

YUKON ENERGY CORPORATION

2021 GENERAL RATE APPLICATION
ROUND 2 INTERROGATORY RESPONSES FILED

August 24, 2021

City of Whitehorse
(CW)

TOPIC: **Normalized Sales versus Long Term Average**

REFERENCE: **CW-YEC-1-2**
CW-YEC-1-9
CW-YEC-1-11

PREAMBLE: CW notes that YEC does not appear to use weather normalization as a basis for sales forecasts.

QUESTION:

a) Please fully explain why YEC does not use weather normalized data to derive sales forecasts.

b) Please discuss the difference between using weather normalized data and long-term average data.

c) Please fully explain YEC's understanding of how weather normalization is implemented.

d) Please fully discuss YEC's views on whether the use of weather normalized data would improve sales forecasts.

e) Please fully explain whether the use of weather normalized data could be useful in the determination of Hydro Generation for the LWRF.

ANSWER:

(a)

The response to CW-YEC-1-2 states YEC does not provide a weather normalized version of its actual sales to retail and industrial customers. As reviewed in Tab 2 of the Application, YEC directly serves customers only in seven separate communities, accounting for only 10% of 2021 forecast firm YEC energy sales – separate weather normalized analysis for each community's retail sales by customer class has not been considered to be a worthwhile exercise. With respect to industrial sales forecast, forecasts

are based on information from each customer and weather normalization is not a relevant factor for consideration.

The GRA Application in Tab 2 states that YEC's Wholesale sales forecast model does weather normalize the actual sales data (internally in the model) and uses this along with other variables to forecast a 'weather normal' sales forecast based on historical average temperatures.

(b) and **(c)**

Weather normalization is a process that is used to correct sales forecasts for weather impacts. The process adjusts actual energy or peak sales to what would have happened under normal weather conditions. When normalizing actual data, the long-term average temperature is used to define normal (average) weather conditions.

Weather normalization does not apply directly to long-term average generation forecasts. The total sales forecasts plus system losses becomes the generation forecast. The utility applies long-term average modelling to the generation forecast to determine the expected source of generation, assuming long term average water conditions.

(d)

YEC does use normal or expected weather in the wholesale sales forecast. Similar analysis would not be likely to materially improve YEC retail sales forecasts (see response to "a" above) and would not improve industrial sales forecasts.

(e)

Weather normalized data is not directly relevant to the determination of Hydro Generation for the LWRF however there is an indirect connection. Weather-normalized data is used to generate wholesales forecasts which in turn are combined with other customer class forecasts to determine the total grid load that is used for assessing long-term average annual hydro generation based on available water year records for the Yukon Integrated System.

TOPIC: **Sales Forecasts – Wholesale Sales to ATCO 1 Electric Yukon (AEY)**

REFERENCE: **CW-YEC-1-3**

PREAMBLE: In the response, YEC refers CW to AEY for responses to the CW questions. Given that this is a YEC application, and YEC has incorporated AEY data, the CW requires information to understand how YEC, and parties, can test the information.

QUESTION:

a) Please fully discuss all processes and analyses that YEC used to assess or test the AEY data. In the response, please fully explain if YEC sought the requested information from AEY in the preparation of the response.

b) In the context of a YEC application, please fully explain how parties, such as CW, can test the information related to AEY.

ANSWER:

(a)

YEC receives Fish Lake forecast directly from AEY as well as historical AEY sales data. AEY actual sales is one of the inputs into YEC's wholesales forecast.

YEC assumes that the Fish Lake forecast provided is accurate but tests its reasonableness by comparing it to historical results; by confirming that the amounts provided are within operating limits; and by assessing whether both AEY hydro units are scheduled to operate.

(b)

YEC has explained the approach to validation of Fish Lake forecasts in (a). Other than the Fish Lake forecast, YEC does not use AEY sales forecasts for forecasting sales (only AEY actual historical data). YEC only uses AEY sales forecasts as a comparison to YEC forecasts for reasonableness, not as a direct input.

TOPIC: **Sales Forecasts – General Service Sales – Faro Mine Remediation**

REFERENCE: **CW-YEC-1-8**

PREAMBLE: YEC states that "YEC reviewed the reasonableness of the forecast and compared it to actual historical results."

QUESTION:

a) Please fully explain the review for reasonableness that YEC conducted, along with any analyses or working papers.

ANSWER:

(a)

YEC reviewed Faro Mine's history and noted that it was on a planned upward trend in consumption with 2018 growing 7% over 2017, 2019 growing by 22% over 2018 and 2020 forecast to grow 52% over 2019. This growth is consistent with previous expectations developed from customer communications to the effect that new electrical loads related to water treatment were connected to the system in 2019. In terms of assessing the 2021 forecast load, YEC compared 2020 actual sales to June 30 to the 2020 forecast. Actual Faro consumption in the first half of 2020 was 49% of the full year forecast. Based on this analysis, YEC assessed the 2021 forecast as reasonable.

TOPIC: **Labour**

REFERENCE: **CW-YEC-1-15**

PREAMBLE: In the response YEC mentions prior AMR\AMI applications.

QUESTION:

a) Please provide a list of YUB decisions that dealt with YEC AMR\AMI implementations.

ANSWER:

(a)

YEC has not to date sought to implement Automated Meter Reading (AMR) or Advanced Metering Infrastructure (AMI). AMR/AMI implementation was previously sought by AEY and reviewed as part of AEY (or YECL) GRA proceedings in 2008/09 and 2014.

YUB decisions on AMR/AMI implementation along with key directions are provided in two separate AEY GRA decisions. As noted in the summaries that follow, each time the Board noted concern with the business case for the project, and stated that it was not prepared to accept the project and that AEY was to remove the project and its costs from rate base:

1. **2009-2 – Appendix A Reasons for Decision:** The Board is not prepared to accept the AMR project at this time and directs YECL to remove this project and its costs from rate base. The Board encourages YECL to work with all Intervenors, including YEC, to review and assess the costs and potential benefits of the AMR project. Upon completion of the review, YECL is to submit a new business case that outlines the benefits of such a project over time, how it addresses the concerns raised by Intervenors, and describe potential economies by partnering with YEC and the City of Whitehorse in the scope and implementation of the project. The Board expects this business case to be filed with YECL's next GRA. (Page 42)

2. **2014-06 – Appendix A Reasons for Decision:** The Board has concerns with the business case because the cross-over of the benefits is still nine years away which puts the economic benefits of the business case at risk. The Board agrees with

UCG's submission that the payback period is too long for such a small customer base, especially when one considers the rate at which technology changes. Furthermore, the Board shares the concerns of CW that until there is conclusive evidence either way regarding the imposition of TOU billing, proceeding with AMR at this time may result in additional risk to customers. Due to these concerns the Board is not prepared to accept the project and directs YECL to remove this project and its costs from rate base. The Board further directs YECL to reflect this finding in its compliance filing. (Page 76)

TOPIC: **Labour Rates**

REFERENCE: **CW-YEC-1-16**

PREAMBLE: **In the response, at lines 7-17 YEC states:**

> Regarding performance increments, employees subject to the Collective Bargaining Agreement can have up to two increments per year (every six months) if they are not capped at their maximum salary level. With many new hires recently this means a lot of performance increments. Management and Professional employees are eligible for performance increments annually if they are not capped at their maximum salary level. As union employees can have different dates for increments based on their start dates throughout the year, YEC forecasts performance increments by using an average wage for that position for the year. Additionally, due to the timing of the performance increase being dependent on the timing of the performance review, we also get into situations were increments are late and run between different years, but the retro ends up in year it is paid. As such, a calculation of cost of performance increments would be extremely difficult.

QUESTION:

a) Please provide an analysis of each of collective Bargaining employees and Management and Professional employees that identifies:

   i) The number of employees that are capped at the maximum for their salary level, and

   ii) The number of employees below the maximum salary level.

b) Please provide the information for each of 2019, 2020, and 2021.

ANSWER:

(a) and **(b)**

The analysis of collective bargaining employees is as follows:

	2019	2020	2021
Capped at Maximum	40	37	40
Below Maximum	26	25	25

The analysis of management and professional employees is as follows:

	2019	2020	2021
Capped at Maximum	8	8	15
Below Maximum	16	20	13

TOPIC: **Production**

REFERENCE: **CW-YEC-1-17**

PREAMBLE: In Q (a), CW asked "Please provide copies of all analysis or business cases that YEC has done or prepared comparing the cost of owning diesel generation compared to rentals. If no such analysis or business cases have been prepared, please fully explain why not." In the response, YEC states:

> Yukon Energy's 2016 Resource Plan included action plans focusing on short and long term options to reduce the capacity shortfalls, including building a new 20 MW diesel plant.
>
> However, based on feedback received from Yukoners as well as to address impacts of the Yukon government Climate Change Strategy Yukon Energy's Board of Directors decided not to pursue a new 20 MW thermal plant at this time and look at options to replace capacity at Yukon Energy's existing generation facilities as diesel engines reach end-of-life.
>
> Yukon Energy is pursuing the new renewable generation capacity options as outlined in the 10-Year Renewable Electricity Plan [please see CW-YEC-1-36 (a) Attachment 1 for the copy of the Plan], including battery energy storage system, Atlin Hydro Expansion Project, and the potential development of pumped storage at Moon Lake. Until the new renewable resource options are developed, diesel rentals are continuing to be the best available option at this time to address capacity shortfalls.

QUESTION:

a) Please confirm that no "analysis or business case" comparing the cost of owning generation and renting diesel generation exists. If not confirmed, please provide copies of all analyses or business cases that YEC has done or prepared comparing the cost of owning diesel generation to the cost of rentals.

b) Please provide an analysis of the impact on the YEC forecasts of not pursuing a new 20 MW thermal plant at this time.

ANSWER:

(a)

Not confirmed.

During the 2017/18 GRA proceeding it was noted that rented diesels were being adopted as the only option available to address the identified N-1 dependable capacity shortfall, i.e., there was no time available to develop any permanent or owned resource option. The business case assessment in this instance was very simple, i.e., rented diesel were required to meet the N-1 criterion and there was no other reasonable alternative at the time given YEC's mandate to ensure safe and reliable service to customers.

The initial diesel rentals were implemented as a near term solution, and YEC has carried out ongoing assessments of options to displace reliance on rented diesels, including various YEC-owned diesel plant options. The alternatives considered are summarized below. Please see also Yukon Energy's most recent resource plan provided as CW-YEC-1-36(a) Attachment 1 for details regarding renewable energy options considered.

- **20 MW Diesel Plant:** Following issuance of the 2016 Resource Plan, YEC examined in detail a 20 MW new greenfield diesel plant option as well as a range of other resource options. Ongoing Yukon Energy review and consultation regarding the 20 MW plant option indicated a wide range of public concerns regarding development of a new large greenfield diesel plant. The results of the public engagement indicated very limited social license for a greenfield diesel project in Yukon at this time.

- **Diesel Replacement at Existing GS Plants:** In October 2019, it was determined that considering the results of the technical, environmental and socio-economic research, as well as feedback from the public, YEC would focus on potential options to add or replace capacity at existing thermal generation facilities on an incremental basis as diesel engines are retired.

- **Renewable Capacity Alternatives:** The 10-Year Renewable Electricity Plan identified potential renewable generation options that could significantly reduce the need to rely primarily on thermal generation to address the forecast N-1 dependable capacity shortfall. Reduction in the reliance on thermal generation aligns with the emerging policy directions, such as Yukon government's 93% long-term average renewable electricity requirement and 97% renewable target, and the Federal government's Net Zero by 2050 policy.

  YEC's current resource plan (the 10-Year Renewable Electricity Plan) does not contemplate the construction of a new 20 MW greenfield thermal plant in the future. Should a change in circumstance trigger a re-evaluation of YEC's long-term resource plan, a greenfield thermal project may be considered at that time. The current resource plan includes consideration of 12.5 MW of near-term diesel retirement replacements at Whitehorse, Faro and Dawson City, as well as the near-term BESS project, dependable hydro capacity provided by the Atlin Hydro Expansion project, and longer-term Tutshi-Moon Lake Pumped Storage project (Phase 1).

For specific business case comparison of rented diesel with owned diesel, YEC can provide the following current Levelized Cost of Capacity (LCOC) cost comparisons that include capital and non-fuel O&M costs for diesel rentals versus a 12.5 MW plant of YEC owned diesels[1](all estimates assume YEC weighted average cost of capital at 4.794%, based on an assumed 8.70% return on equity [40% of capital] and 2.19% interest on new long-term debt [60% of capital]):

1. **Diesel Rental LCOC costs (2022$) of $211 per kW-yr for a 20-year life (comparable to BESS), and $243 per kW-yr for a 40-year life (comparable to new owned diesel):** These LCOC costs assume diesel rental costs [includes cost of spares] of $162,400/MW (2021$) connected for winter 2021/22 to provide 27MW of operating capacity, 4% per year escalation of diesel rental costs over an assumed 20 or 40 year life, $27,000 per year (2022$) escalated at 2%/yr for variable non-fuel O&M, and $3.5 million (2022$) of infrastructure capital costs (based on infrastructure capital costs for existing 17 rentals [30.8 MW] escalated

[1] The LCOC estimates are consistent with analysis provided during the BESS Project Part 3 proceeding, subject to adjustment to reflect comparison here between rented and owned diesels with an assumed 40 year life for each option.

at 2%/year). Excluding the infrastructure capital, the LCOC is $200.9 per kW-yr for a 20-year life.

2. **12.5MW Owned Diesel plant LCOC costs (2022$) of $186/kW-yr without property tax and $212/kW-yr with property tax:** The Midgard estimate for the 12.5 MW new greenfield diesel located at Takhini included 5 units, each 2.5 MW, with a capital cost (2019$) of $2.6 million per MW and O&M non-fuel fixed O&M cost (2019$) of $64,500 per MW escalated at 2% per year. The assumed diesel plant life was 40 years. The assumed plant location at Takhini meant that this new diesel LCOC did not include any property tax.[2]

   YEC has updated the above LCOC for a new diesel plant within Whitehorse City limits, with Whitehorse property tax is included,[3] to address public concerns identified with locating a new diesel plant at Takhini. The updated new diesel plant LCOC is $212/kW-year (2022$), based on 2019$ LCOC of $199.8/kW-year escalated at 2% per year to 2022.

The analysis is very sensitive to the ongoing rental cost escalation assumed for the rented diesel option, i.e., rented diesel LCOC (2022$) over 40 years is $243/kW-yr with 4%/year rental escalation, $203/kW-yr with 3%/year rental escalation, and $172/kW-yr with 2%/year rental escalation.

(b)

There can be no impact to 2021 revenue requirements because the 20 MW thermal plant could not have been in service for this test year under any reasonable scenario. YEC is not able to provide useful assessment of the impact on future year revenue requirements, given the range of options (e.g. site location, building v. modular, etc) that need to be considered for each permanent diesel option and the continued near-term ability to rely on cost-effective rented diesel options.

[2] The plant location is outside the Whitehorse city limits and not subject to City of Whitehorse property taxes.
[3] Midgard's estimate in a separate study of new diesel fixed O&M with Whitehorse property tax is at least $91,000/MW (2019$).

A range of relevant other impacts on YEC resource planning are reviewed below.

The main impact on resource planning of YEC not pursuing a 20 MW new greenfield project at this time is the ability to provide concerted attention to the assessment and development of a range of other options involving renewables and non-fossil fuel generation as well as diesel replacements.

Initial focus on a new 20 MW greenfield diesel plant, with potential expansion as capacity requirements continued to grow, meant that diesel replacement requirements outside of Whitehorse were not prioritized. These are now receiving priority attention, and highlighting overall grid dependable capacity requirements going forward involving replacement of retired diesel units.

Government policy development and public responses to consultation on the 20 MW diesel project have also highlighted priorities and options for the BESS project and other renewable resource dependable capacity projects that can secure potential federal grant funding support. These options are receiving priority attention.

Near-term reliance on rented diesels has enabled rapidly evolving dependable capacity requirements to be met on a timely basis and with low near-term cost impacts for ratepayers. As highlighted in response to “a” above, near-term rental costs are a comparatively low-cost option – the concern from the cost perspective comes with expected annual cost escalations over a few decades. In contrast, new owned plant options will require up front capital costs with peak rate increase impacts tending to come in the initial years of operation.

TOPIC: **Brushing**

REFERENCE: **CW-YEC-1-18**

PREAMBLE: **In the last paragraph of the response YEC states:**

> The vegetation management budget is typically about 80/20 split transmission/distribution. In 2019, the distribution portion was less due to the TLR work and the requirement to prioritize the brushing on the transmission system where the work was to take place.

QUESTION:

a) Please fully explain what is meant by "to prioritize the brushing on the transmission system." In the response, please provide a detailed analysis of the brushing activities and volume of work for the distribution system for each of 2016, 2017, 2018, and 2019.

ANSWER:

(a)

The decrease in distribution spending in 2019 is directly related to prioritizing the transmission ROW brushing for the TLR project. A detailed analysis of the brushing activities for each of 2016 through 2019 are as follows:

Year	2016	2017	2018	2019
Total Brushing Actual	**1,044,435.58**	**1,386,676.07**	**1,064,582.00**	**1,109,798.00**
Total Distribution Cost	**182,283.87**	**305,526.08**	**198,725.00**	**42,935.27**
Canyon	157,716.96	-		
South Fox	3,897.85		127,790.00	
Dawson	-	146,575.67		2,085.12
Drury Creek				25,648.35
Faro	384.66	37,371.53		1,075.55
Mayo (incl Keno)	135.78	67,446.19		3,265.60
Braeburn	7,026.54	6,131.60		
Champagne	-	9,870.43		
Johnsons Crossing	-	10,882.63		3,388.09
Little Fox	5,161.49	-		
Little Salmon	1,303.58	-	48,215.00	
McGundy	-	-	22,720.00	
Mendenhall	6,657.01	27,248.03		1,786.11
Wareham Hydro Structure				5,686.45
% Distribution Cost/Brushing Actual	**17%**	**22%**	**19%**	**4%**

TOPIC: **LWRF Stabilization Mechanism**

REFERENCE: **CW-YEC-1-22**

PREAMBLE: In the last paragraph of the response, YEC states "Yukon Energy is working to provide an updated LWRF Term Sheet in March 2021, along with related LWRF Annual Reports for 2019 and 2020."

QUESTION:

a) Please provide the status of the LWRF Term Sheet in March 2021, along with related LWRF Annual Reports for 2019 and 2020.

ANSWER:

(a)

On April 8, 2021, Yukon Energy provided correspondence to the Board seeking appropriate Board approvals in relation to an updated LWRF Term Sheet, and Yukon Energy's LWRF Annual Reports and Energy Reconciliation Adjustment ("ERA") Filings for 2019-2020.

Please see the correspondence available on the Board's website at the link below.
https://yukonutilitiesboard.yk.ca/pdf/YEC_2021_GRA/YEC_LWRF_Term_Sheet_and_Reports.Apr_8__2021.pdf

On April 16, 2021, the Board issued Order 2021-07 and directed that final determinations regarding Rate Schedule 39 and the LWRF Term Sheet and LWRF annual reports will be considered as part of YEC's 2021 GRA currently before this Board. This was reiterated in Order 2021-09.

On July 5, 2021 the Board also provided correspondence which outlined the proceeding schedule with respect to the UCG and NY motions and Round 2 IRs noting, "Round 2 IRs will be limited to matters related to Rate Schedule 39, the Low Water Reserve Fund, and follow-up on Round 1 IR responses. Further process steps will be determined after comments are received on August 24, 2021."

TOPIC: **Rate Relief**

REFERENCE: **CW-YEC-1-25**

PREAMBLE: YEC indicates it has not conducted any research into specific ways to provide rate relief to customers.

QUESTION:

a) Please fully explain, and discuss any additional research or analysis that YEC may have done in the intervening months, since the filing of the response to CW-YEC-1-25.

ANSWER:

(a)

YEC continues to pursue funding opportunities for key infrastructure projects (e.g. Atlin Hydro, Moon Lake Pumped Storage, Southern Lakes Transmission) to ensure affordability of electricity for ratepayers. No other additional research or analysis has been conducted.

TOPIC: **Transmission Line Refurbishment**

REFERENCE: **CW-YEC-1-28**

PREAMBLE: In the response, YEC indicates that the cost of Transmission Line Refurbishment was materially higher than the forecast because more work was completed.

QUESTION:

a) Please fully explain the YEC asset management strategy, including all testing, monitoring and other asset management lifecycle practices. In the response, please explain how YEC determined that more work than forecast was required. What criteria were used to drive this conclusion?

b) Please provide an analysis of the condition of the additional assets replaced, that indicate that more work than planned was required.

c) Please fully discuss, and provide an analysis of the impact on future costs of Transmission Line Refurbishment resulting from the increased work.

ANSWER:

(a)

Transmission line assets undergo a test and treat program that identifies the shell thickness of the pole and treats insect infestation. These assessments started in 2009 with a planned renewal every 10-15 years.

YEC also performs detailed line inspections. Detailed Inspections provide detailed information on the condition of Transmission structures in the field and identify defects that require correction.

- Detailed inspection provides information on the following structure elements: Poles, Crossarms, Insulators, Crossbraces, Hardware, Foundation, Guys, Vibration Dampers, Aerial Markers, Conductor & Shield Wires, Grounding & Bonding. Detailed Inspection also provides information on Vegetation.

- Detailed Inspection data is used to drive corrective maintenance and preventative replacement programs as well as to modify vegetation management cycles for the lines. Overhead Line Detailed Inspection cycles are planned for Transmission Lines 15 years after initial construction, and every 10 years thereafter.

The result of the assessments determines the scope of the transmission maintenance and refurbishment projects. The increase in work scope and spending in 2018 was justified due to lower contractor unit costs, reduced customer impact from outage frequency and duration, and reduced mob/demob costs for the contractor. This explanation was provided as follows in the initial response to CW-YEC-1-28:

> "The quantity of work accomplished in 2018 was significantly more than was forecasted, as a large portion of the overall 5 year planned work was completed in one year. The increase in work scope and 2018 spending was justified due to lower unit costs; the reduced customer impact of the transmission outage number and duration; and reduced mobilization and demobilization costs for the contractor."

(b)

As described in (a) above, YEC received favorable contractor rates through the RFP process in 2018. In order to capitalize on these favorable terms, YEC chose in bring forward work planned from future years into 2018. This was work that was recommended by the consultant as part of the assessment work and was previously planned to be completed as part of the multi-year Transmission Line Refurbishment project. YEC advanced the timing to take advantage of favorable financial terms as stated.

(c)

The quantum of identified work from the asset assessments has not changed (see response to "a" above). The efficiencies described in CW-YEC-2-10 (a) for completing additional work in 2018 reduces the amount of work in future years.

TOPIC: **Replacement of P125 Head Gate**

REFERENCE: **CW-YEC-1-31**

PREAMBLE: YEC indicates that the 2021 project was delayed until 2022.

QUESTION:

a) Please provide updated schedules that have the 2021 costs removed.

ANSWER:

(a)

Project construction has been delayed until 2022 - a more precise schedule has yet to be developed. Planning continues in 2021 which includes revision of the technical specifications based on learnings from the WH2 headgate replacement, as well as preparation and release of an RFP in Q4 2021.

TOPIC: **Diesel Retirement Replacement**

REFERENCE: **CW-YEC-1-37**

PREAMBLE: In the response, YEC states that the project will remain in WIP in 2021.

QUESTION:

a) Please confirm that YEC is NOT seeking approval in this rate application of the costs of the project for inclusion in rate base in 2022 or some later year, based on the information filed in this application. If not confirmed, please provide the business case for the Diesel Retirement Project.

ANSWER:

(a)

YEC confirms it is not seeking approval in this rate application of the costs of the project as the asset is not projected to be in-service by the end of 2021.

Nathaniel YEE
(NY)

REFERENCE: **Follow-up on NY-YEC-1-5, NY-YEC-1-8(a) and NY-YEC-1-13(a,c)** Original request was for an "updated Yukon Integrated System Generation Inventory" and I was sent "Appendix A from the 10-Year Renewable Electricity Plan" as what is current. However, some of the capacities differ from the correspondence with the regulator provided in response to NY-YEC-1-8(a)

	YEC GRA Nov 2020 in reply to NY-YEC-1-5 and YUB-YEC-1-50 and UCG-YEC-1-18	App to Regulator, Sep 2020 in reply to NY-YEC-1-8(a) and sound and dispersion studies NY-YEC-1-13(a,c)
FD1 Dependable Capacity:	**3.0 MW**	**2.4 MW**

The 3.0MW listed in the 10-Year Renewable Electricity Plan was given as the current capacity list in IRs NY-YEC-1-5, UCG-1-18, YUB-YEC-1-50 and others.

However that capacity was reduced to 2.4 for all communications with the regulator – and for all sound and air dispersion studies. Noting that the 2.4 MW is more convenient for regulation (allowing FD1+FD7+3 Rentals to be 10.6MW), but also that the 3.0 MW is needed for N-1 Capacity.

QUESTION:

a) These numbers should be consistent and not arbitrarily chosen. Which is correct? Why were the two different numbers used?

b) Please provide a history of capacity of the FD1 generator – from nameplate capacity of 5.15MW down to the 3.0MW or 2.4MW currently claimed.

c) Please provide dated documentation used in support of each change in dependable capacity.

ANSWER:

(a) through **(c)**

The dependable capacity for individual diesel units is subject to ongoing updates based on available information and assessments. Dependable capacity of diesel generators typically drops as the units age, and YEC's practice is to complete periodic assessments to confirm the derated capacities of old diesel generators such as FD1. Updates are summarized when applicable in updated resource plans or GRAs. Beyond reporting on changes, there is no specific documentation that can be provided to support each such change.

The Faro Diesel #1 unit with a nameplate installed capacity of 5.15 MW was recommissioned with 5 MW capacity in 2008, later was rated at 4.0 MW in the 2011 and 2016 YEC Resource Plans with expected retirement in 2021. This rating was reduced to 3.0 MW by the time 10-Year Electricity Resource Plan was prepared [the work for the plan was started in November 2019 after Yukon government released a draft of its Our Clean Future strategy]. The following additional information is provided on this unit:

- Faro unit #1 is the oldest unit in the fleet (built in late 60's).

- It requires manual adjustment in order to run at its maximum output and YEC has not had qualified mechanical maintenance staff located in Faro for approximately 5 years (staff in Whitehorse have the expertise to perform this function but Faro is at least 4 hours drive so re-deploying forces would not meet the requirement of keeping the lights on during an emergency).

- The unit has also experienced issues with its cooling system that restricts output.

- Based on internal review by YEC Mechanical Maintenance, YEC concluded that the unit could be run up to 2.4 MW while in remote mode without risking over-heating shutdown.

The 10-Year Electricity Resource Plan assumed the unit will retire in 2023. Please see revised response to UCG-YEC-1-18 that provides copy of Appendix A to the 10-Year Electricity Resource Plan with the list of existing hydro and thermal resources including dependable capacity assumed in the 2016 Resource Plan and updated dependable capacity and retirement assumptions for each unit.

The dependable capacity analysis for the 2021 GRA is based on 10-Year Electricity Resource Plan, therefore it assumes 3.0 MW dependable capacity for Faro Diesel #1.

More recent assessments [the Noise Impact Assessment at Faro Facility (February 2021) provided in NY-YEC-1-13(a) Attachment 1 and Air Dispersion Modelling Assessment for Faro Facility (December 2020) provided in NY-YEC-1-13(c) Attachment 1] show Faro Diesel #1 was derated from 3.0 MW to 2.4 MW, a reduction of 0.6 MW.

As noted in GRA Tab 2, page 2-14, the forecast dependable capacity based on the single contingency (N-1) criterion is forecast for the YIS to be about 1.25 MW in excess of the forecast non-industrial winter peak for 2021. Therefore, the reduction of 0.6 MW in dependable capacity will not impact the 2021 GRA assessment that overall dependable capacity exists to meet the N-1 requirement.

REFERENCE: Follow-up on NY-YEC-1-5, NY-YEC-1-8(a) and YUB-YEC-1-50(b)
GRA Page 2-14, "Installed YEC and AEY dependable grid capacity for the winter peak in 2021, based on existing capacity today and any planned additions/retirements and excluding Fish Lake hydro, is 139.1 MW in 2021 (70.5 MW of YEC hydro, 12.6 MW YEC LNG, 23.5 MW of YEC diesel, 5.6 MW of AEY diesel and plus 27 MW20 diesel from rented diesel units in order to meet the N-1 criterion assessment).[21]" and

"[20] 15 units at 1.8 MW for each unit to total 27 MW for 2021."

Of the 23.5MW of YEC diesel, Faro FD1&FD7 provide 5.8MW, according to the 10-Year Renewable Plan. So in the GRA and for N-1 puropses, Faro diesel provides 14.8 MW (FD1+FD7=5.8MW + 5 Rentals @ 1.8MW Ea=9MW).

However, 14.8 MW clearly exceeds the maximum 10.6MW permitted by the regulator or listed in the expired 2008 and 2011 decision documents. YEC is counting 4.2MW (14.8 MW-10.6 MW)that it has no authority to install or use to meet N-1.

And from GRA Page 2-15 "In summary, under N-1, there is surplus of dependable capacity of approximately 1.25 MW in 2021. Without rented diesel units, the N-1 capacity shortfall would be 25.75 MW in 2021."

This is not true, as YEC actually has an N-1 capacity shortfall of 2.95 MW. (1.25 – 4.2)

QUESTION:

a) Please explain how N-1 is affected with Faro capacity being limited to 8.15 or 10.6 MW, at least 4.2 MW less than the 14.8 MW cited on the GRA and 10-Year Renewable Plan?

b) Please provide a corrected and complete answer to YUB-YEC-1-50(b).

ANSWER:

(a) and **(b)**

The N-1 requirement set out in this application was, and continues to be, met by YEC installing the rented diesels at Faro. The volume of diesel rentals at this site were and are needed to address higher N-1 dependable capacity requirements demonstrated by the extraordinary cold spell in winter 2019/2020. In that regard -- the GRA N-1 requirement is not affected by the 10.6 MW cap.

Further context is provided below.

Prior to the 2020/21 winter YEC was renting eight diesel generators plus one spare (all in Whitehorse) to address the capacity shortfall under the N-1 criteria. However, the peak forecasted by Yukon Energy's load forecasting model for the winter of 2019/2020 (which was used to determine the number of diesel rental units required) was lower than the actual peak demand experienced in January 2020 during an extraordinary cold snap. This meant that during that cold snap Yukon Energy did not have sufficient capacity to meet the N-1 criteria.

Yukon Energy updated its non-industrial peak capacity demand forecasting model to account for that new peak. That update demonstrated a requirement for additional capacity to meet the N-1 capacity criterion.

In order to address the capacity shortfall for winter 2020/21, Yukon Energy initiated rental diesel infrastructure enhancements increasing the total number of rented diesel generators from eight units in the winter of 2019/2020 to 15 units [plus two spares], including six [plus one spare] in Faro. YEC was able to complete these changes in 2020 to ensure YEC had sufficient reserve to meet the N-1 criteria for the 2020/21 winter.

Starting in 2020 -- Yukon Energy also began the process to amend the Faro emissions permit to take into account this added diesel generation capability. In October 2020 -- as part of that process -- it was determined that the Faro air emissions permit needed to be amended and further that it would need to go through a YESAA assessment process. Appropriate consultations have been ongoing since that time (including with the RRDC) and a formal amendment application was recently filed with YESAB (see NY-YEC-2-6 for

more details on engagement activities over this period). YEC expects that approval will be received before this upcoming winter.

Because Yukon Energy believed that sufficient capacity was connected to prevent outages under the emergency circumstances (such as N-1 event) in winter 2020/21, no revisions are required to YUB-YEC-1-50(b).

REFERENCE: **Follow-up on NY-YEC-1-8(a)**

From Elizabeth Barker's reply to Travis Ritchie 23-Sept, 2020:

"Specifically, the Faro generating station underwent a YESAA assessment in 2014. In the assessment, FD1 and FD7 were assessed with production capacities of 5.15MW and 3MW for a total of 8.15MW. Currently, FD1 and FD7 have been derated to 2.4MW and 2.8MW however, with the addition of YM20-22 (5.4MW) and the addition of the YM23-25(5.4MW) as emergency backup, this brings the station capacity to a total of 16MW. This is 7.85MW greater than the capacity that was previously assessed in 2014. As the modification of production capacity is greater than 50kW, this project will need to proceed through YESAB before we can issue any permit amendments. Please let me know if you would like to discuss this further.

And from Travis Ritchie's email to Elizabeth Barker 24-Sept, 2020:

"I was anticipating that either Decision Document 2008.0230 or 2011.0246 were technically still valid for the purposes of granting an approval..."

and

"I understand the need to assess the additional capacity (beyond what has been assessed historically) before it can be permitted, but I would ask for approval to reinstall the previously relocated and de-rated capacity pursuant to the 2008/2011 assessment findings and related decision documents."

and

"If you need, I can resubmit the amendment application for reinstallation of only the previously assessed capacity, removing reference to the 3 additional units (YM23-YM25). YEC can then work on getting a YESAA assessment completed for the additional capacity, which could be permitted afterward. Does that sound reasonable?"

And from Elizabeth Barker's reply to Travis Ritchie 13-Oct, 2020: *"We have determined that the information provided in YEC's previous Faro station YESAA assessments (2008-0230 and 2011-0246) is still valid for the proposed 2020 amendment of reinstalling capacity of approximately 5.65MW at the Faro generating station. YEC has authorization to reinstall previously relocated/de-rated capacity of up to 10.6MW, cumulative station capacity, without proceeding through the YESAA assessment process. As discussed, any additional capacity increase that will bring the Faro station's cumulative capacity above 10.6MW will need to proceed through the YESAA assessment process before being considered."*

These documents were for the 2008 and 2011 permits and were not considered valid for the 2014 permit in 2014. A new YESAB assessment was required, and produced Decision Document 2014.0119.

QUESTION:

a) Were the 2008 and 2011 Decision Documents "still valid" in 2014 when a new permit was required to replace the expiring 2008 and 2011 permits? And, if they are "still valid" now, why were they not used for the 2014 permit?

b) In giving this exception, Elizabeth Barker specifically states that YEC can reinstall 5.65MW for "up to 10.6MW, cumulative station capacity" and "any additional capacity increase that will bring the Faro station's cumulative capacity above 10.6MW will need to proceed through the YESAA assessment process before being considered. and yet, YEC installed 6 generators at 1.8MW each, bringing cumulative capacity to 16 MW. This is of course exactly what Elizabeth Barker rejected in the email of 23-Sept. How does YEC justify this?

c) Exactly how many rental generators has YEC installed in Faro? Physically, it seems to be seven – and the GRA uses the cost of installation and rental of 7 generators to justify a significant portion of the rate increase. However for purposes of the N-1 Capacity, 5 generators are listed as operational in Faro, and for the regulator, only 3 can actually be installed. So how many generators are there? How can using these different numbers be justified? Which one is real?

d) What is the social license of asking the regulator to use documents created for expired permits instead current documents? Having submitted the YESAB documents in 2008, 2011 and 2014, Travis Ritchie must have known that the 2008 and 2011 permits had expired?

e) The original (rejected) application of 10-Sept, 2020 is to "Reinstall relocated/derated capacity (aprx. 5.65 MW) & add 3 x1.8 MW emerg-only units." This is rejected in Elizabeth Barker's email of 23-Sept, and Travis alters the application and resubmits on 28-Sept, "removing reference to the 3 additional units (YM23-YM25)." So three of the six generators were removed from the application to get a pass from the regulator, but… then they were installed anyway, in direct contradiction of the regulator and the regulators explanation of YESAA requirements. Please explain.

f) I was under the impression that expired permits are no longer "still valid." Are there other examples or instances where the limits from expired permits can take precedence over current limits? Most expired permits actually expire – ie the catch limits of a 2008 or 2011 fishing permit would not be suddenly "still valid" in 2021, but somehow limits on expired YEC pollution permits are "still valid." What other expired permits are "still valid" after expiration? What precedent did YEC have for suggesting using expired documents in this way?

g) Explain the ethical and legal aspects of bypassing the clear intent of YESAA and the regulator?

ANSWER:

(a) (d) and **(g)**

Part (a), (d) and (g) question whether the Decision Documents relied upon by the regulator in issuing the permit amendment were "still valid"; the social licence for asking a regulator to use decision documents for "expired permits" instead of current decision documents; and the "ethical and legal aspects of bypassing the clear intent of YESAA and the regulator."

The presumptions in these questions are not valid.

The YESAA legislation is clear with respect to a Decision Body's role in determining whether it needs a Decision Document (or a new Decision Document) in order to enable its regulatory agencies to issue project approvals.

In this case, the Decision Body determined that a previous YESAA assessment and duly issued Decision Document were sufficient for its regulatory agency to authorize the reinstallation of previous site capacity under Yukon Energy's existing air emissions permit as the proposed activity (previously assessed and recommended to proceed under YESAA) was not a material departure or substantive change from what was previously authorized at the FGS.

More specifically, the regulator confirmed in the October 13, 2020 correspondence [quoted above] from Elizabeth Barker, Environmental Protection Analyst, Department of Environment, Standards & Approvals Section, Yukon Government, as follows:

> "We have determined that the information provided in YEC's previous Faro station assessments (2008-0230 and 2011-0246) is still valid for the proposed 2020 amendment of reinstalling capacity of approximately 5.65MW at the Faro generating station. YEC has authorization to reinstall previously relocated/de-rated capacity of up to 10.6MW, cumulative station capacity, without proceeding through the YESAA assessment process."

Therefore, in response to parts (a),(d) and (g), the regulator has determined that the information available from the prior assessments, including prior decision documents, is still valid and could be relied upon by the regulator for its determinations on reinstalling

capacity of approximately 5.65 MW at the Faro generating station. Consequently, the intent of YESAA and the regulator were not bypassed.

(b) and **(e)**

The authority provided under the Air Emissions Regulation, and permits issued under that regulation, is focused on contaminant emissions to the atmosphere, i.e., air pollution is the target of the Regulations. As such, a proponent can have any number of emitting devices at a site, but can only operate such equipment in a manner that is compliant with the authority provided under their air emissions permit.

In her correspondence, the Yukon government representative was "rejecting" the allowance to ***operate*** any capacity beyond the existing permit threshold without further YESAA assessment, not rejecting the ***installation*** at the facility.

In this case, despite the total capacity of the generators on site at the Faro Generating Station that includes connection of six rented diesels [plus one spare] during the critical winter season, Yukon Energy is currently limited to operating only up to 10.6 MW of that capacity at any one time, using a combination of any units at site. Yukon Energy has not run more than 10.6 MW of diesel generation at this site over the past year.

As reviewed in response to NY-YEC-2-2, notwithstanding the current permit limit of 10.6 MW Yukon Energy ensured in winter 2020/21 (and is ensuring again in winter 2021/22) that sufficient capacity is made available and connected at the Faro generating station to prevent outages under the emergency circumstances (such as N-1 event). In the event of an emergency (i.e., an N-1 event for which the back-up capacity was rented) YEC has retained the required N-1 dependable capacity capability and would plan if required to operate units as needed during the emergency.

Yukon Energy is also proceeding with assessments and permitting reviews as required to authorize it to operate at any time in future installed capacity available at the FGS of up to 15.5 MW.

(c)

Seven (7) rental generators are installed at the FGS. Six units are required to address N-1 dependable capacity requirements and one unit is a spare.

As mentioned in the response to NY-YEC-2-3(b) any number of units can be installed at a facility, but the facility must comply with the capacity thresholds for air emissions. YEC is currently authorized to operate 10.6MW - and this could be provided with five rental units, as per the current stacking order for this site (see response to NY-YEC-1-6 Revised). Capacity installed at the FGS beyond the current operating/emitting threshold is intended to provide emergency back up as well as redundancy in case of unit failure or when required maintenance or repair schedules coincide with system demand that calls on that capacity to come online. As reviewed in response to "b and e" above, and in the current stacking order for this site (see response to NY-YEC-1-6 Revised), YEC plans if required to operate units as needed during an N-1 or other emergency.

YEC is currently proceeding with assessments and permitting reviews as required to authorize it to operate at any time in future installed capacity available at the FGS of up to 15.5 MW.

(f)

The permit is not expired; YEC sought an approval, pursuant to its existing air emissions permit (i.e., Part 2, Clause 5)[1], to install previously relocated and de-rated capacity based on available assessment materials. Yukon Energy accordingly did not suggest that expired *permits* should allow for reinstallation of previously assessed and permitted site capacity at the FGS.

YEC suggested, and the Regulatory Authority agreed, that a previous *Decision Document* and its related assessment information was still valid for decision making with respect to Yukon Energy's request for approval to reinstall generation capacity at the site up to the previously (and favorably) assessed and permitted capacity. See response to parts (a), (d) and (g).

[1] This clause states: "The permittee shall obtain approval from an environmental protection analyst prior to: a) any addition, modification, removal or replacement of any equipment or components related to the release, abatement, control or treatment of air emissions; or b) any change in location of the source(s).

REFERENCE: **Follow-up on NY-YEC-1-10 – YESAB / Generating Capacity**

From YEC's reply to NY-YEC-1-10, emphasis added:

*"Yukon Energy is requesting a recommendation by the Designated Office to allow the Permit amendment to proceed, on the basis that the Project (i.e., the continuing operation of the Yukon Energy's Faro Diesel Facility with the addition of **4.9 MW** of additional diesel generating capacity (total of **15.5 MW** of generating capacity) in accordance with the terms and conditions of the amended Permit and the applicable provisions of the Environment Act and Air Emissions Regulations)..."*

QUESTION:

a) How did YEC come up with 15.5MW as a total? There is no combination of the installed generators and rentals that actually adds up to this total?

b) The sound and air dispersion studies also note that given the capacities of the generators, there is no actual way for this to be the total, and therefore no way to model for it. The studies are based on 16MW (Derated FD1+FD7 + 6 Rentals) which is physically and mathematically possible. How/why does YEC propose a generating capacity of 15.5MW while the actual installed generation capacity will be 16MW (or 16.6MW if using the 10-Year Renewable Plan for capacities)?

c) Why claim the addition of only 4.9 MW, when the proposal is for 5.4 MW, the 3 rentals actually being installed?

ANSWER:

(a) and **(c)**

The proposed site capacity expansion was limited to 4.9 MW so as not to trigger an Executive Committee (EC) Screening, i.e., a 5 MW increase would trigger an EC Screening.

All of Yukon Energy's previous twelve (12) diesel generating station assessments have been conducted under YESAA at the Designated Office level. Based on Yukon Energy's

experience, a YESAA assessment at the Designated Office level can be completed on a more timely basis than an Executive Committee level review. This would allow for the assessment to be completed in order for the additional capacity to be available for the upcoming winter.

(b)

As noted in response to NY-YEC-2-1, operating capacity will be directed by the limits provided under Yukon Energy's air emissions permit regardless of the capacity installed at the FGS. The 16 MW ceiling was chosen as the threshold for the air quality and noise impact assessments (and related modelling) as a measure to ensure conservative assessment results. The 15.5 MW threshold was selected for the purposes of assessment and permitting as described in the response to question NY-YEC-2-2(a), above.

REFERENCE: Follow-up on NY-YEC-1-10 – YESAB and communications

Noting that in materials currently being distributed to residents of Faro, some interesting and quite deceptive definitions have appeared that could use further explanation.

The common understanding in Faro is that the term “permanent generators” and “existing generators” and “permitted generators” would refer to FD1 and FD7, the only generators that have been installed or permitted since 2014 until the arrival of the rentals in 2020.

YEC uses these terms to refer to FD1 and FD7 **and** 3 of the rental generators, despite the fact that the rentals are not permanent, did not exist here before 2020 and were not on the 2014 permit application or the 2014 YESAB – the last notice the public had about what was permitted.

The common understanding of “the rental generators” would be the seven rental generators installed in 2020. It is sometimes used this way. YEC also often uses “the rental generators” to refer to only three of the rentals, as YEC hides three of the new rentals by considering them “permanent” or “existing” generators and one as a spare. This is common in communications distributed to residents of Faro. Confusing?

And an example from “reporting back on a winter with rental diesels in Faro” distributed to Faro residents 21-June, 2021.

“When we added the rental units last winter, we also modelled what air emissions would be like with the addition of the rentals.”
This report (provided in response to NY-YEC-1-13(c)) actually models FD1 + FD7 + 3 rentals (baseline) vs FD1 + FD7 + 6 rentals. So “the addition of the rentals” means “addition of three more rentals – not counting the three rentals added that we now consider permanent.”

The sound study does the same thing, using “Existing/Current Operation” to refer to FD1+FD7+ 3 Rentals. Also referred to as “old

permanent engines" in the "reporting back on a winter with rental diesels in Faro document." Referring to half the rentals as "old permanent engines" or "existing/current" is deceptive.

QUESTION:

a) Please explain the social license in using such terms as "Existing Permitted Emission Capacity," "Existing capacity," and "permanent generators" to refer to a capacity that has not existed or been permitted since 2014.

b) Would you reasonably expect anyone to interpret "Existing Permitted Emission Capacity," "Existing capacity," "existing site" or "permanent generators" to mean FD1 + FD7 + 3 of the new rentals? Please explain how a member of the public would come to this correct interpretation.

c) Would you reasonably expect anyone to interpret "the addition of the rentals" to mean only 3 of the 7 newly installed rentals? Please explain how a member of the public would come to understand this interpretation that YEC is using.

d) Previous to the 2020 addition of the rental generators, when was the most recent date that the Faro facility had the physical installed capacity for generating 10.6MW?

e) Discuss the role of a public company in misleading the public.

ANSWER:

(a) to **(e)**

Yukon Energy has communicated accurately the key information relevant to the current permit application at the Faro diesel generation site.

The central message in relation to the current Faro permit application is that YEC is seeking a permit for an additional 4.9 MW of diesel operation at Faro, and that today this added capacity will be provided by three 1.8 MW rental diesel units.

As reviewed in response to NY-YEC-2-3(a), YEC is currently authorized to operate 10.6 MW of diesel capacity at Faro. The 10.6 MW is therefore considered the “Existing Permitted Emission Capacity” or “Existing capacity”. “Permanent generators” refers to FD1 and FD7 with respect to the current complement non-mobile generators themselves, not the permitted site emissions capacity. At this time, three rented diesel units provide the balance of the capacity needed to operate at the existing permitted 10.6 MW.

Capacity of the Faro Generating Station was last at 10.6 MW in 2011, whereafter Yukon Energy voluntarily relocated FD3 and FD5 to meet operational needs at other generating stations in Yukon.

REFERENCE: **Follow-up on NY-YEC-1-9 Consultation, approval and thanks, RRDC**

While YEC is unwilling to provide any of the actual correspondence with RRDC, YEC did provide a list of attempts to contact RRDC in the meeting notes of the Faro virtual meeting on 2-December, 2020 and a comment by the RRDC representative in attendan[c]e on 2-December.

As stated in the YEC distributed meeting notes, previous to the installation of the rental generators, YEC made only three attempts to contact RRDC, all by email only, on April 9 and 17 and September 1, 2020.

At the meeting on 2-December, 2020, the RRDC contact who was supposedly emailed *"expressed his deep concern and disappointment that Yukon Energy did not consult with Ross River Dena Council (RRDC) before adding the temporary diesel generators to the Faro site. Stanley noted that RRDC was not informed of the project or of the procurement opportunities."* (from YEC distributed meeting notes).

PREAMBLE:

QUESTION:

a) Did YEC consider sending three (unanswered, possibly not received) emails to be sufficient consultation and interaction with RRDC before proceeding to install the generators?

b) Did YEC confirm the emails were received? Please provide confirmation if any exists.

c) Why were no phone calls made to anyone at RRDC previous to installation of the generators?
From the meeting handout: *"We give thanks to the Ross River Dena Council for allowing our facilities and this project to take place on their Traditional Territory."*

We give thanks, but can't we also at least give them a call?

ANSWER:

(a) to **(c)**

Part (a), (b) and (c) question what YEC considered to be the appropriate level of engagement prior to proceeding with installation of diesel generators; and whether YEC was able to make contact with RRDC; and question the measures YEC undertook to share information with RRDC. As noted below – YEC proceeded with a level of engagement considered appropriate for the project activities it was undertaking at each stage; YEC has also continued to make efforts to engage with RRDC and share information regarding the project (as detailed in the table provided below).

Generally speaking, replacement of previously installed capacity (i.e., 3 of the rentals) is a basic operational activity. This type of activity does not typically require public engagement. With regard to expanded capacity at the site, consultation became appropriate once an assessment by YESAB was determined to be required for the expansion of the site air emissions permit. The project is required to be assessed at the Designated Office level of YESAB and Yukon Energy has proceeded with engagement activities taking this into consideration.

The table below summarizes consultation activities with RRDC/the community of Faro after it was determined after winter 2019/20 that diesel rentals were needed at the Faro generating station. Yukon Energy notes this level of consultation took place under COVID 19 conditions, and exceeds the minimum required by YESAB for projects assessed at the Designated Office level.

Activity Description	Date
Town of Faro Council Presentation	July 2020
Information Brochure on Project mailed to all Faro addresses	September 2020
Virtual Community Meeting for RRDC and Ross River	December 2, 2020
Senior Leadership travelled to Ross River to meet with Chief and Council	October 15, 2020
Presentation and overview with RRDC Chief and Council and Development Corporation	June 2021
YEC engaged a RRDC owned environmental consulting firm to provide a third-party review of the YESAA application and recommendations were included in YESAA submission.	2021
Copy of YESAA application provided to RRDC lands management lead prior to submission.	August 2021
Copy of community presentations available on YEC website	As required

1

Utilities Consumers' Group
(UCG)

REFERENCE: Low Water Reserve Fund Report Table 1 Calculations DCF and Table 2 DCF Continuity
Schedule 2013-2017(Preliminary)
Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2 LWRF Continuity
Schedule 2017 and 2018
Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2: LWRF Continuity
Schedule 2019 and 2020, April 2021

QUESTION:

a) Is Yukon Energy aware that the Board ordered you to file at each years end a LWRF Report?

b) Why is that Yukon Energy did not do so?

c) Will Yukon Energy comply going forward?

d) As the continuity schedule for 2020 exhibits a negative ending balance of $4.272 million, when and how will Yukon Energy recover this?

e) With high water levels this year, does Yukon Energy forecast a positive return to the LWRF in 2021?

f) If yes, do you have a conservative estimate?

g) Does the table and schedule listed April 2021 comply with the OIC 2021-16, (7) (a) or (b)? If not, why not?

h) Do these above tables and schedules listed comply with ALL the Board directions on the LWRF? If not why not?

ANSWER:

(a), (b) and **(c)**

YEC acknowledges that the LWRF Term Sheet as last reviewed by the Board (i.e., the updated Term Sheet and Annual Reports for 2017 and 2018 filed on December 10, 2019) included provision for annual reporting, and for related direction of the Board on the additions and deletions to the Fund and on any proposed rate rider.

The Board's last review of an annual LWRF filing (i.e., the Board's letter of March 19, 2020 regarding the updated Term Sheet and the 2017-2018 LWRF Annual Filing) acknowledged receipt of correspondence from YEC dated December 10, 2019 but did not approve the updated Term Sheet or the Annual LWRF filings. The Board stated "any future issues regarding the term sheet are to be addressed in the next YEC GRA". YEC accordingly deferred further LWRF filings until the next GRA, at which time the relevant term sheet issues would be reviewed.

As reviewed in Tab 1 of YEC's 2021 GRA Application, YEC's next GRA filing after the 2017-18 GRA was not feasible until the current filing for 2021.

YEC anticipates that an updated LWRF Term Sheet will be approved by the Board as part of the current proceeding; after this proceeding is complete, YEC intends to resume regular LWRF annual filings as directed.

(d), **(e)** and **(f)**

The LWRF Term Sheet provides for rate changes related to the account balance only when the Fund exceeds the approved caps, which currently are +/-$8 million as last approved by the Board in Board Order 2015-01. Accordingly, no action is to be taken at this time regarding the account balance of negative $4.272 million as at the end of 2020.

YEC expects a positive impact on the LWRF balance from the 2021 fiscal year, given that water availability is above the long-term average.

YEC does not have any estimate at this time of the LWRF balance expected to occur as at the end of 2021.

(g) and **(h)**

The April 8, 2021 LWRF filings comply with OIC 2021/16 (including the provisions of subsection 9(7) (a) or (b)) and with past Board directions, subject to any changes to these directions that are required to comply with OIC 2021/16.

REFERENCE: OIC 2021-16 Section 9 (1-10)

QUESTION:

a) Does Yukon Energy see any changes resulting from the above OIC as to what was determined by the Board in Order 2019-08 Reason for Decision for the Low Water Reserve Fund (LWRF) going forward past November 1, 2020? Please explain.

ANSWER:

(a)

Yes, the Board's mandate in relation to the LWRF has changed and now the LWRF must comply with OIC 2021/16. The 2019-2020 LWRF Annual Report schedules comply with directions under Section 9 of OIC 2021/16, given that the relevant filing was made in the first instance to the Board after November 1, 2020 and that no order has been issued with regard to this filing under section 27 of the Act prior to February 11, 2021.

See also YEC answer to UCG-YEC-2-9.

REFERENCE: **3.3 Low Water Reserve Fund**

Appendix A to Board Order 2019-08 — Reasons for Decision 9 30. With respect to the DCF, the Board concluded that, given the isolated nature of the Yukon environment, the ramifications that low water events can have on electricity prices and the need to mitigate those impacts, a DCF-type of mechanism was required. The Board stated that a simpler mechanism for adjusting for variances between the approved forecast for hydro generation and thermal generation and actual hydro generation and thermal generation in a test year is needed. However, the Board found that the DCF is complex and that it does not show the hydro generation and thermal generation in a given year when actuals are determined because the actuals are based on modelled results. **Therefore, the Board directed YEC to create a deferral account that reconciles forecasts with actuals, not modelled results. Further, the onus is on YEC to adequately explain any variance between actual results and its forecast amounts. For these reasons, the Board directs YEC in future GRA filings to show actual hydro and thermal generation results when comparing previous and forecast test years.**

QUESTION:

a) Does Yukon Energy Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2 LWRF Continuity Schedule 2017 and 2018 and Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2: LWRF Continuity Schedule 2019 and 2020, April 2021 comply with these directions? Please explain.

ANSWER:

(a)

YEC's 2017-18 LWRF Annual Report schedules as filed with the Board on December 10, 2019 have been acknowledged by the Board's letter of March 19, 2020. YEC believes this filing complied with Board directions applicable at that time.

Appendix A to Board Order 2019-08 as quoted above in this IR set out directions for future YEC GRAs. OIC 2021/16 has now provided direction for LWRF determinations related to the current 2021 (wherein 2019 and 2020 LWRF reports are to be addressed) and future GRAs. YEC hydro and thermal generation forecasts for GRA purposes continue to be based on long-term average (LTA) water availability. Tab 2 of the 2021 GRA (Table 2.2), and Table 2.1-1 of the 2019-2020 LWRF Annual Report, show actual and forecast hydro and thermal generation results as applicable and available for the years addressed.

REFERENCE: **3.3 Low Water Reserve Fund**

Appendix A to Board Order 2019-08 — Reasons for Decision 9 40. YEC filed a revision to its LWRF on February 25, 2019. In Board Order 2019-04 (first compliance filing decision), the Board did not accept YEC's revised LWRF. In that decision, the Board noted that YEC accepted the forecast risk for incremental generation costs for incremental loads in excess of the approved forecast. 41. In the first compliance filing decision, the Board recognized there are two regulatory principles to be met. First, YEC bears the risk of revenue requirement items varying from approved GRA forecasts. Second, costs due to variances from forecast thermal generation fuel volumes should be assigned to the utility when those costs are due to variances from forecast load or maintenance requirements. The Board found that the steps to separate thermal generation changes due to overall load changes from thermal generation changes due to water conditions included in the LWRF deferral account proposal did not adequately reflect these two regulatory principles. **42. Accordingly, the Board considered it necessary to preserve the principle that costs should be assigned to the utility when total load varies from forecast load.** YEC's proposal in the compliance filing created an asymmetrical risk profile whereby YEC imposed certain risks – e.g. incremental generation costs to customers – and yet there is no offsetting of potential benefits that YEC would gain, and those benefits would not be shared with customers – e.g. incremental sales and amortization of costs over greater sales volumes. **Therefore, the Board considered that incremental generation due to incremental load must be removed from the LWRF calculations because this is a risk borne by the utility.**

QUESTION:

a) Does Yukon Energy Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2 LWRF Continuity Schedule 2017/2018 and Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2: LWRF Continuity Schedule 2019 and 2020, April 2021 comply with these directions? Please explain.

ANSWER:

(a)

YEC's 2017-18 LWRF Annual Report schedules as filed with the Board on December 10, 2019 have been acknowledged by the Board's letter of March 19, 2020 and complied with Board directions applicable at that time.

The 2019-2020 LWRF Annual Report schedules comply with directions under Section 9 of OIC 2021/16, given that the relevant filing was made in the first instance to the Board after November 1, 2020 and that no order has been issued with regard to this filing under section 27 of the Act prior to February 11, 2021. As reviewed below, the above Board Order 2019-08 directions to remove from the LWRF calculations the incremental generation due to incremental load are not consistent with OIC 2021/16 directions.

In summary, OIC 2021/16 directs that the low water deferral account annual determinations after each financial year of YEC are to be based on the difference between (a) fuel costs for thermal generation needed to meet actual customer requirements (as a result of any shortfall between actual renewable generation and actual customer requirements), and (b) fuel costs for thermal generation that would have been needed to meet actual customer requirements for the financial year if renewable generation had been consistent with long-term average annual renewable source availability.

Accordingly, the 2019-2020 LWRF Annual Report schedules do not comply with the above Board Order 2019-08 directions.

REFERENCE: **3.3 Low Water Reserve Fund**

Appendix A to Board Order 2019-08 — Reasons for Decision 9 41. A second compliance filing was directed by the Board. **3.3.2 YEC's 2017-18 GRA Second Compliance Filing** 43. YEC submitted its second compliance filing on September 23, 2019, and provided further changes to its proposed LWRF. YEC provided details of the changes to its LWRF in Appendix 2.1 and Attachment 2.1-1 (LWRF Term Sheet) of its September 23, 2019, second compliance filing. Included as part of the application is a revised Attachment 2.1-1, the LWRF term sheet which retains the general structure of the previously approved term sheet and fund procedures. Of the five items listed in the term sheet, the fifth on the list states: The new mechanism proposed in the 2017-18 GRA to provide that costs for YEC thermal generation savings (excess) are calculated so that YEC's final fiscal year expense for the total expected thermal generation (i.e. YEC expense after all transfers) is 90% LNG and 10% diesel as assumed in the GRA forecast, subject to the constraint that the LNG share of any transfer into or out of the LWRF cannot exceed 100%. **Views of the Board 3.3.2.1** Current test period 47. Board Order 2019-04 required YEC to determine what the actual thermal generation with water availability impacts would have been at the forecast (rather than the actual) level of load. To test YEC's assumptions, the Board requested in YUB-YEC-1-4 an explanation of YEC's separation of changes in thermal generation costs due to changes in water conditions and due to changes in load (actual load). ***The questions included: c) For a test period in which a load forecast has been determined, at the start of that test year would YEC expect the forecast load to equal its forecast?*** *48. The Board was seeking to determine if the generation mix (hydro and thermal) is expected to incrementally change as the expectation for load changes. For example, at the time of the forecast, YECSIM modelled generation output for the forecast load level.* ***However, as the expectation for load changes, in this case, an upward change, does the incremental generation mix change (i.e. weight more heavily to thermal) versus hydro generation? If the generation mix changes on an incremental basis, how is this phenomenon reflected in***

YEC's separation of load and water level effects on the LWRF? *Also,* ***if there are differences, would they be material?***

QUESTION:

a) From the preamble above: Please answer all the above questions in bold/italics for the Low Water Reserve Fund Table 1 Calculations LWRF and Table 2: LWRF Continuity Schedule 2019 and 2020, April 2021? Please explain each answer.

ANSWER:

(a)

YEC's response to the original Board IR (YUB-YEC-1-4(c),(d) and (e) in the 2017-18 GRA proceedings related to compliance filing issues[1]) is copied below in response to the questions being repeated. In general, responses provided here on LTA forecasts with regard to LWRF determinations for 2018 will apply equally to LWRF determinations after any other financial year for which a GRA had been concluded. LTA renewable resource forecasts are required for the 2021 GRA in accordance with directions under Section 9 of OIC 2021/16.

YEC is unclear as to what is being asked in question (c). Forecasts are subject to change continuously, particularly for load which can be affected by numerous factors (e.g., customer counts, weather, water supply, economic activity, etc.).

The LWRF for 2018 must address the LTA hydro and thermal generation forecast approved for GRA purposes. YEC's operation "short-term" hydro and thermal generation forecast for 2018 were not used for the GRA forecast, and therefore have no bearing on LWRF determinations for 2018. Therefore, how and when YEC updates operational short-term forecasts has no bearing on LWRF determinations for 2018.

[1] YUB-YEC-1-4 (c),(d) and (e) was filed in response to IRs on the 2nd compliance filing (IR responses provided on October 21, 2019).

In the event that short-term forecasts were reconsidered in future GRAs, additional information is provided below on YEC's internal short-term forecasts for ongoing operations.

A test year forecast is often (but not always) developed prior to the start of the test year. As events unfold after the forecast is made, YEC will adjust its internal short-term forecasts accordingly in response to new information, i.e., there is no reason to assume that YEC will not change its internal forecast prior to the start of the test year.

Moreover, short-term operation forecast estimates will continue to change as required throughout a test year, i.e., there is no set dates/ times within the year for making such changes, beyond normal spring hydro updates based on winter snow load information. Hydro generation forecasts in particular are changed when needed during the year in response to new water supply information as well as new load information. Experience in the early 1990s highlighted a case where water supply was suddenly greatly enhanced by above normal rainfall at Aishihik Lake in late summer. Experience in 2019 has highlighted changes throughout the summer in expected water conditions at both Aishihik Lake (more than was expected pre-summer) and Mayo Lake (lower than expected pre-summer).

Such operational forecast changes at any time during a test year, however, typically have no bearing on what forecast will in fact be approved by the Board in a GRA for that test year, and certainly do not affect LTA forecasts used for GRA and LWRF determinations.

The 2018 GRA approved load forecast is a simple example in this regard. Evidence provided during the GRA proceeding indicated updated information with regard to this load forecast, including the updated expectation that it would materially exceed the initial GRA forecast of approximately 420 GWh. The final GRA approved forecast nevertheless, in accordance with past GRA practice, did not materially change the 2018 load forecast (beyond reflecting the fact that Minto's load was expected to decline somewhat). And short term hydro and thermal generation forecasts for test years were reviewed and not adopted for 2017-18 test year GRA purposes.

In contrast, the Board approved actual load results for the 2017 GRA test year, reflecting the extent that the proceeding had been extended well beyond that test year.

REFERENCE: **3.3 Low Water Reserve Fund Reference**

Appendix A to Board Order 2019-08 — Reasons for Decision 9 49. YEC responded that these question was in effect asking to rerun the model after each year, assuming forecast load and actual water conditions, in order to estimate actual thermal generation for the forecast load. YEC stated that this was not achievable with the current model. 50. YEC has previously provided testimony that the results of the model cannot be retrospectively verified and that the Board has previously identified its concerns with the verifiability of the model in Board Order 2015-01 and Board Order 2015-06. The Board remains concerned that the estimate provided by YEC does not accurately reflect the generation costs for the incremental load and questions if the generation costs are muted by the modelling of the total load. 51. With respect to the second compliance filing term sheet, the UCG argued that the use of the term sheet increases the LTA thermal generation estimate used at the actual 2018 generation load. After preparing responses to information requests and the technical session, YEC concluded that the term sheet approach provides a more accurate result and can be considered more straightforward to implement. 52. The Board agrees that the term sheet provides a more straightforward result than an estimate (the fixed change factor estimate) based on the term sheet. For the 2017-18 test period, the Board directs YEC to use the term sheet and to amend the paragraph that refers to the fixed change factor to remove fixed change factor references from the term sheet. **Further, as the Board has ruled that the LWRF is only applicable up to forecast load, the Board only approves term sheet calculations that are equal to or below the forecast load.**

QUESTION:

a) Does Yukon Energy Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2 LWRF Continuity Schedule 2017/2018 and Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2: LWRF Continuity Schedule 2019 and 2020, April 2021 comply with these directions? Please explain each.

ANSWER:

(a)

YEC's 2017-18 LWRF Annual Report schedules as filed with the Board on December 10, 2019 have been acknowledged by the Board's letter of March 19, 2020 and complied with Board directions applicable at that time.

The 2019-2020 LWRF Annual Report schedules comply with directions under Section 9 of OIC 2021/16, given that the relevant filing was made in the first instance to the Board after November 1, 2020 and that no order has been issued with regard to this filing under section 27 of the Act prior to February 11, 2021. As reviewed below, OIC 2021/16 includes directions that are not consistent with the above Board Order 2019-08 directions to remove from the LWRF calculations the incremental generation due to incremental load, i.e., to approve only term sheet calculations that are equal to or below the forecast load.

In summary, OIC 2021/16 directs that the low water deferral account annual determinations after each financial year of YEC are to be based on the difference between (a) fuel costs for thermal generation needed to meet actual customer requirements (as a result of any shortfall between actual renewable generation and actual customer requirements), and (b) fuel costs for thermal generation that would have been needed to meet actual customer requirements for the financial year if renewable generation had been consistent with long-term average annual renewable source availability.

Accordingly, the 2019-2020 LWRF Annual Report schedules use term sheet calculation without reference to the earlier "fixed charge factor", but these term sheet calculations do not comply with the above Board Order 2019-08 directions to approve only term sheet calculations that are equal to or below the forecast load.

REFERENCE: **3.3 Low Water Reserve Fund**

Appendix A to Board Order 2019-08 — Reasons for Decision 9 53, The Board, in IR YUB-YEC-1-8, inquired about a paragraph in the term sheet concerning the thermal fuel mix. YEC responded that the paragraph was required as it establishes rules for addressing fuel mix to LTA thermal generation transfer costs. It should be noted that the Board previously accepted the fuel mix as part of YEC's 2017-18 GRA and that no further direction was given for YEC to comply with on this issue. However, further information on fuel mix has been provided in YEC's second compliance filing. The Board will not reopen this issue in the compliance filing. **However, due to the concerns the Board has regarding YEC's fuel mix calculations and the unverifiable nature of the results of those calculations provided in the second compliance filing and the resulting thermal fuel costs, those calculations will not be accepted by the Board for use in future GRAs.**

QUESTION:

a) Does Yukon Energy in the Low Water Reserve Fund Report Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2: LWRF Continuity Schedule 2019 and 2020, April 2021 comply with these directions? Please explain.

ANSWER:

(a)

The above quote from Board Order 2019-08 states that the Board will not accept thermal fuel mix calculations for use in future GRAs, without providing any direction as to what thermal fuel mix is to be provided.

The IR response referenced in the above quote from Board Order 2019-08 addressed the LWRF Term Sheet rules for addressing fuel mix to determine LTA thermal generation transfer costs. The IR response re-iterated the necessity to specify fuel mix in order to translate energy impacts (kWh) to dollars that adjust YEC fuel cost and LWRF account balances, i.e., removal of the LWRF provision without a replacement would render the

LWRF inoperable. Fuel mix rule options in the LWRF have a direct impact on YEC final thermal costs (i.e., after all LWRF transfers) for a completed fiscal year. The stated objective as noted in the earlier IR response is to end up with YEC actual fuel mix costs unchanged from the GRA forecast (based on 90% LNG and 10% diesel, using GRA forecast fuel prices).

The 2021 GRA retains long-term average (LTA) forecast renewable and thermal generation to meet forecast customer requirements, and the forecast 90/10 LNG/ diesel fuel mix for the LTA forecast thermal generation.

Use of LTA forecasts for hydro and other renewables (and the resulting LTA thermal generation forecast) is consistent with OIC 2021/16 direction in subsection 9(3) that forecast fuel costs to be recovered in rates of YEC are to be determined by forecasting the amount of renewable generation available to contribute to meeting forecast customer requirements based on long-term average annual renewable source availability. Experience confirms that fuel mix can vary depending an actual versus LTA renewable resource availability, i.e., actual LNG share of fuel mix may be less than 90% when renewable resource availability exceeds LTA, and vice versa when renewable resource availability is less than LTA. The 90/10 LNG/ diesel fuel mix is YEC's best available estimate of fuel mix applicable to LTA annual renewable source availability.

The updated LWRF Term Sheet filed on April 8, 2021 provides that costs for YEC thermal generation savings (excess) for annual LWRF determinations after the end of a YEC financial year are to be calculated so that YEC's final fiscal year expense for the total expected thermal generation (i.e., YEC expense after all transfers) equals the last GRA approved LTA fuel mix, subject to the constraints noted in Table 1.1-2 of the Term Sheet and in footnote 6 of the Term Sheet. These provisions are consistent with prior LWRF provisions on required fuel mix determinations.

Please also see response to YUB-YEC-2-4.

REFERENCE: **3.3 Low Water Reserve Fund**

Appendix A to Board Order 2019-08 — Reasons for Decision 9
3.3.1 Term Sheet 55. In response to a Board IR concerning quarterly and annual reporting, YEC responded… the LWRF implementation at fiscal year-end requires prior completion of a GRA process. Accordingly, LWRF determinations for GRA test years cannot be concluded until the GRA is concluded – and can be addressed therefore as part of the process for a GRA. After GRA test years have been addressed, the LWRF determinations should proceed on an annual basis until the next GRA test years occur. 56. The Board agrees with the quarterly and yearly reporting being added to the term sheet.

QUESTION:

a) Has Yukon Energy complied with quarterly and yearly reporting from this determination?

ANSWER:

(a)

YEC included the above reporting provisions in the updated LWRF Term Sheet provided to the Board on December 10, 2019, along with YEC's 2017-18 LWRF Annual Reports.

The Board's March 19, 2020 review of the updated Term Sheet and the 2017-2018 LWRF Annual Filing (as provided by YEC on December 10, 2019) acknowledged receipt of correspondence from YEC dated December 10, 2019 but did not approve the updated Term Sheet or the Annual LWRF filings. The Board stated "any future issues regarding the term sheet are to be addressed in the next YEC GRA". YEC accordingly deferred further LWRF filings until the next GRA, at which time the relevant term sheet issues would be reviewed. YEC's next LWRF filing, as provided on April 8, 2021, included Annual Reports for 2019 and 2020.

REFERENCE: **3.3 Low Water Reserve Fund**

Appendix A to Board Order 2019-08 — Reasons for Decision 9
Views of the Board

95. Going forward, the Board provides the following summary on its findings in this decision and future directions for YEC regarding the LWRF:

a) For forecasting hydro generation for GRA purposes, the Board's focus in determining the revenue requirements for these and future test years will continue to be on the reasonableness of YEC's forecasts and forecasting accuracy.

b) The Board has previously approved the use of LTA by YEC to forecast its GRA hydro generation requirements. Consideration of future trends due to phenomenon such as climate change will be evaluated by the Board in subsequent proceedings when assessing the forecasting accuracy of hydro generation. This allows YEC the option to continue to use LTA for its hydro generation forecasts.

c) The approved LWRF will continue to cover variances due to deviations from forecast water levels up to forecast load levels. This is expected to reduce the risk to YEC of changes in hydro generation due to changes in water levels up to forecast load levels. As stated in Board Order 2019-04, this maintains the principle that ratepayers carry the risk for changes in water levels that was established when the LWRF was initially established (with the recognition that costs for generation for loads above forecast are a utility risk). YEC has stated that this should be trued up on an annual basis when there is not a GRA before the Board and as part of a GRA when there is such an application before the Board. Although this proposal is not optimal in that it does not result in an annual true-up, the Board accepts that this will provide a better price signal to customers than the previous LWRF submitted by YEC. As the LWRF will be for actual values compared to forecast values up to the load forecast, this should resolve the issues with respect to fuel mix ratios as the deferral account will reflect actual fuel mix.

d) The Board will not accept YEC's use of the expected long-term cost of power in its LWRF calculations. As stated, this is redundant to

accrual and depreciation accounting and creates unnecessary complexities.

e) The Board will not accept YEC's thermal fuel calculations for the reasons cited earlier in the decision. In its future GRAs, YEC is directed to compare actual fuel costs (for up to forecast load) to forecast fuel costs for LWRF and GRA purposes.

f) YEC should consider the Board's comments in paragraphs 80 and 81. The Board recognizes that the directly focused LWRF above does not provide customer protection in years of drought. Therefore, the Board suggests that YEC examines whether a drought deferral account could be established to mitigate the effects of any future drought event(s). In its review of this issue, for example, YEC could consider the possibility of establishing a rate rider, on a cents/kWh basis, to build up the account and apply to the Board when it recognizes a drought situation and requires mitigation from this account.

g) The Board directs YEC to address intergenerational equity issues with respect to the LWRF in the next GRA.

QUESTION:

a) Does Yukon Energy comply with all of the a) to g) directions as to what was determined by the Board in Order 2019- 08 Reason for Decision for the Low Water Reserve Fund in the filing of Low Water Reserve Fund Report Table 1 Calculations LWRF and Table 2: LWRF Continuity Schedule 2019 and 2020, April 2021? Please explain for each question.

ANSWER:

(a)

The Board's mandate in relation to the LWRF has been modified by OIC 2021/16. The 2019-2020 LWRF Annual Report schedules comply with directions under Section 9 of OIC 2021/16, given that the relevant filing was made in the first instance to the Board after November 1, 2020 and that no order has been issued with regard to this filing under section 27 of the Act prior to February 11, 2021. Accordingly, the directions outlined above are no longer applicable given the principles outlined in OIC 2021/16.

See also YEC's responses to UCG-YEC-2-2 through UCG-YEC-2-8.

REFERENCE: Rate Schedule 39

QUESTION:

a) Please provide the total amount of money forecast to be collected via Rate Schedule 39 for the 2021 test year.

b) Please provide how any new money from this schedule will adjust the revenue requirement requested for the 2021 test year.

c) Do all the mines on the integrated grid pay portion of the costs of the C/S transmission line, substations on this line, as well as all other associated costs to this line? If no, please explain why not? If yes, please explain how much each mine pays in percentage to usage (i.e. 85% or?) and amount in $?

d) Please give the total load forecast for each mine on the Mayo/Keno grid for the 2021 test year?

e) Please give the total amount of power forecast for all other customers on the Mayo/Keno grid for the 2021 test year?

f) Please explain how Yukon Energy determined that 85 per cent of the costs of the Mayo/McQuesten transmission line and StatCam was allocated to the two mines to determine the Interim Rate Schedule 29. Please do not give the old out-dated answer of “that's how it has always been done in the Yukon, so this is how we do this now.”

g) Please give the forecast load for the Minto mine in the 2021 test year?

h) Please give the amount of dollars forecast to be collected from the Minto mine in the 2021 test year.

ANSWER:

(a)

Total forecast industrial revenues for the 2021 test year with the proposed rates equal $15.229 million, based on the following:

- **Forecast base rate revenues in the GRA application with estimated Fixed Charge at the time of filing the GRA:** Forecast industrial revenues for the 2021 test year at base rates [excluding Rider J] with the inclusion of the estimated Fixed Charge [$0.428 million as noted in Appendix 4.3, Table 4.3-2] are outlined in Tab 2, Table 2.1 at $11.535 million.

- **Adjusted Fixed Charge:** Board Order 2021-09 approved an applicable interim Schedule 39 Fixed Charge increase for 2021 based on applicable added rate base of $3,993,118 and added depreciation of $57,787.[1] The adjusted Fixed Charge for 2021 is $0.285 million[2] [based on $31,656/month for nine months effective April 1, 2021] which is $0.143 million lower than the amount included in the GRA [$0.428 million less $0.285 million].[3] Total revised forecast base rate revenues at $11.392 million.

- $3.837 million Rider J revenues with 2021 GRA proposed rider for industrial rates at 33.68% [applied to base revenues].

(b)

The revenue requirement for the 2021 test year is based on forecast YEC costs, and is not affected by rate adjustments such as the adjustments to the Fixed Charge applicable to VGC Group and Alexco.

[1] YEC limited scope application of March 23, 2021; Table 2, New Transmission Facilities (net of contributions), rate base and depreciation for 9 months.

[2] Calculated based on 2017/18 GRA approved Weighted Average Cost of Capital (WACC) of 4.82%. The final Fixed Charge will be calculated based on 2021 GRA WACC when the YUB issues the final GRA order. Any variances between forecast Fixed Charge and final Fixed Charge will be collected from/refunded to two industrial customers [VGC Group and Alexco].

[3] The adjustments to the Fixed Charge from the initial Appendix 4.3 estimate reflect delay in facilities commissioning (9 months versus 12 months for Fixed Charge in 2021) and reductions to estimated applicable costs.

(c)

All customers, including all industrial customers, share in paying for all associated Yukon Energy costs of the Carmacks-Stewart Transmission and related substations, as well as similar costs for the Whitehorse-Aishihik-Faro transmission line and the Mayo-Dawson transmission line. No ongoing fixed charge is allocated to any industrial customers with regard to fixed costs for any of these three transmission facilities.

YEC has not developed a cost of service assessment of the percentage of the 2021 GRA forecast costs (for these transmission facilities or other facilities) allocated to each customer class, and therefore cannot provide an estimate of the percentage or amount allocated to each mine customer.

(d)

See Tab 2, Table 2.1 for the 2021 test year industrial sales forecast. Table 2, Section 2.2.2 notes as follows:

- The forecast sales to Victoria Gold in 2021 is 43.1 GW.h.
- The forecast sales to Alexco as a Major Industrial Customer is 24.1 GW.h.

(e)

Retail customers at Keno City and on the Mayo-Keno transmission line are served by AEY, and therefore YEC only has a 2021 forecast for the industrial customers served on this transmission line (67.2 GW.h as reviewed in “d” above). YEC retail sales in Mayo are forecast at 6.8 GW.h for 2021.

YEC’s Stewart-Keno City Transmission Project YESAA Project Proposal Chapter 6, Page 6-3 Footnote 1 noted that there are approximately 23 non-industrial customers currently connected to the line between Mayo and Keno City (L250).

(f)

The question references “Interim Rate Schedule 29” and “StatCam” – however, it is assumed this question is referencing Rate Schedule 39 and SVC/StatCom.

The question asks how Yukon Energy determined for the Interim Rate Schedule 39 that 85 per cent of the costs of the Mayo/McQuesten transmission line and SVC/StatCom was to be allocated to the two mines. Yukon Energy made this determination based on compliance with the PPA for each mine, as approved by the Board.

Further background is provided below.

This issue was reviewed in detail during the Alexco mine PPA proceeding and the Victoria Gold PPA proceeding. In each case Yukon Energy reviewed in detail the basis for its approach and the Board provided an Order accepting the approach for each PPA.

Order 2010-14 regarding the Alexco PPA, Appendix A, page 5-6 notes:

> The Board concludes that the precedents cited by YEC provide some support for the direct transmission allocation (85%) as applied for. Most of the cases cited refer to cost of service and not the fundamental basis or appropriateness for the establishment of fixed charges to industrial customers. The Board notes that no other alternatives have been presented (in terms of allocation of transmission costs through fixed charges) in this proceeding. The comparison to the Faro situation when determining fixed charges for transmission line costs is the best available evidence for this proceeding. Furthermore, the Board accepts the information with respect to calculations provided by YEC in Attachment B to YUB-YEC-1-3(b) and approves the fixed charge to Alexco of $7,289 per month. The Board also concludes that the single fixed charge will apply to what is defined in the PPA as the District, that is, independent of the number of Points of Delivery.

This was also reviewed in detail during the Victoria Gold PPA proceeding in Order 2018-04, Appendix A, at pages 10-13. At para 54 and 55 (page 13 of Appendix A) the Board notes:

> 54. The Board is of the view that a cost-based approach is the best approach to determine fixed-cost charges for Rate Schedule 39. However, at this time, costs and revenues are not linked in Rate Schedule 39. For the VGC Group PPA, the only evidence on the record of this proceeding is the 1985 NEB report used to support an allocation of 85% of the fixed costs, the Alexco PPA, and YEC's assertion that the revenue-to-cost ratio for the Industrial Rate class exceeds unity. Further, the Board considers that no evidence was presented that would lead the

Board to treat the VCG Group PPA differently than the Alexco PPA, as neither are based on a COSS. For these reasons, the Board accepts an allocation of 85% of the fixed costs in the VGC Group PPA.

55. However, in future PPA applications, YEC is directed to provide cost-based studies that demonstrate that the industrial customer costs are being fully covered by the proposed rates, including the fixed charges. In addition, YEC is directed to provide detailed rationale on how the fixed cost level is established and why it applies.

(g)

See Tab 2, Section 2.2.2 which notes the Minto mine forecast for the 2021 test year at 35.7 GW.h.

(h)

The revenue forecast from Minto mine for the 2021 test year is $5.373 million, including Rider J revenues at proposed industrial customer rate 33.68% as shown in Table 4.2 of the Application.

REFERENCE: YUB-YEC-1-48 Table 1 p.2 of 4

QUESTION:

a) How are the differences/variances in this table accounted for going forward?

ANSWER:

(a)

The full cost to complete a capital project is included in YEC capital accounts on the balance sheet (Property plan and equipment, intangible assets or deferred assets). Asset depreciation commences in the month the asset is placed in service; however, no rates are collected for these assets until the YUB has completed a prudency review and approved inclusion in rate base at the next GRA.

REFERENCE: UCG-YEC-1-22 Cost of Debt

QUESTION:

a) How is the 120 basis points added to Bond rate determined?

b) Does the YUB determine the interest rate to be charged for each GRA?

ANSWER:

(a)

The 120 PBS adder was determined in the early 1990s as a proxy for interest cost on intercompany debt. The YUB confirmed this approach in its direction on GRA 2012/13 in response to a recommendation from CW (para 194 of Appendix A to Order 2013-01), and reconfirmed this in the 2017/18 GRA Order 2018-10 (para 238, Appendix A).

The response to UCG-YEC-1-22(b) quotes Board Order 2018-10 direction regarding the 120 basis points to be used in forecasting future costs of debt, i.e., long-term Canada bond interest rate plus the 120 basis points.

As described at page 3-27 of the Application, the rate of 2.19% used for new long-term 2020 and 2021 debt equals 120 basis points plus Government of Canada Long-Term Bond Benchmark at 0.99% as of June 30, 2020.

(b)

The YUB does not “determine” the interest but they do direct the utility in its approach to forecasting test year interest costs. From this direction, YEC estimates the interest rate for GRA test years based on current market conditions, and the YUB reviews and approves the test year revenue requirement that includes interest costs. In the 2017-18 GRA, the YUB directed in Order 2019-10 that YEC should continue to use the formulaic approach to forecast the cost for new debt as directed previously in Board Order 2013-01.

REFERENCE: **YUB-YEC-1-49 Table 6 and YUB-YEC-1-50**

YEC states in response to YUB-50 that "The Faro rental site was commissioned and in service December 1, 2020. The construction of the site was primarily carried out by YEC staff. Construction support was provided through existing vendor service contracts." In response YUB-49 YEC provides a table with unelaborated breakdown of costs.

QUESTION:

a) Please provide a further breakdown of each of the 5 major listed costs in Table 6 to clearly demonstrate a business case for the cost of this project.

b) Explain the total cost difference from Table 6 of $2.446 million and the cost from Tab 5 of the Application of $2.037 million.

ANSWER:

(a)

The business case for this project is the requirement for YEC to provide continuous service to customers under the N-1 capacity planning criteria. There was no viable short-term solution available to YEC to meet these criteria other than upgrading equipment in Faro to connect 7 rental mobile diesels. The cost components reflect the standard approach to cost accounting for a project of this nature and are consistent with YEC historical project budgeting and reporting. It is unclear what additional detail is requested, or how additional detail would inform the Board's prudency assessment given the stated business case.

(b)

The figure in the application ($2.037 million) was an estimate based on information available at the time of application preparation (approximately Sept/Oct 2020); the project was completed in late November and final project costs were not known until after GRA filing. The extra cost was related to additional civil site requirements and additional equipment needs to accommodate 7 rental mobile diesels.

REFERENCE: **UCG-YEC-1-26 (c) and (d) In this request UCG asks c) Explain why the vice president cannot do the job of FN relations? and d) What exactly is the VP job description? YEC responds as which VP?**

QUESTION:

a) Please answer both question with VP of Business and Corp. Development as the target.

ANSWER:

(a)

The staffing of a VP, First Nations Relations was a direction of the Board of Directors. Previously, the VP Business and Corporate Development (BDC) would handle some of these duties, but the contact was transactional and only where required for specific projects. The Board recognized that establishing and maintaining on-going relationships with Yukon First Nations in whose territory we operate is critical for YEC to be successful in any projects in the territory. The time required to develop and maintain these relationships, as well as participation in project engagement and project agreements is well beyond the capacity of the VP, BCD. This position already has lead responsibility for Information Technology, Human Resources and Health and Safety as well as governance roles in the IPP development and Yukon Government relations.

The job description was provided in response to UCG-YEC-1-26(b); that response is copied below for convenience.

- **Vice-President, Business and Corporate Development -** In conjunction with the President, liaises with key stakeholders to promote positive relationships and strong partnerships for the benefit of the corporation. Ensures that the Human Resources, IT, Health and Safety and Communications departments corporate objectives are met and in line with Yukon Energy's mission and vision. Contributes in the development of corporate goals, business plans, and strategies to ensure the effective planning and delivery of programs and services to achieve the Corporate mandate Contributes to the vision, mission and values of Yukon Energy through responsible, accountable and effective work performance. As a key

member of the senior management team is accountable for overall organizational performance.

REFERENCE: **In UCG-YEC-1-53 (e) for WH 2 project, YEC responds: "Internal work includes: YEC engineering, Project Management, procurement, health and safety, operations, and site construction monitoring support. The estimated cost of YEC internal support is $500,000."**

QUESTION:

a) Please provide a breakdown of each portion referenced above with costs associated for each and what work was done for each.

ANSWER:

(a)

The estimated cost of $500,000 was not broken out at the outset for the above components. An estimate of the breakdown by these components is provided below:

YEC engineering – $50,000

- Provides engineering support duties include: Review of IFC drawings, performing Quality Control checks, Involved in Factory Acceptance tests (FAT), management of the YEC Owners Engineer.

Project Management – $150,000

- Provides Project Management Services, duties include development of project management plans, RASCI tables, risk registers and management of scope, schedule and budget.

Procurement – $10,000

- Provides procurement support, duties include, drafting, finalizing and releasing RFP, contract development, negotiation and verification of adherence, processing change orders.

Health and safety – $10,000

- Provides Health and Safety support, duties include, supports the development of Project Safety Plans, provides safety site monitoring and spot checks, ensuring

adherence to YEC corporate policies, involved in investigating health and safety incidents.

Operations – $30,000

- Provides operational support, duties primarily include involvement in commissioning.

Site construction monitoring support – $250,000

- Provides site construction monitoring support, duties primarily include on site management of the contractor, coordinating onsite activities and management of multiple contractors simultaneously, ensuring daily health and safety requirements are met, involvement in disassembly and reassembly of the unit, supporting the PM to manage scope, schedule and budget, involvement with commissioning.

REFERENCE: **Application Tab 5.4.1.1 p. 5-28 and Response to YUB-YEC-1-70**

In response to YUB-YEC-1-70, Yukon Energy states: "EAM implementation is a separate project from Asset Management Framework (AMF) and PAMMS."

QUESTION:

a) Please give the total cost of the Asset Management Plan from 2013/14 until today. Include all costs for Enterprise Management (EAM) System Purchase, Enterprise Management (EAM) Implementation, Asset Management Framework (EMF), PAMMS and the Enterprise Resource Plan (ERP) with 2019 Upgrade. Break into component costs and then give total.

b) Are these plans now all in place and operating?

ANSWER:

(a) and **(b)**

There appears to be confusion regarding the projects in this question; YEC does not have a project called 'Asset Management Plan'. Based on the references in the question, YEC believes UCG is asking about the following individual projects:

- Asset Management Framework (AMF)
- ERP System Upgrades
- Enterprise Asset Management (EAM)

Actual costs from 2013 to 2020 and updated 2021 forecast costs are as follows:

($ Million)	2013	2014	2015	2016	2017	2018	2019	2020	2021
Asset Management Framework	-	-	-	-	-	0.439	1.349	1.530	0.946
ERP System Upgrades	-	-	-	0.066	-	-	-	0.158	-
Enterprise Asset Management	-	-	-	-	-	0.276	0.534	2.972	0.875

Asset Management Framework is a multi-year project that is expected to be in service in 2022, therefore, YEC is not asking for this to be approved and added to rate base in this Application.

ERP Upgrades are single year projects and were completed in 2016 and 2020. These projects were upgrades to the utilities core financial system (Microsoft Great Plains and related modules) and are not related to the Asset Management projects.

Enterprise Asset Management is a multi-year project that was put in-service in the first half of 2021.

See also YUB-YEC-2-25 for explanation of the objectives of the asset management projects.

REFERENCE: Yukon Energy response to YUB-YEC-1-47 (a to d)

QUESTION:

a) Is YEC now planning to add all past DSM cost to rate base?

b) Exactly what are YEC's current DSM programs?

c) Demonstrate how YEC has validated the cost to benefit for each program.

ANSWER:

(a)

No. Historic DSM costs were written off when YEC lost its court of appeal challenge.

(b)

Yukon Energy is currently delivering the Residential Demand Response Pilot (Peak Smart), which is funded by Natural Resources Canada, AEY and Yukon Development Corporation.

(c)

The goal of the Residential Demand Response Pilot is to test the effectiveness of this new demand response technology in reducing the morning and winter peak as well as the acceptance of participants of utility control of their appliances. YEC sought funding to complete this pilot study. Cost effectiveness tests are not being conducted for the pilot study given the level of funding available for the project. If the results of the pilot are favorable, a full DSM program could be designed and launched to the public. If this is the case the standard cost to benefit tests would be forecast and completed for the program.

REFERENCE: Yukon Energy response to YUB-YEC-1-48 Table 1

QUESTION:

a) How does Yukon Energy handle the differences/variances of these projects when applying them into the books for rate base?

ANSWER:

(a)

See response provided to UCG-YEC-2-11.

REFERENCE: Yukon Energy Response to YUB-YEC-1-51 p.6 Table 2
Costs for STATCOM/SVC and Syn. Cond. for SkTP/MMTL

QUESTION:

a) Do you now have an updated costs on each of these projects? If yes, please give.

ANSWER:

(a)

Please see response to YUB-YEC-2-17 for the updated cost information.

REFERENCE: **Yukon Energy response to YUB-YEC-1-51 p. 7 Table Preliminary Cost Budget SKTP and (k) states L180 to be completed and energized March 2021**

QUESTION:

a) Is this now complete and energized?

b) Please give updated cost of this complete project compared to budget.

ANSWER:

(a)

The Transmission line was energized and in service in March.

(b)

Please see response to YUB-YEC-2-17.

REFERENCE: Yukon Energy Response to YUB-YEC-1-64

QUESTION:

a) Considering the business plan explained in this response, how will Yukon Energy track and demonstrate tangible benefits? Explain.

ANSWER:

(a)

The focus to date has been on bringing the project live on schedule this year. YEC will now determine metrics for the tangible benefits which will allow for tracking of results on a go forward basis. YEC will determine what metrics will be put in place and will implement in 2022 on a go forward basis.

REFERENCE: Yukon Energy response to YUB-YEC-1-99
Whitehorse Diesel Substation improvements

QUESTION:

a) Please explain exactly what work Yukon Energy completed for this $100k improvement.

ANSWER:

(a)

An engineered wooden structure was erected which holds multiple disconnect switches to allow for isolation of the rental generators; this ensures workers can safely work on units. A ground grid and fencing for safety was also included in the project.

Yukon Utilities Board
(YUB)

TOPIC: **Diesel Rentals**

REFERENCE: **YUB-YEC-1-5(a), PDF page 9**

QUOTE: "The firm capacity provided by the 15 diesel rental units for 2021 is 27 MW (1.8 MW per unit). Note the contract price includes two additional 1.8 MW units for reliability."

QUESTION:

a) Please clarify whether YEC is renting 15 or 17 diesel units.

b) Of the base rentals (i.e., not including the additional two units for reliability), how many of the units are for previously retired diesel units? How many are to meet increased capacity needs (i.e., to satisfy YEC's N-1 capacity criterion)? Please explain.

c) What are the costs for the two additional units required for reliability?

d) When YEC discusses reliability in the context of this question, does YEC refer to other rental units not being operational when required? Please explain.

ANSWER:

(a) and **(d)**

YEC is renting 17 diesel units for 2020/21 and 2021/22 winters. This includes 15 units required to address the N-1 capacity shortfall and two spare units, one in each Whitehorse and Faro locations.

The spare rental units are connected to the Yukon Grid and were secured to provide a back-up for the other rental diesel units given concerns regarding reliability of rental units during operation. For example, if one of the rental units is not available for reliability reasons YEC would use the spare unit instead. These spare units, however, can also provide back-up for any other grid reliability issues.

(b)

YEC does not specifically rent the diesel units to replace retired diesel units. Instead, the number of rental units is determined by assessing the dependable capacity shortfall for the entire grid. That is, total required capacity under the N-1 criterion less available dependable capacity.

The 27 MW for the base rental diesel units address the N-1 capacity shortfall due to increased peak demand, changes in dependable capacity for hydro units due to ice issues and changes in diesel units due to derating and other reasons.

In 2017/18 GRA the N-1 capacity shortfall for 2018 was 8.74 MW before considering diesel rentals. The 17 MW N-1 capacity shortfall increase in 2021 GRA compared to 2017/18 GRA reflects the following:

- 14.25 MW N-1 shortfall increase due to increase in non-industrial peak demand (100.65 MW in 2021 GRA compared to 86.40 MW in 2017/18 GRA).

- Change in hydro dependable capacity (no net impact). The Mayo GS dependable capacity has been reduced from 9 MW assumed in the 2017-18 GRA to 6.5 MW to reflect updated winter downstream flow restrictions and Whitehorse GS increased from 24.5 MW to 27 MW to reflect increased winter max flows. No net impact [reduction of 2.5 MW is offset by increase of 2.5 MW]. Please see YUB-YEC-1-20 for details.

- Added LNG 3rd engine [-3.8 MW impact on N-1 shortfall].

- Reductions in YEC diesel units [+6.71 MW impact on N-1 shortfall]:
    - Retired WH diesel #3 [4.5 MW added to shortfall].
    - Changes in Whitehorse diesel unit ratings [0.95 MW added to shortfall].
    - Changes in Faro diesel unit ratings [1 MW added to shortfall].
    - Changes in Dawson diesel unit ratings [0.26 MW added to shortfall] offset by added unit [0.85 MW old Faro unit – but this old unit was included in grid total in 2017/18 GRA].

- Increase in AEY diesel unit ratings [-0.177 MW impact on N-1 shortfall].

- Total net added capacity shortfall is about 17 MW. This increases the capacity shortfall (prior to considering rented diesels) from 8.74 MW from 2017/18 GRA to 25.75 MW in 2021 GRA.

(c)

The forecast cost of rental units for the 2021 calendar year [included in the GRA revenue requirement] is about $3.8 million. The rental costs include unit based rental costs for generators [17 generators], transformers [17 transformers] and fuel tanks [10 fuel tanks], and fixed costs for transportation, engineering, testing, start-up and commissioning. Therefore, the spare units only impact the unit based costs for generators and transformers as follows:

- Whitehorse location: generator rental cost at $0.110 million and transformer rental cost at $0.04 million, total $0.150 million for a 140-day rental period.

- Faro location: generator rental cost at $0.151 million and transformer rental cost at $0.041 million, total $0.192 million for a 140-day rental period.

TOPIC: **Independent Power Production (IPP)**

REFERENCE: **YUB-YEC-1-10(a), PDF page 16**

QUOTE: "YEC has considerable uncertainty as to timing for forecast IPP amounts for 2021. The first project that was to be operational in November 2020 has been delayed into spring 2021."

QUESTION:

a) Please provide an update on IP production in terms of expected projects.

b) Does YEC have an updated forecast for IP production for 2021? If so, please provide that forecast.

ANSWER:

(a)

The table below summarizes the projects currently in queue under the IPP SOP.

Project Name / Activity	Energy Type	Community	Connect...	Installed Capacity (kW)	Annual Energy (kWh)	Annual Energy MWh	IPP SOP Grid GWh	Stat...	Project Status	Project Develop... Status	COD Date
TOTAL SOP in Development	12			18,349	35,168,600	10,507	11.2				2021.10.0
Solvest North Klondike Highway Solar	Solar	Whitehorse	AEY+YEC	1,000	1,840,400	1,100	1.84		Project Under Construction		2021.10.01
Nomad Mt. Sima Solar	Solar	Whitehorse	AEY+YEC	150	270,000	270	0.27		Project Under Construction		2021.10.01
KDO Dawson Dome Road Solar	Solar	Dawson	YEC Direct	199	279,000	279	0.28		EPA Ready for Signing		2021.10.31
KDFN Eagle Hill Wind	Wind	Whitehorse	AEY+YEC	4,000	8,858,000	8,858	8.86		EPA in Development		
Sunergy Haines Junction Solar A/B	Solar	Haines Junction	AEY+YEC	1,000	1,840,400				Interconnectic Study		
Sunergy Haines Junction Solar B/B	Solar	Haines Junction	AEY+YEC	1,000	1,840,400				Interconnectic Study		
ArcticPharm	Solar	Whitehorse	AEY+YEC	2,000	3,680,000				Interconnectic Study		
CTMC2 Carcross S-316B1	Solar	Carcross	AEY+YEC	2,000	3,680,000				System Impact Study		
CTMC2 Carcross S-316B1	Solar	Carcross	AEY+YEC	2,000	3,680,000				System Impact Study		
Northern Blue Bird Farm	Solar	Mayo	YEC Direct	2,000	3,680,000				System Impact Study		
Partridge Creek Farm	Solar	Mayo	YEC Direct	2,000	3,680,000				System Impact Study		
Carcross Brownfield Solar	Solar	Carcross	AEY+YEC	1,000	1,840,400				Application Received		

(b)

As of the date of drafting, YEC expects three projects will connect to the grid under the SOP program. All are expected to connect during October 2021 and the total generation provided is forecast at 0.2 GWh.

Project Name / Activity	Energy Type	Community	Connect...	Installed Capacity (kW)	Annual Energy (kWh)	IPP SOP Grid GWh	2021 % Energy based on COD	2021 Energy Generation Forecast (kWh)	Stat...	Project Status	Project Develop... Status	COD Date
- TOTAL SOP in Development	12			18,349	35,168,600	11.2		198,306				2021.10.0
Solvest North Klondike Highway Solar	Solar	Whitehorse	AEY+YEC	1,000	1,840,400	1.84	9%	165,636		Project Under Construction		2021.10.01
Nomad Mt. Sima Solar	Solar	Whitehorse	AEY+YEC	150	270,000	0.27	9%	24,300		Project Under Construction		2021.10.01
KDO Dawson Dome Road Solar	Solar	Dawson	YEC Direct	199	279,000	0.28	3%	8,370		EPA Ready for Signing		2021.10.31

TOPIC: **Diesel Rental Units**

REFERENCE: **YUB-YEC-1-31(a), PDF page 49**

QUOTE: "The rental of 15 diesel generator units plus two spare units is required to address the N-1 dependable capacity shortfall, as explained in Section 2.4 of the Application (the specific measurement of the shortfall is addressed at pages 2-14 and 2-15). This requirement is related to the factors noted regarding the N-1 capacity shortfall, and is not related to forecast thermal generation."

QUESTION:

a) If the rental of the 15 diesel units is to address an N-1 dependable capacity shortfall, in the absence of such an event, are those units expected to be idle? Please explain.

b) If the primary function of the 15 diesel rental units is to provide N-1 dependable capacity, why are 17, rather than 15, diesel rental units necessary to provide N-1 dependable capacity?

ANSWER:

(a)

The primary purpose of diesel rentals is to address the N-1 dependable capacity shortfall. For this purpose, YEC expects the rental units to be idle the vast majority of the time. However, based on experience and given certain favorable contract terms, YEC does not expect these units to be idle if diesel generation is required on the YIS.

The specific terms of the rental agreement permit YEC to use the rental units to a certain degree at a cost less than use of owned diesel, and thereby to reduce overall YEC diesel operation costs. Using the rental diesel units in priority before the permanent diesels reduces engine hours for YEC's permanent diesels [therefore postponing both routine maintenance the potential overhaul of the permanent diesel units]; it is also less costly to run rental diesel units as YEC is only responsible for fuel cost and cost of oil change.

Therefore, the rental units are used in priority after LNG units in response to peak demand requirements as noted in NY-YEC-1-6 Revised.

(b)

The two spare units provide back-up for the remaining rental diesels. Please see response to YUB-YEC-2-1 (a) and (d).

TOPIC: **Thermal Fuel Mix**

REFERENCE: **YUB-YEC-1-32(b), PDF page 51**

QUESTION:

a) Please provide the statistics or any other numerical analysis that supports the 90:10 LNG/diesel fuel mix.

b) Please explain how the proposed thermal fuel mix in this application addresses all the concerns expressed by the Board in Appendix A to Board Order 2019-08.

ANSWER:

(a)

Statistics or other numerical analysis supporting the 90:10 LNG/diesel fuel mix must address long-term average (LTA) thermal generation fuel mix rather than the short-term fuel mix that is actually expected (or that actually occurs) in the test year. OIC 2021/16 mandates that LTA renewable generation continue to be used for GRA thermal generation fuel cost forecasts adopted for setting rates of YEC.

The response to YUB-YEC-1-32(b) referenced available information on actual LNG/diesel fuel mix since LNG was first used by YEC. The response reviewed the basis for the initial 90:10 fuel mix proposal, i.e., while diesel would be used for peaking, emergencies and other specific uses such that diesel's share of thermal in many years with average or higher-than-average water conditions may well significantly exceed 10%, the impact of high LNG use in low water conditions favors the average mix of 90:10 on LTA basis.

Available statistics as reviewed in the response to YUB-YEC-1-32 (a) and (b) confirm that the LNG share of the fuel mix has been below 90% when hydro generation was similar to or in excess of LTA, and above 90% in 2019 when hydro generation was well below LTA.

The 90/10 ratio has been confirmed to be reasonable ratio for the 2021 test year based on actual results for 2018[1] and 2019[2] [average for all thermal in 2018 and 2019 is 90% LNG and 10% diesel]. YEC has no reason to believe there should be a change at this time to the 90% LNG/10% diesel for the LTA thermal split purposes under LTA water conditions.

To assist the Board, YEC includes earlier numerical analysis put on the record during the 2017/18 GRA that supports this LTA fuel mix ratio by highlighting the importance of the small percentage of years with drought conditions. Appendix 1 to this response copies Figure 3.4.1 from Appendix 3.4 of YEC's 2017-18 GRA to demonstrate potential thermal generation variability (GWh/year) depending on water conditions (35 water years available at that time) and grid loads ranging between 380 and 450 GWh/year (the 2018 GRA forecast load was 420 GWh).

As reviewed in Appendix 1, LTA thermal generation determinations are driven by thermal generation requirements during the small percentage of years with drought conditions. Results at 420 and 450 GW.h per year load as summarized below for the last GRA's conditions demonstrate this point:

- At 420 GW.h per year load, Appendix 1 LTA thermal generation is 13.9 GW.h (median 1.6 GW.h) with more than 75% of this thermal generation occurring in the 20% of the 35 water years with the worst drought conditions. During these drought years, the thermal generation is 225% or more of LTA thermal generation.

- At 450 GW,h per year load, Appendix 1 LTA thermal generation is 28.6 GW.h (median 25.5 GW.h) with 51% of this thermal generation occurring in the 20% of the 35 water years with the worst drought conditions. During these drought years, the thermal generation is 190% or more of LTA thermal generation.

In summary, the Appendix 1 analysis highlights why LTA thermal generation fuel mix estimates need to consider expected actual requirements during the small percentage of years with drought conditions (of which the statistics in YUB-YEC-1-32 (a) and (b) include

[1] The 2018 LNG ratio was 81% when actual thermal was 119% of LTA thermal reflecting water availability below LTA.
[2] The 2019 LNG ratio was 95% when actual thermal was 276% of LTA thermal reflecting water availability materially below LTA.

only one such year when actual thermal was 276% of LTA thermal and the LNG share of fuel mix was 95%).

Appendix 1 also highlights the extent to which LTA thermal increases and approaches median thermal as grid load increases, thereby enhancing LNG generation share of the thermal fuel mix under even average water conditions. The forecast firm grid load for the 2021 test year at 532.5 GWh (net of expected IPP, Fish Lake hydro, and expected generation from WH uprates[3]) is well above any of the grid loads considered in Appendix 1, with an estimated LTA thermal generation of 84.3 GW.h. This information provides further support for the 90:10 LNG/diesel fuel mix for the 2021 GRA test year.

(b)

YEC understands the Board's concerns regarding LWRF fuel mix determinations, as set out in Board Order 2019-08, to focus on seeking verifiable actual results based on actual thermal generation and fuel mix results.

The added information now available on actual results from past years reviewed in response to "a" of this IR provides empirical support for the forecast 90:10 LNG/diesel fuel mix at LTA thermal generation for the 2021 GRA load forecast. As reviewed below, fuel mix at LTA thermal generation remains the critical requirement for LWRF determinations.

The proposed thermal fuel mix in the 2021 GRA at 90:10 LNG/diesel reflects the fact that forecast thermal generation for the test year is based on LTA annual renewable resource availability (and therefore LTA thermal generation) rather than on forecast actual thermal generation or fuel mix. Actual thermal requirements not related to the actual load (e.g., thermal generation for RFID and capital projects) are removed so as not to affect the LWRF. The LWRF determinations are not otherwise addressing actual thermal generation requirements or fuel mix results during the relevant financial year.

This LTA forecast approach is now also mandated by OIC 2021/16.

Please also see response to UCG-YEC-2-7.

[3] See GRA Application, Appendix 2.1, Table 2.1-1.

Appendix 1: Figure 3.4.1 from Appendix 3.4 of 2017-18 YEC GRA

Figure 3.4-1: Duration Curve – Grid Thermal Generation Variability over 35 Water Years

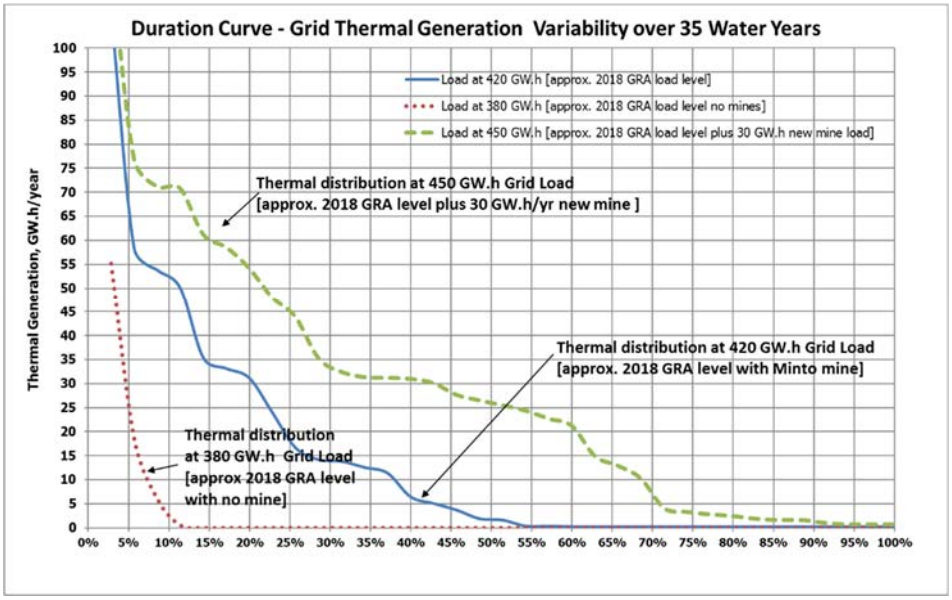

Figure 3.4-1 highlights the sensitivity of the 2017-18 GRA LTA thermal generation assessments as firm grid load varies from -40 GW.h to + 30 GW.h from the 420 GW.h/year level that approximates that Application's 2018 load forecast. In summary, Figure 3.4-1 shows the following:

- At 420 GW.h per year load with the Minto mine, LTA thermal generation is 13.9 GW.h (median 1.6 GW.h) with more than 75% of this thermal generation occurring in the 20% of the 35 water years with the worst drought conditions, and less than 1% of this thermal generation occurring in the 46% of the 35 water years with the best water conditions.

- At 450 GW,h per year load with Minto mine plus 30 GW.h/yr new mine load, LTA thermal generation is 28.6 GW.h (median 25.5 GW.h) with 51% of this thermal generation occurring in the 20% of the 35 water years with the worst drought conditions, and 10% of this thermal generation occurring in the 46% of the 35 water years with the best water conditions.

- At 380 GW,h per year load without the Minto mine, LTA thermal generation is 2.3 GW.h (median 0.0 GW.h) with 99% of this thermal generation occurring in the 20% of the 35 water years with the worst drought conditions, and about 0.5% of this thermal generation occurring in the 46% of the 35 water years with the best water conditions.

TOPIC: **VGC and Alexco Fixed Charge**

REFERENCE: **YUB-YEC-1-45(a), PDF page 94**

QUOTE: "The Transmission Facilities Development Operation Date has been delayed to March 2021. YEC therefore now expects to file the amended Transmission Facilities Fixed Cost application in March 2021, requesting an interim Fixed Charge adjustment effective May 1, 2021 in order to establish a necessary rate adjustment for VGC Group and Alexco as soon as feasible. This filing will be based on the 2020-2021 to date forecast costs of the new facilities and YEC's approved 2018 GRA cost of capital at 4.82%, i.e., these initial adjustments do not include any changes related to YEC's 2021 GRA proposed cost of capital."

QUESTION:

a) What is the expected life of the VGC mine?

b) Although the response above notes cost of capital, can depreciation rates affect the fixed charge to VGC and Alexco? Please explain.

c) If the forecast capital cost related to the new facilities for VGC are approved in this GRA, does that imply that the fixed charge can be finalized for 2021? Please explain.

ANSWER:

(a)

Based on publicly available information and the approved PPA, the mine life is expected to be 11 years; further disclosure indicates a management plan to extend life by an additional 10 years, but this cannot be relied upon at this time.

(b)

Yes. The calculation of the fixed charge is based on the sum of return and depreciation on the related transmission assets.

(c)

No, with respect to updates to the overall fixed charge (i.e., the fixed charge that is to be allocated between the two mines) the VGC PPA requires the fixed charge to be re-calculated when the SVC/Statcom is added later this year and costs are finalized; in addition, at the end of each fiscal year once actual mine loads are known for that year the allocation of the annual fixed charge between the mines is finalized for the year. The fixed charge allocations are to be finalized within 60 days of each year end.

TOPIC: **Applicable Years**

REFERENCE: **Low Water Reserve Fund (LWRF) Term Sheet, (April 8, 2021 submission), PDF page 1**

QUOTE: "Attachment 1 includes the Updated LWRF Term Sheet applicable for fiscal years after 2018, in conformance with OIC 2021/16…"

QUESTION:

a) Please explain the applicability of a LWRF term sheet for years after 2018 when it is based on an OIC dated 2021.

b) OIC 2021/16 is dated February 11, 2021. Please confirm that OIC 2021/16 applies on a prospective basis from February 11, 2021. If not, please explain why not.

c) Is it YEC's view that the Board has the authority to apply OIC 2021/16 to YEC's tariff for years before 2021? Please explain.

ANSWER:

(a), **(b)** and **(c)**

OIC 2021/16, dated February 11, 2021, amends the *Rate Policy Directive (1995)* (the "Directive") regarding three different topics, and specifies the time period applicable to the amendment for each topic or section, as reviewed below:

(a) Fuel costs and Low Water Deferral Account (Section 9 added to the Directive) - Section 9(10) states: "This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force."

(b) Recovery of costs for Demand-Side Management Program (Section 10 added to the Directive) - Section 10(4) states: "This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on

or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force."

(c) Recovery of costs for Renewable Generation Project Planning or Development (Section 11 added to the Directive) - Section 11(2) states: "This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force."

Accordingly, with respect to the LWRF, YEC OIC 2021/16 applies to any application, report or other filing made in the first instance to the Board on or after November 1, 2020 provided that no order has been issued on the matter under section 27 of the Act before February 11, 2021. On this basis, OIC 2021/16 applies as follows with regard to LWRF annual reports currently before the Board:

- OIC 2021/16 applies to LWRF and ERA annual reports for 2019 and 2020, and related deferral account determination applications, that were filed in the first instance with the Board on April 8, 2021, and that no prior order was issued on 2019 and 2020 annual LWRF and ERA determinations.

- OIC 2021/16 does not apply to LWRF annual reports, or related deferral account determinations, for 2018 or prior years.

TOPIC: **LWRF Cap**

REFERENCE: **Low Water Reserve Fund (LWRF) Term Sheet, (April 8, 2021 submission), PDF page 7**

QUOTE: "In compliance with OIC 2021/16 (Sections 9(6) and 9(8)), the updated LWRF Term Sheet increases the LWRF cap from +/- $8 million to +/ $16 million. This change reflects the material increase in YEC's forecast generation load for the 2021 test year compared to the last GRA 2018 test year forecast. The objective is to reduce Rider E impact frequency and enable the LWRF to be more robust in dealing with severe drought."

QUESTION:

a) Does OIC 2021/16 dictate the cap level for the LWRF? Please explain.

b) Is the change in the cap level for the LWRF from $8 million to $16 million a request from YEC to this Board for approval?

c) Please provide further explanation as to why YEC requires the LWRF cap to be increased by $8 million.

d) Is it YEC's position that any change from the renewable generation forecast is now charged to the LWRF? Please explain.

ANSWER:

(a)

OIC 2021/16 sets out basic principles to be followed by the Board in setting the cap level for the LWRF, without dictating specific maximum or minimum cap levels.

Subsection 9(6) provides the basic principles to be followed in setting LWRF cap levels, i.e., to operate the LWRF for the purpose of minimizing the effect on rates that would otherwise be caused by the actual variability in renewable source availability.

Effects on rates occur (subsection 9(9)) when the LWRF exceeds the cap levels due to the amounts charged or credited to the LWRF for each financial year (subsections 9(4) and 9(7)).

OIC 2021/16 directs that the LWRF caps be set to smooth over the long term impact on rates due to variability in renewable source availability.

(b)

Yes.

(c)

YEC is applying to increase the cap by $8 million in order to minimize the effect on rates for retail customers and major industrial customers that would otherwise be caused by the variation in actual renewable source availability. This will reduce expected Rider E (i.e., rate rider changes required when the LWRF goes outside the stipulated caps) impact frequency, and enable the LWRF to be more robust in dealing with severe drought impacts on Rider E.

The need for this change reflects the material increase in YEC's forecast generation load for the 2021 test year compared to the last GRA 2018 test year forecast.

Appendix 1 to this response copies Table 3.4-5 from Appendix 3.4 of 2017-18 YEC GRA which was prepared to demonstrate potential impact of high loads to the LWRF cap and frequency of needed rate rider changes depending on load levels at 420 GWh/year and 450 GWh/year (the 2018 GRA forecast load was 420 GWh).

As the table shows at the load range of 450 GW.h, a LWRF (at the time of filing 2017/18 GRA it was DCF) cap increased to $16 million from the current $8 million would have the following key positive impacts:

a) Increased years not needing rate riders, from 20 to 26 (out of 35) water years. This change relates to reducing the number of years with rate changes for charges as well as rebates.

b) Major reduction in drought year rate rider charges - reduces the peak drought year charge from $14.0 million to $8.2 million, and the average charge year amount (for years with rate rider charges) from $4.8 million to $3.5 million.

At that time it was noted that at 450 GW.h load peak drought year thermal requirement was 117.0 GW.h (vs. LTA thermal of 28.6 GW.h), costing $18.5 million for 90% LNG/10% diesel generation.

The forecast firm grid load for the 2021 test year at 532.5 GWh (net of expected IPP, Fish Lake hydro, and expected generation from WH uprates[1]) is well above any of the grid loads considered in Appendix 1. At the 2021 GRA load the thermal generation required during the drought years could be more than 155 GWh costing about $29 million based on 90% LNG/10% diesel generation assumption. This is well above the thermal costs assumed in Appendix 1 analysis and supports the proposed increase in LWRF cap limit.

(d)

Subject to clarifications, YEC agrees that changes from the LTA renewable generation forecast applicable to the actual grid load are charged to the LWRF.

OIC 2021/16 requires charging or crediting the LWRF for thermal generation fuel costs variances due to the difference between actual renewable generation and renewable generation consistent with “long-term average annual renewable source availability” as defined in subsection 9(1). LWRF determinations therefore must take into account, subject to Board approval, any material changes to renewable resource generation capability that affect long-term average annual renewable source availability during the financial year, e.g., changes in IPP forecasts need to be considered for the LWRF determinations. Standard exclusions continue to apply, e.g., thermal generation for maintenance, RFID and capital projects is not to be included in LWRF assessments.

[1] See GRA Application, Appendix 2.1, Table 2.1-1.

Appendix 1: Table 3.4-5 from Appendix 3.4 of 2017-18 YEC GRA

Table 3.4-5: Summary - DCF Cap Option Impacts - 420 & 450 GW.h/yr. Loads with Minto Mine

	420 GW.h/year load (13.9 GW.h/yr LTA thermal)		450 GW.h/yr load (28.6 GW.h/yr LTA thermal)	
	"+/-" DCF Cap ($million)		"+/-" DCF Cap ($million)	
	8	16	8	16
	Table 3.4-6A	Table 3.4-6B	Table 3.4-7A	Table 3.4-7B
DCF at 90% LNG and 10% Diesel				
Number of water years (out of 35) with				
No rate rider impact	16	21	20	26
Rider rebates	12	8	8	4
Max rebate	8	6	1	1
Rider charges	7	6	7	5
Rider Impact ($M/yr)				
Max Rebate	-2.16	-2.16	-5.06	-4.14
Peak Charge	13.63	4.67	14.00	8.24
Average charge year	4.18	2.20	4.82	3.54
Net impact after 35 yrs	5.90	-2.10	8.00	5.06
DCF at 100% Diesel				
Number of water years (out of 35) with				
No rate rider impact	11	17	17	22
Rider rebates	15	11	10	7
Max rebate	9	8	1	1
Rider charges	9	7	8	6
Rider Impact ($M/yr)				
Max Rebate	-3.59	-3.59	-7.34	-7.09
Peak Charge	24.66	17.27	23.28	23.28
Average charge year	6.58	6.17	8.34	8.45
Net impact after 35 yrs	8.00	7.12	8.00	16.00

TOPIC: **Outstanding Issues**

REFERENCE: **YEC Rate Schedule 39 (March 23, 2021 submission)**

QUESTION:

a) The Board approved YEC's interim rate request for Rate Schedule 39 in Board Order 2021-09. In YEC's view, are there any other outstanding determinations required from the Board regarding this issue for this GRA? Please explain.

ANSWER:

(a)

Yes, there will be adjustments to this rate schedule in the future that will require Board review.

Board Order 2021-09 approved an interim Fixed Charge for the VCG Group mine and the Alexco mine and mill to reflect YEC's McQuesten Substation Fixed Costs and Transmission Facilities Development Costs for the new transmission facilities between Mayo and McQuesten. Outstanding determinations on this Fixed Charge required as part of this 2021 GRA regarding Rate Schedule 39 relate to approving a final Fixed Charge for the specified facilities to reflect the following:

- Any adjustments to final Transmission Facilities Development Costs for the new transmission facilities between Mayo and McQuesten Substation that are to be reflected in the required year end reconciliation for the Fixed Charge or in the compliance filing for the 2021 GRA (whichever occurs sooner);

- As part of the 2021 GRA, an update to the Fixed Charge to reflect the Weighted Average Cost of Capital (WACC) as approved for the 2021 GRA (the interim Fixed Charge effective April 1, 2021 is based on the approved WACC for 2018 at 4.82%); and

- Any required true-up provision to the applicable Fixed Charge since April 1, 2021.

As noted in Yukon Energy's March 23, 2021 limited scope application, future adjustments will also be required to Rate Schedule 39 Fixed Charge for the VCG Group mine and the Alexco mine and mill when the SVC/Statcom at Stewart Crossing is completed (forecast to occur in November 2021). YEC will file a limited scope application, within 60 days of completion date, to update the Rate Schedule 39 Fixed Charge as required for this facility.

TOPIC: **Reserve for Injuries and Damages (RFID) Costs**

REFERENCE: **YUB-YEC-1-37(g), PDF page 64**

QUOTE: Information request (IR):
"Please identify any additional costs or savings experienced by or actively sought by YEC during 2020 as a result of the current economic conditions surrounding the COVID-19 pandemic."

IR Response:
"Significant additional costs as a result of the current economic conditions surrounding the COVID-19 pandemic are included as RFID. Savings as a result of the current economic conditions surrounding the COVID-19 pandemic include significantly reduced travel costs for YEC employees."

PREAMBLE: YEC has forecast 2020 RFID costs in the amount of $1.598 million as noted in its Tab 3 workbook on Table 3.11.1.

QUESTION:

a) Please clarify the amount of "significant additional costs" resulting from the current economic conditions surrounding the COVID-19 pandemic that have been included in YEC's 2020 RFID forecast of $1.598 million.

b) Please explain why the additional costs referred to in part (a) should be recoverable through YEC's 2020 RFID account and associated policy. As part of this IR response, please include a copy of YEC's RFID policy and a reference to the applicable section.

c) Please clarify the amount of the "significantly reduced travel costs" for YEC employees and confirm whether those cost reductions have similarly been reflected in YEC's 2020 RFID forecast. Please explain fully regardless of whether the response to part (c) is confirmed or denied.

d) Please provide the "significant additional costs" and, separately, the "significantly reduced travel costs" on an actual basis for 2020. If YEC is not able to provide

these costs on an actual basis, then please provide updated 2020 forecast information.

e) Please provide a breakdown of YEC's actual 2020 RFID costs by each constituent component. If YEC is not able to provide these costs on an actual basis, then please respond by providing updated 2020 forecast information.

f) Of the $0.411 million of RFID costs forecast for 2021, how much is related to costs (or cost reductions) associated with the COVID-19 pandemic?

ANSWER:

(a)

In 2020 YEC charged $0.073 million to RFID for COVID-19 for incremental costs such as laptop costs to work from home, health and safety supplies and communications costs/signage.

(b)

The additional costs referred to in part (a) should be recoverable as they meet the criteria of the RFID policy below:

4. Criteria
   4.1. Uninsured and uninsurable losses and associated costs will be charged to RFID if they meet the following criteria:
      a) The loss exceeds $10,000;
      b) The loss was sudden and accidental and not the result of normal wear and tear;
      c) The incident was of significance to the operation of the unit; and
      d) The loss was one of low probability, not normally expected to occur in a typical operating year.

A copy of the RFID policy is provided as Attachment 1 to this response.

(c)

It is not possible to exactly calculate costs that were not charged due to COVID-19 as there can be more than one reason for reduced travel, but evidence of reduced travel costs (regardless of the reason) can be shown in the chart below which shows actual administration and O&M admin travel costs from 2013 to 2020:

2013	2014	2015	2016	2017	2018	2019	2020
$ 448,514	$ 584,736	$ 460,715	$ 408,142	$ 454,804	$ 562,796	$ 526,663	$ 377,397

Travel cost reductions are not reflected in the 2020 RFID forecast, nor are other costs YEC did incur that were also not as specifically identifiable as those costs that were charged in part (a).

(d)

Please see responses to parts (a) and (c).

(e)

A breakdown of YEC's actual 2020 RFID costs is as follows:

LNG Vapourizer Failure	$ 0.349
S252 Breaker Failure	0.128
Covid-19 Incremental	0.073
WG1 & WG2 Failure	0.583
WH1 & WH2 Penstock Failure	0.100
	$ 1.233

The WH1 & WH2 Penstock Failure costs charged in 2020 reflect the insurance deductible and assume the remaining costs will be 100% insured.

(f)

The $0.411 million of costs forecast for RFID in 2021 in the Application is based on the 10-year average charge as shown in Table 3.11 of the Application as the forecast for the Application was done prior to 2021.

APPENDIX 3.2
RESERVE FOR INJURIES AND DAMAGES (RFID) POLICY

YUKON ENERGY	FINANCE POLICY FA-014	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Chief Financial Officer	Reserve for Injuries and Damages
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2012	February 2015	President & CEO

1.0 Purpose

1.1 The Reserve for Injuries and Damages ("RFID") is utilized to address uninsured and uninsurable losses, and associated costs, as well as the deductible portion of insured losses.

1.2 The reserve serves two purposes: (1) it allows for an appropriate balance to be maintained between self-insurance, deductibles, commercial insurance and sudden and accidental losses; and, (2) it allows the costs in question to be smoothed over a number of years to avoid rate instability for ratepayers.

2.0 Background

2.1 An RFID account is a risk management tool commonly used by regulated utilities to address uninsured and uninsurable losses in a manner that allows for smoothing of rate impacts over time[1]. If an uninsured or uninsurable loss occurs, and it meets defined criteria, then the value of the loss is charged against the balance in the RFID[2].

2.2 Prior to the 2012/13 GRA, the Corporation's RFID had been approved by the Yukon Utilities Board ("Board") and funded through an annual appropriation as approved by the Board. Historically, this amount fluctuated between $50,000 and $150,000 per year.

2.3 A 2010 study commissioned by the Corporation concluded that an annual appropriation of $195,000 per year was appropriate. Pursuant to Board Order 2013-01, the appropriation against the RFID was set to an approved 2013 amount of $0.190 million per year.

3.0 Annual appropriation to the RFID

3.1 Subject to the approval of any increase in the annual appropriation to the RFID by the Board as part of future Yukon Energy General Rate Applications, the RFID will be funded and raised through an approved annual appropriation of $190,000 with no specific limits on surpluses or deficits.

[1] Due to the nature of these losses, the timing and quantum of the loss cannot be forecast accurately. Consequently, an annual appropriate to the reserve is approved in rates. This amount is charged to the reserve and effectively "builds up" the account over time.

[2] This expectation would be that the accumulation of annual appropriations will net out against losses incurred. However, historically, the account tends to go negative (losses exceed accumulated appropriation); at the next GRA, the utility will ask to be made whole for this amount.

4.0 Criteria

4.1 Uninsured and uninsurable losses and associated costs will be charged to the RFID if they meet the following criteria:

(a) The loss exceeds $10,000;
(b) The loss was sudden and accidental and not the result of normal wear and tear;
(c) The incident was of significance to the operation of the unit; and
(d) The loss was one of low probability, not normally expected to occur in a typical operating year.

4.2 The deductible portion of insured losses and any portion of a loss not covered by insurance and not related to betterment of the asset, and any extra expense related to an uninsurable or uninsurable unplanned plant outages[3] will also be charged to the RFID.

[3] For example, the loss of a hydro generating unit may require the utility to burn diesel to meet demand. Unless the utility specifically purchases Extra Expense coverage for this loss, these amounts are uninsured.

TOPIC: **Depreciation Expense under Straight-line Amortization**

REFERENCE: **YUB-YEC-1-118(b) and YUB-YEC-139(a), PDF pages 541, 631**

PREAMBLE: In response to YUB-YEC-118(b) asking for the directional impact to depreciation expense related to the proposed change to a 50-R2 life and curve from the approved 50-R3 life and curve for Account 1625-305 Distribution System – Survey Costs, YEC responded that "There is no change to depreciation as the life has not changed and YEC uses straight-line amortization."

However, in response to YUB-YEC-139(a), YEC implies that, for Account 1665-500 LNG Plant – Generators, using a 40-R2 life and curve in lieu of using the proposed 40-SQ life and curve would "slightly increase the depreciation expense for the 1665-500 account."

QUESTION:

a) Given that YEC uses straight-line depreciation, please explain why no change in depreciation expense would be anticipated for Account 1625-305 (notwithstanding a change in the Iowa curve dispersion from R3 to R2), whereas for Account 1665-500, depreciation expense would increase slightly (as resulting from a change in the Iowa curve dispersion from SQ to R2).

ANSWER:

(a)

Upon further review, the earlier response is amended as reviewed below.

In accordance with International Financial Reporting Standards, as approved by YEC's independent auditors, YEC has two components to its depreciation rate: the whole life rate indicated by the proposed curve for each account and another component that recovers the difference between accumulated depreciation and the calculated depreciation (sometimes called theoretical depreciation reserve). Changing the curve type without changing the life will not change the depreciation expense. However, it is necessary to also recover the difference between the actual and theoretical reserves over the remaining

life of YEC's assets. The remaining life is dependent on both the life and curve so any changes in life or curve (or reserve position) would cause a change in the annual amount related to that recovery. Remaining life is a widely used depreciation system by many regulatory bodies to recover any reserve differences.

For Account 1625-305, the proposed depreciation rate of 2.00% recovers the investment over the remaining life of the facility. The amount (1,361) for that account is necessary to incorporate any reserve difference between per book and calculated accumulated depreciation. Moving the curve from an R3 to an R2 would have the effect of decreasing the remaining life from 40.61 to 39.65 years, and therefore, slightly increasing the annual amount of the recovery of the difference from (1,361) to (1,101).

TOPIC: **2019 Total Firm Generation Load**

REFERENCE: **YUB-YEC-1-9(a), PDF page 15**

QUOTE: "(a) The 2017-18 GRA proceeding did not provide any forecast for 2019 load on the YIS. Aside from YEC internal business plan forecasts, the only public forecast was provided in YEC's 2016 Resource Plan where the forecast total firm generation load on the Yukon Integrated System for 2019 was 443 GW.h, which compared relatively well with the actual 440.7 GW.h."

QUESTION:

a) Please confirm that there was no 2019 forecast because there was no GRA proceeding for 2019.

b) Is it YEC's practice to make "internal business plan forecasts" for business planning purposes for the years in which there is no GRA proceeding? If so, please provide the forecast for YEC's internal business plan. If not, please explain why not.

ANSWER:

(a)

Confirmed.

(b)

Yes. YEC's annual budget for 2019 included a generation forecast of 454 GWh.

TOPIC: **Independent Power Production (IPP)**

REFERENCE: **YUB-YEC-1-10(a), (b), PDF page 16**

QUOTE: "(a) YEC has considerable uncertainty as to timing for forecast IPP amounts for 2021. The first project that was to be operational in November 2020 has been delayed into spring 2021.

(b) We do not know how IPP projects have been affected to date by the COVID-19 pandemic. The IPP did not commence in 2020 as scheduled."

QUESTION:

a) Please explain why YEC did not look into how IPP projects have been affected to date by the COVID-19 pandemic, given the fact that "YEC has considerable uncertainty as to timing for forecast IPP amounts for 2021".

ANSWER:

(a)

The "uncertainty" referenced in YEC's initial response refers to commitments by the IPP proponents that are largely beyond YEC control and pre-date COVID-19. Typically, a proponent will require an executed Electricity Purchase Agreement well in advance of being in-service (Commercial Operations Date – "COD") in order to secure financing and the agreement includes a forecasted COD. All the risks of construction (e.g., supply chain, market restrictions, site condition risk, permitting, etc.) are wholly within the control of the proponent. In YEC's experience, the proponents struggle to meet their commitments and COD tends to delay, without any added COVID-19 issues. YEC has no reasonable means to estimate if these delays will materialize or how long delays can last.

The proponents of the projects provide regular updates of the COD to YEC. The number of updates (and delays) are indicative of the realization of different challenges that arise during the various stages of financing, procurement and construction of the projects. By way of example, the first project that was to be operational in November 2020 and then in

spring 2021 has still yet to be commissioned (current expectation is Q4) for reasons unrelated to YEC.

TOPIC: **Sales for Lighting**

REFERENCE: **YUB-YEC-1-17(a), PDF page 26**

PREAMBLE: **"(a) YEC does not have the level of detail requested. Available information on sales for lighting is below. From project records, YEC notes 429 streetlights were retrofitted from High Pressure Sodium to LED between 2016 and 2018."**

Street Lights		Sentinel Lights		Total		
Year	Sales (MWh)	Number of Lights	Sales (MWh)	Number of Lights	Sales (MWh)	Number of Lights
2010	282.8	576	14.3	25	297	601
2011	283.0	577	13.9	25	297	602
2012	283.1	577	14.0	25	297	602
2013	283.2	578	14.1	25	297	603
2014	286.7	584	14.1	25	301	609
2015	291.8	594	14.3	25	306	619
2016	263.3	604	14.3	27	278	631
2017	228.2	614	11.6	26	240	640
2018	227.0	623	11.2	25	238	648
2019	167.8	632	10.1	23	178	655
2020	167.6	632	9.8	24	177	656

QUESTION:

a) Please confirm that, based on the quote above, including the information in the table, there were still 194 high pressure sodium street lights by the end of 2018. If not confirmed, please explain.

b) Does YEC have an updated number of retrofitted streetlights for 2019-20? If confirmed, please provide the number for each year. If not, please explain.

ANSWER:

(a)

Confirmed.

(b)

YEC does not have an updated count of retrofitted streetlights.

TOPIC: **Thermal Generation Forecast and Weather**

REFERENCE: **YUB-YEC-1-19(b), PDF page 29**

QUOTE: "Mechanical issues include premature wear of valves, failures of exhaust valves, failures of heat exchangers and premature wear of engine block. There was 2.6 GWh of added diesel generation due to LNG outages. The net increase in fuel cost due to burning diesel was $303,160 based on the 2018 approved GRA forecast average fuel costs per kWh for diesel ($0.2633/kWh) and LNG ($0.1467/kWh)." (footnote removed)

QUESTION:

a) Please explain what caused the "premature" wear of valves and engine block.

b) Please explain what caused the failures of exhaust valves and heat exchangers.

ANSWER:

(a)

The block did not experience premature failure. It was replaced as a result the extensive damage caused by the valve failure.

Valve recession is when the valve, or more commonly the valve seat, wears and the valve clearance gradually disappears, allowing gases to escape and burn the valve/seat even more. Valve recession is caused by excessive heat, lack of lubrication, or inferior material. The WG2 valve failure root cause was determined to be inferior material (soft) on the valve seats and the secondary cause was valve cooling.

Cylinder head 18 had an exhaust valve fracture resulting in a subsequent catastrophic failure of this cylinder head releasing coolant into the power cylinder. These components along with the coolant became debris within the power cylinder severely damaging the piston, liner and turbos. This debris was ejected in to both the exhaust and intake manifold resulting in collateral damage to the B bank high- and low-pressure turbo chargers.

The remaining 11 B bank power cylinders and 4 A bank power cylinders (5, 6, 7 and 8) were also damaged by the debris.

(b)

Valve recession is caused by excessive heat, lack of lubrication or inferior material. The WG2 valve failure root cause was determined to be inferior head material (soft) on the valve seats and the secondary cause was valve cooling.

The LNG pressure building coils and vaporizer have experienced premature failure. Root cause was determined to be cracks in tubing welds caused by excessive vibration during operation, resulting in methane leaks into the glycol system. Tubing bundles have been re-designed with no-tube-in-window, impingement plates, thicker tubing and sealing welds. Shells have been redesigned with larger glycol inlet and outlet.

TOPIC: **Dependable Capacity Requirements**

REFERENCE: **YUB-YEC-1-21(a), PDF page 33**

QUOTE: "(a) The loss of load expectation and emergency N-1 standards were first developed as part of the 2006 Resource Plan, and were reconfirmed with the 2016 Resource Plan. YEC is not aware of any basis to seek revisions to these standards at this time. The N-1 dependable capacity standard continues to be very relevant for non-industrial load reliability during winter months on this isolated Yukon grid. Consideration of an N-1 contingency is standard in the industry."

QUESTION:

a) How often does YEC review the loss of load expectation and emergency N-1 standards? Please explain.

ANSWER:

(a)

YEC reviews the loss of load expectation (LOLE) and emergency N-1 standards (N-1), at the time it undertakes development of each Yukon Energy resource plan (based on past practices, and as recommended by the YUB in its January 2007 report on the 2006 Resource Plan, this is undertaken approximately every five years).

As noted in the preamble, these criteria were first developed as part of YEC's 2006 Resource Plan where each system (Whitehorse – Aishihik – Faro [WAF] and Mayo – Dawson [MD]) should not exceed a LOLE of two hours per year and each system (WAF and MD) should be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency. A separate section was provided in the 2011 Resource Plan to reflect updated grid conditions, including interconnection of WAF and MD as well as updated N-1 and LOLE assessments to reflect updated generation capacity. A similar exercise was performed in the 2016 Resource Plan and 10-year Renewable Electricity Plan. YEC periodically assesses the capacity adequacy based on N-1 and

LOLE criteria. However, the LOLE and N-1 planning criteria standards remain the same as reviewed in 2006 Resource Plan [i.e., LOLE of no more than two hours per year].

YEC is not aware of any basis to seek revisions to these standards at this time. YEC relied upon these planning criteria in its most recent 10-Year Renewable Electricity Plan.

TOPIC: **Construction Work in Progress (CWIP) Continuity Schedules for Capital Projects**

REFERENCE: **Application, Tab 5 tables**

PREAMBLE: As part of its application, YEC provided an Excel spreadsheet that outlined the costs for capital projects. There was a total of eight tables in the spreadsheet:

- Table 5.1: Expenditures on Property, Plant and Equipment – Summary
- Table 5.2-1: Expenditures on Property, Plant and Equipment – Projects Included in 2021 Rate Base
- Table 5.2-2: Expenditures on Property, Plant and Equipment – Major Projects Forecast to Remain in WIP by end of 2021
- Table 5.3: Continuity Schedule of Deferred Costs (2018)
- Table 5.4: Continuity Schedule of Deferred Costs (2019)
- Table 5.5: Continuity Schedule of Deferred Costs (2020)
- Table 5.6: Continuity Schedule of Deferred Costs (2021)
- Table 5.7: Continuity Schedule of Intangible Assets

While these tables are associated with all of the capital projects presented in YEC's application, the Board requires consistency in how costs for capital projects are presented. For example, continuity schedules as presented in Tables 5.3 to 5.7 should be consistently applied to all capital projects.

QUESTION:

a) Please provide schedules for all capital projects in this application in the following CWIP continuity format:

	[YEAR] Actual or Forecast or Approved (please complete as applicable for each of 2018, 2019, 2020, and 2021)			
Category of capital project	**Opening CWIP**	**Capital Expenditures**	**Capital Additions**	**Closing CWIP**
Capital Works – Major projects > $1 million – Rate Base Additions *Include each applicable project*				
Capital Works – Projects $100,000 to $1 million *Include each applicable project*				
Deferred Costs – Major projects > $1 million – Rate Base Additions *Include each applicable project*				
Deferred Costs – Projects $100,000 to $1 million *Include each applicable project*				
Intangible Assets – Major projects > $1 million – Rate Base Additions *Include each applicable project*				
Capital Projects > $1 million not impacting rate base *Include each applicable project*				
Capital Projects > $100,000 and < $1 million added to rate base *Include each applicable project*				
Deferred Projects > $1 million not impacting rate base *Include each applicable project*				
Deferred Studies > $100,000 and < $1 million added to rate base *Include each applicable project*				
Deferred Studies > $100,000 and < $1 million not impacting rate base *Include each applicable project*				
Intangible Assets > $100,000 and < $1 million added to rate base *Include each applicable project*				

1

Please ensure that the detail requested is provided in an Excel spreadsheet format with subtotals for each category of project and that it includes all working formulas. As noted in the heading for the requested tables, please provide the actual, forecast, and approved costs. For example, actual and approved for the years 2017 and 2018; actuals for 2019; forecast and actuals for 2020, and forecast for 2021.

ANSWER:

(a)

Continuity schedules for capital projects and deferred costs based on the above categories are provided below. The 2018, 2019 and 2020 schedules are based on actuals, while 2021 is based on current forecast (including updated variances to date since the GRA filing). Please see YUB-YEC-2-17 (a) and (b) for the variance explanations for the projects where 2020 actuals and updated 2021 forecasts vary from the 2021 GRA forecasts.

Please note that the project costs in the tables below are net of contributions, and are allocated to the stipulated categories based on current cost estimates. There are also some projects which were not included in the GRA table but are now included in the tables below as the total cost is above $0.1 million based on information available today [Wareham Spillway Concrete Repair, WG1 Overhaul, WG2 Overhaul].

Table 1: Work in Progress Continuity Schedule for the projects with capital cost over $0.1 million – 2018 ($000)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects – Major projects > $1 million – Rate Base Additions				
Breaker Replacement Program	$111	$1,167	-$798	$479
Mayo to McQuesten Transmission Line Upgrade	$0	$0	$0	$0
McQuesten Substation	$120	$123	$0	$243
N-1 Capacity Shortage Mobile Genset	$0	$227	$0	$227
Replace P125 WH2 Head Gate	$0	$0	$0	$0
N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure	$0	$0	$0	$0
Transmission Line Refurbishment - 2019	$0	$0	$0	$0
WAF L178	$0	$0	$0	$0
WH2 Uprate	$0	$0	$0	$0
WH4 Uprate [Servomotor]	$0	$52	$0	$52
LNG Third Engine / Critical Spares	$3,156	$5,008	-$8,163	$0
MH2 Ten Year Overhaul	$0	$1,645	-$1,645	$0
Transmission Line Refurbishment - 2018	$0	$6,280	-$6,280	$0
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions				
Dam Safety Program	$0	$0	$0	$0
Dam Safety Recommendations 2017/18	$0	$110	$0	$110
P126 LNG Boil-off-gas Heat Exchanger	$0	$0	$0	$0
Wareham Gate Heater	$0	$0	$0	$0
Wareham Gate Refurbishment	$0	$0	$0	$0
Whitehorse Diesel System Grounding for Generators	$0	$39	$0	$39
WH1 and WH2 Design and Install Dewatering System	$0	$0	$0	$0
WH4 Ventilation	$0	$0	$0	$0
L177 Re Route	$0	$0	$0	$0
Protection and Control Program	$0	$0	$0	$0
Transmission Line Access	$0	$215	$0	$215
WAF Transmission Upgrades	$0	$870	-$870	$0
Customer Extensions	$89	$356	-$144	$301
L355 Voltage Regulator	$0	$0	$0	$0
System Improvements for Eagle Gold Mine	$0	$352	$0	$352
Communications Upgrade	$0	$255	-$255	$0
Building Upgrades	$0	$77	-$77	$0
Crane Replacement/Refurbishment	$0	$0	$0	$0
Vehicle Purchases	$0	$209	-$209	$0
Wareham Spillway Concrete Repair	$0	$0	$0	$0
WG1 Overhaul	$0	$0	$0	$0
WG2 Overhaul	$0	$0	$0	$0
Decommission WD3	$0	$0	$0	$0
Decommission WW1	$17	$165	-$182	$0
Site Restoration Transmission Lines	$0	$0	$0	$0
Injuries and Damages Costs	$0	$651	-$651	$0

Table 1: Work in Progress Continuity Schedule for the projects with capital cost over $0.1 million – 2018 ($000) - continued

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Deferred Costs – Major projects > $1 million – Rate Base Additions				
Aishihik Relicensing (Three Year License Renewal)	$0	$0	$0	$0
DSM Program Development	$0	$257	$0	$257
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions				
IPP Standing Offer Program Implementation	$0	$48	$0	$48
Dam Safety Review 2020	$0	$0	$0	$0
Mt Sumanik Wind Feasibility Study	$618	$76	$0	$694
WH2 Uprate Engineering	$0	$208	$0	$208
Business Continuity Plan	$3	$48	-$4	$48
Mayo and Aishihik Climate Change	$305	$170	$0	$474
PMF Flood Study	$0	$0	$0	$0
10 Year Renewable Energy Plan	$0	$0	$0	$0
Atlin Hydro EPA Preparation	$0	$0	$0	$0
General Rate Application 2017-18	$551	$374	$0	$925
Victoria Gold PPA	$97	$29	-$126	$0
Intangible Assets – Major projects > $1 million - Rate Base Additions				
Enterprise Asset Management Purchase and Implementation	$0	$276	$0	$276
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions				
ERP System Upgrades	$0	$0	$0	$0
Capital Projects – Major projects > $1 million – Not impacting Rate Base				
Dawson Voltage Conversion	$0	$0	$0	$0
Stop Log Crane WH Main Spillway	$0	$0	$0	$0
Asset Management Framework	$0	$439	$0	$439
Battery Energy Storage System	$15	$8	$0	$23
Pumped Storage	$0	$0	$0	$0
Whitehorse Interconnection	$0	$0	$0	$0
Aishihik Contract Dispute	$786	$13	$0	$798
Capital Projects – Projects $100,000 to $1 million – Not impacting Rate Base				
Aishihik Control Structure Refurbishment	$0	$103	$0	$103
Deferred Costs – Major projects > $1 million – Not impacting Rate Base				
Aishihik Generating Station Water Use 25 Year License Renewal	$2,974	$1,983	$0	$4,957
Whitehorse Rapids Generating Station Water Use License Renewal	$0	$0	$0	$0
Diesel Retirement Replacement	$5	$36	$0	$41
Southern Lakes Storage	$7,168	$151	$0	$7,319
Mayo Lake Storage Enhancement (including Outlet Channel)	$2,951	$422	$0	$3,373
Deferred Costs – Projects $100,000 to $1 million – Not impacting Rate Base				
General Rate Application 2021	$0	$0	$0	$0
Intangible Assets – Major projects > $1 million – Not impacting Rate Base				
No projects in this category				
Intangible Assets – Projects $100,000 to $1 million – Not impacting Rate Base				
No projects in this category				

Table 2: Work in Progress Continuity Schedule for the projects with capital cost over $0.1 million – 2019 ($000)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects – Major projects > $1 million – Rate Base Additions				
Breaker Replacement Program	479	1,781	-2,260	0
Mayo to McQuesten Transmission Line Upgrade	0	227	0	227
McQuesten Substation	243	11,496	-11,739	0
N-1 Capacity Shortage Mobile Genset	227	1,070	-1,298	0
Replace P125 WH2 Head Gate	0	93	0	93
N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure	0	0	0	0
Transmission Line Refurbishment - 2019	0	4,272	-4,272	0
WAF L178	0	0	0	0
WH2 Uprate	0	3,044	0	3,044
WH4 Uprate [Servomotor]	52	79	0	131
LNG Third Engine / Critical Spares	0	97	-97	0
MH2 Ten Year Overhaul	0	0	0	0
Transmission Line Refurbishment - 2018	0	0	0	0
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions				
Dam Safety Program	0	0	0	0
Dam Safety Recommendations 2017/18	110	272	-308	74
P126 LNG Boil-off-gas Heat Exchanger	0	194	-194	0
Wareham Gate Heater	0	574	-43	531
Wareham Gate Refurbishment	0	0	0	0
Whitehorse Diesel System Grounding for Generators	39	218	0	257
WH1 and WH2 Design and Install Dewatering System	0	137	-137	0
WH4 Ventilation	0	0	0	0
L177 Re Route	0	0	0	0
Protection and Control Program	0	0	0	0
Transmission Line Access	215	324	0	539
WAF Transmission Upgrades	0	793	-793	0
Customer Extensions	301	33	-226	108
L355 Voltage Regulator	0	144	0	144
System Improvements for Eagle Gold Mine	352	487	-839	0
Communications Upgrade	0	801	-801	0
Building Upgrades	0	370	-370	0
Crane Replacement/Refurbishment	0	0	0	0
Vehicle Purchases	0	258	-258	0
Wareham Spillway Concrete Repair	0	0	0	0
WG1 Overhaul	0	87	-87	0
WG2 Overhaul	0	57	-57	0
Decommission WD3	0	999	-999	0
Decommission WW1	0	0	0	0
Site Restoration Transmission Lines	0	174	-174	0
Injuries and Damages Costs	0	62	-62	0

Table 2: Work in Progress Continuity Schedule for the projects with capital cost over $0.1 million – 2019 ($000) – continued

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Deferred Costs – Major projects > $1 million – Rate Base Additions				
Aishihik Relicensing (Three Year License Renewal)	0	805	-805	0
DSM Program Development	257	210	-399	68
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions				
IPP Standing Offer Program Implementation	48	184	0	232
Dam Safety Review 2020	0	0	0	0
Mt Sumanik Wind Feasibility Study	694	31	0	726
WH2 Uprate Engineering	208	44	0	252
Business Continuity Plan	48	27	-75	0
Mayo and Aishihik Climate Change	474	124	0	599
PMF Flood Study	0	0	0	0
10 Year Renewable Energy Plan	0	311	0	311
Atlin Hydro EPA Preparation	0	0	0	0
General Rate Application 2017-18	925	-791	0	134
Victoria Gold PPA	0	0	0	0
Intangible Assets – Major projects > $1 million - Rate Base Additions				
Enterprise Asset Management Purchase and Implementation	276	534	0	809
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions				
ERP System Upgrades	0	0	0	0
Capital Projects – Major projects > $1 million – Not impacting Rate Base				
Dawson Voltage Conversion	0	60	0	60
Stop Log Crane WH Main Spillway	0	0	0	0
Asset Management Framework	439	1,349	0	1,788
Battery Energy Storage System	23	12	0	35
Pumped Storage	0	0	0	0
Whitehorse Interconnection	0	0	0	0
Aishihik Contract Dispute	798	-318	0	480
Capital Projects – Projects $100,000 to $1 million – Not impacting Rate Base				
Aishihik Control Structure Refurbishment	103	45	0	148
Deferred Costs – Major projects > $1 million – Not impacting Rate Base				
Aishihik Generating Station Water Use 25 Year License Renewal	4,957	513	0	5,470
Whitehorse Rapids Generating Station Water Use License Renewal	0	0	0	0
Diesel Retirement Replacement	41	554	0	595
Southern Lakes Storage	7,319	375	0	7,694
Mayo Lake Storage Enhancement	3,373	262	0	3,636
Deferred Costs – Projects $100,000 to $1 million – Not impacting Rate Base				
General Rate Application 2021	0	155	0	155
Intangible Assets – Major projects > $1 million – Not impacting Rate Base				
No projects in this category				
Intangible Assets – Projects $100,000 to $1 million – Not impacting Rate Base				
No projects in this category				

Table 3: Work in Progress Continuity Schedule for the projects with capital cost over $0.1 million – 2020 ($000)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects – Major projects > $1 million – Rate Base Additions				
Breaker Replacement Program	0	0	0	0
Mayo to McQuesten Transmission Line Upgrade	227	4,881	0	5,108
McQuesten Substation	0	0	0	0
N-1 Capacity Shortage Mobile Genset	0	0	0	0
Replace P125 WH2 Head Gate	93	1,958	-1,923	129
N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure	0	2,446	-2,446	0
Transmission Line Refurbishment - 2019	0	39	-39	0
WAF L178	0	0	0	0
WH2 Uprate	3,044	866	0	3,910
WH4 Uprate [Servomotor]	131	254	0	385
LNG Third Engine / Critical Spares	0	0	0	0
MH2 Ten Year Overhaul	0	0	0	0
Transmission Line Refurbishment - 2018	0	0	0	0
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions				
Dam Safety Program	0	0	0	0
Dam Safety Recommendations 2017/18	74	124	-108	90
P126 LNG Boil-off-gas Heat Exchanger	0	0	0	0
Wareham Gate Heater	531	107	-637	0
Wareham Gate Refurbishment	0	146	0	146
Whitehorse Diesel System Grounding for Generators	257	11	-268	0
WH1 and WH2 Design and Install Dewatering System	0	0	0	0
WH4 Ventilation	0	0	0	0
L177 Re Route	0	104	-104	0
Protection and Control Program	0	0	0	0
Transmission Line Access	539	3	0	542
WAF Transmission Upgrades	0	0	0	0
Customer Extensions	108	73	-70	111
L355 Voltage Regulator	144	53	-196	0
System Improvements for Eagle Gold Mine	0	0	0	0
Communications Upgrade	0	0	0	0
Building Upgrades	0	236	-236	0
Crane Replacement/Refurbishment	0	155	-155	0
Vehicle Purchases	0	528	-528	0
Wareham Spillway Concrete Repair	0	192	0	192
WG1 Overhaul	0	125	-125	0
WG2 Overhaul	0	122	-122	0
Decommission WD3	0	0	0	0
Decommission WW1	0	0	0	0
Site Restoration Transmission Lines	0	47	-47	0
Injuries and Damages Costs	0	1,233	-476	757

Table 3: Work in Progress Continuity Schedule for the projects with capital cost over $0.1 million – 2020 ($000) - continued

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Deferred Costs – Major projects > $1 million – Rate Base Additions				
Aishihik Relicensing (Three Year License Renewal)	0	112	-112	0
DSM Program Development	68	92	0	160
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions				
IPP Standing Offer Program Implementation	232	48	0	280
Dam Safety Review 2020	0	174	0	174
Mt Sumanik Wind Feasibility Study	726	25	-751	0
WH2 Uprate Engineering	252	7	0	259
Business Continuity Plan	0	0	0	0
Mayo and Aishihik Climate Change	599	68	-667	0
PMF Flood Study	0	1	0	1
10 Year Renewable Energy Plan	311	323	-634	0
Atlin Hydro EPA Preparation	0	202	0	202
General Rate Application 2017-18	134	-27	-106	0
Victoria Gold PPA	0	0	0	0
Intangible Assets – Major projects > $1 million - Rate Base Additions				
Enterprise Asset Management Purchase and Implementation	809	2,972	0	3,782
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions				
ERP System Upgrades	0	158	-158	0
Capital Projects – Major projects > $1 million – Not impacting Rate Base				
Dawson Voltage Conversion	60	8	0	68
Stop Log Crane WH Main Spillway	0	0	0	0
Asset Management Framework	1,788	1,530	0	3,318
Battery Energy Storage System	35	166	0	201
Pumped Storage	0	0	0	0
Whitehorse Interconnection	0	0	0	0
Aishihik Contract Dispute	480	6	0	487
Capital Projects – Projects $100,000 to $1 million – Not impacting Rate Base				
Aishihik Control Structure Refurbishment	148	4	0	152
Deferred Costs – Major projects > $1 million – Not impacting Rate Base				
Aishihik Generating Station Water Use 25 Year License Renewal	5,470	2,157	0	7,627
Whitehorse Rapids Generating Station Water Use License Renewal	0	0	0	0
Diesel Retirement Replacement	595	476	0	1,071
Southern Lakes Storage	7,694	245	0	7,939
Mayo Lake Storage Enhancement	3,636	425	0	4,061
Deferred Costs – Projects $100,000 to $1 million – Not impacting Rate Base				
General Rate Application 2021	155	866	0	1,021
Intangible Assets – Major projects > $1 million – Not impacting Rate Base				
No projects in this category				
Intangible Assets – Projects $100,000 to $1 million – Not impacting Rate Base				
No projects in this category				

Table 4: Work in Progress Continuity Schedule for the projects with capital cost over $0.1 million – 2021 ($000)

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Capital Projects – Major projects > $1 million – Rate Base Additions				
Breaker Replacement Program	0	0	0	0
Mayo to McQuesten Transmission Line Upgrade	5,108	3,521	-8,628	0
McQuesten Substation	0	0	0	0
N-1 Capacity Shortage Mobile Genset	0	0	0	0
Replace P125 WH2 Head Gate	129	21	-149	0
N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure	0	0	0	0
Transmission Line Refurbishment - 2019	0	0	0	0
WAF L178	0	0	0	0
WH2 Uprate	3,910	8,357	-12,267	0
WH4 Uprate [Servomotor]	385	1,015	-1,400	0
LNG Third Engine / Critical Spares	0	0	0	0
MH2 Ten Year Overhaul	0	0	0	0
Transmission Line Refurbishment - 2018	0	0	0	0
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions				
Dam Safety Program	0	300	-300	0
Dam Safety Recommendations 2017/18	90	0	-90	0
P126 LNG Boil-off-gas Heat Exchanger	0	0	0	0
Wareham Gate Heater	0	0	0	0
Wareham Gate Refurbishment	146	0	-146	0
Whitehorse Diesel System Grounding for Generators	0	0	0	0
WH1 and WH2 Design and Install Dewatering System	0	0	0	0
WH4 Ventilation	0	150	-150	0
L177 Re Route	0	75	0	75
Protection and Control Program	0	125	-125	0
Transmission Line Access	542	0	-542	0
WAF Transmission Upgrades	0	0	0	0
Customer Extensions	111	200	-311	0
L355 Voltage Regulator	0	0	0	0
System Improvements for Eagle Gold Mine	0	0	0	0
Communications Upgrade	0	0	0	0
Building Upgrades	0	0	0	0
Crane Replacement/Refurbishment	0	400	-400	0
Vehicle Purchases	0	482	-482	0
Wareham Spillway Concrete Repair	192	750	-942	0
WG1 Overhaul	0	0	0	0
WG2 Overhaul	0	0	0	0
Decommission WD3	0	0	0	0
Decommission WW1	0			0
Site Restoration Transmission Lines	0	0	0	0
Injuries and Damages Costs	757	680	-1,437	0

Table 4: Work in Progress Continuity Schedule for the projects with capital cost over $0.1 million – 2021 ($000) - continued

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Deferred Costs – Major projects > $1 million – Rate Base Additions				
Aishihik Relicensing (Three Year License Renewal)	0	0	0	0
DSM Program Development	160	120	-280	0
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions				
IPP Standing Offer Program Implementation	280	50	-330	0
Dam Safety Review 2020	174	80	-254	0
Mt Sumanik Wind Feasibility Study	0	0	0	0
WH2 Uprate Engineering	259	0	-259	0
Business Continuity Plan	0	75	-75	0
Mayo and Aishihik Climate Change	0	0	0	0
PMF Flood Study	1	150	-151	0
10 Year Renewable Energy Plan	0	0	0	0
Atlin Hydro EPA Preparation	202	315	-517	0
General Rate Application 2017-18	0	0	0	0
Victoria Gold PPA	0	0	0	0
Intangible Assets – Major projects > $1 million - Rate Base Additions				
Enterprise Asset Management Purchase and Implementation	3,782	875	-4,657	0
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions				
ERP System Upgrades	0	0	0	0
Capital Projects – Major projects > $1 million – Not impacting Rate Base				
Dawson Voltage Conversion	68	0	0	68
Stop Log Crane WH Main Spillway	0	200	0	200
Asset Management Framework	3,318	946	0	4,264
Battery Energy Storage System	201	4,895	0	5,096
Pumped Storage	0	80	0	80
Whitehorse Interconnection	0	2,000	0	2,000
Aishihik Contract Dispute	487	0	0	487
Capital Projects – Projects $100,000 to $1 million – Not impacting Rate Base				
Aishihik Control Structure Refurbishment	152	0	0	152
Deferred Costs – Major projects > $1 million – Not impacting Rate Base				
Aishihik Generating Station Water Use 25 Year License Renewal	7,627	1,855	0	9,482
Whitehorse Rapids Generating Station Water Use License Renewal	0	135	0	135
Diesel Retirement Replacement	1,071	1,420	0	2,491
Southern Lakes Storage	7,939	1,645	0	9,584
Mayo Lake Storage Enhancement	4,061	640	0	4,701
Deferred Costs – Projects $100,000 to $1 million – Not impacting Rate Base				
General Rate Application 2021	1,021	500	0	1,521
Intangible Assets – Major projects > $1 million – Not impacting Rate Base				
No projects in this category				
Intangible Assets – Projects $100,000 to $1 million – Not impacting Rate Base				
No projects in this category				

TOPIC: **Consistent Capital Cost Breakdowns for Capital Projects**

REFERENCE: **YUB-YEC-1-49(a), PDF pages 111, 113; YUB-YEC-1-59(a), (b), PDF pages 274, 275; YUB-YEC-1-63(a), (b), PDF pages 286, 287; YUB-YEC-1-64(c), PDF page 290; YUB-YEC-1-70(c), PDF page 337; YUB-YEC-1-72(a), PDF page 345; YUB-YEC-1-73(a), PDF page 348; YUB-YEC-1-74(a), PDF page 349; YUB-YEC-1-75(a), PDF page 351; YUB-YEC-1-80(a), PDF page 360; YUB-YEC-1-90(a), PDF page 433; YUB-YEC-1-91(a), PDF page 445; YUB-YEC-1-92(b), PDF page 448; YUB-YEC-1-93(b), PDF page 452; YUB-YEC-1-94(b), PDF page 456; YUB-YEC-1-95(d), PDF page 460; YUB-YEC-1-96(a), PDF page 463; and YUB-YEC-1-102(b), PDF page 473.**

QUOTE: **From response to YUB-YEC-1-49(a), PDF page 111:**

Table 1: LNG Third Engine Project Cost Breakdown, $000

	Total Cost
Engineering & Construction Management	473.9
Engine Package & Transportation	5,710.2
Balance of Plant Installation	1,453.1
Commissioning	10.7
Owner Costs	265.2
Spare parts	347.5
Total	**8,261**

Table 2: N-1 Capacity Shortage Whitehorse Thermal Rental Site, $000

	Total Cost
Internal Labour	288.8
Other Internal Costs	18.2
Engineering	30.7
Materials	745.4
Contractors	214.7
Total	**1,298**

Table 3: Transmission Line Refurbishment Project, $000	
	Total Cost
Materials	719.0
L170 Installation Contractor	1,006.1
L171 Installatoin Contractor	1,622.7
Construction Support	923.7
Total	**4,272**

From response to YUB-YEC-1-49(a), PDF page 113:

Table 7: Mayo – McQuesten Transmission Line Upgrade Project, $000				
	2019	**2020**	**2021**	**Total Cost**
Mayo-McQuesten Transmission Line				
Project Mgmt & Owner's Engineer	34	960	63	1,058
Surveying	13	157	43	212
Brushing & Access	0	2,674	0	2,674
Line Construction	87	8,239	2,324	10,650
Internal Costs	20	215	265	500
Subtotal	**154**	**12,245**	**2,695**	**15,094**
STATCOM				
Equipment	73	671	5,718	6,462
Project Mgmt & Owner's Engineer	45	597	709	1,351
Substation Construction	13	2,848	1,642	4,503
Internal Costs	10	226	14	250
First Nations Benefits	205	400	0	605
Subtotal	**347**	**4,741**	**8,083**	**13,171**
Total	**501**	**16,986**	**10,778**	**28,265**
Per 2021 GRA Application	501	20,000	11,200	**31,701**
Variance	0	-3,014	-422	-3,436

From response to YUB-YEC-1-59(a), PDF page 274:

Table 1: Aishihik Generating Station Three-Year Licence Renewal Project Costs

Year	Description	Cost
2019	Compensation-related activities including negotiating compensation with claimants pursuant to the Waters Act and legal support for negotiations	$127,325
2019	Project Management	$125,631
2019	Conducting impact assessment for YESAA Project Proposal	$21,607
2019	Conducting baseline studies and early monitoring in support of development of YESAA Project Proposal and MAMP	$62,144
2019	Assessment and review process activities, including: Development of YESAA Project Proposal, submission of Project Proposal to Designated Office and all activities supporting path through assessment process (e.g. interrogatories), Preparation of Yukon Water Board Application and DFO Fisheries Act Authorizations.	$368,061
2019	Stakeholder Engagement activities, including capacity funding of CAFN for technical review and participation in project activities	$99,704
2019	Accrual of AFUDC	$122
	Total 2019:	**$804,593**
2020	Project Management	$11,445
2020	Assessment and review process activities, including: Yukon Water Board hearing and DFO Fisheries Act Authorizations, activities to complete these processes.	$89,819
2020	Compensation payments under the Yukon Waters Act for the 3-year License Period	$8,700
2020	Accrual of AFUDC	$2,314
	Total 2020:	**$ 112,278**

From response to YUB-YEC-1-59(b), PDF pages 274, 275:

"Breakdown of $832,906 costs spent in 2019:

- $385,009 DSM Program Design.
- $433,612 Residential Demand Response Pilot (gross cost; contributions of $365,315 received and separately noted in Table 5.4).
- $14,285 inCharge maintenance.

… The actual 2020 DSM costs are broken out as follows:

- $571,901 Residential Demand Response Pilot (gross cost; contributions of $488,932 received and recorded as offset to project costs).
- $8,576 HPS light disposal and inCharge admin.
- Total Net Project Cost $91,545.

… The table below provides breakdown for the updated cost for 2021.

Demand Side Management		
DSM Administration	$	25,000
New Program Design Completion	$	300,000
New Program Implementation	$	240,000
Energy Management Tracking	$	-
Peak Smart Pilot (Gross Costs)	$	250,000
Total Gross Project Cost	**$**	**815,000**
Contributions (PeakSmart funding)	*$*	*(215,000)*
Total Net Project Cost	**$**	**600,000**

"

PREAMBLE: In the following IRs related to capital projects, the Board requested YEC to provide a cost breakdown of each applicable project:

- YUB-YEC-1-49(a)
- YUB-YEC-1-59(a), (b)
- YUB-YEC-1-63(a), (b)
- YUB-YEC-1-64(c)
- YUB-YEC-1-70(c)
- YUB-YEC-1-72(a)
- YUB-YEC-1-73(a)
- YUB-YEC-1-74(a)
- YUB-YEC-1-75(a)
- YUB-YEC-1-80(a)
- YUB-YEC-1-90(a)
- YUB-YEC-1-91(a)
- YUB-YEC-1-92(b)
- YUB-YEC-1-93(b)
- YUB-YEC-1-94(b)
- YUB-YEC-1-95(d)
- YUB-YEC-1-96(a), (b)
- YUB-YEC-1-102(b)

The format of these cost breakdowns was not consistent throughout the IR responses, as seen from the quotes above which illustrate the various ways YEC presented the cost breakdown for projects. Additionally, some projects had updated costs that varied from the costs presented in the application. For example, updated costs were

provided for the following projects (as seen in the response to YUB-YEC-1-49 on PDF page 110):

- N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure
- Mayo-McQuesten Transmission Line Upgrade Project
- Replacement of the P125 Head Gate Project
- WH2 Uprate Project
- WH4 Uprate – Servomotor Replacement Project

Another example can be found in the response to YUB-YEC-1-59(b) for the DSM programs on PDF page 275.

The Board requires YEC to present its cost breakdown for the IR responses referenced above in a consistent manner and, if applicable, provide variances where costs now differ from those costs seen in the original application.

QUESTION:

a) Using Table 7: Mayo – McQuesten Transmission Line Upgrade Project as a reference example (for presentation purposes), please provide a cost breakdown for the projects in the IR responses referenced above, identifying the years and the capital amounts for each of those years. If applicable, please ensure that a variance row is included in your updated tables and provide an explanation of the variance. Please use the response to CW-YEC-1-26(b) as a reference for variance explanations.

b) Please explain if there are variances in the costs for any other capital project presented in Tab 5 – Capital Project of the 2021 General Rate Application. If so, please identify and provide explanations of those variances, using the response to CW-YEC-1-26(b) as a reference for variance explanations.

ANSWER:

(a)

The preamble for the question lists 18 Information Requests (IR) from Round 1 IR process. These 18 IRs include 31 projects. Yukon Energy organized the referenced IRs in the preamble consistent with the sections of the GRA application, focusing on projects proposed to be included in 2021 test year rate base.

The following tables and/or cross references to other IR responses provide a more consistent cost breakdown for the projects in the IR responses referenced above, identifying the years and the capital amounts for each of those years. Updated variances with added explanations are provided for each project, where applicable.

In response to the direction to use Table 7 from YUB-YEC-1-49(a) as a reference example for presentation purposes, the cost estimate with detailed breakdown for Mayo – McQuesten Transmission Line Upgrade Project was different than typical cost estimate breakdowns for YEC's other projects because of requirements by the federal government to secure federal funding towards this major capital project. YEC does not use this specific format, or any uniform cost estimate breakdown, for all projects due to differences in project requirements [for example, relicensing project cost breakdown is different than the cost breakdown for construction projects] and magnitude of the projects [the smaller projects do not have the same detailed cost components as large projects]. Therefore, the tables below with cost breakdowns for the projects are not in consistent format – however, additional cost breakdown information is provided in as consistent a manner as possible in the time available.

1. **Major Capital Projects with total cost over $1 Million and proposed to be included into Rate Base.**

- YUB-YEC-1-49(a)[1]
    - LNG Third Engine Project
    - N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure Project

[1] This IR provided cost tables for the 10 projects listed here. The 11th major project with a total cost over $1 million (i.e., the McQuesten Substation Project) was built by VGC Group and transferred to YEC – therefore YEC does not have cost breakdown by activities for this project (net cost to YEC of $0.931 million after VGC Group's asset contribution valued at $10.688 million).

- Transmission Line Refurbishment Project
- Transmission Line Refurbishment – L178 Project
- Breaker Replacement Program Project
- N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure Project
- Mayo – McQuesten Transmission Line Upgrade Project
- Replacement of the P125 Head Gate Project
- WH2 Uprate Project
- WH4 Uprate – Servomotor Replacement Project

The following tables provide updated costs for 2020 and 2021 in the format provided in response to YUB-YEC-1-49 (a) for the five major capital projects that have 2020 and/or 2021 capital expenditures subject to further cost updates, with explanations for the variances. These tables retain the format provided in response to YUB-YEC-1-49 (a) as this is what is available for each project separate from the added contractor details in UCG-YEC-1-34 Revised. There are no changes in costs and cost breakdowns from YUB-YEC-1-49 (a) for the remaining major capital projects that are completed in 2018 and 2019 as provided in YUB-YEC-1-49 (a), and therefore the tables for these other projects are not included below.[2]

[2] The response to UCG-YEC-1-34 Revised c) and d) provides a cost breakdown by year and components that includes costs by major contractors for the 10 major projects included in the response to YUB-YEC-1-49(a). The response also includes the same explanations for updated variances, where applicable, as provided in YUB-YEC-2-17.

Table 1: Mayo – McQuesten Transmission Line Upgrade Project, $000

	2019	2020	2021	Total Cost
Mayo-McQuesten Transmission Line				
Project Mgmt & Owner's Engineer	34	960	259	1,254
Surveying	13	157	43	212
Brushing & Access	0	2,674	0	2,674
Line Construction	87	8,239	2,942	11,268
Internal Costs	20	215	146	381
Subtotal	**154**	**12,245**	**3,390**	**15,789**
STATCOM				
STATCOM Purchase	73	671	5,922	6,666
Project Mgmt & Owner's Engineer	45	597	779	1,421
Substation Construction	13	2,848	1,814	4,675
Internal Costs	10	226	210	446
Surveying & Brushing			16	16
Subtotal	**142**	**4,341**	**8,741**	**13,224**
First Nations Benefits	205	400	1	606
Total before contributions	**501**	**16,986**	**12,132**	**29,619**
Contributions	**-274**	**-12,105**	**-8,611**	**-20,991**
Total after contributions	**227**	**4,881**	**3,521**	**8,628**
Per 2021 GRA Application [before contributions]	501	20,000	11,200	**31,701**
Variance	0	-3,014	932	-2,082
Per 2021 GRA Application [after contributions]	227	5,000	2,800	**8,027**
Variance	0	- 119	721	601

The 2021 forecast cost and contributions are on forecast basis and subject to change.

The Mayo – McQuesten Transmission Line Upgrade Project reflects project actual costs for 2020 and updated 2021 forecast based on information available now. Updated total cost at $29.619 million is $2.082 million lower than the GRA forecast reflecting $3.014 million lower than the forecast costs for 2020 and $0.932 million higher forecast costs for the 2021 test year.

YEC internal cost assessments have been made relative to a budget of $30.317 million ($1.384 million lower than the GRA forecast). The following are noted regarding the cost variances relative to the internal budget:

- Brushing and access road work was completed during Q3 2020. Final actual costs for this work are $0.982 million higher than the forecast. Most of the additional costs were the result of access road construction, as this work wasn't identified in project scope or cost from inception. Extensive hand clearing of riparian areas and additional temporary roads were also required to mobilize equipment around the riparian areas.

- Transmission line construction work is expected to be completed with about $1.992 million below the GRA forecast.

- Budget surpluses are also forecasted for project management, owner's engineers, surveying work and YEC internal costs for transmission line portion of the project.

- During Q4 2020, unknown risks associated with field design and subsoil conditions contributed to a higher cost with about $0.898 million additional cost in substation construction costs and unplanned aggregate supply costs also contributed $0.064 million in overages to the project.

- Additionally, the STATCOM supply and installation contract exceeded the original cost estimates by $1.450 million. Several small design change requests and other costs, such as communication upgrades at the substation have also led to a higher costs increasing the project cost by about $0.216 million.

- Multiple design interface issues also led to increased costs, including project management, owner's engineers and YEC internal costs for STATCOM portion of the project.

- Despite the cost increases relating to substation construction and STATCOM installation, these cost increases are partially covered by contingency and further offset by lower than expected costs for transmission line construction.

- Overall, the project is forecasted to be completed under budget.

Table 2: Transmission Line Refurbishment – L178 Project, $000

	Total Cost 2021
YEC Internal Costs	168.3
Contractors	115.0
AFUDC	17.0
Total	**300.3**
Per 2021 GRA Application	1,300
Variance	-1,000

This project did not proceed in 2021 as forecast in the GRA application. During the procurement process the market price came back much higher than YEC expected. YEC has reduced the project scope for 2021 to $0.3 million to reflect work completed by YEC power line crews, and this cost will be closed in 2021.

Table 3: Replacement of the P125 Head Gate Project, $000

	2019	2020	2021	Total Cost
Engineering, Project Mgmt & Internal Costs	93	94	21	208
Installation Contractor	0	1,865	0	1,865
Total	**93**	**1,958**	**21**	**2,072**
Per 2021 GRA Application	93	2,300	3,500	5,893
Variance	0	-342	-3,479	-3,821

The updated capital spending forecast for 2021 includes only $0.02 million for this project, which is a reduction of approximately $3.5 million from the 2021 GRA forecast. The original scope of the project included work on WH1, WH2 and WH3 headgates with total project cost at $5.893 million, including about $3.5 million in 2021 for WH1 and WH3 headgates.

Yukon Energy completed the replacement of the WH2 headgate in 2020. As part of YEC's annual business planning process, team capacity was assessed and upon completion of the assessment it was determined that the replacement and refurbishment of the gates and related infrastructure for units WH1 and WH3 will be deferred to 2022 and 2023 respectively. Planning is currently underway for the replacement of the WH1

headgate which includes revision of the technical specifications based on learnings from the WH2 headgate replacement, as well as preparation and release of an RFP in advance of the 2022 project.

Table 4: WH2 Uprate Project, $000

	2018	2019	2020	2021	Total Cost
Owner's Engineer		167	213	622	1,002
Turbine & Generator		2,618	114	6,034	8,766
Internal Costs & Project mgmt		228	173	585	986
Balance of plant		32	366	770	1,168
Contingency & AFUDC		0	0	345	345
Subtotal		**3,044**	**866**	**8,357**	**12,267**
Reported under Deferred Costs	208	44	7	0	259
Total	**208**	**3,089**	**873**	**8,357**	**12,526**
2021 GRA Forecast					
Table 5.2-1	0	3,044	1,693	7,300	12,038
Tables 5.3-5.5	208	44	7	0	259
Total	**208**	**3,089**	**1,700**	**7,300**	**12,297**
Variance	0	-0	-827	1,057	230

The 2021 cost breakdown is on forecast basis and subject to change. The total cost of $12.526 million includes $0.259 million reported in the deferred cost tables [please see Table 5.5 in Tab 5 of the Application]. The capital expenditures portion is $12.267 million [$12.526 - $0.259].

The WH2 Uprate Project reflects project actual cost for 2020 which was about $0.827 million lower than the forecast and updated 2021 forecast which is about $1.057 million higher than the forecast in the application resulting in a net project cost increase of $0.230 million.

Once the WH2 unit was disassembled, assessments of both the embedded components as well as the removable components were undertaken. The condition of these components can only be assessed upon completion of disassembly. These assessments revealed in many cases that the condition of the components was worse than originally expected, and these components had to be refurbished as part of the

project ensure proper operation and acceptable service life of the unit. In addition, during this inspection and assessment process certain components of the WH2 unit were found to be misaligned. This discovery resulted in the need for additional machining of several components to bring the items back into proper alignment.

Table 5: WH4 Uprate – Servomotor Replacement Project, $000

	2018	2019	2020	2021	Total Cost
Servomotor supplier	0	0	142	591	733
Owner's Engineer	0	0	47	83	130
Internal Costs & Project Mgmt	52	79	63	136	329
Balance of Plant	0	0	3	205	208
Total	**52**	**79**	**254**	**1,015**	**1,400**
Per 2021 GRA Application	52	79	400	1,000	1,531
Variance	0	0	-146	15	-131

The 2021 forecast cost breakdown is preliminary and subject to changes. It reflects actuals to date and forecast to completion.

WH4 Uprate – Servomotor Replacement Project reflects project actual costs for 2020 which was $0.146 million lower than the forecast and updated forecast for 2021 which is $0.015 million higher than the forecast in the application. Overall, the project is expected to be completed with about $0.131 million lower cost than the forecast in the GRA [mostly due to not used contingency provision].

2. Capital Projects with cost between $100,000 to $1 Million and proposed to be included into Rate Base.

- YUB-YEC-1-74(a)
    - Dam Safety Program Project.
- YUB-YEC-1-75(a)
    - Dam Safety Recommendations 2017-18.

- YUB-YEC-1-80(a)

    - Building Upgrades.

Please see tables below for the available cost breakdowns, project cost updates and explanations for variances from the GRA forecast, where applicable.

Table 6: Dam Safety Program Project

	2021 Total Cost
Warning/danger signage	$50,000
Public safety around Marsh Lake	$150,000
Emergency Preparedness Plan and Operational	$25,000
Canyon Lake control structure repairs	$75,000
Total	**$300,000**
Per 2021 GRA Application	$300,000
Variance	$0

No cost variance from the GRA forecast.

Table 7: Dam Safety Recommendations 2017-18

	2018	2019	2020	Total
Labor	$1,133	$68,169	$42,161	$111,463
Travel Exp	$0	$3,840	$1,141	$4,982
Matetirals, Supplies, Inventory	$0	$5,295	$0	$5,295
Canadian Projects Limited	$8,192	$7,721	$0	$15,913
Challenger Geomatics	$500	$0	$0	$500
Dimensions Tech Services	$2,180	$2,010	$0	$4,190
Dunbrack, Geoff	$428	$860	$0	$1,288
Maven Consulting Limited	$7,030	$74,723	$0	$81,753
Northland Earth & Water Consulting Inc	$20,153	$37,715	$11,400	$69,268
Tetra Tech Canada Inc.	$58,525	$10,385	$522	$69,432
Mobile Maintenance Services	$0	$1,635	$0	$1,635
Peterson, Ashley	$0	$89	$0	$89
R.C. Crane and Construction	$0	$6,280	$0	$6,280
Wilf's Contracting Ltd.	$0	$2,530	$0	$2,530
WSP Canada Inc.	$0	$44,935	$64,537	$109,472
Other	$11,305	$0	$0	$11,305
Rental	$0	$470	$0	$470
Fuel & Util	$70	$224	$0	$294
AFUDC	$203	$5,395	$4,250	$9,847
Total	**$109,720**	**$272,275**	**$124,011**	**$506,006**
Per 2021 GRA Application	$109,720	$272,275	$300,000	$681,995
Variance		$0	-$175,989	-$175,989

For 2020 YEC had planned Mayo Lake wall planking construction work, but with the high water levels the planned work did not occur as no contractors were interested in the work. Therefore, 2020 actuals were lower than the forecast included in the GRA.

Table 8: Building Upgrades

	2018	2019	2020	Total 2018-2020
Labour Cost	$1,815	$4,631	$1,470	$7,915
Travel Expense	$123	$19,717	$93	$19,933
Materials and Supplies		$27,642	$6,887	$34,529
Contractor - Arcan Roofing & Cladding Ltd			$226,458	$226,458
Contractor - Neil Talsma Construction	$28,289			$28,289
Contractor - Dynamic Systems	$34,039			$34,039
Contractor - Canada Flooring		$68,091		$68,091
Contractor - Floor by Floor Contracting		$13,285		$13,285
Contractor - Superior Roofing & Renovations		$20,020		$20,020
Contractor - Ace Electrical		$13,346		$13,346
Contractor - Meerholz Canada		$164,145		$164,145
Contractor - For Hire Plumbing		$36,506		$36,506
Contractor - Other	$12,360			$12,360
Other		$382		$382
AFUDC	$181	$2,166	$1,372	$3,719
Total	**$76,807**	**$369,930**	**$236,280**	**$683,017**
Per 2021 GRA Application	**$76,807**	**$369,930**	**$275,000**	**$721,737**
Variance			-$38,720	-$38,720

The actual costs for the roofing was lower than expected, therefore the actual cost was lower than the forecast cost.

3. Major Deferred Costs with total cost over $1 Million and proposed to be included into Rate Base.

- YUB-YEC-1-59(a), (b)
    - Aishihik Generating Station Three-Year Licence Renewal Project.
    - Demand Side Management Project.

Please see tables below for the available cost breakdowns, project cost updates and explanations for variances from the GRA forecast, where applicable.

Table 9: Aishihik Generating Station Three-Year Licence Renewal Project

Description	2019	2020	Total
Compensation-related activities including negotiating compensation with claimants pursuant to the Waters Act and legal support for negotiations	$127,325		$127,325
Project Management	$125,631	$11,445	$137,076
Conducting impact assessment for YESAA Project Proposal	$21,607		$21,607
Conducting baseline studies and early monitoring in support of development of YESAA Project Proposal and MAMP	$62,144		$62,144
Assessment and review process activities, including: Development of YESAA Project Proposal, submission of Project Proposal to Designated Office and all activities supporting path through assessment process (e.g. interrogatories), Yukon Water Board Application and DFO Fisheries Act Authorizations.	$368,061	$89,819	$457,880
Stakeholder Engagement activities, including capacity funding of CAFN for technical review and participation in project activities	$99,704		$99,704
Compensation payments under the Yukon Waters Act for the 3-year License Period		$8,700	$8,700
Accrual of AFUDC	$122	$2,314	$2,436
Total	**$804,593**	**$112,278**	**$916,872**
2020 Forecast per 2021 GRA Application	**$804,593**	**$200,000**	**$1,004,593**
Variance	$0	-$87,722	-$87,721

No change in project cost details from the information provided in response to YUB-YEC-1-59(a). The actual costs for project management and assessment and review process activities were lower than the initial GRA forecast resulting in lower than forecast actual costs for 2020.

Table 10: Demand Side Management Project

	Total Cost
2019	
DSM Program Design.	$385,009
Residential Demand Response Pilot	$433,612
inCharge maintenance	$14,285
Total before contributions	**$832,906**
Residential Demand Response Pilot contributions	-$365,315
Total Net Cost	**$467,591**
2020	
Residential Demand Response Pilot	$571,901
HPS light disposal and inCharge admin.	$8,576
Total before contributions	**$580,477**
Residential Demand Response Pilot contributions	-$488,932
Total Net Cost	$91,545
2020 Forecast per 2021 GRA Application	**$375,000**
Variance	-$283,455
2021	
DSM Program Development	$335,000
Total before contributions	$335,000
Contributions	-$215,000
Total Net Cost	$120,000
2021 Forecast per 2021 GRA Application	$894,000
Variance	-$774,000

The DSM program design cost in the table of $385,009 for 2019 includes $257,478 spent in 2018; the net spending for 2019 is $127,531. Please see Tables 5.3 and 5.4 in Tab 5.

The original 2020 DSM program work budget was largely completion of updated program design and some initial implementation of programs. Work as forecast in the GRA was originally planned to be initiated by YEC during 2020, based on Yukon Government policy announcements regarding “Our Climate Future: A Yukon strategy for climate change, energy and a green economy.” However, OIC 2021/16 providing direction to the YUB was not issued until February 2021 and YEC therefore did not

undertake the planned DSM program design work in 2020, resulting in a lower actual spending on DSM in 2020 compared to forecast (the only DSM costs in 2020 were related to the demand response pilot and a small amount for administering the inCharge rebate). The GRA forecast 2021 budget was based on implementation of a full suite of DSM programming in 2021, assuming program design was completed in 2020. The lower actual spending in 2020 has shifted the program design to being completed in 2021, with program implementation costs not being forecast until 2022 and later. Accordingly, the updated forecast of $0.120 million is based on completing program design and the costs of the demand response pilot after funding contributions.

4. Deferred Costs with cost between $100,000 to $1 Million and proposed to be included into Rate Base.

- YUB-YEC-1-63(a), (b)
    - Mayo and Aishihik Hydro Climate Change Study.
    - Transmission Access Road Program Study.
- YUB-YEC-1-95(d)
    - IPP Standing Offer Program Implementation.
- YUB-YEC-1-96(a), (b)
    - Mt. Sumanik Wind Feasibility Studies.

Please see tables below for the available cost breakdowns, project cost updates and explanations for variances from the GRA forecast, where applicable.

Table 11: Mayo and Aishihik Hydro Climate Change Study

	2015	2016	2017	2018	2019	2020	Total
Labour	$2,193	$4,221	$23,523	$9,657	$5,315	$2,315	$47,223
Travel	$95	$5	$69	$309	$576		$1,053
Materials			$34	$25,841	$94,203		$120,077
Aasman Brand Communications Inc.						$849	$849
INRS	$15,000	$71,249	$106,663	$88,967		$33,696	$315,575
Yukon University		$26,220	$48,800	$37,500			$112,520
Smith, Douglas Ian					$9,060	$16,725	$25,785
Other	$1,761		$276		$3,111		$5,148
AFUDC	$12	$774	$3,864	$7,283	$11,984	$14,906	$38,822
Total	**$19,061**	**$102,469**	**$183,227**	**$169,556**	**$124,249**	**$68,491**	**$667,053**
Forecast per 2021 GRA Application	**$19,061**	**$102,469**	**$183,227**	**$169,556**	**$124,249**	**$40,000**	**$638,562**
Variance						$28,491	

The additional costs for this project associated with INRS (the contractor who developed forecasting models on Aishihik, Mayo and Yukon River) were made to enhance the long term forecasting ability in the Upper Yukon system and primarily Marsh Lake. The additional scope was added after the budget was set as the importance of this modelling in this system with respect to Climate Change.

Table 12: Transmission Access Road Program Study

	2020	2021
Completion of a desktop GIS study	$87,526	$0
Total cost	**$87,526**	**$0**
Forecast per 2021 GRA Application	**$132,787**	**$200,000**
Variance	-$45,261	-$200,000

The project proposed in the GRA had three phases:

- Phase 1 desktop GIS study.
- The Phase 2 activities will focus on field work to confirm the findings of the desktop study undertaken in Phase 1; and
- Phase 3 includes final reporting to tie the results of desktop GIS study and subsequent field work together.

Phase 1 activities were completed by Tetra Tech in 2020 at a total cost of $87,526. Phase 2 and Phase 3 activities planned for 2021 have been deferred to 2022.

Table 13: IPP Standing Offer Program Implementation

	2018	2019	2020	2021	Total Cost
ATCO Electric Yukon - PO		$154,950			$154,950
DLA Piper (Canada) LLP	$11,066	$24,798	$41,261		$77,124
Teshmont Consultants LP	$36,985				$36,985
AFUDC	$76	$3,636	$6,533		$10,245
Labour			$225		$225
Travel		$529			$529
Orbis Engineering Field Service Ltd.					$0
Forecast for 2021				$50,000	$50,000
Total	**$48,127**	**$183,912**	**$48,018**	**$50,000**	**$330,057**
Forecast per 2021 GRA Application	**$48,127**	**$183,912**	**$0**	**$0**	**$232,039**
Variance	$0	$0	$48,018	$50,000	$98,018

The full scope of the legal work required by both YEC and AEY to develop the Program Rules, the EPA template and all of the other supporting documentation was not known at the time of preparing the budget.

The increased costs came from the legal costs working with AEY's legal team (the first line item in the table) and YEC's legal costs. The objective was to jointly develop the Standing Offer Program which was very technical in nature and required significant discussion and alignment to adapt the BC Hydro model to the Yukon.

Table 14: Mt. Sumanik Wind Feasibility Studies

	2014	2015	2016	2017	2018	2019	2020	Total
Communication		$317	$3,033	$4,209	$1,219	$480	$480	$9,738
Consultants	$11,078	$304,937	$83,785	$26,543		$11,790		$438,132
Subscription: Land permit					$150	$150		$300
YEC internal labour: includes project management and site visits and maintenance	$1,449	$39,217	$31,973	$24,558	$10,319	$1,640	$1,403	$110,558
Propane		$150	$100		$1,751	$270		$2,271
Materials and supplies: Includes Lidar repair		$3,805	$20,766	$7,049	$31,659		$235	$63,514
Shipping: Lidar and equipment for repair					$4,257			$4,257
Other		$16,513	$2,318	$170				$19,002
Travel to site	$57	$4,510	$1,958	$2,072	$12,350	$20	$4,666	$25,633
AFUDC	$22	$3,372	$10,919	$13,304	$14,537	$16,804	$18,221	$77,181
Total	**$12,607**	**$372,821**	**$154,852**	**$77,904**	**$76,242**	**$31,155**	**$25,005**	**$750,587**
Forecast per 2021 GRA Application	**$12,607**	**$372,821**	**$154,852**	**$77,904**	**$76,242**	**$31,155**	**$50,000**	**$775,581**
Variance	$0	$0	$0	$0	$0	$0	-$24,995	-$24,995

The $50,000 was budgeted to purchase a new remote energy supply for the wind monitoring Lidar system on Mt Sumanik. The previous propane generator was causing issues and labour to keep it running. After this budget was put in place it was decided to end our collection of wind Lidar data on Mt Sumanik, as YEC had adequate data from previous years of collection. The $25,000 was spent in 2020 to remove the propane generator and Lidar from Mt Sumanik. This included staff labour, helicopter costs, refurbishment costs to the generator trailer and AFUDC.

5. Intangible Assets with total cost over $1 Million and proposed to be included into Rate Base.

- YUB-YEC-1-64(c)
    - Enterprise Asset Management (EAM) System Purchase and Implementation Project.

Please see table below for the available cost breakdowns, project cost updates and explanations for variances from the GRA forecast.

Table 15: Enterprise Asset Management, $000

	2018-2019*	2020	2021	Total Cost
Labor	$134,317	$244,577	$186,389	$565,283
Travel	$22,749	$56,703	$31,885	$111,337
Materials, Supplies and Inventory	$172	$836,917	$1,033	$838,123
Contractors	$639,021	$1,658,758	$446,459	$2,744,239
Rental	$240	$2,593	$2,150	$4,983
General	$0	$113,473	$0	$113,473
AFUDC	$12,692	$59,339	$42,072	$114,103
Remaining forecast for 2021			$165,012	$165,012
Total	**$809,192**	**$2,972,361**	**$875,000**	**$4,656,552**
Forecast per 2021 GRA Application	$809,192	$3,853,514	$275,000	$4,937,706
Variance	$0	-$881,153	$600,000	-$281,153

* - portion of the expenditures recorded in 2018 and transferred to the project in 2019.

As indicated in response to YUB-YEC-1-64 (c) the variance from the GRA forecast is due to an error in the GRA forecast for this project. The lower expenditures for 2020 reflect shift of some the project costs to 2021.

6. Major Capital Projects with total cost over $1 Million and not impacting the Rate Base in 2021 test year (remain in WIP at end of 2021).

- YUB-YEC-1-70(c)
    - Asset Management Framework Project.
- YUB-YEC-1-72(a)
    - Pumped Storage.
- YUB-YEC-1-73(a)
    - Southern Lakes Transmission Line and Whitehorse Interconnection Projects.

These projects that remain in WIP at the end of 2021 do not impact rates proposed in the 2021 GRA. At this stage the activities and capital costs for these projects are high level estimates and are subject to ongoing and material refinements. For example, as indicated in response to YUB-YEC-1-65, monitoring activities for the Pumped Storage project did not commence in 2020 as originally forecast. Initiation of these activities is contingent on securing federal funding and alignment with First Nations whose Traditional Territories the project is located on. YEC is not able to provide added cost breakdowns or cost updates for these projects at this time, and the forecasts for these WIP-related project costs will not impact the test year 2021 revenue requirement forecast.

7. Major Deferred Costs with total cost over $1 Million and not impacting the Rate Base in 2021 test year (remain in WIP at end of 2021 test year).

- YUB-YEC-1-90(a)
    - Aishihik Generating Station (AGS) Long-Term Water Use Licence Renewal Project.
- YUB-YEC-1-91(a)
    - Whitehorse Generating Station Water Use Licence Renewal Project.
- YUB-YEC-1-92(b)
    - Diesel Retirement Replacement Project.
- YUB-YEC-1-93(b)
    - Southern Lakes Enhanced Storage Project (Marsh Lake Storage Project).
- YUB-YEC-1-94(b)
    - Mayo Lake Storage Enhancement Project.

Similar to the projects noted in #6 above, these deferred projects that remain in WIP at the end of 2021 do not impact rates proposed in the 2021 GRA. No new information is

available for Whitehorse Generating Station Water Use Licence Renewal Project and Diesel Retirement Replacement Project. The other three projects continue to be worked on by YEC with continuing updates expected. YEC is not able to provide useful new cost breakdowns or cost updates for these projects at this time, and the forecasts for these WIP-related project costs will not impact the test year 2021 revenue requirement forecast.

8. Deferred Costs with cost between $100,000 to $1 Million and not impacting the Rate Base in 2021 test year (remain in WIP at end of 2021 test year).

- YUB-YEC-1-102(b)
    - P125 Trashrack Study.

The project costs includes $100,000 for detailed design, $30,000 for project management, and $70,000 for procurement and selection of vendor(s). As noted in response to YUB-YEC-1-65 (a), the projects is now to be completed in 2023 in conjunction with the remaining headgate replacement projects. Synergies with equipment rentals, and a reduction in mob and demob costs is the rationale to postpone the project.

(b)

The following tables provide, for other projects not included in “a” above, updated costs for 2020 based on actual costs as well as updated 2021 forecasts based on information available today. Please note the tables are for only the other projects initially proposed to be included into rate base in this GRA and where the 2020 actual costs and 2021 updated forecasts differ from the 2021 GRA forecast. Updated cost variances are not provided for projects that remain in WIP at the end of 2021 and therefore do not affect the forecast 2021 test year revenue requirement.

There are some projects not included below where actual costs vary from GRA forecast, however, the cost variance is fully recovered through contributions therefore no impact to customers [e.g., Alexco Mobile Substation Connection, Van Gorda Substation).

Capital Projects

Table 1: Wareham Gate Refurbishment, $000

	2018	2019	2020	2021	Total
Updated Cost	$0.0	$0.0	$146.3	$0.0	$146.3
2021 GRA Forecast	$0.0	$0.0	$250.0	$0.0	$250.0
Variance	$0.0	$0.0	-$103.7	$0.0	-$103.7

This project was deferred in 2020 due to the high water conditions in Mayo Lake. Additional work requirements are also identified in the 2020 Dam Safety review after the GRA submission. This project is now expected to be completed in 2022; with one gate being refurbished at this time and the remaining in 2022. The expenditures to date will be closed in 2021.

Table 2: WH4 Ventilation, $000

	2018	2019	2020	2021	Total
Updated Cost	$0.0	$0.0	$0.0	$150.0	$150.0
2021 GRA Forecast	$0.0	$0.0	$0.0	$750.0	$750.0
Variance	$0.0	$0.0	$0.0	-$600.0	-$600.0

The WH4 ventilation project required additional studies in order to determine greater cost certainty. Project construction will now commence in 2022. The expenditures to date will be closed in 2021.

Table 3: L177 Re Route [net of contributions], $000

	2018	2019	2020	2021	Total
Updated Cost	$0.0	$0.0	$103.6	$75.0	$178.6
2021 GRA Forecast	$0.0	$0.0	$105.0	$250.0	$355.0
Variance	$0.0	$0.0	-$1.4	-$175.0	-$176.4

Project was required due to Yukon Government highway upgrades. At the time of funding request the timeline and full scope for the highways work was unclear. Therefore, the forecast was a high-level cost estimate. As the scope became more the cost estimates are refined for 2021.

Table 4: Protection and Control Program, $000

	2018	2019	2020	2021	Total
Updated Cost	$0.0	$0.0	$0.0	$125.0	$125.0
2021 GRA Forecast	$0.0	$0.0	$0.0	$300.0	$300.0
Variance	$0.0	$0.0	$0.0	-$175.0	-$175.0

The scope for the 2021 cost was refined due to overall volume of capital projects.

Table 5: Transmission Line Access, $000

	2018	2019	2020	2021	Total
Updated Cost	$215.4	$323.9	$2.7	$0.0	$541.9
2021 GRA Forecast	$215.4	$323.9	$300.0	$0.0	$839.3
Variance	$0.0	$0.0	-$297.3	$0.0	-$297.3

Scope for 2020 was revised as no accesses were required to be constructed.

Table 6: Mayo Earthworks, $000

	2018	2019	2020	2021	Total
Updated Cost	$0.0	$0.0	$37.9	$50.0	$87.9
2021 GRA Forecast	$0.0	$0.0	$300.0	$0.0	$300.0
Variance	$0.0	$0.0	-$262.1	$50.0	-$212.1

Due to capital budget constraints (overall volume of capital projects), the project scope was refined to address urgent issues at this time. The project will be closed in 2021.

Table 7: New Mobile Office Unit - IT, $000

	2018	2019	2020	2021	Total
Updated Cost	$0.0	$0.0	$0.0	$0.0	$0.0
2021 GRA Forecast	$0.0	$0.0	$0.0	$230.0	$230.0
Variance	$0.0	$0.0	$0.0	-$230.0	-$230.0

The quotes received for the project were too high compared to what YEC had anticipated. Therefore, the project was deferred.

Table 8: Vehicle Purchases, $000

	2018	2019	2020	2021
Updated Cost	$208.9	$257.8	$527.7	$481.8
2021 GRA Forecast	$208.9	$257.8	$476.0	$580.0
Variance	$0.0	$0.0	$51.7	-$98.2

The variances are due to realignment of priority of vehicle replacements [unit #99 engine blew up removing a 2 tonne replacement with a 1/2 tonne].

Table 9: Water Improvement Upgrades, $000

	2018	2019	2020	2021	Total
Updated Cost	$0.0	$0.0	$56.3	$6.8	$63.0
2021 GRA Forecast	$0.0	$0.0	$150.0	$0.0	$150.0
Variance	$0.0	$0.0	-$93.7	$6.8	-$87.0

The scope of work changed after two unsuccessful RFP's. Installation of Grunfoss pumps with variable speed drives and sensors along with PEX pipe replacement assisted with ongoing continued water leaks in existing piping. Only cost in 2021 was missing pressure sensor which could not be sourced in 2020.

Table 10: FD7 Overhaul, $000

	2018	2019	2020	2021	Total
Updated Cost	$0.0	$0.0	$0.0	$0.0	$0.0
2021 GRA Forecast	$0.0	$0.0	$0.0	$580.0	$580.0
Variance	$0.0	$0.0	$0.0	-$580.0	-$580.0

Deferred to 2022 resulting from capital budget prioritization/constraints (overall volume of capital projects).

Table 11: Compact Digger Truck, $000

	2018	2019	2020	2021	Total
Updated Cost	$0.0	$0.0	$0.0	$0.0	$0.0
2021 GRA Forecast	$0.0	$0.0	$0.0	$185.0	$185.0
Variance	$0.0	$0.0	$0.0	-$185.0	-$185.0

The track will not arrive in 2021 and postponed to later years.

Deferred Costs

Table 12: 10-Year Renewable Electricity Plan, $000

	2019	2020	2021	Total
Updated Cost	$310.8	$323.1	$0.0	$634.0
2021 GRA Forecast	$310.8	$402.1	$0.0	$713.0
Variance	$0.0	-$79.0	$0.0	-$79.0

The variance for 2020 was driven by savings in travel/internal labour for meetings held virtually instead of in-person due to COVID-19 restrictions, and savings in the actual costs required to finalize the technical report compared to the estimate.

Table 13: Atlin Hydro EPA Preparation, $000

	2019	2020	2021	Total
Updated Cost		$201.7	$315.0	$516.7
2021 GRA Forecast		$200.0	$0.0	$200.0
Variance	$0.0	$1.7	$315.0	$316.7

Despite having an Agreement-in-Principle, the Project Definition was redone when the Proponent hired new engineers (SNC Lavalin) which impacted the project economics and the operating regime of the plant. The delay and additional costs are due to the significant work required to collaborate on the technical information and the impact on developing a pricing regime for both capacity and energy that is bounded by the avoided cost of thermal.

Table 14: Dam Safety Review, $000

	2019	2020	2021	Total
Updated Cost		$173.6	$80.0	$253.6
2021 GRA Forecast		$315.0	$0.0	$315.0
Variance	$0.0	-$141.4	$80.0	-$61.4

There is a shift of some work to 2021. The updated forecast is expected to be lower than the initial forecast as uncertainties in the initial forecast are firmed up as work progressed.

Table 15: Building Condition Reports 2021-2024, $000

	2019	2020	2021	Total
Updated Cost			$0.0	$0.0
2021 GRA Forecast			$175.0	$175.0
Variance	$0.0	$0.0	-$175.0	-$175.0

Deferred to 2022 resulting from capital budget prioritization/constraints (overall volume of capital projects).

Table 16: Whitehorse Diesel Rental Substation Improvements, $000

	2019	2020	2021	Total
Updated Cost			$0.0	$0.0
2021 GRA Forecast			$100.0	$100.0
Variance	$0.0	$0.0	-$100.0	-$100.0

Deferred to 2022 resulting from capital budget prioritization/constraints (overall volume of capital projects).

TOPIC: **Mayo-McQuesten Transmission Line Upgrade Project**

REFERENCE: **YUB-YEC-1-51(b), (c), and (e); (d); (f), (g), and (h); (i); PDF pages 121 - 128**

QUOTES: **From response to YUB-YEC-1-51(b), (c), and (e), PDF pages 121, 122:** "[A] new line from Mayo to the Keno City region is required at this time to replace the end of life existing 69 kV line constructed in the 1950's. This line is in poor condition and there has been a significant degradation in reliability. This was reviewed previously during the 2017 VGC Group PPA proceeding and the 2017/18 GRA, and is also supported by data collected from inspections." (footnote removed)

From the response to YUB-YEC-1-51(b), (c), and (e), PDF page 122: "In the early 1990s, Yukon Energy noted that the line was significantly deteriorated and needed to be rebuilt or abandoned due to safety and reliability concerns; however, at the time a rebuild could not be justified due to the closure of UKHM. As an alternative, minimal capital improvements were undertaken at that time to maintain the line and ensure continued service to existing non-industrial customers; and over the past 15+ years transmission line repairs have been required on an ongoing basis to address reliability concerns." (footnotes removed)

From the response to YUB-YEC-1-51(b), (c), and (e), PDF page 122: "Further, in 2011, 35% (or 188 of 535) of the structures on L250 failed the test…"

From the response to YUB-YEC-1-51 (b), (c), and (e), PDF page 123:
"See Table 1 for a summary of the outages from 2011 to 2020 mid-year. Total cost to respond to outages (planned and unplanned) are about $320,900 (2012 to date) with an average annual cost of roughly $35,655. Additionally, capital investment in this line over the same period totaled $963,700."

From the response to YUB-YEC-1-51(d), PDF page 124:
"YEC explored three alternatives: the STATCOM (Static synchronous compensator); SVC (static VAR compensator); and the synchronous condenser.

The synchronous condenser was proposed as the best solution as it provided reactive power support while also being able to recover the system frequency with excursions below 64Hz in a large load loss such as Eagle Gold Mine. However, due to the associated costs the STATCOM was chosen as a compromise as its more responsive than the SVC solution."

From the response to YUB-YEC-1-51(d), Table 2 - Stewart Crossing Potential FACTS Solutions, PDF page 124:
"[SVC] is fading in popularity. A STATCOM would be the preferred solution for reactive power support."

From the response to YUB-YEC-1-51(f), (g) and (h), PDF pages 125, 126: "The decision to complete the design of the project using a 138 kV standard was made in March 2017 as a result of completion of the detailed design of the powerlines and substations and comparative pricing using 138 and 69 kV design standards. Table 3 below provides a cost comparison. Cost reductions shown in Table 3 are in comparison with the 138 kV H-frame design. For L180 line the cost reduction to use a 69 kV design compared to 138 k [sic] was less than 10% (between 3.8% and 9.4%).

The decision to utilize a 138 H-frame design was based on the following factors…"

From the response to YUB-YEC-1-51(f), (g) and (h), PDF page 127:
"Once the line is in service, reliability will be tracked."

From the response to YUB-YEC-1-51(i), PDF page 128:
"Contractors were selected through a competitive RFP process. Each of the contacts were evaluated based on technical ability, price and the ability to provide FN opportunities. Once the evaluation process was

completed and successful bidder selected based on total score, contract negotiations began, were finalized and signed.

The L180 Transmission line will be completed and fully energized in March 2021. Upon energization of the new line, the old 69kV line will be decommissioned /removed with an anticipated end date of April 2021."

QUESTION:

a) Please provide a summary of the relief requested, reasons for the request, and the relief granted in the VGC Group PPA proceeding and the 2017/18 GRA around the existing line between Mayo and Keno City.

b) Please explain further why a rebuild could not be justified due to the closure of UKHM. How did the closure of UKHM impact the line rebuild?

c) Please describe the minimal capital improvements undertaken to maintain the line between Mayo and Keno City when a rebuild could not be undertaken.

d) In its responses to the Board's IRs referenced above, YEC quoted a passage from the Steward-Keno Transmission Line Project Proposal filed with YESAB in 2015. The passage mentioned 35 per cent of the structures on L250 failing a test. Please clarify which test was performed on L250.

e) YEC provided the number and duration of outages from 2011 to 2020 on the line between Mayo and Keno City. In 2014 and 2015, the total number of outage hours was 126.24 and 105.1 hours respectively. Please provide further details on the outages that occurred in these two years and the reasons for the outage hours.

f) (Please indicate whether any portion of the costs incurred due to outages and capital investments on the line have been approved by the Board in previous GRAs. If confirmed, please identify the applicable Board decisions and paragraph numbers of those decisions.

g) YEC provided the alternatives for reactive power support and the associated budgetary costs in Table 2: Stewart Crossing Potential FACTS Solutions. Please

explain why the costs associated with the synchronous condenser are higher compared to the other two alternatives.

h) Please explain how much more responsive the STATCOM solution is compared to the SVC solution (i.e., how many seconds faster is STATCOM compared to SVC?) Additionally, please explain why SVC is fading in popularity and identify any other benefits of STATCOM compared to SVC. How much more effectively will STATCOM provide reactive power support on the Yukon Integrated System compared to SVC?

i) As seen on Table 3: Preliminary Cost Estimates SKTP (or PDF page 125 of the response), for the L180 line, the estimated cost of the 138-kV Mono Pole option was $11,392,153.10, whereas the estimated cost of the 138-kV H-Frame option was $12,117,969.81. In its responses to the Board's IRs, YEC indicated that the H-Frame option was preferred. Please explain why this option, which appears more expensive, was preferred over the Mono Pole option.

j) YEC mentioned that once the new line is in service, reliability will be tracked. Please explain how often YEC plans to track the reliability of this new line.

k) YEC advised that it followed a competitive RFP process. Regarding costs for contractors for the project:
   i) Does YEC have a policy for competitive RFP processes? If confirmed, please provide a copy of the policy.
   ii) Please confirm that the competitive RFP process used was compliant with YEC procurement policies.
   iii) How many contractors bid in the competitive RFP process?
   iv) Can YEC confirm that the contractor chosen was the lowest cost bid? If not confirmed, please explain.
   v) Please indicate where the contractors' costs are located in the cost breakdown of this project, as presented in Table 7 on PDF page 113 of YEC's response to YUB-YEC-1-49. For example, are the costs for contractors located under the "Project Mgmt & Owner's Engineer" line item?

l) Please confirm that the L180 transmission line is now completed and fully energized and that the old 69kV transmission line has been decommissioned and salvaged.

ANSWER:

(a)

Other than the need (for reasons noted in the references quoted for this IR) to replace the existing line between Mayo and McQuesten with the new transmission now completed, Yukon Energy has not requested relief in this application nor is it aware of any relief being granted by the Board in any previous proceeding in relation to the existing line between Mayo and Keno City.

(b)

In the absence of an industrial customer, there are very few customers connected to this line[1]; at the time, Yukon Energy concluded service levels could be maintained with the existing line, thus avoiding many millions of dollars of rate base additions to replace the line. Line rebuild has been viewed as requiring restoration of industrial loads to be served in this area. Yukon Energy maintained the existing line after the UKHM closure to protect the opportunity to provide renewable energy to any such new industrial loads.

(c)

Minimal capital improvements included structure replacement where it was determined that line failure was occurring or imminently would occur.

When YEC became aware of the possibility of a new mine near McQuesten, capital improvements were focused on the line between McQuesten and Keno as it was assumed any new mine would require a rebuild of this first segment of line. As well, it was generally known that the power line condition was at its worst condition where it crossed Galena Hill (between McQuesten and Keno).

[1] YEC's Stewart-Keno City Transmission Project YESAA Project Proposal Chapter 6, Page 6-3 Footnote 1 noted that there are approximately 23 non-industrial customers currently connected to the line between Mayo and Keno City (L250).

(d)

The test performed was part of YEC's test and treat program; qualified contractors perform a series of tests (sample boreholes, inspection of insect activity or voids, soundings, etc.) that lead them to a conclusion based on life expectancy of the structure.

(e)

Please note there is an error in the response to YUB-YEC-1-51 (b), (c) & (e); in Table 1, YEC reported 2015 outage hours at 105.10. one unplanned outage (lightning) for 24 hours was mistakenly recorded twice. The figures below reflect the corrected total of 81.1.

Outage Reason Code	2014	2015
Scheduled Outage	122.09	8.16
Wet Snow	0.76	16.41
Defective Equipment	3.07	32.22
Lightning	0.02	24.00
Extreme Wind	0.23	0.00
Icing	0.04	0.09
Tree contact	0.00	0.20
Customer Requested	0.00	0.03
Unknown	0.04	0.00

(f)

YEC does not specifically budget for outage costs. Capital improvements to this line are included in all previous applications. In some cases, the annual capital amounts are not separately disclosed based on materiality and, to YEC's knowledge, the YUB has never explicitly approved any small capital expenditures in any of its applications. As reported in YUB-YEC-1-51, Yukon Energy has spent approximately $321,000 in capital improvements since 2011. All of these costs were previously approved by the YUB in previous proceedings, excluding $54,000 spent in 2018 and included in this application in Tab 5, Table 5.2-1, Transmission, Other projects under $100K.

(g)

In early 2019, ATCO polled vendors of synchronous condensers on behalf of YEC for budgetary estimates for a +15/-7.5 MVAr machine and associated transformers, equipment, and enclosures. The configuration of a condenser is that of a generating facility less the prime mover. The condenser machine requires cooling, controls, lubricating systems, and the ability or operate within a -60C to +40C ambient temperature range. A detailed list of SC components is provided in response to “h” below. Vendor responses were in the $10M+ range for an installation at Stewart Crossing South or 150% of the cost of an equivalent STATCOM.

A proposal from GE Grid Solutions is provided as Attachment 1 to this response and is typical of the vendor responses.

(h)

The response time of a STATCOM is less than one cycle (16 milliseconds). SVC response times are 1 to 1.5 cycles (16-24 milliseconds). While the difference may appear insignificant, the 8 millisecond delay in SVC response provides less operating margin with other protection and control systems (with a 2-3 cycle response times). Should these other systems operate, unnecessary circuit breaker operation and the interruption of customer load would occur.

A STATCOM is a voltage source converter and provides better reactive power support at low grid voltages than an SVC as the maximum reactive current output of a STATCOM is not affected. The SVC's reactive output is proportional to the square of the grid voltage magnitude and the provided reactive power decreases rapidly when voltage decreases, thus reducing the SVC’s stability.

SVC’s emit power system harmonics from point on wave thyristor switching that may require the addition of harmonic filters. STATCOM’s do not require harmonic filters. Thus, the footprint of the SVC is larger, and the installation has more high voltage apparatus. STATCOM’s sized for the Stewart Crossing application are housed in a 40 foot container type building.

Recent procurement of a static VAr solution by ATCO in northern Alberta saw SVC pricing for a +/-50 MVAr system at 110-120% of an equivalent STATCOM. The pricing difference

in that application was due to increased footprint, foundations, and harmonic filters. The STATCOM alternative was chosen in that instance.

For the Stewart Crossing South application, the equivalent pricing of the STATCOM when compared to an SVC along with faster response and reduced construction effort were the deciding factors when choosing a STATCOM over an SVC.

Synchronous Condenser vs STATCOM Comparison

Synchronous Condenser

- Unloaded synchronous generator that provides reactive power (inductive and capacitive) to a network by way of changing its field excitation.
- Major machine components consist of the following:
    - Stator
    - Rotor
    - Exciter
    - Liquid cooling system with outdoor heat exchanger
    - Lubrication oil injection system
    - Pony motor for start-up
    - Variable frequency drives
    - Controls
    - Housing for stator, rotor, exciter etc.
- Detailed engineering relating to integration of mechanical systems.
- Large footprint to accommodate above components.
- Foundation requirements onerous for the weight of the machines.
- Maintenance component due to machines is significant during ongoing operation.
- Due to inertia of moving parts, response to system events is within the seconds time frame, however the stored kinetic energy of the rotating machine will contribute to the total stability of the network in terms of frequency for example.

STATCOM

- Static Synchronous Compensator
- No moving parts; consists of semiconductors, such as IGCTs (Integrated Gate-Commutated Thyristor) in the case of the YEC installation, that have controlled turn on and turn off capability to sequentially switch in and out pre-charged capacitor elements within voltage source control modules to synthesize an AC voltage waveform connecting to a transmission or distribution network. If the

resulting transformed STATCOM voltage is larger than the grid voltage, this is a capacitive mode, and reactive power is transferred to the network. If lower, this is an inductive mode and reactive power is absorbed from the network.

- Response time to support the reactive power needs of the network in the event of large voltage sags or swells due to transient event.
- Main components of STATCOM:
  - Converter modules consisting of IGCTs and capacitor elements
  - Cooling system, with outdoor heat exchanger
  - Controls
  - Container houses all STATCOM components except outdoor heat exchanger
- Sub cycle response to transient events on system.
- Very low footprint.
- Foundation requirements greatly reduced compared to that of synch condenser.
- Maintenance during ongoing operation involves primarily the cooling system.

STATCOM vs SVC

SVC

- Main components are thyristor-controlled reactor (TCR) and, in some cases, thyristor switched capacitor (TSC).
- Reactive power controlled by switching in a reactor connected to the transmission system through a step-up transformer via turn on of thyristors at point of wave of the AC voltage.
- Thyristors can only be controlled to switch on by firing pulse and naturally turn off during reverse cycle of AC voltage. Hence, to control both halves of AC waveform, thyristors in a “back-to-back “configuration are required.
- The point on wave switching controls the amount of time during the cycle that the reactor is on and hence, the level of reactive power (inductive) for the network.
- The point on wave switching creates harmonics (characteristically 5th and 7th) that require filtering. The filter banks must be on continuously and hence are a source of capacitive reactive power at 60Hz that must be compensated for by the level of inductive power from the TCR. Often, no additional TSC required to provide the capacitive output of the SVC as the filter output, compensated by the TCR, is of a sufficient level to meet the requirement at the location.
- Response time to system transients is 1-1/2 cycles.

- To achieve reactive power ratings, either both TSC and TCR components are required or large reactor ratings if TCR only is used, to offset capacitive output of filter banks.
- Structural and civil designs more involved for yard components and foundations.

STATCOM

- As described above, consists of IGCTs (Integrated Gate-Commutated Thyristor) in the case of the YEC installation, that have controlled turn on and turn off capability to sequentially switch in and out pre-charged capacitor elements within voltage source control modules to synthesize an AC voltage waveform connecting to a transmission or distribution network. If the resulting transformed STATCOM voltage is larger than the grid voltage, this is a capacitive mode, and reactive power is transferred to the network. If lower, this is an inductive mode and reactive power is absorbed from the network.
- The AC waveform is synthesized as opposed to controlled by switching during a point on the system voltage half cycle and hence no harmonics created and no requirement of filter banks.
- Footprints and capital costs greatly reduced in comparison to SVCs because filter banks, and large components such as reactor and capacitor banks as in the case of TCR and TSC configurations respectively, not required. This is especially the case if a containerized solution is applicable.
- Response time to system transients is sub cycle.

Additional Advantages of STATCOM Over Traditional SVC

- STATCOM provides inherent symmetry of capacitive and inductive output.
- Higher overload capabilities.
- Cooling system simplified over the case of a TCR/TSC combined SVC where separate cooling loops are required for each.
- Reactive power output of conventional SVC varies as the square of system voltage at point of connection whereas STATCOM output is linear.

(i)

The H-frame option was preferred for the following reasons:

1. H-frame structures are more robust than a single mono pole structure. YEC has an issue with "conductor slapping" resulting from ice buildup, high winds and

existing monopole structures having tighter clearances between conductors. Clearances between conductors are greater with H-frame structures and will result in less "conductor slapping" related outages.

2. YEC has a 138kV standard that was developed prior to the MMTP. YEC's entire 138kV system backbone is comprised if H-frame structures. As a result, YEC has standardized on components resulting in better management of spares. Furthermore, YEC powerline technicians are familiar with the existing structures which is beneficial from both a safety and efficiency perspective.

(j)

Yukon Energy tracks reliability continuously. The new line has a separate designation (L180) and outages are reported in quarterly reports to the YUB as previous directed.

(k)

(i)

Confirmed, see attached.

(ii)

Confirmed.

(iii), (iv) & (v)

See table below.

Contract Description	# Bidders	Lowest Bid (Yes/No)	Table 7 Line Reference
MMTP			
- Transmission Line Construction	5	Yes	Line Construction
- Centre Line Survey	3	Yes	Surveying
- Project Management Services (2)	5	Yes	Project Management & Owners Engineer
- Owners Engineer	8	No (1)	Project Management & Owners Engineer
- Access Road Construction	2	Yes	Brushing & Access
- Brushing	3	Yes	Brushing & Access
STATCOM			
- Supply, deliver, install – STATCOM	6	Yes	Equipment
- Substation EPC Services	4	Yes	Substation Construction
- Project Management Services (2)	5	Yes	Project Management & Owners Engineer
- Owners Engineer	6	No (1)	Project Management & Owners Engineer

Notes:

(1) Pricing was 30% of evaluation criteria scoring; higher score on technical attributes (70%) offset slightly higher pricing.

(2) Note project management services for both transmission line and STATCOM install were tendered and awarded under one RFP.

(I)

Confirmed.

GE
Grid Solutions

GE Budget Letter

January 21, 2019

4200 Wildwood Pkwy
Atlanta, GA 30339

To: Mark Mielke P.Eng
Senior Manager HVDC & FACTS
Electricity Transmission & Distribution
ATCO
10035-105 St
Edmonton AB Canada T5J 2V6

RE: Yukon Electric Stewart Crossing Synchronous Condenser
GE Budgetary Estimate No. OP17061097988

Dear Mark:

GE is pleased to provide this budgetary estimate for the Stewart Crossing Synchronous Condenser. An estimate is included for a +15/-7.5 MVAR Synchronous Condenser. We will provide budget numbers for the additional options and the information requested in your RFI in January.

This estimate is based on GE providing Synchronous Condenser equipment, engineering, and installation services, testing, and commissioning as follows for each unit:

1. GE will furnish the following synchronous condenser equipment:
   - GE Synchronous Condensers per above, with brushless excitation
   - Main Terminal Box (line side) and Neutral Terminal Box per machine
   - Embedded RTD temperature detectors in the stator windings
   - One (1) GE EX2100e Brushless Regulator, Warm Back-up (redundant) per machine
   - One (1) Lubrication system per machine with two AC Pumps one DC Pump , single oil-to-water cooler
   - One (1) Lot High pressure lift oil pumps per machine (used during starting)
   - One (1) Starting variable speed drive and pony motor or static start system depending upon the design
   - One (1) Machine Neutral Grounding Package
2. GE will furnish the following auxiliary equipment:
   - One (1) Generator Circuit Breaker
   - One (1) Auxiliary Power Transformer
   - One (1) Lot of outdoor coolers.
   - One (1) Lot Cooling water pump skid(s) with redundant pumps and accessories
   - One (1) Lot of redundant GE Mark VIe controls.

- SCADA, HMI, and DFR equipment
- One (1) Lot Redundant Protective Relaying covering from the Transformer HV terminals through the machine
- One (1) 480 V Motor Control Center(s)
- One (1) Lot Special Tools and Spare Parts
- One (1) Lot of conductors, raceways, ground grid that start and terminate within the GE scope
- 125 VDC power (batteries and chargers) equipment

3. Supply of the following equipment is not included, but can be added:
   - One (1) Step-up Transformer(s) to 138 kV.
   - All work outside of the GE footprint
   - Foundations for GE equipment
4. GE will provide the following engineering services:
   - Control Engineering
   - System Studies and Engineering
   - Design Engineering
5. GE will provide the following site services:
   - The building to enclose the synchronous condenser and auxiliary equipment compliant with the National Building code of Canada
   - Site construction and installation of GE equipment
   - Technical Advisory Services during equipment assembly and erection
   - Testing and commissioning of the GE supplied equipment
6. Comments / Clarifications:
   - Delivery to the site is included for all equipment. GE assumes that all roads and bridges are suitable for heavy hauling of the synchronous condenser(s) and transformer(s) to the project site.
   - Site conditions assume the following. Additional clarification may be provided later.
     - GE shall not be liable for any latent or pre-existing subsurface conditions that have an impact on price or schedule and adjustments to design, price and schedule will be made accordingly.

GE's understands that others will provide:

- Generator Step-Up Transformer (GSUT) and all 138kV equipment
- All access roads suitable to transport the synchronous condenser

GE
Grid Solutions

- All site preparation, ground grids, lighting, gravel, fencing, etc. suitable for the synchronous condenser.

This budgetary proposal is based on GE 2019 price levels.

For the scope of work outlined herein we suggest that you establish the following budget:

Single +15/-7.5 Mvar Synchronous Condenser:

$10,640,000 CAD

Two +15/-7.5 Mvar Synchronous Condensers in same building:

$19,950,000 CAD

The price does not include any taxes.

This is a budgetary proposal and all prices are subject to change. The performance of any work hereunder, including the sale/license of any products and services, shall be expressly conditioned upon and subject to the parties reaching a mutual written agreement on the terms and conditions applicable to the work. GE shall have no obligations hereunder unless and until such terms and conditions are specifically agreed to in writing by GE.

The foregoing is intended only to assist you in your budget planning and does not constitute a firm quotation on our part. Construction services are not included in this budgetary estimate but if they would be required, a site walkthrough must be conducted with potential contractors before a firm price proposal could be offered. We do, however, request and look forward to the further opportunity of submitting a firm offering when your plans have been finalized.

Sincerely,

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YUKON ENERGY	FINANCE POLICY FA-009	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Finance	Purchasing Policy
		ISSUED:	REVIEW DATE:	APPROVED BY:
		September 2006	August 2009	President & CEO

1.00 Purpose

1.01 To control, manage and provide guidance to the various departments in the procurement of goods and services and to obtain optimum economic benefit for the corporation. These goals will be achieved through the promotion of ethical business practices, application of appropriate purchasing techniques and compliance with all applicable legislation.

1.02 All purchasing activities will be executed in a confidential and timely manner with all legal, safety and risk management issues addressed.

2.00 Principles

2.01 To promote ethical business practices accessibility and openness (as appropriate) throughout the purchasing process.

2.02 To promote favorable vendor and department relationships with the goal of long-term partnerships that achieves mutual long-term value.

2.03 To promote competitive bidding practices, when possible, while ensuring that vendors are provided an equal opportunity to offer their goods and services.

2.04 To promote and encourage the appropriate use of specific criteria and financial thresholds to determine the level of competition for the supply of goods and services. Under certain circumstances, non-competitive purchases may be justified.

2.05 To promote and ensure that evaluation criteria and standards used to evaluate bids and proposals are fully and clearly described in "Request" documents, and that only those evaluation criteria are used to evaluate any bids or proposals received.

2.06 To promote standardization where possible, to enable cost effectiveness through the volume amalgamation, and reduced support and maintenance costs.

2.07 Promote consistency of quality and added value in all purchases.

3.00 Policy

3.01 Corporate Services solicits competitive bids and makes the final award for purchases. All requesters are consulted on a purchasing partnership basis, as required, before any awards are made.

3.02 Corporate Services will make best efforts to purchase and/or contract for goods and services in the community in which they are used, to the extent that doing so reasonably conforms to the objectives of Yukon Energy's Corporate Purchasing Guidelines, and to the extent that their needs can be met by community-based businesses.

3.03 Corporate Services requests pricing, product and market information through various "Request" documents.

3.04 All pricing and supplier information received will be kept confidential unless specified in the bid and in the case of the formal public bid process.

3.05 All purchases are made on credit terms (wherever possible) using a variety of methods such as: Contracts, Purchase Order, Corporate Procurement Cards, Local Purchase Orders, Standing Agreement etc.

3.06 The Corporation will only honor purchases issued by Corporate Services or properly authorized delegated purchasing authorities.

3.07 a) The President & CEO may waive any provision of this policy when it would be in the best interest of Yukon Energy to do so.

b) Directors may award non-competitive contracts up to a maximum value of $25,000.00. The President & CEO must approve all other non-competitive contracts. The criteria as set out in the Non-Competitive Guideline (GS-005) shall be adhered to.

c) In all other cases, competitive bidding will be applied as follows:

Purchase Value Threshold	***Competitive Bid Application***
Up to $5,000	Competitive bids **not** required; delegated purchasing/ contracting authorities may enter into a Purchasing Agreement (minor works contract, Consulting Contract, Purchase Order, LOP, Visa, Standing Agreement, etc.)
$5,001 to $25,000	Competitive bids required – a minimum of two (2) phone vendor quotations are required.
$25,001 to $50,000	Competitive bids required – a minimum of three (3) written vendor quotations are required
$50,001 to $100,000	Competitive bids required – Corporate Services solicits bids from a minimum of three vendors.
More than $100,000	Competitive bids required – Corporate Services releases a public bid where any number of vendors can compete. A minimum of three vendors must be invited.

4.00 Roles and Responsibilities

4.01 Corporate Services:

Corporate Services has the responsibility for the overall administration and performance of purchasing, bidding, tendering and contract awards and ensures adherence to Yukon Energy's purchasing policies and guidelines.

- Ensures that all vendor and cost information is kept confidential and not released to any other vendor, party or other employee unless specified in the bid;
- Oversees the procurement of goods and services;
- Develops and prepares purchasing documents such as: bids, tenders, addendums, evaluations, awards, contracts, amendments, etc.;
- Coordinates the evaluation of the bids in accordance with pre-established evaluation criteria. If necessary, arranges and coordinate vendor interviews and structures the process and evaluative selection methodology;
- Performs due diligence (i.e. legal, safety and risk management);
- Participates in the evaluation, supplier interviews or any other evaluative methodology used in determining the successful supplier;
- Awards, issues, receives and manages all Purchase Orders for non-stock items;
- Maintains and monitors the procurement card system;
- Receives and ships goods or forwards the shipment to the appropriate individual for receipt and acceptance;
- Develops, maintains and monitors vendor alliances;
- Coaches and guides employees and client departments;
- Liaisons with the vendor community providing information and responding to their inquiries and requests for information;
- Oversees and maintains the pre-qualification process for vendors;
- Responsible for records management of contract documents, pre-qualification documents and contractor(s)/consultant(s) database; and
- Maintains and reconciles purchasing logs.

4.02 Requestor:

- Ensures that all vendor and cost information is kept confidential and not released to any other vendor, party or other employee unless specified in the bid;
- Ensures that the proper approval for expenditure has been obtained prior to the work being bid;
- Provides a detailed scope for work to be bid;
- Provides any technical drawings or specifications that will need to be adhered to in the performance of the work;
- Provides timetable for start and completion of the work;
- Provides evaluation criteria for selection of vendor (if required); and
- Participates in the evaluation, vendor interviews or any other evaluative methodology used in determining the successful supplier.

4.03 Corporate Services & Requestor will work in partnership to determine:

a) Decide the type of purchase agreement that is required. Determining factors to include:
   - Amount of risk;
   - Dollar value for material, goods or services; and
   - Type of service or purchase agreement being requested.

b) Decide the appropriate type of "Request" Document that will be sent out (e.g. Request for Bid; Request for Quote; Request for Proposal; Request for Information; Request for Expression of Interest, etc.).

c) Decide whether the bid should be competitive or non-competitive. See Competitive Bid Guideline GS-004 and/or Non-Competitive Purchases Guideline GS-010.

d) Decide what type of evaluation criteria to use. See Evaluation Criteria Guideline GS-007.

e) Evaluate the responses received.

f) Negotiate new contacts.

TOPIC: **Transmission Line Refurbishment Project**

REFERENCE: **YUB-YEC-1-53(c), PDF pages 211, 212**

QUOTE: From the response to YUB-YEC-1-53(c), PDF pages 211, 212:
"… Outage data is not available for L172…"

From the response to YUB-YEC-1-53(c), PDF pages 211, 212:
"L170 total cost to respond to outages (planned and unplanned) are $313,500, with an average annual cost (2012-2020) of $34,800; additionally, capital investment in this line over the same period totaled $7,064,600.

L171 total cost to respond to outages (planned and unplanned) are $100,500, with an average annual cost (2012-2020) of $11,200; additionally, capital investment in this line over the same period totaled $3,718,600.

L172 total cost to respond to outages (planned and unplanned) are $25,400, with an average annual cost (2012-2020) of $2,800; additionally, capital investment in this line over the same period totaled $321,000."

QUESTION:

a) Please explain why outage data was not available for L172.

b) Please indicate whether any portion of the costs incurred due to outages and capital investments for lines L170, L171, and L172 have been approved by the Board in previous GRAs.

ANSWER:

(a)

L172 is a short 10 km transmission line. This line was mistakenly excluded from the YEC outage database. It has since been added. There were two outages directly related to events on L172.

- May 4/2008 - Vandalism (shot insulator)
- July 2/2013 - Tree contact

(b)

Outage costs are normally[1] expensed as incurred. These costs are not predictable so YEC does not forecast them in GRA's. As such, no forecast O&M outage costs have been approved by the Board in previous GRA's and rates are not impacted by them.

Capital costs other than the $4.272 million in 2019 identified in the Application at 5.2.1.5 were approved as part of previous GRA's, including the original capital costs of construction.

[1] Exception for material premature equipment failure which may be charged to RFID (subject to assessment against policy).

TOPIC: **Transmission Line Refurbishment – L178 Project**

REFERENCE: **YUB-YEC-1-54(a), PDF page 243**

QUOTES: "The total costs incurred from 2014-2020 due to outages on L178 is $1,213,581 ($782,723 O&M and $430,858 capital). The average annual cost over the period is $173,368. Cost estimate amounts are available for the period from Jan 2014-Dec 2020."

QUESTION:

a) Please indicate whether any portion of the costs incurred due to outages for this line have been approved by the Board in previous GRAs. If confirmed, please provide the amounts approved by year.

ANSWER:

(a)

Outage costs are normally[1] expensed as incurred. These costs are not predictable so YEC does not forecast them in GRA's. As such, no forecast O&M costs have been approved by the Board in previous GRA's and rates are not impacted by them.

[1] Exception for material premature equipment failure which may be charged to RFID (subject to assessment against policy).

TOPIC: **Replacement of the P125 Head Gate Project**

REFERENCE: **YUB-YEC-1-56(d), (e), PDF page 249**

QUOTES: **From the response to YUB-YEC-1-56(d), PDF page 249:**
"The WH2 Headgate Project was completed in 2020. The work was carried out by a prime contractor selected through an RFP process.

The RFP was issued and posted publicly through MERX. Two bids were received and were evaluated. A best value approach was taken with points awarded based on the following criteria: technical, cost and FN content. The Proponent with the highest total score was recommended."

From the response to YUB-YEC-1-56(e), PDF page 249:
"YEC will complete the preliminary design and tendering of the WH1 and WH3 headgate in 2021 for project completion in 2022. YEC will engage an engineering firm for assistance with this process."

QUESTION:

a) Please explain the "FN content" criteria and how much weight is assigned to this criteria.

b) Please advise if the lowest cost bid was approved during YEC's RFP process. If not confirmed, please explain.

c) Please provide an update on the preliminary design and tendering of the WH1 and WH3 headgates and specifically if YEC has found an engineering firm to handle this initial step.

ANSWER:

(a)

FN (First Nation) was weighted at 10% of the RFP criteria value. FN content were specific to or a combination of:

(1) Revenue Sharing Benefit to FN Development Corporation.
(2) Sub-contract - Value to a FN business (at least 50% owned by a designated FN or majority owner is a member of a designated FN).
(3) In-Kind - Opportunity for flexible and innovative collaboration to establish a relationship and provide relevant and meaningful benefits to the First Nation, the Development Corporation and/or its citizens.

(b)

YEC received two bids in response to this RFP. The contract was awarded to the lowest cost bid.

(c)

As reported, Yukon Energy completed the replacement of the WH2 headgate in 2020. As part of YEC's annual business planning process, team capacity was assessed and upon completion of the assessment it was determined that the replacement and refurbishment of the gates and related infrastructure for units WH1 and WH3 will be deferred to 2022 and 2023 respectively. Planning is currently underway for the replacement of the WH1 headgate which includes revision of the technical specifications based on learnings from the WH2 headgate replacement, as well as preparation and release of an RFP in advance of the 2022 project. Engineering aspects of this planning work is being completed by SNC Lavalin.

TOPIC: **WH2 Uprate Project**

REFERENCE: **YUB-YEC-1-57(c), PDF page 267**

QUOTES: "Hatch was awarded the work to undertake the study noted through a competitive RFP process. Proposals were evaluated based on technical and organizational competence and price; and demonstrated the best value for price submitted."

QUESTION:

a) Please confirm that the competitive RFP process used was compliant with YEC procurement policies.

b) Please provide further details on the RFP process, including names and bids of all the contractors for this project.

ANSWER:

(a)

This RFP process was compliant with YEC procurement policies. The estimated budget for this work was greater than $100,000.00 CAD. The opportunity was advertised publicly as required by policy.

(b)

RFP Name: Whitehorse Uprate WH1, 3, 4 and Sync Condenser.

Scope - The Corporation asked for firm price proposal submissions from qualified firms for engineering services to perform an assessment of the potential for the upgrade/uprate of the hydraulic turbines #1, #3 and #4 located at the Whitehorse Generating Station (WGS).

Bids were received from:

- Hatch: $143,200.00

- KGS Group: $184,817.00

- Klohn Crippen Berger: $328,000.00

- CAP Engineering: $911,570

TOPIC: **WH4 Uprate – Servomotor Replacement Project**

REFERENCE: **YUB-YEC-1-58(c), (e), (f), PDF page 272**

QUOTES: "The current servo motors were not meeting IEEE code in terms of operation and reliability…

Hatch was selected through an RFP process…

Final design and manufacturing are complete and the project is expected to be completed by June 2021."

QUESTION:

a) Please provide further details on how the current servo motors were not meeting IEEE code. For example, were there specific codes the servo motors failed to comply with?

b) Please confirm that the competitive RFP process used was compliant with YEC procurement policies.

c) Please confirm that the referenced project is now complete.

ANSWER:

(a)

The servomotors did not have the capacity to overcome the wicket gate stall force that is recommended in IEEE 1207 as highlighted in Table 4-2 in Attachment 1 to this response.

(b)

The response to YUB-YEC-1-58(e) was incorrect with respect to the award of engineering services on this project. There was no public RFP; the work was awarded on a sole-source basis to Hatch engineering during 2018. This approach was deemed acceptable based on: (1) Hatch previously participated in the 2017 WH4 overhaul/spider upgrade and therefore had detailed technical knowledge of this unit; and (2) the rates offered were

similar to previously tendered work; and (3) the original estimate of work required was modest (i.e., not to exceed $0.039 million).

This scope included advising the OEM (Andritz Hydro) on design issues and confirming design against enhancement objectives. In 2019, this contract was amended to increase the scope to test the existing breaker on the generator and the suitability of the existing breaker, generator leads and generator step-up transformer to evacuate generator nameplate power of 23.6 MVA (not previously attainable). The value of this work was $0.044 million.

(c)

This project was successfully completed in June 2021.

HATCH

Yukon Energy
Whitehorse Generating Station Unit WH4

Capacity Increase Desktop Study



2017-11-09	0	Issued for Use	P. Rodrigue/ R. Ahmed	S. Smith/ V. Kovalishyn	R. Ahmed	
Date	Rev.	Status	Prepared By	Checked By	Approved By	Approved By
			HATCH			Client

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Disclaimer

This report has been prepared by Hatch for the sole and exclusive use of Yukon Energy (the "Client") for the purpose of assisting the management of the Client in making decisions with respect to the potential development of the WH4 Capacity Increase; and shall not be (a) used for any other purpose, or (b) provided to, relied upon or used by any third party.

This report contains opinions and recommendations made by Hatch using its professional judgment and reasonable care. Use of, or reliance upon this report by Client, is subject to the following conditions:

(a) the report being read in the context of and subject to the terms of the Consulting Contract CG17013 between Hatch and the Client dated March 24, 2017 (the "Agreement"), including any methodologies, procedures, techniques, assumptions and other relevant terms or conditions that were specified or agreed therein;

(b) the report being read as a whole, with sections or parts hereof read or relied upon in context;

(c) the conditions of the Whitehorse Unit # 4 may change over time or may have already changed due to natural forces or human intervention, and Hatch takes no responsibility for the impact that such changes may have on the accuracy or validity or the opinion and recommendations set out in this report; and

(d) the report is based on information made available to Hatch by the Client or by certain third parties, and unless stated otherwise in the Agreement, Hatch has not verified the accuracy, completeness or validity of such information, makes no representation regarding its accuracy and hereby disclaims any liability in connection therewith.

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Executive Summary

Whitehorse Generating Station Unit 4 (WH4) has a nominal capacity of 20 MW. The unit has a fixed blade propeller turbine rated at 21.3 MW at 18.2 m net head, direct connected to a synchronous generator rated at 23.6 MVA (20 MW at 0.85 pf). During commissioning of the unit in early 1984, it was found that power in excess of the rated or guaranteed power levels was possible. However, a wicket gate stall issue at gate openings beyond 96% became evident during commissioning; therefore, the turbine wicket gates have been limited to approximately 92% of their theoretical maximum opening. Although Yukon Energy upgraded the governor actuator to supply higher pressure which can achieve increased servomotor force, the wicket gate limit was maintained; this limits the utilization of the available full turbine capacity.

The WH4 unit is a base load unit and is critical to the stability of the Yukon Energy grid and as such Yukon Energy is exploring the capability of operating the unit at higher capacity (increased gate opening) for short durations to support the grid while back-up resources (diesel generator and gas turbines) are being brought on line.

Yukon Energy retained Hatch to undertake a desktop study for evaluating the maximum MW available on the turbine shaft and potential impact of higher power on the governor system including WG linkages and shear pins, and equipment (e.g., generator leads, generator breaker and generator step-up transformer).

Hatch solicited and clarified the relevant information and undertook a desk top study to evaluate maximum available turbine power, to check suitability of governor system, and to check compatibility of the other equipment involved in power evacuation.

From the review of the information made available and a high-level analysis, the following conclusions and recommendations are presented as a result of this review and analysis:

- The maximum power available at the maximum gross head of 19 m at generator terminals is 22.3 MW.
- The existing servomotor operating pressure of 375 psi exceeds the pressure of 346 psi allowed in accordance with prudent industry practice, test pressure (450 psi) should be at least 1.3 times of the operating pressure. With the existing operating pressure of 375 psi, closing force past the WG opening of 92% is less than 1.42 (100% (operating)/70% (stall)) times of the WG stall force. A sluggish operation of WG or stalling of WG is expected; the WG stall force at 100% WG opening corresponds to 396 psi with current design which requires governor design pressure of 515 psi. The existing servomotors should be replaced with larger bore servomotors to achieve higher closing force to address sluggish operation and WG stalling. As an alternative, the existing servomotors can be retained and a spring can be added to aid the WG closing from openings higher than 92%.

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- It will be necessary to provide new wicket gate operating mechanism shear pins, shear pin levers and bushings for servomotor links.
- There will be added turbine cavitation damage equating to roughly 20% additional metal loss.
- The generator can be operated at a power output above the rating of 23.6 MVA without exceeding the stator temperature limits. This will require confirming the design of mechanical components for their suitability for sustaining the higher stresses associated with power levels exceeding 23.6 MVA. Typical governing design conditions for mechanical components are the forces associated with runaway speed, out-of-phase synchronization and stator and rotor short circuits, these forces will not change substantially with operation at the increased power output and as a result no issues with the existing mechanical components are expected.
- The existing Square D type MVR vacuum circuit breaker continuous current rating exceeds the potential power upgrade rating of the generator. The breaker capability to interrupt delayed zero crossing faults and out of phase switching needs to be confirmed. The generator breaker is rated for 15 kV and it is expected that 6.9 kV system TRV will be lower than breaker TRV capability.
- The GSU transformer can sustain minor overload of the order of 5% above its 24 MVA ONAF rating without any appreciable loss of insulation life.

The cost of replacing servomotors and generator breaker is of the order of $457,000. The addition of a spring assembly to the operating mechanism is an alternative to the servomotor replacement and allows retaining the existing servomotors; the cost of addition of spring assembly together with generator breaker replacement is of the order of $462,000. Hatch recommends replacement of the servomotors if space in the turbine pit permits, as it is a better technical solution. Alternate option of spring assembly to provide additional force past the 92% wicket gate opening can be considered if the existing servomotor replacement with larger bore size servomotor is not viable. An evaluation of the generator design by the OEM is also recommended to confirm if there are any mechanical or electrical upgrades or modifications required as a result of operating the unit at the increased power output. The adequacy of generator breaker for out of phase switching and fault interruption should also be confirmed.

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L&S Reports

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Typical Spring Assembly Arrangement

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1. Introduction and Background

Whitehorse Generating Station Unit 4 (WH4) has a nominal capacity of 20 MW. The unit has a fixed blade propeller turbine rated at 21.3 MW at 18.2 m net head, direct connected to a synchronous generator rated at 23.6 MVA (20 MW at 0.85 pf). During commissioning of the unit in early 1984 it was found that power in excess of the rated or guaranteed power levels was possible. However, a wicket gate (WG) stall issue at gate openings beyond 96% became evident during the commissioning; therefore, the turbine wicket gates have been limited to approximately 92% of their theoretical maximum opening. Although Yukon Energy upgraded the governor actuator to supply higher pressure which can achieve increased servomotor force, the wicket gate limit was maintained; this limits the utilization of the full turbine capacity.

The WH4 unit is a base load unit and is critical to the Yukon Energy grid and Yukon Energy is exploring the capability of operating the unit at higher capacity (increased gate opening) for short durations to support the grid while back-up resources (diesel generator and gas turbines) are being brought on line.

Yukon Energy retained Hatch to undertake a desktop study for evaluating the maximum MW available on the turbine shaft and potential impact of higher power on the governor system including wicket gate linkages and shear pins, and equipment (e.g., generator leads, generator breaker and generator step-up transformer).

2. Terms of Reference

The scope of this assignment [2.1] is as follows:

- Data Collection and Review:
  - Develop a request for information to collect information on the hydrology, wicket gate openings, servomotor operating pressure, governor system and associated water to wire equipment required for the desktop study.
  - Review the servomotor capability for closing the wicket gates with control actuator limits corresponding to 92% to 100% wicket gate opening positions. Identify upgrades or modifications required to achieve the objective.
  - Complete a high-level overview of the equipment and the impact of higher power output on the equipment and devices.
- Present review findings and potential solutions to Yukon Energy.
- Develop a report to summarize the review findings, recommended solutions, and further actions required, including budgetary cost estimates of recommended solutions.

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3. WH4 Power Levels at Increased Wicket Gate Opening

The nominal power output of the unit is 20 MW; however, the actual power level depends on the operating head and the turbine wicket gate opening.

Headwater level at the plant is generally constant at El. 653.1 m. Average tailwater level in summer is El. 636.6 m, and in winter the average level is El. 634.7 m. From historical tailwater-flow data, the minimum tailwater level is approximately El. 634.1 m. Therefore, WH4 gross head is as follows:

- Average summer: 653.1-636.3= 16.8 m.
- Average winter: 653.1-634.7= 18.4 m.
- Maximum: 653.1-634.1= 19.0 m.

Power output (at the generator terminals) versus gate opening from various sources is shown on Figure 3-1. The incremental power increase going from 92% to 100% gate opening varies with head and is approximately 0.8 MW at the higher operating heads but only about 0.3 or 0.4 MW at the lower operating heads. An estimated curve of generator power output versus head is shown on Figure 3-2. The evaluation of the generator in Section 5 is based on a generator power output of 22.3 MW which corresponds to 100% gate opening at 19.0 m gross head.

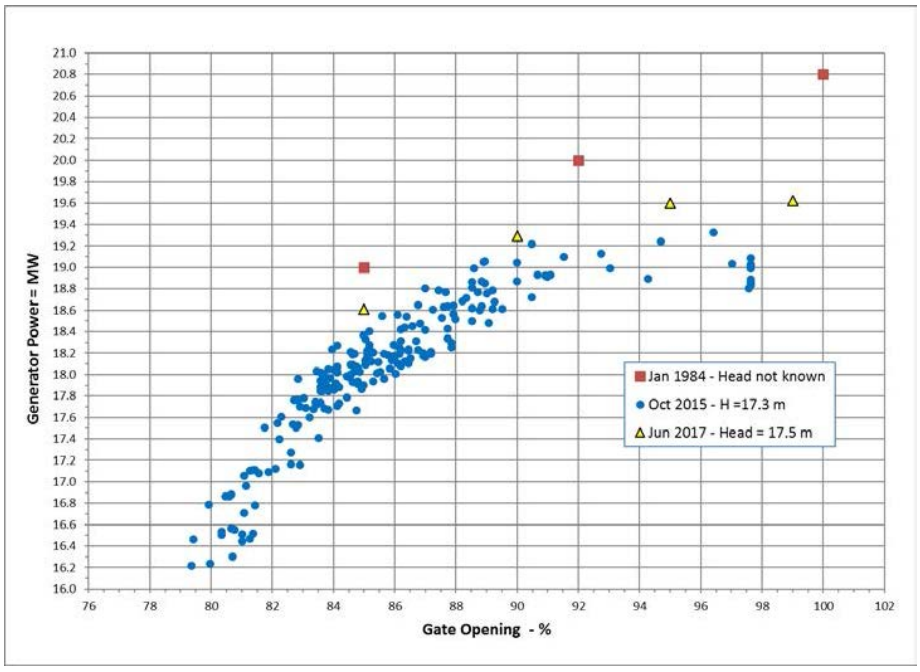

Figure 3-1: Power Output Versus Gate Opening

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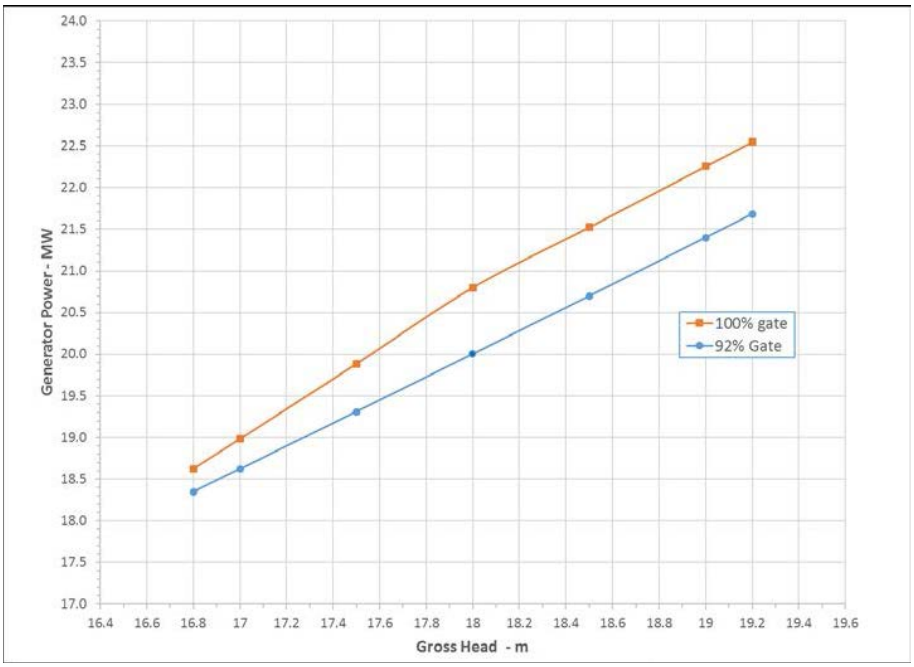

Figure 3-2: Maximum Generating Unit Power

The estimated turbine efficiency versus flow for the WH4 turbine, showing the present operating limit as well as operation at 100 % gate, is shown on Figure 3-3.

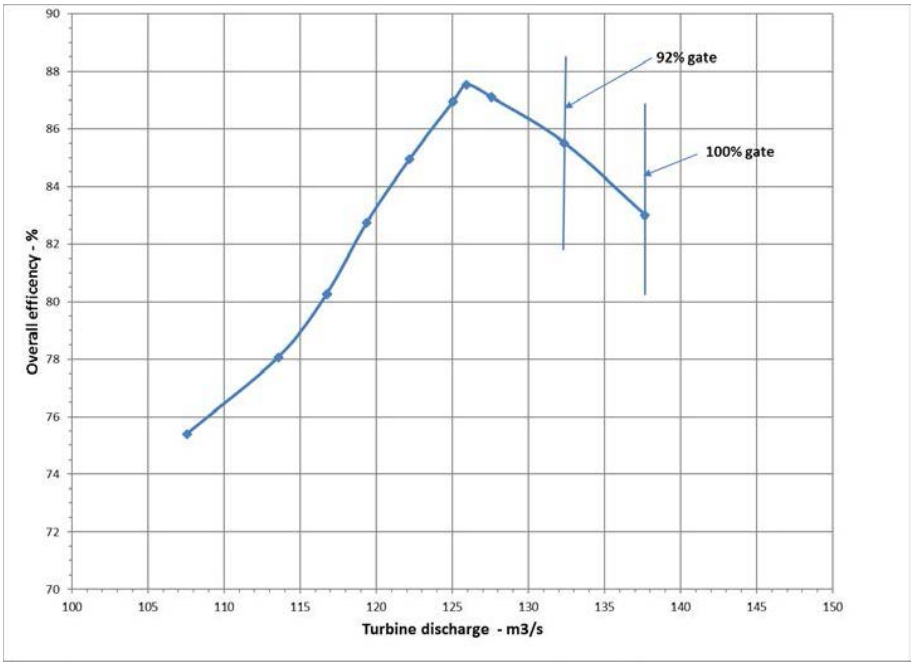

Figure 3-3: Estimated WH4 Turbine Efficiency

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4. Turbine

4.1 Governor System Operating Pressure

WH4 was originally equipped with a 300 psi governor system, which was set for a maximum operating pressure (pump shut-off) of 280 psi. During commissioning, it was found that the wicket gates could open to 100% but would not close (the intake gate had to be closed to stop the units). It was also found that a pressure of 306 psi was necessary to close the wicket gates from 96% gate.

Turbine distributors are usually designed so that there is always a closing tendency on the wicket gates except at and below about 15% gate. However, on some turbines there is an opening tendency at very high gate openings, and this is the case at WH4.

L&S analyzed the wicket gate stalling issue [5.9] and established that stall force corresponds to 335 psi operating pressure at 85% WG opening, 72,500 pound force with the existing servomotor. L&S reviewed the use of high pressure and low pressure governor systems to address the WG stalling issue and recommended upgrades to the existing low pressure governor hydraulics. The recommended upgrade included replacement of the existing servomotor with 14” dia servomotors, new accumulator with 400 psi air safety, replacement of 15 hp actuator motor with 20 hp motor and add 14 GPM kidney loop filter. L&S has also recommended temporary settings for the governor to improve the governing of WG [5.10]. The L&S reports are included in Appendix E. Yukon Energy upgraded the accumulator and implemented temporary settings however servomotors were not replaced.

A test was conducted to measure the servomotor differential pressure at various gate openings with the unit under load in June 2017. The results of the test are shown on Figure 4-1.

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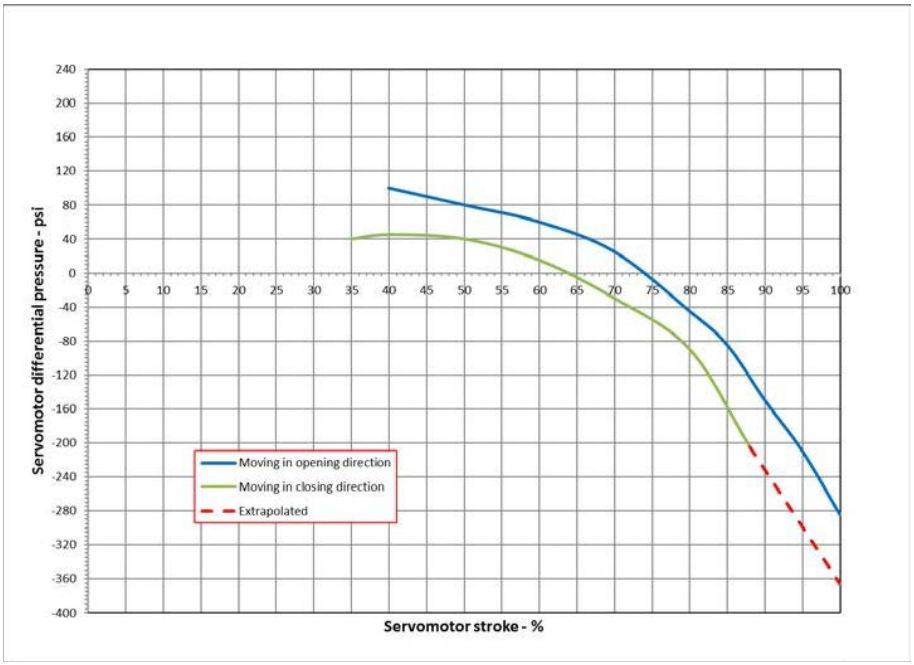

Figure 4-1: Servomotor Differential Pressure Test

The test indicates a wicket gate stall pressure of 365 psi at 100% gate (extrapolated). The head during the test was 17.53 m. Wicket gate torque is approximately proportional to head; therefore, the stall pressure at average winter head of 18.4 m is 385 psi, and at maximum head of 19.0 m it is 396 psi.

Yukon Energy has upgraded the governor pressure system including a new accumulator tank with a maximum working pressure of 400 psi. The present governor operating pressures are summarized in Table 4-1.

Table 4-1: Present Governor Operating Pressures

Description	Temporary	Normal
High (pump off)	375 psi	350 psi
Low (pump on)	345 psi	315 psi
Trip	335 psi	281 psi

It is noted that a trip pressure of 335 psi is lower than the stall pressures given above, by a sizeable margin.

A maximum operating pressure of 375 psi represents a 25% increase over the original governor system rating. A further significant increase in pressure is believed to be impractical without impacting the complete governor hydraulic system.

New larger diameter servomotors could be installed in the WH4 turbine to address the stall forces at 100% gate. IEEE Standard 1207 “IEEE Guide for Application of Turbine Governing

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Systems for Hydroelectric Generating Units" can be used as a guide for servomotor sizing, this standard recommends that the servomotor force equal the wicket gate stall force at 70% of nominal system pressure. Using this criteria, the new servomotors should have a diameter of 15 inches as compared to the present 12 inch servomotors.

A less conservative criteria would be possible, provided than the trip setting on the governor pressure system is set higher than the wicket gate stall pressure. However, the wicket gate opening would have to be limited and governor operation would become sluggish at high gate openings with slower operating times [5.7] and therefore new servomotors would still be required.

With 15 inch servomotors, the amount of oil required for servomotor operation increases; however, the accumulator tank has a volume equal to 20 servo-volumes, the usual criteria for minimum accumulator tank size. Oil velocity in the servomotor piping is still within recommended limits.

As an alternative to providing new servomotors, a large spring mechanism can be added to the operating ring that acts in the 85% to 100% gate range and provides added force to help close the gates from full open. Designs with leaf springs or Belleville washers have been used. This solution would require some custom design, but will allow the existing servomotors to be retained.

4.2 Servomotor Design

New servomotors would be required to provide adequate servomotors force for operation at 100% wicket gate opening, unless a spring mechanism is provided to assist in gate closure.

The wicket gate servomotors are shown on Dominion Engineering Works (DEW) drawing 224-1-33928. Per the drawing, they have been pressure tested to 450 psi, which is consistent with the original design pressure of 300 psi, as servomotors are commonly tested to 150% of their design pressure. However, as servomotors (hydraulic cylinders) are not specifically classified as pressure vessels they do not necessarily come under the rules of the ASME pressure vessel code (which requires a test pressure of at least 1.3 times the maximum working pressure).

A preliminary analysis indicates that the servomotor cylinder and flanges would be satisfactory for operation at 375 psi. However, this is based on assumptions of material strength properties and more rigorous analysis would be needed to confirm the adequacy of the servomotors. The flanges on the cylinder itself rather than the servomotor head appears to be the weakest part of the design.

The servomotor differential pressure measurements and analysis completed suggest that WG stall pressure is higher than 375 psi under certain operating pressure. In addition, the requirement for a design pressure of 1.42 (100% (operating)/70% (stall)) time the pressure corresponding to wicket gate stall force is not met with which will result in sluggish WG operation under certain operating conditions.

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Therefore, it is recommended to replace the existing servomotors with larger bore servomotor to achieve higher operating force with the existing governor system operating pressures. The existing drawing [Ref. 5.8] shows that servomotor is installed in a notch made in the concrete. The space available could not be adequate for the larger bore size servomotor. Yukon Energy shall verify the available space for a larger bore size servomotor. Alternate option of spring assembly to provide additional force past the 92% wicket gate opening can be considered if the existing servomotor replacement with larger bore size servomotor is not viable; see Appendix F for typical spring assembly arrangement.

Table 4-2 summarizes the original, current and proposed upgrade design parameters.

Table 4-2: Summary of Servomotor Options

Description	Original	Current (Temporary)	Proposed - Servomotor Replacement	Proposed - Spring Assembly Addition
Max Operating Pressure (psi)	300	375	375	375
Trip Pressure (psi)	Not available	335	335	335
Servomotor	2 x 12” dia bore, 3.5” rod	2 x 12” dia bore, 3.5” rod	2 x 15” dia bore, 4” rod	2 x 12” dia bore, 3.5”rodAdded spring(s) with 41,200 lbs capacity
Servomotor Force at Max Operating Pressure (pounds force)	64,900	81,200	127,800	81,200 + 41,200 lbs from Spring Assembly
Stall Force at 100% WG and 19.0 m head (pounds force)	85,700	85,700	85,700	85,700
IEEE 1207 Recommended Servomotor Capacity at Max. Operating Pressure (pounds force) (1.43 x Stall Force)	122,400	122,400	122,400	122,400

4.3 Capacity of WG Operating Mechanism

A preliminary stress analysis of the wicket gate operating mechanism has been made including:

- Servomotor cylinder rods.
- Servomotor links.
- Operating ring.

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- Links.
- Shear levers.
- Wicket gate levers.
- Wicket gate stems.
- Respective pins and bushings for the above components.

The analysis was made for a servomotor operating force of 127,800 pounds (assuming new 15 inch servomotors). The analysis indicates that many of the components in the operating mechanism are suitable for the increased servomotor force. Areas of excessive load (stress) are:

- The wicket gate shear pins.
- The shear levers.
- The bushings in the servomotor links.

The shear pins appear to be at or near their point of failure even with the existing servomotors and operating pressure of 375 psi. It is possible to provide new shear pins with higher strength. Shear levers fabricated using higher strength material will be required. New bushings with increased load capacity will also be required for the servomotor links.

The material properties of the wicket gate stems would also need to be verified to confirm acceptable stress levels.

4.4 Turbine Cavitation Damage

At present, cavitation damage occurs on both the pressure and suction side of the runner blades as well as on the draft tube liner below the discharge ring. Pressure side cavitation damage is indicative of operation at low head and may occur during the summer, in spite of the higher tailwater level. Suction side cavitation is often a result of operation at high flow and low tailwater level.

With increased gate opening and added turbine flow, it is reasonable to expect that the extent of cavitation damage will increase. A very rough estimate would be a 20% increase in damage. Present weld repairs require about four days to one week per year; therefore, additional outage time should be allowed with the higher power operation to address the additional cavitation damage. Actual damage would be related to the number of hours operated at higher wicket gate openings.

4.5 Turbine Thrust Load

Based on model test data for other propeller turbines an increase in thrust load can be expected with an 8% increase in gate opening. The increase is expected to be approximately 7%. The total generator thrust bearing load consists of the weight of the turbine and generator rotating parts, plus the hydraulic thrust, and it is estimated that the hydraulic thrust load makes up approximately 70% of the total bearing load. A 7% increase in thrust would

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increase the thrust bearing loads by 4.9%. As problems with overheating of the thrust bearing have not been reported to date, it is anticipated that the increase in turbine wicket gate opening and associated increase in turbine hydraulic thrust will not materially affect the operation of the generator thrust bearing.

4.6 Turbine Review Findings

Following a review of the pertinent data and operating parameters of the existing unit it can be concluded that operation of the unit at higher power outputs and higher gate openings is possible, however:

- New larger diameter servomotors will be required; alternatively, a spring mechanism will be required for the operating ring to assist in gate closure at higher gate openings.
- It will be necessary to provide new wicket gate operating mechanism shear pins, new shear levers and new bushings for the servomotor links.
- The strength analysis of the wicket gate stem materials should be checked and a further overall review of the gate mechanism should be completed to confirm the results of the preliminary analysis described in Section 4.3.
- There will be added turbine cavitation damage.

5. Electrical Equipment Capacity

This section outlines the existing design parameters and maximum ratings for the generator and associated major electrical equipment as well as the expected impact that the increase in generator power output would have on this equipment.

5.1 Generator

5.1.1 Existing Generator

The generator is of umbrella type (IEC designation IM8201) with combined thrust and guide bearing located below the rotor supported on the lower bracket. The generator is rated for 23.6 MVA at 0.85 pf and the design temperature rise is 60° C above ambient 40° C [5.1] (Appendix A). The rated voltage is 6900 V phase-to-phase.

The stator winding has Class F temperature rise insulation and is comprised of Roebel type bars with individual conductor insulation of polyester glass and ground wall insulation of epoxy impregnated mica paper tape [5.2]. A total of 270 coils form the complete stator winding assembly. The winding leads are brought out into a terminal box for cable termination [5.3] [5.4]. The generator is equipped with recirculated air cooling system; cooling air for the stator winding is directed horizontally through the stator core vents under fan action of fan blades mounted on the rotor rim. The actual winding temperature rise under various load conditions is summarized in Table 5-1[5.5], the associated heat run tests are included in Appendix B

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Table 5-1: Actual Stator temperature Rise Values

Test	Load Rating	Average Winding Temperature (°C)	Stator Cooler Output Air Temperature (°C)	Effective Winding Temperature Rise (°C)
01	5.2 MW Load at pf= 0.94 Lagging (5.5MVA)	29.1	26.2	2.9
02	17.7MW Load at pf=0.94 Lagging (18.8 MVA)	59.0	36.0	23.0
03	21.2 MW Load at pf =0.945 (22.5 MVA)	72.4	37.7	34.4

The winding temperatures recorded during the heat run testing exhibited a slightly greater-than-normal scatter in values (and the Test 01 data appears to include a reversal in stator air cooler temperature data). However, even with the addition of 5°C to the average temperatures, as representative of the approximate winding hot spot temperature, the resulting winding operating temperatures remain lower than the design temperature of 100°C, or 60°C rise over 40°C degree air ambient cooling air. These tests indicate that the stator windings can accommodate increased capacity without any increased loss of insulation lifetime.

The rotor assembly includes 48 poles assembled from high permeable steel punchings. The assembled pole body includes T-shaped mounting dovetails and amortisseur winding bars on the face side of the pole body. The cooling mechanism is the same as that of the stator assembly. The field winding resistance at ambient is not known and was not measured as part of Andritz Hydro field tests on WH4 [5.5]. Normally, rotor winding temperature rise is lower than stator for a salient pole machine and consequently the rotor winding operating temperature is expected to be lower than stator winding temperature rise and consequently lower than the design temperature of 100°C.

The thrust bearing consists of babbitted segments each supported by pre-compressed coil springs. The segments are retained in place around the periphery of base ring by inter-segment radial keys and individual radial clamp. The thrust block transfers static and dynamic loads to the bearing assembly. Heat generated within the bearing is removed using oil-to-water heat exchanger coils mounted inside the bearing tub. The thrust bearing is rated for a total load of 333,767 kg, which includes a hydraulic thrust component of 231,332 kg generated by the turbine runner.

The generator rated field current is 1050 A at rated terminal voltage, rated power factor of 0.85 and rated MVA of 23.6. The existing excitation system is rated for 1400 A, see Appendix C for excitation system nameplate. The excitation system can support the nameplate rating of 23.6 MVA at rated power factor of 0.85.

The brake and jack assembly, collector assembly and high pressure oil injection system are not impacted by an increase in turbine mechanical power and hence no issues are foreseen.

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5.1.2 *Impact of Increased Turbine Power*

As indicated on Figure 3-2 in Section 3 maximum power available from generator will be 22.3 MW at 19 m net head on the turbine and the generator is evaluated for a maximum output of 22.3 MW at the stator terminals. This corresponds to 0.94 pu of generator name plate rating at unity power factor. The generator can deliver this power at a pf of 0.94 or higher as depicted in the Figure 5-1, mark-up of generator capability curve.

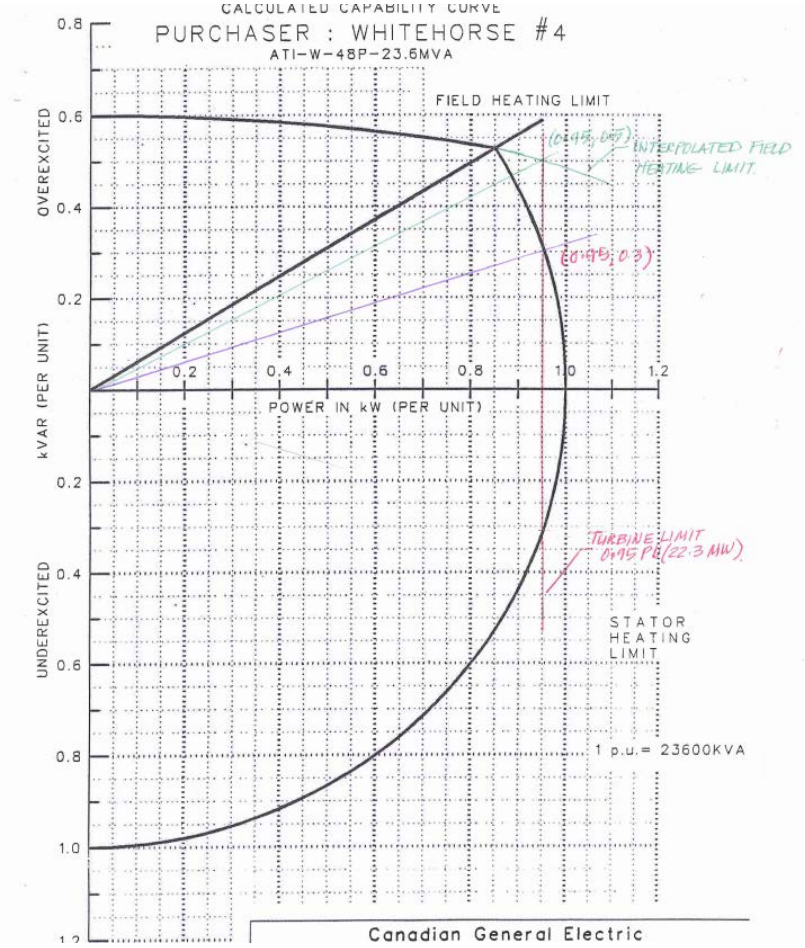

Figure 5-1: Operating zone within the vendor defined capability

This assessment is based on the assumption that the generator winding operating temperature approaches the design limit of 100°C at rated output. The temperature rise tests completed recently [5.5] suggest the actual operating temperature of 77.2°C (hot spot 5°C higher than measured value) at 22.5 MVA (21.2 MW at 0.945 pf) is well below the design limit. The expected operating temperature at 23.6 MVA is 87 °C (hotspot), 42°C rise over 40°C ambient.

This suggests that the generator winding design is conservative and the actual stator thermal limit is higher than 23.6 MVA; a 25.4 MVA will result in temperature approaching 95°C (hot

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spot), ambient of 40°C assumed. The generator can be operated to a power factor 0.88 while staying under the field thermal limit, which corresponds to generator output of 25.2 MVA, see Figure 5-1.

Operation at outputs higher than generator stator rated thermal limit and power level exceeding 23.6 MW will require review of the generator mechanical design (sole plates, stator and rotor assembly), field pole assembly and field winding by original equipment manufacturer (OEM) to confirm that these systems and components are suitable for operation at the increased power levels. Typical governing design conditions for mechanical components are the forces associated with runaway speed, out-of-phase synchronization and stator and rotor short circuits, these forces will not change substantially with operation at the increased power output and as a result no issues with the existing mechanical components are expected. The field current requirement is expected to increase by 3-4% for an increase of 5% power based on the saturation curves included as part of generator data in Appendix A. This translates into 1092 A which is within the limits of the excitation system capacity.

Refer to section 4.5 for the discussion on the generator thrust bearing capability.

5.2 Generator Leads

The generator leads comprised of nine 500 MCM TECK cables, three cable per phase, fully spaced at cable diameter spacing as evident in Figure 5-2.



Figure 5-2: Generator Lead Arrangement

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The cable sheaths and armours are bonded at one end only. Ampacity of the cable with one end bonding is roughly 685 A (NEC Table 310.69). Therefore, the existing circuit has a rating of 2055 A.

This circuit ampacity is adequate for the current rating of 23.6 MVA (1975 A) and a marginal generator output power increase of 4%.

5.3 Generator Circuit Breaker

The existing Square D type MVR is a vacuum circuit breaker rated for 15 kV maximum continuous current of 3000 A, symmetrical short circuit current of 23 kA and interrupting time of 3 cycles, see Appendix C for the breaker name plate. The test reports and manual provided indicate that it is general purpose breaker tested to IEEE C37.9 and not designed in accordance with generator breaker standard IEEE C 37.13. Consequently, the breaker is not tested for breaker application especially out of phase switching and delayed zero crossing (X/R=45). The general purpose breakers are tested at X/R of 17 and out of phase switching is not a prescribed design test.

A 15 kV rated breaker is being used for 6.9 kV system. The peak TRV value of 12.97 kV peak for the system (E2 = 1.88 V) [5.6] is less than the rated maximum voltage of 15 kV; the breaker will have the TRV capability to interrupt without a restrike. The breaker capability for interrupting the system source and generator source faults with higher X/R ratios needs to be evaluated and capability of out of phase switching needs to be confirmed.

5.4 Generator Step Up Transformer

The existing GSU is 18/24 MVA ONAN/ONAF. It is assumed that the transformer is designed to CSA C88.1 with maximum ambient of 40°C and daily average of 30°C. The unit is not capable of operating continuously at 25.2 MVA (generator at 22.3 MW and 0.88 pf). However, for a short duration overloading is acceptable; the overload capability can be qualified based on IEEE C57.91 guidelines. Typically, an overload of 120% for 24 hours does not result in any appreciable loss of insulation life. In this case, the actual ambient temperature is generally lower than the design ambient temperature, the expected overload of 5% will therefore not cause any loss of life.

It is recommended to define the expected duration of the overload based on input from operations and evaluate the capability of the transformer to sustain the overload condition without any appreciable loss of life. If it is determined that the transformer requires replacement, it should be replaced with a transformer of 26 MVA ONAF rating.

6. Cost Estimate

The upgrades to utilize the full capacity of the turbine requires addressing the servomotor capability issues and confirming the generator breaker capability (an existing issue).

The servomotor capability issue can be addressed through replacing the existing servomotor with larger bore servomotor to increase the servomotor force or a spring assembly can be

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added to aid the closing past 92% wicket gate open position. The shear pin, shear levers and WG lever bushings need to replaced as well.

There is a possibility that circuit breaker could be rated for the generator switching application however the cost of replacement is included in Table 6-1 below.

The cost estimates for two alternatives are developed: Alternative 1 with servomotor replacement and Alternative 2 with spring assembly addition. Table 6-1 summarizes the cost of the alternatives.

Table 6-1: Cost Estimate for Unit Capacity Uprate

Item #	Description	Cost ($)
1	Alternative 1- Replacement of servomotors	457,000
2	Alternative 2- Addition of spring assembly to aid the WG closing past 92 % WG opening	462,000

The costs include only upgrades required to address technical constraints arising from WG opening past 92% or the existing deficiencies. The upgrades required due to existing equipment condition (e.g., generator step-up transformer) are not included in the estimate.

The estimate details including basis of estimate, contingency considered and overhead and profits factored in are included in Appendix D.

7. Conclusions and Recommendations

From the review of the information made available and a high-level analysis, the following conclusions and recommendations are presented as a result of this review and analysis:

- The maximum generator power at the maximum gross head of 19 m is estimated to be approximately 22.3 MW at the generator terminals.
- The existing servomotor operating pressure of 375 psi exceeds the pressure of 346 psi allowed in accordance with prudent industry practice, test pressure (450 psi) should be at least 1.3 times of the operating pressure. With the existing operating pressure of 375 psi, closing force past the WG opening of 92% is less than 1.42 (100% (operating)/70%(stall)) times of the WG stall force. A sluggish operation of WG or stalling of WG is expected; the WG stall force at 100% WG opening corresponds to 396 psi with current design. The existing servomotors should be replaced with larger bore servomotors to achieve higher closing force to address sluggish operation and WG stalling. As an alternative, the existing servomotor can be retained and a spring can be added to aid the WG closing from openings higher than 92%.
- It will be necessary to provide new wicket gate operating mechanism shear pins, shear pin levers and bushings for servomotor links.
- There will be added turbine cavitation damage equating to roughly 20% additional metal loss.

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- The generator can be operated at a power output above the rating of 23.6 MVA without exceeding the stator temperature limits. This will require confirming the design of mechanical components to confirm their suitability for sustaining higher the stresses associated with power levels exceeding 23.6 MVA. Typical governing design conditions for mechanical components are the forces associated with runaway speed, out-of-phase synchronization and stator and rotor short circuits, these forces will not change substantially with operation at the increased power output and as a result no issues with the existing mechanical components are expected.
- The existing Square D type MVR vacuum generator circuit breaker continuous current rating exceeds the potential power upgrade rating of the generator. The breaker capability to interrupt delayed zero crossing faults and out of phase switching needs to be confirmed. The generator breaker is rated for 15 kV and it is expected that 6.9 kV system TRV will be lower than breaker TRV capability.
- The GSU transformer can sustain minor overload of the order of 5% above its 24 MVA ONAF rating without any appreciable loss of insulation life.

The cost of replacing servomotors and generator breaker is of the order of $457,000. The addition of a spring assembly to the operating mechanism is an alternative to the servomotor replacement and allows retaining the existing servomotors; the cost of addition of spring assembly together with generator breaker replacement is of the order of $462,000. Hatch recommends replacement of the servomotors if space in the turbine pit permits [Ref. 5.8], as it is a better technical solution. Alternate option of spring assembly to provide additional force past the 92% wicket gate opening can be considered if the existing servomotor replacement with larger bore size servomotor is not viable.

An evaluation of the generator design by the OEM is also recommended to confirm if there are any mechanical or electrical upgrades or modifications required as a result of operating the unit at the increased power output.

The adequacy of generator breaker for out of phase switching and fault interruption should also be confirmed.

8. References

[2.1] Hatch Proposal 17-1338 Dated March 16, 2017.

[5.1] Generator Data appended as Appendix A to this report.

[5.2] Generator Manual Section 3 Detailed Descriptions.

[5.3] 0912D0600CC Sht 01 “Location of Leads.”

[5.4] 0912D0600CC Sht 02 “Location of Leads.”

[5.5] S-85-A50760-081 Andritz Hydro WH4 Pre-Dismantling Test Report (Draft version, final version does not include heat run test at 5 MW, 17.7 MW.

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[5.6] IEEE C37.4 “Standard Rating Structure for AC High Voltage Circuit Breaker.”

[5.7] IEEE 1207 “Guide for the Application of Turbine Governing System for Hydroelectric Generating Unit”.

[5.8] 224 0 33900 Sht. 1 “Blade Propeller Turbine, Plan View”.

[5.9] MA75860 “Whitehorse Unit 4 Governor Upgrade Evaluation”, October 2009

[5.10] L&S Report “YEC WH4 Governor HPU Temporary Modifications”

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Appendix A

Generator Data Report

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GENERATOR DATA

NAMEPLATE

No 525L0509 TYPE-ATI FORM-W
CLASS-ATI POLES- 48. MVA-23600 R.P.M.-150 V- 6900 PF-.85 PHASE-3 H_z 60

GENERATOR		EXCITATION		TEMPERATURE RISE (C)	
KVA	AMPS	VOLTS	AMPS	STATOR BY RTD	ROTOR BY RESISTANCE
23,600	1975	146	967	60°C	60°C

BEARING OIL COOLER RATING

Inlet cooling water temperature ..... 20°C
Thrust bearing water flow rate..... 3ℓ/sec.

SURFACE AIR COOLER RATING

Water flow rate.(Total for 4 Coolers)..... 20ℓ/sec.
Cooler inlet water temperature..... 20°C

GUARANTEED PERFORMANCE (23.6 MVA; 0.85 PF; 6.9 KV; 60 H_z

Temperature rise at 23.6 MVA, 0.85 PF..... 60°C
Flywheel effect (GD^2) ..... 1.6 x 10^6 kg-M^2

THRUST BEARING RATING

Load due to generator rotor..... 79615 kg.
Load due to turbine and shaft..... 22830 kg.
Load due to hydraulic thrust..... 231332 kg.

Minimum recommended continuous running speed..... 25 RPM

MASSES (Excluding Lifting Devices)

Rotor assembly..... 65500 kg.
Stator assembly..... 35000 kg.
Total installed mass (approx.)..... 140000 kg.

Doc 3433d:0106d:slc
Whitehorse

CALCULATED CHARACTERISTICS

Time required to stop from 25% speed	1 Minute
Short circuit ratio	1.3
Capacitance - 3 phase to ground	1.32 uf
Efficiency	97.32

REACTANCES (Per Unit)

Direct-axis synchronous reactance		Xd	0.85
" " transient	saturated	Xd'	0.30
" " transient	unsaturated	Xdu'	0.34
" " subtransient	saturated	Xd"	0.24
" " subtransient	unsaturated	Xdu"	0.28
Quadrature-axis synchronous reactance		Xq	0.61
" " subtransient reactance	saturated	Xq"	0.37
" " "	unsaturated	Xqu"	0.40
Negative sequence reactance saturated		X_2	0.30
Negative sequence reactance unsaturated		X_{2u}	0.33
Zero sequence reactance		X_o	0.10

RESISTANCE (at 25°C)

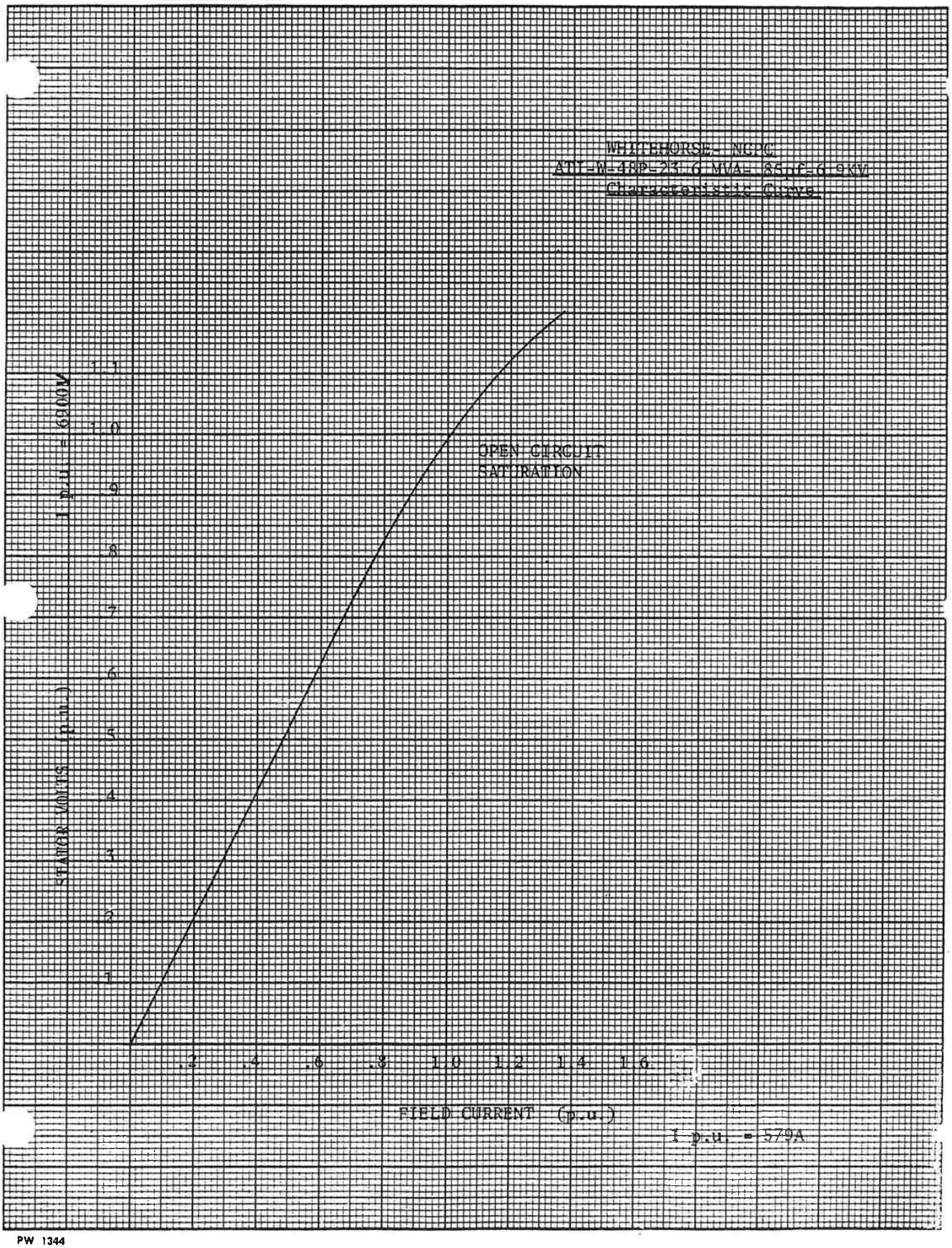
Stator winding resistance, L-L	0.022 ohms
Rotor winding resistance	0.117 ohms

TIME CONSTANTS

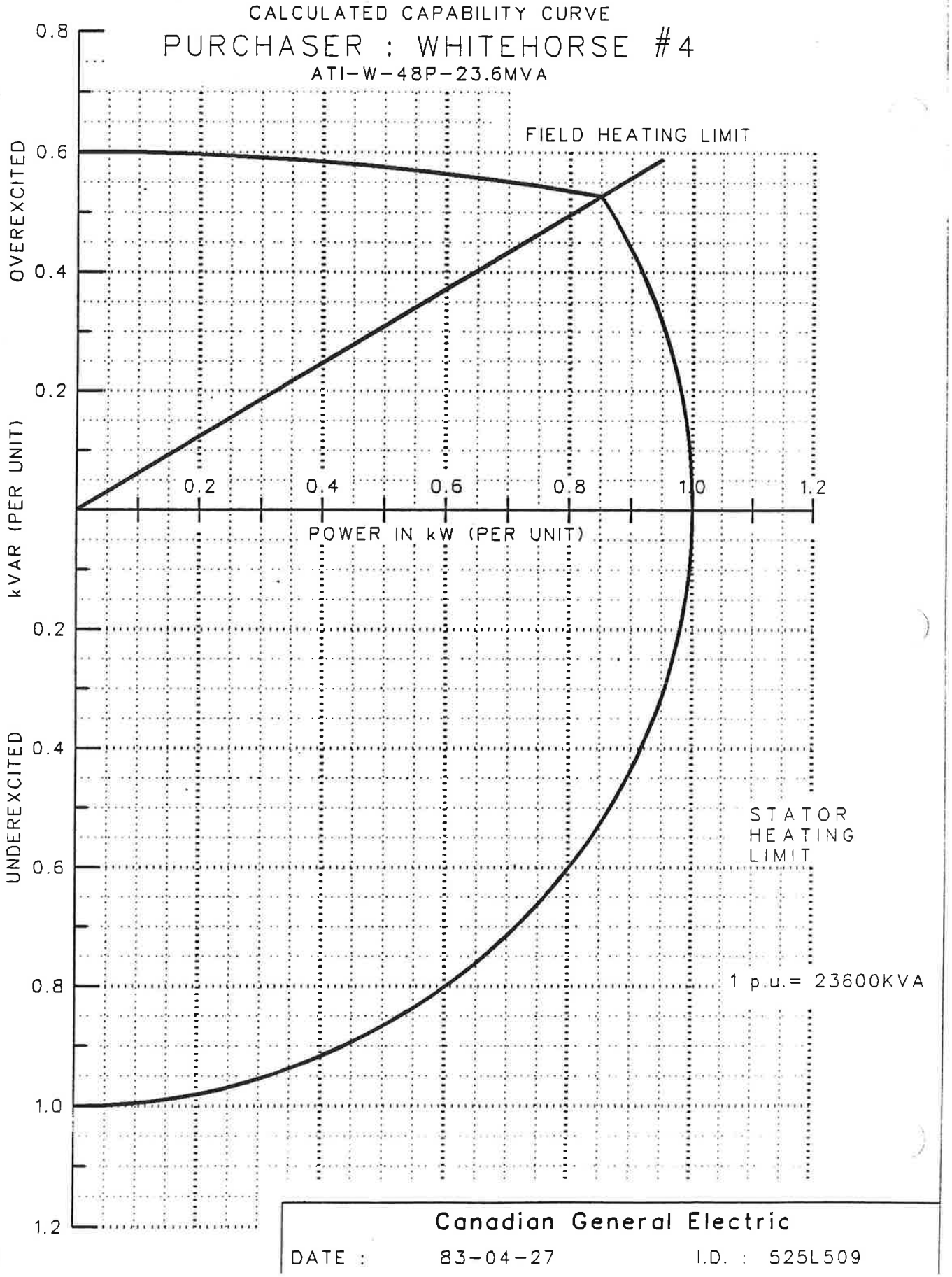
Direct-axis open-circuit transient time constant	Tdo'	3.03 sec.
Direct-axis short circuit transient time constant	Td'	1.20 sec.
Direct-axis open-circuit subtransient time constant	Tdo"	0.04 sec.
Direct-axis short-circuit subtransient time constant	Td"	0.03 sec.
Short-circuit armature time constant	Ta	0.10 sec.

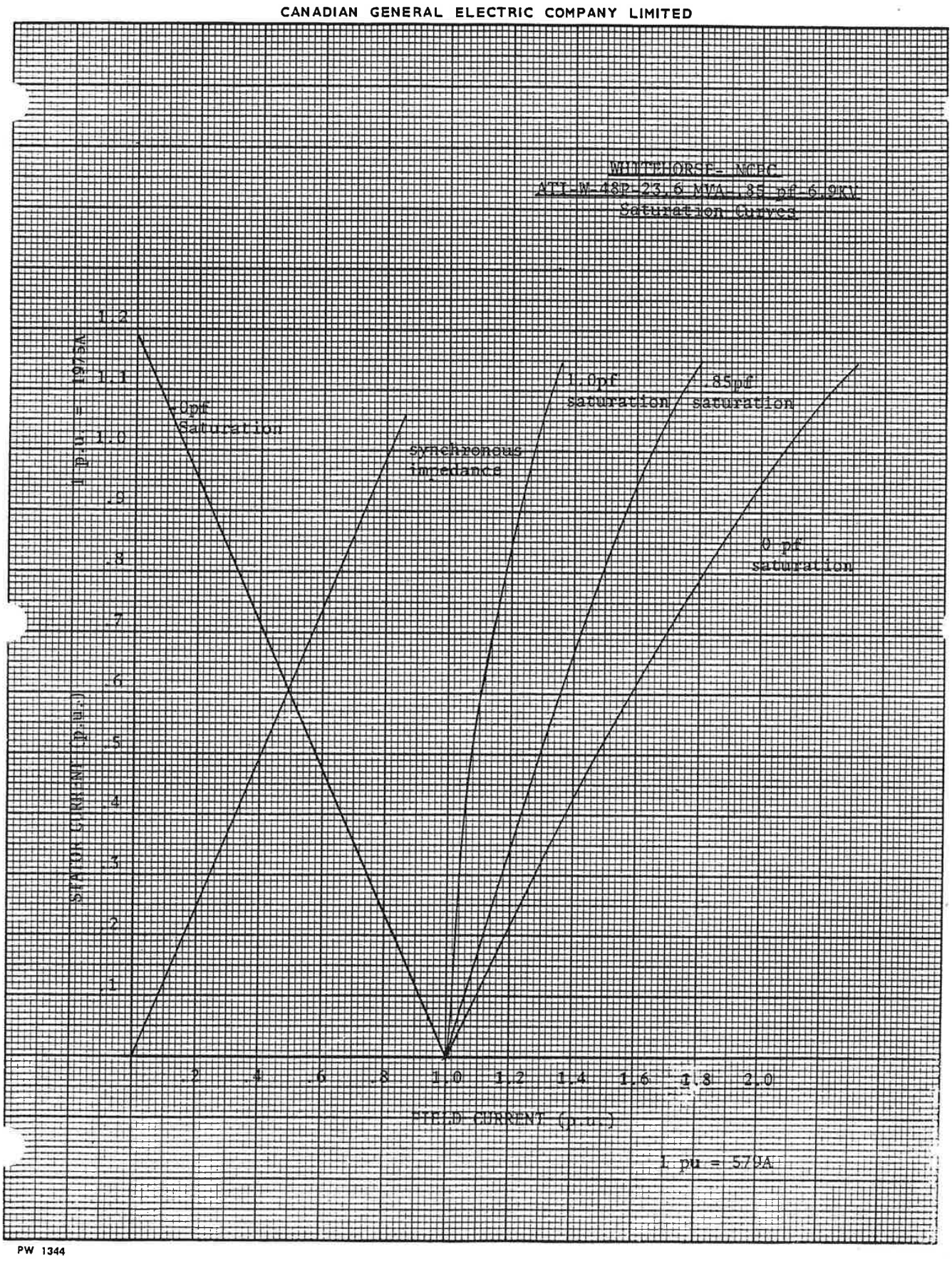
oc 3433d:0106d:slc
Whitehorse

CANADIAN GENERAL ELECTRIC COMPANY LIMITED



PW 1344


CALCULATED CAPABILITY CURVE
PURCHASER : WHITEHORSE #4
ATI-W-48P-23.6MVA
FIELD HEATING LIMIT
STATOR HEATING LIMIT
1 p.u.= 23600KVA
OVEREXCITED
UNDEREXCITED
kVAR (PER UNIT)
POWER IN kW (PER UNIT)
0.8
0.6
0.4
0.2
0.2
0.4
0.6
0.8
1.0
1.2
Canadian General Electric
TKEB
DATE : 83-04-27
I.D. : 525L509


CANADIAN GENERAL ELECTRIC COMPANY LIMITED
WHITEHORSE - NCPC
ATI-W-48P-23.6 MVA, .85 pf, 6.9KV
Saturation Curves
1.2
1.1
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
1 pu = 1975A
STATOR CURRENT (p.u.)
0pf Saturation
synchronous impedance
1.0pf saturation
.85pf saturation
0 pf saturation
.2
.4
.6
.8
1.0
1.2
1.4
1.6
1.8
2.0
FIELD CURRENT (p.u.)
1 pu = 579A
PW 1344



Appendix B

Heat Run Test Report

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ANDRITZ Hydro

Installation and Commissioning

Quality Control Record

Generator Heat run - 5 MW

Q-1524-040

ITP step #: 1550-08

Revision # 03

Project: Whitehorse

Unit : 4

Power Readings:

Parameters	Units	Time		
		13H00	13H30	14H00
Field Volts	V	650	650	655
Field Amps	A	60	60	60
Arm volts 1	N/A	N/A	N/A	N/A
Arm Volts 2	N/A	N/A	N/A	N/A
Arm Volts 3	N/A	N/A	N/A	N/A
Avg Arm Volts	kV	6.75	6.75	6.75
Arm Amps 1	A	580	560	525
Arm Amps 2	A	500	500	490
Arm Amps 3	A	590	590	540
Avg Arm Amps	A	556.67	550.00	518.33
MVA	N/A	N/A	N/A	N/A
MW	MW	5.4	5.3	5.0
Mvars	MVars	1.2 Out	1.35 Out	1.6 Out
PF	pf	0.94 Lag	0.94 Lag	0.93 Lag
Hertz	N/A	N/A	N/A	N/A
T winding average	°C	29.07	29.15	28.92

Parameters	Units	Time		
		13H00	13H30	14H00
Vib. UGB -x	mils pp	19	19	19
Vib. UGB -y	mils pp	16	16	16
Vib. LGB-x	mils pp	7	8	7
Vib. LGB-y	mils pp	8	8	9
Vib. TGB-x	mils pp	6	7	6
Vib. TGB-y	mils pp	7	6	4

Note; * Adjust Load point to required MVA @ rated PF
* Run at load point until stator temp stabilize < 2 degrees /hr (rise)
* Take 3 consecutive readings at 1/2 hr interval

NCR #: N/A

Measurement Instruments	T°		
AH DAQ # 376-415-703	Before:	N/A	
Unit control board	After:	N/A	
N/A			

Measured by: MA Pilon		dd-mmm-yyyy
		28-Mar-2017
ANDRITZ Rep.: MA Pilon		29-Mar-2017
Cust. Repres.:		

ANDRITZ Hydro

Installation and Commissioning

Quality Control Record

Generator Heat run - 5 MW

Q-1524-040

ITP step #: 1550-08

Revision # 03

Project: Whitehorse

Unit : 4

Additional parameters

Parameters	Units	Time		
		13H00	13H30	14H00
Weir Flow	N/A	197	194	194
Gate Position	%	46.3	46.3	45.1
Air gap 1	mils min	473	474	474
Air gap 2	mils min	525	524	524
Air gap 3	mils min	581	581	581
Air gap 4	mils min	479	480	479
Stator core accel #1	mils pp	6.4	6.5	6.7
Stator core accel #2	mils pp	6.5	6.3	6.2
Spiral Case	kPa	107.5	106.0	106.0
Field Volts Exciter	V	590	580	590
Field Amps Exciter	A	99	98	100
N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A

Parameters	Units	Time		
		13H00	13H30	14H00
Winding #1	°C	29.4	29.4	29.1
Winding #2	°C	32.8	32.8	32.5
Winding #3	°C	29.1	29.2	29.6
Winding #4	°C	27.4	27.5	27.2
Winding #5	°C	33.5	33.9	33.3
Winding #7	°C	27.6	27.7	27.5
Winding #8	°C	28.0	28.0	27.8
Winding #9	°C	29.4	29.5	29.2
Winding #10	°C	26.2	26.3	26.0
Winding #11	°C	27.3	27.2	27.0
SAC air in	°C	26.2	26.2	26.2
SAC air out	°C	32.0	32.0	32.0
Turbine brg	°C	48.3	48.8	49.2
Guide brg	°C	51.2	51.2	51.3
Thrust # 1	°C	54.2	54.2	54.2
Thrust # 2	°C	55.9	55.9	55.8
Thrust Ave	°C	55.1	55.1	55.0

NCR #: N/A

Measurement Instruments	T°			dd-mmm-yyyy
AH DAQ # 376-415-703	Before:	N/A	Measured by: MA Pilon	28-Mar-2017
Unit control board	After:	N/A	ANDRITZ Rep.: MA Pilon	29-Mar-2017
N/A			Cust. Repres.:	

ANDRITZ Hydro

Installation and Commissioning

Quality Control Record

Generator Heat run - 17.5 MW

Q-1524-040

ITP step #: 1550-08

Revision # 03

Project: Whitehorse

Unit : 4

Power Readings:

Parameters	Units	Time		
		8H00	8H30	9H00
Field Volts	V	820	800	800
Field Amps	A	95	90	90
Arm volts 1	N/A	N/A	N/A	N/A
Arm Volts 2	N/A	N/A	N/A	N/A
Arm Volts 3	N/A	N/A	N/A	N/A
Avg Arm Volts	kV	6.8	6.8	6.8
Arm Amps 1	A	1520	1510	1510
Arm Amps 2	A	1510	1505	1505
Arm Amps 3	A	1525	1525	1525
Avg Arm Amps	A	1518.33	1513.33	1513.33
MVA	N/A	N/A	N/A	N/A
MW	MW	17.7	17.6	17.75
Mvars	MVars	4.0 Out	3.4 Out	3.3 Lag
PF	pf	0.94 Lag	0.94 Lag	0.94 Lag
Hertz	N/A	N/A	N/A	N/A
T winding average	°C	59.33	59.04	58.95

Parameters	Units	Time		
		8H00	8H30	9H00
Vib. UGB -x	mils pp	9	9	9
Vib. UGB -y	mils pp	10	10	9
Vib. LGB-x	mils pp	4	4	4
Vib. LGB-y	mils pp	5	5	5
Vib. TGB-x	mils pp	2	2	2
Vib. TGB-y	mils pp	2	2	2

Note; * Adjust Load point to required MVA @ rated PF
* Run at load point until stator temp stabilize < 2 degrees /hr (rise)
* Take 3 consecutive readings at 1/2 hr interval

NCR #: N/A

Measurement Instruments	T°			
AH DAQ # 376-415-703	Before:	N/A	Measured by: MA Pilon	29-Mar-2017
Unit control board	After:	N/A	ANDRITZ Rep.: MA Pilon	31-Mar-2017
N/A			Cust. Repres.:	

ANDRITZ Hydro

Installation and Commissioning

Quality Control Record

Generator Heat run - 17.5 MW

Q-1524-040

ITP step #: 1550-08

Revision # 03

Project: Whitehorse

Unit : 4

Additional parameters

Parameters	Units	Time 8H00	8H30	9H00
Weir Flow	N/A	197	194	193
Gate Position	%	74.4	74.4	74.4
Air gap 1	mils min	523	523	524
Air gap 2	mils min	564	564	564
Air gap 3	mils min	608	607	608
Air gap 4	mils min	522	522	521
Stator core accel #1	mils pp	2.9	2.7	2.4
Stator core accel #2	mils pp	2.9	3.1	2.9
Spiral Case	kPa	129.0	127.5	127.0
Field Volts Exciter	V	749	748	745
Field Amps Exciter	A	115	115	115
N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A

Parameters	Units	Time 8H00	8H30	9H00
Winding #1	°C	59.5	59.2	59.1
Winding #2	°C	63.6	63.3	63.2
Winding #3	°C	59.9	59.4	59.5
Winding #4	°C	57.3	57.0	56.9
Winding #5	°C	63.3	63.1	63.0
Winding #7	°C	57.8	57.5	57.4
Winding #8	°C	58.8	58.5	58.4
Winding #9	°C	60.0	59.7	59.6
Winding #10	°C	56.0	55.7	55.6
Winding #11	°C	57.1	57.0	56.8
SAC air in	°C	42.0	42.0	42.0
SAC air out	°C	36.0	36.0	36.0
Turbine brg	°C	47.2	47.2	47.2
Guide brg	°C	51.7	51.7	51.7
Thrust # 1	°C	56.9	56.9	56.9
Thrust # 2	°C	59.2	59.2	59.2
Thrust Ave	°C	58.1	58.1	58.1

NCR #: N/A

Measurement Instruments	T°	Measured by: MA Pilon	dd-mmm-yyyy
AH DAQ # 376-415-703	Before: N/A		29-Mar-2017
Unit control board	After: N/A	ANDRITZ Rep.: MA Pilon	31-Mar-2017
N/A		Cust. Repres.:	

ANDRITZ Hydro

Installation and Commissioning

Quality Control Record

Generator Heat run - 21 MW

Q-1524-040

ITP step #: 1550-08

Revision # 03

Project: Whitehorse

Unit : 4

Power Readings:

Parameters	Units	Time		
		13H00	13H30	14H00
Field Volts	V	855	850	860
Field Amps	A	100	100	100
Arm volts 1	N/A	N/A	N/A	N/A
Arm Volts 2	N/A	N/A	N/A	N/A
Arm Volts 3	N/A	N/A	N/A	N/A
Avg Arm Volts	kV	6.8	6.8	6.8
Arm Amps 1	A	1800	1805	1805
Arm Amps 2	A	1800	1805	1800
Arm Amps 3	A	1805	1810	1805
Avg Arm Amps	A	1801.67	1806.67	1803.33
MVA	N/A	N/A	N/A	N/A
MW	MW	21.25	21.2	21.25
Mvars	MVars	3.5 Out	3.4 Out	3.6 Out
PF	pf	0.945 Lag	0.945 Lag	0.945 Lag
Hertz	N/A	N/A	N/A	N/A
T winding average	°C	68.99	69.24	69.32

Parameters	Units	Time		
		13H00	13H30	14H00
Vib. UGB -x	mils pp	12	13	12
Vib. UGB -y	mils pp	12	11	11
Vib. LGB-x	mils pp	4	4	4
Vib. LGB-y	mils pp	5	5	5
Vib. TGB-x	mils pp	2	2	2
Vib. TGB-y	mils pp	2	2	2

Note; * Adjust Load point to required MVA @ rated PF
* Run at load point until stator temp stabilize < 2 degrees /hr (rise)
* Take 3 consecutive readings at 1/2 hr interval

NCR #: N/A

Measurement Instruments	T°	Measured by: MA Pilon	dd-mmm-yyyy
AH DAQ # 376-415-703	Before: N/A		29-Mar-2017
Unit control board	After: N/A	ANDRITZ Rep.: MA Pilon	31-Mar-2017
N/A		Cust. Repres.:	

ANDRITZ Hydro

Installation and Commissioning

Quality Control Record

Generator Heat run - 21 MW

Q-1524-040

ITP step #: 1550-08

Revision # 03

Project: Whitehorse

Unit : 4

Additional parameters

Parameters	Units	Time 13H00	13H30	14H00
Weir Flow	N/A	195	196	198
Gate Position	%	88.2	88.2	88.2
Air gap 1	mils min	525	525	525
Air gap 2	mils min	566	566	566
Air gap 3	mils min	610	610	609
Air gap 4	mils min	524	524	524
Stator core accel #1	mils pp	3.3	2.9	2.9
Stator core accel #2	mils pp	5.1	3.0	4.1
Spiral Case	kPa	124.5	124.5	124.5
Field Volts Exciter	V	760	760	760
Field Amps Exciter	A	130	125	140
N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A

Parameters	Units	Time 13H00	13H30	14H00
Winding #1	°C	72.3	72.5	72.6
Winding #2	°C	77.1	77.2	77.0
Winding #3	°C	72.3	72.6	72.6
Winding #4	°C	70.1	70.2	70.4
Winding #5	°C	76.2	76.4	76.6
Winding #7	°C	70.8	70.9	71.0
Winding #8	°C	72.1	72.3	72.4
Winding #9	°C	73.2	73.4	73.5
Winding #10	°C	68.8	68.9	69.1
Winding #11	°C	70.1	70.3	70.3
SAC air in	°C	48.0	48.0	48.0
SAC air out	°C	37.0	38.0	38.0
Turbine brg	°C	46.6	46.5	46.5
Guide brg	°C	52.5	52.6	52.6
Thrust # 1	°C	58.8	58.9	58.9
Thrust # 2	°C	61.3	61.3	61.4
Thrust Ave	°C	60.1	60.1	60.2

NCR #: N/A

Measurement Instruments	T°	Measured by: MA Pilon	dd-mmm-yyyy
AH DAQ # 376-415-703	Before: N/A		29-Mar-2017
Unit control board	After: N/A	ANDRITZ Rep.: MA Pilon	31-Mar-2017
N/A		Cust. Repres.:	



Appendix C

Exciter and Circuit Breaker Nameplates

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Excitation System Nameplate



Generator Circuit Breaker Nameplate

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Appendix D

Cost Estimate

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Whitehorse Generating Station Unit WH4
Capacity Increase Desktop Study
Cost Estimate

Labour Rates = 100 $/hour

				Unit Costs				Subtotal Cost	
Item #	**Description**	**Qty**	**Unit**	**Material Cost**		**Labour Cost**		**Material Cost**	**Labour Cost**
A.1	Servo motor replacement with larger dia servomotor	2	ea	42000	See Note 5	4,000.0	40 hours labour per servo motor.	84,000.0	8,000.0
A.2	Piping and fittings	1	Lot	5000	Allowance	4,000.0	Allowance	5,000.0	4,000.0
A.3	Shear pins and installation device	10	ea	250.5	Component wt. (25+0.5 lb) @10$/lb	1,000.0	Engineering + Installation	2,505.0	10,000.0
A.4	Shear Pin Links	20	Lot	520	Component wt 52 lb @ $10/lb	700.0	Engineering + Installation	10,400.0	14,000.0
A.5	Bushings in servo motor links	2	ea	500	assumed	1,000.0	Engineering + Installation	1,000.0	2,000.0
B	**Generator Leads**								
	Cables (30 meter, 9 lengths)	0	m	45	Typical Cost	8,000.0	80 hours	0.0	0.0
	Terminatioon kits	0	ea	200	Typical Cost	200.0	Two hours per kit	0.0	0.0
	Supports and anchors	0	lot	3000	Allowance	2,000.0	Allowance	0.0	0.0
C	**Generator Circuit Breaker**								
	Circuit Breaker	1	Lot	65000	Typical Cost	10,000.0	100 hours	65,000.0	10,000.0
D	**Subtotal Material and Labour (A+B+C)**							167,905.0	48,000.0
E	**Contingency (30% material & 50% labour)**							50,371.5	24,000.0
F	**Engineering (30% of the Material and Labour)**								64,771.5
G	**Overheads and Profits (20% material and 30% labour)**							33,581.0	14,400.0
H	**Project Management (20% of material and Labour)**								43,181.0
I	**Testing and Commisioning (5% of the material and labour)**								10,795.3
J	Total Cost							**251,857.5**	**205,147.8**
K	**Grand Total**								**457,005.3**

HATCH

Alternative 2 - Spring Assembly

A	Addition of spring to aid Closing	Qty	Unit	Material Cost		Labour Cost		Material Cost	Labour Cost
A.1	Spring assembly	1	ea	100,000.0	Assumed	4,800.0		100,000.0	4,800.0
A.2	Shear pins and Installation device	10	ea	250.5	Component wt. (25+0.5 lb) @10$/lb	1,000.0	Engineering + Installation	2,505.0	10,000.0
A.3	Shear Pin Links	20	Lot	520.0	Component wt 52 lb @ $10/lb	700.0	Engineering + Installation	10,400.0	14,000.0
A.4	Bushings in servo motor links	2	ea	500.0	assumed	1,000.0	Engineering + Installation	1,000.0	2,000.0
B	**Generator Leads**								
	Cables	0	Lot	45.0	Typical Cost	8,000.0	80 hours	0.0	0.0
	Terminatioon kits	0	ea	200.0	Typical Cost	200.0	Two hours per kit	0.0	0.0
	Supports and anchors	0	lot	3,000.0	Allowance	2,000.0	Allowance	0.0	0.0
C	**Generator Circuit Breaker**								
	Circuit Breaker	1	Lot	65,000.0	Typical Cost	10,000.0	100 hours	65,000.0	10,000.0
D	**Subtotal Material and Labour (A+B+C+D)**							178,905.0	40,800.0
E	**Contingency (30% material & 50% labour)**							53,671.5	20,400.0
F	**Engineering (30% of the Material and Labour)**								65,911.5
G	**Overheads and Profits (20% material and 30% labour)**							35,781.0	12,240.0
H	**Project Management (20% of material and Labour)**								43,941.0
I	**Testing and Commisioning (5% of the material and labour)**								10,985.3
J	Total Cost							**268,357.5**	**194,277.8**
K	**Grand Total**								**462,635.3**

Notes/Assumptions

1 All costs are in Canadian Dollars for year 2017 excluding taxes.
2 Mobiliztion/demobilization costs are not included.
3 Since actual construction cost and time and operating cost are each contingent upon factors over which Hatch has no control, Hatch cannot and does not warrant or represent that such cost and/or time will not exceed the estimate(s) thereof
4 Owner's cost are not included.
5 Servomotor cost is estimated @20% of the overall governor system cost. Cost for a governor system for a unit of this size is expected to be $420,000.



Appendix E

L&S Reports

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Confidential for Customer Information Only		
L&S ELECTRIC, INC. ENGINEERING DIVISION 1810 COUNTY ROAD XX ROTHSCHILD, WI 54474 USA	CLIENT: YUKON ENERGY CORP. PROJECT: WHITEHORSE UNIT 4 GOVERNOR L&S PROJECT: MA75860	
PREPARED BY: DAVID BISHOFF DATE ORIGINATED: SEPTEMBER 22, 2009 DATE LAST REVISION: OCTOBER 22, 2009	WHITEHORSE UNIT 4 GOVERNOR UPGRADE EVALUATION	

Rene Garcia and I visited Darrell Johnson of Yukon Energy in September of 2009, and we learned the following:

In 1982 when DEW installed W-4, they learned when they went over 85% gate they were having servo loading problems, so they installed an 85% high gate limit to prevent going over 85%. They did meet their power requirements at this maximum gate, so they left the turbine with the permanent "85% high gate limit".

Earlier this year, Yukon Energy wanted to take advantage of this extra 15% gate opening (to gain up to 1½ MW of extra power). It was soon learned that once gates were above 85% the gates were no longer responding at normal governor pressures. It was then determined that with 340 PSI pressure the gates were freely moving again. For the purpose of this study we will use 335 PSI as our "stall pressure".

The intent of this study will be to end up with a solution using the experience and suggestions from IEEE-125, supplement code 1207, paragraph 7.7.2 (servo motor loading).

This code suggests we use a servo differential load of no more than 70% of normal system pressure, and that a pressure be provided with a minimum float valve closure pressure of 75% of normal system pressure. In discussing this section of the code with its Author, he explained that the concept of "stall pressure" is hard for people to agree on. So, when covering this in 1207 they worded it as above, but in fact they are meaning the actual stall pressure needs to be no more than 70% of normal pressure.

Study of our stall force at 335 PSI:

Fstall = (Pstall)(area of the two existing servos)

Area study, with 12" bores, and their 3½" rods

A (12) = 113 square inches, A(3 ½) = 9.62 square inches, and delta A = 103.4 square inches. So the total area for the two servos is 113 + 103.4 = 216.4 square inches

Fstall = (335)(216.4) = 72,500 pounds

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Solution #1:

First we will study a system using nearly the same system pressure, and see what size of servo is required to produce this stall force at 70% of normal pressure.

We will do this study using a 14" bore servo, with a 4" diameter rod, and 21 ¼" stroke:

A(14) = 154 square inches, A(4) = 12.6 square inches, and a delta A = 141.4 square inches. So the total area of these two servos is 154 + 141.4 = 295.4 square inches.

Next let's study the normal system pressure with this servo design:

We know F = PA, so Pstall = Fstall/A(total) = 72,500/295.4 = 245 PSI , and:

Pnormal = Fstall/.7 = 350 PSI, and this is perfect for our new pump stop pressure. We will design the new pressure tank using IEEE-125 (1207), calling for 20 servo volumes above the float valve, and have attached computer printout of this new tank. We have selected a max design pressure of 400 PSI, and this would be the new air safety set point. All present systems are at proper ratings with this maximum pressure of 400 PSI.

List of changes to complete option # 1: (see attached sketch SK10120901 for reference)

1. Need two new 14" dia. servos, designed for 400 PSI, and with a 4" dia. rod, and 21¼" stroke, with 2 ½" SAE outlet ports - - with cushions at respective closing ends, and provisions for manual gate lock on one of the cylinders (see SK10120901).

2. The following new parts are also needed:
   a. (2) new rod end clevises, and (2) new servo mounting pads.
   b. (1) new manual gate lock "horseshoe clamp".
   c. (4) 6 foot, new 1000 PSI flex hoses, with 2½" male SAE end fittings.
   d. (4) 2½", #61, SAE weld flanges to connect to existing 2½" pipes in pit.
   e. (1) new MLDT, bracket, restoring post to fit on new servo (use existing MLDT if possible).
   f. (1) new pressure tank, with: float valve, 400 PSI sight gauge assembly, 400 PSI air safety, shut off valve to bring pilot pressure oil to actuator, and 12"X16" man-door, 4"-300 pound slip on flange to adapt to existing 4" piping (a field weld will be required to connect to existing piping).

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3. Replace existing 15 HP motor in actuator with 20 HP motor, and fix heaters in Starter. Pumps need to be raised slightly and re-piped. Add a new control box to allow an "auto echelon control" of oil pumps (to cut motor starts per hour in half).

4. Need to add new 14 GPM KLF system in existing governor cabinet and a 5 HP motor starter.

5. All equipment in existing governor is OK, except oil safeties need to be re-set to 380 PSI, and governor stop nuts need to be reset to compensate for new servo volume (reset to existing timing).

Solution #2:

On this option we will use a new high pressure solution and see what this system looks like. Our size for this is a 7" dia. bore and a 3½" dia. rod with the same 21¼" stroke with all of the components in this system being designed for 3000 PSI:

A(7) = 38.5 square inches, A(3 ½:) = 9.6 square inches, and delta A = 28.9 square inches, so the total servo area = 38.5 + 28.9 = 67.4 square inches.

We again need to study the normal system pressure for this new servo:

Pstall = Fstall/A(total) = 72,500/67.4 = 1075 PSI, and;

Pnormal = Pstall/.7 = 1536 PSI, so lets make this 1550 PSI.

Notes: a) On L&S, standard HPUs, we have all our pump and motor sized to provide up to 2200 PSI normal pressure; b) I prefer pressures below 2000 PSI when possible, and this 1550 PSI is a good pressure level for high pressure systems.

With this system we have the following list of requirements and/or changes:

1. Our standard 130 gallon oil sump, with two 1750 RPM, 15 HP, and 8.25 GPM, (2) vertical mounted oil pumps, each with unloader valve assemblies, with kidney loop filter system provided, and for fewer starts per hour, auto echelon pump controls. This HPU would be located in the same location as the present oil pressure tank in basement. The upstairs cabinet actuator and all its piping would be completely removed.

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2. (1) accumulator bank, with 5, 15 gallon bladders, and 5, 15 gallon nitrogen tanks, interconnected, and with a mounting rack frame to support tanks allowing the assembly tanks, valves, and tubing in our shop.

3. (2) new 7" dia. servos with 3½" dia. rods and 21¼" stroke (3000 PSI rated).

4. (2) new rod end clevises and (2) new servo mounting pads.

5. (1) new manual gate lock.

6. (4) 6 foot, new 3000 PSI rated (12,000 PSI burst) flex hoses. Customer to provide and install 1 ½" SS tubing to suit interconnections of accumulator bank, HPU, and open and close lines from HPU to the turbine pit.

7. 1 MLDT, bracket, and restoring post to fit new servo.

Comments and conclusions:

1. These new options both provide the force recommended by IEEE-125 (1207), but this adds a new force capability going from 72,500 pounds to a new force at 104,000 pounds. The actual force at the wicket gates will be no more than what you have now, but these new servos do have a higher force capability:

    A. We are not making any changes to the turbine other than adding the new servo mounting pads and front rod clevises, but your steel turbine parts should be designed with a 3 to 1 safety factor, so our additional force should not be dangerous - - but to clarify, we are not evaluating these turbine parts or their stresses.

    B. We are proposing new servos with the same exact stroke and the same exact servo squeeze. Our suggestion (with this new higher force capability) is to take extra care when adjusting the gate squeeze to only apply the same amount of squeeze you have now, so you'll only be applying the same gate squeeze (and same load) as you have now.

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2. We do see our option #1 as being more cost effective than our option #2, and this may be your preference, but let's look at some pros and cons:

   A. Your new low pressure system will require a little over 400 gallons of oil (same kind of oil you are using now), while the high pressure option will only require about 100 gallons to fill the system. This new oil should be of an ISO 46, with a high pressure additive (like Mobil DTE-25).

   B. In the low pressure option, you keep the entire upstairs cabinet actuator, but you do need to upgrade the two pump motors and do some re-piping of the unloader connections, plus you will need to add a new kidney loop filter assembly and its starter. You also can keep all of your existing 3½" header piping (a field weld is required at the new pressure tank outlet flange), and you can also keep most of the control piping going down to the turbine pit, but you will need to make some flange connections for the new flex hoses at the new servos.

   C. In the high pressure option all of the old cabinet actuator goes, and all the low pressure piping goes, but you will need to add new 1½" high pressure SS tubing to interconnect these new systems.

   D. With the high pressure system you will now need to charge your new accumulator system with nitrogen, while for your low pressure system you can keep charging your tank with your existing system.

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```
Inputs:
   Yukon Energy Option #1:
ID Tank
Using servo volumes for volume inputs.
Tank Diameter- 42
Outlet pipe diameter- 4
Servo volume-     3.570
Tank ratio-    20.00
Tank Design pressure-    400.
Calculation Start point
Pressure-     350.
Volume-     5.00


                  Yukon Energy Option #1:
             2009/ 9/ 4     12:11: 0
Tank Type-                           ID
Tank Diameter-                       42 inches
Base Height-                          4 inches
Height at top head exterior-    109.375 inches
Outlet pipe diameter-                 4 inches
Thickness of Shell-                .6250 inches
Thickness of Heads-                .5000 inches
Servo Volume-                     3.570 cubic feet
Active Volume-                   71.400 cubic feet
Dead Oil Volume-                  6.990 cubic feet
Tank Design Pressure           400. psig at    46.625 inches of oil
Calculation Start Pressure     350. psig at    38.500 inches of oil
Dead Oil Pressure              259. psig at    16.250 inches of oil.

                Pressure Volume Table

Pressure    Level   Active oil volume   Oil vol. change   Air volume
 (psig)     (in)   (servo vol,cubic ft)   (cubic ft)      (cubic ft)

   350.    38.500     5.00     17.85         17.85           53.55
```

INTRODUCTION **2**

HPU CONFIGURATION CHANGES **2**

AS DESIGNED HPU SETTINGS 2
AS DESIGNED ALARM/TRIP SETTINGS 2
TEMPORARY HPU SETTINGS 3
TEMPORARY ALARM/TRIP SETTINGS 3

PROGRAM CHANGES **4**

SUMMARY **4**

REVISION HISTORY **5**

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Introduction

Due to the gate stalling issues on WH4 gate servo motors, some setting and program modifications were made to help with some of the associated problems. These changes do not solve the problem, but help eliminate some potential risks by giving some more visibility to some of the conditions that are associated with the gate stalling. It is the recommendation of L&S Electric that larger servomotors replace the existing servomotors on WH4. This will give the servos more force and will eliminate the gate stalling. After the servomotors are replaced, the settings and program modifications should be set back the as designed conditions.

HPU Configuration Changes

Some of the pump control settings were changed to help alleviate some of the stalling problems. The HPU pressures were increased a little so the oil pressure stays out of the stalling range (found to be about 330 to 340 psi while on site in May 2010).

As Designed HPU Settings

Lead Pump Start Press. (psi)	315
Lead Pump Stop Press. (psi)	350
Lag Pump Start Press. (psi)	300
Lag Pump Stop Press. (psi)	350
Pump 1 MtrStopDlyTime (sec)	3
Pump 1 UnloaderDlyTime (sec)	2
Pump 1 MtrFailDlyTime (sec)	4
Pump 2 MtrStopDlyTime (sec)	3
Pump 2 UnloaderDlyTime (sec)	2
Pump 2 MtrFailDlyTime (sec)	4
Air Charge Level (in)	41.5
Air Charge Time (sec)	180
Temp Ctrl High (degF)	85
Temp Ctrl Low (degF)	110
KLF Motor Dly Time (sec)	2

As Designed Alarm/Trip Settings

Accumulator Level HI (in)	45.5
Accumulator Level LO (in)	27.4
Oil Pressure LO (psi)	290

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Oil Pressure HI (psi)	380
Oil Sump Level LO (in)	2.25
Oil Sump Level HI (in)	9
Oil Temperature LO (degF)	70
Oil Temperature HI (degF)	130
Accum. Level LOLO (in)	25
Oil Pressure LOLO (psi)	281
Oil Sump Level LOLO (in)	1.75
HPU Alarm Delay Time (msec)	5000
HPU Trip Delay Time (msec)	2000

Temporary HPU Settings

Lead Pump Start Press. (psi)	350
Lead Pump Stop Press. (psi)	375
Lag Pump Start Press. (psi)	340
Lag Pump Stop Press. (psi)	375
Pump 1 MtrStopDlyTime (sec)	3
Pump 1 UnloaderDlyTime (sec)	2
Pump 1 MtrFailDlyTime (sec)	4
Pump 2 MtrStopDlyTime (sec)	3
Pump 2 UnloaderDlyTime (sec)	2
Pump 2 MtrFailDlyTime (sec)	4
Air Charge Level (in)	41.5
Air Charge Time (sec)	180
Temp Ctrl High (degF)	85
Temp Ctrl Low (degF)	110
KLF Motor Dly Time (sec)	2

Temporary Alarm/Trip Settings

Accumulator Level HI (in)	45.5
Accumulator Level LO (in)	27.4
Oil Pressure LO (psi)	345
Oil Pressure HI (psi)	380
Oil Sump Level LO (in)	2.25

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Oil Sump Level HI (in)	9
Oil Temperature LO (degF)	70
Oil Temperature HI (degF)	130
Accum. Level LOLO (in)	25
Oil Pressure LOLO (psi)	330
Oil Sump Level LOLO (in)	1.75
HPU Alarm Delay Time (msec)	5000
HPU Trip Delay Time (msec)	2000

Program Changes

In the program, some additional logic was added in the event of a low pressure alarm. If a low pressure alarm is active in the governor, the governor will not allow a gate limit higher than 92%. This will help keep the governor position out of the known stalling range.

Another alarm was added which will help indicate that the servomotors are beginning to stall. In the governor configuration, the maximum gate limit was changed to 99.75%. If the gate position is greater than 99.95% a "Gates are Stalling" alarm is generated. This alarm indicates that the water force is starting to overcome the servomotor force because the governor cannot hold the gate position at the maximum setting of 99.75%.

Summary

1.) The normal pump stop pressure was raised from 350 psi to 375 psi.
2.) The lead pump on pressure was raised from 315 psi to 350 psi.
3.) The low pressure alarm was raised from 290 psi to 345 psi.
4.) The lag pump pressure was raised from 300 psi to 340 psi.
5.) The low pressure trip was raised from 281 psi to 330 psi.

This will keep the oil pressure normally above 350 psi which is above the known stall pressure. If the lead pump fails, it will cause a low pressure alarm right away which will give the operator some visibility and allow the operator to start unloading the generator before the gates stall. In addition, the governor will automatically lower the gate limit to 92% (if it is above 92%). However, since the pressure settings are so close together, it is possible that during a normal start or a large frequency change, the servomotors could consume oil from the accumulator very quickly before the HPU pumps have time to load and start pumping more oil in the tank. In this situation, the low pressure alarm will come in and have to be cleared.

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If the gate position is greater than 0.2% above the gate limit, a "Gates are Stalling" alarm will be generated.

Revision History

Rev	Date	Change Description	By	App
NEW	8/11/10	New	JRT	JAR

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Appendix F

Typical Spring Assembly Arrangement

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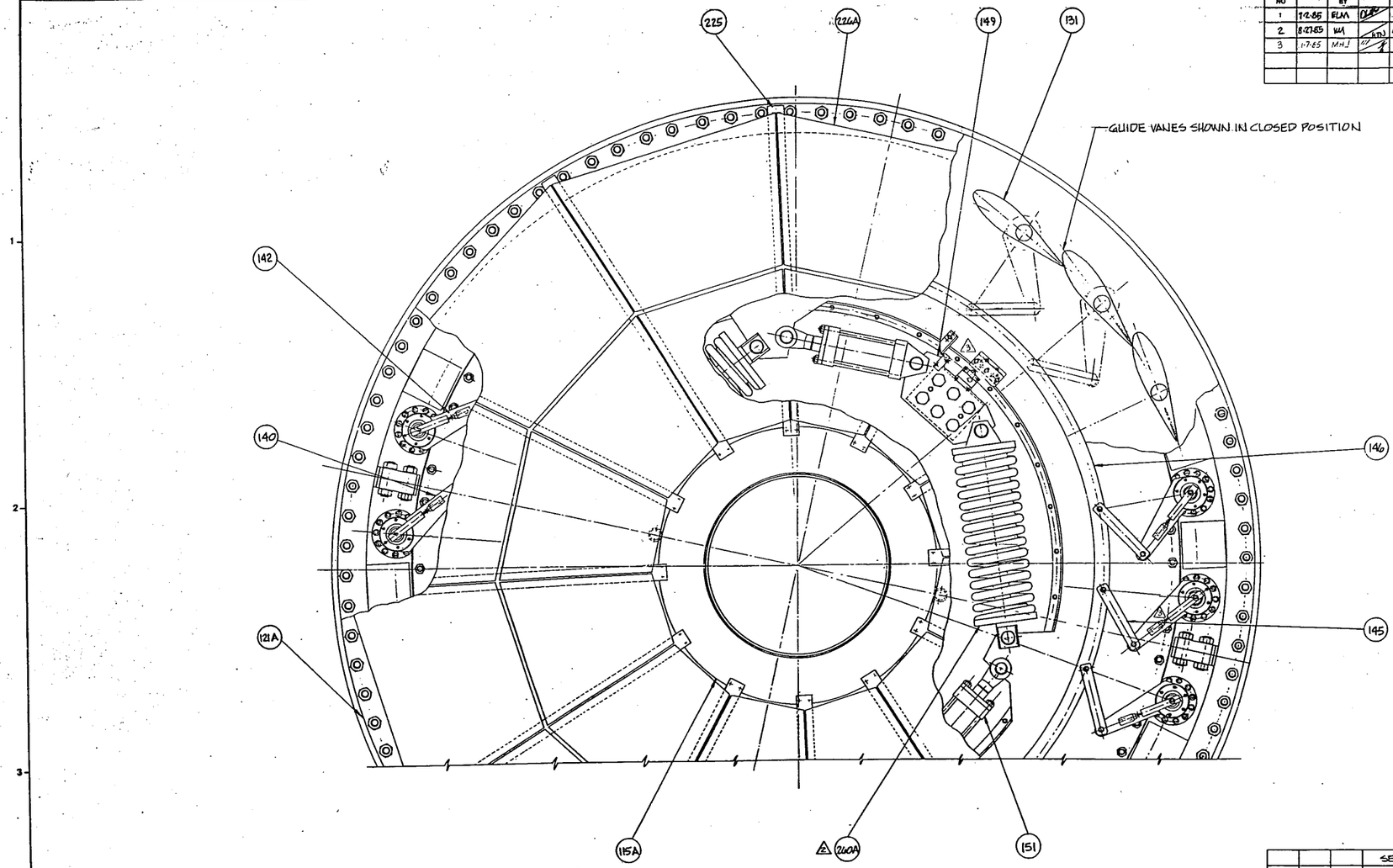
ISSUE NO	DATE	DRAWN BY	APPR'D	REVISION
1	7-2-85	ELM		ORIGINAL ISSUE
2	8-27-85	WH	KTJ	ADDED ITEM 260A ; REDRAWN
3	1-7-85	MHJ	KTJ	ADDED DECLERATION VALVE & LIMIT SWITCHES



VIEW "A-A"
SHT. 2

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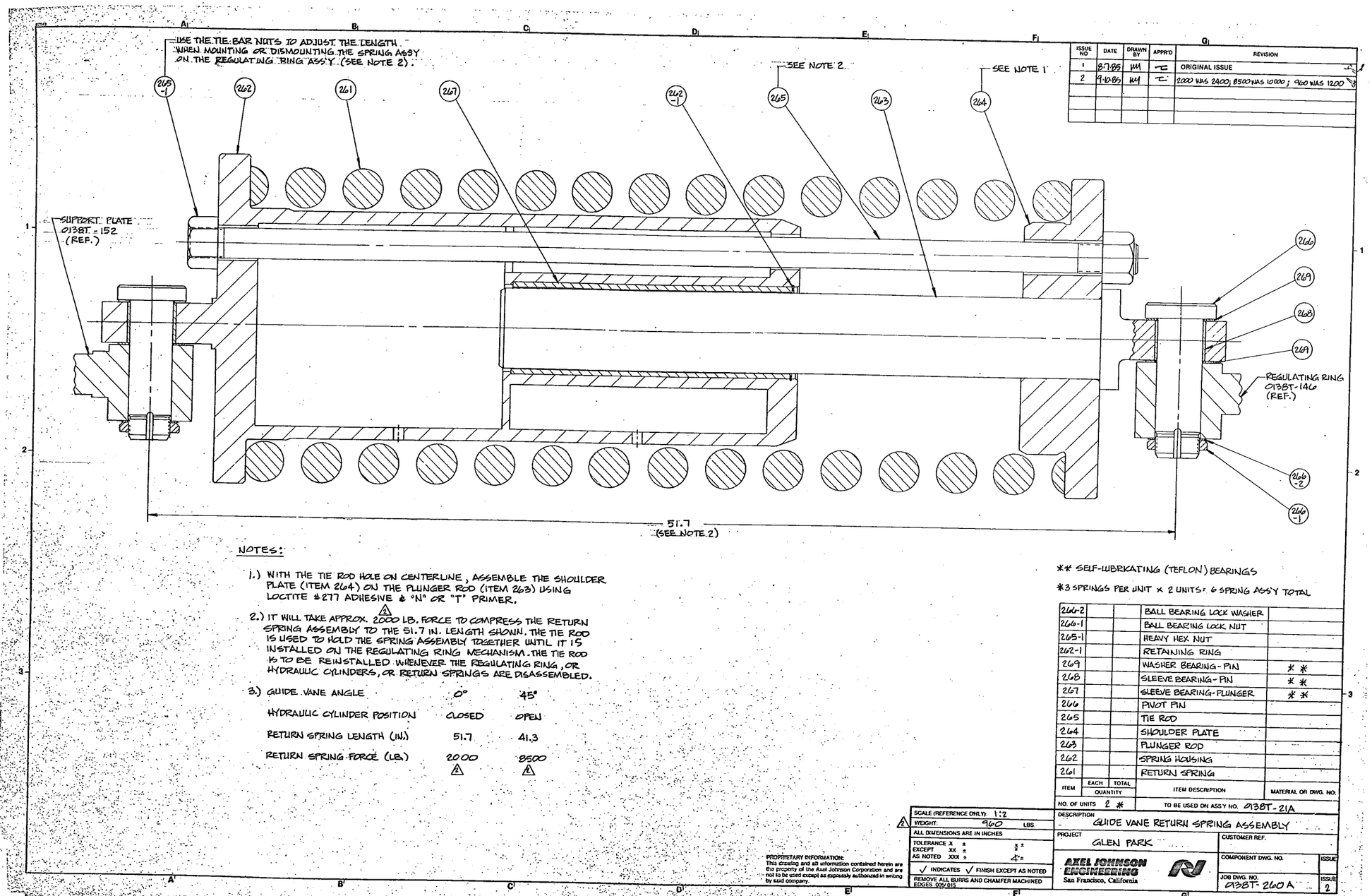
SEE 0138-DD-13

ITEM	QUANTITY EACH	QUANTITY TOTAL	ITEM DESCRIPTION	MATERIAL OR DWG. NO.
NO. OF UNITS	2		TO BE USED ON ASS'Y NO.	

SCALE (REFERENCE ONLY): NTS
WEIGHT: ——— LBS.
ALL DIMENSIONS ARE IN INCHES
TOLERANCE X ± EXCEPT .X ± AS NOTED .XX ± .X ± ANGLES ±
√ INDICATES √ FINISH EXCEPT AS NOTED
REMOVE ALL BURRS AND CHAMFER MACHINED EDGES .005/.015

DESCRIPTION: TURBINE SECTIONAL
PROJECT: GLEN PARK
CUSTOMER REF.
AXEL JOHNSON ENGINEERING
San Francisco, California
COMPONENT DWG. NO. — ISSUE
JOB DWG. NO. 0138T-02A — SHT. 3 OF 10 — ISSUE 3



ISSUE NO	DATE	DRAWN BY	APP'D	REVISION
1	8-7-85	MM	TC	ORIGINAL ISSUE
2	9-10-85	MM	TC	2000 WAS 2400; 8500 WAS 10000; 960 WAS 1200

NOTES:

1.) WITH THE TIE ROD HOLE ON CENTERLINE, ASSEMBLE THE SHOULDER PLATE (ITEM 264) ON THE PLUNGER ROD (ITEM 263) USING LOCTITE #277 ADHESIVE & "N" OR "T" PRIMER.

2.) IT WILL TAKE APPROX. 2000 LB. FORCE TO COMPRESS THE RETURN SPRING ASSEMBLY TO THE 51.7 IN. LENGTH SHOWN. THE TIE ROD IS USED TO HOLD THE SPRING ASSEMBLY TOGETHER UNTIL IT IS INSTALLED ON THE REGULATING RING MECHANISM. THE TIE ROD IS TO BE REINSTALLED WHENEVER THE REGULATING RING, OR HYDRAULIC CYLINDERS, OR RETURN SPRINGS ARE DISASSEMBLED.

3.) GUIDE VANE ANGLE 0° 45°

HYDRAULIC CYLINDER POSITION CLOSED OPEN

RETURN SPRING LENGTH (IN.) 51.7 41.3

RETURN SPRING FORCE (LB.) 2000 8500

** SELF-LUBRICATING (TEFLON) BEARINGS

*3 SPRINGS PER UNIT x 2 UNITS = 6 SPRING ASS'Y TOTAL

ITEM	EACH	TOTAL	ITEM DESCRIPTION	MATERIAL OR DWG. NO.
266-2			BALL BEARING LOCK WASHER	
266-1			BALL BEARING LOCK NUT	
265-1			HEAVY HEX NUT	
262-1			RETAINING RING	
269			WASHER BEARING - PIN	**
268			SLEEVE BEARING - PIN	**
267			SLEEVE BEARING - PLUNGER	**
266			PIVOT PIN	
265			TIE ROD	
264			SHOULDER PLATE	
263			PLUNGER ROD	
262			SPRING HOUSING	
261			RETURN SPRING	

NO. OF UNITS 2 * — TO BE USED ON ASS'Y NO. 013BT-21A

DESCRIPTION: GUIDE VANE RETURN SPRING ASSEMBLY

PROJECT: GLEN PARK — CUSTOMER REF.

AXEL JOHNSON ENGINEERING, San Francisco, California

COMPONENT DWG. NO. — ISSUE

JOB DWG. NO. 013BT-260A — ISSUE 2

SCALE (REFERENCE ONLY) 1:2

WEIGHT: 960 LBS

ALL DIMENSIONS ARE IN INCHES

TOLERANCE X ± EXCEPT XX ± AS NOTED XXX ± — X ± 1/8 ± 4° ±

√ INDICATES √ FINISH EXCEPT AS NOTED

REMOVE ALL BURRS AND CHAMFER MACHINED EDGES .005/.015

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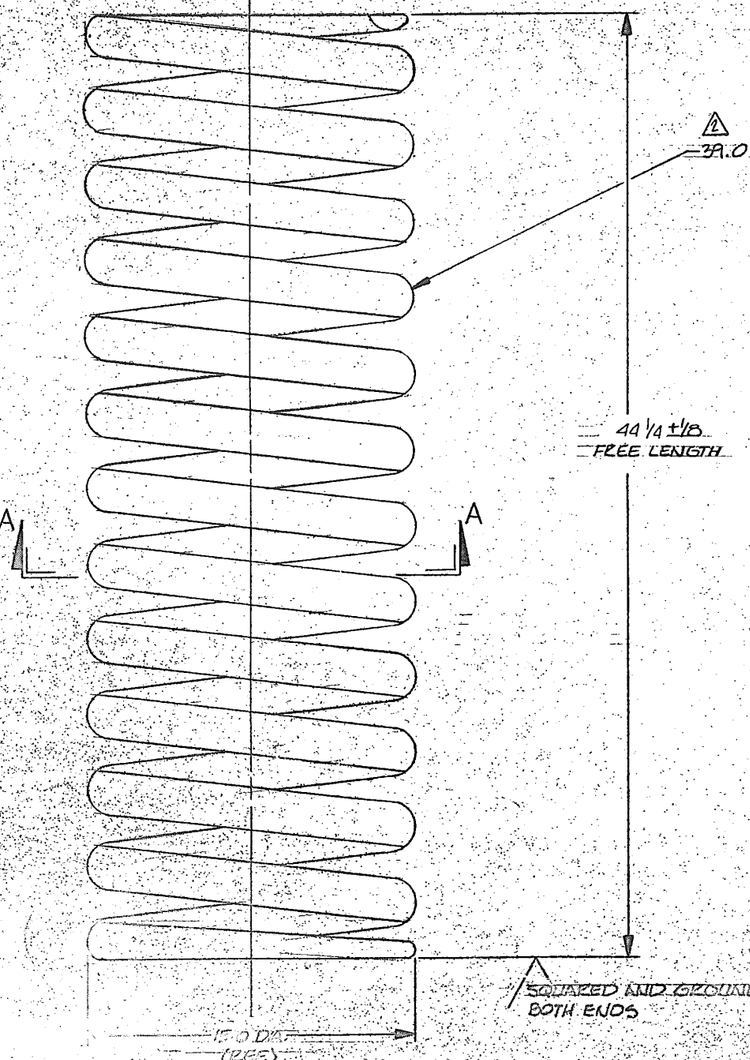
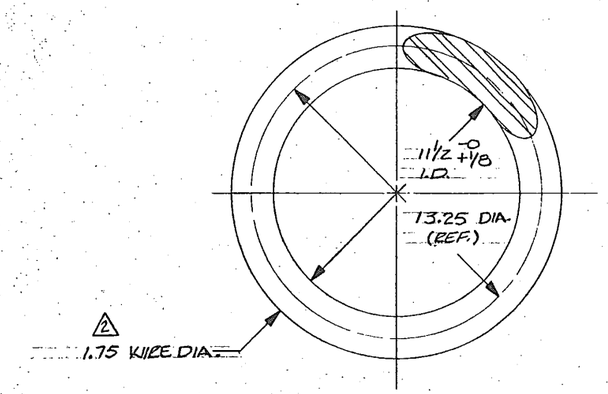
ISSUE NO	DATE	DRAWN BY	APPR'D	REVISION
1	7/25/85	N.E.	[illegible]	ORIGINAL ISSUE
2	9.10.85	MM	[illegible]	REDESIGNED - WAS 2" DIA WIRE





SECTION A-A

NOTES:

1.) FINISHES AND TOLERANCES TO BE PER ASTM A125 EXCEPT OTHERWISE SPECIFIED.

2.) COMPRESS EACH SPRING TO 30.0 IN. LENGTH & MEASURE FORCE REQ'D. NOTIFY AJEC OF RESULTS PRIOR TO SHIPMENT.

* 5160 STEEL OIL QUENCHED AND TEMPERED TO A HARDNESS OF 45-48 ROCKWELL C

ITEM	EACH QUANTITY	TOTAL QUANTITY	ITEM DESCRIPTION	MATERIAL OR DWG. NO.
	3	6	1.75 DIA. ROD x 40 FT.	*
NO. OF UNITS 2			TO BE USED ON ASS'Y NO. 0138T-260A	
DESCRIPTION GUIDE VANE RETURN SPRING				
PROJECT GLEN PARK			CUSTOMER REF.	
San Francisco, California			COMPONENT DWG. NO.	ISSUE
			JOB DWG. NO. 0138T-261	ISSUE 2

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TOPIC: **Enterprise Asset Management (EAM) System Purchase and Implementation Project**

REFERENCE: **YUB-YEC-1-64(a), (d), PDF pages 292, 293, and 296**

QUOTES: **From the response to YUB-YEC-1-64(a), Table 1: Anticipated Tangible Benefits Summary, PDF page 292:**

Benefits Description	Annual Expenditure	Low % Improvement	High % Improvement	Low Estimated Annual Benefit	High Estimated Annual Benefit
Productivity Gains	$3,055,143[2]	12%	25%	$366,617	$763,786
Inventory Management - Reduced Cost of Procured Parts	$1,153,181	0.5%	3%	$5,766	$34,595
Improved Reliability – Extended Asset Life	$11,770,068[3]	2%	3%	$235,401	$353,102
Improved Reliability - Reduced Diesel Consumption	$156,724	20%	30%	$31,345	$47,017
Improved Reliability - Revenue Recovery	$8,000	20%	30%	$1,600	$2,400
Warranty Claims Improvements	$10,000	100%	200%	$10,000	$20,000
TOTAL ESTIMATED BENEFITS:				**$650,729**	**$1,220,900**

From the response to YUB-YEC-1-64(a), PDF page 292:
"Implementation of an EAM solution is expected to improve YEC's overall maintenance performance and increase efficiency of execution of maintenance works. A study conducted for the power industry [footnote removed] has shown that wrench time can increase between 10 – 40% as a result of improvement in maintenance capabilities that are enabled by EAM…

… Other electric utilities have estimated savings of 0.5 – 3% as a result of better contract management for purchases."

From the response to YUB-YEC-1-64(a), PDF page 293:
"Oganizations [sic] that have implemented EAM have reported reductions in long term asset costs of up to 5% by extending asset life."

From the response to YUB-YEC-1-64(d), PDF page 296:

"YEC moved to a formal public tender in 2018. The process was divided into a two-part process including an RFSQ and an invitational request for proposal (iRFP) to be referred to as (RFP) in this report. A total of 9 vendors participated in the RFSQ, and 4 moved on to the detailed RFP. Submissions were scored and ranked based on their submissions, results of demos as well as their respective costs. At the RFP evaluation, vendor submissions for implementation cost ranged from $967k to $1,400k…

… YEC is expecting to go live with the EAM project on March 15, 2021. YEC is currently on schedule with this project."

QUESTION:

a) Please explain how the percentages presented in Table 1: Anticipated Tangible Benefits Summary were determined. For example, how did YEC determine that the EAM System Purchase and Implementation Project would provide a productivity gains improvement between 12 – 25 per cent?

b) In its response to YUB-YEC-1-64(a), YEC provided the following reference for a study showing that wrench time could increase between 10 – 40 per cent (Source: Booz & Company). Please provide the exact study conducted to show increased wrench time as a result of improvement in maintenance capabilities.

c) Please specify the other electric utilities that have estimated savings of 0.5 – 3 per cent as a result of better contract management for purchases.

d) Please identify the other organizations that have reported reductions in long-term asset costs.

e) Please confirm that the competitive RFP process used was compliant with YEC procurement policies.

f) Please explain whether the lowest cost bidder was successful in the RFP process.

g) Please provide further details on the RFP process, including names and bids of all the contractors for this project and the vendor selected for the project.

h) Please confirm that the EAM project is now active.

ANSWER:

(a)

The anticipated Tangible Benefits related to productivity gains were determined by utilizing a case study. See Attachment 1 to this response.

The case study states that a mid-sized power generator with multiple plants that raises wrench time from 30% to 50% could save over $20 million per year. YEC performed a sensitivity analysis using a 12% and 25% increase in productivity which resulted in estimated benefits of $366,617 and $763,786 respectively.

(b)

See YUB-YEC-2-24(a) Attachment 1.

(c)

Attachment 1 to this response provides BC Hydro's Final Submission document for their Supply Chain Application (SAP). This provides an assessment of the anticipated savings from better inventory management.

(d)

YEC used case studies in determining the reductions in long term assets costs. No organizations were mentioned in the case studies. Please see Attachment 1 to this response.

(e)

Confirmed. This RFP process was compliant with YEC procurement policies. The process was run in two stages. The first stage (Request for Supplier Qualification/RFSQ) was fully open and the opportunity was posted publicly (on MERX) as required by policy. Successful proponents that passed through the first phase were invited to submit proposals to the next and final stage (Request for Proposal/RFP).

(f)

The lowest price bidder was not successful.

Each RFP was evaluated against the following criteria:

• Stage 1: Proposal and Compliance to Requirements;	420
• Stage 2 - Solution Cost;	300
• Stage 3 – Presentations; and	250
• Stage 4 - Corporation Site visit to proponent reference site	300
	1070

The price weighting for the second stage RFP was 25%. Infor was the second lowest bidder on the project however they scored higher on technical merits and overall were the highest ranked bid. The evaluated price difference between Infor and the lowest price was $12,718.00 (0.5% difference).

(g)

Respondents to the invitational RFP were:

- ABB Enterprise Software Inc. $2,962,890 (evaluated price)
- Infor $2,257,690 (evaluated price)
- Ontracks Consulting $2,244,971 (evaluated price)
- Createch – deemed to be non-compliant, price not evaluated

Infor was selected as the proponent to execute on this work.

(h)

The EAM project is now active.

Perspective

Andrew Steinhubl
John Van Leeuwen
William Rogers

booz&co.

Beat the Clock
Increasing Workforce Productivity in Process Industries

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EXECUTIVE SUMMARY

In today's economic environment, companies are under intense pressure to reduce costs. Process-intensive industries such as power generation, power transmission and distribution, and oil and gas have significant opportunities to cut costs by increasing worker productivity. Ironically, many of these companies excel at keeping their physical assets at optimum productivity levels, but they fail to manage their human capital as effectively.

The potential savings can be substantial, especially in the current labor market, where a shortage of skilled workers has led to an increase in wages. An analysis of operations and maintenance divisions at process-intensive companies shows that productivity increases can result in cost savings of 5 to 10 percent of overall maintenance and operations expenditures.

So why do many plants fail to improve productivity? Is it that employee productivity is hard to measure? That thinking of workers as units of production is socially unacceptable? That employees and unions resist efforts to improve productivity? That non-repetitive work is difficult to quantify and make more efficient?

While all of these arguments have superficial merit, the most successful process-intensive companies manage to operate at high productivity levels, and in the past few years, a handful of lagging companies have proven that improvement is indeed possible.

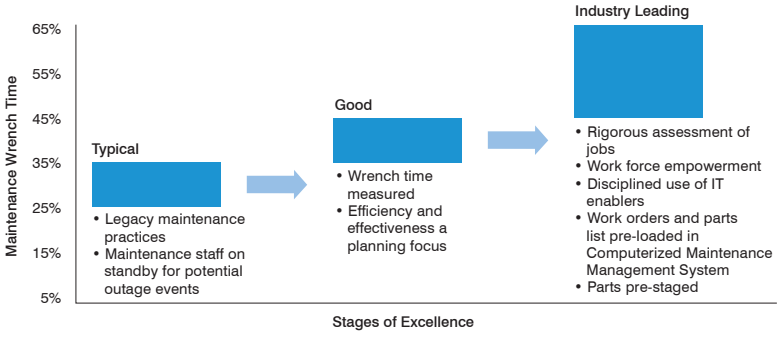
WRENCH TIME

In its simplest form, productivity measures the time that employees spend on value-added work (known as "wrench time" in most industries). For example, maintenance workers in the power industry have an average wrench time of about 25 to 35 percent, with a maximum of about 60 percent *(see Exhibit 1)*. A mid-sized power generator with multiple plants that raises wrench time from 30 to 50 percent could save over $20 million a year.

It's important to note that wrench time by itself does not measure the effectiveness of the work being done—that is, there's no guarantee the time is being used productively. Some tasks may take longer than necessary (e.g., a pump could have been replaced in 30 percent less time) because of workers' inexperience, a lack of appropriate tools, or poor planning. Worse, defective work needs to be redone. All of these problems undermine overall productivity.

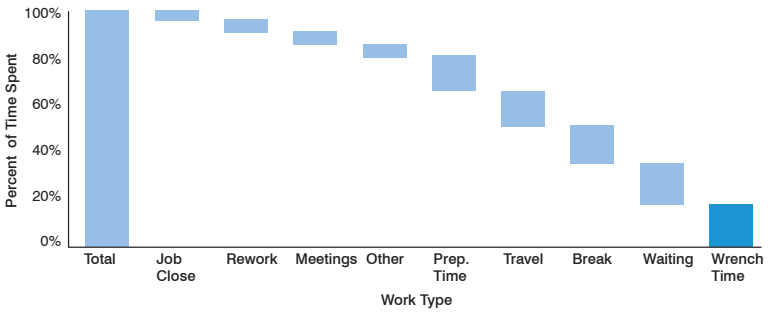
The remainder of a worker's time—everything outside of wrench time—includes things like safety meetings, training, and traveling to and from work sites, along with searching for tools or waiting *(see Exhibit 2)*. This time can be reduced through improved planning, supervision, and communication, as well as through physical changes (rearranging a workspace, moving a lock-out/tag-out location, etc.).

Exhibit 1
Observed Maintenance Wrench Time, Power Industry



Source: Booz & Company

Exhibit 2
Typical Maintenance Worker's Wrench Time Analysis



Source: Booz & Company

KEY FACTORS

Operations and maintenance wrench time varies to a great degree, depending on factors that are both physical and cultural. Specifically:

- *Facilities/plant footprint.* Compact, well laid-out plants yield greater wrench time, whereas significant transportation time between work sites erodes productivity. This is particularly true for plant operations. For example, are plant controls set up in a way that requires two operators where one might suffice? Are there multiple control rooms, or are the controls consolidated to eliminate unnecessary walking? The level of automation and plant history are also key drivers. At a newer plant with few reliability issues, operators are much more willing to trust sensors and alarms. In older plants where sensors were recently installed, workers are less inclined to trust them and instead tend to check equipment manually.
- *Supervision.* Many supervisors get bogged down with administrative responsibilities like data entry. This isn't the best use of their time, and it takes away from their more important role of overseeing front-line maintenance and operations workers.
- *Planning.* Productivity shortfalls frequently originate in the planning phase. Planning at many sites tends to be done manually (i.e., marking up a printed spreadsheet) and for the short term, often not more than a week ahead of current work. This handcuffs the workers and prohibits them from thinking long term to solve more systemic problems. At the same time, there's a risk in relying too heavily on sophisticated planning software. The challenge is to assemble a plan that puts responsibility on each worker or technician to schedule tasks more efficiently, taking into account the longer-term planning horizon.

PRODUCTIVITY GAINS

Here are some examples of performance improvements that process-intensive companies have achieved using the framework outlined in this article.

Operations

A chemicals unit was responsible for desulfurizing the by-products in an industrial process and disposing of the materials. To improve productivity, the area supervisor—with the input of a set of operators—identified work tasks for each position and allocated time to each task. The company also eliminated a number of steps, including duplicate pH testing. Wireless controls were installed, freeing control-room operators to monitor and troubleshoot equipment. By selectively installing SO2 monitors, the company was able to eliminate a weekly manual monitoring round. Further, upgrades to mill controls, along with increased working capacity in slurry tanks, enabled the plant to scale back sludge-plant operation from daily to every other day. Overall productivity improved by 25 percent, and the company saved more than $1 million a year in unit operating costs.

Contract Services

The exploration and production operations of an oil company had invested in a number of improvement efforts. However, it realized that the contractors employed to service production sites were taking eight hours to complete tasks that could be done in half that time. When company representatives were on-site, activities usually took the estimated time, but the company didn't have enough staff to monitor all the contract work. To fix the problem, it stopped paying the contractors by the hour and instead established a menu of standard tasks, with the preset time allotments and prices. Total contractor hours dropped by 15 to 20 percent.

Maintenance

A large, regulated utility faced significant maintenance budget overruns. Repeated staffing reductions to rein in costs did not solve the problem. Analysis revealed that the work management system—identifying, planning, and executing work and closing out the work orders—needed to be revamped. Through direct observation of maintenance work orders relative to existing and best practice processes, the organization focused on streamlining the process. Changes included clarifying lock-out/tag-out procedures, linking the work schedule to activity lists, and training the existing staff in work order management and materials planning practices. Improvements resulted in a productivity increase of 20 percent.

Supervisory

At a chemicals company, the workforce lacked sufficient training and guidance. The fundamental issue was that supervisors were being pulled away from their direct staff responsibility by administrative tasks. An assessment of each supervisor's workday revealed large blocks of time spent attending meetings, completing paperwork, and doing data entry. (Union workers were considered "not qualified.") To address this problem, much of the administrative and data entry work was offloaded to junior staffers. The approval process was automated, which freed up foremen and supervisors to spend more time with the workforce and ultimately improve plant operations and workforce effectiveness. Some 30 percent of weekly administration time was ultimately eliminated or reassigned.

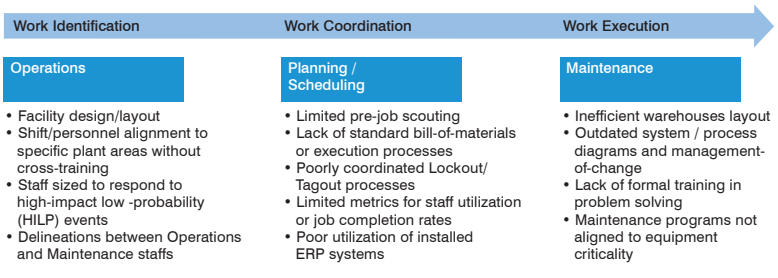
ANALYSIS AND MEASUREMENT

Improving productivity starts with an in-depth analysis to determine where the true opportunities lie. The goal is to measure actual wrench time and identify how and where value gets destroyed during the workers' time on the job *(see Exhibit 3)*. The process takes a few weeks and involves both self-assessment by managers and direct, impartial observations of workers and technicians.

The first step in analyzing the overall productivity of a facility is to establish a baseline for how long specific tasks should take and then compare it with how long they actually take. This applies to all of the activities of maintenance employees, operators, contractors, and supervisors. Personnel data—including capabilities, years of experience, shift patterns, and time off—is factored in. To help determine a baseline, jobs should also be benchmarked against industry standards.

Workout sessions are conducted with line staff and supervisors to identify unnecessary steps or wasted time, along with possible solutions. It's critical that the plant workforce participates in measurement and baselining, so that they understand the process and begin to see how it will

Exhibit 3
Productivity Losses in Operations and Maintenance Workflow



Source: Booz & Company

improve the efficiency of their facility. Plant personnel, particularly midlevel supervisors and above, typically believe they know all the issues and only need help to "fix the problem" or justify the million-dollar investment for new equipment. Clearly, the plant operations and maintenance staff are fighting fires every day and intimately know the symptoms that cause them to fall short of their performance aspirations. However, a rigorous baseline frequently uncovers unexpected root causes—the pain points that plants have lived with for years.

After baseline data for the amount of time required to do each task is compiled, activities should be classified into three categories: customer value-add, business value-add, or non-value-add. For example, meetings can be business value-add or non-value-add. Meetings for equipment certification or safety refresher training clearly add value to the business. But meetings to re-explain basic procedures to a poorly performing worker add no value. Even physical work may include non-value-add time if the actual time spent on a task is more than the planned amount (provided that the planned amount is based on industry standards or past history).

Key questions in this analysis include:

Customer value-add
- Does the task add form, feature, or function to the component or service?
- Does the task enable a competitive advantage (lower price, faster delivery)?

Business value-add
- Does the task reduce owner financial risk?
- Is this task required by law or regulation?

Non-value-add
- If you were the customer, would you be willing to pay for the task?
- Could the task be categorized as waste?

Finally, this kind of analysis must be applied to all facets of the plant—not just routine operations and maintenance but also outages and turnarounds (which can be complex, given the number of workers on-site and the need to get the facility back online quickly). In addition, on-site contractors involved in technical services—such as maintenance, environmental management, predictive measurements, and the like—should be evaluated as thoroughly as full-time staff. Many facilities hire contractors on time-and-materials agreements, which do not give contractors incentives for improving productivity.

SOLUTIONS

At this step, a detailed list of problems, root causes, and potential solutions is compiled. Human nature drives people to focus only on the most obvious issue, which may not result in a sustainable fix. The investment of time required to analyze multiple problems from many angles, connect the dots, and develop a long-term solution will pay significant dividends.

A typical effort will generate more opportunities than the organization can support. Prioritizing on the bases of implementation time and expense will narrow the options to the most promising for a given facility. Only then can management choose specific targets and set aside funding.

Direct communication with the organization at all levels during this phase can help persuade the workforce to accept proposed changes. This includes mapping out the implementation schedule, developing project plans, and assigning accountability for delivering the expected benefits on time. Workplace cultures can be stubbornly resistant to change, especially those where a strong union may balk at productivity improvements that result in lost jobs. But coordinated efforts to explain the vision and emphasize the long-term goal of a more streamlined, efficient organization will help generate early-stage momentum. Frequent and transparent validations of activities and progress will help sustain this momentum as the improvements take effect.

In maintenance, most of the productivity gains can be found by focusing on non-value-add activities, such as travel, waiting, and searching for tools. Conversely, in operations, the gains typically come in one of four areas:

- *Work reduction.* Some tasks don't need to be performed as frequently. (In rare cases, certain tasks don't need to be performed at all.) Reduction can involve small steps like modifying operator rounds so that equipment is checked less frequently, or scaling back the frequency of preventive maintenance. More significant changes eliminate duplicate steps. All proposed changes should be monitored to gauge their real effectiveness.

- *Separation of shift activities.* Many facilities operate with the idea that certain work must be done on-shift, or off-shift, or by plant personnel. This can keep staffing levels unnecessarily high. The goal is to evaluate the priority and skill level required for each task, and then assign tasks

Improving productivity is a continuous journey. It's not a binary before-and-after proposition.

as appropriate to fully utilize the workforce and use low-cost options wherever possible.

- *Technology and automation.* Advances in remote sensing and telemetry have brought down the cost of automation. While process automation has received significant attention, less emphasis has been placed on automating time-consuming or risky tasks. Increased control-room automation can unshackle operators from the desk and free them to roam the plant when necessary. Furthermore, installing cameras and sensors to eliminate the need to climb a tower or enter a hazardous area can provide significant payback in both time and safety.

- *Qualification levels.* Staff certification requirements may limit work load leveling. Evaluate restrictive work rules and staff training deficiencies to identify work that can be reassigned both within and across departments. Examples include tapping underutilized operator time for routine equipment maintenance, and certifying them for heavy equipment operations. Once standards are put into place, supervisors can monitor compliance.

CONTINUOUS IMPROVEMENT

While successful implementation is absolutely critical, productivity gains will fade away without a continuous improvement program. Consequently, these steps should happen in parallel.

First, the implementation program needs to be formally launched, managed, and monitored. This takes place at a program office staffed by an overall program leader, an analyst to evaluate progress (especially results falling to the bottom line), and subject matter experts (SMEs) to assist in such areas as planning and work area layout in order to deliver the intended productivity improvements. These SMEs also serve as on-the-ground fixers whenever issues are encountered or progress bogs down.

Second, the company needs to implement its brand of continuous improvement along with changes to the facility's culture. This may draw on TQM, Lean, or Six Sigma principles and will involve employee training, a clearly defined set of performance metrics, and participation in the overall improvement effort. In addition, executives need to be visibly involved. A Lean principle of executive leadership on the factory floor is highly valuable.

CONCLUSION

Improving productivity is a continuous journey. It's not a binary before-and-after proposition, but rather an evolution of careful analysis and detailed implementation, followed by feedback and periodic adjustments. The most successful initiatives improve not only the efficiency of a workforce but the culture of an organization. Given the current economic downturn and the increase in skilled wages, improving productivity has become more important than ever, and it can pay compelling financial dividends

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BC Hydro
Power smart

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June 23, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

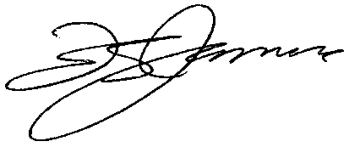
Dear Mr. Wruck:

RE: Project No. 3698901
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Supply Chain Applications Project

BC Hydro writes in compliance with Commission Order No. G-78-17 to provide its Final Submission.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Fred James
Chief Regulatory Officer

cu/tn

Enclosure

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE UTILITIES COMMISSION ACT

R.S.B.C. 1996, CHAPTER 473

and

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

SUPPLY CHAIN APPLICATIONS PROJECT

Final Submissions of BC Hydro

June 23, 2017

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PART ONE: INTRODUCTION AND OVERVIEW

A. INTRODUCTION

1. BC Hydro expects to spend over $2 billion each year over the next ten years on third-party services and materials as part of providing safe and reliable electricity service to customers.[1] BC Hydro has over 5,000 different suppliers of materials and services, and the vast majority of BC Hydro employees have contact with the supply chain each year. Virtually every item and service purchased is the subject of multiple business processes.[2] Maintaining an effective supply chain system is essential to the proper management of materials and service acquisition.

2. BC Hydro's existing core PassPort supply chain IT system (also referred to as Asset Suite 8), has been in place since 2003. When it was implemented, BC Hydro had different supply chain business requirements. PassPort and BC Hydro's existing business processes have limitations when viewed in the context of BC Hydro's current business requirements. The Supply Chain Applications Project ("SCA Project") positions BC Hydro to meet current and future business needs, reduce risk, and benefit customers.[3] The preferred project option, an SAP-based system that will integrate with BC Hydro's overall SAP platform, delivers the greatest benefits with the least risk. The Commission should find that the SCA Project is in the public interest.

3. BC Hydro set out the specific approvals it is seeking in section 1.3 of the Application. In accordance with the proposed two-phase regulatory process accepted by the Commission in Order G-32-17, BC Hydro is requesting acceptance of the Definition Phase capital expenditures of the SCA Project as reflected in the draft order in Attachment A of the

[1] Exhibit B-1, Application, p. 1-1.

[2] A list of supply chain business processes is provided in Exhibit B-1, Application, Attachment E.

[3] Exhibit B-1, Application, p. 1-1.

Application.[4] BC Hydro will seek acceptance of the Implementation Phase capital expenditures in the second phase of the regulatory process.[5]

B. SUBMISSION OVERVIEW AND KEY POINTS

4. This Final Submission is organized around the following key points:

- Part Two: The Phase Two process should proceed expeditiously with minimal regulatory process to reduce the risk of costly delays in SCA Project implementation.

- Part Three: The governing public interest consideration in accepting the proposed expenditure schedule for the SCA Project should be the fact that BC Hydro's customers benefit from the project.

- Part Four: The scope of the SCA Project is well defined, and the robust cost estimate meets the requirements for estimating accuracy in the Commission's CPCN Guidelines.

- Part Five: The SCA Project is required to address capability gaps in the existing supply chain management system. It will deliver financial benefits, and will reduce or eliminate safety, financial, reputational and reliability risks related to BC Hydro's supply chain.

- Part Six: The SAP alternative is superior to the PassPort alternative. SAP will fully meet the identified capability gaps, is the lower risk alternative, and delivers greater benefits to customers.

- Part Seven: BC Hydro has identified and mitigated SCA Project risks.

[4] Exhibit B-1, Application, Attachment A (Phase One).

[5] Exhibit B-1, Application, Attachment B (Phase Two).

PART TWO: TWO-PHASE PROCESS FACILITATES EARLY STAKEHOLDER INVOLVEMENT AND MITIGATES PROJECT RISK

5. BC Hydro proposed a two-phase regulatory process for the SCA Project to facilitate Commission review at the two critical decision points in the project lifecycle.[6] In the absence of material changes to the cost, benefits, scope and schedule assumptions, the Commission should issue a phase two order accepting the Implementation Phase capital expenditures as being in the public interest with minimal regulatory process.

A. PROJECT CHARACTERISTICS SUIT A TWO-PHASED PROCESS

6. In phase one, BC Hydro is seeking acceptance of the Definition Phase capital expenditures for the SCA Project. In phase two, BC Hydro is seeking acceptance of the Implementation Phase capital expenditures. The two-phase process is not the customary regulatory process employed by the Commission. It was proposed considering the specific attributes of the SCA Project, including the large percentage of project expenditures in the Definition Phase and the need for an expeditious transition between the Definition and Implementation Phases.[7] In Order G-32-17, the Panel agreed that BC Hydro's two-phase process is appropriate. The Commission's Reasons for Decision noted that there was common agreement among the parties that some type of two-phase review is the best option. The Commission invited parties to provide any additional comments on future process as part of their Final Submissions.[8]

7. The phase two process, described on pages 1-18 to 1-19 of the Application, will be initiated when BC Hydro submits a verification report (the "Phase Two Verification Report"). The Phase Two Verification Report will include updated cost, benefit, scope, and schedule information based on the completed Definition Phase work. It will also include an initial set of baselines and metrics to measure benefits of the SCA Project.[9] The Phase Two Verification

[6] Exhibit B-1, Application, pp. 1-17 to 1-19.

[7] Exhibit B-1, Application, pp. 1-3 and 1-8.

[8] Exhibit A-5, Order G-32-17, Appendix A, p. 3.

[9] Exhibit B-6, BCUC IR 2.51.4.

Report will identify whether there has been any material change in the cost, benefit, scope, and schedule information for the SCA Project. A reasonable definition of a material change is provided in the Application.[10]

B. AN EXPEDITIOUS PHASE TWO PROCESS IS APPROPRIATE AND IMPORTANT

8. An expeditious phase two process is appropriate in light of the evidentiary record, and important for mitigating project risk.

9. BC Hydro presented sufficient information in its Application for review and approval of all project expenditures. The phase one regulatory process has been rigorous and robust. BC Hydro anticipates that the Commission's decision to accept the Definition Phase capital expenditure will rest on a determination that, in principle, the SCA Project is in the public interest based on the project justification, including the cost, benefits, scope, and schedule assumptions provided in the Application.

10. Therefore, if the Phase Two Verification Report does not identify any material changes in the initial assumptions,[11] the Commission should be confident, based on the record and decision in phase one and the Phase Two Verification Report, that it can accept the Implementation Phase capital expenditures as being in the public interest without further process. To the extent that regulatory process is considered necessary, due to a material change to the SCA Project or otherwise, it should be tailored and focused to minimize delay.

11. An expeditious phase two process is essential from the perspective of minimizing risk of a costly project delay. The SCA Project, unlike typical large generation, transmission or distribution projects, has a unique human resource element, namely that the people who will perform Definition Phase activities are largely the same people who will implement the project. It is important for BC Hydro to move from Definition to Implementation Phase activities without unnecessary disruption to the project or the project team.[12] A delay to Implementation Phase

[10] Exhibit B-1, Application, pp. 1-18 to 1-19.
[11] Exhibit B-1, Application, pp. 1-18 to 1-19.
[12] Exhibit B-1, Application, p. 1-8.

activities would require BC Hydro and the System Integrator to cease work on the SCA Project. This outcome could be expected to impact the cost and/or quality of the project. The cost implication of a delay is currently estimated at approximately $3.6 million for a four-month delay in moving from Definition Phase to Implementation Phase.[13]

[13] Exhibit B-1, Application, p. 1-19. As discussed on page 2-18 of the Application, BC Hydro included a $3.6 million project reserve for delay to a regulatory process between the Definition and Implementation Phases, but this does not include a schedule contingency. See Exhibit B-3, BCUC IR 1.13.4 for a further discussion of the impact of a delay for regulatory process between the Definition and Implementation Phases.

PART THREE: CUSTOMER BENEFITS, REDUCED RISK, KEY TO PUBLIC INTEREST DETERMINATION

12. BC Hydro filed the Application pursuant to paragraph 44.2(1)(b) of the *Utilities Commission Act* (the "UCA"), which states that a public utility may file an expenditure schedule of capital expenditures that the public utility anticipates making. The UCA establishes a public interest test for acceptance of an expenditure schedule under section 44.2, setting out a number of factors that the Commission must consider in determining the public interest. Attachment C to the Application discussed the applicable legal framework in further detail. The governing public interest consideration in accepting the proposed expenditure schedule for the SCA Project should be the fact that BC Hydro's customers will benefit from the SCA Project.

13. Subsection 44.2(5.1) of the UCA lists a number of matters that the Commission must consider when considering whether to accept an expenditure schedule filed by BC Hydro. It states:

> 44.2(5.1) In considering whether to accept an expenditure schedule filed by the authority [BC Hydro], the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider
>
> (a) British Columbia's energy objectives,
>
> (b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,
>
> (c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and
>
> (d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

14. As an IT project, the SCA Project has no environmental impacts. It does not trigger any obligation to consult with First Nations. The 2013 Integrated Resource Plan, referenced in paragraph (b), does not address IT investments. The Application is neutral in

terms of reducing electricity demand, which is referenced in section 44.2(5.1)(c). The Application is unrelated to demand-side management.[14]

15. The public interest factors identified in section 44.2 of the UCA that are relevant to the SCA Project are: (i) the interests of persons in British Columbia who receive or may receive service from BC Hydro; and (ii) the government's energy objective of ensuring that BC Hydro's rates remain among the most competitive of rates charged by public utilities in North America. As discussed below in this Final Submission, the capital expenditures will improve efficiency and reduce BC Hydro's costs and risks of acquiring and deploying third-party services and materials. The SCA Project thus advances the interests of customers (i.e., "persons in British Columbia who receive or may receive service" from BC Hydro) and helps to maintain BC Hydro's current position of having among the most competitive rates in North America.[15]

[14] Exhibit B-1, Application, Attachment C.

[15] Exhibit B-1, Application, Attachment C. The SCA Project will also result in 77 person-years of employment in British Columbia, which supports British Columbia's energy objective in section 2(k) of the *Clean Energy Act*, to "to encourage economic development and the creation and retention of jobs". See Exhibit B-3, BCUC IR 1.30.12 for further discussion.

PART FOUR: PROJECT SCOPE AND COST

A. INTRODUCTION

16. In this Part, BC Hydro addresses the scope and cost of the SCA Project. BC Hydro highlights the following points:

- First, the SCA Project will close the identified capability gaps in BC Hydro's current supply chain technology and processes, allowing BC Hydro to meet current business requirements more efficiently and with less risk.

- Second, the SCA Project cost estimate meets the Commission's requirements for estimating accuracy, with significant components already subject to firm pricing and appropriate contingencies included.

B. SCA PROJECT WILL IMPROVE BC HYDRO'S SUPPLY CHAIN BUSINESS PROCESSES

17. The SCA Project will replace BC Hydro's core PassPort supply chain IT system with an SAP supply chain IT system, and will improve BC Hydro's supply chain business processes to meet current business requirements.

18. There are three core areas for which supply chain functionality is being implemented in SAP:

- ***Materials Management*** – inventory management, forecasting and demand planning, material requirements planning, and warehouse operations for all materials;

- ***Purchasing*** – purchasing processes, contract administration and invoice processing for all materials and services; and

- ***Integration*** – integration of SAP supply chain modules with other previously implemented SAP modules (Project System, Finance & Controlling, Quality Management) and other systems, including PassPort (work management), Oracle

Primavera Unifier (Construction Contract Management), and Supply Chain Workspace (sourcing, category, and contract management).[16]

19. The SCA Project scope is discussed in Chapter 4 of the Application and detailed information on the project scope is provided in the Conceptual Design Report included as Attachment H of the Application.[17]

20. BC Hydro's implementation of the new IT system and processes as described in the Conceptual Design Report will address 150 of the 153 Supply Chain Business Requirements.[18] In doing so, BC Hydro will close the identified capability gaps that exist in BC Hydro's current supply chain technology and processes, resulting in reductions in cost, effort and risk.[19] BC Hydro addresses the project benefits in Part Five of this Final Submission.

C. THE SCA PROJECT COST ESTIMATE IS ROBUST

21. The SCA Project cost estimate meets the Commission's requirements for estimating certainty. BC Hydro is justified in its confidence that it can complete the SCA Project without exceeding the upper end of the cost estimate range.[20]

(a) Mid-Range Cost Estimate

22. BC Hydro has estimated the total cost of the SCA Project as being between $60.5 million and $79.3 million, with a mid-range cost estimate of $65.9 million.[21] The mid-range cost estimate of the SCA Project has an accuracy range of +15 per cent/-10 per cent, and is

[16] Exhibit B-1, Application, pp. 1-5 and 1-6.

[17] Exhibit B-1, Application, p. 4-13 and Attachment H.

[18] Exhibit B-1, Application, p. 4-13; Exhibit B-4, BCOAPO 1.25.1. The 150 of 153 business requirements noted on page 4-13 of the Application are the same as the 322 requirements described in Attachment H and Attachment K. The reason they are counted as 153 in the Application, while as 322 in the other Attachments, is that the 322 value is based on the number of times an individual unique requirement appears across BC Hydro's 5 unique supply chains, while the 153 value is a count of the unique requirements.

[19] Exhibit B-1, Application, p. 1-4.

[20] Exhibit B-1, Application, p. 3-5; Exhibit B-6, BCUC IR 2.43.1.

[21] The expected capital cost portion of the SCA Project is $59.2 million, with a project capital cost range of between $54.3 million and $71.8 million (Exhibit B-1, Application, p. 1-6).

analogous to a P50 cost estimate.[22] A breakdown of the Mid-Range cost estimate is provided in the following table:[23]

SAP Project - Mid-range cost Cost (000's)	Life to date	Future estimate (inflated)	Total	%
Early Design Work (Transformation WIP)				
IOMA	$ -	$ -	$ -	0%
Capital[1]	$ 7,310	$ -	$ 7,310	100%
Interest during construction	$ -	$ -	$ -	0%
Sub-total	$ 7,310	$ -	$ 7,310	100%
Identification				
IOMA	$ 1,236	$ -	$ 1,236	100%
Capital	$ -	$ -	$ -	0%
Interest during construction	$ -	$ -	$ -	0%
Sub-total	$ 1,236	$ -	$ 1,236	100%
Early Definition				
IOMA	$ 115	$ 252	$ 367	8%
Capital	$ 3,012	$ 968	$ 3,980	84%
Interest during construction	$ 83	$ 296	$ 379	8%
Sub-total	$ 3,210	$ 1,516	$ 4,726	100%
Mobilization & Design				
IOMA	$ -	$ 783	$ 783	7%
Capital	$ -	$ 9,379	$ 9,379	89%
Interest during construction	$ -	$ 414	$ 414	4%
Sub-total	$ -	$ 10,576	$ 10,576	100%
Implementation (pre go-live)				
IOMA	$ -	$ 2,178	$ 2,178	8%
Capital	$ -	$ 22,944	$ 22,944	84%
Interest during construction	$ -	$ 2,211	$ 2,211	8%
Sub-total	$ -	$ 27,333	$ 27,333	100%
Implementation (post go-live)				
IOMA	$ -	$ 1,240	$ 1,240	20%
Capital	$ -	$ 4,924	$ 4,924	80%
Interest during construction	$ -	$ -	$ -	0%
Sub-total	$ -	$ 6,164	$ 6,164	100%
Total before contingency	$ 11,756	$ 45,589	$ 57,345	
Contingency - 20% of future estimates	$ -	$ 8,534	$ 8,534	
Total after contingency	$ 11,756	$ 54,123	$ 65,879	
[1]Transformation blueprint value				
[2]Source: Attachment F, Tab C2				

[22] Exhibit B-1, Application, pp. 2-15 to 2-16. The upper end of the accuracy range is analogous to a P90 cost estimate. See Exhibit B-1, Application, p. 3-5 and Exhibit B-6, BCUC IR 2.43.1.

[23] Exhibit B-3, BCUC IR 1.16.1.

23. BC Hydro included its detailed estimate of Definition and Implementation Phase costs in Attachment F, workbook tab C1 – Direct Cost Detail.

(b) BC Hydro's Estimate is Robust

24. Section 2.4 of the Application describes how BC Hydro developed the estimated cost range for the SCA Project. The cost estimate is robust, and BC Hydro "has high confidence that it can complete the Supply Chain Applications Project without exceeding the upper accuracy range".[24] The following evidence justifies BC Hydro's confidence in the estimates:

- The Identification Phase and Early Definition Stage costs up to the end of November 2016 are the actual recorded costs.[25]
- The remaining Definition and Implementation Phase forecast costs have been developed using a bottom-up approach based on pricing and proposal information submitted to BC Hydro from the System Integrator and Quality Assurance Advisor.[26]
- A significant portion of the direct costs are subject to fixed price contracts with the Systems Integrator and Quality Assurance Advisor.[27]
- BC Hydro has used the System Integrator's proposed cost in the project cost estimate, without incorporating any potential cost savings from the gain sharing provision in the Master Services Agreement with the Systems Integrator. Under this provision, BC Hydro and the System Integrator will share any cost savings that occur if the notional calculated fees for the System Integrator's work regarding a fixed-price statement of work are less than the fixed price for the

[24] Exhibit B-6, BCUC IR 2.43.1.

[25] Exhibit B-1, Application, p. 2-14.

[26] Exhibit B-1, Application, p. 2-14.

[27] Exhibit B-3, BCUC IR 1.4.3. BC Hydro's response to BCOAPO IR 1.4.1 (Confidential) provides a breakdown of the mid-range cost estimate categorized by spend area such as System Integrator, QA Consultant, Other Consultants, Hardware, Software, BC Hydro Labour, Contingency, Reserve.

statement of work. If any cost savings due to the gain sharing provision occurs, this would reduce the project cost.[28]

- BC Hydro calculated Interest during Construction based on the committed in-service date, rather than the earlier target date. BC Hydro's approach was conservative, since it leads to higher interest costs being reflected in the SCA Project estimate. The mid-range cost estimate would be reduced by $770,000 in interest costs if the target in-service date was used rather than the committed in-service date.[29]

- The SCA Project estimate includes a 20 per cent contingency, calculated on the costs still to be incurred. It represents costs that BC Hydro expects to expend, but that are not detailed in the base estimate of the direct project costs. The 20 per cent contingency is consistent with the cost contingency used on other BC Hydro projects.[30]

- The upper bound of the cost estimate incorporates a project reserve, with incremental interest during construction. The project reserve includes an incremental contingency of 15 per cent to mitigate unknown risks and an additional reserve amount to mitigate cost impacts associated with known risks.[31]

25. BC Hydro will provide an updated cost estimate in the Phase Two Verification Report.[32]

[28] Exhibit B-3, BCUC IR 1.30.9; Exhibit B-6, BCUC IR 2.41.2.
[29] Exhibit B-3, BCUC IR 1.13.4.
[30] Exhibit B-3, BCUC IR 1.13.7.
[31] Exhibit B-1, Application, pp. 2-17 to 2-18.
[32] Exhibit B-1, Application, p. 1-18.

(c) The Cost Estimate Appropriately Excludes the Cost of SAP Platform Upgrades

26. It was appropriate for BC Hydro to exclude the cost of an SAP platform upgrade to S/4 HANA from the SCA Project estimate for four reasons:

- First, an SAP platform upgrade is not necessary to meet the SCA Project objectives.[33]

- Second, BC Hydro will have to upgrade its SAP Platform in the future, independent of the decision to use SAP for Supply Chain. BC Hydro's SAP platform supports multiple business process areas including Customer Care, Finance, Human Resources, Project and Portfolio Management, Incident Management, and partial implementations of Supply Chain and Work Management functionality. As with any software system, periodic SAP Platform upgrades are necessary to maintain the health and operability of the overall platform.[34]

- Third, SAP platform upgrades cannot be performed for individual business modules. As such, BC Hydro's practice since it began operating SAP in 2003 has been to treat upgrades as separate initiatives, each justified by its own business case.[35]

- Fourth, it is premature to quantify the costs of a migration to S/4 HANA, given the newness of the SAP S/4 HANA product and the lack of reference sites. There are few examples of SAP S/4 HANA having been implemented by major utilities. BC Hydro does not consider it prudent to become an early adopter of this platform.[36]

[33] Exhibit B-6, BCUC IR 2.42.2.

[34] Exhibit B-6, BCUC IR 2.42.2.

[35] Exhibit B-6, BCUC IR 2.42.2.

[36] Exhibit B-3, BCUC IR 1.7.2; Exhibit B-6, BCUC IR 2.42.1.

27. BC Hydro will assess the details of an upgrade when the SAP S/4 HANA product and market are more mature.[37]

[37] Exhibit B-6, BCUC IR 2.42.1.

PART FIVE: THERE IS A COMPELLING RATIONALE FOR THE SCA PROJECT

A. INTRODUCTION

28. BC Hydro has provided a compelling rationale for the SCA Project. In this Part of the Final Submission, BC Hydro elaborates on the following points, which support a finding that the SCA Project is in the public interest.

- First, the SCA Project will close the capability gaps in the current supply chain system and business processes.
- Second, the SCA Project will provide net financial benefits, which ultimately flow to BC Hydro's customers.
- Third, the SCA Project will reduce or eliminate safety, financial, reputational and reliability risks in the supply chain.
- Fourth, the SCA Project is required before BC Hydro can achieve the full benefits from additional investments in work management and asset management business processes and IT systems.[38]

B. SCA PROJECT WILL CLOSE THE CAPABILITY GAPS IN THE CURRENT SUPPLY CHAIN

29. BC Hydro assessed its supply chain business requirements, and identified 13 capability gaps in the current IT system and business processes. The SCA Project will close those gaps.

30. The PassPort supply chain IT system and associated business practices were implemented in 2003, and designed primarily to support materials and inventory management. They do not adequately support the acquisition of non-inventoried materials or services. Currently, about 90 per cent of BC Hydro's total third-party expenditures is related to purchases

[38] Exhibit B-1, Application, pp. 2-7 to 2-8.

that are not maintained (or maintainable) as inventory, and between 60 per cent and 80 per cent of BC Hydro's total third-party expenditures is for services rather than materials.[39]

31. BC Hydro's third-party service and material needs have also increased since 2003. BC Hydro's annual capital expenditures increased from approximately $600 million in fiscal 2003 to approximately $2.3 billion in fiscal 2016, and operating costs increased from approximately $580 million in fiscal 2003 to over $950 million in fiscal 2015.[40] Approximately 85 per cent of BC Hydro's capital spending and approximately 55 per cent of BC Hydro's operating costs are third-party services and materials that must be procured using BC Hydro's supply chain.[41]

32. BC Hydro undertook a formal process to identify its supply chain needs across the organization. The outcome of this process was the Supply Chain Business Model, which identified 153 supply chain-specific business requirements.[42] The implementation of the Supply Chain Business Model will require changes in technology, and changes in processes, roles, and responsibilities.[43]

33. BC Hydro experts performed a gap assessment of its current supply chain IT system and business processes.[44] BC Hydro identified 13 capability gaps in the current supply chain IT system and associated business practices.[45] The 13 capability gaps are specific to technology limitations that prevent BC Hydro from fully implementing the Supply Chain Business Model.[46] The successful implementation of the Supply Chain Business Model contemplates the closing of all of the capability gaps.[47]

[39] Exhibit B-1, Application, p. 2-7.
[40] Exhibit B-1, Application, pp. 1-4 and 1-5.
[41] Exhibit B-4, BCOAPO IR 1.1.1 and 1.1.2.1.
[42] Exhibit B-1, Application, p. 4-6.
[43] Exhibit B-4, BCOAPO IR 1.18.1 and CEC IR 1.53.1.
[44] Exhibit B-3, BCUC IR 1.11.1.
[45] Exhibit B-1, Application, pp. 2-8 to 2-12.
[46] Exhibit B-3, BCUC IR 1.3.1.
[47] Exhibit B-4, CEC IR 1.42.1.

34. The SCA Project will close the 13 capability gaps. The table below summarizes the 13 capability gaps identified by BC Hydro's assessment team, which will be addressed by the SCA Project. ABB does not contest BC Hydro's assessment that these capability gaps exist based on how BC Hydro's PassPort system is configured and operated currently. ABB's evidence is premised on the functionality of Asset Suite 9, the latest ABB upgrade that has yet to secure a significant market presence.[48]

	Capability Gap	**Explanation**
1	Inability to Manage Service-Related Spend	Services represent between 60 and 80 per cent of BC Hydro's $2.5 billion supply chain procurement spend. The services procured include construction services, equipment installation services, and maintenance services. The current supply chain systems do not allow BC Hydro to easily track and view the different types of services for which BC Hydro regularly contracts and their associated costs.[49] This system limitation has also prevented BC Hydro from developing an accessible and current listing of the various types of services and their respective costs (referred to as a "services catalogue") that would allow for process automation. Developing a services catalogue as part of the SCA Project will: improve BC Hydro's negotiating position *vis-a-vis* vendors; provide historical pricing and contract terms for services; and allow BC Hydro to develop a self-service application for the requisition of common services.[50]
2	Limitations in BC Hydro's Ability to Manage Contracts	BC Hydro's contract management and administration function aims to maximize financial performance and minimize risk in contractual arrangements. Effective contract management and administration[51] requires accessing contract terms, contract conditions, and contract performance data. The current systems place a high burden on users by requiring them to work in multiple systems, and impede access to contract terms. These limitations could prevent a contract manager from taking advantage of contract terms (e.g., volume discounts) due to a lack of visibility of these terms in the system.[52]

[48] Exhibit B-5, BCUC-ABB IR 2.0.

[49] Exhibit B-1, Application, p. 2-8.

[50] Exhibit B-1, Application, p. 2-8 to 2-9.

[51] Contract administration refers to the administrative transactional processes that must be performed to initiate and maintain each contract, including administration of invoices, changes, and closeouts. See Exhibit B-1, Attachment H, p. 47.

[52] Exhibit B-1, Application, p. 2-9.

		The SCA Project will make more real-time operational contract information available to users and will allow for both services and materials to be requisitioned in one process.[53] Real-time operational contract information relates to having operational data for a contract codified and readily available in the system throughout the contract lifecycle. This includes information relating to spend, units consumed (for both services and materials), volume discounts, variable contract terms and conditions, and extension options. In BC Hydro's current PassPort supply chain system, much of this data is stored as free text, limiting its value in processing, reporting, and analysis.[54] The new SAP supply chain system will have a data model that will improve BC Hydro's ability to forecast contract expiry and manage contract extension processes, with reduced manual effort.[55]
3	Limitation on Inventory Management	BC Hydro must assess most of its inventory requirements manually, since there is no system in place that automates inventory requirements processes. BC Hydro's lack of an inventory management system can cause BC Hydro to carry more inventory than necessary, incur rush orders, and issue multiple orders for similar materials. It also constrains BC Hydro's ability to manage the entire scope of third-party materials and services acquisition. This has resulted in higher 'spot buy' activity whereby BC Hydro purchases materials more frequently, in smaller quantities, and at a higher cost versus negotiating bulk purchase contracts at a lower cost.[56] The new supply chain IT system will allow for automated tracking of inventory requirements and will allow BC Hydro to optimize inventory levels.[57]
4	Limitation on Managing Supplier Performance	BC Hydro's existing processes for tracking performance metrics against actual supplier performance are manual, inconsistent, inefficient and subject to error. The review of supplier performance is also generally performed on a case-by-case basis. Information about common suppliers is not available across the organization, which results in a risk that BC Hydro may continue to use suppliers with poor performance. A system that tracks and consolidates information about supplier performance, which will be an outcome of the SCA Project, will allow BC Hydro to avoid poor performing suppliers.[58]
5	Limitation on Managing Supply	BC Hydro is unable to plan materials and services on infrastructure projects directly in the IT system. There is also no way to automatically update the supply chain when changes to schedule or scope

[53] Exhibit B-1, Application, p. 3-9.
[54] Exhibit B-6, BCUC IR 2.48.3.1.
[55] Exhibit B-4, CEC IR 1.13.3.
[56] Exhibit B-1, Application, p. 2-9.
[57] Exhibit B-1, Application, p. 2-5.
[58] Exhibit B-1, Application, p. 2-10.

	Chain for Capital Projects	occur; the updates must be inputted manually and across various systems. The manual processes require BC Hydro to expend greater effort than necessary on capital project management.[59] The SCA Project will allow for direct integration between the SAP supply chain module and the SAP Project Systems module.[60] The SCA Project will provide better ability to manage supply chain for capital projects through planning and visibility of material and services requirements directly in the IT system and automatic updating to the supply chain when changes to project schedule or scope occur. The SCA Project is also expected to improve BC Hydro's ability to manage service-related spend, manage and administer contracts, and manage individual supplier performance, all of which will enable better contracting on large capital projects.[61]
6	Lack of Order, Delivery and Payment Tracking	BC Hydro's supply chain does not have a consolidated system that tracks requests, receipt of materials, delivery of services, and payment details in one application. The information is entered and managed in multiple applications. When process exceptions occur, users must manually trace transactions through multiple systems to determine the cause and resolve the issue.[62] The deployment of SAP for supply chain will allow for the order, delivery, and payment processes to occur in one system.[63]
7	Inability to Support Sales and Return of Unused Materials	There is no system capability or mechanism to track when unused materials have been returned to warehouses from job sites. At present, the returns process requires significant manual effort. Due to the lack of visibility of surplus materials, BC Hydro risks replenishing stock when the same material is sitting unused in the field or in a warehouse. The SCA Project will improve visibility of surplus materials, which will reduce the risk of holding unnecessary inventory.[64]
8	Inability to Pre-package Materials for Field Crews	The current supply chain does not enable BC Hydro to pre-assemble materials for specific jobs or recurring jobs that require the same set of materials. This results in increased effort at remote storage sites to prepare materials for crews on a case-by-case basis.[65] The SCA Project will provide the functionality to permit pre-packaging of job materials for crews.[66]
9	Lack of Wireless Access to Inventory	Mobile access to inventory information is not available to storekeepers as they move through the warehouse. Greater effort is required to manage inventory. Inventory information collected manually is also not as accurate or current as it could be, resulting in more inventory being held than

[59] Exhibit B-1, Application, p. 2-10.
[60] Exhibit B-1, Application, p. 3-10.
[61] Exhibit B-3, BCUC IR 1.4.2.
[62] Exhibit B-1, Application, p. 2-10.
[63] Exhibit B-1, Application, p. 3-10.
[64] Exhibit B-1, Application, pp. 2-10 to 2-11.
[65] Exhibit B-1, Application, p. 2-11.
[66] Exhibit B-1, Application, p. 3-11.

	Information	is optimal.[67] The SCA Project will enable wireless access to inventory information, which will assist in optimizing inventory levels through more accurate inventory data.[68]
10	No Self-serve Option for Routine Service Requests	There is currently no self-service application that allows users to select from a drop-down menu the specific service they require and submit the service request automatically. There is greater effort required for service requests because each request must be made to a buyer accompanied by a written description of the specific services needed. [69] In the new supply chain there will be a self-service IT application for low-value and low-risk services that will allow users to select from a drop-down menu the specific service they require and submit the request for services automatically. This will be faster and more efficient than the current system.[70]
11	Inability to Pay Suppliers Without an Invoice	The supply chain system does not allow BC Hydro to automatically pay suppliers without an invoice in certain circumstances where there are adequate controls to ensure receipt of goods or services. Instead, all goods received must be accompanied by an invoice that must be manually matched (or checked against) the underlying contract with the supplier. The SCA Project will enable BC Hydro to pay suppliers without an invoice, which will save invoice processing costs[71] and is expected to permit the company to negotiate lower per unit pricing on certain types of goods and services.[72]
12	Inability to Streamline Controls and Approvals Process	The current approvals process is inflexible and does not provide for streamlining approval processes where appropriate. There is limited ability within the current system to streamline the approvals processes while maintaining required controls.[73] Closing this capability gap requires work to be managed, including approval, in a single system. The SCA Project will largely allow the financial control and approval of work to occur in SAP.[74]
13	Inability to Integrate with Work Management Systems	BC Hydro manages its work management processes using a number of IT systems, including Spatial Asset Management System, System for Transmission Asset Recording & Reporting, PowerOn, ServiceLink, SAP, and PassPort. Work orders created in each of these systems are interfaced to BC Hydro's SAP-based finance system. This interface allows work orders to be used as charge codes for purchasing materials and services or for charging employee time. No similar interface exists with PassPort. As a result, work orders created in any system other than PassPort do not directly link to the PassPort supply chain system and must be manually re-created in PassPort to allow for materials

[67] Exhibit B-1, Application, p. 2-11.
[68] Exhibit B-1, Application, pp. 2-5 and 3-11.
[69] Exhibit B-1, Application, p. 2-11.
[70] Exhibit B-1, Application, p. 2-5.
[71] Exhibit B-7, CEC IR 2.83.1, 2.83.2, and 2.83.3.
[72] Exhibit B-1, Application, p. 2-11.
[73] Exhibit B-1, Application, pp. 2-11 to 2-12.
[74] Exhibit B-1, Application, p, 3-12.

		and services to be planned. Additional manual effort is required to update changing work schedules in PassPort in order to coordinate material and service deliveries.[75] While future effort will be required to put all work order related information in SAP, the SCA Project will provide benefits such as the ability to plan the materials and services to the work order in SAP.[76]

C. PROJECT PROVIDES NET FINANCIAL BENEFITS

35. BC Hydro has devoted a significant amount of time to understanding the range of potential benefits associated with improving existing processes and creating new processes to drive value. In examining the SCA Project, BC Hydro determined that it will provide significant net financial benefits, which will ultimately benefit BC's Hydro customers. Most aspects of the analysis went unchallenged in information requests. For any issues that were canvassed in the information requests, BC Hydro has provided compelling responses.

(a) The Detailed and Conservative Analysis Demonstrates Significant Benefits

36. BC Hydro developed the benefits analysis from the "bottom up", identifying 64 specific benefits that it believes are achievable and that will result in reduced costs, effort, and risk for BC Hydro. This analysis is detailed in Attachment F of the Application, and updated in the attachment to BC Hydro's response to BCUC IR 2.39.1.

37. The benefits calculation reflects the expectation that the benefits of the SCA Project will ramp up over a two- to four-year time horizon. Cost and monetized effort benefits will begin to be recognized one year after the project goes into service. The effort benefits will increase over a two-year period. Cost benefits will increase over a four-year period.[77]

38. BC Hydro took a conservative approach to assessing the benefits of the SCA Project. Although BC Hydro will seek to achieve 100 per cent of the estimated benefits, BC Hydro selected 50 per cent as the potential for monetized benefits to be achieved. The upper ceiling of 60 per cent and lower floor of 30 per cent were similarly selected to be

[75] Exhibit B-1, Application, p. 2-12.
[76] Exhibit B-1, Application, p. 3-12 and Attachment H, p. 27.
[77] Exhibit B-3, BCUC IR 1.4.3.

conservative.[78] In response to BCUC IR 2.33.4, BC Hydro stated that "given the bottom-up development of the forecasted benefits, BC Hydro believes there is a high likelihood of realizing 50 per cent or more of the benefits."

Financial Benefits Are Significant Despite Conservative Assumptions

39. BC Hydro's proposed investment in a new supply chain is expected to yield annual recurring monetized expected benefits of $26 million.[79] The expected financial benefits are significant despite BC Hydro's conservative assumptions outlined above.

40. Over the course of the proceeding, BC Hydro made four corrections to the calculation of the estimated annual benefits. The four corrections had no impact on the cost estimate, and only marginally reduced the estimated annual benefits as shown in the table below:[80]

Annual Potential Benefits

	Mid	**Low**	**High**
SAP (Dec 21, 2016 Application)	27,460	16,595	33,186
SAP (Updated)	26,172	15,704	31,403

41. As discussed in the next section, the Net Present Value ("NPV") of both discounted cash flows and incremental revenue requirements impact remain overwhelmingly positive. The mid-range cost and benefit estimates correspond to a NPV of $68 million on a discounted cash flow basis and $53 million on an incremental revenue requirements basis.[81]

Financial Benefits Relate to Cost and Effort Reduction

42. The monetized benefits of the SCA Project are derived from either cost reduction or effort reduction savings.[82] Cost reduction savings are based on total addressable spend that flows through the supply chain. Effort reduction savings are based on the number of

[78] Exhibit B-4, CEC IR 1.33.1.

[79] Exhibit B-1, Application, p. 1-6, as updated in Exhibit B-6, BCUC IR 2.39.1.

[80] Exhibit B-6, BCUC IR 2.39.1.

[81] Exhibit B-1, Application, p. 1-6, as updated in Exhibit B-6, BCUC IR 2.39.1.

[82] Exhibit B-1, Application, p. 2-27.

transactions that are processed annually by the supply chain. The benefit amounts are then allocated between capital and operating based on historical spend and effort information. Based on this historical information, BC Hydro has assumed that 76 per cent of cost reduction benefits will be attributable to capital activities and 24 per cent will be attributable to operating activities. With respect to effort reduction benefits, BC Hydro has assumed that 40 per cent will be attributable to capital activities and 60 per cent will be attributable to operating activities.[83]

43. BC Hydro will include forecast savings to revenue requirements attributable to the SCA Project starting in its next revenue requirements application, as fiscal 2021 will be the first year the SCA Project is expected to provide ratepayer benefits.[84] BC Hydro expects that some FTEs will be reduced and some FTEs will be diverted to other activities based on operational requirements. The effort reduction will be spread across multiple employees and multiple departments. Any decisions about eliminating positions will need to consider all of BC Hydro's operational requirements at that time, and will be reflected in future iterations of BC Hydro's Workforce Plan.[85]

(b) Specific Issues Regarding Benefits Raised in Information Requests

44. Most aspects of BC Hydro's analysis went unchallenged in the information requests. For issues that were raised in the information requests, BC Hydro provided compelling responses. These issues are briefly addressed below.

Benefit 7: Reduction of Effort in Operations Managing Completion of Work

45. Benefit 7 described on Tab F1 in Attachment F is the reduction of effort in operations managing completion of work. In determining this potential benefit, BC Hydro estimated that, for the approximately 4,000 people working in PassPort performing supply

[83] Exhibit B-3, BCUC IR 1.4.3.

[84] Exhibit B-1, Application, p. 1-6.

[85] Exhibit B-3, BCUC IR 1.30.13; Exhibit B-7, CEC IR 2.76.1.

chain functions and managing contracts for downstream activities, about 30 per cent of their time is inefficient.[86]

46. The inefficient time is attributable to the shortcomings of the current supply chain, which necessitates manual processes (i.e., the use of spreadsheets and other systems to track, approve, and report work).[87] BC Hydro believes that the SAP supply chain system can eliminate 100 per cent of the inefficient time.[88]

Benefit 14: Reduction of Cost of Capital through an Increase in Inventory Turns

47. Benefit 14 described on Tab F1 in Attachment F is the potential reduction of cost of capital through an increase in inventory turns. Holding less overall inventory to support a given volume of work results in lower carrying costs while the material sits in inventory. In turn, this frees up BC Hydro's working capital (i.e., cash or borrowings that would have otherwise been used to purchase higher levels of inventory can be used for other purposes).[89]

48. The current inventory turn metric for active stock materials is 1.6 on $200 million annual spend ($125 million active stock on hand), with $5.6 million per year in associated carrying costs. Benchmarking information indicates that members of BC Hydro's peer group have, on average, been able to attain an inventory turn ratio of 2.79, which is a reasonable and achievable target.[90] Increasing the inventory turn metric to 2.79 would result in a savings of $2.4 million a year in lower carrying costs.[91] As with all other monetized benefits, BC Hydro has applied a 30 per cent, 50 per cent and 60 per cent factor to estimate the low, medium and high benefit scenarios.

[86] Exhibit B-1, Appendix F, Tab F1.

[87] Exhibit B-4, CEC IR 1.11.2; Exhibit B-1, Appendix F, Tab F1, Cell E9.

[88] Exhibit B-6, BCUC IR 2.34.1.

[89] Exhibit B-6, BCUC IR 2.35.3. In Exhibit B-6, BCUC IR 2.35.4, BC Hydro updated Tab F1 of Attachment F to reflect the correct calculation logic.

[90] Exhibit B-6, BCUC IR 2.35.2.

[91] Exhibit B-6, BCUC IR 2.35.3.

49. The calculation of this benefit excludes spares inventory that is kept in reserve to address situations of critical failure. Increasing the inventory turn ratio above the current 1.6 on active inventory would not result in reduced spares inventory. BC Hydro will continue to ensure system reliability at higher inventory turns for active inventory by maintaining existing levels of critical spares inventory.[92]

Benefit 23: Evaluated Receipt Settlement

50. The Evaluated Receipt Settlement benefit (benefit ID 23) described on Tab F1 in Attachment F is related to the reduction of effort to process invoices and resolve discrepancies associated with vendor-supplied invoices. Where Evaluated Receipt Settlement can be used to replace vendor generated invoices, it eliminates the risk that the vendor invoice is incorrect, and therefore reduces the effort required to resolve invoice errors.[93] BC Hydro estimated the potential mid-range benefit at $59,000 annually.[94]

51. BC Hydro processes 144,000 invoices per year.[95] If BC Hydro has an agreement with vendors to use Evaluated Receipt Settlement, the system will use the receipt of materials or acceptance of services as the basis to generate, post and pay an invoice based on the conditions of the purchase.[96] Evaluated Receipt Settlement will reduce the number of invoices received at Accounts Payable, ensure payment is made at the contracted rate, eliminate need for suppliers to send a separate invoice, and eliminate invoice variances.[97]

52. Eliminating the need for suppliers to issue a separate invoice is also a benefit to suppliers. BC Hydro has not included in its calculations the benefit of potential price discounts that suppliers might provide for the use of Evaluated Receipt Settlement.[98]

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[92] Exhibit B-6, BCUC IR 2.35.2.
[93] Exhibit B-1, Attachment F, Tab F1.
[94] Exhibit B-1, Attachment F, Tab F1.
[95] Exhibit B-1, Attachment F, Tab F1.
[96] Exhibit B-7, CEC IR 2.83.1.
[97] Exhibit B-4, CEC IR 1.18.1 and CEC IR 1.18.4.
[98] Exhibit B-7, CEC IR 2.83.3.

Benefit 60: Reduction of the Cost of Materials Created by Reducing Premiums Paid for Spot Buy Activity

53. Benefit 60 described on Tab F1 in Attachment F is the potential reduction of the cost of materials created by reducing premiums paid for spot buy activity. BC Hydro spends approximately $200 million a year on stock materials. It is estimated that approximately 30 per cent of materials requests results in an expedited purchase, and this creates a 15 per cent increase in costs. BC Hydro estimated a potential mid-range benefit of reducing premiums paid for spot buy activities at $4.5 million annually.[99]

54. The opportunity to reduce spot buy activity may be characterized, partly, as improved category management. Limited visibility of demand in the system can result in reactive spot buy activity, as opposed to a more planned, strategic approach. Category management may improve the process by establishing key contracts in advance. On its own, however, category management would not necessarily reduce spot buy activity or expedited purchases. Accurate master data, lead times, and need dates are required to release an order at the appropriate time, and therefore reduce expediting and costs for rush deliveries. Even without category management, increased visibility of demand would improve the ability of planners to execute manual spot buy activities, and avoid potential expediting and rush delivery charges.[100]

(c) Project Yields Positive Net Present Value

55. BC Hydro calculated the NPV of the SCA Project, taking into account upfront capital costs, future benefits, and ongoing capital and operating costs to measure the total value added to the organization. In general terms, the NPV is calculated as: PV Future Benefits – PV Capital Costs – PV Future Operating Costs. A NPV greater than zero means the project creates economic value.[101]

[99] Exhibit B-1, Attachment F, Tab F1.
[100] Exhibit B-6, BCUC IR 2.36.1.
[101] Exhibit B-7, Landale IR 2.3.1.

56. The updated NPV analysis tables in BC Hydro's response to BCUC IR 2.39.1 demonstrate that the SCA Project is beneficial.[102] The results of the revised analysis are:

NPV of discounted cash flows (millions)

	Mid	Low	High
SAP (Dec 21, 2016 Application)	74.4	6.4	111.6
SAP (Updated)	68.3	2.2	103.2

NPV of incremental revenue requirements impact (millions)

	Mid	Low	High
SAP (Dec 21, 2016 Application)	59.0	(4.0)	94.0
SAP (Updated)	53.5	(7.8)	86.2

57. In response to an information request from Mr. Landale, BC Hydro provided benefit-cost ratios. These numbers were calculated by dividing the present value of the forecast benefit by the present value of the forecast capital and operating costs. A ratio of less than 1.0 indicates that the project destroys value, while a ratio greater than 1.0 indicates that a project creates value. Higher values indicate that the value creation is more robust, and is thus more likely to survive adverse cost, schedule, or market variation. The cost-benefit ratios for the SCA Project are robust:[103]

SAP	Low Benefit	Mid Benefit	High Benefit
Low Cost	**1.64**	**2.74**	**3.29**
Mid Cost	**1.34**	**2.23**	**2.68**
High Cost	**1.03**	**1.72**	**2.06**

58. The above cost-benefit ratios and NPV analysis demonstrate that the SCA Project is expected to create economic value.

[102] Exhibit B-7, Landale IR 2.3.1.

[103] Exhibit B-7, Landale IR 2.3.1.

(d) Benefits will Apply to Innovative Procurement Approaches

59. A portion of the $2.5 billion of materials and services that flow through BC Hydro's supply chain may be contracted through innovative procurement approaches such as Design Build or Public Private Partnership.[104] The SCA Project will benefit all projects regardless of the procurement approach by improving visibility of requirements and contract data in the system, and improving supplier performance management capabilities.[105] While the number of individual contract packages for a project is lower under an innovative procurement approach, the analysis, sourcing, and contracting process may be just as onerous as under traditional procurement approaches.[106]

60. BC Hydro explained in detail that the benefits of the SCA Project would apply to a large project contracted under a competitive innovative procurement approach:[107]

- For Benefit 5, BC Hydro explained that the calculation was based on addressable spend multiplied by estimated average cost savings of 0.5 per cent. BC Hydro purposefully selected a low percentage rate, recognizing that some portion of the addressable spend or that certain categories of services and materials may not achieve cost savings, while others could achieve a significantly higher cost savings rate. For large projects contracted under an innovative procurement approach, there may be less potential for negotiated cost savings on individual services and materials. However, these projects will still benefit from BC Hydro having better data regarding historical purchase volumes and prices, which would be useful information while estimating project costs, analyzing proposals received from proponents and negotiating the overall contract.

- For Benefit 7, the calculation logic is based on the estimated number of hours spent by employees across BC Hydro to manage contracts and completion of work, and the portion that is considered inefficient. This is an effort-based benefit. As with any

[104] Exhibit B-3, BCUC IR 1.4.2.2; Exhibit B-6, BCUC IR 2.37.1.
[105] Exhibit B-3, BCUC IR 1.4.2.2.
[106] Exhibit B-3, BCUC IR 1.4.2.2.
[107] Exhibit B-6, BCUC IR 2.37.2.

construction project, a large portion of contracts under an innovative procurement approach relate to services. As such, these contracts benefit from a system and processes that reduce or eliminate the need for manual effort and working in different systems to manage the completion of work under a contract. While the number of contracts that BC Hydro would process under an innovatively procured project would generally be lower than under a traditionally procured project, these contracts tend to be larger and more complex. Therefore, the total effort necessary to manage the contracts does not correlate with the number of contracts.

- For Benefit 26, the calculation logic is based on the number of service-related invoices that BC Hydro processes annually and the reduction in effort to approve these invoices if there was an automated three-way match in the system. In calculating the benefit, BC Hydro assumed that 70 per cent of invoices have average complexity and 30 per cent are more complex, requiring additional effort to approve. BC Hydro did not further categorize the complex invoices into more granular levels of complexity, as the potential increase in accuracy of the estimate would not have warranted the manual effort to do so. The benefit is applicable to all service-related invoices, regardless of the procurement approach. The number of invoices for a given project under innovative procurement would likely be lower than the number of invoices for the same project under traditional contracting. However, the innovative procurement invoices are also likely to be more complex and require more effort to process. BC Hydro does not have a breakdown of invoice volumes by procurement approach, but is confident that, of the 144,000 invoices processed across BC Hydro annually, only a very small portion relates to projects contracted under an innovative procurement approach.

- For Benefit 60, the calculation logic is based on reducing spot buy and expediting costs for stock materials by increasing visibility of material demand in the system. The benefit calculation is based on BC Hydro's actual spend on stock materials. Consequently, it reflects the actual usage of stock materials across all BC Hydro operations and projects, including those contracted under an innovative procurement approach. Due to the

nature and scope of large capital projects, the majority of their costs are not related to stock materials, irrespective of the underlying procurement approach. Therefore, this benefit is not expected to be impacted by any increase or decrease in innovative procurement.

(e) BC Hydro Will Track and Report Benefits

61. BC Hydro will identify measures and metrics that will be used for tracking the realization of financial benefits from the SCA Project. BC Hydro will use direct measures wherever feasible. Where direct measures are not feasible, BC Hydro will seek to develop indirect metrics and measures that are effective and accurate.[108]

62. BC Hydro will develop an initial set of metrics and measures in the Design and Implementation Planning Stage, based on the impact assessment performed at that time. BC Hydro will file the initial set of baselines and metrics and measures in the Phase Two verification report.[109]

63. During the Implementation Phase, BC Hydro will provide updates on the benefits realization monitoring plan as part of the semi-annual project progress reports. This will include updates on planned baselines, metrics, and measures for tracking the realization of benefits.[110]

64. The Project's final completion report will provide an update on the status and plans for the realization of benefits. As benefits will be realized over a ten-year period, beginning a year after onboarding and increasing over two to four years, progress on realized benefits will be reflected in future Revenue Requirement Applications.[111]

[108] Exhibit B-6, BCUC IR 2.51.2.
[109] Exhibit B-6, BCUC IR 2.51.4.
[110] Exhibit B-6, BCUC IR 2.51.3.
[111] Exhibit B-6, BCUC IR 2.51.3.

D. SCA PROJECT WILL REDUCE RISK IN THE SUPPLY CHAIN

65. The SCA Project reduces the overall risk in the supply chain by reducing the likelihood of risks materializing.[112] The SCA Project's ability to mitigate risks is an important part of the project's justification despite the challenges in quantifying the consequences of the risks and risk reduction benefits.[113]

66. Table 2-9 in the Application summarizes the key risk reduction benefits of the SCA Project. In response to an information request, BC Hydro reproduced the table with additional examples and a qualitative estimate of the likelihood and consequences of these risks materializing, both before and after the SCA Project. BC Hydro provided the information with the caveat that it had applied significant judgment, and that there is a broad range of potential likelihood and consequence combinations.[114] The revised table is reproduced below for reference.

[112] Exhibit B-1, Application, p. 2-25; Exhibit B-3, BCUC IR 1.2.1; Exhibit B-7, CEC IR 2.78.1.

[113] Exhibit B-1, Application, p. 2-28; Exhibit B-3, BCUC IR 1.2.1.

[114] Exhibit B-3, BCUC IR 1.2.1.

Risk Category & Description from Table 2-9	Likelihood & Impact[115]		Qualitative Discussion
	Today	After SCA	
Safety The current system does not maintain adequate information regarding what services vendors are qualified to perform for BC Hydro. As such there is a risk that vendors perform work that they are not fully qualified to do which could result in a safety incident.	Moderate likelihood, low to high impact	Low likelihood, low to high impact	This risk broadly considers various qualifications for vendors, which could include safety certifications, technical qualifications, and past-performance. For example, a vendor could be contracted to perform a certain type of work which does not require safety certifications or specific technical qualifications, and then because they are already on contract, they could be assigned additional work which does require safety certifications or specific technical qualifications. While this would be of low to moderate likelihood, potential consequences could range from a near miss (low) to fatality (high). A vendor may have performed poorly in the past, and that feedback may not be known by those initiating and managing subsequent contracts. For example, a contractor consistently does not demonstrate an understanding of the hazards for a work zone and consequently does not establish proper procedures for proceeding safely with their work. This would be of low to moderate likelihood, but could have low to high consequence for the contractor's team and for BC Hydro team members.

[115] The evaluation of likelihood is assessed as follows: Low likelihood represents potentially a single annual occurrence; moderate likelihood represents potentially multiple annual occurrences; and high likelihood represents regular, frequently repeated occurrences.

Consequence severity, or impact, is assessed as follows: Low represents a minor impact of limited financial consequence, limited complaints by shareholder or a minor impact on reliability. Moderate represents impact ranges from financial impacts that are substantial, customer groups impacted or significant (but mitigatable) reliability impacts. High represents financial impacts that are high, reputational impacts that are broad and involve loss of trust and reliability issues that required a reduction in BC Hydro's supply.

Risk Category & Description from Table 2-9	Likelihood & Impact[115]		Qualitative Discussion
	Today	After SCA	
Financial Risks in the supply chain process can lead to situations where BC Hydro pays too much for goods and services or pays for goods not actually received.	Low to moderate likelihood, low to moderate impact	Low likelihood, low to moderate impact (impacts could also reduce)	Examples of Financial risks are as follows: BC Hydro has in some cases negotiated contracts with volume based discounts. The system does not track these volumes and automatically apply the discount. Therefore, there is a risk that the discounts will not be applied and BC Hydro will pay more than it should for the goods or services. Lack of visibility of work or project-related supply chain demand (i.e. work is not planned in the system such that it is visible to supply chain) results in a risk that requests for materials or services are made with only a short lead time. Consequences of requesting materials or services with short lead times could include higher pricing for services or for rush manufacture or delivery of materials, an inability to take advantage of natural market fluctuations that affect certain commodities. Another consequence is that supply chain may carry higher inventory than is actually necessary to support the work or projects underway. Ultimately, work may need to be deferred if the required materials or services are not available in time. When materials and services are purchased together on the same Contract Order, there are no automated controls linking the receipt of the goods or services to the Contract Order. Instead invoice approval relies on a manual process where the approver is accountable for guaranteeing acceptance of the work. This process can be labour intensive and prone to error, and there is a low to moderate risk of invoices being approved for payment without the materials or services having been received, or at higher prices than the underlying Contract Order.
Reputational Not being able to accurately report on how much BC Hydro spends on specific categories of goods or services and where it is spent is a reputational risk for BC Hydro.	Moderate likelihood, low to moderate impact	Low likelihood, low to moderate impact	The risks in this area have consequences that include complaints by other companies, or customer groups that are critical of BC Hydro, both of which could lead to adverse publicity and loss of confidence in BC Hydro. For example: There is a moderate risk that BC Hydro is unable to provide accurate financial reporting on services. The consequence of this is that we are unable to disclose the value spent on specific services, potentially leading to a perception of poor management and lack of reliability in our financial reporting in general. There is a low - moderate risk that BC Hydro conducts a procurement event without accurate knowledge of past spending, which could impact the procurement process as well as the subsequent contract. If a contract is put in place that does not accurately reflect BC Hydro's requirement, this could impact the organization's reputation with the vendor as well as the other vendors that competed for the work.

Risk Category & Description from Table 2-9	Likelihood & Impact[115]		Qualitative Discussion
	Today	After SCA	
Reliability When materials and or services of low quality are introduced into the system it can impact reliability. The current supply chain system cannot automatically trigger a quality inspection for all materials that should be inspected. Reliance on manual tracking of quality inspection requirements increases the risk that poor quality items are accepted by BC Hydro and introduced into the system.	Moderate likelihood, low to moderate impact	Low to moderate likelihood, low to moderate impact	Moderate risks associated with material quality today can be lowered by linking material acceptance to quality inspections as part of the SCA Project. Two examples to support this include: 1. Today there is no ability to systematically associate single or multiple material quality inspections of equipment with partial acceptance and payment, as is commonly experienced in supply and install contracts. There is low to moderate risk of paying for achievement of milestones related to manufacture, delivery or installation without verifying quality. 2. Similarly, the inspection process for routine material supply contracts is highly manual, and there are low to moderate risks that materials are accepted without there having been sufficient quality checks completed. The consequences in this case are typically low.

67. The qualitative risk assessment provided by BC Hydro is consistent with the Capital Investment Analysis Guide and demonstrates that the risk reduction benefits of the SCA Project are significant.[116]

E. PROJECT POSITIONS BC HYDRO TO ACHIEVE FULL BENEFITS FROM INVESTMENT IN WORK MANAGEMENT AND ASSET MANAGEMENT

68. The SCA Project is a precondition to achieving the full benefits from BC Hydro's additional investments in work management and asset management business processes and IT systems.[117] BC Hydro explained the relationship between supply chain and work and asset management in the Application, as follows:

> There is a close relationship amongst the supply chain, work management, and asset management processes and systems. Work management refers to the business processes and systems required to implement capital and maintenance work programs. Asset management refers to the business processes through

[116] Exhibit B-6, BCUC IR 2.33.7.

[117] Exhibit B-1, Application, pp. 2-7 to 2-8; Exhibit B-3, BCUC IR 1.6.5.

> which physical assets and their associated performance, risks, and expenditures are managed. BC Hydro has invested, and expects to continue to invest, in work management and asset management processes and IT systems to realize productivity improvement benefits. However, the supply chain improvements contemplated by the Supply Chain Applications Project are required before BC Hydro can achieve the full benefits from additional investments in work management and asset management business processes and IT systems.[118]

69. BC Hydro expects to make more specific plans regarding when to proceed with investments in work and asset management IT systems over the next two years. These plans will be followed by specific decisions and approvals to proceed with individual projects.[119] BC Hydro expects this investment will include the implementation of the work and asset management IT systems that will result in the retirement of the PassPort system.[120] An estimate of the potential cost savings from the retirement of the PassPort system is included in the NPV analyses for the SCA Project.[121]

F. CONCLUSION AND REQUESTED FINDINGS

70. The Commission should find that BC Hydro has provided a compelling rationale for undertaking the SCA Project. The SCA Project will address the identified capability gaps in BC Hydro's existing supply chain system, allowing BC Hydro to meet the supply chain business requirements identified in the Supply Chain Business Model. The SCA Project will provide net financial benefits and will reduce risk related to BC Hydro's supply chain. It will also enable BC Hydro to achieve the full benefits from additional investments in work management and asset management business processes and IT systems.

[118] Exhibit B-1, Application, pp. 2-7 to 2-8. Also see Exhibit B-3, BCUC IR 1.6.1.

[119] Exhibit B-3, BCUC IR 1.6.3.

[120] Exhibit B-3, BCUC IR 1.6.3.1.

[121] Exhibit B-1, Attachment F; Exhibit B-3, BCUC IR 1.12.4 and BCUC IR 1.24.5.

PART SIX: SAP IS THE SUPERIOR ALTERNATIVE FOR BC HYDRO

A. INTRODUCTION

71. Chapter 3 of the Application sets out BC Hydro's assessment of alternative IT platforms for the SCA Project. BC Hydro explained how it identified the two viable alternatives (SAP and PassPort), its assessment criteria, and the application of those criteria to the two alternatives. The evidence demonstrates that SAP is the superior alternative for BC Hydro's SCA Project. The following points, each of which is addressed in this Part of the Final Submission, support BC Hydro's selection of SAP:

- First, SAP and PassPort are viable alternatives for addressing the identified capability gaps. The use of an alternate IT system, or a major upgrade to ABB's Asset Suite 9 or SAP S/4 HANA, are not realistic alternatives.

- Second, SAP better addresses the identified capability gaps, is aligned with BC Hydro's Common Platform Strategy, has a lower risk profile, and is superior under NPV analyses.

- Third, third-party assessments of SAP and PassPort support BC Hydro's selection of SAP.

B. SAP AND PASSPORT ARE THE VIABLE ALTERNATIVES

72. BC Hydro identified SAP (ECC6/EhP8) and PassPort (Asset Suite 8) as the two viable alternatives for the SCA Project. A third alternative IT system would be very unlikely to fill the capability gaps better than PassPort or SAP. A major upgrade to either ABB's Asset Suite 9 or SAP S/4 HANA is not a realistic alternative.

(a) Viability of SAP and PassPort Confirmed

73. SAP and PassPort are viable technology platform alternatives. The viability of SAP is confirmed by the Conceptual Design Report for the SCA Project, which is Attachment H

to the Application. The viability of PassPort is confirmed by its current use as the supply chain application at BC Hydro.

(b) Other Alternatives Would Be Unlikely to Address Capability Gaps Better

74. A third alternative IT system would be very unlikely to fill the capability gaps better than PassPort or SAP for the following reasons:

- SAP can fully address the capability gaps. No other alternative (including PassPort) would provide incremental functional benefits over SAP.[122]

- SAP is a "best of breed" supply chain solution.[123] There are third-party studies on the record that reinforce this. SAP is ranked first, with 21 per cent market share, for supply chain management applications. SAP is also number one among procurement software vendors, with 22 per cent market share.[124] Gartner regards SAP as one of only two "leaders" in Energy and Utilities Enterprise Asset Management Software, having regard to both "completeness of vision" and "ability to execute".[125] SAP also shares top spot with Oracle at 9 per cent of market share for utility software vendors.[126] These studies are addressed further below.

- BC Hydro already owns the necessary PassPort and SAP licenses and hardware for a new supply chain. Incremental software licenses and hardware costs, including ongoing maintenance, would add unnecessary cost to the project and ongoing maintenance costs.[127]

[122] Exhibit B-1, Application, p. 3-3.
[123] Exhibit B-3, BCUC IR 1.8.3 and BCUC IR 1.1.4.
[124] Exhibit B-3, BCUC IR 1.1.4.
[125] Exhibit B-3, BCUC IR 1.8.3.1. See also BCUC IR 1.8.2.
[126] Exhibit B-3, BCUC IR 1.1.4.
[127] Exhibit B-1, Application, pp. 3-2 and 3-3.

- Implementing a third alternative would require new personnel with the system skills necessary to train existing personnel in the use of a new system. Hiring new personnel would drive up incremental operating costs. It would be more difficult for BC Hydro to share support resources across platforms.[128]

- Adopting a third alternative would necessitate developing at least one additional set of interfaces to allow users of the new IT system to access the existing SAP and PassPort systems. Adding interfaces increases the complexity of, and adds costs to, BC Hydro's IT environment.[129]

- BC Hydro personnel have experience with PassPort and SAP. Any third alternative would entail more risk to both the SCA Project and its sustainment.[130]

75. BC Hydro did not undertake any further analysis of potential alternatives in addition to SAP and PassPort, given that a full analysis of an IT system other than PassPort and SAP would require considerable expense[131] and an alternative technology platform was unlikely to provide any material advantage over SAP or PassPort.

(c) Major Upgrade to Asset Suite 9 is not a Feasible SCA Project Alternative

76. BC Hydro assessed PassPort's capabilities based on Asset Suite 8, which is the current system in place at BC Hydro. ABB, in its evidence, suggested that BC Hydro should upgrade to ABB's Asset Suite 9.[132] ABB based its critique of BC Hydro's analysis largely on the functionality of Asset Suite 9.[133] An upgrade to Asset Suite 9 is not a feasible SCA Project alternative.

[128] Exhibit B-1, Application, p. 3-3.
[129] Exhibit B-1, Application, p. 3-3.
[130] Exhibit B-1, Application, p. 3-3.
[131] Exhibit B-3, BCUC IR 1.8.3.
[132] Exhibit C3-3; Exhibit C3-5, BCUC-ABB IR 1.3.1.
[133] Exhibit C3-5, BCUC-ABB IR 1.3.

77. BC Hydro, in its Rebuttal Evidence, identified four reasons why ABB Asset Suite 9 is not a feasible alternative for the SCA Project:

> First, the scope of a major upgrade to Asset Suite 9 is significantly greater than the scope of the Supply Chain Applications Project. BC Hydro currently uses Asset Suite 8 for work management, asset management and supply chain. If BC Hydro were to implement a major upgrade to Asset Suite 9, BC Hydro would need to upgrade its work management and asset management functions and business processes, in addition to its supply chain. Such an upgrade would be a large transformation initiative spanning work management, asset management, and supply chain. It would be inaccurate to categorize such a project as a straightforward technical upgrade. Further, BC Hydro has significant customizations built on Passport and custom applications built to work with Passport. It is not known how Asset Suite 9 would work with these customizations. A major upgrade to Asset Suite 9 would be a different, and larger, project than the Supply Chain Applications Project.
>
> Second, the scope of a major upgrade to Asset Suite 9 would greatly increase risk due to the extent of business change that will be required. As noted above, if BC Hydro were to implement a major upgrade to Asset Suite 9, BC Hydro would have to upgrade all of its work management and asset management functions and business processes, in addition to its supply chain. The scope of the change management required for such a project would be much greater, as it would impact a larger user base, including all contractors and employees using Asset Suite for asset management (e.g. processing work orders), who would not be impacted by the Supply Chain Applications Project. An Asset Suite 9 upgrade would also require: changes to the end user interface and the backend technical codebase (i.e. COBOL to Java); and re-validation of all existing integration points, customizations, and existing business processes.
>
> As discussed in Chapter 4 of the Application, BC Hydro made the strategic decision in 2013 to proceed with its Transformation Blueprint IT Projects (including work management, asset management and supply chain, amongst others) in a measured way to reduce risks. This decision has reduced the risk of the Supply Chain Applications Project. In BC Hydro's assessment, it would not be prudent to upgrade its work management, asset management and supply chain functions in a single project.
>
> Third, Asset Suite (either version 8 or 9) does not meet BC Hydro's supply chain business requirements as well as SAP. Asset Suite is primarily an Enterprise Asset Management product. Enterprise Asset Management products focus on the maintenance of plant assets. Asset Suite focuses on asset and work management

> functionality, and has supply chain functionality primarily focused on the maintenance of plant assets. While Asset Suite is a leading Enterprise Asset Management product for power generation utilities, it is not a leading product for transmission and distribution or a leading supply chain product. As indicated in response to BC Hydro IR 1.1, [REDACTED].
>
> In contrast, SAP offers a comprehensive common platform product, which includes asset management, but also modules such as finance, customer care, project management, and human resources. SAP's supply chain module is more fulsome than Asset Suite with regard to how it manages services and integrates with project management. Given the size of BC Hydro's capital portfolio, the need to improve the management of services and the integration with project management is a primary business driver for the Supply Chain Applications Project. As BC Hydro already uses SAP for customer care, finance, human resources, and project and portfolio management, the use of SAP for supply chain reduces manual efforts and complexity related to using two different platforms and removes the need for interfaces between two platforms. Further, a large portion of BC Hydro's current users of Asset Suite are also users of SAP, and only use Asset Suite for supply chain, not asset management. Using SAP for supply chain will simplify the experience for these users as they would only have to use one platform. Using SAP for supply chain will also position BC Hydro to be able to phase-out Asset Suite in the future and eliminate the operating costs associated with maintaining two platforms.
>
> Fourth, given the significant scope and change management issues associated with an upgrade to Asset Suite 9, BC Hydro is not willing to bear the risk of being an early adopter of Asset Suite 9. See BC Hydro's response to BCUC IR 1.7.2 and 2.42.1.[134]

78. BC Hydro submits that these reasons are compelling. These reasons undermine much of ABB's critique of BC Hydro's analysis, as ABB had based its critique on Asset Suite 9. ABB states that it "is absolutely committed to the successful closure of the gaps identified in the application, presuming that BCH is interested in an Asset Suite 9 upgrade".[135] BC Hydro is clear that it will not invest in a major upgrade to Asset Suite 9 at this time.[136]

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[134] Exhibit B-11, Rebuttal Evidence, pp. 2 to 5. As stated in BC Hydro's response to BCUC IR 1.7.2 and 2.42.1, given the recent introduction of Asset Suite 9, there are few examples of it having been implemented by major utilities. ABB's responses to information requests confirm this (Exhibit C3-5-1, FEI-ABB IR 3.4; BCUC-ABB IR 1.1 and 3.3).

[135] Exhibit C3-5, Landale-ABB IR 2.5.

[136] Exhibit B-11, Rebuttal Evidence, p. 2.

(d) Major Upgrade to SAP S/4 HANA is Not Required at this Time

79. As in the case of PassPort, BC Hydro assessed SAP capabilities based on the current version that BC Hydro runs. In the case of SAP, the current version is ECC6/EhP8. An upgrade to SAP S/4 HANA is not required for the SCA Project, and it is too early to consider adoption of the new platform.[137] BC Hydro cited some of the same reasons that applied to ABB's Asset Suite 9: the 13 capability gaps can be closed with software that BC Hydro already owns and operates, without the need for a major system upgrade, and BC Hydro does not consider it prudent to become an early adopter of the new platform.[138] BC Hydro expects to upgrade its SAP platform in the future, irrespective of whether the SCA Project proceeds.[139]

C. SAP IS SUPERIOR TO PASSPORT FOR MEETING BC HYDRO'S REQUIREMENTS

80. BC Hydro compared the SAP and PassPort alternatives using appropriate financial and non-financial criteria: ability to support the Supply Chain Business Model; alignment with the Common Platform Strategy; risk; project cost; and monetized benefits. The results of BC Hydro's alternatives assessment, as updated in BCUC IR 2.39.1 and BCOAPO 2.28.1, are summarized in the table below.[140]

[137] Exhibit B-3, BCUC IR 1.7.2.

[138] Exhibit B-3, BCUC IR 1.7.2. Please also refer to BC Hydro's response to ABB IRs 1.4.0 and 1.6.0.

[139] Exhibit B-6, BCUC IR 2.42.1.

[140] Exhibit B-1, Application, pp. 3-6 and 3-7; Exhibit B-6, BCUC IR 2.39.1; Exhibit B-7-2, BCOAPO 2.28.1.

Criteria	Measure	Alternative 1 - (SAP)	Alternative 2 – (PassPort)
Ability to support the implementation of the SC Business Model	Degree to which capability gaps are closed by the alternative, with all capability gaps weighted equally. Scored out of 52	50	37[141]
Alignment with BC Hydro Common Platform Strategy	Binary (Yes / No)	Yes	No
Risk	Risk assessment rating relative to baseline	Baseline	Higher Business and Delivery Risk
Project cost	Cash flow ($ millions)	60 to 79	37 to 115
Monetized benefits[142]	Cash flow savings at stabilization ($ million/year).[143]	16 to 31	11 to 22
	NPV of discounted cash flows ($ millions)	2 to 103	(47) to 69
	NPV of revenue requirements impact ($ millions)	(7.8) to 86	(42.5) to 63

81. The alternatives analysis demonstrates that the SAP alternative (also referred to as Alternative 1) is the preferred alternative for undertaking the SCA Project for the following reasons:

- SAP closes the capability gaps to a significantly greater degree, whereas PassPort leaves material capability gaps;
- SAP is aligned with the Common Platform Strategy, whereas the PassPort alternative is inconsistent with the Strategy;
- SAP has lower business and technology risk;
- The cost of the two alternatives are reasonably comparable;
- SAP is expected to deliver greater financial benefits to the organization;
- SAP has a higher NPV of discounted cash flows and revenue requirements; and
- SAP is a higher-rated supply chain system.

[141] This value was revised upwards from 36 to 37 for the reasons set out in Exhibit B-7-2, BCOAPO IR 2.28.1.

[142] Results are as updated in Exhibit B-6, BCUC IR 2.39.1.

[143] Figures shown are in F2016 dollars.

The evidence supporting these findings is discussed below.

(a) SAP is Best Positioned to Meet Identified Capability Gaps

82. BC Hydro assessed the extent to which SAP and PassPort-based solutions are able to address the 13 capability gaps. The SAP alternative addresses the capability gaps better than PassPort. There were eight instances where SAP scored better than PassPort. There were no instances where PassPort scored better than SAP.

Gap Assessment Process Undertaken by Internal and External Experts

83. BC Hydro was well positioned to assess the current capabilities of the PassPort supply chain, and the ability of PassPort and SAP to fill capability gaps, given BC Hydro's current experience with operating both PassPort and SAP.[144] BC Hydro's gap assessment was undertaken by a team of experts with first-hand knowledge and experience in operating and enhancing SAP and PassPort. BC Hydro summarized the expertise of the evaluation team as follows:

> The three evaluators that developed the relative effort factors each have between ten and 20 years of experience managing and implementing SAP or Passport at BC Hydro and other companies. Their experience includes working with the product versions of SAP and Passport that were considered in the evaluation.
>
> Two additional evaluators were involved in the assessment of the capability gaps of PassPort and SAP, including the analysis attached to BC Hydro's response to CEC IR 1.49.2. These evaluators each have more than 15 years of experience working with Passport and SAP, and combined, have implemented or sustained Passport or SAP at more than 20 businesses around the world.[145]

84. BC Hydro did not consult with ABB or SAP in determining how well SAP or PassPort would close each of the capability gaps. BC Hydro had sufficient in-house knowledge to perform the assessment of the current version of the software. Performing the analysis

[144] Exhibit B-3, BCUC IR 1.1.4; Exhibit B-4, CEC IR 1.49.2.

[145] Exhibit B-3, BCUC IR 1.11.1.

independently of the system vendors avoided any bias or conflict of interest from SAP or ABB.[146] As discussed below, the results of BC Hydro's assessment is aligned with the perspective of third party assessments of the supply chain capabilities of SAP and Passport.

Assessment Methodology

85. BC Hydro assessed the ability of each alternative to address the identified capability gaps according to two dimensions. First, BC Hydro assessed the ability of either SAP or PassPort to close each capability gap and assigned a score between 0 and 4, as set out below.[147] The score took into account BC Hydro's assessment of whether the applications could be reasonably customized to close the capability gap (e.g., BC Hydro assigned a score of 4 in circumstances where reasonable customization results in fully closing the capability gap).[148]

Table 3-4 Capability Gap Scoring Criteria

Criteria	Score
Does not address the capability gap	0
Addresses a small fraction of the capability gap	1
Addresses some of the capability gap	2
Addresses most but not all of the capability gap	3
Fully addresses all of the capability gap	4

86. Second, BC Hydro assessed each capability gap with reference to how dependent it was on being integrated with other business processes and IT systems. BC Hydro adjusted the capability score downwards where integration dependency was considered high, such that the integration that could be reasonably developed would not wholly close the capability gap.[149] There were three instances where BC Hydro reduced the score based on an assessment

[146] Exhibit B-3, BCUC IR 1.9.2 and 1.9.3.

[147] Exhibit B-1, Application, p. 3-8. BC Hydro explained in its response to BCUC IR 1.10.4 (Exhibit B-3) that using a more granular gap analysis scale (e.g., 1 to 10) would imply a level of precision that does not exist in the analysis and could be misleading.

[148] Exhibit B-3, BCUC IR 1.7.1.

[149] Exhibit B-3, BCUC IR 1.7.1; Exhibit B-7, BCOAPO IR 2.27.2.

that integration could not reasonably be built (Capability Gaps 1, 5 and 6). The overall score for PassPort was reduced by a total of four points (from 40 to 36).[150]

Gap Assessment Results Favour SAP

87. The following table summarizes BC Hydro's assessment of how well the SAP and PassPort alternatives will close the 13 capability gaps.[151]

Capability Gap	Alternative 1 (SAP)	Alternative 2 (PassPort)
1 - Inability to manage service-related spend	4	2
2 - Limited contract management	4	3
3 – Limited ability to manage inventory levels	4	4[152]
4 - Limited ability to manage individual supplier performance	4	4[153]
5 – Difficulty managing the supply chain for capital projects	4	0
6 - Lack of order, delivery and payment tracking	4	3
7 - Inability to support sales and returns of unused materials	4	3
8 - Inability to support pre-packaging of materials for field crews	4	4[154]
9 - Lack of wireless access to inventory information	4	4[155]
10 - No self-serve option for routine service requests	4	3
11 - Inability to pay suppliers without an invoice	4	2
12 - Inability to streamline controls and approvals process	3	2
13 - Inability to integrate the work management systems	3	3
Total Score (out of 52)	**50**	**36**

88. The following is a description of the rationale for the score given to each alternative where SAP scored more favourably.

1 - Inability to manage service-related spend	SAP	PassPort
	4	2

[150] Exhibit B-7, BCOAPO IR 2.27.1 and 2.27.2.

[151] The table is based on the information in Table 3-5 in the Application (p. 3-8), but the score for capability gap 11 was revised upwards from 1 to 2 to reflect the adjustment discussed in BC Hydro's response to BCOAPO IR 2.28.1 (Exhibit B-7-2).

[152] Exhibit B-1, Application, p. 3-9.

[153] Exhibit B-1, Application, pp. 3-9 to 3-10.

[154] Exhibit B-1, Application, p. 3-11.

[155] Exhibit B-1, Application, p. 3-11.

89. BC Hydro assessed PassPort a 3 out of 4 for three reasons: (i) PassPort's lack of a services catalogue, (ii) PassPort's separate processes for procuring materials and services, and (iii) PassPort's inability to define variable services as manageable units of work. The PassPort score was then reduced from 3 to 2 (out of 4) due to the high dependence on integration in fully meeting the requirements of this capability, and inability to reasonably build the integration.[156]

90. There is a clear difference in functionality between SAP and PassPort that justified a lower score for PassPort on this capability gap. The three reasons for rating PassPort a 3 out of 4 before the integration adjustment are explained below:

- PassPort does not contain a catalogue of services (although it does contain one for materials). The absence of a defined services catalogue limits BC Hydro's ability to define, manage, and report on specific services over time. In contrast, SAP has the ability to catalogue both materials and services. This functionality is necessary for effective category management, as described in Attachment K – Supply Chain Business Model.[157] Specifically:
    - SAP's services catalogue enables users to plan work by selecting standard pre-defined services from a list, and to have the cost of the work calculated automatically based on the units of work required and the existing negotiated rates. In PassPort, users must describe in text the service for which they need to create a contract and an estimate of the value of the service.[158]
    - SAP's defined services catalogue also allows for SAP to track the amount, quality, rate, and total cost of defined services over time, providing the data to enable future negotiation of preferred rates for services. BC

[156] Exhibit B-6-2, BCUC IR 2.47.1.2.
[157] Exhibit B-6-2, BCUC IR 2.47.2.
[158] Exhibit B-6-2, BCUC IR 2.47.1.1.

Hydro is currently unable to use the unstructured data captured in PassPort in the same way, without extensive manual analysis.[159]

- PassPort has separate modules for the management of inventory (materials) and contracts (services). Separate processes, documents, and data are necessary for procuring and managing materials and services. The initiation of requests for material is through a materials request (MR) document, while initiation of a request for services is through a contract request (CR) document. These documents require separate processes and are stored in separate tables within the PassPort database. Given that a significant portion of the items BC Hydro procures include a combination of materials and services, this is another significant limitation. It results in users adding materials to contract requests as textual line items, bypassing the use of PassPort's materials catalogue, limiting its value. SAP has no such limitation. SAP allows for the procurement of materials, services, or a combination of the two, through a single process and set of documents.[160]

- BC Hydro's ability to manage service-related expenditures depends on its ability to define the scope of work for service contracts as manageable work units. PassPort could be configured to allow non-variable services to be defined as manageable work units, but not variable services. A variable service is a service that is planned, procured, managed and invoiced in terms of a measure of units of work (e.g. service planned and invoiced on an hourly basis). The amount of work performed and invoiced for a variable service in any given period is likely to vary. A non-variable service is planned as a single defined activity or set of milestones that is assigned an overall dollar value, rather than a unit based rate, e.g. janitorial services at a fixed price per month.[161] SAP allows for all services to

[159] Exhibit B-6-2, BCUC IR 2.47.1.1.
[160] Exhibit B-6-2, BCUC IR 2.47.2.
[161] Exhibit B-6-2, BCUC IR 2.47.1.1.

be defined as manageable work units, including those that are variable.[162] As a result:

- SAP is able to contract unit-based work for any type of unit. PassPort can only define unit-based work of labour (hourly) based work, and only achieve the process functionality BC Hydro requires if PassPort's time and labour module is used. BC Hydro currently uses SAP's time and labour system because of the internal integration between it and SAP's human resources module, which BC Hydro also uses.[163]

- SAP has the capability to automatically post financial accruals and adjust commitment amounts to be paid based on varying units of work (e.g., the plan may call for 100 units of work to be performed in a given period, but only 90 are invoiced). PassPort requires manual processing to initially plan a milestone payment via the payment authorization process for the dollar value of 100 units of work, which must be manually updated based on the dollar value of actual 90 units of work completed.[164]

91. For the above reasons, BC Hydro reasonably scored PassPort lower than SAP, as a 3 of 4.

92. BC Hydro confirmed that the information provided by ABB regarding Asset Suite Contract Management application and Compose tool in its intervener evidence did not change its assessment. BC Hydro noted that it "has utilized PassPort's contract management module since its initial implementation of PassPort in 2003 and is well aware of its capabilities."[165] BC Hydro also explained that it is aware of the capabilities of the Compose tool, noting that the Compose tool is not a specific tool for contract management, but is a general tool that can be used to tailor the PassPort application overall. BC Hydro explained: "While the compose tool

[162] Exhibit B-1, Application, p. 3-8 to 3-9; Exhibit B-4, CEC IR 1.49.2, Attachment 1.
[163] Exhibit B-6-2, BCUC IR 2.47.1.1.
[164] Exhibit B-6-2, BCUC IR 2.47.1.1.
[165] Exhibit B-6-2, BCUC IR 2.47.2.

can be used to develop automated workflow and simplify screens for end users, it cannot overcome the limitations noted above as they are fundamental to the structure of the PassPort data model and cannot simply be corrected by adding, updating, or renaming fields."[166] BC Hydro also explained that, while "BC Hydro uses such tools at times to automate workflows and simplify user interactions with its systems, it generally avoids adding, updating, and renaming fields as this is a customization of the core product, and such customizations are generally costly to implement and maintain."[167]

93. Capability gap 1 was one of three instances where BC Hydro reduced the score, given its assessment that the level of integration that could reasonably be built would not close the capability gap. In this instance, BC Hydro reduced the score from 3 to 2. The dependence on integration was rated as "high".[168] BC Hydro explained that fully closing this capability gap requires integration with (i) SAP's project management module (where most of the need for materials and services are generated), and (ii) SAP's finance module for the automation of commitments and monthly accruals.[169]

94. ABB stated on pages 3 and 4 of its Evidence that Asset Suite has multiple avenues for integrating to other business information systems, including SAP Project Systems, and that numerous utility installations can testify to this functionality.[170] BC Hydro's response to BCUC IR 2.49.1 discussed the barriers to full integration and BC Hydro's experience developing and maintaining such interfaces with PassPort. The discussion in that response applies equally to all three instances where the PassPort scores were reduced for reasons of feasibility of closing the gap:

> While BC Hydro agrees in theory with ABBs assertion that "Asset Suite has multiple avenues for integrating to other business information systems including SAP Project Systems", in practice there are significant barriers for achieving workable integration.

[166] Exhibit B-6-2, BCUC IR 2.47.2.
[167] Exhibit B-6-2, BCUC IR 2.47.2.
[168] Exhibit B-7, BCOAPO IR 2.27.2.
[169] Exhibit B-7-2, BCOAPO IR 2.27.3.
[170] Exhibit C3-3.

BC Hydro has extensive experience integrating PassPort and non-PassPort systems, and has developed and maintains 30 interfaces between PassPort and other systems, including 20 with SAP. In the past, BC Hydro has had limited success interfacing PassPort's purchasing and contract management functions and SAP's Project Systems module (please refer to BC Hydro's response to CEC IR 1.50.1 for discussion on this experience). Given BC Hydro's experience and level of understanding of its project management processes, BC Hydro is confident that effective integration between SAP Project Systems and PassPort cannot reasonably be built.

When discussing the ability to integrate business information systems, there are two aspects that must be considered:

1. the technical interfacing methods available (i.e., the technical method of how the systems are able to transfer data from one to the other), and

2. the business functionality perspective (i.e., how well the data structures and associated functionality of the systems align in order to support end-to-end business processes).

It is with regard to item 1 that BC Hydro agrees with ABBs statement; however, it is due to item 2 that BC Hydro has had limited success interfacing PassPort with SAP Project Systems.

BC Hydro has utilized two methods for technically integrating Asset Suite (Passport) and SAP: direct integration and web services middleware software.

Both technical methods have been used by BC Hydro when building interfaces between Asset Suite and SAP.

While it is possible to technically interface business information systems, the effectiveness of those interfaces in enabling a business process has to do with the design of the individual applications, including how their data is defined and structured. Applications define all of the pieces of data they manage in a "data dictionary" and organize that data in a "data model" that defines the data structure and data relationships. As a result, while it may be technically possible to move data from one system to another, that data may have different definitions and be used in very different ways within each application, limiting the ability for a business process to operate efficiently across the applications.

BC Hydro recognizes that this challenge is in part due to the integrated nature of SAP. As noted in the Gartner report provided in response to BCUC IR 1.1.3 "SAP

> EAM is not designed for integration with enterprise applications from other major ERP vendors." This comment is not just true for SAP EAM (the topic of this report is EAM systems) but is true for SAP in general. For example, it is not possible to plan a material of [sic] service within SAP's Project Systems module without it automatically triggering SAP's internal supply chain processes. This functionality cannot be turned off without significant and complex customization to SAP's core program code. As a result, there is no reasonable method that enables materials and services planned in SAP's Project Systems module (as is called for in the process) to be interfaced to PassPort supply chain.[171]

95. BC Hydro's responses to CEC IRs 1.50.1 and 1.54.2 further discuss BC Hydro's experience integrating processes between PassPort and SAP. In response to CEC IR 1.50.1, BC Hydro explained how it attempted to integrate PassPort based contracts with SAP-based projects. The interface took approximately one year and cost between $200,000 and $400,000, but did not deliver on the expected business value.[172] In response to CEC IR 1.54.2, BC Hydro explains that an interface between PassPort and a new third-party software solution was estimated to cost more than $1 million, and still would not eliminate the need for users to work in both systems.[173]

96. BC Hydro explained as follows:

> There is a fundamental mismatch between the lifecycles of some data in SAP and Passport, which causes interface issues. For example, work orders are currently interfaced between Passport and SAP. A PassPort work order's statuses (e.g., approved, ready, closed, etc.) are sequential whereas the equivalent work order in SAP goes through a different series of statuses, some of which are not sequential and some of which do not exist in PassPort. The result is that the technical interface between the systems must attempt to compensate for cases where statuses get out of sync. In practice, not all mismatches can be resolved by the technical interfaces and errors are logged, which in turn must be prioritized and resolved by IT support staff on a daily basis.[174]

[171] Exhibit B-6, BCUC IR 2.49.1.

[172] Exhibit B-4, CEC IR 1.50.1.

[173] Exhibit B-4, CEC IR 1.54.2.

[174] Exhibit B-4, CEC IR 1.54.2.

97. The Commission should give weight to BC Hydro's extensive experience attempting to integrate PassPort with other applications. It was appropriate to reduce PassPort's score from 3 to 2.

2 - Limited contract management	SAP	PassPort
	4	3

98. SAP has an advantage over PassPort in the way that users can access key contract information and requisition materials and services. In SAP, more real-time operational contract information is available to users. SAP users can requisition both services and materials in one process, which is not possible with PassPort. These advantages allow better contract management in SAP.[175] For these reasons, SAP scored 4 and PassPort scored 3.[176]

99. ABB stated on pages 3 and 4 of its Evidence that, as part of Purchased Materials, users can enable the viewing of real-time operational contract information of both materials and services.[177] BC Hydro answered ABB's statement in the response to BCUC IR 2.48.4:

> Yes, BC Hydro did consider ABB's proposed solution to close capability gap 2, however, the proposed solution would not fully close the capability gap and therefore BC Hydro has not changed its assessment.
>
> BC Hydro scored PassPort 3 out of 4 regarding its ability to close capability gap 2 for two reasons:
>
> 1. PassPort has separate processes and data objects for managing the procurement of materials and the procurement of services. This creates complexity when procuring a combination of materials and services from a single vendor. ABB's proposed method to work around this shortcoming does not overcome the fundamental complexity of processing contracts and material purchases separately and then having to manually link them to enable viewing by users. The solution proposed by ABB would not fully close the capability gap.
>
> 2. PassPort does not have a catalogue of services and as a result contains less structured data about the services to be procured and managed than SAP. While ABB's proposed solution would "enable the viewing of real-time contract

[175] Exhibit B-1, Application, p. 3-9.
[176] Exhibit B-1, Application, p. 3-9.
[177] Exhibit C3-3.

> information of both materials and service", the absence of a defined services catalogue in PassPort results in data often being stored as "free text". Data stored as "free text" is similar to an unrestricted comments field in an online survey; while it can be viewed, it does not utilize established rules and data relationships. This limits its usefulness in automated processing and data queries. In contrast, because SAP has a defined services catalogue, more of the required data is stored in structured fields increasing ease of access and use in processing. The absence of a service catalogue in PassPort is not overcome by ABB's proposed solution.[178]

100. BC Hydro therefore reasonably rated PassPort a 3 out of 4.

5 – Difficulty managing the supply chain for capital projects	SAP	PassPort
	4	0

101. Capability gap 5 accounts for the most significant difference between the two alternatives. The evidence supports BC Hydro's assessment.

102. Closing the capability gap is highly dependent on an integrated solution because it requires data and functions that span project management and supply chain systems.[179] SAP rates well (4 of 4) on this item because (i) SAP is a fully integrated enterprise solution, and (ii) BC Hydro has already implemented its capital project management processes in SAP's Projects Systems (PS) module.[180]

103. BC Hydro assigned PassPort a score of 2 for its ability to close the capability gap, but reduced the score to 0 due to the complexity of integrating PassPort with BC Hydro's existing project management systems.[181] BC Hydro's assessment regarding the complexity of integration was based on first-hand experience. BC Hydro had previously investigated during two previous SAP module projects - Finance and Project and Portfolio Management - the possibility of building additional integration between PassPort and SAP Project Systems

[178] Exhibit B-6-2, BCUC IR 2.48.2.
[179] Exhibit B-3, BCUC IR 1.7.1.
[180] Exhibit B-1, Application, p. 3-10.
[181] Exhibit B-3, BCUC IR 1.7.1.

modules. BC Hydro determined in both instances that additional integration was not feasible.[182]

104. ABB disputes BC Hydro's assessment regarding capability gap 5, suggesting that its PassPort product warrants a score of 4.[183] BC Hydro's assessment should be preferred to ABB's position. The evidence provided by ABB includes a lengthy discussion of Asset Suite's design engineering (compatible unit estimating) functionality, but does not describe any project management capabilities. ABB's evidence suggests that customers do not use Asset Suite for project management, but develop interfaces to other project management systems (such as SAP's Project Systems).[184] This integration, however, cannot reasonably be built to fully close the capability gap.[185]

105. BC Hydro's assessment was based on its first-hand experience of being unable to effectively integrate Passport and SAP Project Systems. ABB provided no analysis in support of its assessment despite being asked a direct question about it.[186] Specifically, in BCUC-ABB IR 6.2 the Commission asked ABB to provide details of utilities that have integrated Passport with SAP Project Systems. ABB's response to this question only indicates that its clients run "certain SAP modules" and have experience with "related integration". ABB did not identify any utilities that have effectively integrated Passport with SAP Project Systems.[187]

106. The lack of integration is a critical shortcoming for a PassPort solution. It is very important for BC Hydro to be able to more effectively manage major capital projects, particularly considering the magnitude of BC Hydro's capital plan over the next 10 years.[188]

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[182] Exhibit B-1, Application, p. 3-10.

[183] Exhibit C3-3.

[184] Exhibit B-7-2, BCOAPO IR 2.28.2. For instance, ABB states in its evidence that the data in Asset Suite "could be pulled into an in-application report or BI platform, such as SAP Business Objects or Microsoft PowerBI, and then shared across the organization, as required"; ABB also states, "Asset Suite has multiple avenues for integrating to other business information systems (such as SAP Project Systems)…" (Exhibit C3-3, p. 4).

[185] Exhibit B-7-2, BCOAPO IR 2.28.2; Exhibit B-6, BCUC IR 1.7.1.

[186] Exhibit C3-5, BCUC-ABB IR 6.2.

[187] Exhibit B-6, BCUC IR 2.49.1.

[188] Exhibit B-1, Application, p. 3-10.

6 – Lack of order, delivery, and payment tracking	SAP	PassPort
	4	3

107. This capability requires that the end-to-end process from order, to delivery, to payment be under a single system. Currently, the order and delivery processes are managed in PassPort, and the payment processes are managed in SAP. SAP merited a score of 4 because the deployment of SAP for supply chain would allow for the order, delivery, and payment processes to occur under one system.[189]

108. BC Hydro assigned PassPort a score of 3 because not all of the payment information can be interfaced back to PassPort.[190] That is, the PassPort score was reduced from 4 to 3 because the dependence on integration was rated as "medium" and the integration that can reasonably be built would not fully close this capability gap.

109. In response to ABB's position that PassPort should not be given a lower score,[191] BC Hydro explained that:

> …the setup described by ABB with regard to closing of capability gap 6 is similar to how BC Hydro currently operates with PassPort interfaced to SAP's finance module to complete the processing and posting of financial entries in SAP. BC Hydro agrees that the current gap could be partially closed with a PassPort-based solution, and that the current interfaces could likely be enhanced. However, the gap cannot be fully closed due to the need to split the payables process across two applications (as is done today), which requires users to access multiple systems.[192]

110. BC Hydro further explained that, even with the integration proposed by ABB in place, there are limitations within the process. The fact that it spans two IT systems (SAP and PassPort) means that users cannot access all of the information they may need in order to investigate a payment or invoice without logging into and searching both applications. This

[189] Exhibit B-1, Application, p. 3-10.
[190] Exhibit B-1, Application, p. 3-10.
[191] Exhibit C3-3, p. 7.
[192] Exhibit B-7-2, BCOAPO IR 2.28.2.

limitation is removed with an SAP-based solution, which is why SAP received a higher score of 4.[193]

7 – Inability to support sales and returns of unused materials	SAP	PassPort
	4	3

111. The SAP alternative will fully support the return of unused materials from the field. BC Hydro assumed for the purposes of its analysis that returns processing in PassPort could be improved. However, PassPort does not have a sales and distribution module, which is required to support the sales and returns of unused materials. For this reason, PassPort merited a score of 3.[194]

112. ABB's evidence and responses to information requests did not change BC Hydro's assessment of PassPort.[195] BC Hydro explained that it

> …is aware of Asset Suite's capabilities in this area, and agrees that a PassPort-based solution could meet a number of BC Hydro's requirements. Asset Suite's capabilities are focused on the return of inventoried materials and do not address BC Hydro's requirements to return unused non-stock materials (i.e., non-catalogued materials not carried in inventory). The majority of unused material for which a returns process is required are non-catalogued materials purchased for capital infrastructure projects but not consumed as part of the project.[196]

10 – No self-serve option for routine service requests	SAP	PassPort
	4	3

113. Automation of routine procurement is dependent on a services catalogue and an easy user interface for navigation and workflow. PassPort has more limited services catalogue capability than SAP, justifying the differential in scoring.[197] BC Hydro explained that SAP provides more options for how unitized services can be configured including the Service Master concept. In PassPort, the majority of services utilized by BC Hydro could not be catalogued to a

[193] Exhibit B-7, BCOAPO IR 2.27.2.

[194] Exhibit B-1, Application, p. 3-11.

[195] Exhibit B-7-2, BCOAPO IR 2.28.2; Exhibit B-11, Rebuttal Evidence, p. 8.

[196] Exhibit B-7-2, BCOAPO IR 2.28.2.

[197] Exhibit B-1, Application, p. 3-11.

sufficient degree of detail, thereby limiting PassPort effectiveness as a self-service procurement tool. BC Hydro processes a large volume of services related to contract orders annually. The ability to automate a significant portion of contract orders is a key requirement.[198]

114. ABB stated that it is unclear why Asset Suite (PassPort) is perceived as having a more limited services catalogue, or why this could not be automated.[199] BC Hydro explained:

> The basic difference between SAP and PassPort with regard to a services catalogue capability is that SAP has a services catalogue while PassPort does not. As a result, it is not possible for a user in PassPort to access a list of catalogued services and select them for inclusion in planning a piece of work (i.e., a work order or a project) enabling the automation of subsequent procurement activities. PassPort does provide the ability to establish "background" and "model" contracts, the details of which can be copied into a new contract thereby mimicking some of the capabilities of a service catalogue. The approach is limited compared to the SAP structure which is based on having a defined and approved catalogue of available services that end users can select from.
>
> Absence of a service catalogue limits the amount of structured data as discussed in BC Hydro's response to BCUC IR 2.48.4, which limits the ability to automate routine procurement. Given the importance of having a services catalogue for automating procurement, PassPort was scored a 3 with respect to closing capability gap 10.[200]

115. CEC-ABB IR 4 asked ABB to discuss why its services catalogue is not more limited than SAP's catalogue. ABB's response to the question does not describe a services catalogue. Asset Suite does not have a services catalogue.[201] BC Hydro reasonably assigned PassPort a lower score than SAP.

	SAP	PassPort
11 – Inability to pay suppliers without an invoice	4	2

[198] Exhibit B-3, BCUC IR 1.9.7.

[199] Exhibit C3-3, p. 9.

[200] Exhibit B-6-2, BCUC IR 2.50.1.

[201] Exhibit B-11, Rebuttal Evidence, p. 8.

116. The functionality to pay a supplier without an invoice is called Evaluated Receipt Settlement. SAP has full Evaluated Receipt Settlement functionality.[202] Taking into consideration ABB's intervener evidence, BC Hydro concluded that PassPort provides capability to pay for materials without an invoice. However, it does not provide this ability for contract services.[203] PassPort therefore scored 2 out of 4.

12 – Inability to streamline controls and approvals processes	SAP	PassPort
	3	2

117. Closing this capability gap requires work to be managed, including approval, in a single system. SAP warranted a score of 3 because it will largely allow the financial control and approval of work to occur in SAP. SAP will not fully close this capability gap because certain work (Distribution Design Work and Generation & Transmission Stations) will remain in PassPort unless and until Work Management and Asset Management are undertaken in SAP.

118. PassPort merited a score of 2. Much of the work will never be managed in PassPort. There is also no Human Resources module in PassPort to support the use of organizational roles to determine approval authority.[204]

119. ABB's Evidence provided a description of how controls and approvals are managed within Asset Suite.[205] BC Hydro responded that it "agrees that controls and approvals could be improved with a PassPort-based solution. However, ABB's evidence does not address BC Hydro's reasoning for why PassPort was rated lower than SAP in this area. As described in the Application, fully closing this capability gap would require work to be managed and approved in a single system."[206]

120. In response to CEC-ABB IR 6, ABB asserted that it would rate as a 4 for capability gap 12. While ABB described in this IR response some of PassPort's functionality and some of

[202] Exhibit B-1, Application, pp. 3-11 to 3-12.

[203] The score for capability gap 11 was revised upwards from 1 to 2 to reflect the adjustment discussed in BC Hydro's response to BCOAPO IR 2.28.1.

[204] Exhibit B-1, Application, p. 3-12.

[205] Exhibit C3-3, p. 13.

[206] Exhibit B-7-2, BCOAPO IR 2.28.2.

its limitations, ABB did not address BC Hydro's stated business requirements. As BC Hydro's projects and portfolio management, finance and human resources systems are SAP-based, BC Hydro can never fully close capability gap 12 with PassPort.[207]

(b) SAP is the Only Alternative Aligned with BC Hydro's Common Platform Strategy

121. SAP is the only alternative that is consistent with BC Hydro's Common Platform Strategy.[208]

SAP is BC Hydro's Common Platform

122. In 2008, BC Hydro made a decision to shift to an enterprise-wide SAP IT platform. BC Hydro refers to this as its Common Platform Strategy. The rationale for choosing an enterprise IT platform as a technology standard was that, over time, it will allow all core business processes to be consolidated onto a single platform (SAP). The benefits of the Common Platform Strategy are:

- A reduction in overall complexity of BC Hydro's IT environment;
- More streamlined business processes;
- A single source of information and thus consistency of analysis and reporting; and
- Reduction in the cost of future business and technology changes.[209]

123. Since the Common Platform Strategy was adopted, BC Hydro has implemented SAP for Finance, Human Resources, Project and Portfolio Management as well as other enhancements and partial implementation projects.[210] BC Hydro expects to continue investing in the SAP platform after the SCA Project is completed. Consistent with the Transformation

[207] Exhibit B-11, Rebuttal Evidence, p. 8.
[208] Exhibit B-1, Application, p. 3-13.
[209] Exhibit B-1, Application, p. 3-13.
[210] Exhibit B-1, Application, p. 3-13.

Blueprint described in section 4.2.7 of the Application, future projects supporting work and asset management will likely be on an SAP platform.

The Challenge of Integrating PassPort in an SAP Environment

124. PassPort and SAP are designed to operate as integrated systems performing multiple business functions, not as standalone systems integrated with other systems. Selection of PassPort as the preferred alternative for supply chain would complicate BC Hydro's IT systems, potentially impacting its ability to successfully execute future projects.[211]

125. The Common Platform Strategy was considered in assigning the capability gap scores discussed above, in the sense that BC Hydro took into account the degree of integration to other SAP components required to fully close a given capability gap. PassPort's score was reduced where complex integration between PassPort and the non-supply chain components of SAP would be required. The total PassPort score was only reduced for this reason by 4 points out of a possible score of 52. That is, PassPort would have scored 40 points (rather than 36) out of a possible 52 if BC Hydro had not included a consideration of the integration benefits of a common platform in its assessment.[212]

126. Implementing the SAP supply chain will position BC Hydro to phase-out all use of PassPort, thus reducing complexity and costs of operating and maintaining two systems.[213]

(c) SAP is the Lower Risk Alternative

127. The SAP alternative is lower risk than PassPort, primarily because adopting the PassPort alternative would introduce additional business and project delivery risk.

[211] Exhibit B-1, Application, p. 3-13.

[212] Exhibit B-4, BCOAPO IR 1.17.1.

[213] Exhibit B-1, Application, pp. 2-7 to 2-8; Exhibit B-3, BCUC IR 1.24.5.

PassPort Would Introduce Greater Business Risk

128. Most risks in this category (as summarized in Table 4-3 of the Application) are the same for both alternatives. However, an additional business risk exists with PassPort that does not arise with SAP. BC Hydro's supply chain system has been on a PassPort platform since 2003. Once an IT system has been in use for a significant amount of time, as with PassPort, user behaviour becomes entrenched. Changing processes and changing behaviour in PassPort may therefore be difficult and challenging.[214]

129. ABB claims that BC Hydro's assumptions around business risk are incorrect. ABB, however, does not address BC Hydro's rationale for concluding that PassPort would introduce greater business risk. BC Hydro agrees with ABB that change management will equally be a part of either an SAP transition or a PassPort transition.[215] BC Hydro's view is that it may be more difficult to change user behaviour in Passport. As explained in response to CEC IR 1.53.1, the SCA Project will not just implement new technology, but will also implement new business processes and roles in support of the Supply Chain Business Model. As a result, if BC Hydro implemented a PassPort based solution, people using PassPort would have to undergo behaviour changes to adapt to the new processes, roles, and responsibilities.[216] PassPort has been in place at BC Hydro since 2003, and there are over 4,000 users of the PassPort platform in a calendar year.[217] The potential for entrenched behaviour is therefore a risk with PassPort that does not exist to the same degree with SAP for supply chain.

PassPort Would Introduce Greater Project Delivery Risk

130. Overall project delivery risk is higher for the PassPort alternative for three reasons. First, PassPort has a higher likelihood of an unsuccessful system integrator RFP, given the relative lack of PassPort resources in the market. Due to the specialized nature of the PassPort system and its smaller market presence, external systems integrators have limited

[214] Exhibit B-1, Application, p. 3-14.
[215] Exhibit C3-3, p. 14.
[216] Exhibit B-4, CEC IR 1.53.1.
[217] Exhibit B-4, CEC IR 1.53.2.

PassPort capabilities in comparison to SAP. BC Hydro's perspective is supported by Gartner research, which cautions: "there are limited service provider options, mainly ABB itself (i.e., the PassPort vendor) and references report resource constraints".[218] Second, the PassPort alternative has a higher risk of poor quality as BC Hydro's internal PassPort team capacity is more limited than its internal SAP capacity.[219] Third, SAP benefits from prior work that mitigates the delivery risk of the project, which has not been completed for PassPort.[220]

131. In its evidence, ABB stated that it "works with a number of Systems Integrators, including Deloitte, PricewaterhouseCoopers, Accenture, and potentially others, as well as other niche partners (e.g., Trinoor, whom BC Hydro engages today)."[221] BC Hydro recognizes that ABB works with a number of Systems Integrators, but in BC Hydro's experience the number of overall resources in the marketplace with PassPort-related skillsets is limited in comparison to resources with SAP-related skillsets. As an example, when BC Hydro conducted the RFP for the SCA Project, which requires skills in both SAP (the target platform) and PassPort (the legacy platform), each of the three Systems Integrator finalists proposed their own resources for SAP-related roles, but none proposed their own resources for PassPort-related roles. Instead, the Systems Integrators each partnered with Passport speciality firms (e.g., ABB) to put together viable proposals.[222]

132. ABB acknowledges Gartner's caution that "there are limited service provider options, mainly ABB itself, and references report resource constraints." ABB states that it "has endeavoured to strengthen its partner network and EAM practice".[223] When asked to elaborate on what ABB has done to strengthen its partner network, and whether it still has "resource constraints", ABB's response is equivocal, and does not demonstrate that it has overcome the resource constraints noted by Gartner.

[218] Exhibit B-3, BCUC IR 1.9.9.
[219] Exhibit B-3, BCUC IR 1.9.9.
[220] Exhibit B-1, Application, pp. 3-14 to 3-15.
[221] Exhibit C3-3, p. 14.
[222] Exhibit B-7, BCOAPO IR 2.30.1.
[223] Exhibit C3-3, p. 16.

(d) The Cost of the Alternatives is Not Determinative

133. BC Hydro's approach to developing a cost estimate for PassPort for the purposes of the alternatives analysis was reasonable. The relative cost of the two alternatives is not determinative one way or the other.

BC Hydro Took a Reasonable Approach in Developing the PassPort Cost Estimate

134. The SCA Project conceptual design was developed on the basis of implementing SAP and not on the basis of implementing a PassPort solution. In the absence of having a PassPort-specific conceptual design, BC Hydro used the detailed SAP Definition Phase cost estimate as a base from which it developed a cost range for the PassPort alternative for this evaluation.[224]

135. For each cost component, BC Hydro estimated the level of effort (as a percentage) reasonable for a PassPort-based solution relative to the SAP based solution.[225] Overall, the level of effort to complete the implementation of Passport is estimated to be lower given that the existing supply chain system is PassPort-based. BC Hydro then multiplied the level of effort percentage by the SAP project cost estimate for each project activity and summed each cost to calculate a base cost for PassPort.[226] BC Hydro then applied a contingency of 20 per cent on the cost estimate and added IDC to calculate a mid-range cost estimate. As no conceptual design exists for the PassPort alternative, and consistent with BC Hydro standards, an uncertainty range of +100% / -35%[227] was applied to calculate the upper and lower bounds

[224] As described in section 2.4 of the Application, the detailed cost estimate is included on workbook tab C1 – Direct Cost Detail of Attachment F.

[225] Exhibit B-1, Application, p. 3-15; Exhibit B-3, BCUC IR 1.11.1.

[226] A component was also added to the PassPort estimate to account for the work required to complete the equivalent of the early design work developed as part of the Supply Chain Transformation Blueprint. This component was calculated by taking the ratio of the design costs for PassPort and SAP multiplied by the value of the early design work used for the SAP alternative. See Exhibit B-1, Application, p. 3-15, footnote 26.

[227] This range applies to an AACE Class 5 estimate which is an appropriate classification for the PassPort estimate as no design work has been completed for this alternative. See Exhibit B-1, Application, p. 3-16, footnote 27.

for the estimate. The calculation of the Alternative 2 (PassPort) cost estimate is included in tabs D1 and D2 of Attachment F. [228]

136. Table 3-6 of the Application, reproduced below, provides the components of the Alternative 2 (PassPort) cost estimate range:[229]

Table 3-6 Alternative 2 (PassPort) Cost Estimate

Phase / Activity	Capital Costs	Operating Costs	Total
Identification		1.2	1.2
Definition	17.3	1.9	19.2
Implementation	22.9	2.5	25.4
Contingency (20% x Definition & Implementation)	8.0	0.9	8.9
Total Cost (ex IDC)	48.2	6.5	54.7
Interest During Construction (IDC)	2.5		2.5
Total Expected Cost	**50.7**	**6.5**	**57.2**
Total Upper Bound Estimate (+100%)	**101.6**	**13.2**	**114.8**
Total Lower Bound Estimate (-35%)	**33.0**	**4.3**	**37.3**

137. Table 3-7 of the Application, reproduced below, summarizes the estimated project costs for the two alternatives:[230]

Table 1-7 Comparison of Project Costs for Alternatives

Alternative	Total Estimated Project Cost Range ($ million)
1 – SAP	60.5 - 79.3
2 – PassPort	37.3 - 114.8

138. Based on the methodology for developing a cost estimate for Alternative 2 (PassPort) described above, the fact that BC Hydro has not developed a conceptual design for PassPort, and that there has not been a competitive bid process to provide any cost certainty, the cost range for PassPort is much larger to account for the uncertainty. For this reason, it is

[228] Exhibit B-1, Application, p. 3-16.
[229] Exhibit B-1, Application, p. 3-16.
[230] Exhibit B-1, Application, p. 3-16.

difficult to draw a specific conclusion as to which alternative is preferable based on project cost alone.[231]

139. The approach used by BC Hydro for the PassPort Alternative is valid:

- The implementation of a PassPort-based solution and an SAP-based solution are fundamentally similar. Both involve the design of new supply chain business processes and technology, the configuration of a packaged IT solution, the testing of that solution, the cleaning and migration of required data, and the preparation and delivery of organizational change management and training activities. Therefore, the base estimate used for the SAP implementation in terms of timing, activities required, and resources needed, was appropriate as a starting point for developing the PassPort estimate.[232]

- To model the design costs of the PassPort alternative, BC Hydro required a method to estimate the effort to complete an equivalent amount of the early design work that was completed for SAP. For reasons of estimating consistency and conservatism, it was reasonable to estimate that the early design work for PassPort would cost $6.2 million (i.e., 85 per cent of the $7.3 million for the SAP early design work). The 85 per cent factor reflects the ratio of the direct costs required to complete the SAP design and those required to perform similar work in PassPort. While the cost to complete the early design work for PassPort may be the same as for SAP, BC Hydro used the more conservative approach by applying the 85 per cent. There was no practical ability to go to market and receive meaningful competitive pricing for the early design work.[233]

- The range used for the PassPort Alternative is consistent with BC Hydro's estimation guidelines for alternatives analysis performed during the Conceptual

[231] Exhibit B-1, Application, pp. 3-16 to 3-17.
[232] Exhibit B-3, BCUC IR 1.11.2.
[233] Exhibit B-3, BCUC IR 1.11.3.

Design stage.[234] Selection of a preferred alternative is typically done at a +100/ -35 per cent level of accuracy.[235]

- The reason the SAP Alternative had a tighter estimate range than the guidelines would require at this stage is because BC Hydro completed early project design work under the Transformation Initiative and completed the System Integration procurement. Because these costs are known, the SAP Alternative has a narrow estimate range.[236]

140. Further, the cost and time to complete a Class 3 or Class 4 cost estimate for the PassPort Alternative is prohibitive:[237]

> Developing a Class 3 or Class 4 cost estimate for the PassPort Alternative is not necessary for the alternatives analysis, would cause delay, and increase the cost of the project.
>
> In order to develop a Class 4 cost estimate for the PassPort alternative, BC Hydro would need to develop a conceptual design report similar to the one developed for the SAP-based solution to be used as the basis for such an estimate. Completing this work for the SAP-based solution cost $1.2 million and took four months.
>
> While completing this work for a PassPort-based solution would likely incur a similar cost, it would require at least an additional two to three months as BC Hydro would need to go to market to hire resources to complete the work. At the time BC Hydro started the development of the SAP-based conceptual design, there was a team of SAP knowledgeable resources available due to the recent completion of the Supply Chain Solutions projects.
>
> In order to develop a Class 3 cost estimate for the PassPort alternative, BC Hydro would need to complete the work required for a Class 4 estimate and in addition would need to complete design work equivalent to the early design work completed for the SAP-based alternative and would need to complete a procurement exercise in order to receive firm implementation pricing from the

[234] Exhibit B-4, BCOAPO IR 1.19.1.

[235] Exhibit B-3, BCUC IR 1.9.1.

[236] Exhibit B-4, BCOAPO IR 1.19.1.

[237] Exhibit B-6, BCUC IR 2.46.1.

market. BC Hydro estimates that this would require roughly 12 months to complete at a cost of approximately $8 million.

141. In its responses to information requests, ABB is critical of the cost estimates developed by BC Hydro in 2015 in Attachment P of the Application, and suggests that an upgrade to Asset Suite 9 could be done for less.[238] ABB responses are incomplete and unreliable, and cannot be used to assess the costs of the SCA Project. First, ABB only comments on ABB's own costs to implement Asset Suite 9. ABB does not estimate BC Hydro's or a System Integrator's costs, which are a significant component of the costs of the SCA Project. ABB also offers no details on the upgrades conducted for any of its clients or what its clients' costs were. As a result, ABB provides no comparable cost information. Second, the costs of an upgrade are driven to a large extent by BC Hydro's own business requirements, which BC Hydro is in the best position to assess.[239] ABB's responses to information requests indicate that it does not understand BC Hydro's business requirements. ABB's responses understate the need to interface with other systems and demonstrate that ABB does not understand the scope of the SCA Project or the complexity of BC Hydro's IT environment.[240] BC Hydro's past experience implementing PassPort in 2003, which cost approximately $50 million, is consistent with BC Hydro's estimate for the PassPort alternative.[241] BC Hydro submits that ABB's comments on the costs of implementing an upgrade to Asset Suite should be given little to no weight.

142. In summary, BC Hydro's cost estimate for the PassPort alternative is based on a valid method, and within a reasonable estimating range for an alternatives analysis. The significant cost and time to prepare a Class 3 or Class 4 cost estimate for the PassPort alternative are therefore not necessary.

[238] Exhibit C3-5-1, BCUC-ABB IR 2.2 and 2.3. BC Hydro notes that the cost estimates in Attachment P are no longer valid, and have been replaced by the alternative assessment included in Chapter 3 of the Application (Exhibit B-6, BCUC IR 2.46.2).

[239] Exhibit B-11, Rebuttal Evidence, pp. 5 to 7.

[240] Exhibit B-11, Rebuttal Evidence, pp. 7, 9, and 10.

[241] Exhibit B-11, Rebuttal Evidence, p. 6.

(e) SAP is the Superior Alternative Under the Benefits Analysis

143. The benefits analysis of alternatives is based on the benefits analysis in section 2.5 of the Application for Alternative 1 (SAP). For the purposes of this analysis, BC Hydro multiplied the monetized benefit of addressing each capability gap under Alternative 1 (SAP) by the ratio of the PassPort/SAP score. For example, the low and high monetized benefit estimates associated with addressing the first listed capability gap (Inability to manage service-related spend) under Alternative 1 (SAP) is $7.2 to $14.4 million. The ratio of the PassPort/SAP score with respect to each alternative's ability to close this capability gap is 2/4, or 0.5. Multiplying the monetized benefit range by the ratio yields a benefit of $3.6 to $7.2 million. The Alternative 2 (PassPort) benefit amounts for the 13 capability gaps were then totaled. The results are shown in Table 3-8 of the Application, reproduced below:[242]

Table 3-8 Annual Recurring Benefits Range at Stabilization (F2017 Dollars)

Alternative	Annual Benefits Range ($ million)
1 – SAP	16.6 to 33.2
2 – PassPort	11.8 to 23.7

144. The recurring monetized benefits range at stabilization for Alternative 1 (SAP) is higher by between $5 and $9 million per year.[243]

145. BC Hydro has discussed above why its scoring of the relative ability of PassPort and SAP to close capability gaps is appropriate. It was reasonable to use the scoring for the purpose of determining monetized benefits. BC Hydro elaborated:

> BC Hydro believes the assumption that they [the realization of monetized benefits and the score provided in the capability gap analysis] are linearly proportional is reasonable and appropriate for the level of analysis performed. There is clearly a relationship between the closing of a capability gap and the delivery of the associated benefits. Fully closing a capability gap should enable full delivery of the benefit, and conversely, a capability gap that cannot be closed at all would provide none of the associated benefit. While the actual relationship

[242] Exhibit B-1, Application, p. 3-17.

[243] Exhibit B-1, Application, p. 3-17.

may not be entirely linear, BC Hydro does not have any data to enable a more detailed understanding of the potential relationship between the two.[244]

146. The method used for this analysis likely overstates the monetized benefits associated with the PassPort alternative, since BC Hydro's analysis assumes that addressing a proportion of a capability gap will result in a comparable proportion of benefits of the SAP alternative. As many of the problems to be addressed by the closing of the capability gaps are interrelated, some of the PassPort benefits calculated through this method may not be realizable.[245]

(f) SAP Has Greater Net Present Value (DCF and Revenue Requirements)

147. NPV analyses for Alternative 2 (PassPort) were developed using the same logic and general inputs as the NPV analyses undertaken for Alternative 1 (SAP). The NPV range was determined using the same high cost / low benefit and low cost / high benefit scenario approach that was used for the SAP NPV analyses.[246] For the NPV of Alternative 2 (PassPort), incremental anticipated operating costs of between $0.5 - $0.75 million (operating) and $0.15 - $0.25 million (capital) per year were included.[247]

148. The NPV figures for the two alternatives in Table 3-9, updated in the response to BCUC IR 2.39.1, are as follows (rounded):[248]

Table 3-9 (Updated) NPV Ranges for Alternatives 1 and 2

Scenarios	NPV ($ millions)	
	DCF	Revenue Requirement
Alternative 1 (SAP)	2 to 103	(8) to 86
Alternative 2 (PassPort)	(47) to 69	(43) to 63

[244] Exhibit B-3, BCUC IR 1.10.2.

[245] Exhibit B-1, Application, pp. 3-17 to 3-18.

[246] Exhibit B-1, Application, p. 3-18.

[247] Exhibit B-1, Application, p. 3-18. Also see Exhibit B-3, BCUC IR 1.12 series.

[248] Exhibit B-6, BCUC IR 2.39.1.

149. The NPV range for Alternative 1 (SAP) is higher than Alternative 2 (PassPort) for both the NPV of discounted cash flows as well as the NPV of revenue requirement impacts.[249]

150. To further compare the two alternatives, BC Hydro plotted the range of NPV results for the potential cost and benefit scenarios.[250] BC Hydro assesses the probability of the NPV of Alternative 2 (PassPort) being higher than Alternative 1 (SAP) as low. In the comparison of the NPV values in Tables 3-2 and 3-3 of the Application, the NPV of the PassPort alternative never exceeds the NPV of the SAP alternative for a given like-for-like scenario.[251] This analysis demonstrates that Alternative 1 (SAP) is superior to Alternative 2 (PassPort) based on the NPV assessment criteria.

151. In addition, the benefit-cost ratios, provided in response to an information request from Mr. Landale, provide a different way of comparing the economic benefits of the two alternatives:[252]

SAP	Low Benefit	Mid Benefit	High Benefit
Low Cost	1.64	2.74	3.29
Mid Cost	1.34	2.23	2.68
High Cost	1.03	1.72	2.06

PassPort	Low Benefit	Mid Benefit	High Benefit
Low Cost	1.50	2.50	3.00
Mid Cost	1.00	1.66	2.00
High Cost	0.52	0.87	1.04

152. The above cost-benefit ratios and NPV analyses demonstrate that Alternative 1 (SAP) is superior to Alternative 2 (PassPort).

[249] Exhibit B-1, Application, p. 3-18.
[250] Exhibit B-1, Application, p. 3-18.
[251] Exhibit B-3, BCUC IR 1.9.5.
[252] Exhibit B-7, Landale IR 2.3.1.

(g) SAP Has Surpassed PassPort in the Market as a Supply Chain System

153. From the 1990s to 2008 BC Hydro's IT strategy for enterprise applications was to select and implement "best of breed" solutions. BC Hydro's perspective in the late 1990s was that PassPort was a "best of breed" solution for utility work management and supply chain solutions.[253] SAP has surpassed PassPort in this area, and is now a "best of breed" supply chain solution.[254] BC Hydro stated: "For BC Hydro, this means that "best of breed" functionality is available within SAP, and that this functionality can be leveraged while at the same time retaining the benefits of and maintaining full alignment with its Common Platform IT strategy."[255]

154. The third-party studies on the record reinforce BC Hydro's perspective on SAP's functionality and position in the market:

- In Appsruntheworld.com's "Top 10 Utility Software Vendors and Market Forecast 2015-2020," SAP shares top spot with Oracle at 9 per cent market share for utility software vendors, and SAP leads in terms of year-over-year growth of 23 per cent.[256]

- In Appsruntheworld.com's "Top 10 SCM Software Vendors and Market Forecast 2015-2020," SAP is rated as number 1, with 21 per cent market share, for supply chain management applications.[257]

- In Appsruntheworld.com's "Top 10 Procurement Software Vendors and Market Forecast 2015-2020," SAP is rated as number 1, with 22 per cent market share, for procurement software vendors.[258]

[253] Exhibit B-3, BCUC IR 1.8.2.
[254] Exhibit B-3, BCUC IR 1.8.3 and BCUC IR 1.1.4.
[255] Exhibit B-3, BCUC IR 1.8.2.
[256] Exhibit B-3, BCUC IR 1.1.4.
[257] Exhibit B-3, BCUC IR 1.1.4.
[258] Exhibit B-3, BCUC IR 1.1.4.

- The Forrester Report "Vendor Landscape: ePurchasing Suites, 2016 to 2017" addresses the ePurchasing market overall. The report draws the general conclusion that "Enterprise or suite vendors offer most functions looked for by organizations, however, organizations may want to supplement with best of breed solutions for specific needs." ABB's products are not mentioned in the list of either enterprise or best of breed solutions for supply chain, despite the fact that Forrester identifies some 60 leading companies and products. The report notes that SAP Ariba "has the broadest and deepest suite. Both Ariba and SAP have been in the ePurchasing game since the late 1990s, and it shows in their market presence and product."[259]

- Gartner's report entitled "Magic Quadrant for Energy and Utilities Enterprise Asset Management Software, September 2015" categorizes only the SAP and IBM products as "Leaders" out of approximately 12 Energy and Utilities Enterprise Asset Management software products in the marketplace.[260] The report shows ABB Asset Suite (formerly known as PassPort) as being in the "Niche Players" quadrant. SAP is superior to PassPort on both the "completeness of vision" and "ability to execute" scales.[261]

- The ARC Advisory Group's Enterprise Asset Management Global Market Research Study referenced by ABB is focused on asset management, rather than supply chain IT systems. ABB noted that it is shown as having a greater market share than SAP in Enterprise Asset Management in the category of Electric Power Generation.[262] However, SAP is a leading supplier in the category of Electric Power Transmission and Distribution, whereas ABB is not.[263] Further, SAP has a greater market share than ABB for the category of companies with

[259] Exhibit B-3, BCUC IR 1.1.3, Attachment 1.
[260] Exhibit B-3, BCUC IR 1.1.3, Attachment 2.
[261] Exhibit B-3, BCUC IR 1.8.3.1. See also BCUC IR 1.8.2.
[262] Exhibit C3-3, p. 16.
[263] Exhibit B-11, Rebuttal Evidence, pp. 12 to 13. See Confidential Exhibit B-11-1 for results.

> revenue greater than $1 billion, which applies to BC Hydro.[264] The ARC Study confirms that Asset Suite is an asset management product focused on power generation, including nuclear. In contrast, BC Hydro is a vertically integrated utility, with generation, transmission, distribution, and retail functions. The majority of BC Hydro's overall active inventory is used for transmission- and distribution-related work, and the supply chain requirements for transmission and distribution are different than for generation.[265]

155. The market information underscores BC Hydro's position that SAP is the better alternative for BC Hydro.

D. CONCLUSION AND REQUESTED FINDING

156. The alternatives analysis demonstrates that Alternative 1 (SAP) is the preferred alternative for undertaking the SCA Project as it closes the capability gaps to a greater degree, is aligned with the Common Platform Strategy, is lower risk, and is expected to deliver greater financial benefits. BC Hydro's perspective on the strengths of SAP vs. Passport is supported by independent third-party research.

[264] Exhibit B-11, Rebuttal Evidence, pp. 14 to 15. See Confidential Exhibit B-11-1 for results.

[265] Exhibit B-11, Rebuttal Evidence, p. 13.

PART SEVEN: PROJECT RISKS ARE MITIGATED

A. INTRODUCTION

157. In this Part, BC Hydro makes the following points:

- First, BC Hydro has both the technical capacity and relevant experience to implement the SCA Project;
- Second, BC Hydro has put in place a qualified, experienced team to deliver the SCA Project, including a System Integrator and Quality Assurance Advisor;
- Third, BC Hydro has completed several steps to mitigate project risks in advance of the implementation of the project;
- Fourth, BC Hydro has identified key business, technology, project delivery, and readiness risks that may arise during the course of the SCA Project, and has taken steps to address those risks; and
- Fifth, BC Hydro's Quality Assurance Advisor has endorsed BC's Hydro actions.

B. BC HYDRO HAS BOTH TECHNICAL CAPACITY AND RELEVANT EXPERIENCE

158. BC Hydro has significant experience in implementing SAP technology projects:

- BC Hydro first installed SAP's Utilities Customer Care module in 2003.[266]
- In 2008, BC Hydro shifted to an enterprise-wide SAP IT platform. Since that time, BC Hydro has implemented three major SAP projects: the Financial Systems Replacement Project, the Human Resources Project, and Project and Portfolio Management. Each project implemented a complete SAP module.[267]

[266] Exhibit B-1, Application, p. 1-10.

[267] Exhibit B-1, Application, pp. 1-10 to 1-11.

- BC Hydro has also implemented other smaller SAP projects involving preparatory design work, enhancements, and partial system implementations, including two supply chain-specific SAP projects described in section 4.2.8 of the Application.[268]

C. BC HYDRO HAS THE CORRECT TEAM IN PLACE TO DELIVER THE PROJECT

(a) Project Team

159. The SCA Project team is composed of full-time BC Hydro employees and consultants who have extensive experience in the design, development, and implementation of IT projects, both at BC Hydro and at other large utilities. The SCA Project team structure and key roles are identified in Figure 1-1 of the Application.[269]

(b) BC Hydro Has Appointed a Qualified System Integrator

160. The System Integrator is responsible for providing advisory and implementation services to help BC Hydro develop process and solution designs, and implement the designed solution for the SCA Project. BC Hydro has completed a multi-step public procurement process to select an external partner to provide system integration services for the SCA Project. This process was designed to afford BC Hydro increased cost certainty, to provide an assessment of the value of the design artifacts developed as part of the Transformation Blueprint, and to establish a contract that enables BC Hydro to share project risks with the System Integrator.[270]

161. BC Hydro has received firm pricing from its preferred proponent and has validated its view on the resources required, the amount of the design completed to date, and the amount of time required to finish the preliminary design and to implement the SCA

[268] Exhibit B-1, Application, p. 1-11.
[269] Exhibit B-1, Application, p. 1-11.
[270] Exhibit B-1, Application, p. 4-18.

Project.[271] BC Hydro provided additional details regarding the roles and responsibilities of the System Integrator in response to information requests.[272]

(c) BC Hydro Has Appointed a Quality Assurance Advisor

162. BC Hydro has engaged a Quality Assurance Advisor for the SCA Project, who will provide independent oversight and ongoing assessments of the governance structure, process and staffing, and project status. The primary objective of the Quality Assurance Advisor is to help BC Hydro identify, manage, and mitigate risks associated with the SCA Project.[273]

163. Specifically, the Quality Assurance Advisor is an independent third-party consultant whose role will entail the following responsibilities:

- Providing an initial assessment of the governance structure, processes, and staffing, including contracting arrangements with the System Integrator established by BC Hydro;
- Providing ongoing assessments of the effectiveness of the governance structure, processes, and staffing; and
- Providing ongoing assessments of the project status, including key issues and risks.[274]

164. The Quality Assurance Advisor will have access to Project personnel, records, and meetings. As reflected in Figure 1-1 in the Application, the Quality Assurance Advisor reports directly to the Project Sponsor.[275] The Quality Assurance Advisor will also report on a monthly basis to the SCA Project Steering Committee, on a quarterly basis to BC Hydro's Executive Team, and on an ad hoc basis to both the SCA Project Steering Committee and the

[271] Exhibit B-1, Application, p. 1-7.
[272] Exhibit B-4, BCOAPO IR 1.7.1 and BCOAPO IR 1.7.2.
[273] Exhibit B-1, Application, p. 1-15.
[274] Exhibit B-1, Application, p. 1-15.
[275] Exhibit B-1, Application, p. 1-15.

Executive Team in regard to key milestone readiness reports. Further details on the quality assurance reports are provided in section 1.2.4 of the Application, and anticipated deliverables of the Quality Assurance Advisor are listed in response to BCOAPO IR 1.5.1.[276]

D. BC HYDRO COMPLETED PRE-PROJECT RISK MITIGATION

165. Prior to the SCA Project, BC Hydro undertook several actions to reduce the overall project risk. These actions have had positive implications on the risks described in section 4.8.2 in the Application.

- **Ensuring that Integration with other BC Hydro Systems is Adequately Considered:** The supply chain component of the Transformation Blueprint considers how various IT systems will interact with the supply chain (SAP) IT system. The Transformation Blueprint has therefore advanced BC Hydro's understanding of the project design requirements and how the supply chain interacts with the other systems.[277]

- **Managing the Extent and Speed of Change introduced at BC Hydro:** BC Hydro's decision in 2013 not to implement the Transformation Blueprint IT Projects as a single program reduced the risk of implementing a new supply chain IT system. By dividing the Transformation Initiative into its component parts, implementation of the SCA Project will be more manageable.[278] In addition, BC Hydro has already made organizational changes in anticipation of the implementation of the SCA Project. These changes include the creation of the Supply Chain Business Unit and the implementation of process improvements, particularly in areas like category management. This reflects a conscious strategy to reduce the amount of change impacting BC Hydro's operations, and to limit the amount of organizational and process change occurring concurrently with

[276] Exhibit B-4, BCOAPO IR 1.5.1.
[277] Exhibit B-1, Application, pp. 4-29 to 4-30.
[278] Exhibit B-1, Application, p. 4-30.

the implementation of new IT systems.[279] BC Hydro still considers replacing all remaining PassPort functionality through a single combined supply chain, work management, and asset management project would expose BC Hydro to an unacceptable level of risk.[280]

- **Supply Chain Business Model and Business Requirements:** The early development of the Supply Chain Business Model and Supply Chain Business Requirements have clarified what BC Hydro's supply chain requirements.[281]

- **Implementation of Supply Chain Functionality in SAP:** The Supply Chain Solutions – SAP project included some of purchasing and inventory management processes specifically with regard to smart meters. The SCA Project will, among other things, expand the use of SAP to cover all materials that BC Hydro needs to purchase, issue, and store. The Supply Chain Solutions – SAP project demonstrated that BC Hydro can meet its requirements for purchasing and inventory management with minimal customization of the SAP platform, and that BC Hydro can successfully create the necessary interfaces with PassPort.[282]

E. BC HYDRO HAS IDENTIFIED THE KEY RISKS AND IS ADDRESSING THEM

166. BC Hydro has prudently assessed the risks of the SCA Project and developed mitigation plans for each risk.

167. Section 4.8.2 of the Application identifies key business, technology, project delivery, and readiness risks at the early definition stage of the SCA Project. These categories of risk encompass the following:

- Business risk: Risks related to the realization of benefits that are dependent on the adoption of change within the business;

[279] Exhibit B-1, Application, p. 4-30.
[280] Exhibit B-3, BCUC IR 1.6.8.
[281] Exhibit B-1, Application, p. 4-30.
[282] Exhibit B-1, Application, pp. 4-30 to 4-31.

- Technology risk: Risks related to the maturity of the technology;
- Project Delivery risk: Risks related to the delivery of the Project; and
- Readiness risk: Risks related to the ability of the organization to execute the Project.

168. Section 4.8.2 of the Application lists the mitigation activities that BC Hydro has developed or is planning to address each identified risk. BC Hydro also has a Risk Management Plan in place for the SCA Project, which describes how risks will be managed.[283]

169. As explained in section 4.4.4 of the Application, the System Integrator will have primary responsibility for day-to-day coordination and execution of activities on the SCA Project, including identifying and monitoring risks and developing risk mitigation plans. This model provides the best opportunity to reduce project risk, by leveraging the experience, methodology and teamwork of a System Integrator while allowing BC Hydro to ensure the SCA Project is executed to BC Hydro standards.[284] The System Integrator shares in project risk by providing a fixed price bid for the SCA Project.[285] The Master Services Agreement also has a number of risk-allocation provisions which provide an incentive for the System Integrator to manage project risk appropriately.[286]

170. BC Hydro expects that project risks will be reduced through the course of the Definition Phase as its mitigation plans are advanced. BC Hydro will advise the Commission on changes associated with these risks in the Phase Two Verification Report.[287]

[283] Exhibit B-3, BCUC IR 1.30.7, Attachment 2.
[284] Exhibit B-3, BCUC IR 1.30.7.
[285] Exhibit B-3, BCUC IR 1.30.6.
[286] Exhibit B-3, BCUC IR 1.30.9.
[287] Exhibit B-1, Application, p. 4-38.

F. QUALITY ASSURANCE ADVISOR ENDORSED BC HYDRO'S ACTIONS

171. KPMG's Supply Chain Applications Project: Interim Project Readiness Assessment and System Integrator Procurement and Selection Process Assessment are included as Attachment N to the Application. These documents contain KPMG's full assessment. A summary of KPMG's assessment, observations, and recommendations is provided below.

172. In its Interim Project Readiness Assessment, KPMG's overall interim Project readiness assessment is as follows (page 12):[288]

> Based on this Interim Project Readiness Assessment Report, KPMG's assessment is that the overall SCA Project readiness activities completed by BC Hydro have been strong with much thought and diligence employed in the assessment of the need for change, planning and readiness for the next phase of this project. The Program status is well aligned to KPMG's expectations at this stage of the project.

173. KPMG summarized its observations as follows:[289]

- Strong leadership commitment and involvement for an extended period of time: Business and IT Steering Committee members interviewed to date have clearly articulated the need for a unified platform in order to effectively run business processes and bring standardization to BC Hydro.

- Clear articulation of the case for change: Business stakeholders are ready to support the Project and to enable the capture of business benefits as outlined.

- Effective tailoring and deployment of a robust BC Hydro Information Technology Delivery Standard Practices (ITDSP) methodology for delivering projects of this scale with the appropriate control and approvals.

[288] Exhibit B-1, Application, p. 4-21.

[289] Exhibit B-1, Application, pp. 4-21 to 4-22.

- Evidence of a rigorous financial model with quantifiable benefits expected to be driven by the technology implementation, along with inclusion of the required contingency and risk reserves.

- A robust SI procurement and selection process with an appropriate level of control and input from key decision makers. BC Hydro has incorporated contractual measures to mitigate and share risk and reward scenarios.

174. KPMG also noted a number of risks to the SCA Project (e.g., further delay to Project mobilization) and made a number of recommendations. KPMG's recommendations covered a range of topics, including Project accountability and responsibility, Project governance structure and capability, Project plan and deliverables, resourcing, and change management planning.[290]

175. BC Hydro prepared an action plan for addressing all of KPMG's recommendations in its KPMG Interim Project Readiness Assessment Management Plan, which is included as Attachment O to the Application. Many of these actions were already included in BC Hydro's Project plan for execution closer to mobilization of the Project or during the Mobilization stage.[291]

G. CONCLUSION AND REQUESTED FINDINGS

176. The Commission should find that BC Hydro has the technical capability and relevant experience and the correct team in place to undertake the SCA Project. BC Hydro has successfully reduced the risk of the SCA Project by, amongst other actions, managing the extent and speed of change introduced. BC Hydro has prudently identified the risks of the SCA Project and put in place mitigation activities to address each risk. The Quality Assurance Advisor's conclusions on BC Hydro's actions to date confirm that BC Hydro is proceeding prudently with the SCA Project to date, and is ready to proceed with the remaining Definition Phase activities.

[290] Exhibit B-1, Application, p. 4-22.
[291] Exhibit B-1, Application, p. 4-22.

PART EIGHT: CONCLUSION AND ORDER SOUGHT

177. The evidence demonstrates that the SCA Project is in the public interest. The SCA Project positions BC Hydro to meet current and future business needs, reduce risk, and benefit customers. The preferred project option, an SAP-based system that will integrate with BC Hydro's overall SAP platform, delivers the greatest benefits with the least risk. BC Hydro requests that the Commission accept the Definition Phase capital expenditures as being in the public interest.[292] If the Commission accepts the capital expenditures as in the public interest, BC Hydro will commence Definition Phase activities on the SCA Project and will file its Phase Two Verification Report seeking acceptance of Implementation Phase capital expenditures in due course.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated: June 23, 2017 ***[original signed by Chris Bystrom]***
Christopher Bystrom
Counsel for BC Hydro

Dated: June 23, 2017 ***[original signed by Matthew Ghikas]***
Matthew Ghikas
Counsel for BC Hydro

[292] Exhibit B-1, Application, Attachments A and B. BC Hydro has set out the specific approvals it is seeking in section 1.3 of the Application, and they are reflected in the draft Orders.


As digital disruption changes how we use energy, shouldn't we change how we manage energy assets?
Spotlight on power and utilities infrastructure – formulas for success
Part 2: Maximizing asset performance in a digital and more sustainable world
The better the question. The better the answer.
The better the world works.
EY
Building a better working world



> **"The future competitiveness of power and utility businesses depends on extracting greater value from infrastructure assets."**
>
> **Safia Limousin**
> Global P&U Capital and Infrastructure Lead, EY

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2 Big picture changes
3 Utility perspectives
4 The heart of the matter: unlocking value
5 Seizing new opportunities
7 Leading practice: building blocks of excellence
11 Where to start?
12 Research methodology
14 EY contacts

Executive summary

Achieving excellence in asset management is critical to optimize return on investment in power and utility (P&U) organizations. This report explores the role of asset management in a transforming sector, highlighting three routes to unlock strategic value.

The challenge: balance cost, risk and performance

Aging infrastructure, the growing cost of power generation and the need to respond to disruptive technologies are all intensifying the pressure on utilities to invest in maintaining, growing and modernizing their service delivery assets.

With no letup in safety and service standards — or customer, shareholder and stakeholder expectations — utilities are increasingly challenged to do more with less.

The asset management capability needed to achieve the necessary optimization of cost, risk and performance is far greater than we have seen before. With sector transformation accelerating, and the value chain growing in complexity, investment in assets today has cost implications decades into the future. To maximize this investment, utilities need to understand and manage the whole-life cost, risk and value of assets.

Sector recognizes the need to respond

Research by EY reveals this to be a topic of key concern for P&U businesses.

Seventy percent of senior executives interviewed in a recent EY global survey said they view asset management as increasingly challenging, and that these challenges will persist as disruptive trends continue to impact the sector. But 68% also told us they had not identified specific innovations likely to improve asset management performance.[1]

Major strategic benefits from a fresh approach

Leading asset management standards such as ISO 55000 have created a much broader appreciation of asset management that encompasses the whole organization and its stakeholders.

Studies have shown that adopting a leading approach to asset management can yield benefits equivalent to 20% of the total spending portfolio within three to five years.[2]

Results achieved by leading utilities worldwide demonstrate how focusing on intelligent asset management can significantly improve value. For example, one major MENA utility reduced its annual maintenance costs by 40% after integrating business systems on an enterprise asset management (EAM) platform.[3]

Three leading practices for better value

EY has identified three critical leading practices to transform asset management capability, performance and value:

1. **Align asset strategy to corporate strategy** by taking a holistic, strategic approach to EAM. This means fully coordinating roles and responsibilities across all organizational levels, functions and supply chain partners to deliver effective, end-to-end asset management and generate consciousness of EAM's huge potential to build value. Integrating asset management within the wider strategic capability will be a key differentiator for tomorrow's leading utilities.
2. **Turn data into insight,** recognize and manage data as an asset class, and deploy advanced analytics to generate actionable insight that supports good decisions and boosts value.
3. **Revolutionize field workforce capabilities,** using advanced technology to improve productivity and unlock strong competitive advantage.

The sector needs a fresh approach to asset management to respond to current disruption. This is just the beginning of the journey to better value. Taking the initiative now to adopt an intelligent approach to asset management, refine capabilities and leverage new technologies will create value and set P&U organizations up to thrive as the sector transforms.

> "New and existing infrastructure projects can transform value by embedding asset management throughout the organization, using data better and adopting new technology faster, learning from parallel industries."
>
> Igor Sadimenko
> Asia-Pacific EAM Regional Lead, EY

1. EY research.
2. UMS Group Europe/IES Asset Management.
3. EY research.

Big picture changes

Many utility assets in operation today – particularly large-scale generation, transmission and distribution – were commissioned during the investment booms of the 1960s, '70s and '80s. But since then, investment levels have not always kept pace with the need to grow and replace asset bases, and the established and formerly stable value chain is now experiencing the disruptive effects of new technologies, which utilities increasingly need to leverage.

The P&U sector is undergoing a period of radical transformation, spurred on by technology innovation, shifting population dynamics and burgeoning economic growth.

Technology innovation

Disruption along the traditional value chain, from decentralized generation and demand-side operations to energy storage and the rise of electric vehicles, is changing the way utilities operate.

Population growth

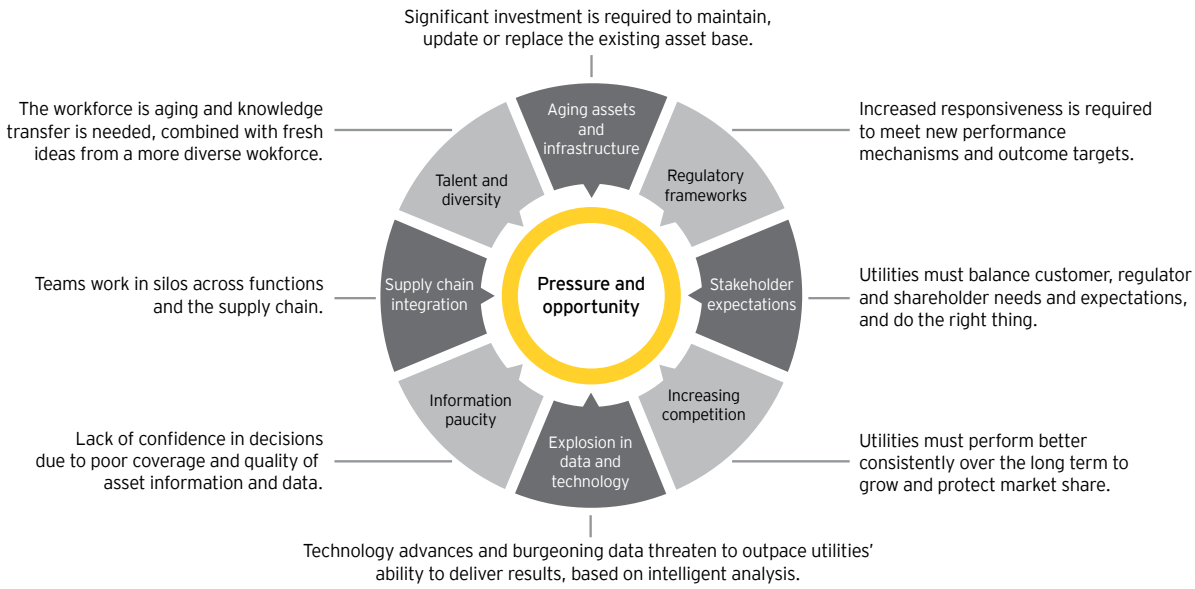
Global population is forecast to grow to **9.2 billion** by 2040,[4] mostly in non-OECD countries where an increasing, aspirational middle class is driving greater energy demand.

World GDP growth

GDP is forecast to grow from **US$74.5t in 2015 to US$136.7t in 2040, an increase of 83%.**[5] Past trends show a strong link between GDP and electricity demand.

Utilities are moving toward a new value chain, augmented and interconnected by digital technologies, with power and information flowing in both directions. These far-reaching changes in technologies, markets and public policies are transforming utilities and the challenges they face.

Figure 1: Utilities face transformational challenges and opportunities



Source: EY.

4. International Energy Agency, World Energy Outlook 2016.
5. Oxford Economics, Global Data Workstation, 2016.

Utility perspectives

EY's survey of top sector executives sought to understand where they see challenges and improvement opportunities in managing infrastructure assets. While acknowledging that new technology is making asset management significantly more efficient, the vast majority of respondents told us that maximizing return on asset investment was an ongoing challenge. Respondents also confirmed that they had not identified specific innovations to overcome challenges in asset management.

Our research revealed that 70% of sector leaders believe asset management is becoming increasingly complex and challenging, and that the challenges faced today will persist as disruptive trends continue to impact the sector.

Figure 2 breaks down the most challenging aspects – with the biggest cited as demonstrating a return on investment (ROI) in line with the original business case. The capabilities of the asset management organization were another key concern. Data collection and confidence in asset condition data also ranked highly, with one in three sector executives placing it in their top three challenges.

In facing these challenges, utilities recognize the potential value of strong asset management and are taking steps to gather and analyze data to support infrastructure projects (see figure 3).

Advances in technology are enhancing these efforts: 71% of sector executives surveyed told us that new technology is making asset management significantly more efficient. But it is apparent that utilities still have some way to go, with nearly the same percentage (68%) saying that they had not identified specific innovations to improve asset management performance (see figure 4).

In the pages that follow, we identify how the sector can leverage leading practice and digital innovation to overcome key asset management challenges.

Top-rated challenges

1. Demonstrating business case ROI
2. Asset management capabilities
3. Data collection and quality

Figure 2: Demonstrating a return on investment in line with business case goals is identified as a major challenge

Q. Regarding your infrastructure projects or programs most recently completed, what are the top three challenges your organization faces in terms of maximizing a return on investment from the assets?

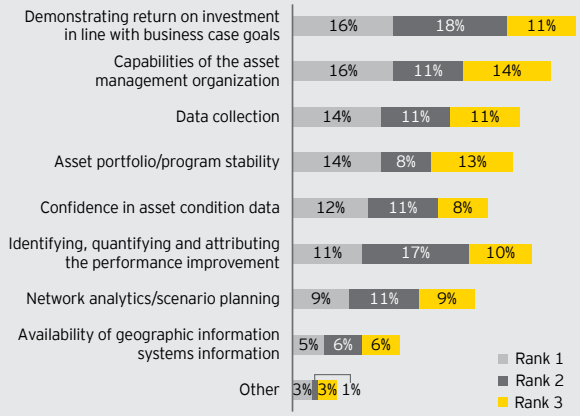


Figure 3: Utilities are taking steps to support their infrastructure projects through data analysis and security

Q. Thinking about how you manage data across your infrastructure projects, to what extent do you agree or disagree with the following statements?

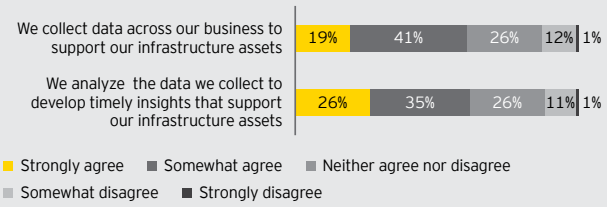
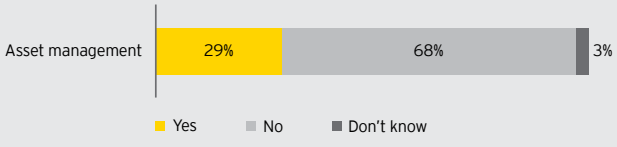


Figure 4: The sector has struggled to identify innovative practice to improve asset management performance

Q: Has your organization identified specific innovations that will be key to improving your asset management performance?



Source: EY research.

The heart of the matter: unlocking value

As the sector transforms, optimizing the commercial and strategic value of utility assets is a tough balancing act. Asset owners and operators need to deliver greater stakeholder value — in particular to customers — while reducing risk and minimizing costs.

In our executive survey, demonstrating ROI emerged as one of the greatest challenges, now and for the future. In markets where the wholesale price of electricity is falling below the level required to provide acceptable ROI in power plants, generators are challenged with optimizing whole-life costs.

Now is the time for utilities to take stock, develop and refine their asset management capabilities and leverage new technologies that will create value and set the business up to perform amid ongoing disruption. EY believes this can best be achieved through a fresh approach to people, processes and technology that:

- Leverages the power of asset management systems, using data and analytics as a strategic asset and differentiator, to drive informed decision-making and value creation
- Fully coordinates the roles all organizational levels and functions play in effective, end-to-end asset management, in a holistic way

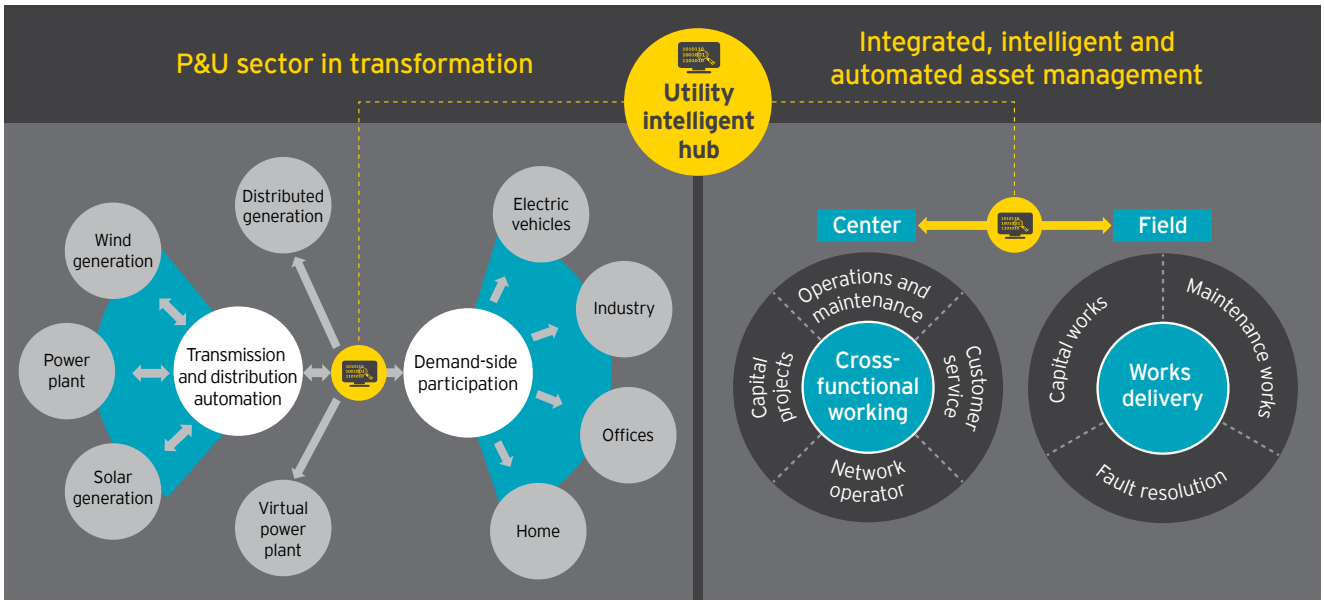
Utilities that adopt these principles should be able to unlock value, gain competitive advantage and outperform their peers. Those that don't adopt them face a widening capability and stakeholder expectation gap on performance, service and cost.

Intelligence drives value

The nature of asset management depends increasingly on intelligence and insight from data. New technologies are transforming how asset information is collected, collated and analyzed, providing a foundation for utilities to run operations in a completely new way from an "intelligent hub" (see figure 5). Physical distance between assets is less of an obstacle to operational efficiency, with devices now capable of remotely monitoring and transmitting asset data in real time. Complex analytics provide new, much more detailed insight on asset risk and performance, opening up new opportunities to deliver optimal performance and boost value.

> "Now is the time to focus hard on developing intelligent asset management as a fundamental driver of value, for today and for the future."
>
> **Claus Jensen**
> Global Program Management Lead, EY

Figure 5: Integrated, intelligent, automated — asset management is evolving as sector disruption demands new capabilities



Source: EY.

Seizing new opportunities

In today's transforming sector, utilities are increasingly challenged to make decisions based on intelligent asset management that fully grasps the relationship between asset cost, risk and performance and the entire organization and supply chain. This holistic approach provides executives with vital information to understand, manage and exploit asset portfolios better, gain greater control of costs, reduce risks and improve customer and shareholder value.

Intelligent asset management unlocks value

Organizational benefits

- Ensures alignment between asset strategies and corporate objectives, which in turn maximize asset portfolio returns
- Reduces costs by identifying asset management inefficiencies
- Enables well-informed, confident decision-making from solid coverage and quality of asset information and data
- Increases confidence of regulators, government and shareholders, and boosts value for customers
- Enables accurate evaluation of potential success in any transformation program
- Ensures overall adoption and increasing levels of business ownership of EAM
- Empowers key individuals to contribute to and drive business outcomes

Case studies

Organizations that undertake improvement initiatives in asset management can reap significant rewards – boosting productivity and cutting down on maintenance and renewals costs, equipment downtime and costly reactive work.

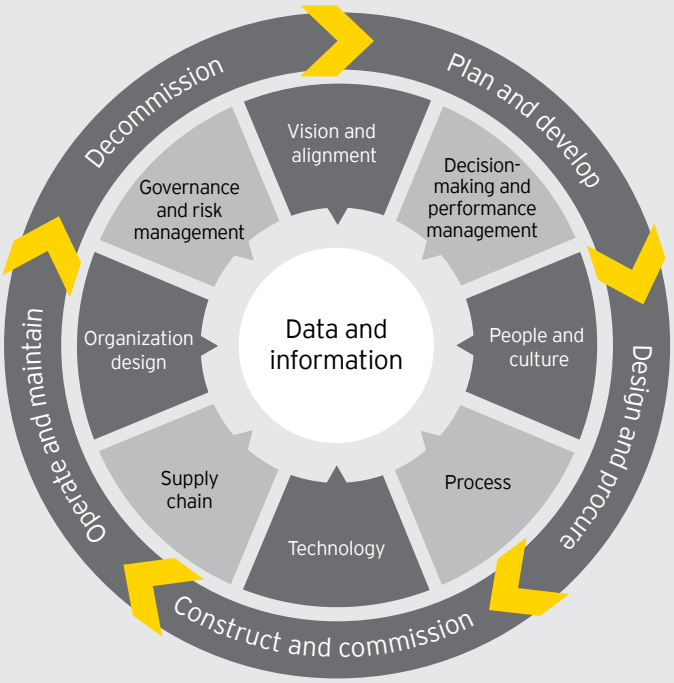
Company type	Improvement initiative	Benefits
UK water utility	Improving levels of preventative and scheduled maintenance	30% reduction in reactive work
Major US electric utility	Implementing a new work and asset management solution	US$9.6m annual savings in asset management costs
Major electricity network owner	Transitioning from scheduled maintenance to condition-based maintenance	10% reduction in asset maintenance and renewals costs
Major MENA electricity and water utility	Integration of business systems on an EAM platform	40% reduction in annual maintenance plan
Medium-sized energy and utilities company	Implementing an EAM solution for preventive maintenance and enterprise resource planning integration	5–10% improvement in labor utilization

Source: EY research.

Creating a broader appreciation of asset management

The evolution of the asset management discipline and its international standards (ISO 55000) provide a framework for leading practice and a reference for utilities to identify improvement opportunities. EY's Asset Excellence Model (figure 6) is a holistic, systemic approach aligned to ISO 55000. Based on a data-rich, risk-informed decision process, our model outlines the key components required to deliver a joined-up and systematic approach to asset management across the asset life cycle.

Figure 6: The EY Asset Excellence Model – a joined-up approach to boost value



Source: EY.

Recent studies suggest that organizations that adopt a leading-practice approach to asset management can achieve financial benefits equivalent to roughly 20% of their total spending portfolio within three to five years.

UMS Group Europe/IES Asset Management



Leading practice: building blocks of excellence

The goal is asset excellence, but where's the starting line? Our survey of senior executives identified three key challenges: asset ROI, asset data and asset management capabilities (see page 3). Based on our experience supporting major enterprise asset management programs worldwide, we identified three leading practices that could help to create new value and transform asset management performance, now and in the future.

Align asset strategy to corporate objectives

Leading practice 1

For asset management to be truly effective, it is critical to take a holistic, strategic approach to EAM, applying responsibilities across functional boundaries and from the boardroom through to the operative level. Utility leaders must ensure all parties are aligned, accountable and aware of these responsibilities.

To maximize the value of asset management, utilities should think holistically, designing and implementing a comprehensive approach that embraces not just the system but the people, processes and tools that underpin it.

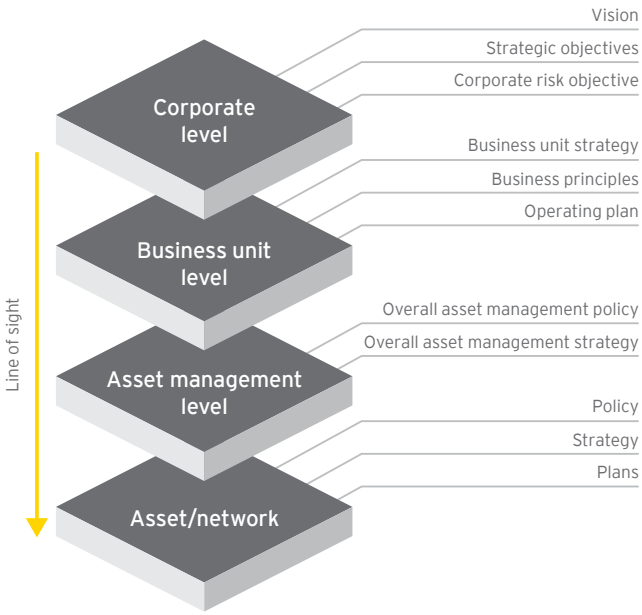
Three key pillars support a holistic approach:

1. **Strong recognition and support at board and executive level:** leadership teams drive and promote the asset management agenda as an essential component of corporate strategy, and ensure it is integrated with customer, commercial and other key agendas. Ideally, responsibility for asset management should be a board-level position.
2. **A clear line of sight between strategic objectives and asset management activities:** the top floor is connected to the shop floor. The route from corporate objectives all the way to the physical asset is mapped out and established (see figure 7). Individuals and teams understand how their day-to-day actions align with long-term corporate goals – and do not act in silos.

> "To deliver optimum value, asset management needs to link effectively with the rest of the organization. This ensures that the asset advances corporate strategic objectives, and value isn't eroded by conflicting functional priorities."
>
> Kristen Westall
> EMEIA EAM Regional Lead, EY

3. **Long-term, strategic relationships with suppliers:** these are focused on developing capabilities and optimizing value. Collaboration with suppliers is based on a shared understanding of goals and supported by technology that enables suppliers and asset owners to share information on the assets they have built. Incentive structures are based on success through interdependency.

Figure 7: Asset management "line of sight"



Source: EY.

Make the data work for you

Leading practice 2

Data informs every management decision throughout the asset life cycle and supply chain. It needs to flow effectively and lead to actionable insight. The more an organization values data and information as a strategic asset and a differentiator in its own right, the greater the efficacy of its asset management and the likelihood of maximizing ROI.

Exercising tight planning and controls to manage data quality makes organizations far better equipped for timely, cost-effective interventions. But collecting and managing the right data throughout the asset life cycle requires robust organizational discipline, particularly where large asset fleets are concerned, as these demands increase with the exponential growth in data volumes.

To turn asset management into asset excellence, leading organizations incorporate the following four data considerations into their asset strategy:

> "Improving asset information and data management remains a big opportunity. Proper risk assessment and mitigation can only be well understood if the right data exists to support it."
>
> Steve McCabe
> Global P&U EAM Lead, EY

1 Treat data as an asset class

Data and data culture need to be key priorities for the organization. Data has strategic significance, can be leveraged and monetized, and requires appropriate management – so it should be valued as an asset in its own right.

2 Identify specific outcomes

- Identify, collect and standardize asset data critical to decision-making
- Establish governance and processes to manage information – how it is acquired, cleansed, stored, secured and evaluated
- Create a data-driven culture with accountability around data
- Take a commercial view of data and prioritize investment accordingly, balancing short- and long-term costs and benefits

3 Seek out further opportunities to exploit data in the organization

Data should be integrated across platforms – such as operational technology, finance and asset systems – to unlock additional insight and promote truly joined-up thinking. Where appropriate, organizations should partner with specialists to gain cost-effective access to new data and analytical capabilities.

4 Pursue insight through enabling technologies and analytical capabilities

Organizations need to commit to consistent investment and development of enabling technologies (figure 8) across the P&U value chain (figure 9).

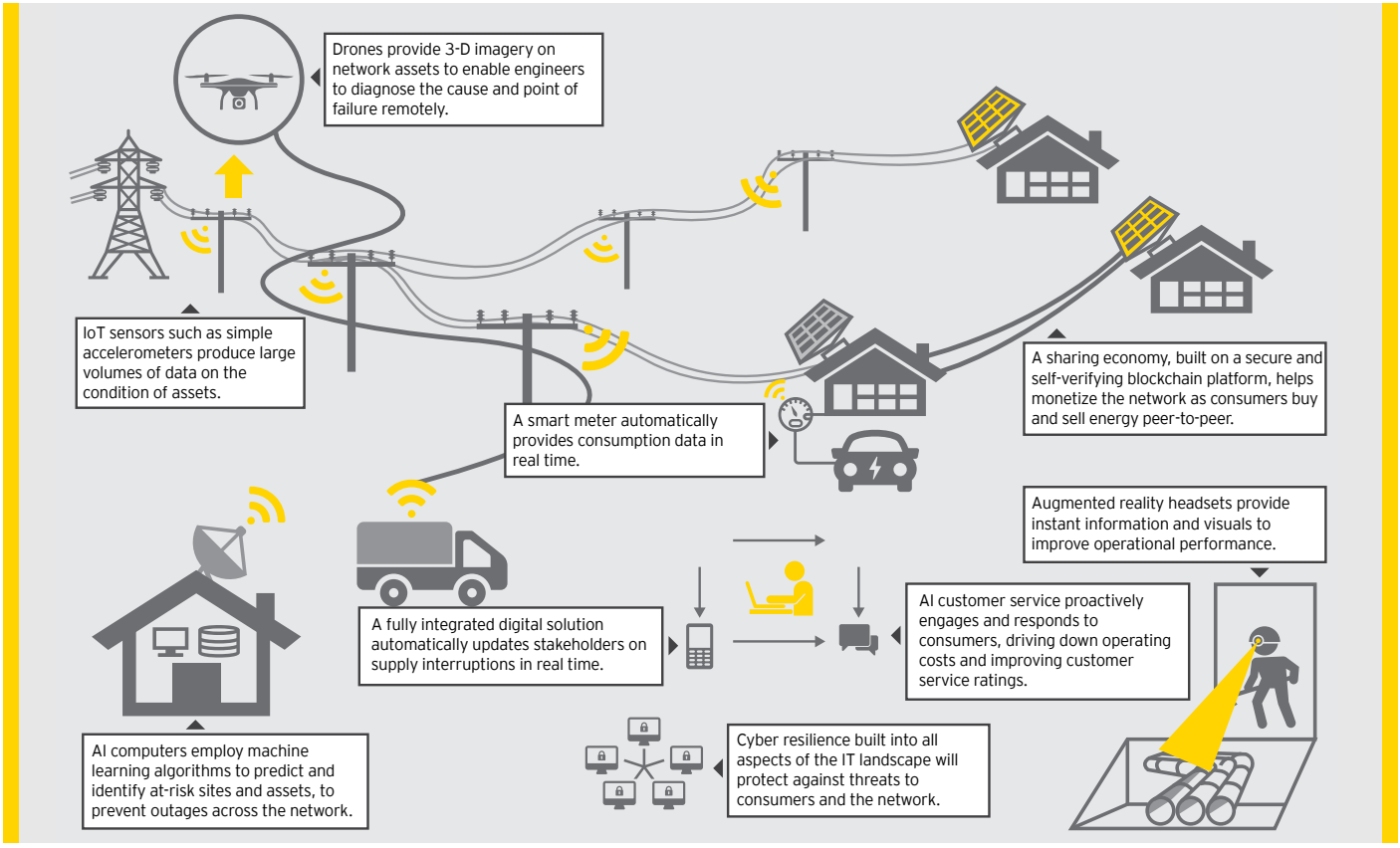


Figure 8: Current application of enabling technologies in asset management

Building information modeling/virtual construction	3-D and 4-D asset and plant models enable knowledge-based, concurrent engineering, improved supply chain collaboration, rapid prototyping and testing, construction sequencing and asset visualization	HD scanning and geolocation	Improved methods to collect input on existing physical layout and transform this into digital models, including all geolocation data, allowing rapid modeling
Analytics	Predictive asset analytics deliver intelligence and insight, and enable more effective decision-making	3-D printing	Development of design prototypes to enable engineering assurance and construction sequencing; on-site production of equipment and spare parts to avoid supply chain delays
Artificial intelligence (AI)	Advanced computing techniques based on cognitive computing and self-learning programing methods to optimize and support decision-making	Mobile	Enablement of the workforce with new technologies (mobile, toughbooks and cameras) to improve asset data collection, workforce productivity, learning and safety
Augmented reality	Enabling operations and maintenance through "smart glasses" – visualization of asset layout, parameters and procedures; use of augmented reality in training and work preparation	Smart labels	Use of smart tracking and tagging labels for assets and equipment, enabling supply chain synchronization and tracking of physical flow
IoT and sensors	Cloud-connected sensors, providing information in real time, enable faster control and response as well as "grid edge" self management	Robotic process automation	Robotic process automation software to automate repetitive, rule-based tasks across multiple systems and email, allowing automation of support processes
Operations centers	Development and enhancement of remote operations support and control centers, leveraging asset information to enable operations improvement and coordination	Autonomous vehicles	Use of self-driving vehicles – e.g., autonomous forklift trucks, cars, trucks, boats and planes
Robots and drones	Use of more intelligent, physical robots to enable more effective operations, e.g., pipeline management, remote inspection and hazardous area management	Blockchain	Leveraging blockchain technology to enable more secure data transfer, contracting and transaction integrity

Source: EY.

Figure 9: Enabling technologies are becoming a key differentiator across the value chain



Source: EY.

Revolutionize field force capabilities

Leading practice 3

Field force productivity plays a particularly significant role in the effective execution of asset management plans. But it is often hindered by a range of "human" factors – from site access and outdated ways of operating, to lengthy journey times and safety issues.

New technologies can help overcome these and other limitations and revolutionize many of the physical aspects of asset management while transforming the productivity, safety and job satisfaction of the field workforce (see figure 10).

Advanced technologies are changing how field work is done, enabling real-time interaction with users, devices and systems, and allowing operatives to take on more of a decision-making role. As a result, the role of the control center will become less "command and control" and more "empower and assure" – a significant operational and cultural shift.

Applying the right technology in the right way will boost the chances of reducing costs, maximizing ROI, maintaining operations and improving customer satisfaction.

> "The P&U sector is at the start of a journey that will see the workforce empowered, and safety, compliance and productivity progressively transformed."
>
> **Andre Winarto**
> Global Power & Utilities and Energy Knowledge Lead, EY

Figure 10: Evolving technology and mobility revolutionize field force capability

Technology	Field application	Field benefit
Remote and mobile devices	From smart meters to wireless sensors, remote devices share specific, real-time data from the business and its suppliers	Field operatives can take on more of a decision-making role
Unmanned aerial vehicles (UAVs, or drones)	Aerial surveys of assets provide detailed inspections and recording of information on asset condition and environmental factors	Substantial cost and safety advantages
Artificial intelligence	Computers employ machine-learning algorithms to predict and identify at-risk sites and assets	Prevents outages across the network, helping the field force move from costly reactive to efficient, risk-based predictive maintenance
Wearable technology	Allows remote tracking of field operatives' location and vital signs	Monitoring of well-being and safety risks in real time
Blockchain	Digitally connected supply chain management systems and processes	Improved efficiency and reduced costs by establishing a "single version of the truth" about asset status

Source: EY.

Where to start?

There are big opportunities to realize the full potential of asset management to improve operations, reduce costs, better manage risk and meet overall corporate goals in today's data-driven, technology-enabled, connected world.

But first, "asset excellence" needs to be strategically prioritized on the board agenda. Crucially, the sector also needs more effective decision-making capability underpinned by better analytics to plan, forecast and optimize performance. Better integration across the business, and intelligent use of information and digital technologies across the entire asset life cycle, will also radically improve the value your infrastructure assets deliver.

So – where to start?

- **Benchmark:** a good basis for change is to benchmark your organization's performance. Running a maturity assessment of your asset excellence capability will reveal how much value you could be losing and help you decide what to target first.
- **Explore:** develop a view of how integrated your systems and data really are. Do you have a robust asset intelligence framework? Is your asset information complete and accurate? Are you able to integrate service delivery assets, risk and commercial data to drive better performance and improve strategic decision-making?
- **Align:** your data strategy must align with the processes and desired outcomes of your asset management function to unlock wider strategic and commercial value.
- **Move fast:** innovative technologies – analytics in particular – will create a disruption effect; early adoption will provide competitive advantage and help to secure your organization's short-term priorities and long-term goals. Consider the potential speed of technology and sector change and how your organization must adapt.

This is just the beginning of the journey to better value for power and utility organizations. Acting fast and focusing on integrating asset management with overall strategic capability will put utilities in a position of strength for the future.

> "Transformational digital technologies provide a foundation to reinvent EAM, to create new information and customer-centric business models. With disruption come new competitors that are cash-rich, agile and aggressive. How are you preparing?"
>
> **Benoit Laclau**
> Global Power & Utilities Lead, EY

More capital projects insight from EY

This is the second report in EY's capital and infrastructure Spotlight series.

The first report, focusing on utility megaproject financing and delivery, is available at ey.com/spotlight.

For more information about our capital and infrastructure services for power and utility organizations, see ey.com/capitalandinfrastructure.

Research methodology

EY industry survey

In late 2016, EY conducted a survey of executives from P&U organizations with turnover categories from US$900m to more than US$5b, using a structured survey questionnaire. Of the 204 respondents, one in four was a C-suite executive, with the remainder at director level across five functional areas comprising finance, strategy, operations, procurement and projects/programs. The respondent geographical split was 23% from Asia-Pacific, 43% from EMEIA and 34% from the Americas. The study targeted executives working in different P&U segments: power generation (nuclear, hydro, coal, gas and renewables), transmission and distribution, and water.





EY contacts

For more information on how we can help you, talk to your regular EY contact or get in touch with one of our Capital and Infrastructure Team.



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TOPIC: **Feasibility Study, Completed Projects: Enterprise Risk Management and Enterprise Risk Management Report**

REFERENCE: Application, Continuity schedule of deferred costs, tables 5.3 through 5.6: Enterprise Risk Management and Enterprise Risk Management Report, PDF pages 148, 150, 152 and 154;
Asset Management Framework, page 5.1-4, PDF page 161;
Application, TAB 10 - 2019 AUDITED FINANCIAL STATEMENTS, page 10-28, PDF page 369

QUOTES: "Risk Management
Yukon Energy is exposed to numerous risks in providing service to our customers. Risk impacts include staff and public safety, financial, reputation, long-term and short-term load/resource balance, stakeholder relationships and funding. These risks can range in scale from minor to catastrophic. Yukon Energy endeavors to manage all the risks we face on a cost-effective basis, taking into account the potential reward to be gained in return for the acceptance of the risk. We have an enterprise risk management framework that provides the basis for consistently applying risk management practices."

PREAMBLE: The Board requires further clarification of the nature of the two feasibility studies referenced in YEC's deferred costs schedules during the years 2018-2021.

QUESTION:

a) Please explain the relationship that the two referenced studies identified by the term "enterprise" or "risk" or "management" have with any capital project currently being requested by YEC that are similarly identified by those terms. Examples include the Enterprise Asset Management (EAM) System, the Asset Management Framework Project and the Physical Asset Management Managed System.

b) Referring to the response to part (a), please prepare a table summarizing the differences and similarities between each of the studies and capital projects such that the table will comprise the total quantum of all related projects?

c) Please provide a copy of the report identified as the "Enterprise Risk Management Report" which appears to have been prepared during the 2017 or 2018 timeframe and any other similar report that has been prepared subsequent to that timeframe.

d) Please clarify whether "Enterprise Risk Management" is the same "enterprise risk management framework" referenced in YEC's 2019 Audited Financial Statements.

e) If part (d) is not confirmed, please identify the "enterprise risk management framework" being referred to and provide a reference to all applicable capital projects (past and current) comprising the framework and a reference to where the business case for each project can be found.

ANSWER:

(a) and **(b)**

The two referenced projects are unrelated to any of the capital projects proposed in this application.

The project "Enterprise Risk Management Report" was a study conducted by KPMG at the request of the Audit Committee to review the current state of ERM at YEC and recommend steps to implement ERM strategies consistent with current business standards. The study completed in 2013 at a capital cost of $0.044 million and is fully amortized and no longer in rate base. The project labelled "Enterprise Risk Management" is the execution of the study recommendations. The key output is a corporate risk management policy (copy is reproduced as Attachment 1 of this response). This project was capitalized in 2017 at a cost of $0.196 million. Both of these projects were approved as part of the 2017/18 GRA.

The Asset Management Framework Project and the Physical Asset Management Managed System are the same project. The project was renamed PAMMS to reflect current industry nomenclature. This is a three-year project 2020-2022 and includes the following deliverables:

- Implementation of a PAMMS framework and governance model;

- Completion of the asset hierarchy and naming convention for the EAM system;

- Data collection for the Enterprise Asset Management (EAM) system;

- Further development of Maintenance Manuals (Maintenance plans and instructions);

- Finalization of the Asset Management Plans (AMPs) which include YEC's protection and control, diesel, substation, dam and distribution assets;

- Maintenance Repair and Operations (MRO) Material Support; and

- Organizational change management.

The Enterprise Asset Management System is a separate project to source, configure and install asset management software. In short, the EAM system is used to operationalize the framework that was developed under PAMMS.

(c)

There was no formal report produced; the presentation provided as Attachment 1 to this response summarizes the findings as they were presented to the YEC Audit Committee.

(d) and **(e)**

They are related. The disclosure in the financial statements reflects the requirements for disclosure by generally accepted accounting principles. The ERM projects discussed above were the development of the policy, practices and procedures that YEC uses to ensure the company is appropriately recognizing and mitigating risk on an on-going basis.

APPENDIX

YUKON ENERGY CORPORATION

Title: Enterprise Risk Management Policy		Board Approval Date: May 2014
Policy Number: XX-XX	**Policy Section:** Corporate Services	**Executive Sponsor/Owner:** Chief Financial Officer

1. PURPOSE AND SCOPE

Yukon Energy Corporation will develop and maintain an effective enterprise risk management program that supports and advances the corporate strategic plan as well as its mission and values. This risk management program will apply risk management processes in strategy setting and in business activities across YEC, in order to identify, evaluate, and manage risks to the achievement of YEC's objectives within acceptable risk tolerances.

The objectives of this policy are to:

- increase the probability of achieving YEC's objectives,
- recognize the importance of risk management to YEC's governance responsibilities,
- support reasoned risk taking,
- support the continuous application of risk management practices in decision making, and
- establish clear responsibilities for risk management within YEC.

YEC requires that the following risk management processes be applied universally across YEC, and is applicable to all employees of YEC and all worksites:

- **Risk Identification**: Processes will be applied and documented (updated at least annually) to identify reasonably foreseeable risks to the achievement of YEC's objectives required to achieve the corporate strategy, vision, mission and values.

- **Risk Evaluation**: Processes will be applied and documented to evaluate identified risks by considering their likelihood and impact, and the applicable levels of acceptable risk tolerance (updated at least annually).

- **Risk Treatment / Mitigation**: Risk management plans will be developed, documented and implemented for risks that exceed acceptable risk tolerance levels (updated at least annually).

- **Risk Monitoring and Reporting**: Identified and assessed risks will be reported to Senior Management by the Risk Management Function and will be re-assessed at least annually. A summary of the risk management activities is to be reported on a quarterly basis to Senior Management and the Board of Directors. Additionally, the Risk Assessment Framework is to be evaluated annually to help ensure risk tolerance and assessment criteria are relevant and in line with YEC's current operating environment.

DRAFT

YUKON ENERGY CORPORATION

2. POLICY

Board Responsibility

- The Board of Directors (the Board) retains the ultimate responsibility for risk management and for determining the appropriate level of risk that the Board is willing to accept in the conduct of YEC's business activities. The Board will review the effectiveness of the risk management systems.

- The Audit and Risk Management Committee of the Board of Directors has responsibilities to oversee YEC's risk management program and activities. The Audit and Risk Management Committee will report quarterly to the Board on risk management oversight. See also the Audit and Risk Management Committee Terms of Reference.

Corporate Responsibility

- The Chief Executive Officer retains ultimate responsibility for compliance with this policy and overseeing the implementation and ongoing execution of risk management within YEC.

- The Chief Financial Officer is responsible for accurately reporting on YEC's consolidated enterprise wide risks and the status of risk management at YEC to the Audit and Risk Management Committee on a quarterly basis. See also the Audit and Risk Management Committee Terms of Reference.

- Department Heads are responsible for identifying, evaluating, managing, and internally reporting on risk within YEC, in accordance with this policy and the requirements of the CEO and Senior Management.

Risk Management Responsibility

- The Risk Management Function under the direction of the Chief Financial Officer is responsible for coordinating YEC's Enterprise Risk Management program, assisting departments in updating their risk identification, evaluation and treatment plans, and preparing quarterly reports to Senior Management and the Board of Directors. The Risk Management Function will consider identified areas of significant risk when developing and conducting periodic reviews of YEC's risks and risk management framework and processes. The Risk Management Function will ensure that the results of its reviews are provided to Senior Management and the Board of Directors as appropriate.

Employee Responsibilities

- Employees have a general duty of care and are responsible for complying with requests from management in connection with the application of this policy. Through appropriate preventative and detective action, reasonable care should be taken to prevent or mitigate adverse impacts on YEC. Additionally, employees are to communicate with the Risk Management Function and/or Department Heads any additions, deletions and changes in facilities, regulations, markets or operations that may add significant risk and/or significantly affect existing risk assessments.

DRAFT

YUKON ENERGY CORPORATION

3. DEFINITIONS

- **Objectives** – The goals that YEC is trying to achieve. These can include strategic, business effectiveness, HR, reporting, and legal/regulatory compliance objectives. Objectives exist at the organization-wide level and divisional/business unit, project, process, and other levels.
- **Risk** – A potential action or event that could adversely or favourably affect the achievement of objectives if it occurs or does not occur. Risk is measured as a combination of likelihood of occurrence of the event (or of failure of occurrence), and impact (consequence) if it does occur (or fails to occur).
- **Impact (Consequence)** – The result, effect or outcome from realization of a risk. There may be a range of possible impacts associated with an event.
- **Likelihood (Probability**) – The probability that a risk will occur (or fail to occur).

Rating	Description	Occurrence	Probability
Rare - 1	May only occur in exceptional circumstances	Once / > 10 years	< 20%
Unlikely - 2	Could occur during a specified time period	Once / 5 – 10 years	21 – 40%
Somewhat Likely - 3	Might occur within a 5 year time period	Once / 12 months – 5 years	41 – 60%
Likely - 4	Will probably occur in most circumstances	Once / 12 months	61 – 80%
Almost Certain - 5	Expected to occur in most circumstances	Multiple / 12 months	> 80%

- **Inherent Risk (Gross Risk)** – The amount of risk to the entity in the absence of any actions management might take to alter the risk's likelihood and/or impact.
- **Residual Risk (Net Risk)** – The amount of risk remaining after management has taken action to alter the risk's likelihood and/or impact.
- **Risk Capacity** – The organization's or stakeholder's ability to bear the risk. Risk Capacity varies depending on the nature and level of the exposure, and is generally higher at the organizational level than at department, project, process, and other levels.
- **Risk Appetite (Target Risk)** – The amount and type of risk that an organization is willing to pursue or retain. Risk Appetite varies depending on the nature and level of the objective, and is generally higher at the organizational level than at department, project, process, and other levels.
- **Risk Management Processes** – The processes applied by YEC during strategy-setting and divisional/business unit planning activities across the company to identify, assess, and manage risks through risk management actions that avoid, reduce, transfer, or retain risk.

Risk Evaluation Matrix

Likelihood \ Impact	1 Insignificant	2 Minor	3 Moderate	4 Major	5 Catastrophic
5 Almost Certain	5	10	15	20	25
4 Likely	4	8	12	16	20
3 Possible	3	6	9	12	15
2 Unlikely	2	4	6	8	10
1 Rare	1	2	3	4	5

Guidance on Response to Risk Rating

Risk Rating	Action Required
Extreme (17-25)	Immediate attention required, risk treatment plan developed and monitored.
High (10-16)	Detailed planning and review by senior management
Moderate (5-9)	Active monitoring and response procedures required
Low (1-4)	Manage through routine procedures

YUKON ENERGY CORPORATION

4. IMPACT CATEGORIES

Human Resources – Impacts the abilities and skills of YEC's people; their performance, development, and engagement.

Operational Efficiency & Effectiveness – Impacts YEC's ability to achieve operating efficiencies. (Technology, Processes, etc.).

Worker Safety – Negative impact to health and well being of YEC's. employees and contractors.

Strategic – Impacts YEC's ability to execute on current and/or desired future strategic directions

Reputation – Impacts the reputational capital of YEC. Also referred to as "Social License", and is driven by experiences, impressions, beliefs, feelings and knowledge stakeholders have about YEC.

Financial – Impacts YEC's capital and operating funds to provide the desired level of programs and services to the population it serves.

Reporting – Impacts YEC's ability to provide reliable internal and external reporting (financial, performance, and other reporting).

Legal / Regulatory – Impacts compliance with relevant applicable laws and regulations.

	1. Insignificant	2. Minor	3. Moderate	4. Major	5. Catastrophic
Severity of Impact Guidance	Insignificant impact on achievement of objective. Outcomes remain within stated risk tolerances. Consequences would be dealt with by routine operations. Negligible monetary loss. No community response. No media interest. No strategic impact.	Minor impact on objective. Outcomes remain within stated risk tolerances. Consequences would threaten the efficiency or effectiveness of some services, but would be dealt with internally. Monetary loss would be managed within operating or project budget. Isolated community complaints. Negative local short-term media interest (days). Difficulties are manageable within the scope of timing of existing strategic goals.	Moderate impact on objective. Outcomes may or may not remain within risk tolerances. Consequences would require review or change in key operating procedures. Monetary loss may require suspension of some services or projects. Moderate environmental implications. Some community complaints. Negative local medium/long-term media interest (week(s)). Scope or timing of strategic goals need to be revised.	Major impact on objective. YEC no longer meets external standards. Consequences would threaten continued effective provision of services and require top-level management intervention. Monetary loss would require cancellation of some services. High environmental implications. Negative community complaints. Major loss of credibility. Negative national short-term media interest. Strategic plan requires major re-orientation, approval; subsequent program re-work.	Catastrophic impact on objective. YEC no longer meets external standards. Consequences would threaten provision of key services causing major problems for customers and YEC. Monetary loss would have extreme consequences for YEC. Far reaching environmental implications. Catastrophic loss of reputation. Parliamentary questions. Negative national medium/long-term media interest. Mandate of the institution or the institution itself is ruined.

5. ASSOCIATED DOCUMENTS AND REFERENCES

Related procedures and documents:

- Audit and Risk Management Committee Terms of Reference
- Human Resource Committee Terms of Reference
- YEC Governance Committee Charter

6. REVISION HISTORY

Version	Date	Revision Notes
YEC Corporate ERM Policy (v1.0)	**Approved Date: May 14, 2014**	
	Updated:	

This policy is to be reviewed annually by the CFO and any changes are to be recommended to the CEO and Board of Directors for review and approval.

Yukon Energy Corporation Audit Committee

Enterprise Risk Management

January 18, 2014

History of ERM

* Risk Management Working Committee created approximately 10 years ago; primarly a tactical focus on insured and like risks (e.g. security)
* Risk management is mandated responsibility of the Audit Committee as defined in the Charter document.

Scope of Study

* Through document review and interviews with key personnel, assess the current state of Risk Management at YEC.
* Provide a road map for implementation of Enterprise Risk Management at YEC.

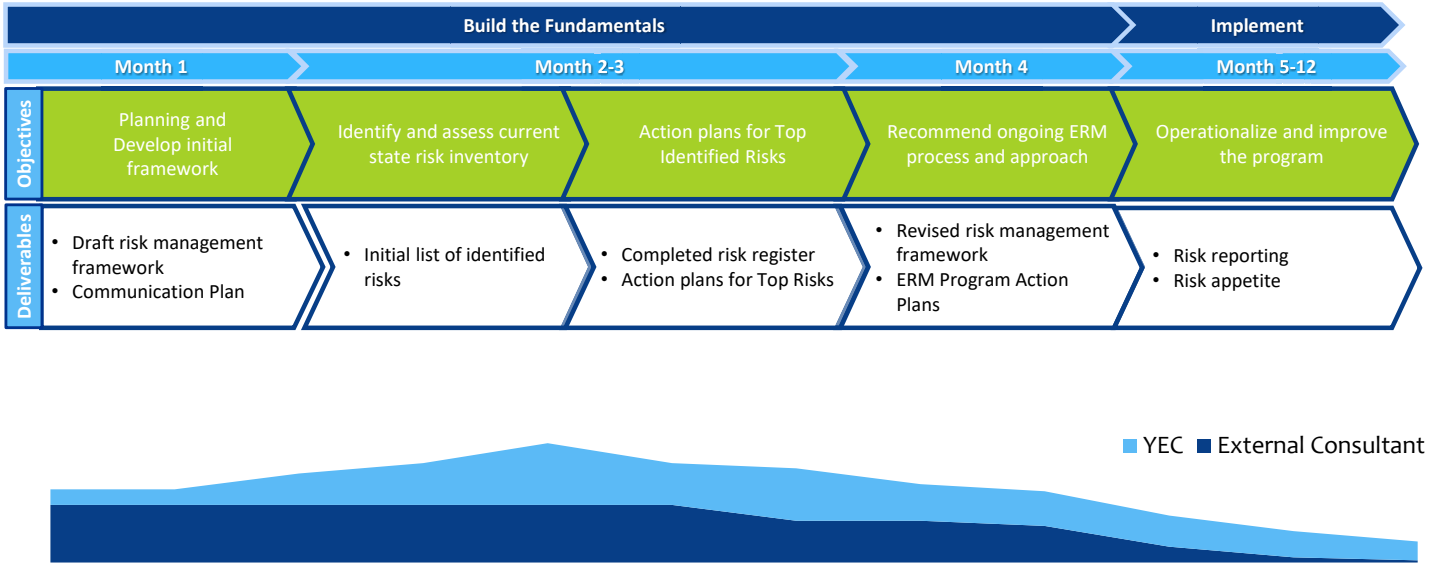
Findings

* Some good practices in certain areas:
  * Environmental and Health & Safety;
  * Project impact assessments;
  * Modeling
  * Capital project management

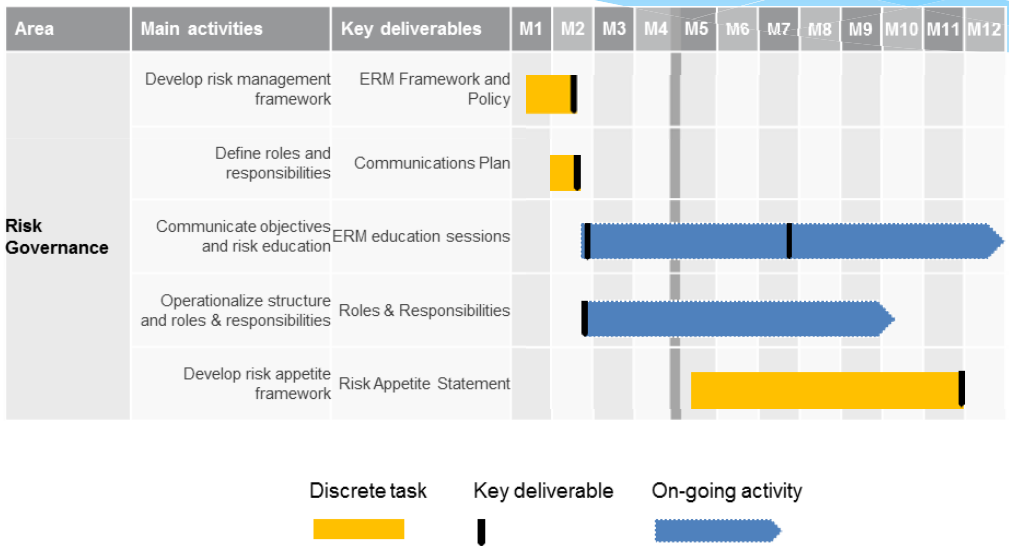
Areas for Improvement

* Where risk identification, assessment and monitoring is being done, results are often silo'd from other functions;
* Limited formal enterprise view to risk appetite, risk levels or risk capacity.
* ERM not operationalized with corporate decision making.

Road Map


Build the Fundamentals
Implement
Month 1
Month 2-3
Month 4
Month 5-12
Objectives
Planning and Develop initial framework
Identify and assess current state risk inventory
Action plans for Top Identified Risks
Recommend ongoing ERM process and approach
Operationalize and improve the program
Deliverables
• Draft risk management framework
• Communication Plan
• Initial list of identified risks
• Completed risk register
• Action plans for Top Risks
• Revised risk management framework
• ERM Program Action Plans
• Risk reporting
• Risk appetite
YEC
External Consultant

Risk Governance



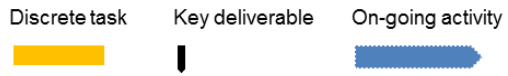
Risk Assessment

Area	Main activities	Key deliverables	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12
Risk Assessment	Use framework to identify and assess key risks	YEC-wide risk register (active updating & monitoring)												
	Develop actionable risk treatment plans for top risks with assigned risk owners	Risk treatment plans (active updating & monitoring)												

Discrete task Key deliverable On-going activity

Risk Quantification & Aggregation

Area	Main activities	Key deliverables	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12
Risk Quantification and Aggregation	Develop YEC wide view of risk	YEC-wide risk exposure report												
	Adopt and develop enhanced risk assessment tools													



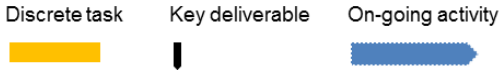
Risk Monitoring & Reporting

Area	Main activities	Key deliverables	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12
Risk Monitoring and Reporting	Develop risk monitoring and reporting processes	Departmental reporting – Ongoing			▬	▬	▬	▬	▬	▬	▬	▬	▬	▬
	Agregate/summarize information for executive reporting package	Executive management reporting – Monthly				▮	▮	▮	▮	▮	▮	▮	▮	▮
	Agregate/summarize information for board reporting package	Board reporting – Quarterly					▮		▮			▮		▮

Discrete task Key deliverable On-going activity

Continuous Improvement

Area	Main activities	Key deliverables	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12
Continuous Improvement and Risk Optimization	Utilize risk appetite & tolerance to optimize risk & mitigation effort	Program recommendations												
	Integrate with the planning and budgeting processes	Improved risk assessment, strategic plan, budgeting												



Next Steps

* Formulate budget for next phase based on resource requirements and phased approach recommended by consultant.
* Need to assess key resource risk

TOPIC: **Replacement of Mayo A Surge Chamber Project**

REFERENCE: **YUB-YEC-1-68(b), PDF page 335**

QUOTES: **"Maintenance was performed twice (2019/2020)**

- **The 2019 cost was $142; and**
- **The 2020 cost was $21,212."**

QUESTION:

a) Please describe the maintenance work conducted in these two years and explain why the 2020 cost was significantly higher compared to the 2019 cost.

ANSWER:

(a)

Maintenance work conducted was as follows:

- 2019 O&M costs ($142) were to service the electric furnace at the surge tank.

- The 2020 O&M costs ($21,212) were associated with the discovery of a pin hole leak at the surge tank. The increased costs included the removal of the surge tank cladding for inspection purposes and a third party engineered repair weld plan.

Under normal circumstances, there is low expectation of maintenance cost for this type of asset – it is essentially a large steel tank with virtually no moving parts. However, as disclosed in the application, the tank is at end of life and failure events such as happened in 2020 will occur more frequently.

TOPIC: **Asset Management Framework Project**

REFERENCE: **YUB-YEC-1-70(d), PDF page 340**

QUOTES: "Utilities that have implemented Asset Management programs based on the ISO 55000 standard have achieved operational savings in the range of 15-25 [footnote removed]…"

From the response to YUB-YEC-1-70(d), footnote 1, PDF page 340:

"From presentation 'Strategic Asset Management Delivering Value across the Organization', presented by the Institute of Asset Management CEATI Strategic Asset Management Planning conference, Vancouver 2017."

QUESTION:

a) Please provide the presentation referred to in footnote 1 of the response to YUB-YEC-1-40(d) and specify the utilities that have achieved operational savings after implementing asset management programs.

ANSWER:

(a)

Please see Attachment 1 to this response for the referenced presentation. Slide 14 provides examples of savings earned by a number of companies, including one power generation company.

the professional body for
through-life management of physical assets

The Institute of Asset Management
Canada

Strategic Asset Management
Delivering Value across the Organization

Boudewijn Neijens

November 2017

IAM Vision

"To be recognised as the leading, international, professional body for asset management"

'The Corporate Journey'
and
'The Individual Journey'

IAM Key Activities

- Professional Membership
  - Professionals engaging with their profession / networking
  - Magazine, newsletter and website
  - Demonstrable competence (formal qualifications being developed)
  - Continuing professional development
- Learned Society
  - Knowledge centre & research
  - Excellent value and quality events / seminars (some 'endorsed' commercial)
- Projects
  - Standards e.g. ISO project
  - Sector Specific Guidelines
- Services
  - Endorsed Trainers
  - Endorsed Assessors

Key "Products"

- Publications
  - Asset magazine
  - Anatomy of Asset Management
  - Subject-Specific Guidelines
  - Maturity guidance
- Conferences
  - Own events
  - Cooperative
- Certification
  - Certificate
  - Diploma
- Knowledge base
  - Website, case studies
  - The Big Picture





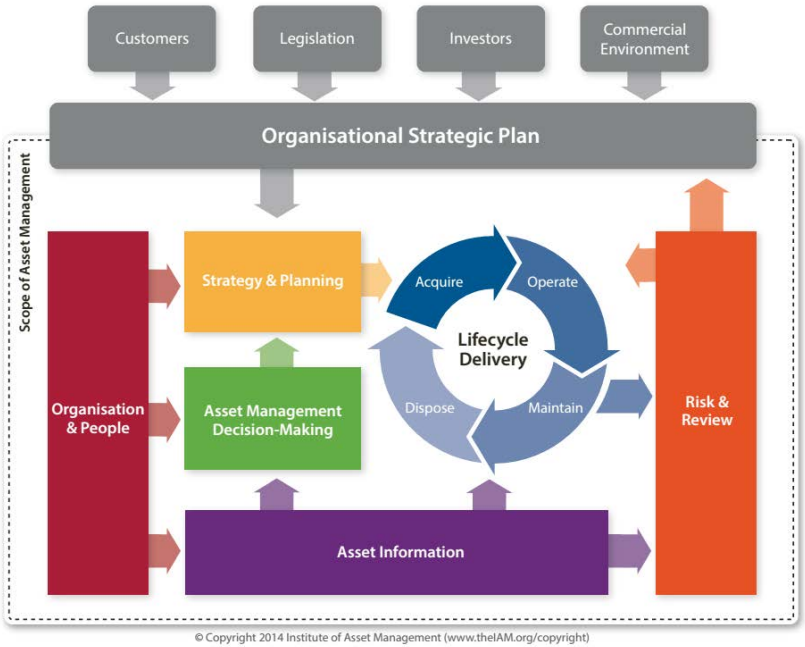






Anatomy

- 39 subjects of asset management
- Complements the ISO 55001 standard
- First layer of “how” to implement



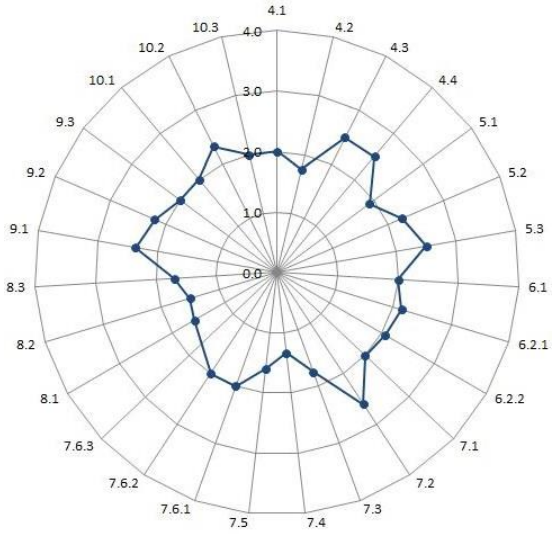
Subject Specific Guidelines

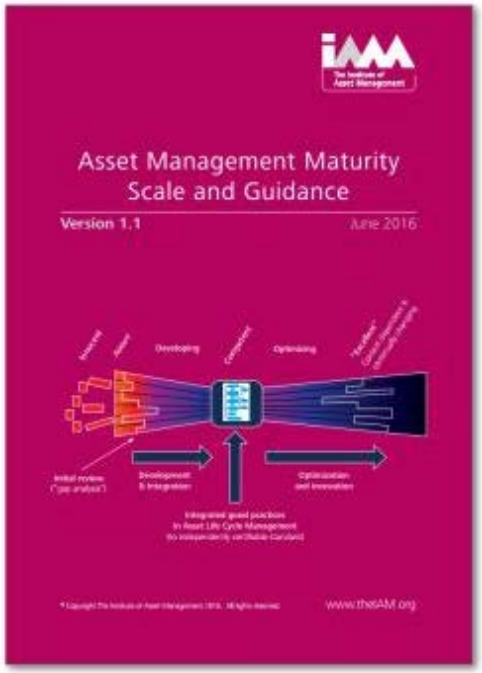
- Second layer of “how” to implement
- One guide per subject
- 8 published, many more under way



Maturity

- From innocence to excellence
- Linked to 39 subjects
- Self-assessment tool





Asset Management

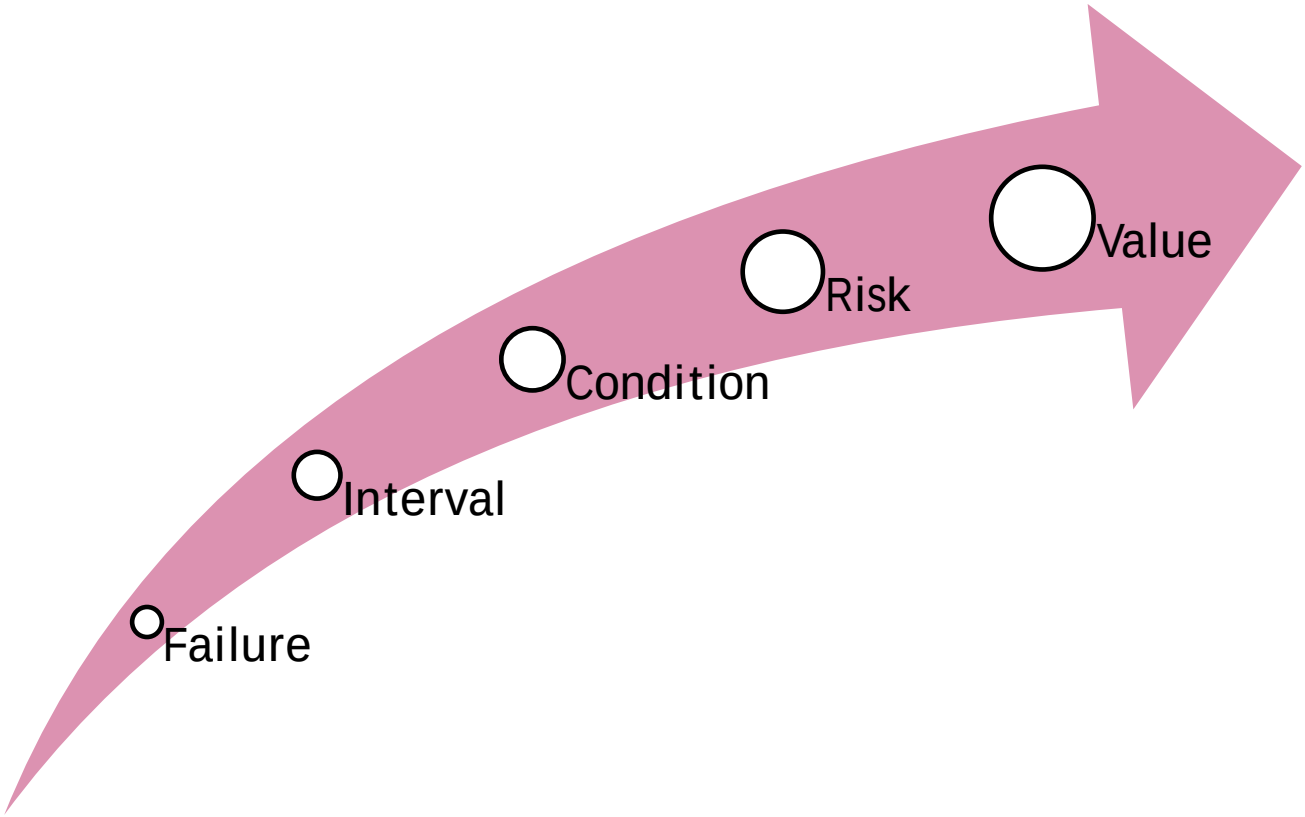
- Uses assets to deliver value and achieve the organization's explicit purposes
- Is strategic (aligned with the organisational strategy)
- Should be 'enterprise' wide (avoiding silos)
- Applies to asset owners, managers and those with delegated management responsibilities (e.g. outsourced asset responsibilities)
- Has to balance costs, risks and performance on different timescales
- Applies to both tangible or physical and intangible assets
- Applies to public, private and not-for-profit organisations

Quick Questions…

- Do you understand the risk profile associated with your asset portfolio and how this will change over time?
- Can you demonstrate the business consequences of reducing - or increasing - your capital investment or maintenance budgets by 10% over the next five years?
- Can you justify your planned asset expenditures to external stakeholders?
- Can you easily identify which investment projects to defer when there are funding or cash flow constraints?
- Do you have the appropriate asset data and information to support your Asset Management decision-making?
- Do you know if your people have the right competences to manage your assets?
- Do you know which Asset Management activities to outsource?

From: Asset Management, an anatomy – The IAM, 2014

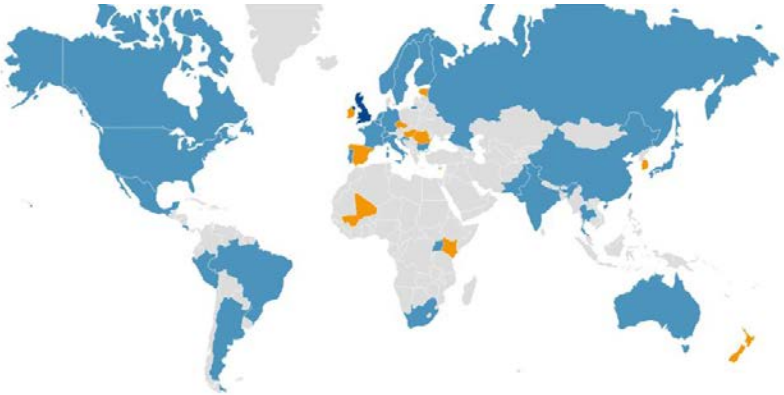
The Concept of Value



The Value of Asset Management



Intuition







- Action goes where money flows

ISO's View

Improved financial performance	Improving the return on investments and reducing costs can be achieved, while preserving asset value and without sacrificing the short or long-term realization of organizational objectives
Informed asset investment decisions	Enabling the organization to improve its decision making and effectively balance costs, risks, opportunities and performance
Managed risk	Reducing financial losses, improving health and safety, good will and reputation, minimizing environmental and social impact, can result in reduced liabilities such as insurance premiums, fines and penalties
Improved services and outputs	Assuring the performance of assets can lead to improved services or products that consistently meet or exceed the expectations of customers and stakeholders
Demonstrated social responsibility	Improving the organization's ability to, for example, reduce emissions, conserve resources and adapt to climate change, enables it to demonstrate socially responsible and ethical business practices and stewardship
Demonstrated compliance	Improving the return on investments and reducing costs can be achieved, while preserving asset value and without sacrificing the short or long-term realization of organizational objectives
Enhanced reputation	Through improved customer satisfaction, stakeholder awareness and confidence
Improved organizational sustainability	Effectively managing short and long-term effects, expenditures and performance, can improve the sustainability of operations and the organization
Improved efficiency and effectiveness	Reviewing and improving processes, procedures and asset performance can improve efficiency and effectiveness, and the achievement of organizational objectives

Anecdotical Evidence

Company	Sector	Benefits
Sodexo (FR)	Facilities management	• 30% increase in operational efficiency • Yearly cost operations reduced 7% to 12% • Reliability increased 10% to 25%
Network Rail (UK)	Rail infrastructure	• Extended asset lives • Capex reduction of 20% • Life cycle costs reduction of 8% • Reduced risk: safest railway in EU • Increased utilisation: 10% more train-km • Punctuality increase from 81% to 90%
ICE (CR)	Power generation	• Total benefits >$10M/year • AM project cost recovered in <6mo
Tongan Ministry of Infrastructure (TO)	Infrastructure	• Budget savings of 25% - 33% over 3 years
National Health Service (UK)	Health infrastructure	• 3% increase in capacity, and reduction of demand for new capital
RTA Dubai (AE)	Transit authority	• 25% asset life extension • Capex savings of $216M
Orange County (US)	Sanitation infrastructure	• 26% reduction of yearly capital outlay

Doing the Financial Math

$$ROIC = \frac{(OR - OE) - (FE - FR)}{Avg.\,Net\ Operating\ Assets}$$

Increase Operating Revenue

- Reduce downtime through reliability and risk control
- Increase demand or prices through better quality and service level / image

Reduce Operating Expense

- Lower lifecycle costs for new assets – better planning
- Work efficiency through procedures and systems
- Negotiate lower insurance costs – higher confidence

Reduce Financial Expense

- Less debt to service through reduced operating assets
- Negotiate lower interest rates through better credit ratings

Reduce Operating Assets

- Rightsizing capacity through model based planning
- Expand useful life of existing assets through maintenance
- Reduce redundancies through increased reliability

Doing the Financial Math

- Reliasset study
  - Physical Asset Turnover

$$PAT = \frac{Net\ Revenue}{Net\ Physical\ Assets}$$

  - Physical Asset Proportion

$$PAP = \frac{Net\ Physical\ Assets}{Total\ Assets}$$

- Asset intensive if:
  - PAT < 1
  - PAP > 50%
- High PPE → High ΔROIC
- Low PAT → High ΔROIC
- High PAP → High ΔROIC

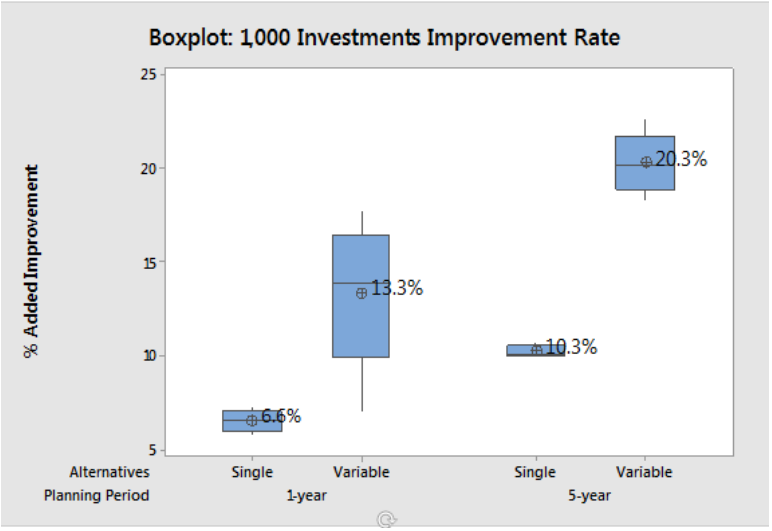
Rank	Industry sector	PAT	PAP	PPE Mill. €	Sample Size
1	Water Supply; Sewerage, Waste	0.10	92.4%	52.17	229
2	Real Estate	0.14	79.1%	5.79	3,474
3	Electricity, Gas, Steam and Air Condition	1.14	67.7%	23.03	266
4	Transportation and Storage	1.17	58.8%	6.94	463
5	Mining and Quarrying (incl. Oil & Gas)	2.00	63.4%	25.21	16
6	Agriculture, Forestry and Fishing	0.79	54.2%	2.28	708



From: Impact on financial performance by physical asset management – Erik Helms Nielsen, Reliasset, 2016

Better Processes Matter

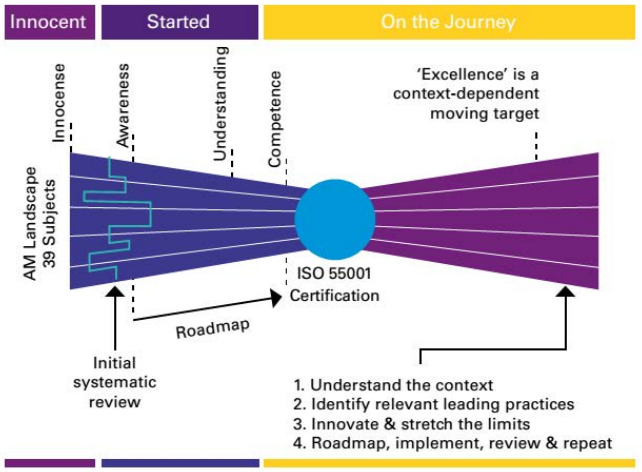
- University of Southampton study
- Comparing conventional ranking and prioritisation with mathematical optimisation
- **7% to 20%** improvement in value
  - Considering multiple options (alternatives) improves results
  - Multi-year portfolios score higher improvements



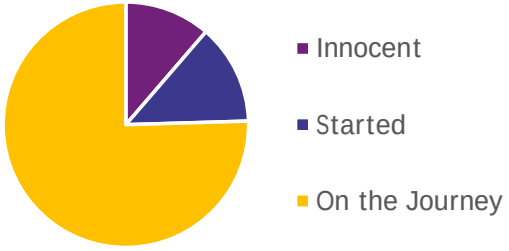
From: Quantifying the benefits of investment portfolio optimisation versus prioritisation for asset intensive organisations – I. Tamimi & Dr. P. Beullens, University of Southampton, 2016

Financial Benefits

- Study of 100 organizations
  - 53 utilities, both public & private entities
  - In the UK, India, Australia, New Zealand
  - Over 5 years (2010 – 2015)

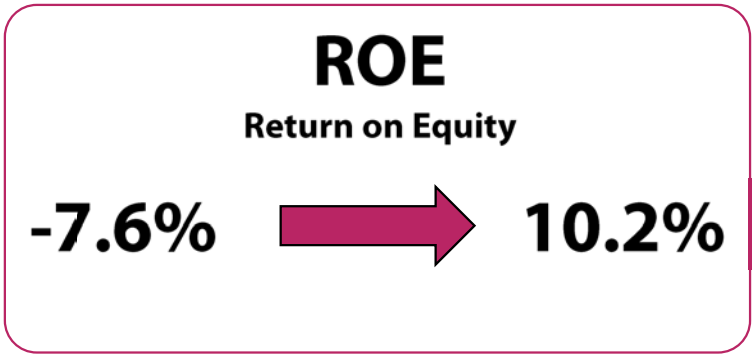


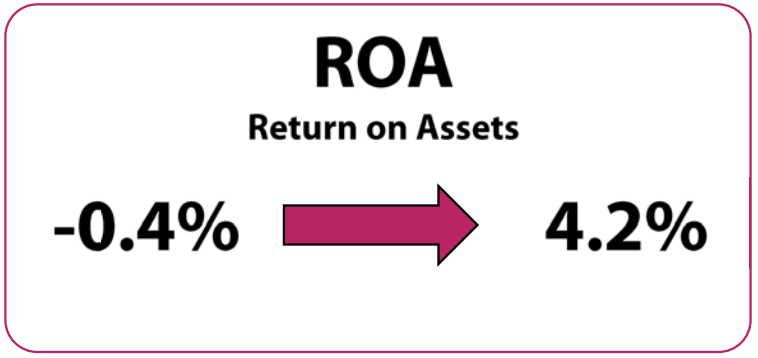
- Financial metrics
  - ROE = Net income/Shareholder equity
  - ROA = Net income/Total assets
  - EBIT Margin = EBIT/Net revenue
  - ROCE = EBIT/Capital employed

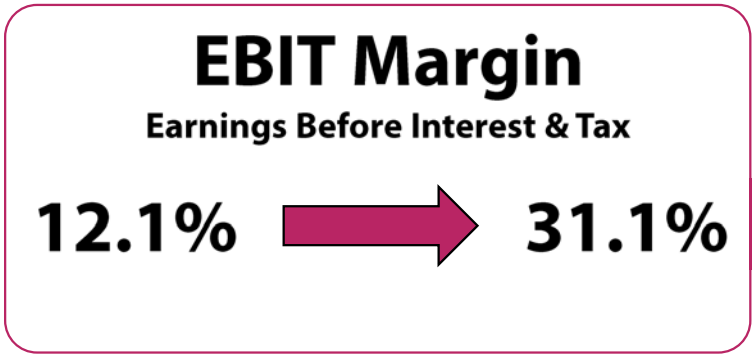


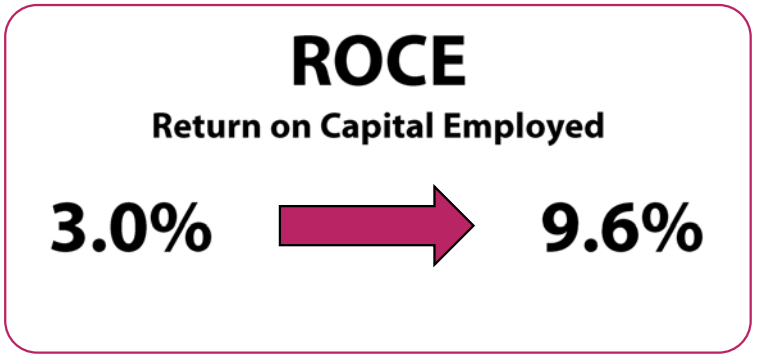
- Performed by KPMG for the IAM

Financial Benefits









- Public companies start lower but show much larger gains

From: Asset Management Financial Benefit Case – Salar Shemirani, KPMG, 2016

Conclusions

- Asset management delivers significant value
- Asset intensiveness increases the value leverage of AM
- No overnight wonders
- Work on both:
  - The management system & processes
  - Tools & techniques to manage assets
- Tell us your story

the professional body for
through-life management of physical assets

The Institute of Asset Management Canada

Thank You

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www.theiam.org *committee.iso.org/tc251*

TOPIC: **Dam Safety Program Project**

REFERENCE: **YUB-YEC-1-74(d), PDF page 350**

QUOTES: "A competitive RFP process was initiated. Eight proposals were received evaluated and awarded based on total score based on best overall proposal which included evaluating technical ability and price. Ecora Engineering was selected as the successful proponent."

QUESTION:

a) Please confirm that the competitive RFP process used was compliant with YEC procurement policies.

b) Was the lowest cost bid selected? Please explain.

ANSWER:

(a)

This RFP process was compliant with YEC procurement policies. The estimated budget for this work was greater than $100,000.00 CAD; in accordance with YEC procurement policy, this value requires a public tender. The opportunity was posted publicly (on MERX) as required by policy.

(b)

Yes. The price weighting for this RFP was 30%. Ecora did provide the lowest price bid. Ecora's technical score and price score gave them the highest mark of the 8 proposals received.

TOPIC: **Dam Safety Recommendation 2017-18**

REFERENCE: **YUB-YEC-1-75(c), PDF pages 352 and 353**

QUOTES: "Mayo Lake Planking not completed due to high water levels. Currently YEC is waiting for lower water levels to drop such that the planking can be replaced safely.

Wareham Dam Seismic Upgrades were also not completed due to high water levels. This work will now be completed as part of other Wareham Dam projects currently being planned.

Public Safety Plan was not completed due to the fact that YEC is waiting for results from the 2020 Dam Safety Review for inclusion into the Public Safety Plan."

QUESTION:

a) Please provide an update on the Mayo Lake Planking construction, Wareham Dam Seismic Upgrades construction, and the Public Safety Plan projects. In the response, please indicate whether anything has changed for the projects since the time that the first round of IR responses was provided that could result in material cost implications.

ANSWER:

(a)

Mayo Planking construction has been deferred to 2022 due to high water creating unacceptable safety risk for workers in that area. Wareham Dam Seismic Upgrades will be completed in 2023 as part of a larger earthworks project and the public safety plans will be completed and rolled out in 2022. At this point in time, YEC is uncertain if there will be material cost implications due to the fact that we are currently in the planning stages of this work and detailed engineering / scope has yet to be completed. These projects will not affect 2021 GRA test year costs included in rates.

TOPIC: **Compact Digger Truck**

REFERENCE: **YUB-YEC-1-81(d), PDF page 365**

QUOTES: "YEC will release a public RFP in 2021 to ensure optimal pricing and fit for service."

QUESTION:

a) Please provide an update on the status of the public RFP.

ANSWER:

(a)

A tender for the purchase of this unit was run in early 2021 and awarded to Altec Industries, the lowest cost bidder on this proposal. During Q2, the vendor advised that, due to COVID-related supply chain issues, the unit delivery would be delayed from Q4 2021 to late Q2 2022. Accordingly, YEC has adjusted its capital forecast for 2021 to reflect the delayed delivery (i.e. removed from 2021).

TOPIC: **Demand Side Management**

REFERENCE: **YUB-YEC-1-46(a) through (f), PDF page 97; Our Clean Future: A Yukon strategy for climate change, energy and a green economy, last updated on September 14, 2020, Order-in-Council (OIC) 2021/16, Section 10(3), page 5.**

QUOTES: From the response to YUB-YEC-1-46(a) through (f), PDF page 97:

(1) "Since the last rate application, the Yukon Government released a climate change strategy – "Our Clean Future: A Yukon strategy for climate change, energy and a green economy". More specifically, YG drafted the action below in the policy:

53. Direct the Yukon Utilities Board to allow Yukon's public utilities to pursue cost-effective capacity demand-side management measures.

This is a material change to how YEC approached DSM. The YG has clearly stated that DSM is a valid supply option for Yukon utilities and that they expect YEC to actively consider and implement prudent DSM programs. They also indicated their intention to direct the YUB to support cost-effective programs administered by YEC and AEY."

…

(2) "Based on YG's DSM policy and also considering growth in electrical load on the system, Yukon Energy DSM planning was undertaken; this planning includes coordination with the Yukon government's DSM programs to meet the overall policy objectives in a cost effective manner."

OIC 2021/16, Section 10(3), page 5:

"In determining whether costs are reasonably incurred by a public utility to provide or participate in a demand-side management program, the Board must consider the extent of any duplication between the program for which costs are incurred and a demand-side management program provided by the Government of Yukon or in which the Government of Yukon is a participant."

QUESTION:

a) Please define a "material change" in the context of quote (1) above. In your response, please explain why YEC considered the Yukon Government's direction to be "a material change to how YEC approached DSM".

b) Please confirm that the "action number 53" referenced in quote (1) above was not taken from the climate change strategy document, Our Clean Future: A Yukon strategy for climate change, energy and a green economy, dated September 14, 2020 (the last updated climate change strategy document, as identified in the reference line above). If confirmed, please provide reference(s) to the other version of the climate change strategy document and explain why YEC referenced the older version of the climate change strategy document in quote (1) above. If not confirmed, please provide reference(s) to the last updated climate change strategy document.

c) Please confirm whether the statements in the last two sentences of quote (1) above are relying on the last updated climate change strategy document. If confirmed, please provide reference(s) for each sentence, including page numbers of the document. If not confirmed, please provide reference(s) to such statements and in what context they were made.

d) Please elaborate on what was involved in the "coordination with the Yukon government's DSM programs" as part of YEC's DSM planning, as stated in quote (2) above. Please provide a complete and detailed response.

e) Given the statement in the OIC 2021/16 in quote (2) above regarding the DSM programs duplication, please confirm that there are no duplications between any

of the DSM programs and costs applied for in the current application and any DSM programs "provided by the Government of Yukon or in which the Government of Yukon is a participant". If not confirmed, please provide a complete and detailed response, including name(s) of the duplicative project(s) and why such duplication is reasonable.

ANSWER:

(a)

Following the Board's direction in Board Order 2018-10 that DSM programs were not necessary, YEC discontinued pursuit and promotion of DSM programs with the exception of the inCharge rebate program (which was open but not promoted) and the standalone residential demand response pilot project.

As stated in the quoted response, the context change referred to by YEC was the direction in the "Our Clean Future" strategy that YG will provide to the YUB to allow YEC to pursue cost-effective DSM programs. This was subsequently provided in OIC 2021/16.

Accordingly, YEC has gone from essentially pursuing little to no DSM, to being required to initiate a refreshed program design targeting capacity reduction in accordance with its long-term resource plan and the Yukon government's climate change strategy. Consequently, the 10-Year Renewable Electricity Plan calls for 7 MW of firm demand reduction from demand side management programs by 2030.

(b)

Confirmed. The action in the response to YUB-YEC-1-46 (a) through (f) was quoted from the original draft released of the "Our Clean Future" strategy, when public notice of this proposed material change was initially provided. The action H26 on page 45 of the final strategy is as follows: "Provide direction to the Yukon Utilities Board in 2020 to allow Yukon's public utilities to partner with the Government of Yukon to pursue cost-effective demand-side management measures."

(c)

Please refer to YUB-YEC-2-31 part (b). The statements apply regardless of the version of the strategy referenced, and rely on both the action as well as the subsequent Order in Council issued by Yukon government.

(d)

The Order in Council issued by Yukon government (OIC 2021/16) specifically references consideration of "the extent of any duplication between the program for which costs are incurred and a demand-side management program provided by the Government of Yukon or in which the Government of Yukon is a participant." Accordingly, YEC has engaged with Yukon government to ensure the existing demand-side management programs offered or planned by the Energy Branch are considered in YEC's program design, to avoid duplication. This engagement to date has been confirming the government's DSM program offerings as preliminary scoping work for the DSM program design was initiated.

Additionally, a subgroup of the Advisory Group on Energy Demand and Supply (AGEDS) has been formed to act as a DSM working group (the DSM Action Group or DSMAG). Through this advisory group YEC will continue to engage with YG as it initiates the Company's updated DSM program design and implements the plan. This will allow for avoidance of duplication, and assessment of potential collaboration or efficiencies.

(e)

Confirmed.

TOPIC: **Demand Side Management**

REFERENCE: **YUB-YEC-1-46(h), PDF page 98; Order-in-Council 2021/16, February 11, 2021, Section 10(4)**

QUOTE: From the response to YUB-YEC-1-46, PDF page 98:

"As stated above, YG has publicly confirmed its support for utility-driven DSM programming and further they indicated that they expect YEC to undertake such programing. Based on YG's clear expectation (now confirmed by OIC 2021/16) and with the knowledge that a significant capacity shortfall exists on the Yukon integrated system, YEC believed it was timely and prudent to include these programming costs in the 2021 application."

From OIC 2021/16, Section 10(4), page 5:

"(4) This section applies only in respect of an application, report or other filing that is made in the first Instance to the Board on or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force."

QUESTION:

a) Please provide reference(s) to where the Yukon Government has confirmed its support for "utility-driven" DSM programs.

b) (Please elaborate on why YEC believed it was "timely and prudent" to include DSM costs (2019, 2020, and 2021) in its 2021 application filed in November of 2020.

c) Generally, rates are set on a prospective basis. Please explain why YEC is requesting the Board to approve rates that were in place prior to the filing date of the application (November 2020).

d) Please explain if approving DSM costs in 2019 and 2020 respectively constitutes impermissible retroactive ratemaking.

e) Under the Public Utilities Act, Section 91,
"In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed by an owner of a public utility.

(a) the Commission may consider all revenues and costs of the owner that are in the Commission's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,

…

(c) the Commission may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Commission's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, as the Commission determines is just and reasonable." (emphasis added)

Please explain why YEC is of the view that the Board has the statutory authority to adjust YEC's rates for 2019, given the application was filed in 2020.

f) Is it YEC's view that OIC 2021/16 is limited to costs for DSM programming incurred from November 1, 2020 onwards? If not, please explain why not.

g) Is it YEC's view that the Board has the authority to apply OIC 2021/16, Section 10, to YEC's DSM programming for time periods prior to November 1, 2020? Please explain.

ANSWER:

(a)

Please see response to YUB-YEC-2-31 (a) and (b), and the related specific references in the initial and final Yukon Government climate change policy strategy "Our Clean Future: A Yukon strategy for climate change, energy and a green economy".

Yukon Energy considers this report a clear statement of support for utility-led DSM programming. OIC 2021/16 has confirmed this support.

(b)

Yukon Energy recognizes the value of DSM to the system and the material change as reviewed in response to YUB-YEC-2-31(a). In discussions with the YEC Board of Directors and shareholders, it was decided that program development efforts should continue and be included in the Application in the 2021 GRA.

(c)

YEC in the 2021 GRA is requesting the Board to approve rates for costs to be included in the 2021 test year revenue requirement, including capital and deferred costs that are to be included in rate base during the test year. YEC is not requesting the Board to approve rates, or changes to rates, prior to 2021.

Any referenced deferred DSM costs that were incurred prior to 2021 (or prior to filing of the GRA in November 2021) are related to development of cost effective DSM programming for delivery in the future. This treatment of DSM costs for inclusion in the 2021 test year rate base is no different from the treatment of any other project that is put into service between GRAs – the YUB is frequently asked to approve projects in rates that have been built or otherwise brought into rate base in prior years.

(d)

No, approving DSM costs from 2019 and 2020 that are included in the 2021 rate base would not constitute impermissible retroactive ratemaking. Please see response to (c) above.

(e)

YEC is not asking the Board in the 2021 GRA to adjust YEC rates for 2019 or 2020. Please see response to (c) and (d) above.

(f) and **(g)**

OIC 2021/16 states as follows in subsection 10(4) as regards the applicability of section 10 on recovery of costs for DSM:

> "This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on or after November 1, 2020 and for which no order is issued under section 27of the Act before this section comes into force".

YEC's 2021 GRA was filed in the first instance after November 1, 2020, and no order was issued by the Board under section 27 of the Act before February 11, 2021 (when the OIC section came into effect) on the 2021 GRA filings with regard to DSM costs to be recovered in the 2021 test year. As reviewed in response to (c), (d) and (e) above, YEC is not asking the Board in the 2021 GRA to adjust YEC rates for 2019 or 2020. Further, proposed treatment of DSM costs incurred prior to 2021 and after 2018 for inclusion in the 2021 test year rate base is no different from the treatment of any other project that is put into service between GRAs – the YUB is frequently asked to approve projects in rates that have been built or otherwise brought into rate base in prior years.

TOPIC: **Effect of DSM on Energy and Capacity Requirements**

REFERENCE: **YUB-YEC-1-47(a) and (b), PDF page 100**

QUOTE: "Yukon Energy in partnership with ATCO Electric Yukon and Yukon Government completed a DSM Program Portfolio which was filed with the Yukon Utilities Board as part of AEYs 2013-2015 GRA. This included a Conservation Potential Review, Market Characterization, Implementation Plan, and Evaluation Measurement and Verification Plan. The Conservation Potential Review was updated for Yukon Energy's 2016 Resource Plan. DSM programs were again shown to be a cost effective resource and were included in the recommended portfolio. These studies concluded the DSM can cost effectively reduce Yukon's energy and capacity requirements.

A portion of the residential programs presented in this portfolio were launched to the Yukon public. Progress reports and evaluations of the energy and capacity savings as well as cost effectiveness of these programs in accordance with the filed Evaluation Measurement and Verification Program were conducted and filed with the YUB. These reports and evaluations clearly demonstrated DSM as a cost-effective energy and capacity resource.

In Order 2014-06, the Board applied four standard cost-effectiveness measures for DSM costs (collectively, the "InCharge Programs Prudency Measures"), namely the total resource cost test (TRC), the program administration cost test (PAC), the rate-impact measure test (RIM), and the participant cost test (PCT). Program elements of the residential non-government DSM portfolio that passed all four cost-effectiveness measures for 2014 and 2015 were approved by the Board.

Evidence provided by Yukon Energy in the 2017/18 GRA indicated that the Approved InCharge Programs met InCharge Programs Prudency Measures endorsed by the Board in Order 2014-06 and were rate neutral for ratepayers." (footnote removed)

QUESTION:

a) In the quote above, YEC stated that, in partnership with AEY and the Yukon Government, it completed a DSM Program Portfolio which was filed with the Board as part of AEYs 2013-2015 GRA and the Conservation Potential Review was updated for Yukon Energy's 2016 Resource Plan.

   i. Does YEC, or its program partners, have more recent studies available in support of YEC's statement that "DSM can … reduce Yukon's energy and capacity requirements" and, more specifically, recent studies in support of the DSM programs applied for in the application?

   ii. If so, please provide those studies. If not, please explain why not. In response, please explain why YEC considers it reasonable to rely on the studies, some of which are almost a decade old, in support of its assertion that they can reduce Yukon's energy and capacity requirements in support of the DSM programs applied for in this application.

b) YEC stated that a "portion of the residential programs presented in this portfolio were launched to the Yukon public". Please list the residential programs referred to in this quote.

c) Please confirm whether YEC, or its program partners, have more recent analysis (other than that discussed in the above quote) of the effect of YEC's DSM projects to date on the energy and capacity requirements for YEC and the associated cost savings as well as cost effectiveness compared to the costs of the DSM programs. If confirmed, please provide YEC's more recent analysis.

d) If (c) is not confirmed, please explain why YEC, or its program partners, did not undertake such analysis more recently. In your response, please explain why YEC considers it reasonable to rely on the older studies to determine whether the applied for DSM projects are cost-effective energy and capacity resources.

e) Please confirm that all DSM projects applied for in the application passed all four standard cost-effectiveness measures for DSM costs for 2019, 2020, and 2021, as applied for in Order 2014-06 and quoted above. If confirmed, please provide details. If not confirmed, please explain.

ANSWER:

(a)

No. An updated DSM program design portfolio will include a current projection of savings and costs as well as forecast cost effectiveness test results before the programs are considered for implementation. As discussed in YUB-YEC-2-31(a), YEC had paused most of its DSM program activity following Board Order 2018-10. Accordingly, an updated study has not yet been conducted.

(b)

The residential DSM programs launched to the Yukon public were:

- LED and Automotive heater Timer Rebate Program;
- Low Cost Energy Efficient Products Program; and
- General Energy Efficiency Communication.

(c) and **(d)**

A project to design a new portfolio of DSM programs for the Yukon was started in 2018 but paused after the issuance of Board Order 2018-10 with regards to DSM. Consequently, a project design report with more recent analysis is not available – and the older studies are the best available information until updated assessments are completed.

The Yukon government has provided policy direction regarding DSM and Yukon Energy has proceeded with development of a project design report that will include projected program costs and standard cost effectiveness testing.

Please see also the response to YUB-YEC-1-34(b).

(e)

YEC has not been actively promoting or evaluating DSM programs since 2019. As such, no cost effectiveness analysis has been conducted. Any new programs designed and launched will be evaluated for cost effectiveness and implemented only subject to confirmation of cost effectiveness.

TOPIC: **Effect of DSM on Energy and Capacity Requirements**

REFERENCE: **YUB-YEC-1-47(c), PDF page 102**

QUOTE: "The RIM test as reviewed in Board Order 2014-06 (see response to (a) and (b) above) recognizes and addresses the possibility that DSM programs may lead to significant decline in energy sales that result in increased rates. As reviewed in response to (a) and (b) above, Yukon Energy DSM programs were previously confirmed to pass the RIM test and were rate neutral for ratepayers.

YEC anticipates that the targets for its ongoing DSM programs will emphasize capacity focused reductions rather than energy reductions. Capacity savings directly result in a reduced requirement for temporary diesel rental units. **These savings, in combination with the fuel savings from any related energy savings, are expected to outweigh any potential rate impacts driven by the reduction of sales." (emphasis added)**

QUESTION:

a) Please elaborate on the assertion that YEC "anticipates" that the targets for its ongoing DSM programs will emphasize capacity-focused reductions rather than energy reductions.

b) Does YEC, or its program partners, have any recent analysis or research that supports the conclusion in the last sentence (highlighted) of the above quote. If confirmed, please provide this information.

ANSWER:

(a)

The 10-Year Renewable Electricity Plan forecasts about 7 MW of firm peak demand reduction from demand side management programs by 2030. Accordingly, YEC expects that the DSM program design will focus on capacity reduction to achieve this target, with some resultant coincident energy reduction.

(b)

YEC together with DSM partners had started working on new DSM portfolio analysis, including the cost effectiveness analysis of the DSM programs. However, these activities were put on hold due to the direction from the Yukon Utilities Board in its Order 2018-10 in relation to the DSM program costs for the period after 2015.

The work for the DSM portfolio analysis now has been resumed based on Order in Council 2021/16 directions enabling YEC to recover through rates the costs reasonably incurred to provide or participate in a demand side management program. These analyses are not yet available; however, based on available information YEC and its DSM partners continue to expect promising results from the DSM programs, particularly the programs focused on peak reduction.

The following can be noted regarding the impact of the capacity focused DSM programs to the rates:

- As indicated in response to (a) above, the 10-Year Renewable Electricity Plan forecasts about 7 MW of firm peak demand reduction from demand side management programs by 2030. This replaces the requirement for four rental diesel units. Table 4-3 from Application for an Energy Project Certificate and an Energy Operation Certificate for the Proposed Battery Energy Storage System Project shows the annual diesel rental cost for four diesels could be around $1.6 million by 2030 [year 8 in the table].

- As noted in the 10-Year Renewable Electricity Plan [page 13], the demand is primarily driven by residential demand for services such as space heating, lighting, cooking and appliance loads. The 10-Year Renewable Electricity Plan [page 29] also notes that a new peak capacity demand record of 103.84 MW (97.6 MW non-industrial peak) was set on January 14, 2020 compared to the previous record peak at 92.99 MW (90.5 MW non-industrial peak). As a result of this record-breaking peak, YEC was required to update its non-industrial peak capacity demand forecasting model to account for updated information on the actual peak demand of the Yukon system during prolonged cold weather events.

- As demand is primarily driven by residential customers the reduction in peak will not impact the revenues received by the utilities as residential customers do not pay demand charges.

- In addition to the above, during peak periods, energy is delivered through thermal generation, mostly by running the diesel units when the demand exceeds the energy provided by LNG. The residential base energy rate is 12.14 cents/kWh [Rate Schedule 1160], and with YEC and AEY riders it would be below the weighted average thermal fuel cost for YEC's 2021 GRA of 18.4 cents/kWh or the diesel fuel cost at 20.51 cents/kWh. These calculations show reductions in revenues would be expected to be lower than the reduction in fuel costs.

TOPIC: **DSM Projects Costs**

REFERENCE: **YUB-YEC-1-59(b), PDF pages 275, 276**

QUOTE: "Breakdown of $832,906 costs spent in 2019:

- $385,009 DSM Program Design.
- $433,612 Residential Demand Response Pilot (gross cost; contributions of $365,315 received and separately noted in Table 5.4).
- $14, 285 inCharge maintenance.

In 2020, YEC planned to complete the design of a new portfolio of DSM programs as well as incur costs to administer the Residential Demand Response Pilot. The DSM 2020 program was delayed and actual 2020 costs were therefore lower than forecast in the Application. The actual 2020 DSM costs are broken out as follows:

- $571,901 Residential Demand Response Pilot (gross cost; contributions of $488,932 received and recorded as offset to project costs).
- $8,576 HPS light disposal and inCharge admin.
- Total Net Project Cost $91,545.

In 2021, YEC planned to implement the new portfolio of DSM programs as well as continuing the administration of the Residential Demand Pilot. The forecast costs for 2021 have been updated as required, given delays in the program starting in 2020.
The table below provides breakdown for the updated cost for 2021.

Demand Side Management		
DSM Administration	$	25,000
New Program Design Completion	$	300,000
New Program Implementation	$	240,000
Energy Management Tracking	$	-
Peak Smart Pilot (Gross Costs)	$	250,000
Total Gross Project Cost	**$**	**815,000**
Contributions (PeakSmart funding)	*$*	*(215,000)*
Total Net Project Cost	**$**	**600,000**

"

Net of contributions, the updated costs for 2020/2021 are $691.545 as compared with $904,000 in the Application."

QUESTION:

a) Please explain why the "DSM 2020 program" was delayed resulting in lower actual 2020 costs of $0.092 million compared to $0.375 million of 2020 forecast costs in the application. In your response, please explain what projects were included in the "DSM 2020 program" and which of those were delayed.

b) (Please explain why the DSM programs were delayed in 2021 resulting in lower forecast 2021 costs of $0.600 million compared to $0.894 million of 2021 costs forecast in the application. Please list the delayed projects or project activities.

ANSWER:

(a)

The 2020 DSM program work forecast was largely completion of updated program design.

Following the Board's direction in Board Order 2018-10 that DSM programs were not necessary, YEC discontinued pursuit and promotion of DSM programs with the exception of the inCharge rebate program (which was open but not promoted) and the standalone residential demand response pilot project.

As reviewed in response to YUB-YEC-2-31(a) and (b), the Yukon government subsequently issued its climate change strategy – "Our Clean Future: A Yukon strategy for climate change, energy and a green economy" which provided Yukon government's policy direction regarding DSM. Yukon Energy deferred proceeding with DSM program design work in 2020 until clarity was provided on this direction. Accordingly, YEC did not undertake DSM program design work in 2020 resulting in a lower actual spending on DSM in 2020 compared to forecast.

(b)

See response to part (a). Based on the release of the Yukon government climate change policy, YEC understood that Yukon government would be providing specific policy

direction. Yukon Energy deferred proceeding with program design work until it understood the specific policy direction that would be provided. OIC 2021/16 was issued in February 2021.

The original forecast contemplated completion of an updated program design in 2020 and implementation of new DSM programs in 2021. Program design is planned to be completed in 2021, and implementation will be completed after 2021, resulting in a lower actual cost compared to forecast.

TOPIC: **DSM Projects Costs**

REFERENCE: **YUB-YEC-1-61(a), PDF pages 280, 281**

QUOTE: "The Residential Demand Response Pilot will install internet-connected, wifi-enabled electric baseboard thermostats and hot water tank controllers in the homes of residential electrical customers anywhere on the Yukon Integrated System. The thermostats and hot water tank controllers will be used to temporarily lower the temperature set-point of the homes heat and hot water during a period of peak demand to lower the demand on the grid.

1000 thermostats and 400 hot water tank controllers will be installed as part of the pilot across 400 Yukon residences.

The actual costs to the end of 2020 are $269K in equipment, $149K in labour, $512 in professional services and $8K in expenses. The forecast remaining costs to complete the pilot are $68K labour and $414 professional services, including ongoing licensing and support."

QUESTION:

a) YEC stated that the Residential Demand Response Pilot (pilot project) would be conducted "anywhere on the Yukon Integrated System". Please explain how YEC decided in which areas of Yukon to conduct this pilot project and why.

b) Please explain how YEC determined which Yukon residences would participate in this pilot project.

c) Based on the quote above, please confirm that this pilot project's actual costs in 2020 amounted to $0.427 million. If not confirmed, please explain.

d) Please elaborate on the nature of the costs included in the $512 in professional services and $8,000 in expenses.

e) Please elaborate on the nature of the "forecast remaining costs to complete the pilot are $68 thousand labour and $414 professional services, including ongoing licensing and support". In the response, please explain in what year these costs will be incurred.

ANSWER:

(a)

YEC did not limit the areas of the pilot project other than requiring participants who were on the Yukon Integrated System. Applications for the program were assessed for eligibility based on the program requirements for internet connections, not location, as discussed further in part (b). YEC promoted the program online and on social media without limiting location.

(b)

Participants in the pilot program were chosen on a first come, first serve basis and were required to meet the following requirements:

- Have an electric baseboard heater with wall mounted thermostats or an electric hot water tank;
- Have cable or DSL internet connection;
- Own your home and live in it for most of the winter;
- Live in a home connected to the Yukon grid;
- Have an electric utility account in good standing; and
- Allow Yukon Energy to control your peak-shifting thermostats or hot water tank controller a few hours before a peak event (maximum of 12 times per winter season).

(c)

The quote referenced in the preamble does not correctly state the costs for professional services (in both instances the "k" is missing). The cost for professional services is actually $512K in 2020 (not $512) and forecast remaining costs to complete the pilot included $414K in professional services (not $414); in addition, it is noted that the costs quoted above are to the end of 2020, incurred in 2018, 2019 and 2020. The actual costs to the end of 2020 are $938K.

(d)

The nature of the professional services costs (corrects at $512k) include detailed design of the pilot, creation of customer marketing material, installation of the hardware in customers' homes, project management of pilot and analysis of pilot data. The expenses include AFUDC and travel costs.

(e)

These costs are expected to be incurred in 2021 and 2022. See correction regarding professional services costs noted in part (c) above.

TOPIC: **DSM Projects Costs**

REFERENCE: **YUB-YEC-1-61(c), (d), (e), pages 3 - 5**

QUOTE: From the response to YUB-YEC-1-61(c), PDF pages 281, 282:
"(ii) No projection has been made as to how many total hot water tanks could take part if this pilot is transitioned into a full program."

"(iv) Controllers are being installed on customers' existing typical hot water tanks. Accordingly, the average lifespan of the hot water tanks in the program are the same as a typical hot water tank. YEC does not have detailed data on this expected lifespan at this time."

"(vi) There are no financial incentives being paid to participants of the pilot."

From the response to YUB-YEC-1-61(d), (e), PDF pages 282, 283:
"(d) This particular pilot was pursued by YEC due to the funding opportunities from NRCan, AEY and YDC largely offsetting the program costs, enabling learnings from the pilot to be applied to future DSM programs at far less than the full project cost. The analysis and design of other DSM programs, such as direct incentives to customers, will now be advanced given OIC 2021/16 directions enabling YEC to recover through rates the costs reasonably incurred to provide or participate in a demand side management program.

(e) YEC has not performed any analysis of this project relative to alternatives. As discussed in (d) this pilot was pursued as funding was available to do so."

QUESTION:

a) Please explain why YEC did not make any projections as to how many homes it could be expanded to if this pilot is transitioned to a full program.

b) Please confirm if the “existing typical hot water tanks” is a reference to older vintages of hot water tanks that have been in service for some time. If not confirmed, please explain.

c) If (b) is confirmed, please explain whether YEC is planning to install controllers on newer hot water tanks as well. If not, please explain.

d) Are there other incentives for participants in this pilot project?

e) Please confirm that this pilot project was the only project that would have been eligible for the NRCan funding. Please explain.

f) If (e) is not confirmed and YEC could have done other projects that would have been eligible for that funding, please explain why YEC did not consider some alternatives.

ANSWER:

(a)

The goal of the Residential Demand Response Pilot is to test the effectiveness of a new demand response technology in reducing the morning and winter peak as well as the acceptance of participants of utility control of their appliances. The scope of the project did not include contemplation of a broader full program; this broader exercise would be conducted as part of a larger DSM program design. The results of the pilot will be used to forecast how many homes could be part of a full program.

(b)

Not confirmed. The "existing typical hot water tanks" refers to both older vintage and newer electric hot water tanks. The controllers can be installed on both.

(c)

Please refer to part (b). The controllers can be installed on both older vintage and newer electric hot water tanks.

(d)

There are no other direct incentives offered by YEC for participants although participants may be able to manage their energy usage for electric baseboard heating more easily through their access to the online portal or smartphone app provided by the program.

(e)

Confirmed. None of the other technologies included in the Conservation Potential Review appeared to meet the NRCan funding requirements.

(f)

Please refer to part (e).