>The DG2 analysis which established Muskrat Falls as the lowest cost option assumed that Muskrat Falls was sufficient to meet the winter loads, without the burning of significant oil, or having to retrofit Holyrood beyond 2021 for reliability reasons.</u>

Table 2 provides a summary of the hydraulic generating capacity in 2022, with Muskrat online, and Holyrood decommissioned [Ref. 11]. Assuming all of Muskrat production is available there is 2116 MW of hydraulic capacity to meet the peak demand in winter, without having to burn fuel in the CT units.

[6] http://www.pub.nl.ca/applications/MuskratFalls2011/files/rfi/MHI-Nalcor-49-1-b.pdf outlines that the amount of energy generation from oil was about 2 GWhr annually until 2027. This is 20 hours at 100 MW.

Table 2: Summary of Hydraulic, Cogen and Wind Firm Capacity (MW) in 2022

	Hydraulic, Cogen	Comments
Newfoundland Hydro	MW	
Bay Despoir	592	
Salmon	84	
Hinds Lake	75	
Cat Arm	127	
GC	40	
Paradise	8	
Snooks	1.3	
Muskrat Falls LIL (Reduced for Line Losses	807	From Exhibit 106
Holyrood		
CT		
Hawkes, St. Anthony		
Newfoundland Power		
Hydraulic	96.6	
CT		
Diesal		
Other		
CPP	121	
Exploits	105.8	
CB Cogen		Retiring in 2022
Rattle Brook	4	
St. Lawerence Wind	27	Retiring in 2028
Fermuse Wind	27	Retiring in 2028
Total	2115.7	

Emera, Alderon, and Peak Deliveries

Although Nalcor's DG2 analysis treated the Labrador-Island Link as 900 MW CT unit, it ignored several realities of the Muskrat Falls project. First, Emera will receive 20% of the energy from Muskrat Falls in exchange for building the Maritime Link. Emera were able to smartly negotiate that delivery during the peak day time hours. The Emera delivery and the lines losses will effectively reduce that 900 MW to a maximum of 645 MW delivered to Soldier's Pond (Ref. 12) for use into the Newfoundland grid. The retirement of Holyrood will result in only 180 MW of additional capacity into the grid.

Second, Nalcor's view of the Labrador Island Link assumed Nalcor could obtain additional capacity and energy from Churchill Falls under the Water Management Agreement. If Hydro-Quebec is successful in its current court case and Nalcor subsequently commits 80 MW to Alderon, that 645 MW would actually be reduced to 580 MW as a maximum.

Table 3 shows the firm hydraulic generation available from 2028 to 2032, taking into account reduced output from the Labrador Island Link (580 MW not 900 MW) and the scheduled retirements of the wind generation. In this period there is a firm capacity of only 1888 MW unless there is dependence upon oil generation.[7]

Table 3: Hydraulic, Wind and Cogen Capacity Considering Nalcor's Commitment to Emera and Alderon

	Hydraulic, Cogen	Comments
Newfoundland Hydro	**MW**	
Bay Despoir	592	
Salmon	84	
Hinds Lake	75	
Cat Arm	127	
GC	40	
Paradise	8	
Snooks	1.3	
Muskrat Falls LIL (Reduced for Line Losses	580	
Holyrood		
CT		
Hawkes, St. Anthony		
Newfoundland Power		
Hydraulic	96.6	
CT		
Diesal		
Other		
CPP	121	
Exploits	105.8	
CB Cogen		Retiring in 2022
Rattle Brook	4	
St. Lawerence Wind	27	Retiring in 2028
Fermuse Wind	27	Retiring in 2028
Total	**1888.7**	

[7] Expansion plan for DG2 is provided within Table 26 of the November 2011 submission by Nalcor to the PUB [Ref. 17]. In this reference you will note that a new 170 MW CT unit was not added until 2037. At DG3 this had been accelerated to 2032 [Ref. 16]

Peak Load and the Muskrat Falls Solution

Figure 6 compares Nalcor's predicted demand with the 1888 MW of non-thermal capacity for 2014, 2021, and 2032. With all hydraulic and cogen facilities at 100% utilization the available capacity will just meet the required demand.

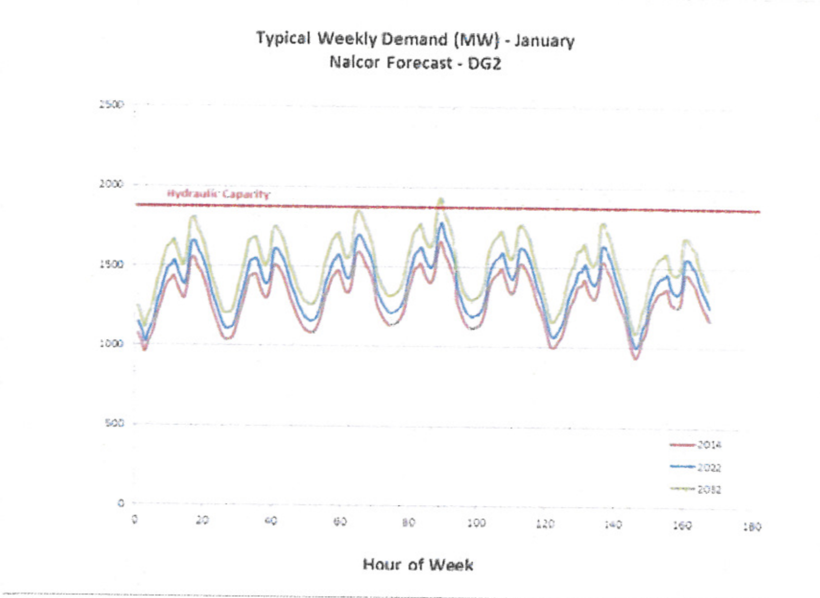


Figure 6: Demand Versus Generation

However, any problems with hydraulic generation, or minor increases in demand will result in the dependence on thermal generation. If the water management agreement is ineffective, Muskrat Falls will likely produce less energy during the peak demand months of January to March. This means the Labrador Island Link would not act like a 900 MW CT unit which formed the basis of Nalcor's Strategist analysis. The result is that Nalcor may not be able to meet the forecasted peak demand for extended periods of time. Any shortfalls would have to be met with external purchases, additional thermal generation within the province, rolling blackouts, or imports of electricity from outside the province. The latter option is entirely dependent on whether electricity is available from Nova Scotia or Quebec.

Changes in Peak Demand

One of the most troubling aspects of the January 2014 power outages was Nalcor's admission that the demand was much higher than what was expected. Figure 6 shows potential problems in 2020s and 2030s if the peak winter demand only increases slightly. What is the true impact of a skyrocketing winter demand profile?

As a sensitivity assessment, let us adjust Nalcor's model to show a peak demand that grows at a rate 25% higher than the current forecast rate of increase in total annual energy. This data is provided within Appendix B, where is it also superimposed upon Figure 3. It does appear as a realistic sensitivity assessment.

The adjusted peak demand is plotted in Figure 7 for 2022, 2032, and 2041, against the hydraulic generating capacity of 1888 MW.

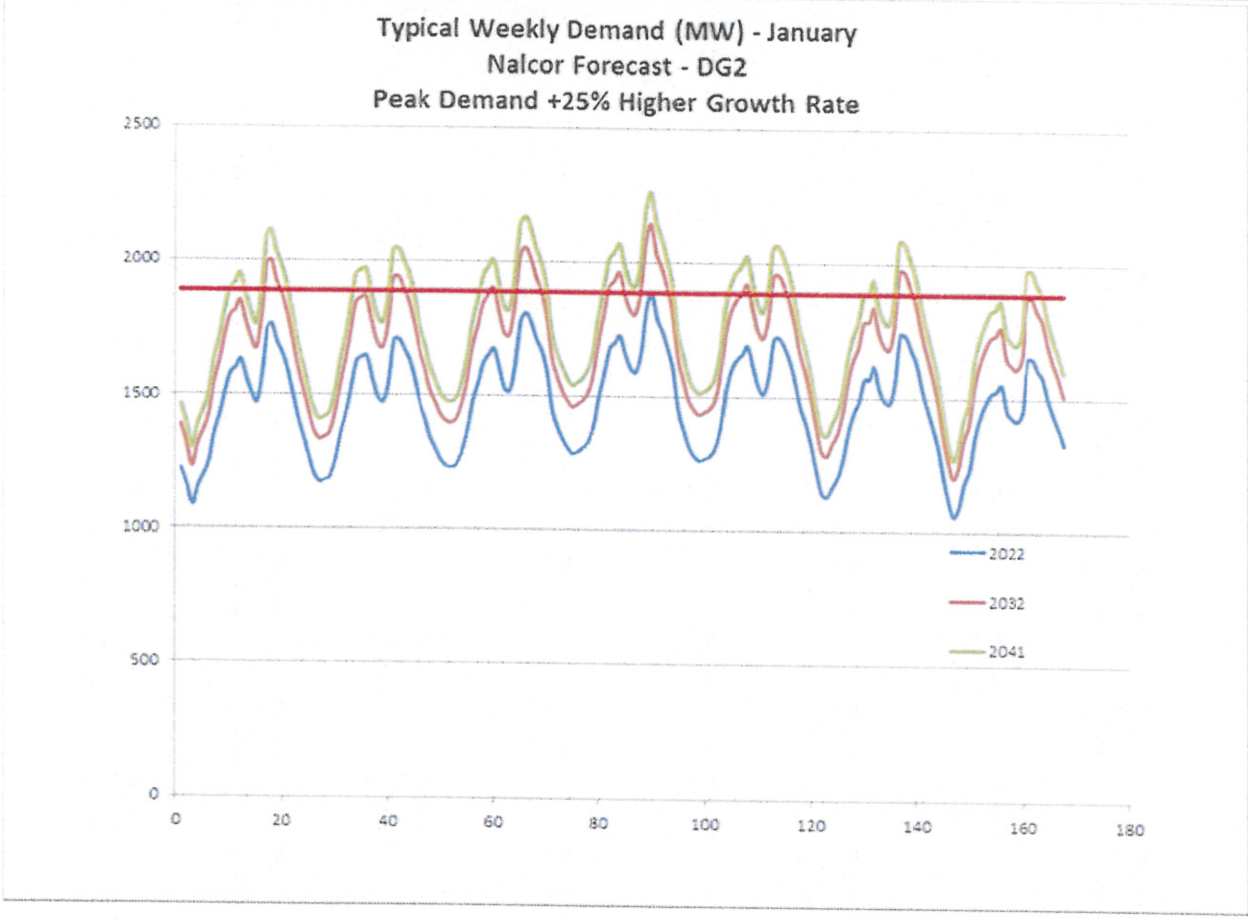


Figure 7: Nalcor Peak Demand January Load Profile Increased by 10% Versus Hydraulic Capacity

Figure 7 shows that if Nalcor's peak demand model is modified such that the Peak Demand grows at a rate 25% higher than the growth rate in annual energy, then there could potentially be an increased reliance on oil generation in the winter months. There is also a requirement for additional thermal backup (CT generation), and at an earlier date than assumed by Nalcor within their Strategist expansion plan for the Muskrat Falls option. Both of these changes will potentially increase the rates to the island rate payer. More alarming is that very shortly after Muskrat Falls there could be additional shortfalls on the cold winter days.

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Conclusions

During the coldest winter in recent memory, Nalcor's electrical system has failed due to lack of generation and, apparently, very high demand. The demand has appeared to exceed what was forecasted by Nalcor. This can be partially explained by the transition of the Island electricity market to one which is dominated by residential winter heating.

If Nalcor's econometric models under- predict peak demand, ratepayers in Newfoundland and Labrador may have to bear considerable additional costs after the completion of Muskrat Falls.

There are several questions that should be answered by Nalcor:

1) With these recent outages, will Nalcor adopt MHI's recommendation to complete end use modelling, and hourly shape demand as completed by other utilities in Canada?
2) If there is any real potential for the peak load to be higher, is it realistic to decommission Holyrood in 2022? Alternatively, does Nalcor have to procure a new 170 MW CT unit for back up earlier than the 2032 date presently planned?
3) Will NLH be dependent upon thermal energy in the cold winter months as early as 2022? How much oil will be burned in the early years after Muskrat Falls considering Nalcor's commitments to Emera and Alderon?
4) Will Nalcor have to maintain Holyrood with the expensive retrofitting and maintenance that was so effectively documented in the isolated island option presented to the PUB?
5) In the event of failure of the LIL (and after closure of Holyrood in 2022) can the required back up power be practically imported from Nova Scotia and/or Hydro Quebec? What is the cost of this power, and impact on our rates? Has this access been negotiated with Emera?
6) Will Nalcor be able to meet the deliveries to Emera in the cold months. What are the damages if we are unable to meet this obligation?
7) Will Nalcor burn oil in Newfoundland in order to provide the 167 MW to Nova Scotia?
8) How do we provide any additional firm capacity to new mining activity in Labrador with this winter peak time restriction?
9) Are the existing weather correction factors correct with the increase in residential heating.
10) How much capacity will the Power Purchase Agreement between Nalcor and Newfoundland and Labrador Hydro provide delivered at Soldiers Pond? Will it be consistent with the Muskrat Falls lowest cost analysis?

This is an issue which requires further investigation. Ideally, Nalcor would adopt Manitoba Hydro's DG2 recommendations to complete load shape data, end use model, and hourly load shape model as other currently performed by other utilities for the residential sector. With the events of January 2014 it would be reckless to not complete this engineering to truly understand our peak demand model. By Nalcor's own admission this is not something they can currently claim.

Table 17: Forecast Methods Used by Other Canadian Utilitie:

FUNCTIONS PERFORMED	RESIDENTIAL			
	NLH	ON	MB	BC
Customer Billing Data	x	x	x	x
Economic/Price Data	x	x	x	x
Demographic Data	x	x	x	x
Weather Data	x	x	x	x
Business Type Coding				
Customer Survey Data	x	x	x	x
Appliance/End-Use Data	x	x	x	x
Commercial Floor Space				
Industrial Output				
Load Research Data	x	x	x	x
Load Shape Data		x	x	x
Regression Model	x	x	x	x
End-Use Model		x	x	x
Weather Adjustment Model	x	x	x	x
Hourly Load Shape Model		x	x	x

References

1. Ed Martin press conference on January 5, 2014
2. http://www.pub.nl.ca/applications/MuskratFalls2011/files/mhi/MHI-Report-VolumeII-Load.pdf
3. http://www.pub.nl.ca/applications/MuskratFalls2011/files/comments/11-JM-2012-02-29-Rev1.pdf
4. http://www.pub.nl.ca/applications/MuskratFalls2011/files/comments/11-JM-2012-02-29-Rev1.pdf
5. http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit101.pdf
6. http://www.pub.nl.ca/applications/MuskratFalls2011/nalcordocs.htm
7. http://www.pub.nl.ca/applications/MuskratFalls2011/nalcordocs.htm
8. http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/NalcorSubmission-July6-11.pdf
9. http://www.pub.nl.ca/applications/MuskratFalls2011/MHIreport.htm
10. http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit99.pdf
11. http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit16-GenerationPlanningIssuesJuly2010.pdf
12. http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit106.pdf
13. Exhibit 116
14. Exhibit 1 http://www.pub.nl.ca/applications/MuskratFalls2011/nalcordocs.htm
15. Presentation
16. http://www.powerinourhands.ca/pdf/MHI.pdf
17. http://www.pub.nl.ca/applications/MuskratFalls2011/files/submission/Nalcor-Submission-Nov10-11.pdf

Dawn Dailey @dawndailey 5 Jan
@BerniceCBC 1550MW was the Hydro System Peak (Hydro assets). The total island system peak that night was approx. 1720MW.
View conversation

Appendix A: Exhibit 1 from Muskrat Falls Hearting [Ref. 14]

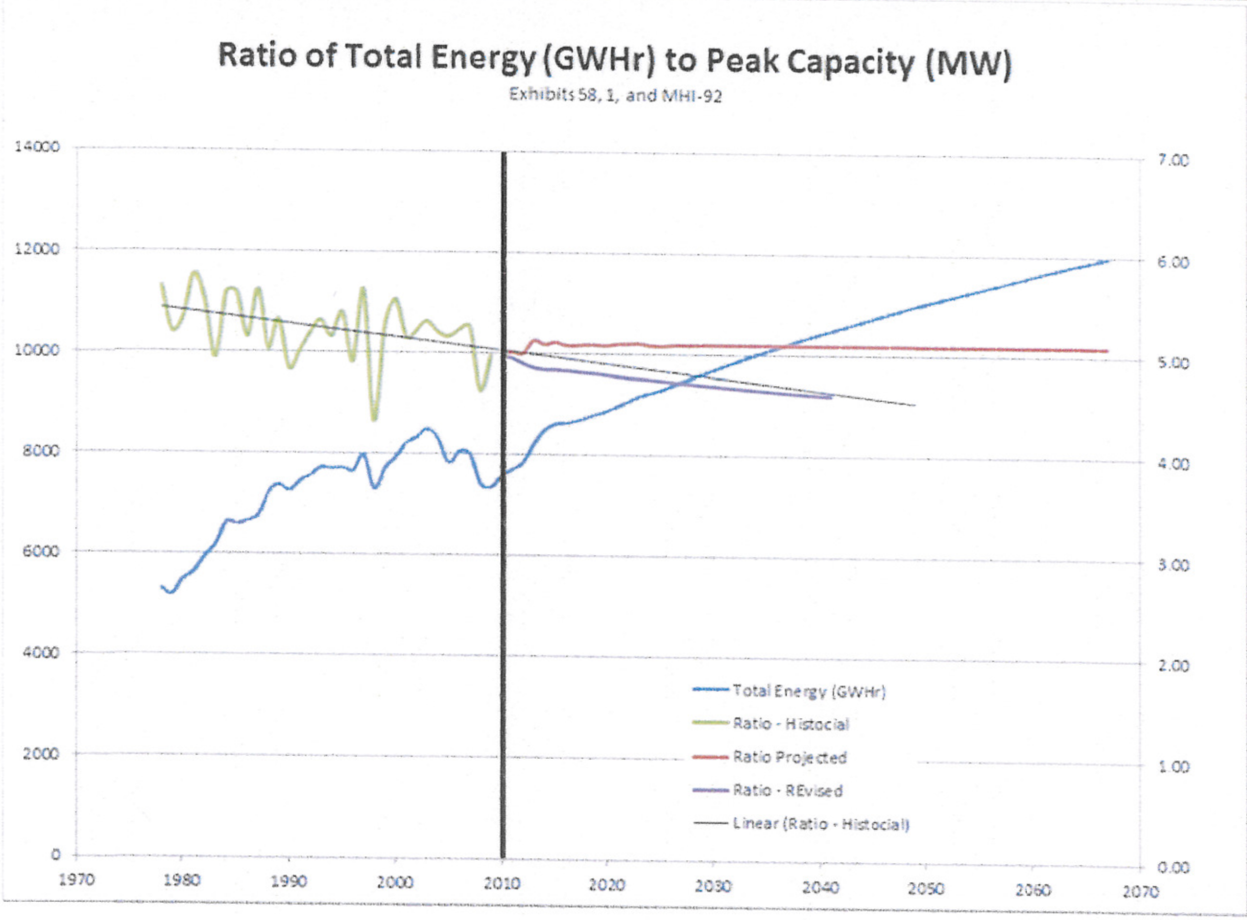
NLH 2010 Planning Load Forecast (PLF) for the Island Interconnected System

	Energy Requirements		Peak Requirements	
	GWh	% Chg	MW	% Chg
2010	7,585		1,519	
2011	7,709	1.6	1,538	1.2
2012	7,850	1.8	1,571	2.1
2013	8,214	4.6	1,601	1.9
2014	8,488	3.3	1,666	4.1
2015	8,608	1.4	1,683	1.0
2016	8,626	0.2	1,695	0.7
2017	8,666	0.5	1,704	0.5
2018	8,735	0.8	1,714	0.6
2019	8,806	0.8	1,729	0.9
2020	8,872	0.8	1,744	0.8
2021	8,967	1.1	1,757	0.8
2022	9,065	1.1	1,776	1.1
2023	9,171	1.2	1,794	1.0
2024	9,235	0.7	1,813	1.1
2025	9,293	0.6	1,827	0.8
2026	9,375	0.9	1,840	0.7
2027	9,464	0.9	1,856	0.9
2028	9,545	0.9	1,872	0.9
2029	9,626	0.8	1,888	0.8
2030	9,704	0.8	1,903	0.8
2031	9,782	0.8	1,918	0.8
2032	9,860	0.8	1,934	0.8
2033	9,938	0.8	1,949	0.8
2034	10,016	0.8	1,964	0.8
2035	10,087	0.7	1,978	0.7
2036	10,157	0.7	1,992	0.7
2037	10,228	0.7	2,006	0.7
2038	10,298	0.7	2,020	0.7
2039	10,368	0.7	2,033	0.7
2040	10,431	0.6	2,046	0.6
2041	10,493	0.6	2,058	0.6
2042	10,556	0.6	2,070	0.6
2043	10,618	0.6	2,082	0.6
2044	10,681	0.6	2,095	0.6
2045	10,744	0.6	2,107	0.6
2046	10,806	0.6	2,119	0.6
2047	10,869	0.6	2,132	0.6
2048	10,931	0.6	2,144	0.6
2049	10,994	0.6	2,156	0.6
2050	11,048	0.5	2,167	0.5
2051	11,103	0.5	2,178	0.5
2052	11,158	0.5	2,188	0.5
2053	11,213	0.5	2,199	0.5
2054	11,267	0.5	2,210	0.5
2055	11,322	0.5	2,220	0.5
2056	11,377	0.5	2,231	0.5
2057	11,431	0.5	2,242	0.5
2058	11,486	0.5	2,253	0.5
2059	11,541	0.5	2,263	0.5
2060	11,596	0.5	2,274	0.5
2061	11,650	0.5	2,285	0.5
2062	11,705	0.5	2,296	0.5
2063	11,760	0.5	2,306	0.5
2064	11,815	0.5	2,317	0.5
2065	11,869	0.5	2,328	0.5
2066	11,924	0.5	2,339	0.5
2067	11,979	0.5	2,349	0.5

Appendix B: Peak Demand Growing 25% Higher Rate than Total Energy

NLH 2010 Planning Load Forecast (PLF) for the Island Interconnected System

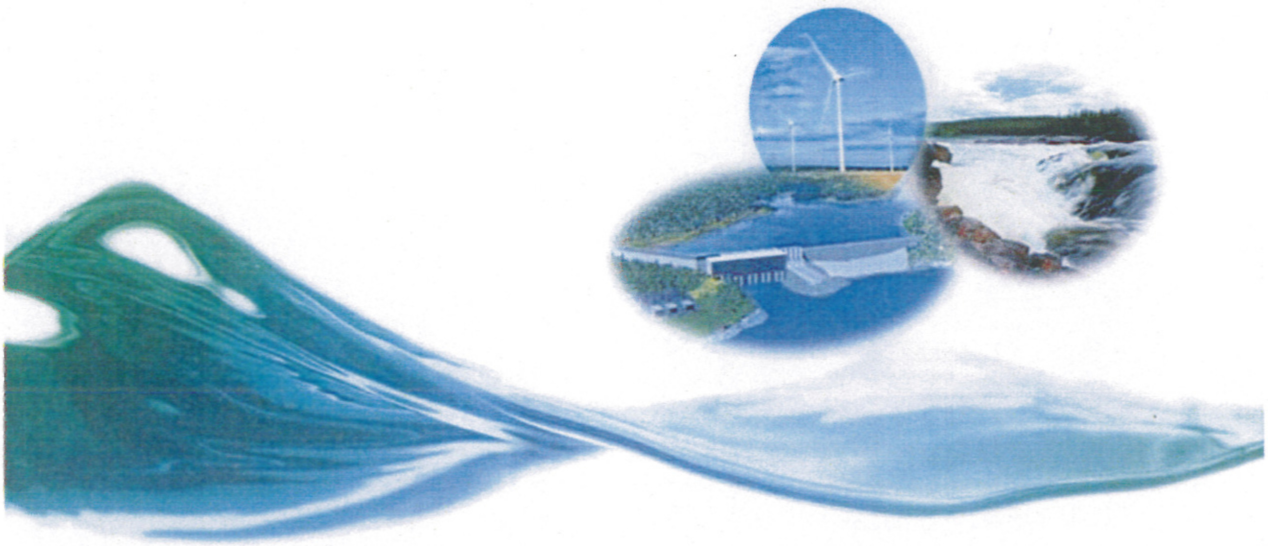
	Energy Requirements		Peak Requirements			Modified		
	GWh	% Chg	MW	% Chg	Factor	1.25	Ratio	% Change
2010	7,585		1,519			1519.00		
2011	7,709	1.6	1,538	1.2		1550.07	4.97	100.81%
2012	7,850	1.8	1,571	2.1		1585.36	4.95	100.94%
2013	8,214	4.6	1,601	1.9		1676.74	4.90	104.76%
2014	8,488	3.3	1,666	4.1		1746.71	4.86	104.82%
2015	8,608	1.4	1,683	1.0		1777.71	4.84	105.64%
2016	8,626	0.2	1,695	0.7		1782.17	4.84	105.15%
2017	8,666	0.5	1,704	0.5		1792.47	4.83	105.18%
2018	8,735	0.8	1,714	0.6		1810.45	4.82	105.62%
2019	8,806	0.8	1,729	0.9		1828.73	4.82	105.75%
2020	8,872	0.8	1,744	0.8		1846.01	4.81	105.88%
2021	8,967	1.1	1,757	0.8		1870.78	4.79	106.46%
2022	9,065	1.1	1,776	1.1		1896.16	4.78	106.78%
2023	9,171	1.2	1,794	1.0		1924.05	4.77	107.23%
2024	9,235	0.7	1,813	1.1		1940.66	4.76	107.02%
2025	9,293	0.6	1,827	0.8		1955.90	4.75	107.04%
2026	9,375	0.9	1,840	0.7		1977.59	4.74	107.47%
2027	9,464	0.9	1,856	0.9		2001.04	4.73	107.81%
2028	9,545	0.9	1,872	0.9		2022.54	4.72	108.02%
2029	9,626	0.8	1,888	0.8		2043.80	4.71	108.27%
2030	9,704	0.8	1,903	0.8		2064.56	4.70	108.49%
2031	9,782	0.8	1,918	0.8		2085.35	4.69	108.71%
2032	9,860	0.8	1,934	0.8		2106.19	4.68	108.92%
2033	9,938	0.8	1,949	0.8		2127.07	4.67	109.14%
2034	10,016	0.8	1,964	0.8		2147.99	4.66	109.35%
2035	10,087	0.7	1,978	0.7		2166.86	4.66	109.54%
2036	10,157	0.7	1,992	0.7		2185.76	4.65	109.73%
2037	10,228	0.7	2,006	0.7		2204.69	4.64	109.92%
2038	10,298	0.7	2,020	0.7		2223.65	4.63	110.11%
2039	10,368	0.7	2,033	0.7		2242.65	4.62	110.29%
2040	10,431	0.6	2,046	0.6		2259.56	4.62	110.46%
2041	10,493	0.6	2,058	0.6		2276.50	4.61	110.62%
2042	10,556	0.6	2,070	0.6		2293.47	4.60	110.79%
2043	10,618	0.6	2,082	0.6		2310.46	4.60	110.95%
2044	10,681	0.6	2,095	0.6		2327.47	4.59	111.11%
2045	10,744	0.6	2,107	0.6		2344.51	4.58	111.27%
2046	10,806	0.6	2,119	0.6		2361.58	4.58	111.44%
2047	10,869	0.6	2,132	0.6		2378.66	4.57	111.60%
2048	10,931	0.6	2,144	0.6		2395.78	4.56	111.76%
2049	10,994	0.6	2,156	0.6		2412.92	4.56	111.91%
2050	11,048	0.5	2,167	0.5		2427.93	4.55	112.05%
2051	11,103	0.5	2,178	0.5		2442.97	4.54	112.19%
2052	11,158	0.5	2,188	0.5		2458.03	4.54	112.33%
2053	11,213	0.5	2,199	0.5		2473.10	4.53	112.47%
2054	11,267	0.5	2,210	0.5		2488.19	4.53	112.60%
2055	11,322	0.5	2,220	0.5		2503.30	4.52	112.74%
2056	11,377	0.5	2,231	0.5		2518.43	4.52	112.87%
2057	11,431	0.5	2,242	0.5		2533.57	4.51	113.01%
2058	11,486	0.5	2,253	0.5		2548.74	4.51	113.14%
2059	11,541	0.5	2,263	0.5		2563.92	4.50	113.28%
2060	11,596	0.5	2,274	0.5		2579.12	4.50	113.41%
2061	11,650	0.5	2,285	0.5		2594.34	4.49	113.54%
2062	11,705	0.5	2,296	0.5		2609.58	4.49	113.68%
2063	11,760	0.5	2,306	0.5		2624.83	4.48	113.81%
2064	11,815	0.5	2,317	0.5		2640.10	4.48	113.94%
2065	11,869	0.5	2,328	0.5		2655.39	4.47	114.07%
2066	11,924	0.5	2,339	0.5		2670.70	4.46	114.20%
2067	11,979	0.5	2,349	0.5		2686.02	4.46	114.33%



Ratio of Total Energy (GWHr) to Peak Capacity (MW)
Exhibits 58, 1, and MHI-92
14000
12000
10000
8000
6000
4000
2000
0
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1970
1980
1990
2000
2010
2020
2030
2040
2050
2060
2070
Total Energy (GWHr)
Ratio - Histocial
Ratio Projected
Ratio - REvised
Linear (Ratio - Histocial)

Attachment 2

The Water Management Agreement and Peak Delivery to the Island



The Water Management Agreement And Peak Delivery to the Island

A Discussion Paper on Muskrat Falls

Volume V

November 2012

Introduction

Within his November 3 blog post [Ref. 1] John Samms had a very detailed summary of Nalcor's response to my comments provided on Geoff Meeker's post on media coverage of the Water Management Agreement [Ref. 2]. My initial concern expressly related to the ability of Hydro Quebec to request their continuous energy on a variable basis following the 2016 renewal. The original comment is provided here for the reader:

> *The issue with the WMA is whether the energy will be there when we need it. It is clear the WMA purports to allow Nalcor to store energy via the CFLCo resevoir in the summer, and non-peak hours when the power is not required in Newfoundland. However, in the DG3 report this week it is clear Nalcor is depending upon 900 MW being available on the Labrador-Island Link during the peak winter periods. This is where the WMA may not be effective. The Guaranted Winter Availability Contract (GWAC) clearly identifies that HQ are entitled to excess capacity generated from the Upper Churchill Plant in the winter months. What would limit HQ from requesting all the power from the UC during the peak winter day time period when we need it? During the winter what would be the resulting flow in the river, and what would be the subsequent power in the Muskrat Falls Plant 265 miles down river? There is limited storage capacity in Muskrat Falls in the winter, as ice coverage prohibits drawing down on the resevoir. The WMA is a major open question, both as to the legal issues it raises and in relation to technically how it would work. It seems to me that Nalcor could answer questions posed by various pundits by simply releasing the hydrology reports (which have been confidential) and producing a plot of the generation (on a monthly basis) that Nalcor is assuming will come from CFLCo. Then produce a letter from CFLCo where this release of power is endorsed by CFLCo. This seems to be a minimum requirement to address the issue prior to the debate within the House of Assembly*

Specifically my concern is how Nalcor can obtain energy from the Upper Churchill during the peak period, when Hydro Quebec have the legal right to effectively the entire capacity of the Plant during the winter months, when the island would require access to the stored energy.

Aside from the unorthodox method for having dialogue, Mr. Bennett's response did provide some much needed clarity on the matter. However, my concerns were not fully addressed. Within the remainder of this essay I will offer 2 separate scenario's for power delivery so the reader can understand the importance of the WMA in meeting Newfoundland's power requirement. Additional questions for consideration have been raised where appropriate.

Delivery Schedule 1: Peak Period Delivery

Following the 2016 renewal of the Power Contract Hydro Quebec have the contractual right to request power on a variable schedule, presumably to meet their requirements for both domestic and export purposes. To better understand my initial concerns the reader is asked to consider the following possible delivery schedule:

First 15 Days of Month:	Full Output of Upper Churchill from 8:30 ET to 20:30 ET Minimum Output for remainder of day
Last 15 Days of Month:	Continuous Output to use remainder of monthly energy allocation.

From the period of 10:00 to 22:00 NT the entire output of the Upper Churchill will be allocated to Hydro Quebec (not considering the Twinco and RECALL blocks of power). During this period Nalcor would not be able to access any banked energy from the Upper Churchill facility, and the obligation to the island will be solely dependent upon available Recall, and the Muskrat Falls Plant.

This period noted above corresponds to both the peak period for Newfoundland consumption, but also the period which the 167 MW delivery is required to meet the Emera obligation.

Although the full output of the Upper Churchill is allocated to Hydro Quebec delivery, the water flow with the Muskrat reservoir should be sufficient to meet island demands via the Muskrat Falls plant. Mr. Bennett clarified this as follows:

> *Running at full output, Churchill Falls would discharge about 2000 cubic metres per second into the Churchill River. Assuming no reservoir draw down, this level of discharge from CF would by itself provide about 630 MW of production at Muskrat Falls. We could run MF at a higher output level for a period of time and draw down the MF reservoir, or we could hold that capacity for reserve in the event of a maintenance issue, and dispatch our other hydro units in the Nalcor fleet. We always maintain reserve in the system, so we could keep it at Muskrat Falls as well as anywhere else. We currently make these dispatch decisions many times per day, responding to water levels, inflows, system load, maintenance issues, on the island. With the interconnection, MF/CF will be added to the mix.*

Upon initial review I was somewhat surprised by Mr. Bennett's response, as it represented a departure from the original plan presented by Nalcor for Muskrat Falls as outlined within the various public submissions.

Filed within the submission to the PUB are exhibits CE-28 [Ref. 3] and exhibit CE-29 [Ref. 4] which outline the energy estimates for the Muskrat Falls facility. These documents clearly identify that the Muskrat Falls reservoir will be maintained at 39.0 meters to optimize the energy output from the falls. These reports were from the Grimes era, and were based on the partnership with Quebec, in which water management would not be an issue due to the integrated approach to power delivery.

From the publically available information this basic premise about the reservoir operation did not substantially vary following Nalcor's "Go it Alone" decision. Within the Environmental Assessment documentation it was also stated that the Muskrat Falls reservoir will be maintained at or about 39.0 meters. See the following extract:

4.5.2 Muskrat Falls

4.5.2.1 Operating Regime

The Muskrat Falls Generation Facility will be operated remotely using a system and maintenance schedule similar to that outlined in for the Gull Island Generation Facility in Section 4.5.1. The generation facility also has the flexibility to be controlled locally at site. Monitoring and maintenance will be completed by crews based in Happy Valley-Goose Bay.

As with Gull Island, Muskrat Falls will be operated as close to FSL (39 m) as possible, with minimum fluctuations in water level. These fluctuations will reflect daily load swings due to hydraulic and production imbalances, which will be minimized. The plant will operate as a base load plant; daily fluctuations will be in the order of a few centimetres and weekly fluctuations will be to a maximum of 0.5 m.

Within the PUB process relating to the Water Management Agreement in 2009 Nalcor did again repeat similar language. In fact the above excerpt was provided in response to a question from an intervener during the hearings RFI-PUB-23 [Ref. 5]. The Labrador aboriginal groups have concerns about fluctuations in the reservoir, and the above language was used in response to these queries. In 2009 the daily fluctuations in the reservoir was estimated to be in the in the range of centimeters.

Aside from resident concerns, there are potential technical issues associated with rapid changes in the reservoir during the winter periods. The Ice Study completed by Hatch in 2010 identified the potential issue with rapid changes to reservoir elevation in the winter. Consider the following excerpts [Ref. 6]:

Once a thermal ice cover has formed on the reservoir, it is possible that the cover could be affected by a rapid change in water levels resulting from increases or decreases in plant load or inflow. In the event of vertical downward movements of the water level from the freeze-in level, the ice will drop with the water in the center of the shore to shore span, leaving the ice in contact with the shore at the margins. If

- The implications of part of the upstream ice cover being lost during the winter should also be considered during future studies. In the event that even a part of this upstream cover breaks up and passes through the spillway, it could lead to rapid water level increases downstream of the plant that may impact any ongoing construction activities in that area.

In Nalcor's various submissions there is minimal reference to drawing down the reservoir during the day, to be refilled at night. Rather a more typical even discharge of power is certainly implied in the various references to the reservoir operation.

The power delivery presented above is likely a worse case for having to draw down on the reservoir. It also clearly identifies that Hydro Quebec have great control of the river flow through their right to request power pursuant to the 1969 Power Contract.

Although Mr. Bennett is correct that full output from the Upper Churchill facility will result in sufficient flow to generate 630 MW from the Muskrat facility, the water must first travel downstream 265 km to the muskrat falls turbines. The Dam Break Study [Ref. 7] indicates that this would be in excess of the 12 hours. Therefore as the Upper Churchill power is being fully dispatched to Hydro Quebec, the Muskrat Facility must draw down on its own reservoir to meet the island demand during the peak period. The question is by how much?

To better understand the issue I have attempted to arrive at what would be the required production profile from the Muskrat Facility to meet the island demand. The daily production can be estimated for a day in January using the data provided within Exhibit 2 [Ref. 8]. Figure 1 provides an estimate of the total hourly island demand for a typical winter day in January for the year 2037.

The minimum production requirement for the Muskrat Falls plant can be estimated assuming that the island generation is producing at the near maximum as represented within the horizontal line within Figure 1. The horizontal line within Figure 1 represents the peak capacity on the island generation facilities based on 98% of available hydro being used, 50% of wind, and the thermal units being used in standby only [Ref. 9].

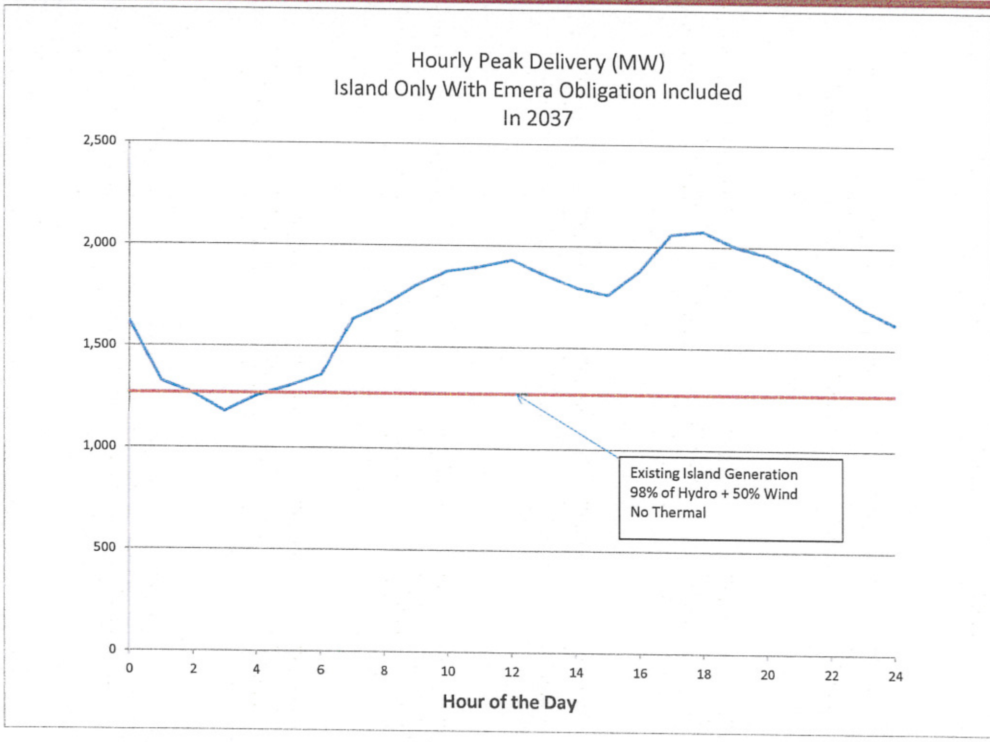


Figure 1: Hourly Island Demand - 2037

Figure 2 provides the estimate of the Muskrat Falls output required to meet the island demand profile. This data has been adjusted for the following:

- The output has been reduced by 10% to account for transmission losses.
- The Emera obligation has been added to the island demand.
- It is assumed that a minimum flow of ~170 MW would be maintained at all times for the Muskrat Falls plant [Ref. 13]. This is based on the Nalcor confirming during the CEAA process that the Lower Churchill would be operated similar to the existing operations. Therefore it can be assumed that the minimum flow in the river would be that matching the existing Upper Churchill Contract.

The red vertical lines included within Figure 2 represent the period of time that the full output of the Upper Churchill Plant is obligated to Hydro Quebec. Therefore if the river flow is at its minimum, and it takes more than 12 hours for the water from the Upper Churchill to travel downstream the area shown in yellow is the energy which must be generated by drawing down on the Muskrat Falls reservoir. As Nalcor would likely want to draw down on it's banked energy outside of this period, the power required outside the peak period would be from the Upper Churchill, which is shown as the blue area.

Based on this simple approximation there is about 64 x 10E6 m3 of water which is required beyond the minimum flow. This would correspond to ~0.65 m of drawdown. Although this is a very simple approximation it shows that essentially the entire live capacity of the reservoir (Which is 0.5 m) would be used to meet the island demand during the day.

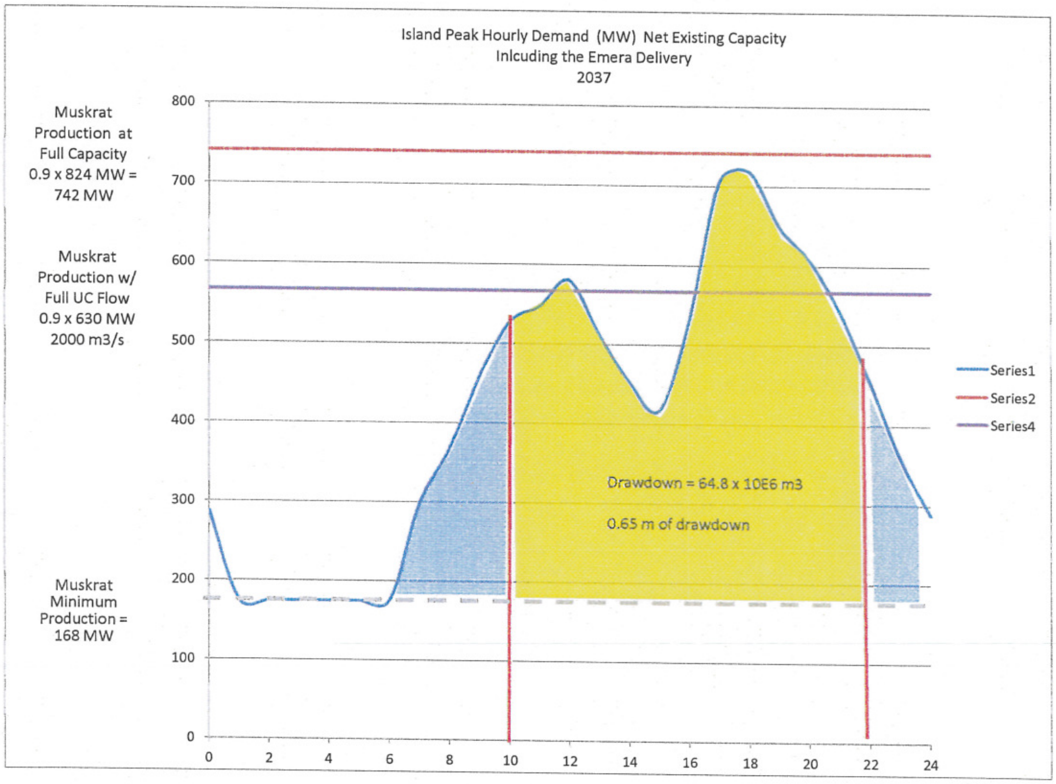


Figure 2: Power Required From Labrador to Meet Island Demand

Although this is an approximation, and subject to revision based on the time-domain profile of water travelling from the Upper Churchill tailrace to the Muskrat Falls Dam, it does raise several questions:

1) Would a daily draw down of the entire live capacity of the reservoir cause issues with ice management as alluded in Ice Study submitted to the PUB?
2) Would running the reservoir at lower head have an appreciable impact on the firm energy from the plant used to arrive at the Power Purchase Agreement? Was this production profile considered in their most recent energy studies which are confidential.
3) Is there a greater propensity to spill water based on this type of delivery of power to Hydro Quebec?

4) Based on question 2 and 3 is the average energy estimate of 4900 GWh per year the correct number to base the Power Purchase Agreement on? Why is the firm energy of 4500 GWhr not used for this calculation?
5) From Figure 2 there is minimal peak energy available in winter periods. How can firm energy and capacity be provided to mining companies without additional generation being brought online to service the island demand? Who pays for this?
6) Is there any impact on the reliability studies? The strategist runs assume that the Labrador Infeed is an unconstrained 900 MW thermal source [Ref. 13]. Is this correct with this type of Upper Churchill delivery profile? If HQ choose to receive their power per this schedule will additional generation (spinning reserve) be required to meet the noted reliability targets on the island. With the closure of Holyrood, and no new generation except for CT units where does the spinning reserve come from?
7) Does this type of water flow have a material impact on the CPW for the interconnected case? Without access to Upper Churchill power (exclusive of remaining RECALL) during the peak period, is there additional thermal generation required?
8) Does the CPW presented in the October 2012 MHI report represent the worse case condition for Upper Churchill Power delivery to Hydro Quebec?
9) For the CPW presented in the October 2012 MHI report how much Recall energy is assumed in the infeed option.
10) In the Power Purchase Agreement between Nalcor and Newfoundland Hydro what is the terms of the energy delivery, and capacity to be provided to the island. Does the CPW presented in the October MHI report reflect the terms of the draft power purchase agreement.

Answers to these questions would clarify the remaining technical questions I have related to the WMA and peak energy concerns. Again I would call for a release of the energy studies, and the production profiles from the Upper Churchill which is assumed to be available, with a letter endorsed by CFLCo. I note Mr. Bennett's opinion:

> ***Bennett:*** *Given that we will be operating in a competitive electricity market, this information is both commercially sensitive and confidential. Release of such material would not be prudent. The matter has been reviewed by multiple experts, including MHI. You may remember that MHI discussed this matter in their DG2 review – refer to Section 2 of Volume 2 of their report for the PUB.*

Nalcor's competitors are either Hydro Quebec, and/or Emera. Both of whom could potentially apply for Open Access to the island market when the links are built. They are also either their

Joint Venture partner in CFLCo or the Labrador Island Link. This information should already be disclosed to both parties in one of the Joint Venture arrangements?

As for MHI, their DG2 review was reportedly limited to the existing Nalcor documentation. Without the release of CE21-MF-1320 or CE26-MF-1330, is cannot be verified if the firm energy estimates was completed for a range of power delivery obligations to Hydro Quebec from the Upper Churchill facility. This should be clarified by Nalcor as indeed being the case.

Delivery Schedule 2: Binary Delivery per Month

The previous example outlines a scenario where the Author has technical questions concerning how the WMA will practically work. The second example is meant to identify to the reader the complete dependence that Nalcor will have on the WMA to meet the required deliveries to the ratepayers of the province. The following example was referenced by Nalcor within their submission to the PUB during the WMA application process. As it is best described by Nalcor, it is repeated here for consistency [Ref. 10]:

Table 1: Irregular CF(L)Co Production Profile

Continuous Energy – First 20 days of month	4,765 MW
Recall and Twinco	495 MW
Total – First 20 days of month	**5,260 MW**
Continuous Energy – Last 11 days of month	900 MW
Recall and Twinco	495 MW
Total – Last 11 days of month	**1,395 MW**

The resulting releases into the lower Churchill reservoirs would be as follows for the above production values:

Table 2: Irregular CF(L)Co Production Water Release

Daily Churchill Falls Water Release – First 20 days of month	160 million m^3
Daily Churchill Falls Water Release – Last 11 days of month	42 million m^3

If Hydro Quebec select to offset their delivery, the scenario presented by Nalcor could result in minimum flows in the Churchill River for 20 days. For this 20 day period there would be some

500 MW of power which will be required from the Upper Churchill facility during the daytime period.

If this energy/capacity is not available from the Upper Churchill then the power will have to be generated from existing thermal units on the island, or the new CT units as they are added to the expansion plan. We are potentially paying 6.4 Billion for 170 MW of firm power, which will just be enough to meet the Emera commitment.

Therefore it is considered essential that Nalcor obtain explicit approval from CFLCo, and Hydro Quebec, that they are in agreement with this power delivery from the Upper Churchill. The reader should note that all the supporting documentation to the WMA application was for the "Gull Island First" scenario. I would also ask Nalcor if they have had any discussion with Hydro Quebec on the WMA (direct or through CFLCO) since the Muskrat First decision was made (July 2010).

Although not a lawyer, I do believe that it is a precarious position at best. It is clear that CFLCo own the rights to generate electricity from the water stored in the Upper Churchill reservoir. This is best described by CFLCo themselves in their written response to the PUB [Ref. 11].

> **CF(L)Co Response:** While the mechanisms in Annex A refer to "water volume" this is simply a means of tracking Nalcor Banked Energy and CF(L)Co Banked Energy (as defined in the WMA). The *Regulations* are directed to the storage of energy not water. Sub-sections 3(2)(j), (k) and (l) of the *Regulations* refer to "energy storage amounts", "lost energy", "amount of energy in storage" and "energy losses", albeit the calculation of same is based on a "water to energy conversion rate".
>
> Furthermore, CF(L)Co is strongly opposed to any application or interpretation of the *EPCA*, the *Regulations* or any water management agreement which would be inconsistent with CF(L)Co's water rights under the *Lease Act*.

The 1961 lease act permits CFLCo the right to generate electricity from water stored in the Smallwood reservoir. The 1969 contract indicates that Hydro Quebec have the rights to this capacity upon request [Ref. 12]:

5.2 Firm Capacity

The Firm Capacity shall be available at all times when Hydro-Quebec has requested it. In addition whenever additional capacity can, in the opinion of CFLCo, be made available, such capacity shall also be available to Hydro-Quebec on request.

The position of Nalcor, as communicated by Mr. Bennett is that Hydro Quebec are only entitled to their Annual Energy Base, and that limits the obligation of CFLCo to deliver energy to Hydro Quebec. This is as communicated on the Samms blog as follows:

> *I agree with this – the GWAC is effective during the winter months. However, section 2.1 of the Renewed Power Contract entitles HQ to take the Continuous Energy in each month, including during the winter. Referring to Volume 1 of our application to the PUB for the water management hearing, the average production at CF is about 34 TWh. If we deduct the 2.36 TWh and 1.97 TWh for recall and Twinco respectively, we're left with approximately 29.7 TWh for HQ, or approximately 2.5 TWh per month. Interestingly enough, this means the plant will deliver on average just over 3470 MW for HQ + 525 for NLH/Twinco (or 3995 MW out of 5428 MW) over the course of the month, meaning that while HQ can have 'additional capacity', they cannot have it all of the time, as they will exceed their energy allowance. This point ensures there will be lots of opportunities to withdraw stored energy from CF, even in the winter. (The math above is 2,500,000 MWh/mo / [30 days/mo] / [24 hr/day] = 3472 MW)*

It must be raised that the 1969 contract is for the supply of both energy and capacity. This is identified within Article 2.1 of the renewed contract.

ARTICLE II

OBJECT

2.1 Object

During the entire term hereof, Hydro-Quebec agrees to purchase from CFLCo and CFLCo agrees to sell to Hydro-Quebec each month the Continuous Energy and the Firm Capacity, at the price, on the terms and conditions, and in accordance with the provisions, set forth herein.

Therefore CFLCo's obligation to HQ is not merely a delivery of energy, but also the firm capacity of the plant. The Guaranteed Winter Availability Contract confirms this interpretation

WHEREAS the Power Contract provides for the sale by CF(L)Co to HQ of power and energy produced by CF(L)Co's Plant on the terms and conditions set out in the Power Contract ;

WHEREAS the Power Contract also provides that whenever additional capacity can, in the opinion of CF(L)Co, be made available from the Plant, such capacity shall also be made available to HQ on request;

WHEREAS CF(L)Co may incur additional expenses to render available such additional capacity to HQ upon its request;

ARTICLE 2

GUARANTEED ADDITIONAL AVAILABILITY

2.1 During the Contract Period, CF(L)Co agrees to guarantee to HQ the Additional Availability at the Delivery Point during each Availability Period and in consideration thereof HQ agrees to pay to CF(L)Co the monetary consideration provided for in Article 5.

Is it correct when Mr. Bennett states *"while HQ can have additional capacity, they cannot have it all of the time"*? This is very much the argument. Consider that CFLCo's rights to other capacity has been defined to be either Twinco and the Recapture provision.

5.4 Recapture

CFLCo may, on not less than three years prior written notice to Hydro-Quebec, elect to withhold from the power and energy agreed to be sold hereunder blocks at a specified load factor per month, to be stated in said notice, of not less than 60% nor more than 90%, which blocks in the aggregate shall not exceed, during the term hereof and after taking into account recaptures made by CFLCo under the original Power Contract, 300,000 kilowatts for a maximum withholding thereunder and hereunder of 2.362 billion kilowatthours per year provided that:

It is also been established from previous court cases [Ref. 14] that the only power/energy which is not allocated to Hydro Quebec is the Twinco and Recall amounts. This is perhaps best documented within the Goodridge decision from the Newfoundland Supreme Court:

> Hydro Quebec and CFLCo. The negotiations were done with a view to arriving at a figure that would satisfy the future needs of the province. They were embarked upon with the clear expression from Hydro Quebec that there would be no power contract unless the amount of power that could be recaptured for sale in the province or to the Newfoundland consumer was limited to an express figure.
>
> **502** There were 5,225 MW of power available to produce energy for sale. Of these 225 MW was reserved to provide energy to meet the commitments of the Twinco.
>
> **503** That was provided for in the Power Contract. This commitment and understanding existed from the beginning.
>
> **504** The only other reservation in the Power Contract was the annual energy that could be produced by 300 MW of power not exceeding 90 percent load factor per month, as contained in Clause 6.6.
>
> **505** The recapture right belonged to CFLCo. It was designed, however, to meet the obligation of CFLCo to the province.

The 1983 decision also clearly documents that the Government knew that its rights were limited to 300 MW recall power. Therefore on what basis does the Government / Nalcor now believe they have access to an addition 500 MW of capacity, which is obligated under the existing Power Contracts?

> **509** Moreover, it is equally clear that the Government knew of the negotiations between CFLCo and Hydro Quebec in this respect and acquiesced in them. The Government knew and made known to CFLCo that it knew that the extent of its rights under Clause 2(e) was considered by CFLCo and Hydro Quebec to be limited to 300 MW. The Government accepted this limitation and made known its acceptance to CFLCo.
>
> **510** It recognized that its rights were limited in the energy that could be produced by 300 MW and that its further energy requirements would have to be generated by development on the Lower Churchill.

This may be clear to the lawyers from Nalcor but I understand the position offered by Mr. Coffey. This is not a black or white issue. Considering we have previously lost 2 court cases to Hydro Quebec, which were undoubtedly considered "sure bets" when the case was initiated, I do agree with Mr. Coffey.

<u>We need 100% legal certainty prior to committing a 6.4 Billion dollar undertaking</u>.

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