John Maissan
(JM)

TOPIC: **Project Description**

REFERENCE: **Page 3 and 5 Re. new 1.7 km 34.5 kV transmission line:**

QUESTION:

a) Has YEC now secured the easements on Crown land?

b) With respect to the portion on or following the ATCO power lines, please outline the results of discussions to date with ATCO Electric Yukon (ATCO).

c) Please provide YEC plans if discussions with ATCO have not resulted in an agreement.

ANSWER:

(a) to **(c)**

No, YEC has yet not secured easements on Crown Land.

It is YEC's understanding from its discussions with ATCO Electric Yukon (AEY) to date that they are supportive of the proposed interconnection route. No formal agreement has been drafted between YEC and AEY. YEC will further engage with AEY in pursuit of an agreement during the detailed design of the interconnection.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 3 Re. "grid-sized BESS with 40 MWH of useful energy storage capacity"**

QUESTION:

a) Please provide the nameplate storage capacity included in the project budget.

ANSWER:

(a)

The project costs are for a 40 MWh BESS with a 20% overbuild, resulting in a 48 MWh energy storage capacity at the beginning of project life. Please see the response to YUB-YEC-1-11.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 4 Re. "…LNG plant – Three units with combined installed capacity of 13.2 MW and dependable capacity of 12.6 MW":**

QUESTION:

a) Does the 12.6 MW of dependable capacity signify that when the LNG units are base loaded for continuous operation the three-unit plant is operated at 12.6 MW (4.2 MW each)?

b) If not, please indicate the normal base load level for the units when in continuous operation.

ANSWER:

(a) and **(b)**

Yes. 12.6 MW of dependable capacity is what YEC can rely on the three LNG units to provide under continuous operation.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 4 Re. “Mobile / rented diesel units…”:**

QUESTION:

a) Do these units have a nameplate capacity of 1.8 MW or is this the normal base load level for continuous operation?

b) If 1.8 MW is the base load for continuous operation, please provide the nameplate (peak) capacity.

ANSWER:

(a) and **(b)**

1.8 MW is the nameplate, peak, and dependable capacity of the temporary diesel units. They can be operated continuously at this level.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 4 Re. KDFN site lease:**

QUESTION:

a) Is 1.5 ha the area of the entire KDFN Category B settlement land parcel?

b) If not, what portion of the entire parcel is this?

ANSWER:

(a)

No, the 1.5 ha is a portion of the KDFN Category B Settlement land.

(b)

It is approximately 15% of the parcel.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 4 Re. battery container system modules:**

QUESTION:

a) Please confirm that the containers will have insulated floors as well as walls and roof.

b) If not confirmed please explain.

ANSWER:

(a) and **(b)**

Yes, the container walls, roof, and floors will be insulated.

TOPIC: **Section 3 Project Description**

REFERENCE: **Pages 4 and 5 Re. transformer(s) "…(provision for 2 X 20 MW if this level of redundancy is selected)."**

QUESTION:

a) How many transformers are provided for in the project budget?

b) If the answer is one, please explain on what bases and when YEC will decide to procure a second transformer.

ANSWER:

(a)

One Main power transformer is included in the Project budget.

(b)

At this point in time, YEC has no plans to procure a second transformer. As a result, YEC does not know the basis for which a second transformer is required.

TOPIC: **Section 3 Project Description**

REFERENCE: Page 5 Re. "A competitive procurement process has been initiated to select battery vendors qualified to design a battery able to meet Yukon Energy's operational requirements…"

QUESTION:

a) Please provide an update on this procurement process and the present status.

ANSWER:

(a)

Please see response to YUB-YEC-1-13.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 5 Re. BESS life of 20 years and "…or capacity augmentation at year ten."**

QUESTION:

a) If the "typical year" number of cycles are experienced would YEC extend the project life to 25 or 30 years?

b) In battery systems it is typically not recommended to mix batteries of significantly different ages or use histories. Furthermore lithium-ion battery technology is evolving fairly rapidly, please explain if capacity augmentation at year ten is a realistic option / expectation compared to an overbuild at the outset.

c) Is the future battery augmentation option described provided as a possible means of holding the BESS project on budget by reducing the initial build size if price quotes come in higher than expected?

ANSWER:

(a)

BESS life is currently set at 20 years, which is the upper limit that most vendors provide. YEC will need to assess the ability to extend the battery's life as it approaches 20 years or decide if an alternative technology is more appropriate at that time.

(b)

Vendors are developing strategies within their controls and battery management systems to accommodate partial augmentation throughout the batteries life span.

YEC will work with the selected vendor to select the most appropriate approach to achieve a 20 year lifespan (either initial overbuild or capacity augmentation) based on vendor recommendations, the available technology and the risks.

(c)

No. Future battery augmentation is a standard approach to extend the life of a BESS, where the other components have a 20-year (or greater) lifespan (e.g., containers, inverter, transformer, etc.).

While the preliminary capital cost would be lower with augmentation versus capacity overbuild, BESS vendors will be evaluated on total lifecycle costs, not only initial capital cost.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 5 Re. "At the end of life, many battery vendors will take back the battery modules…":**

QUESTION:

a) Is this a requirement that YEC is putting in their procurement process for vendors?

b) If not, why not?

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-12(d).

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 6 Table 3-1 Re. frequency of use and number of cycles:**

QUESTION:

a) The BESS Use frequency column on the left side of each of the two cases add up to many more cycles (i.e. 165+ for Typical Year case) than the “Total Throughput Useable Cycles” (i.e. 79 for Typical Year case). Please explain how these numbers can be different.

b) The Hatch report (Appendix B at page B-27) indicates that the state of charge for a battery should be between 10% and 90%, does this mean using 10% of the battery capacity 8 times in small cycles is equivalent to one “Total Throughput Useable Cycle”?

c) The author has not heard of the term “Total Throughput Useable Cycles” before, please define this term. Is this a term used only by lithium-ion battery manufacturers to describe / measure the useful lives of their batteries?

ANSWER:

(a)

“Frequency” in this table is the number of events; other than N-1 events, none of these events result in a full discharge of the battery. “BESS Use” in this table is the estimated MWh discharged per year for these events (assumptions for the events are provided in Appendix B of the Application, Hatch report, Section 8).

- For N-1 events, one 2-week event is assumed in 10 years. The one event involves BESS Use of 40 MWh times 14 days = 560 MWh; this equals an average annual use of 56 MWh.

- For Operating Reserve, 1 event per month is assumed – each event is assumed to be 30 minutes, with 20 MW/2 = 10 MWh BESS Use; annual BESS Use then equals 10 times 12 months = 120 MWh.

- For Blackstart Outage Restoration, 53 events assumed per year with average BESS Use of 40 MWh/event.

- For Peak Shifting, 244 MWh per year BESS Use as estimated in Hatch Report (Section 6.4.2.4, Application pages B-64 to B-65) for events at Whitehorse and Faro.

- For Renewable Integration, 100 cycles assumed per year at 15% discharge of battery capacity (40 MWh) = 6 MWh BESS Use per event.

"Total Annual Throughput" in this table is a metric used to estimate the total energy discharged by the BESS over the year (sum of all energy discharged, i.e., sum of BESS Use in the table). This is used by vendors to estimate degradation.

"Total Throughput Useable Cycle" is the total discharged energy for the year (MWh) divided by the energy storage capacity of the system (40 MWh).

(b)

No. Total throughput useable cycle is based on total useable capacity (40 MWh in this case) so you could do 10 discharge events of 10% to achieve 1 cycle (10 x 4 MWh/event = 40 MWh discharged energy).

As noted in the Hatch Report (Appendix B of Application, page B-47), the 20% overbuild required due to the limited state-of-charge range (20%-100% or 10%-90%, depending on the vendor recommendation) results in the "useable energy" as reference, e.g., the Project's installed capacity of 48 MWh provides the referenced useable energy of 40 MWh.

(c)

Yes. Total Throughput Useable Cycle is the total discharged energy (MWh) divided by the energy storage capacity (40 MWh). This is one metric used by battery vendors to estimate degradation.

TOPIC: **Section 3 Project Description**

REFERENCE: **Pages 6 – 10 Re. BESS N-1 Capacity Reserve use and Other BESS Uses:**

QUESTION:

a) In an N-1 event when the BESS is being used to provide the 7.2 MW of Dependable Capacity all useable energy in the battery appears to be used, in this circumstance are all “Other BESS Uses” excluded?

b) If, as it appears, the N-1 use of BESS excludes all other uses, would the “other uses” be excluded as the YIS system approaches a peak load day to be available for a potential N-1 requirement?

c) If some of the “other uses” can be provided while the N-1 need is being served, which are they?

d) If the BESS is being used for one or more “other uses” when an N-1 event occurs how would the BESS be transitioned to N-1 use and how would 7.2 MW of dependable capacity be provided during that transition time?

ANSWER:

(a)

During an N-1 event, most of the other use cases would be excluded. However, the BESS may be able to provide frequency response (e.g., adjust its output to manage frequency excursions).

(b)

It is not necessarily assumed that “other uses” will be excluded as YIS approaches a peak load day. If the BESS is partially charged at the time of initial N-1 event, it will be used as best possible to reduce outages, and will be recharged overnight and used beginning the next day to cover the peak.

(c)

The BESS's output can be adjusted to respond to frequency excursions (i.e., if frequency is high, BESS output can be reduced).

(d)

The BESS is not meant to prevent an instantaneous N-1 outage, but rather to be firm capacity for two weeks until Aishihik generation and/or transmission can be restored. The responses provided above confirm how BESS operation will enable this firm capacity to be provided.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 10 Re. “Operating reserve”:**

QUESTION:

a) Is “operating reserve” the same as what is often referred to as “spinning reserve”?

b) If not please explain the differences.

ANSWER:

(a) and **(b)**

The terms are similar as both relate to standby capacity to manage unplanned loss of generation or increases in load. Quite often these are used interchangeably, but there is a slight deviation. Spinning Reserve is "spinning" generation that is available to the operator on a short interval to meet demand. Operating Reserve includes all generation, including non-spinning assets, that are available to the operator on a short interval to meet demand.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 10 Re. Diesel peak shifting:**

QUESTION:

a) Please confirm that LNG peak shifting can and would occur when LNG is being used on the margin in the same manner as described for diesel peak shifting.

b) If not confirmed please explain.

ANSWER:

(a) and **(b)**

LNG peak shifting could occur when operationally feasible. Unit operating restrictions will need to be given consideration when assessing the potential for LNG peak shifting, as the ability to peak-shift LNG will depend on the particular circumstances at the time.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 10 Re. Diesel peak shifting. To provide a clearer understanding of the use of diesel and LNG for thermal generation and the potential for diesel and / or LNG peak shifting please provide the following:**

QUESTION:

a) For the period January 2019 through February 2021 please provide a table of actual monthly total generation broken down by: hydro, IPP plus micro-generation, LNG thermal, and diesel thermal.

b) For the period January 2020 through 2021 (using GRA forecast generation for March through December 2021) please provide a similar table but using hydro generation figures based on long-term average water availability.

ANSWER:

(a)

Please see JM-YEC-1-15 (a) Attachment 1 which provides the actual monthly generation for hydro, LNG and diesel generation for the period from January 1, 2019 to the end of February 2021. During this time period, no IPP energy was generated. Micro-generation is embedded in the load and is not visible to YEC.

(b)

Please see JM-YEC-1-15 (b) Attachment 1 which provides the expected long-term average generation based on long-term average water availability [38 water years]. As requested, the table uses actual total generation numbers for the period from January 2020 through February 2021, and March through December 2021 are forecasts from the 2021 GRA. Please see notes to the table that explain assumptions used for LTA calculations.

Actual Generation for the period from January 2019 to February 2021

		Total MWh	Hydro MWh	Wind/SOP MWh	Diesel MWh	LNG MWh
2019	**JAN**	47,771	40,215	-	991	6,565
	FEB	44,425	36,990	-	91	7,345
	MAR	35,785	27,216	-	35	8,534
	APR	34,653	25,041	-	168	9,444
	MAY	28,684	20,970	-	21	7,692
	JUN	25,973	24,566	-	600	806
	JUL	29,380	29,222	-	158	1
	AUG	29,071	29,013	-	36	22
	SEP	32,041	31,020	-	37	984
	OCT	40,102	32,808	-	102	7,191
	NOV	42,155	33,408	-	196	8,551
	DEC	50,636	40,350	-	1,357	8,929
	Total	**440,676**	**370,819**	**-**	**3,793**	**66,065**
2020	**JAN**	58,659	41,507	-	7,946	9,206
	FEB	48,294	38,492	-	1,900	7,902
	MAR	47,088	35,107	-	2,869	9,112
	APR	39,294	27,787	-	4,912	6,595
	MAY	32,766	27,666	-	193	4,907
	JUN	32,117	30,986	-	44	1,087
	JUL	33,180	33,137	-	33	10
	AUG	33,144	33,096	-	41	7
	SEP	33,033	32,057	-	259	717
	OCT	42,472	41,864	-	434	175
	NOV	52,738	47,778	-	1,088	3,872
	DEC	52,198	46,069	-	2,005	4,124
	Total	**504,984**	**435,546**	**-**	**21,723**	**47,714**
2021	**JAN**	48,657	43,652	-	1,518	3,487
	FEB	58,064	47,385	-	5,454	5,225

Actual/Forecast Generation; LTA Hydro and LTA Thermal

		Total MWh	LTA Hydro MWh	Wind/SOP MWh	LTA Thermal MWh
2020	**JAN**	58,659	47,515	-	11,144
	FEB	48,294	39,120	-	9,175
	MAR	47,088	38,142	-	8,945
	APR	39,294	31,829	-	7,465
	MAY	32,766	26,541	-	6,225
	JUN	32,117	30,628	-	1,489
	JUL	33,180	33,028	-	152
	AUG	33,144	33,144	-	-
	SEP	33,033	33,033	-	-
	OCT	42,472	39,558	-	2,914
	NOV	52,738	42,720	-	10,019
	DEC	52,198	42,282	-	9,916
	Total	**504,984**	**437,541**	**-**	**67,443**
2021	**JAN**	48,657	39,489	-	9,168
	FEB	58,064	47,124	-	10,940
	MAR	47,351	38,430	178	8,744
	APR	43,313	35,152	251	7,910
	MAY	40,037	32,494	261	7,283
	JUN	38,233	31,712	273	6,248
	JUL	38,935	34,197	263	4,474
	AUG	38,786	34,826	249	3,711
	SEP	41,171	34,620	185	6,367
	OCT	44,008	40,958	125	2,924
	NOV	48,974	39,747	47	9,181
	DEC	54,562	44,282	19	10,261
	Total	**542,092**	**453,032**	**1,851**	**87,210**

Notes:

1. YEC does not calculate LTA hydro and thermal on monthly basis. The LTA hydro and thermal are based on annual numbers. In order to provide monthly breakdown of the annual LTA, the breakdown for June through October was prepared based on average hydro generation for the last three years; and the breakdown for the remainder months is prepared based on share of the monthly load compared to the total annual load.
2. The LTA thermal for 2020 is based on LWRF estimate and excludes Fish Lake impact.
3. The LTA thermal for 2021 is calculated based on LTA thermal calculation table provided in 2021 GRA, Appendix 2.1.
4. The total generation numbers for the period from January 2020 through February 2021 are actuals. March through December 2021 are forecasts from 2021 GRA.
5. The LTA thermal is not broken down to diesel and LNG. For LTA assessments, LNG is expected to be up to 90% of total thermal.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 10 (and page 23 bottom) Re. Grid reliability and ancillary services:**

QUESTION:

a) Please explain what level of intermittent energy supply can be stabilized by the BESS. Would this be the 40 GWh per year of IPP SOP energy supply, or would it be more related to the capacity of individual projects (e.g. risk of tripping off)?

b) In the absence of a hydro energy surplus, could a surplus of intermittent energy be used to charge the BESS for “other uses” including diesel (or LNG) peak shifting?

ANSWER:

(a)

Stabilization relates to the capacity of generation (MW). The BESS can be used to cover unplanned loss of renewable generation or variance in the output of generation (e.g., if wind output begins to decline). The BESS is expected to be able to cover the loss of up to 20 MW of generation for 30 minutes under the current operating reserve assumptions outlined in the Hatch Report (see Appendix B of the Application).

Please see also response to YUB-YEC-1-20(a).

(b)

Yes.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 10 Re. “other uses”:**

QUESTION:

a) Can all “other BESS uses” be provided at the same time?

b) If they cannot all be provided at the same time please list, for each of the “other uses” which “other uses” can and cannot be provided.

ANSWER:

(a) and **(b)**

All “other BESS uses” can be provided at the same time, except for blackstart/outage restoration. This service would only be provided in the event of an outage. Reactive power support may be provided at the same time within the total MVA rating of the power conversion system.

Consideration will be given to the priority of these functions during controller development if multiple functions were to be triggered or in use at the same time.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 11 Re. operating reserve:**

QUESTION:

a) If the answer to JM-YEC-1-13 is that “operating reserve” is the same as “spinning reserve”, and if spinning reserve is equated to load following [YEC 2017-2018 GRA response to IR JM-YEC-1-19(c)], would not a high (full) state of charge essentially preclude load following which may require charging as well as discharging?

ANSWER:

(a)

Correct. If the BESS is at a high state of charge it will not be able to charge at all, or for very long, and could not load-follow "upwards" (for example, charge to offset the ramping up of wind energy or to absorb a loss of load). However, it is anticipated that the BESS will be configured to idle at a moderate state-of-charge in order to be available to respond to system events requiring either charging or discharging. Please see also response to YUB-YEC-1-20(a). The BESS only needs to be partially charged to provide operating reserve.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 11 Re. operating reserve "there are several weeks in winter when no operating reserve benefits can be achieved due to water flow limitations."**

QUESTION:

a) Please explain this statement by describing in detail the grid load and generation situation(s) during these weeks.

ANSWER:

(a)

There are several weeks in winter when no operating reserve can be provided by the hydro units due to operating restrictions. For example, during a high load period in the winter, it is likely the output of the generators will be maximized to serve load. If YEC cannot increase their output due to flow limitations, they are unable to provide reserve. Winter restrictions can further limit the ability to increase the output of the units and hence prevent them from providing operating reserve. For example, Mayo Hydro has ramping limitations during the winter, and Whitehorse Rapids GS is subject to Marwell ice flow restrictions which can limit the output of the units.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 13 Re. Operating reserve"… Based on YEC's 2021 GRA fuel prices the annual thermal fuel cost savings … is about $1.156 million."**

QUESTION:

a) What are the current March 2021 (most recent) YEC LNG and diesel prices?

b) What would be the annual savings at the current LNG and diesel prices?

c) If the project is provided with the necessary Part 3 certificates and built, how does YEC propose to measure, record, and track the actual savings?

ANSWER:

(a)

Current prices are as follows:

- **Diesel -** The weighted average diesel cost is about $0.2732/kWh based on March 2021 diesel fuel prices and 2021 GRA efficiencies.

- **LNG -** The average LNG cost is $0.1936/kWh based on most recent LNG delivered commodity price (Feb 27, 2021) and 2021 GRA efficiencies.

(b)

Please see response to JM-YEC-1-33(a).

(c)

YEC will develop procedures before start of project operations to record BESS operating reserve use and estimated savings related to this use.

TOPIC: **Section 3 Project Description**

REFERENCE: Page 15 Re. Grid Reliability and Ancillary Services "Yukon Energy is also exploring other options such as BESS use for stabilizing hydro operation during periods of downstream winter ice formation, reducing downstream winter flooding …":

QUESTION:

a) Would this potential use extend to mitigating Aishihik River downstream impacts as well as for Whitehorse Rapids and Mayo B?

ANSWER:

(a)

YEC is still exploring these options, though it is anticipated the BESS could potentially be used to help to mitigate downstream impacts at Aishihik, Mayo and Whitehorse. Please see also response to YUB-YEC-1-14.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 16 Re. Project Costs:**

QUESTION:

a) The text indicates that a 15% contingency is included in the estimate, however the figures in Table 3-4 seem to imply that the 15% contingency was only applied to the Hatch portion of the estimate and no contingency is applied to the YEC portion (Planning Costs and Owner's costs). Is this what was intended?

b) If no contingency is added to the YEC portion of the cost estimate why not?

c) If, as indicated, the estimate is indeed +/- 30%, is it fair to say that the cost estimate is $31.7 million +/- $9.5 million?

ANSWER:

(a) and **(b)**

Contingency was applied on the large equipment purchases and construction, which represent the majority of the project costs. Contingency was not applied to planning costs as they are based on actuals of the planning phase that was completed in November 2020. Contingency was not applied on the Owners Costs as there is less uncertainty regarding these activities.

(c)

Correct.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 17 Re. Project Costs Table 3-5 Site Lease:**

QUESTION:

a) The site lease term is indicated to be 25 years. Does the lease contain an option to extend the lease should the life of the BESS be extended or a BESS replacement at the end of life be contemplated?

b) If not please explain why not.

ANSWER:

(a) and **(b)**

The draft lease includes one renewal option for an additional 25 years.

TOPIC: **Section 3 Project Description**

REFERENCE: Page 18 Re. Project Costs "in summary…the specified need …would best be met through development of the project. Compared to the feasible and best alternative available today (i.e., diesel rental) …":

QUESTION:

a) Please explain why replacement diesels (e.g. standard CAT 3616 4.4 MW diesels) for the three retired Mirrlees generators at the existing Whitehorse Rapids diesel plant, at least two of which have been retired since the LNG plant was completed, is or was not feasible in the same time frame.

ANSWER:

(a)

YEC is pursuing the replacement of retired diesel engines with new diesel engines, including 5 MW to replace the retired generation at the Whitehorse Rapids Generating Facility diesel plant. Overall, 12.5 MW of diesel to replace diesel unit retirements is included in YEC's 10-Year Renewable Electricity Plan. Additional capacity, currently provided by rental diesel units, is still required beyond these additions.

TOPIC: **Section 3 Project Description**

REFERENCE: **Pages 20-21 Re. Other Project Planning:**

QUESTION:

a) Please provide updates on each of these three planning items.

ANSWER:

(a)

Updates for each of the items noted are as follows:

- **Finalize Lease for KDFN Site**: YEC is in the process of reviewing the lease terms and conducting legal review to enable YEC to enter into a lease for the site in the near term. This item is on track.

- **Procurement Process and Preliminary Engineering**: Please see response to YUB-YEC-1-13 for an update on the BESS procurement process. YEC conducted a procurement process to select an Owner's Engineer for the Project. Hatch was awarded this contract and has initiated the preliminary engineering work for the Project. These items are on track.

- **Related Other Investigations and Agreements**: The system impact study is currently in progress by the Owner's Engineer. Please see response to YUB-YEC-1-71 for the status of the geotechnical investigation. Engineering for the route and transmission connection has been undertaken, as described in the response to YUB-YEC-1-3. YEC continues to work with both First Nations partners via the Project Committee on a Project Agreement to define the First Nation benefits for the project. These items are on track.

TOPIC: **Section 3 Project Description**

REFERENCE: **Page 22 Re. Summary of Environmental and Socio-economic impacts, "The YESSA assessment has not been initiated at this time."**

QUESTION:

a) Please provide an update of the YESSA assessment that is to be filed by March 31.

ANSWER:

(a)

The draft Project Proposal for the YESAA assessment has been completed. YEC expects to finalize its documentation and submit a Project Proposal to the YESAB Designated Office in early April.

TOPIC: **Section 4 Project Justification**

REFERENCE: Page 24 Yukon Grid Context, "Seasonal generation constraints also present additional challenges to the YIS. Electricity demand on the YIS is highly variable with seasonal mismatch between the timing of maximum available electricity production from renewable generation …The result is surplus renewable generation during the summer (which cannot be sold to other jurisdictions) and reliance on thermal generation to supply peak load requirements during winter."

QUESTION:

a) Please confirm that there are SCADA connected secondary sales customers (e.g. the Canada Games Centre) that are able and willing to buy surplus energy when available.

b) Please confirm that there were secondary sales in the last half of 2020 when YEC had surplus hydro generation available due to high water flows.

ANSWER:

(a)

Confirmed.

(b)

Confirmed. Secondary sales were made available during September and October 2020 due to high water inflows and full water reservoirs; secondary sales were again ceased by the end of October due to resumed need for thermal generation.

TOPIC: **Section 4 Project Justification**

REFERENCE: **Page 25 Re. Evolving Grid Load Conditions, "…Yukon Energy continues to pursue …and also to implement a Demand Side Management (DSM) program aimed to reduce load growth, especially peak demand reductions.":**

QUESTION:

a) The author signed up for a "Peak Smart" program in the first few days of it being advertised a year or more ago and has yet to have any equipment installed to enable the remote controls to limit peak load demands, despite following up at least 3 times over the past 8 months. Is this program still being pursued and if so, why does it not appear to be being implemented?

b) Please describe any other peak load growth limiting DSM initiatives that are currently being contemplated or implemented and indicate whether being contemplated or implemented.

ANSWER:

(a)

The PeakSmart program continues to be implemented. Over 50% of program installations have been completed by the contractors executing the project. During 2020, customer in-home installations were halted for several months due to COVID-19 restrictions, resulting in delays of the original installation schedule contemplated. Accordingly, the pilot is expected to operate for an additional winter to ensure sufficient data is collected for analysis of the results. YEC has contacted the project contractor to ensure the author is contacted as soon as possible for coordination of device installation.

(b)

In February 2021, Yukon government issued Order-In-Council 2021/16 which enables YEC to recover through rates the costs reasonably incurred to provide or participate in a demand side management program. In 2021, YEC will initiate the design of a new portfolio of DSM programs with a capacity-savings focus to manage peak loads. The program design in 2021 will define the specific DSM initiatives to be implemented.

TOPIC: **Section 4 Project Justification**

REFERENCE: **Page 25 Re. "The 10-year Renewable Electricity Plan … Ongoing generation projects include …":**

QUESTION:

a) Please provide the status of / updates on each of the following: WH2 uprate, WH4 uprate, renewable energy purchases from IPP SOP projects, solar energy from the micro-generation program, southern lakes enhanced storage program, Mayo Lake enhanced storage program, replacement of diesel generators (if not already updated in JM-YEC-1-24) and each of the three major projects proposed in the 10-year Renewable Electricity Plan.

ANSWER:

(a)

Status/ updates for each of the noted projects or programs is as follows:

- **WH2 uprate:** The WH2 uprate project is proceeding according to plan and is expected to be completed in July 2021. Contractors are currently on site disassembling the generator in preparation for major components to arrive on site.

- **WH4 uprate:** The WH4 uprate project is proceeding according to plan and is expected to be completed in June 2021. The design and manufacturing of the Servo motors have been completed and await delivery to site. Preparations are being made in anticipation for equipment delivery to site.

- **IPP SOP:** Under the Standing Offer Program (SOP), YEC has executed Electricity Purchase Agreements with two Independent Power Producers (IPPs). The IPP contracts signed to date are expected to provide approximately 2.1 GWh annual renewable energy. YEC is currently working with an additional nine applicants which represent a potential 27 GWh of annual generation. YEC forecasts the total program cap of 40 GWh of annual energy will be provided by program proponents by 2024.

- **Solar Micro-generation:** The solar micro-generation program is administered by Yukon government. Currently, YEC understands from Yukon government that 2.8 GWh of micro-generation solar is expected to be exported to the grid in 2021, rising to 4.6 GWh by 2024.

- **Southern Lakes Enhanced Storage:** Following an additional public engagement effort on the Southern Lakes Enhanced Storage Project (SLESP), in 2020 YEC's Board of Directors decided to move forward with the preparation of a Project Proposal to be considered for submission to YESAB. YEC is engaging with the First Nations who would be impacted by the Project, in particular those who are Decision Bodies under YESAA, to confirm their support for moving forward with a submission to YESAB.

- **Mayo Lake Enhanced Storage:** YEC is currently working with the First Nation of Na-Cho Nyak Dun to facilitate the First Nation's review of the project and understand their perspective prior to the Company's submission of the Project Proposal to the YESAB Designated Office.

- **Diesel Replacements:** YEC is currently conducting preliminary engineering and required assessment activities for the three diesel replacement projects in Whitehorse, Faro, and Dawson, which are expected to be in-service by the winter of 2023/24.

- **Atlin Hydro Expansion:** YEC is in active discussions with THELP Homeland Energy Limited Partnership, who will be the owners of the project, to determine the terms of an Electricity Purchase Agreement. The project is currently expected to be in-service by 2024.

- **Moon Lake Pumped Storage:** Planning for this project is not expected to commence until Federal funding is secured.

- **Southern Lakes Transmission Expansion:** Planning for this project is not expected to commence until Federal funding is secured.

TOPIC: **Section 4 Project Justification**

REFERENCE: **Page 30 Re. Demand Side management:**

QUESTION:

a) Does YEC propose any DSM programs involving rate structures, or building and appliance codes or standards?

ANSWER:

(a)

Please see response to JM-YEC-1-28. Program design to be undertaken in 2021 will define the specific DSM initiatives to be implemented.

YEC understands that rate structure and building and appliance codes or standards are an effective DSM tool; however, they may not be available for the utility itself to pursue at this time under the current regulatory structure.

TOPIC: **Section 4 Project Justification**

REFERENCE: **Page 31 Re. new 20 MW Wind Project:**

QUESTION:

a) Would the proposed 20 MW / 40 MWh BESS be capable of keeping the grid frequency stable with such a wind farm connected to the YIS?

b) Even if it does not supply dependable capacity, would a 20 MW wind farm not reduce winter diesel and LNG generation, as well as reduce water storage pressure/requirements at Southern Lakes, Mayo Lake, and Aishihik Lake?

c) Could such a wind farm not provide significant benefits to the grid in reduced thermal generation in the event of a drought such as experienced from 2017 to the summer of 2020?

d) In the absence of a pumped hydro energy storage system could not a portion of any summer surplus energy be sold as secondary sales to SCADA connected secondary sales customers?

ANSWER:

(a)

A common use case for batteries is to act as a stabilizing entity for fluctuating renewable generators. This can be accomplished on a power (ramp rate control) basis or frequency basis. A BESS of this size would be able to stabilize any frequency variations due to a wind farm.

See also the response to YUB-YEC-1-24(d). The BESS could be set to respond to frequency excursions outside of a certain range (right now +/- 0.5 Hz) irrespective of what generation/load is causing this excursion.

(b)

While a wind farm would reduce winter thermal generation, it would increase the pressure/requirements on the Aishihik, Mayo and Whitehorse reservoirs due to its addition of incremental summer energy when the system already experiences an excess of energy availability (unless there was a significant increase in the summer load from new demands). The reservoirs would be required to allow for the shifting of more power from the summer to the winter when its needed and may encounter further challenges in this regard.

(c)

In drought years a wind farm would reduce thermal generation requirements.

(d)

Yes, it is anticipated when the IPP Standing Offer Program wind and solar comes online the amount of summer secondary sales will increase.

TOPIC: **Section 4 Project Justification**

REFERENCE: **Page 39 Re. Table 4-3 Annual Ratepayer Impacts from BESS:**

QUESTION:

a) Do the savings from Operating Reserve and from Peak Shifting include any variable costs such as consumables and variable labour from reduced operating hours of diesel and LNG generators?

b) If not, why are these not included as a cost savings?

ANSWER:

(a)

No, the savings in Table 4-3 only account for the fuel costs.

(b)

In practice, non-fuel variable cost savings will likely result in additional savings from these use cases above what is presented in the Application. For the purpose of the current assessments, these additional cost savings have not been estimated. Past estimates have suggested that such savings might approximate 1.5 cents per kWh of diesel generation avoided.

TOPIC: **Section 4 Project Justification**

REFERENCE: **Page 39 Re. Table 4-3:**

QUESTION:

a) Please provide an updated Table 4-3 based on the present (March 2021) actual LNG and diesel fuel prices.

b) Based on the present actual costs of diesel and LNG, at approximately what BESS project cost over-run would the project be break-even?

c) Please provide a Table 4-3 based on the project coming in at 30% below the estimate.

d) Please provide a Table 4-3 based on the project coming in at 30% above the estimate.

e) Please reference the Hatch Report page B-113 and provide a Table 4-3 based on a long-term avoided cost of diesel at $0.277 per kWh and a long-term avoided cost of LNG at $0.248 per kWh.

ANSWER:

(a)

Please see Table 1 below that shows updated version of Table 4-3 with most recent actual fuel prices.

Table 1: Annual Ratepayer Impacts from BESS (20 MW/ 40 MWh) based on March 2021 Fuel Prices

$000	BESS Annual Costs ($000)				BESS Annual Savings ($000)				
	Annual Capital Cost	Annual Operating Cost [excl. recharging]	Annual Net Recharging Cost [15% return loss plus 3% idling loss]	Total Annual Costs	Avoided Diesel Rental Costs	Annual Savings from Operating Reserve Use	Annual Savings from Peak Shifting	Total Annual Savings	Net Annual Ratepayer Savings (Costs) ($000)
	A	B	C	D=A+B+C	E	F	G	H=E+F+G	I=H-D
Year 1	$1,530	$652	$89	$2,271	$1,216	$1,236	$25	$2,477	$205
Year 2	$1,492	$665	$91	$2,247	$1,265	$1,261	$25	$2,550	$303
Year 3	$1,454	$678	$93	$2,224	$1,315	$1,286	$26	$2,627	$403
Year 4	$1,416	$691	$94	$2,201	$1,368	$1,311	$26	$2,705	$505
Year 5	$1,378	$704	$96	$2,178	$1,423	$1,338	$27	$2,787	$609
Year 6	$1,340	$717	$98	$2,156	$1,480	$1,364	$27	$2,871	$715
Year 7	$1,302	$731	$100	$2,134	$1,539	$1,392	$28	$2,958	$825
Year 8	$1,264	$745	$102	$2,112	$1,600	$1,420	$28	$3,048	$936
Year 9	$1,226	$759	$104	$2,090	$1,664	$1,448	$29	$3,141	$1,051
Year 10	$1,189	$774	$106	$2,069	$1,731	$1,477	$29	$3,237	$1,168
Year 11	$1,151	$789	$109	$2,048	$1,800	$1,506	$30	$3,337	$1,288
Year 12	$1,113	$804	$111	$2,028	$1,872	$1,537	$31	$3,439	$1,412
Year 13	$1,075	$820	$113	$2,007	$1,947	$1,567	$31	$3,545	$1,538
Year 14	$1,037	$835	$115	$1,987	$2,025	$1,599	$32	$3,655	$1,668
Year 15	$999	$851	$117	$1,968	$2,106	$1,631	$33	$3,769	$1,801
Year 16	$961	$868	$120	$1,949	$2,190	$1,663	$33	$3,886	$1,938
Year 17	$923	$885	$122	$1,930	$2,278	$1,697	$34	$4,008	$2,078
Year 18	$885	$902	$125	$1,912	$2,369	$1,730	$34	$4,134	$2,222
Year 19	$847	$919	$127	$1,894	$2,463	$1,765	$35	$4,264	$2,370
Year 20	$810	$937	$130	$1,876	$2,562	$1,800	$36	$4,398	$2,522
NPV	**$16,318**	**$10,147**	**$1,394**	**$27,859**	**$22,647**	**$19,353**	**$386**	**$42,386**	**$14,527**

Notes:

1 2021 assumed as Year 1. Capital costs (Table 3-4) and operating costs (Table 3-5) each escalated 2% for one year inflation.
2 YEC WACC at 4.794% per 2021 GRA (real WACC with 2% inflation at 2.739%) is used for all net present values (NPVs).
3 Annual Capital Cost includes depreciation (20 year life) and return on mid-year rate base at YEC WACC of 4.794%.
4 Annual Net Recharging Cost assumes diesel generation for N-1 dependable capacity and operating reserve recharge losses, 75% LNG and 25% hydro for other recharge losses (peak shifting saving already addresses these losses), and hydro for idling losses.
5 Avoided Diesel Rental Costs assumes $168,896 per MW (2022$) and 7.2 MW (4 rental units) of dependable capacity.
6 The table assumes diesel fuel price at $0.273/kW.h and LNG fuel price at $0.194/kW.h based on March 2021 prices.

(b)

Based on the present costs of diesel and LNG as provided above in response to part (a), Table 1 (footnote 6) and the other costs and savings in Table 1, the BESS project would break even for NPV ratepayer cost impacts with capital cost over-run of approximately 42.5%.

(c)

Table 2 below shows an updated version of Table 4-3 assuming a Project capital cost 30% below the estimate included in the Application.

Table 2: Annual Ratepayer Impacts from BESS (20 MW/ 40 MWh) assuming a Project Capital Cost 30% below the estimate included in the Application

	BESS Annual Costs ($000)				BESS Annual Savings ($000)				
$000	Annual Capital Cost	Annual Operating Cost [excl. recharging]	Annual Net Recharging Cost [15% return loss plus 3% idling loss]	Total Annual Costs	Avoided Diesel Rental Costs	Annual Savings from Operating Reserve Use	Annual Savings from Peak Shifting	Total Annual Savings	Net Annual Ratepayer Savings (Costs) ($000)
	A	B	C	D=A+B+C	E	F	G	H=E+F+G	I=H-D
Year 1	$793	$652	$82	$1,528	$1,216	$1,125	$11	$2,351	$823
Year 2	$774	$665	$84	$1,522	$1,265	$1,147	$11	$2,423	$900
Year 3	$754	$678	$85	$1,517	$1,315	$1,170	$11	$2,496	$979
Year 4	$734	$691	$87	$1,512	$1,368	$1,193	$11	$2,573	$1,061
Year 5	$715	$704	$89	$1,507	$1,423	$1,217	$12	$2,651	$1,144
Year 6	$695	$717	$91	$1,503	$1,480	$1,242	$12	$2,733	$1,230
Year 7	$675	$731	$92	$1,499	$1,539	$1,267	$12	$2,817	$1,318
Year 8	$656	$745	$94	$1,495	$1,600	$1,292	$12	$2,904	$1,409
Year 9	$636	$759	$96	$1,492	$1,664	$1,318	$12	$2,994	$1,503
Year 10	$616	$774	$98	$1,489	$1,731	$1,344	$13	$3,088	$1,599
Year 11	$597	$789	$100	$1,486	$1,800	$1,371	$13	$3,184	$1,698
Year 12	$577	$804	$102	$1,483	$1,872	$1,398	$13	$3,284	$1,800
Year 13	$557	$820	$104	$1,481	$1,947	$1,426	$13	$3,387	$1,906
Year 14	$538	$835	$106	$1,479	$2,025	$1,455	$14	$3,493	$2,014
Year 15	$518	$851	$108	$1,478	$2,106	$1,484	$14	$3,604	$2,126
Year 16	$499	$868	$111	$1,477	$2,190	$1,514	$14	$3,718	$2,241
Year 17	$479	$885	$113	$1,476	$2,278	$1,544	$15	$3,836	$2,360
Year 18	$459	$902	$115	$1,476	$2,369	$1,575	$15	$3,958	$2,483
Year 19	$440	$919	$117	$1,476	$2,463	$1,606	$15	$4,085	$2,609
Year 20	$420	$937	$120	$1,476	$2,562	$1,638	$15	$4,216	$2,740
NPV	**$8,464**	**$10,147**	**$1,286**	**$19,897**	**$22,647**	**$17,612**	**$167**	**$40,426**	**$20,530**

Notes:

1 2021 assumed as Year 1. Capital costs (Table 3-4) and operating costs (Table 3-5) each escalated 2% for one year inflation.
2 YEC WACC at 4.794% per 2021 GRA (real WACC with 2% inflation at 2.739%) is used for all net present values (NPVs).
3 Annual Capital Cost includes depreciation (20 year life) and return on mid-year rate base at YEC WACC of 4.794%.
4 Annual Net Recharging Cost assumes diesel generation for N-1 dependable capacity and operating reserve recharge losses, 75% LNG and 25% hydro for other recharge losses (peak shifting saving already addresses these losses), and hydro for idling losses.
5 Avoided Diesel Rental Costs assumes $168,896 per MW (2022$) and 7.2 MW (4 rental units) of dependable capacity.
6 The table assumes the capital cost if 30% below the estimate included in the Part 3 Application.

(d)

Table 3 below shows an updated version of Table 4-3 assuming a Project capital cost 30% above the estimate included in the Application.

Table 3: Annual Ratepayer Impacts from BESS (20 MW/ 40 MWh) Assuming the Project Capital Cost 30% above the estimate included in the Application

	BESS Annual Costs ($000)				BESS Annual Savings ($000)				
$000	Annual Capital Cost	Annual Operating Cost [excl. recharging]	Annual Net Recharging Cost [15% return loss plus 3% idling loss]	Total Annual Costs	Avoided Diesel Rental Costs	Annual Savings from Operating Reserve Use	Annual Savings from Peak Shifting	Total Annual Savings	Net Annual Ratepayer Savings (Costs) ($000)
	A	B	C	D=A+B+C	E	F	G	H=E+F+G	I=H-D
Year 1	$2,487	$652	$82	$3,221	$1,216	$1,125	$11	$2,351	-$870
Year 2	$2,425	$665	$84	$3,174	$1,265	$1,147	$11	$2,423	-$751
Year 3	$2,364	$678	$85	$3,127	$1,315	$1,170	$11	$2,496	-$630
Year 4	$2,302	$691	$87	$3,080	$1,368	$1,193	$11	$2,573	-$507
Year 5	$2,240	$704	$89	$3,033	$1,423	$1,217	$12	$2,651	-$382
Year 6	$2,179	$717	$91	$2,987	$1,480	$1,242	$12	$2,733	-$254
Year 7	$2,117	$731	$92	$2,941	$1,539	$1,267	$12	$2,817	-$123
Year 8	$2,055	$745	$94	$2,895	$1,600	$1,292	$12	$2,904	$9
Year 9	$1,994	$759	$96	$2,849	$1,664	$1,318	$12	$2,994	$145
Year 10	$1,932	$774	$98	$2,804	$1,731	$1,344	$13	$3,088	$283
Year 11	$1,871	$789	$100	$2,760	$1,800	$1,371	$13	$3,184	$424
Year 12	$1,809	$804	$102	$2,715	$1,872	$1,398	$13	$3,284	$568
Year 13	$1,747	$820	$104	$2,671	$1,947	$1,426	$13	$3,387	$716
Year 14	$1,686	$835	$106	$2,627	$2,025	$1,455	$14	$3,493	$866
Year 15	$1,624	$851	$108	$2,584	$2,106	$1,484	$14	$3,604	$1,020
Year 16	$1,563	$868	$111	$2,541	$2,190	$1,514	$14	$3,718	$1,177
Year 17	$1,501	$885	$113	$2,498	$2,278	$1,544	$15	$3,836	$1,338
Year 18	$1,439	$902	$115	$2,456	$2,369	$1,575	$15	$3,958	$1,503
Year 19	$1,378	$919	$117	$2,414	$2,463	$1,606	$15	$4,085	$1,671
Year 20	$1,316	$937	$120	$2,372	$2,562	$1,638	$15	$4,216	$1,844
NPV	**$26,528**	**$10,147**	**$1,286**	**$37,961**	**$22,647**	**$17,612**	**$167**	**$40,426**	**$2,466**

Notes:

1. 2021 assumed as Year 1. Capital costs (Table 3-4) and operating costs (Table 3-5) each escalated 2% for one year inflation.
2. YEC WACC at 4.794% per 2021 GRA (real WACC with 2% inflation at 2.739%) is used for all net present values (NPVs).
3. Annual Capital Cost includes depreciation (20 year life) and return on mid-year rate base at YEC WACC of 4.794%.
4. Annual Net Recharging Cost assumes diesel generation for N-1 dependable capacity and operating reserve recharge losses, 75% LNG and 25% hydro for other recharge losses (peak shifting saving already addresses these losses), and hydro for idling losses.
5. Avoided Diesel Rental Costs assumes $168,896 per MW (2022$) and 7.2 MW (4 rental units) of dependable capacity.
6. The table assumes the capital cost if 30% above the estimate included in the Part 3 Application.

(e)

Please see Table 4 below for the requested information.

Table 4: Annual Ratepayer Impacts from BESS (20 MW/ 40 MWh) based on avoided cost of diesel at $0.277 per kWh and a long-term avoided cost of LNG at $0.248 per kWh

	BESS Annual Costs ($000)				BESS Annual Savings ($000)				
$000	Annual Capital Cost	Annual Operating Cost [excl. recharging]	Annual Net Recharging Cost [15% return loss plus 3% idling loss]	Total Annual Costs	Avoided Diesel Rental Costs	Annual Savings from Operating Reserve Use	Annual Savings from Peak Shifting	Total Annual Savings	Net Annual Ratepayer Savings (Costs) ($000)
	A	B	C	D=A+B+C	E	F	G	H=E+F+G	I=H-D
Year 1	$1,530	$652	$112	$2,294	$1,216	$1,547	$14	$2,777	$483
Year 2	$1,492	$665	$114	$2,271	$1,265	$1,578	$14	$2,857	$586
Year 3	$1,454	$678	$116	$2,248	$1,315	$1,610	$14	$2,939	$691
Year 4	$1,416	$691	$119	$2,225	$1,368	$1,642	$15	$3,024	$799
Year 5	$1,378	$704	$121	$2,203	$1,423	$1,675	$15	$3,112	$909
Year 6	$1,340	$717	$124	$2,181	$1,480	$1,708	$15	$3,203	$1,022
Year 7	$1,302	$731	$126	$2,159	$1,539	$1,742	$16	$3,296	$1,137
Year 8	$1,264	$745	$129	$2,138	$1,600	$1,777	$16	$3,393	$1,255
Year 9	$1,226	$759	$131	$2,117	$1,664	$1,813	$16	$3,493	$1,376
Year 10	$1,189	$774	$134	$2,096	$1,731	$1,849	$17	$3,596	$1,500
Year 11	$1,151	$789	$136	$2,076	$1,800	$1,886	$17	$3,703	$1,627
Year 12	$1,113	$804	$139	$2,056	$1,872	$1,924	$17	$3,813	$1,757
Year 13	$1,075	$820	$142	$2,036	$1,947	$1,962	$18	$3,927	$1,890
Year 14	$1,037	$835	$145	$2,017	$2,025	$2,001	$18	$4,044	$2,027
Year 15	$999	$851	$148	$1,998	$2,106	$2,041	$18	$4,165	$2,167
Year 16	$961	$868	$151	$1,979	$2,190	$2,082	$19	$4,291	$2,311
Year 17	$923	$885	$154	$1,961	$2,278	$2,124	$19	$4,420	$2,459
Year 18	$885	$902	$157	$1,944	$2,369	$2,166	$19	$4,554	$2,611
Year 19	$847	$919	$160	$1,926	$2,463	$2,210	$20	$4,693	$2,767
Year 20	$810	$937	$163	$1,909	$2,562	$2,254	$20	$4,836	$2,927
NPV	**$16,318**	**$10,147**	**$1,752**	**$28,217**	**$22,647**	**$24,227**	**$217**	**$47,091**	**$18,874**

Notes:

1. **2021 assumed as Year 1. Capital costs (Table 3-4) and operating costs (Table 3-5) each escalated 2% for one year inflation.**
2. **YEC WACC at 4.794% per 2021 GRA (real WACC with 2% inflation at 2.739%) is used for all net present values (NPVs).**
3. **Annual Capital Cost includes depreciation (20 year life) and return on mid-year rate base at YEC WACC of 4.794%.**
4. **Annual Net Recharging Cost assumes diesel generation for N-1 dependable capacity and operating reserve recharge losses, 75% LNG and 25% hydro for other recharge losses (peak shifting saving already addresses these losses), and hydro for idling losses.**
5. **Avoided Diesel Rental Costs assumes $168,896 per MW (2022$) and 7.2 MW (4 rental units) of dependable capacity.**
6. **The table assumes diesel fuel price at $0.277/kW.h and LNG fuel price at $0.248/kW.h as requested in the IR question.**

TOPIC: **Appendix B Hatch Report**

REFERENCE: **Page B-14 Re. TKC Land –Whitehorse Access road:**

PREAMBLE:

QUESTION:

a) Is the reference to an ‘existing access across from the Yukon Energy access’ referring to the Robert Service Way access road toward Yukon Energy (and Miles Canyon Road)?

b) If so, can YEC confirm that Hatch is mistaken with respect to the existence of traffic lights at this intersection?

ANSWER:

(a)

Yes.

(b)

Confirmed. The report was mistaken regarding the existence of traffic lights.

TOPIC: **Appendix B Hatch Report**

REFERENCE: **Page B-19 Re. "A 2 MW wind farm is currently being planned for operation in 2021":**

PREAMBLE:

QUESTION:

a) Please describe the wind farm that is being referenced here and what is its present status?

ANSWER:

(a)

The 2MW wind farm planned for 2021 at the time the Hatch report was authorized is a wind project on Haeckel Hill now known as the Eagle Hill Wind Project. Eagle Hill Wind is now a 4 MW, 100% First Nation owned, fully funded project. The project has secured the site lease and initial site works are expected to begin in summer of 2021. It is currently expected to be operational in 2023.

TOPIC: **Appendix B Hatch Report**

REFERENCE: **Page B-78 Re. "Several of the major underfrequency events lasted for extended periods, one lasting for several days.":**

PREAMBLE:

QUESTION:

a) Please provide the dates involved in the underfrequency event that lasted for several days and describe the circumstances that caused this event.

ANSWER:

(a)

Since the Hatch report was authored, further review has indicated the event referenced were the result of offline transducers and their duration should be ignored/excluded as erroneous.