Muskrat Falls to Happy Valley Interconnection
Questions from the Public Utilities Board

1. Page 9 of the report entitled Eastern Labrador Transmission System – Planning Report (Revision 1 – January 25, 2018) states that "the 7.6 MW increase in the 2017 forecast is a direct result of service applications for new data centers".
   a. Please confirm that the data centre load is coincident with the peak load for Happy Valley – Goose Bay.

      The data centre load is coincident with the peak load for Happy Valley-Goose Bay. There are three (3) data centre customers in Happy Valley-Goose Bay with expected loads greater than 1 MW that are currently connected. Hydro expects that the data centre load in Happy Valley-Goose Bay will operate in a manner similar to those operating in Labrador City once fully operational. The Labrador City data centre loads indicate they are operating at greater than 90 percent annual load factor with winter demand requirements greater than 90 percent of the customer's peak demand requirements. This operating load profile results in highly coincident customer demand at system peak demand.

   b. Does Hydro have long-term commitments from these data centre customers? If so, please provide the commitment timelines.

      There are no long term commitment contracts in place for these data centre customers. The current process for connecting these data centres to the power system is the same as connecting any other General Service customer.

   c. Has Hydro completed or reviewed any analyses with respect to price elasticity associated with these types of cryptocurrency data mining centres? Does Hydro expect these data centre customers to remain customers in the Happy Valley – Goose Bay area if electricity costs increase significantly or even moderately given the relative ease with which the data centres can be relocated?

      Hydro has not completed nor reviewed analyses with respect to price elasticity associated with these types of cryptocurrency data mining centres. Hydro has recently observed through media reports that these types of cryptocurrency data mining centres are currently being developed in higher priced jurisdictions including Alberta and British Columbia, which indicates there are likely other market factors, in addition to power prices, driving such developments. While Hydro is of the opinion that the siting of cryptocurrency data mining centres within the Labrador Interconnected System stems from its low cost of electricity and favourable climate conditions, Hydro does not expect the magnitude of retail rates within the Labrador Interconnected System to change it from being a low cost jurisdiction to a high cost jurisdiction in the context of Canadian electricity pricing. Hydro does not anticipate that Labrador Interconnected System retail electricity prices through the medium term will be a significant factor in the decision of these types of cryptocurrency data mining centres to relocate.

2. Please provide the actual peak load attained in 2016, 2017, and to date in 2018 for the Happy Valley – Goose Bay area. In the event that the actual peak load for 2017 differs from the forecasted 79.9 MW please provide the reason(s) for the difference.

Table 1 provides actual peak demands for the Happy Valley-Goose Bay system since the winter of 2000/2001.

The 2017/2018 peak of 66.9 MW (to February 28, 2018) is less than the forecast requirement of 79.9 MW primarily because the connected data centre customer loads have not ramped up to operational load requirements. In addition, the temperatures during system peak periods for the current winter to date have been milder than normal peak period weather conditions for this region.

Table 1: Happy Valley-Goose Bay System Winter Peak Demands

Winter Season	*Date*	*Time*	*MW*[1]
2000/2001	*02/15/01*	*09:00*	*48.7*
2001/2002	*01/31/02*	*09:30*	*54.4*
2002/2003	*12/10/02*	*09:00*	*51.6*
2003/2004	*02/16/04*	*09:00*	*55.5*
2004/2005	*01/24/05*	*09:00*	*56.9*
2005/2006	*02/15/06*	*09:30*	*51.2*
2006/2007	*01/18/07*	*09:00*	*55.0*
2007/2008	*01/22/08*	*09:00*	*59.0*
2008/2009	*01/16/09*	*11:00*	*59.8*
2009/2010	*02/02/10*	*09:00*	*57.8*
2010/2011	*02/02/11*	*09:00*	*62.1*
2011/2012	*01/12/12*	*09:00*	*61.1*
2012/2013	*01/18/13*	*09:00*	*67.3*
2013/2014	*01/03/14*	*09:30*	*70.3*
2014/2015	*01/08/15*	*08:00*	*71.0*
2015/2016	*02/09/16*	*09:00*	*70.6*
2016/2017	*02/13/17*	*08:00*	*71.1*
2017/2018p[2]	*01/15/18*	*09:00*	*66.9*

[1] ***System peaks exclude Muskrat Falls construction power requirements.***
[2] ***2017/2018 is preliminary and is for period ending February 28, 2018.***

3. Hydro indicates that the cumulative present worth costs associated with transmission line L1301 (including its associated assets at Churchill Falls Terminal Station and Muskrat Falls Tap Station MFATS3) and the Happy Valley Gas Turbine are approximately $8 million and $21 million respectively over the study period if current operating and maintenance procedures remain unchanged.
   a. Hydro states in its January 29, 2018 correspondence accompanying the revised project submission that "with respect to the operational and maintenance plan for the Happy Valley gas turbine, as part of the recommended option, the unit will have a much lower utilization as it will not be required to operate as a synchronous condenser for load transfer". Please provide an estimate of the cost savings over the study period associated with this reduced gas turbine utilization as well any savings resulting from L1301 being open circuited at MFATS3.

- ***Wood Pole Line Management (WPLM) and future of L1301:***
  - ***Hydro provided the cost per km for WPLM in Appendix I of its 2018 Capital Budget Application. The existing L1301/L1302 configuration has a line length of 269 km giving an annual estimate of $407,000 for WPLM. The reconfiguration has L1302 connected to MFATS2 increasing the line length by 6 km bringing the total line length under WPLM to 275 km for an annual estimated cost of $416,100 for WPLM. The cost benefit analysis assumes that all 138 kV transmission line is maintained under WPLM whether under load or open circuit under normal operation. If the decision was made to not maintain the section of L1301 that would be open circuit under normal operation, there would be 239 km of 138 kV not maintained. The estimated cost savings associated with the decision to not maintain L1301 would be $361,600 per year. Hydro recommends that maintenance on this transmission line continue until such time that the decision is made to abandon or remove L1301 from service.***
  - ***The effect of this cost reduction on the NPV of the project was provided in 2018 Capital Budget Application Request For Information response to NP-NLH-025***
  - ***Decommissioning and removal of L1301, should it be deemed as no longer required***
    - ***A 2015 cost estimate for the decommissioning of L1301 between Churchill Falls and Gull Island equals $12.2M***
    - ***A 2015 cost estimate for the decommissioning of L1301 between Churchill Falls and Muskrat Falls equal $15.2M***
- ***Terminal Station:***
  - ***The cost benefit analysis assumes that both the Churchill Falls 230/138 kV station and the MFATS3 station would be maintained under the preferred option. The annual maintenance costs for Churchill Falls and MFATS3 are $15,300 and $27,700 per year, respectively. A decision to not maintain these assets would result in a $43,000 per year savings. Hydro recommends that maintenance on these assets continue until such time that the decision is made to abandon or remove the assets from service.***
  - ***The effect of this cost reduction on the Net Present Value (NPV) of the project was also included in 2018 CBA RFI response to NP-NLH-025.***

- ***Happy Valley Gas Turbine:***
  - ***Gas turbine operation for cross arm replacement will be reduced with the preferred option. The cost savings equates to the difference between the $1.33M per week in Option One and the $165,800 per year in the preferred option, or $2.494M in total per year.***
  - ***Hydro does not expect a significant reduction in the operation and maintenance costs associated specifically with synchronous condenser operation. While the preferred option results in a reduced requirement for synchronous condenser operation for load transfer, the unit will require regular maintenance including inspections, tests to ensure operability, etc. Only if the Gas Turbine was completely removed from service would there be significant savings; however, this is not possible under the current arrangement, as currently maintenance outages are mitigated with the generation from the GT which also provides emergency backup up power for 25 MW in the event of a line failure. Once the new interconnection is built, the gas turbine will still be maintained as an emergency backup source until the final determination is made as to the future of the GT in the interconnected grid.***

4. If this project were to be deferred until confirmation of the approximately 12 MW of additional DND load currently anticipated in 2020, what solution (e.g., mobile diesel generators, curtailment, etc.) would Hydro implement to handle the load in the Happy Valley – Goose Bay area?

This project cannot be deferred until confirmation of the addition of DND load anticipated in 2020. The existing system has a transfer capacity of 77 MW. The load forecast for the 2018-2019 winter is 80.6 MW, which exceeds the transfer capacity of the system. Without system reinforcement the winter peak load cannot be met. The addition of mobile diesels is a temporary, or "band-aid" solution that should only be considered when a permanent, least cost solution cannot be achieved in the required time frame. In this case the preferred alternative can be completed before the winter peak. In this particular case the installation of temporary, mobile diesels results in additional expenditure with no tangible benefit and is not consistent with least cost reliable planning.

5. Please provide a cost estimate for Option 7 – Addition of Mobile Diesels such that sufficient mobile diesel generation is installed to accommodate the 2019 forecasted peak load of 81.4 MW. The cost estimate should include the costs associated with fuel storage, fuel supply, staffing maintenance, interconnection costs and permitting. The mobile diesel generation would be in addition to the existing diesel generator and support infrastructure already in place at Happy Valley – Goose Bay.
   - ***A preliminary estimate for mobile diesel operation assumes:***
     - ***XQ2000 Units***
     - ***Prime unit rating 1.825 MW***
     - ***Maximum output at 85% for efficiency rating (1.551 MW)***
     - ***Minimum load per machine at 30% rating (0.548 MW)***

- ***The calculated mobile diesel energy and fuel requires are as follows:***
  - ***2018***
    - ***Five units minimum***
    - ***208 MWh and 59,726 L of fuel (approximately 60,000 L)***
  - ***2019***
    - ***Six units minimum***
    - ***383 MWh and 108,985 L of fuel (approximately 110,000 L)***

Provision of five to six diesel units installed and operational to meet the loads noted would be in the order of $11M over a two year lease period.

6. Within the response to RFI IOC-NLH-033, as part of Hydro's 2017 GRA, Hydro states that "Hydro is in the process of developing a network addition policy in preparation for meeting the requirements to provide open access transmission".
   a. Has Hydro developed a network addition policy? If so, please provide a copy to the Board.
   b. Will the network addition policy apply to the Labrador Interconnected System? If so, how would the policy treat new loads such as those associated with the data centres and DND?

Hydro has not yet developed a network addition policy. In any regard, it is not anticipated that such a policy would be applicable to General Service customers.

7. Please confirm that the primary reason for this project is to accommodate load growth and that while reliability improvements are welcome the project would not proceed based on reliability alone.

This project was proposed in the 2017 Capital Budget Application in the Five Year Plan as a reliability improvement. At that time the project included two 138 kV transmission lines connecting MFATS2 to Happy Valley as well as a new 138/25 kV station in Happy Valley. The addition of general service customers (driven by data centres) in late 2016 and early 2017 has resulted in a load forecast for 2018 – 2019 winter peak that exceeds the current transfer capacity of the system. As a result, connecting one 138 kV transmission line (existing L1302) to MFATS2 is required to increase the transfer capacity of the system to meet the load forecast. This alternative has been referred to as "Phase I" of the original project proposed in the 2017 plan. The project under discussion provides not only the transfer capacity to meet the immediate load needs of the region, but also provides for additional longer term load growth brought on by economic activity in the region and provides a substantial reliability improvement. One must note that incremental builds on the transmission system provide increases in transfer capacities that come in relatively larger blocks when compared to slow but steady load growth. Consequently, it may take many years to consume the entire transfer capacity addition. The application of cost benefit analysis and cumulative present worth ensure that the large capital investments for transmission up front provide the least overall cost, over time, when compared to smaller multiple capital investments over time. In this particular instance, the costs of additional generation in the form of a new gas turbine is more than four times the capital cost of the preferred transmission line option. The cost of mobile diesels merely delays the preferred transmission alternative and in turn increases the

preferred transmission alternative by the cost of the mobile diesel plant cost with no long term tangible benefit to the customer.

a. How does the Happy Valley – Goose Bay area compare in terms of reliability (SAIDI, SAIFI, etc.) with western Labrador and the Northern Peninsula on the island portion of Newfoundland and Labrador?

Please refer to Tables 2 through 7 for the Transmission metrics (T-SAIFI, T-SAIDI, and averages) and Distribution metrics (SAIFI, SAIDI and averages) for Happy Valley (Labrador East), Labrador City/Wabush (Labrador West), Northern Interconnected (Great Northern Peninsula), Hydro Corporate, and CEA averages.

Table 2: T-SAIFI 2013 to 2017

	T-SAIFI				
SYSTEM	2013	2014	2015	2016	2017
Happy Valley	8.00	8.00	12.00	7.00	7.00
Labrador City/Wabush	3.00	4.00	3.00	0.50	3.00
Northern Interconnected	9.75	10.75	7.83	9.00	5.42
Hydro Corporate	3.45	3.78	3.10	2.87	2.25
CEA All Canada	0.92	0.89	0.74	0.81	N/A

Table 3: T-SAIDI 2013 to 2017

	T-SAIDI				
SYSTEM	2013	2014	2015	2016	2017
Happy Valley	1587.0	414.0	1597.0	594.0	2005.0
Labrador City/Wabush	1048.0	984.5	1341.0	228.0	801.0
Northern Interconnected	957.0	816.5	842.1	582.9	590.4
Hydro Corporate	468.5	457.7	476.6	324.7	512.9
CEA All Canada	115.9	86.1	69.8	97.2	N/A

Table 4: T-SAIFI and T-SAIDI Averages for 2013 to 2017

	All Causes	
SYSTEM	T-SAIFI	T-SAIDI
Happy Valley	8.40	1239.40
Labrador City/Wabush	2.70	880.50
Northern Interconnected	8.55	747.15
Hydro Corporate	3.08	447.88
CEA All Canada (2012-2016)	0.86	88.42

Table 5: SAIFI 2013 to 2017

	SAIFI				
SYSTEM	2013	2014	2015	2016	2017
Happy Valley	10.57	7.84	14.55	8.38	10.53
Labrador City/Wabush	7.21	11.38	2.62	2.83	9.57
Northern Interconnected	4.77	7.07	6.26	9.86	2.22
Hydro Corporate	5.76	6.75	6.95	6.62	5.30
CEA Region 2	2.94	2.67	2.62	3.71	N/A

Table 6: SAIDI 2013 to 2017

	SAIDI				
SYSTEM	2013	2014	2015	2016	2017
Happy Valley	13.93	6.93	21.97	12.05	39.34
Labrador City/Wabush	41.40	49.88	39.56	11.12	20.27
Northern	11.51	20.08	13.67	16.18	9.90
Hydro Corporate	18.85	18.32	17.54	15.68	19.63
CEA Region 2	9.83	7.81	6.26	7.08	N/A

Table 7: SAIFI and SAIDI Averages for 2013 to 2017

SYSTEM	All Causes SAIFI	All Causes SAIDI
Happy Valley	10.37	18.84
Labrador City/Wabush	6.72	32.45
Northern Interconnected	6.03	14.26
Hydro Corporate	6.27	17.80
CEA Region 2 (2012-2016)	2.96	7.32