

**Yukon Utilities Board
(YUB)**

1 **REFERENCE:** **Application - Overview, Energy & Peak Load Changes, pages 1**
2 **to 4**

4 **ISSUE:** **Energy and Peak Load Changes (8.4% of revenue shortfall)**

6 **QUOTE:** “Dependable capacity requirements caused by peak load growth for
7 non-industrial sales drives diesel rental costs that account for \$3.8
8 million (34.9%) of the 2021 GRA revenue shortfall.”

10 **PREAMBLE:**

12 **QUESTION:**

- 14 a) Based on the current load forecast, please provide the incremental costs on a per
15 kWh basis for the diesel rental units using only the rental and set-up costs.
- 17 b) Based on the current load forecast, please provide the incremental variable costs
18 on a per kWh basis for the diesel rental units.
- 20 c) Considering YEC’s current load forecast, does the sum of the rental costs
21 (response to part (a)) and the variable costs (response to part (b)) equal YEC’s
22 incremental cost of generation? If not, please explain and provide the incremental
23 cost for generation, separately identifying the portion based on fixed costs, variable
24 costs and total costs on a per kWh basis.

26 **ANSWER:**

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

30 Dependable capacity requirements caused by peak load growth lead to requirements for
31 dependable capacity to be in place during the critical winter grid peak period. Options to
32 meet this requirement are assessed based on fixed costs (capital and fixed non-fuel O&M
33 costs) without any focus on variable fuel costs, i.e., the facilities are primarily in place to
34 provide for the N-1 contingency event and would not normally be called upon to use fuel
35 in order to generate electricity. Accordingly, dependable capacity options are assessed
36 based on cost per kW of dependable capacity rather than based on costs per kWh of
37 possible generation.

- 1 The identified \$3.8 million of diesel rental costs for 2021 represent the incremental rental
2 costs for 17 units (15 units, each 1.8 MW to provide 27 MW as required for the N-1
3 dependable capacity shortfall, plus 2 spare units for reliability). These are fixed costs, i.e.,
4 they remain regardless of any generation; however, the units are rented and therefore the
5 costs can be removed when the rental period ends.
6
7 Please also see response to NY-YEC-1-3 (a) and CW-YEC-1-17 for details on diesel
8 rental unit costs.

1 **REFERENCE:** Application – Overview: PDF pgs. 2-5; Summary of Requested
2 Orders: PDF pgs. 5-7; Retail & Industrial: PDF pg. 62
3

4 **ISSUE:** 2021 Rates
5

6 **QUOTE:** “Approval of an increase of the current YEC Rider J by 15.01
7 percentage points, starting no later than December 1, 2021 applicable
8 to all YEC and AEY retail firm rates (all AEY recoveries from this rider
9 would flow through to YEC) and to all major industrial firm rates,
10 including the fixed Rider F charge of 0.211 cents/kWh.”
11

12 **PREAMBLE:**
13

14 **QUESTION:**
15

- 16 a) Please provide a discussion of rebasing, and not rebalancing, the rates — by
17 incorporating Rider J into base rates, for example — in a potential compliance filing
18 to any decision on this application. Include a discussion of any challenges and
19 benefits to implementing a rebasing of rates.
20

21 **ANSWER:**
22

23 **(a)**
24

25 In order to comply with OIC 1995/090, Section 2.1(1), any rate adjustments must apply
26 equally, when measured as percentages, to all classes of retail customers and to the class
27 of major industrial customers; this direction includes the customers of both YEC and AEY.
28

29 Accordingly, simple rebasing of rates in practice would require adjusting all base rates for
30 all retail and industrial customers by the same percentage increase to cover all existing
31 YEC and AEY percentage rate riders (excluding Rider F and any Rider E). Individual
32 ratepayers, and each customer class, would then see no change to bills as a result of this
33 rate rebasing. In addition, added measures would be required to ensure that YEC and
34 AEY each continued to secure rate rider revenues recovered from the other utility’s
35 customers but due to be passed through to the utility with the current rate rider.

1 In summary, simple rate rebasing as described above would provide little real benefit but
2 would add complexities in that all base rates for both utilities must then be changed each
3 time rates change, as compared with the current efficient process of charging specific rate
4 riders that may be adjusted as required from time-to-time.

5
6 Historically, rate rebasing has been accomplished whereby rate revenues for each retail
7 and industrial customer class remains unchanged as required by OIC 1995/90, but rates
8 within each customer class are restructured in response to an updated cost of service
9 study (COSS) assessment. This option would require the involvement of both utilities,
10 based on a common approved test year revenue requirement for the two utilities and a
11 joint COSS. It would result in changes to wholesale rates to address revenue allocation
12 between the two utilities in the absence of rate riders, and would remove each utility's
13 direct rate rider revenue access to the other utility's' customers, e.g., YEC rate riders apply
14 to all AEY customers in the hydro and diesel rate zones, and AEY rate riders apply to all
15 YEC customers (including major industrial customers where load growth has been
16 material since the last AEY GRA). This more complex rate rebasing would require a
17 separate joint YEC/ AEY proceeding and could not be implemented through a compliance
18 filing for any decision on the current YEC GRA.

REFERENCE: Application, Section 1.1, Need, context and proposed approach for 2021 GRA, Table 1.1, page 1-1

ISSUE: YEC Return on Equity

QUESTION:

- a) Please revise Table 1.1 to include 10 years of historical information on both an approved and actual basis commencing with the year 2012. Please state all assumptions relied on as a result of the requested revision.

ANSWER:

(a)

Please see Table 1 for the requested information.

Table 1: YEC Historical ROE: Approved and Actuals/Forecasts

	Approved	Actual	Note for Approved
2012	8.25%	6.75%	2012/13 GRA
2013	8.25%	7.42%	
2014	8.25%	8.44%	
2015	8.25%	8.10%	
2016	8.25%	8.69%	
2017	8.70%	8.72%	2017/18 GRA
2018	8.70%	6.25%	
2019	8.70%	3.81%	
2020 F	8.70%	3.88%	
2021 F		3.10%	

Notes:

- The Yukon Utilities Board (YUB) uses the benchmark ROE from the British Columbia Utilities Commission (BCUC). However, at the time of filing 2012/13 GRA a low-risk utility ROE benchmark from the BCUC was not available. Therefore, in 2012/13 GRA YEC proposed an ROE at 8.77% based on Alberta Utilities Commission (AUC) ROE benchmark of 8.75% plus 52-basis-point risk

1 premium as was applied in YEC's 2008-09 GRA, and subtract 50 basis points
2 pursuant to the direction provided in OIC 1995/90. In its Order 2013-01 [Appendix
3 A, Reasons for Decision] the YUB approved an ROE for YEC at 8.25% for the
4 2012/13 GRA noting that "the AUC model does not allow for an equity premium,
5 and since it is the model that is followed, no equity premium is allowed".
6

7 2. In 2017/18 GRA YEC proposed an ROE at 8.82% based on the BCUC low-risk
8 utility benchmark ROE at 8.75% plus 57-basis-point risk premium, and subtract 50
9 basis points pursuant to the direction provided in OIC 1995/90. In its Order 2018-
10 10 [Appendix A, Reasons for Decision] the YUB approved an ROE for YEC at
11 8.70% noting that the Board awards YEC 25 basis points for its small size plus "in
12 recognition of YEC's risks for generation, isolated grid and customer diversity, the
13 YUB awards YEC an additional 20 basis points" for a total risk premium of 45 basis
14 points above the BCUC benchmark utility. The YUB also noted that "the additional
15 20 basis points acknowledges the overall risk of YEC as being greater than that of
16 FortisBC (Electric) and greater than that of AEY."

1 **REFERENCE:** Application, Section 1.3, Changes in Forecast Loads, page 1-7

2
3 **ISSUE:** Industrial Load

4
5 **QUOTE:** "Forecast firm Yukon Energy sales to industrial customers for the 2021
6 test year is 102.9 GW.h."

7
8 **PREAMBLE:**

9
10 **QUESTION:**

- 11
12 a) The 2021 load increase over 2018 approved load forecast for Victoria Gold Group
13 and Alexco Resources is 67.2 GWh. Please provide the 2018 approved load
14 forecast for Minto mine.

15
16 **ANSWER:**

17
18 **(a)**

19
20 The 2018 Minto mine load forecast approved in YEC's 2017-18 GRA compliance filing is
21 32,193 MWh, i.e., this was the only mine load included in the approved 2018 forecast.

1 **REFERENCE:** Application, Section 1.3, Peak Capacity and N-1/LOLE
2 requirements in test years, page 1-8
3

4 **ISSUE:** Diesel Rental Units
5

6 **QUOTE:** "Diesel rental unit costs of approximately \$3.8 million are forecast for
7 the diesel rental units expected to be required for the 2021 GRA test
8 year."
9

10 **PREAMBLE:**
11

12 **QUESTION:**
13

14 a) Please provide the additional firm capacity of the diesel rental units.
15

16 b) For 2021, how much energy is forecast to be generated from the diesel rental
17 units?
18

19 **ANSWER:**
20

21 **(a)**
22

23 The firm capacity provided by the 15 diesel rental units for 2021 is 27 MW (1.8 MW per
24 unit). Note the contract price includes two additional 1.8 MW units for reliability.
25

26 **(b)**
27

28 The forecasted 2021 energy to be generated by temporary rented diesel units is 2.5 GWh.

1 **REFERENCE:** Application, Section 1.4, pages 1-8, 1-9

2
3 **ISSUE:** VGC Group and Alexco Fixed Charge

4
5 **QUOTE:** “As reviewed in Appendix 4.3 of this Application, YEC expects to file
6 with the Board in late November/ early December 2020 for approval of
7 an amended Transmission Facilities Fixed Cost effective January 1,
8 2021 of \$428,812, resulting in an interim Fixed Charge (85% of the
9 Transmission Facilities Fixed Cost) effective January 1, 2021 of
10 \$35,734 per month, with allocation of the interim Fixed Charge between
11 VCG Group and Alexco [Table 4.3-2, Appendix 4.3 of this Application].”
12

13 **QUESTION:**

- 14
15 a) Please confirm that the amended Transmission Facilities Fixed Cost application is
16 part of this application. If not confirmed, then please explain when the application
17 will be filed with the Board.
18

19 **ANSWER:**

20
21 **(a)**
22

23 The amended Transmission Facilities Fixed Cost application and related interim Fixed
24 Charge are required to be filed within 60 days of the Transmission Facilities Development
25 Operation Date as directed by YUB in Order 2018-04. This requirement exists separate
26 from the 2021 GRA application, and was therefore assumed not to be part of the 2021
27 GRA application.
28

29 Since drafting of the 2021 GRA, the Transmission Facilities Development Operation Date
30 has been delayed to March 2021. YEC therefore now expects to file the amended
31 Transmission Facilities Fixed Cost application in March 2021, requesting an interim Fixed
32 Charge adjustment effective May 1, 2021.
33

34 Please also see response to YUB-YEC-1-45.

1 **REFERENCE:** Application, Section 2.1, pages 2-1

2
3 **ISSUE:** Sales – Overview

4
5 **QUOTE:** “Yukon Energy directly serves about 2,300 customers at the distribution
6 (retail) level, most of whom live in and around Dawson City, Mayo and
7 Faro. Indirectly, Yukon Energy also provides power to Yukon retail
8 customers served on the Integrated System (including those located in
9 Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and
10 Teslin, Pelly Crossing, Keno and Stewart Crossing) through its
11 wholesale sales to ATCO Electric Yukon (AEY).”
12

13 **QUESTION:**

- 14
15 a) Please provide the incremental per unit (\$/kWh) of sales revenue YEC would
16 receive for the next kWh of energy sold above the forecast: 1) Using a blended
17 rate based on this application that incorporates retail, wholesale and industrial
18 customers; and 2) including and specifying all applicable riders. Please explain
19 any assumptions that are necessary in your response.
20

21 **ANSWER:**

22
23 **(a)**

24
25 Incremental per unit (\$/kWh) of sales revenue that YEC would receive for the next kWh of
26 energy sold above the 2021 forecast based on the Application will vary considerably
27 depending on the customer class and the customer group within each customer class (i.e.,
28 which rate block is affected).
29

30 An overall blended average rate is about 13 cents per kWh before 2021 GRA rate
31 increases [9.7 cents/kW.h before rider as shown in Tab 7, Schedule 9, line 45 plus 3.2
32 cents/kW.h Rider J revenues] and about 15 cents per kWh with 2021 GRA increases which
33 adds about 2.2 cents/kW.h [\$10.971 million GRA shortfall in Schedule 9, line 48 divided
34 by 495.151 GW.h sales shown in line 43].
35

36 Blended incremental energy-only revenue rates per kWh resulting from added energy
37 sales will be lower than the averages shown above for all rate revenues (which include

- 1 customer charges, demand charges and varying retail energy rates for different
- 2 customers). Based on last block energy rates applicable to YEC sales for different
- 3 customer groups, a blended incremental YEC energy sales revenue of about 13 cents per
- 4 kWh is estimated for forecast 2021 sales assuming Rider J as proposed in the Application.

REFERENCE: Application, Appendix 2.1, Table 2.1-1, page 2.1-1

ISSUE: Expected Thermal Generation

QUESTION:

a) Please expand Table 2.1-1 down to grid load of 350 GWh.

ANSWER:

(a)

Please see Table 1 for extended version of Table 2.1-1. Please note that the table is extended to minimum 385 GW.h compared to 350 GW.h requested in the question as the LTA thermal generation for the loads lower than 385 GW.h is insignificant.

Table 1: Expected Thermal Generation Based on LTA Hydro Generation (2021)

Line Number	YEC Grid Load Net of Wind (GWh)	YEC Hydro Generation (GWh)	YEC Thermal Generation (GWh)	Increase in		Thermal as % of Increased Load
				Load (GWh)	Thermal Generation (GWh)	
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	385.0	383.525	1.475			
2	390.0	387.708	2.292	5.0	0.817	16%
3	395.0	391.622	3.378	5.0	1.085	22%
4	400.0	395.303	4.697	5.0	1.319	26%
5	405.0	398.782	6.218	5.0	1.522	30%
6	410.0	402.084	7.916	5.0	1.698	34%
7	415.0	405.233	9.767	5.0	1.851	37%
8	420.0	408.247	11.753	5.0	1.986	40%
9	425.0	411.142	13.858	5.0	2.105	42%
10	430.0	413.928	16.072	5.0	2.214	44%
11	435.0	416.613	18.387	5.0	2.315	46%
12	440.0	419.198	20.802	5.0	2.414	48%
13	445.0	421.685	23.315	5.0	2.514	50%
14	450.0	424.066	25.934	5.0	2.618	52%
15	455.0	426.334	28.666	5.0	2.732	55%
16	460.0	428.476	31.524	5.0	2.858	57%
17	465.0	430.474	34.526	5.0	3.002	60%
18	470.0	432.169	37.831	5.0	3.306	66%
19	475.0	433.735	41.265	5.0	3.434	69%
20	480.0	435.293	44.707	5.0	3.441	69%
21	485.0	436.810	48.190	5.0	3.484	70%
22	490.0	438.277	51.723	5.0	3.532	71%
23	495.0	439.690	55.310	5.0	3.587	72%
24	500.0	441.043	58.957	5.0	3.647	73%
25	505.0	442.334	62.666	5.0	3.710	74%
26	510.0	443.557	66.443	5.0	3.776	76%
27	515.0	444.713	70.287	5.0	3.844	77%
28	520.0	445.800	74.200	5.0	3.913	78%
29	525.0	446.819	78.181	5.0	3.982	80%
30	530.0	447.769	82.231	5.0	4.049	81%
31	535.0	448.654	86.346	5.0	4.115	82%
32	540.0	449.477	90.523	5.0	4.177	84%
33	545.0	450.242	94.758	5.0	4.235	85%
34	550.0	450.954	99.046	5.0	4.288	86%
35	555.0	451.618	103.382	5.0	4.335	87%
36	560.0	452.243	107.757	5.0	4.375	88%
37	565.0	452.836	112.164	5.0	4.407	88%
38	570.0	453.406	116.594	5.0	4.430	89%
39	575.0	453.963	121.037	5.0	4.443	89%
40	580.0	454.519	125.481	5.0	4.444	89%
41	585.0	455.085	129.915	5.0	4.434	89%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid net of IPP generation, secondary sales related generation and Fish Lake hydro generation. The load will also be adjusted for WH2 and WH4 uprates as noted in #7 below.
2. The thermal generation and increase for the added load are based on a polynomial equation derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.
3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 38 "water years" on record (1981-2018) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake) and restricted Mayo GS winter flows (based on new Mayo Ice Protocol Mayo GS outflows are restricted at max 19 cms in November and 15 cms in December, after which restrictions are relaxed by 1.75 cms/week reaching 20 cms by early January and 24 cms by February [compared to 20 cms restriction through winter used in the 2017/18 GRA]).
5. The simulation model results are based on 2021 forecast load and IPP distributions, and requires modifications when new mines, industrial loads or IPP generation are connected to [or disconnected from] the grid.
6. The table assumes max YEC Grid Load (i.e., excluding IPP generation) at 585 GW.h and minimum YEC Grid Load at 385 GW.h. If the YEC Grid Load exceeds these limits then the table needs to be updated.
7. YEC is undertaking capital projects that will increase hydro generation output in Whitehorse GS [WH2 and WH4 uprates]. The preliminary estimates show that these capital projects will increase generation output by 7.1 GW.h/year [4.2 GW.h for 2021 considering expected in service date effective July 1, 2021 - monthly allocation based on Whitehorse GS monthly generation forecast]. Therefore, the YEC Grid Load is reduced to reflect increased output from these capital projects [not all incremental generation will directly displace LTA thermal].
8. Numbers are subject to rounding.

Example

Expected YEC Thermal Generation for the YEC generation at 536.743 GW.h (net of expected IPP & Fish Lake)

Remove Expected Generation for WH uprates [estimate for 2021 at 4.213 GW.h] to get net load at 532.530 GW.h

Step 1.	Find the closest load from Column A that is less than 532.530 GW.h = 530 GW.h (Line 12).
Step 2.	Find the thermal generation from Column C = 82.231 GW.h (Line 12).
Step 3.	Find the difference between the given load (532.530 GW.h) and load from Step 1 (530 GW.h) = 2.530 GW.h
Step 4.	Apply the percentage from Column F (Line 12, 82%) to the difference from Step 3 (2.530 GW.h) = 2.075 GW.h
Step 5.	Add numbers from Step 2 (82.231 GW.h) and Step 4 (2.075 GW.h) = 84.306 GW.h
	The expected thermal generation at 536.743 GW.h load [net of Fish Lake and IPPs] is 84.306 GW.h.

1 **REFERENCE:** Application, Tab 2, page 2-2, line 16

2
3 **ISSUE:** Total Firm Generation Load

4
5 **QUOTE:** "Overall, **total firm generation load** to be supplied by Yukon Energy
6 on the Yukon Integrated System was forecast at 420.3 GW.h in the
7 2018 Compliance Filing. Actual total firm generation load was 450.1
8 GW.h in 2018 reflecting higher sales compared to the forecast. Actual
9 total firm generation load in 2019 was 440.7 GW.h, and full year
10 forecast for 2020 is 508.0 GW.h. Forecast total firm generation load for
11 the 2021 test year is 538.7 GW.h."

12
13 **QUESTION:**

14
15 a) What was the forecast total firm generation load on the Yukon Integrated System
16 for 2019?

17
18 **ANSWER:**

19
20 **(a)**

21
22 The 2017-18 GRA proceeding did not provide any forecast for 2019 load on the YIS. Aside
23 from YEC internal business plan forecasts, the only public forecast was provided in YEC's
24 2016 Resource Plan where the forecast total firm generation load on the Yukon Integrated
25 System for 2019 was 443 GW.h, which compared relatively well with the actual 440.7
26 GWh.

1 **REFERENCE:** Application, Tab 2, page 2-3, line 19

2
3 **ISSUE:** Independent Power Production

4
5 **QUOTE:** "Independent Power Production (IPP) renewable generation is forecast
6 to commence in November 2020 with less than 0.4% of forecast
7 generation impact for 2021."
8

9 **QUESTION:**

10
11 a) What is YEC's level of certainty regarding the forecast IPP amounts for 2021?
12 Please explain.

13
14 b) How have IPP projects been affected to date by the COVID-19 pandemic? Did the
15 IPP commence in November 2020, as scheduled?
16

17 **ANSWER:**

18
19 **(a)**

20
21 YEC has considerable uncertainty as to timing for forecast IPP amounts for 2021. The
22 first project that was to be operational in November 2020 has been delayed into spring
23 2021.
24

25 **(b)**

26
27 We do not know how IPP projects have been affected to date by the COVID-19 pandemic.
28 The IPP did not commence in 2020 as scheduled.

1 **REFERENCE:** Application, Tab 2, page 2-4, line 2

2
3 **ISSUE:** Forecast Renewable Generation

4
5 **QUOTE:** "This impact is starting to be offset by new renewable generation
6 planned as part of Yukon Energy's 10 Year Renewable Electricity Plan,
7 commencing with the new IPP generation forecast to provide 0.06
8 GW.h of solar generation in 2020 and 2.0 GW.h of new renewable
9 generation in 2021 based on information available at the time of filing."

10
11 **PREAMBLE:** The Board requires additional information with respect to YEC's
12 forecasts being based on "information available at the time of filing."

13
14 **QUESTION:**

- 15
16 a) What specific information did YEC rely on to forecast the new renewable
17 generation?
18
19 b) To what date was information available in preparing these forecasts?
20

21 **ANSWER:**

22
23 **(a) and (b)**

24
25 The information available on IPPs when the generation forecasts were finalized for the
26 2021 GRA Application in September/ early October 2020 was the forecast IPP deliveries
27 and target dates noted in the following two agreements signed with potential IPP projects:
28

- 29 • North Klondike Highway Solar PV Project with target commercial operation date of
30 November 1, 2020 with 1,840 MWh annual energy delivered.
31
32 • Mount Sima Solar Project with target commercial operation date of June 1, 2021
33 with 270 MWh annual energy delivered.

1 **REFERENCE:** Application, Tab 2, page 2-5, line 21

2
3 **ISSUE:** Working with ATCO Electric Yukon on Forecasts

4
5 **QUOTE:** "YUB Order 2018-10 directed YEC to refine its methodology of
6 forecasting Wholesale Sales to ensure its forecasts align closely with
7 the AEY forecasts in future applications. To develop YEC's Wholesale
8 Sales forecasts for the test years, YEC worked closely with AEY. YEC
9 reached out to the AEY Regulatory team and YEC and AEY staff
10 worked closely to understand forecasting methodology and inputs into
11 the respective forecasts. AEY cautioned YEC that AEY's forecast is for
12 business plan purposes and it did not necessarily undergo the same
13 rigor as a forecast that AEY would file in a GRA.
14

15 **QUESTION:**

- 16
17 a) Please explain how the forecasting process for business planning is different from
18 the forecasting process for a GRA.
19

20 **ANSWER:**

21
22 **(a)**

23
24 Based on YUB Order 2018-10 YEC communicated with AEY during the development of
25 wholesale forecast for the test year. YEC's forecast wholesales sales for 2021 test year
26 are very close to the power purchase forecast provided by AEY [as reviewed in section
27 2.2.1 of the Application the AEY forecast for 2021 is 0.7% higher than YEC's forecast].
28

29 During the forecast exchanges AEY cautioned YEC that AEY's forecast is for business
30 plan purposes and it did not necessarily undergo the same rigor as a forecast that AEY
31 would file in a GRA. Beyond this, YEC does not have specific information on how AEY's
32 forecasting process for business planning is different from its forecasting process for an
33 AEY GRA.

REFERENCE: Application, Tab 2, page 2-5, footnote 4

ISSUE: Information Provided by Energy, Mines and Resources

QUOTE: “YEC has forecast a micro-generation impact of about 1.5 GW.h for 2021. The micro-generation forecasts are based on information available from Energy Mines & Resources of the Yukon government.”

QUESTION:

- a) Please provide the source information provided to YEC by the Department of Energy, Mines and Resources and any other information from the Department that informed or influenced YEC’s micro-generation forecasts for this application.

ANSWER:

(a)

The Micro-generation data below was provided by the Manager, Energy Programs in the Energy Branch at Energy Mines & Resources. The actual 2020 program total is embedded in historical sales and is included in the regressed forecasted load. Only the 2021 incremental program total of 1.5 GWh has been used to reduce the 2021 load. No adjustments were made to the peak forecast related to microgen as solar installations do not provide energy during peak winter hours.

	Installed DC Capacity At Year End [kWdc]	Capacity Added This Year [kWdc]	Exported Energy [kWh]	Payout Value	Forecasted Payout Value
2014	31		2,484	\$1,643	\$535
2015	83	51	16,576	\$4,768	\$3,573
2016	424	341	66,586	\$16,925	\$14,352
2017	972	549	259,673	\$57,028	\$55,970
2018	2,135	1,163	666,333	\$143,623	\$143,623
2019	3,058	923	1,357,079	\$285,000	\$292,508
2020	4,500	1,442	1,951,685	TBD	\$420,671
2021	5,918	1,418	2,826,307	TBD	\$609,188

	Installed DC Capacity At Year End [kWdc]	Capacity Added This Year [kWdc]	Exported Energy [kWh]	Payout Value	Forecasted Payout Value
2022	6,917	999	3,660,798	TBD	\$789,057
2023	7,530	613	4,242,805	TBD	\$914,504
2024	7,877	346	4,597,937	TBD	\$991,050

1

1 **REFERENCE:** Application, Tab 2, page 2-7, line 5

2
3 **ISSUE:** Potential Mine Load Additions

4
5 **QUOTE:** "Yukon Energy continues to monitor the situation with respect to
6 prospects for additional connected industrial mine loads within the next
7 few years. Yukon Energy is not aware of any other potential near term
8 mine loads that could be connected to the grid."
9

10 **QUESTION:**

11
12 a) Please explain how and using what methods YEC monitors for potential additional
13 industrial connections.
14

15 **ANSWER:**

16
17 **(a)**

18
19 YEC keeps abreast of developments in the mining sector through direct contact with key
20 stakeholders (e.g., Chamber of Mines, YG Energy Mines & Resources), monitoring of
21 media disclosure on new developments, participation in and monitoring of key mining
22 forums/conferences in Whitehorse (Geoscience) and Vancouver (Roundup) and
23 monitoring of regulatory proceedings (YESAB, Water Board). Potential mining customers
24 will also contact the utility directly with questions regarding interconnection to the YEC
25 system; YEC tracks these contacts and confirms the stage of development. While YEC
26 keeps track of most major mining development projects in Yukon, for obvious reasons the
27 utility focus is on those developments with a likely potential to connect to the YEC grid.

1 **REFERENCE: Application, Tab 2, Section 2.2, page 2-4**

2
3 **ISSUE: Sales Forecast**

4
5 **QUESTION:**

6
7 a) How does YEC incorporate new residential and commercial construction into its
8 sales forecasts?

9
10 b) How has YEC incorporated the effect of increased numbers of people working from
11 home, due to the COVID-19 pandemic, into its sales forecasts?

12
13 **ANSWER:**

14
15 **(a)**

16
17 Finance reaches out to staff in each community who provides Finance with an update of
18 activity in the area (for example, new residential projects and commercial activity). For
19 larger commercial customers, Finance receives power consumption forecasts from the
20 commercial customer.

21
22 **(b)**

23
24 For residential and commercial sales forecasts, YEC has not incorporated the effect of
25 increased numbers of people working from home. This is primarily due to uncertainty and,
26 at the time of preparation of the residential and commercial sales forecasts, Yukon people
27 working from home were starting to go back to working at work. For residential and
28 commercial sales, YEC uses a three year average to forecast sales, subject to other
29 adjustments as considered necessary such as those that result from part (a) above.

1 **REFERENCE:** Application, Tab 2, page 2-7, line 15

2
3 **ISSUE:** Residential Sales Forecasts

4
5 **QUOTE:** “Actual firm residential retail sales were 15.6 GW.h in 2018 and
6 15.4 GW.h in 2019; the full year forecast for 2020 is 16.7 GW.h and for
7 the 2021 test year is 16.2 GW.h. The higher forecast sales in 2020
8 reflect colder than normal weather and modest growth in the number of
9 customers. Residential sales forecasts are done on a community by
10 community basis and are based on historical averages and input from
11 YEC staff that is obtained through their work in the communities.”
12

13 **QUESTION:**

- 14
15 a) With respect to YEC’s statement that “higher forecast sales in 2020 reflect colder
16 than normal weather”, what is the time period used by YEC to determine “normal
17 weather”?
18
19 b) With respect to YEC’s statement that higher forecast sales in 2020 reflect modest
20 growth in the total number of customers, please provide the number of customers
21 served by AEY and YEC for the last ten years, along with forecast customer counts
22 for 2020 and 2021.
23
24 c) What input from YEC staff was obtained from work in the communities?
25
26 d) Please provide tables showing actual and forecast residential sales for the past
27 ten years, both with and without demand side management. In your response,
28 please comment on the YEC’s residential sales forecasting accuracy for those
29 years.
30

31 **ANSWER:**

32
33 **(a)**

34
35 The time period used by YEC to determine “normal weather” is ten years. YEC uses the
36 Environment Canada Canadian Climate Normal for Whitehorse Airport found at the link
37 below:

https://climate.weather.gc.ca/climate_normals/results_1981_2010_e.html?searchType=stnProv&stProvince=&txtCentralLatMin=0&txtCentralLatSec=0&txtCentralLongMin=0&txtCentralLongSec=0&stnID=1617&dispBack=0

YEC uses the daily average monthly temperature and the most current data set is 1981 to 2020. The analysis is updated once every 10 years (industry standard) and includes a full statistical update of temperatures and Heating Degree Days.

(b)

AEY customers on the grid are supplied by YEC through Wholesales, and are not included in YEC residential customers. Average annual YEC residential customers for the last ten years, along with forecast counts for 2021 are as follows:

Table 1: Summary of Average Annual YEC Residential Customers (2011-2021)

Year	Customers
2011	1515
2012	1529
2013	1559
2014	1561
2015	1588
2016	1609
2017	1653
2018	1689
2019	1730
2020	1778
2021	1780

(c)

As noted in YUB-YEC-1-15 (a), Finance reaches out to staff in each community who provide Finance with an update of activity in the area (for example, new residential projects and commercial activity). YEC does not have a record of specific adjustments that were tied to this information.

1 (d)

2
3 Below is a table showing actual and forecast (annual budgeted) residential sales
4 generation for the past 10 years. Sales are not calculated with or without demand side
5 management. YEC's forecasting accuracy is very strong as evidenced by 4 years being
6 below business plan and 6 years being above business plan.

7 **Table 2: Actual and Forecast Residential Sales**

Year	Forecast (MWh)	Actuals (MWh)
2011	11,601	12,710
2012	12,325	13,102
2013	12,639	13,385
2014	13,596	13,327
2015	13,625	13,121
2016	13,441	13,390
2017	13,480	14,965
2018	14,607	15,626
2019	15,705	15,384
2020	16,730	15,646

REFERENCE: Application, Tab 2, page 2-8, line 5

ISSUE: Sales for Lighting

QUOTE: “Actual firm retail sales for lighting were 235 MW.h in 2018, 178 MW.h in 2019 and forecast to remain at 178 MW.h for 2020 and for the 2021 test year. The decrease in lighting sales in 2019 was primarily due to conversion to LED street lights.”

QUESTION:

- a) Please provide the quantity, type and power consumption of all lights for the past ten years.

ANSWER:

(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.

Year	Street Lights		Sentinel Lights		Total	
	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

REFERENCE: Application, Tab 2, page 2-8, line 21

ISSUE: Loses

QUOTE: "Total generation is based on the sum of total sales plus losses. The 2018 approved forecast losses were 8.8%. Actual losses were 9.2% in 2018 and 2019, and full year forecast for 2020 is 9.1%. The losses are forecast at 8.8% for the 2021 test year which is the same as the 2018 approved level in the 2017/18 GRA and also within the range of historical losses for last three years, from 2017 (at 8.1%) through 2018 and 2019 (each at 9.2%)."

QUESTION:

- a) Please provide the detailed working document, with formulas intact, used to determine and justify YEC's forecast for losses in the test year.

ANSWER:

(a)

The losses for the 2021 test year are forecast at 8.8% which is the same as the 2018 approved level in the 2017/18 GRA. It is also within the range of historical losses for the last three years as illustrated in Table 1 below. Attachment 1 to this response provides an excel copy of the calculations.

Table 1: Line Losses for 2017, 2018 and 2019 Years (GWh)

Year	Firm Generation (GWh)	Firm Sales (GWh)	Losses (GWh)	Losses as % of Sales
2017	446.5	413.2	33.3	8.1%
2018	450.1	412.2	37.9	9.2%
2019	440.7	403.5	37.2	9.2%
Average				8.8%

Table 1: Line Losses for 2017, 2018 and 2019 Years

Year	Firm Generation (GWh)	Firm Sales (GWh)	Losses (GWh)	Losses as % of Sales
2017	446.5	27.3	419.2	1538.3%
2018	450.1	27.6	422.5	1532.4%
2019	440.7	27.5	413.2	1502.0%
Average				1524.3%

1 **REFERENCE:** Application, Tab 2, page 2-11, line 23

2
3 **ISSUE:** Thermal Generation Forecast and Weather

4
5 **QUOTE:** "For the 2020 full year forecast actual LNG is forecast to be about 74%
6 of the total thermal due to colder-than-normal weather (specifically
7 January 2020 was colder than normal weather) that resulted in high
8 loads with diesel generation being required to supply baseload energy
9 as LNG units were running at max output."
10

11 **QUESTION:**

12
13 a) Please explain what constitutes "colder-than-normal weather" and how it is
14 determined (e.g. coldest temperature during the month, average temperature,
15 number of days below a certain temperature).
16

17 b) Please outline the performance of the LNG facility in 2020, including any
18 mechanical issues or outages, and any increased costs resulting from failures due
19 to burning diesel required to make up for any loss or shortfall in LNG output.
20

21 **ANSWER:**

22
23 **(a)**

24
25 Yukon Energy historically uses a peak design mean temperature of -35 deg C at
26 Whitehorse Airport. On Jan 13, 2020, the daily average temperature at the Whitehorse
27 Airport was -37.8 deg C and this resulted in a 'colder-than-normal' or colder than design
28 event.
29

30 **(b)**

31
32 Mechanical issues include premature wear of valves, failures of exhaust valves, failures
33 of heat exchangers and premature wear of engine block. There was 2.6 GWh of added
34 diesel generation due to LNG outages. The net increase in fuel cost due to burning

- 1 diesel was \$303,160 based on the 2018 approved GRA forecast average fuel costs per
- 2 kWh for diesel (\$0.2633/kWh) and LNG (\$0.1467/kWh).¹

¹ LNG costs of \$381,420 at 14.67 c/kWh, compared to Diesel costs of \$684,580 at 26.33 c/kWh, results in difference of \$303,160.

1 **REFERENCE:** Application, Tab 2, page 2-12, footnote 14

2
3 **ISSUE:** Hydro Generation

4
5 **QUOTE:** "This reflects 37 MW at Aishihik, 6.5 MW at Mayo and 27 MW at
6 Whitehorse. The Mayo GS dependable capacity has been reduced
7 from 9 MW assumed in the 2017-18 GRA to reflect updated winter
8 downstream flow restrictions and Whitehorse GS increased from 24.5
9 MW to 27 MW to reflect increased winter max flows."

10
11 **PREAMBLE:** YEC's website states: "The Mayo A hydro facility has served Yukoners
12 since 1951. It was developed to supply electricity to the United Keno
13 Hill Mine at Elsa, about 45 kilometres north of Mayo. It also generates
14 power for other Yukon communities via Yukon Energy's transmission
15 system.

16
17 The Mayo B hydro project, completed in 2011, involved building a new
18 powerhouse 3.7 kilometres downstream from the existing hydro plant
19 (Mayo A). This increased our capacity to generate additional renewable
20 energy at the existing site from five megawatts to 15 megawatts,
21 without the need for a new dam or reservoir.

22
23 Together the two plants can supply electricity to as many as 7,000 non
24 electrically heated homes."

25
26 **QUESTION:**

27
28 a) Please explain the changes, and when the changes occurred, which led to the
29 increased winter max flows for Whitehorse GS.

30
31 b) Please provide the dependable capacity and the energy generated per year of
32 Mayo A and Mayo B (each shown separately) from the time period previous to the
33 re-runnering of Mayo A.

34
35 c) Please compare the results provided in part (b) to the expected performance of
36 Mayo A and B as stated in the preamble to this question. Please explain any
37 variances.

1 d) If there is a deviation between the expected performance of Mayo A and B and
2 actual performance, please explain if this will be an issue with the re-runnering
3 project for the Whitehorse GS. If it will not be an issue, then explain how the issue
4 will be avoided.

5
6 **ANSWER:**

7
8 **(a)**

9
10 The maximum flows for Whitehorse GS are limited to the ice conditions in Marwell area in
11 Whitehorse. After reviewing the past data, Yukon Energy was able to increase the
12 maximum allowable flow without causing problems in Marwell.

13
14 **(b) to (d)**

15
16 Mayo Generation has not recently been re-runnered.¹ Dependable capacity at Mayo has
17 therefore not been recently affected by re-runnering.

18
19 Mayo was expanded in 2011 with a new plant (Mayo B) which has a higher head and
20 efficiency from Mayo A. The dependable winter capacity from the combined Mayo facility
21 was always expected to be well under the 15 MW of installed capacity. As noted in the
22 Application, Mayo dependable winter capacity in the 2017-18 GRA was estimated at 9
23 MW.

24
25 In recent years a Mayo River ice protocol has been implemented to reduce the risk of
26 flooding in the town of Mayo due to ice jams. This protocol limits the flow to 15 CMS
27 (6.5MW) until an ice cover is formed. Once the Ice is formed the river flows can increase
28 by 0.5CMS every 2 days to the maximum output.

29
30 Without the flow restriction, Mayo has a 9MW dependable capacity. With the flow
31 restriction Mayo can provide 6.5MW of N-1 dependable capacity. YEC does ramp up
32 Mayo to maximum flows by the end of each winter.

¹ Mayo B is a new facility developed in 2011. Mayo was developed in 1951, and two units were re-runnered in 2001.

1 **REFERENCE: Application, Tab 2, page 2-13**

2
3 **ISSUE: Dependable Capacity Requirements**

4
5 **QUESTION:**

6
7 a) In YEC's view, are revisions to the loss of load expectation and emergency N-1
8 standard warranted? Please explain why or why not.

9
10 **ANSWER:**

11
12 **(a)**

13
14 The loss of load expectation and emergency N-1 standards were first developed as part
15 of the 2006 Resource Plan, and were reconfirmed with the 2016 Resource Plan. YEC is
16 not aware of any basis to seek revisions to these standards at this time. The N-1
17 dependable capacity standard continues to be very relevant for non-industrial load
18 reliability during winter months on this isolated Yukon grid. Consideration of an N-1
19 contingency is standard in the industry.

1 **REFERENCE:** Application, Tab 2, Table 2-1 and Table 2-2, pages 2-16 and 2-17

2
3 **ISSUE:** Additional Historical Information

4
5 **QUESTION:**

6
7 a) Please provide new versions of Table 2-1 and Table 2-2 that include the previous
8 ten years.

9
10 **ANSWER:**

11
12 **(a)**

13
14 Please see Attachment 1 to this response for the requested information.

Table 2.1
Summary of Customers, Energy Sales and Revenues

Line No.	Description	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	Forecast
											2021
1	Residential										
2	Customers	1,529	1,559	1,561	1,588	1,609	1,653	1,689	1,730	1,756	1,780
3	Sales in MWh	13,102	13,385	13,327	13,121	13,390	14,965	15,626	15,384	16,730	16,210
4	MWh sales per customer	8.6	8.6	8.5	8.3	8.3	9.1	9.3	8.9	9.5	9.1
5	Revenue (\$000s)	1,927	1,943	1,938	1,913	1,956	2,203	2,262	2,262	2,413	2,384
6	Cents per KWh	14.7	14.5	14.5	14.6	14.6	14.7	14.5	14.7	14.4	14.7
7	General Service										
8	Customers	464	470	475	480	488	499	506	517	516	514
9	Sales in MWh	22,432	22,283	23,616	24,551	24,994	26,132	27,171	29,148	32,250	32,323
10	MWh sales per customer	48.4	47.4	49.8	51.1	51.2	52.4	53.7	56.4	62.5	62.9
11	Revenue (\$000s)	3,622	3,621	3,894	4,048	4,180	4,350	4,490	4,833	5,351	5,388
12	Cents per KWh	16.1	16.3	16.5	16.5	16.7	16.6	16.5	16.6	16.6	16.7
13	Industrial										
14	Sales in MWh	44,030	40,513	36,302	37,186	41,169	43,419	36,910	27,286	64,856	102,904
15	Revenue (\$000s)	5,083	4,595	3,958	4,159	4,478	4,829	4,378	3,673	7,260	11,535
16	Cents per KWh	11.5	11.3	10.9	11.2	10.9	11.1	11.9	13.5	11.2	11.2
17	Street lights										
18	Sales in MWh	283	281	290	290	256	228	224	168	168	168
19	Revenue (\$000s)	90	89	92	92	88	88	87	82	82	82
20	Cents per KWh	31.7	31.6	31.6	31.6	34.5	38.6	39.1	48.8	48.8	48.8
21	Space lights										
22	Sales in MWh	14	14	14	14	14	12	11	10	10	10
23	Revenue (\$000s)	4	4	4	4	4	3	3	3	3	3
24	Cents per KWh	27.2	26.5	26.6	25.9	26.0	28.6	29.2	26.7	28.1	26.6
25	Total Company - Firm Retail & Ind.										
26	Customers	1,992	2,029	2,036	2,068	2,098	2,152	2,195	2,247	2,272	2,293
27	Sales in MWh	79,861	76,476	73,549	75,162	79,823	84,756	79,941	71,997	114,013	151,614
28	Revenue (\$000s)	10,725	10,252	9,886	10,214	10,705	11,474	11,221	10,853	15,108	19,392
29	Cents per KWh	13.4	13.4	13.4	13.6	13.4	13.5	14.0	15.1	13.3	12.8
30	Wholesale sales										
31	Sales in MWh	310,264	307,927	295,284	297,961	301,207	328,426	332,270	331,495	351,775	343,537
32	Revenue (\$000s)	25,809	25,546	24,503	24,725	24,994	27,253	27,572	27,507	29,190	28,507
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
34	Total Company - Firm										
35	Sales in MWh	390,125	384,403	368,833	373,122	381,030	413,182	412,212	403,491	465,788	495,151
36	Revenue (\$000s)	36,534	35,798	34,388	34,939	35,700	38,727	38,792	38,360	44,298	47,899
37	Cents per KWh	9.4	9.3	9.3	9.4	9.4	9.4	9.4	9.5	9.5	9.7
38	Secondary										
39	Sales in MWh	1,993	3,959	5,415	7,030	4,835	8,385	258	0	0	0
40	Revenue (\$000s)	141	275	410	544	371	470	20	0	0	0
41	Cents per KWh	7.1	6.9	7.6	7.7	7.7	5.6	7.6	0.0	0.0	0.0
42	Total Company										
43	Sales in MWh	392,118	388,363	374,248	380,152	385,865	421,567	412,470	403,492	465,788	495,151
44	Revenue (\$000s)	36,676	36,073	34,798	35,483	36,071	39,196	38,812	38,360	44,298	47,899
45	Cents per KWh	9.4	9.3	9.3	9.3	9.3	9.3	9.4	9.5	9.5	9.7
46	Rider J (\$000s)	1,882	6,288	6,167	6,172	6,342	7,883	13,329	13,842	15,289	15,897
47	Total Sales Revenues¹	38,557	42,360	40,966	41,655	42,413	47,079	52,141	52,203	59,588	63,796
48	Total Sales Revenues excluding secondary sales	38,416	42,086	40,556	41,111	42,042	46,610	52,121	52,203	59,588	63,796

Note:

1. Excludes revenues from other revenues.

Table 2.2
Summary of Energy Balance, Losses, Peak and Load Factor

Line No.	Description	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	Forecast
											2021
	Sales and Losses										
1	Total Energy Sales	392,118	388,363	374,248	380,152	385,865	421,567	412,470	403,492	465,788	495,151
2	Losses - MWh	34,588	35,127	28,076	37,883	32,186	33,987	37,898	37,185	42,193	43,575
3	Losses - %	8.8%	9.0%	7.5%	10.0%	8.3%	8.1%	9.2%	9.2%	9.1%	8.8%
4	Total Generation	426,706	423,490	402,323	418,035	418,051	455,554	450,368	440,676	507,980	538,726
5	Secondary Sales Related Generation	2,168	4,318	5,821	7,731	5,238	9,061	282	0	0	0
6	Firm Load Generation	424,538	419,172	396,502	410,304	412,812	446,493	450,086	440,676	507,980	538,726
	Actual Generation - MWh										
	Hydro Generation										
7	Whitehorse	230,216	221,312	219,243	234,063	232,820	224,583	228,695	233,673	263,231	259,116
8	Aishihik	143,253	137,991	112,095	97,330	100,111	156,857	126,748	97,293	118,792	176,165
9	Mayo	49,736	62,000	69,082	81,123	78,480	59,607	57,610	39,853	54,703	71,201
10	Total Hydro	423,206	421,303	400,421	412,517	411,411	441,048	413,052	370,819	436,725	506,483
11	Wind Turbine	445	277	337	650	509	33	0	0	0	0
12	IPPs	0	0	1	2	3	0	0	0	56	1,983
	Diesel Generation¹										
13	Whitehorse	2,205	840	978	1,672	1,727	3,848	5,518	2,188	13,848	1,870
14	Faro	530	900	338	405	193	281	302	802	889	237
15	Dawson	298	135	223	1,477	938	451	1,279	720	2,936	823
16	Mayo	22	34	26	20	22	39	87	84	748	21
17	Total Diesel	3,055	1,910	1,566	3,574	2,879	4,618	7,186	3,793	18,422	2,951
18	LNG Generation¹	0	0	0	1,295	3,251	9,856	30,130	66,065	52,778	27,309
19	Total Thermal¹	3,055	1,910	1,566	4,868	6,131	14,474	37,316	69,858	71,199	30,260
	Source - %										
20	Hydro Generation	99.2%	99.5%	99.5%	98.7%	98.4%	96.8%	91.7%	84.1%	86.0%	94.0%
21	LNG Generation	0.0%	0.0%	0.0%	0.3%	0.8%	2.2%	6.7%	15.0%	10.4%	5.1%
22	Diesel Generation	0.7%	0.5%	0.4%	0.9%	0.7%	1.0%	1.6%	0.9%	3.6%	0.5%
23	IPP Generation	0.1%	0.1%	0.1%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.4%
	LTA Generation - MWh										
24	LTA Hydro Generation		405,643	390,976	400,055	402,038	433,199	418,695	415,377	438,905	452,437
25	LTA Wind Generation		238	238	238	238	33	0	0	0	0
26	IPP Generation		0	0	0	0	0	0	0	56	1,983
27	LTA Thermal Generation		13,291	5,288	10,011	10,536	13,261	31,391	25,300	69,019	84,306
28	Total LTA Generation		419,172	396,502	410,304	412,812	446,493	450,086	440,676	507,980	538,726
	Peak - MW²										
29	Integrated System	82.2	82.7	76.5	82.1	88.1	91.8	93.0	90.0	103.8	112.7

Notes:

1 Actual thermal generation reflects actual generation required for maintenance, capital, RFID and all other generation, e.g., peaking. Forecast Actual Generation includes peaking, maintenance (diesel of 0.198 GW.h in 2021, and LNG of 0 MW.h) and capital (0.234 GW.h diesel) requirements reflecting short-term hydro generation forecasts.

2 Peak load is one-hour maximum load on the grid (forecasts assume weather normalized temperature).

1 **REFERENCE:** Application, Tab 2, Table 2-2, line 7, page 2-17

2
3 **ISSUE:** Whitehorse Hydro Generation

4
5 **QUESTION:**

6
7 a) Please explain why Whitehorse hydro generation is forecast to decrease from
8 2020 to 2021.

9
10 **ANSWER:**

11
12 **(a)**

13
14 The year 2020 is a partial forecast and part actuals. In 2020, freshet started a month early
15 which increased the generation in May and June. 2021 is based on long-term average
16 inflows and does not assume a similar high-water year such as that experienced in 2020.

1 **REFERENCE:** Application, Section 3.5.1, page 3-27

2
3 **ISSUE:** Cost of debt

4
5 **QUOTE:** "As per Board Order 2018-10, the interest rate is a formulaic approach
6 based on the long-term Canada Bonds rate plus 120 basis points
7 (Government of Canada Long-Term Bond Benchmark at 0.99% as of
8 June 30, 2020)."

9
10 **QUESTION:**

11
12 a) Please provide the long-term Canada Bonds rate as of September 30, 2020 and
13 December 31, 2020.

14
15 **ANSWER:**

16
17 **(a)**

18
19 The long-term Canada Bonds rate as of September 30, 2020 was 1.11%, and as of
20 December 31, 2020 was 1.21%.

1 **REFERENCE:** Application, Section 3.5.2, Return on Common Equity, page 3-27

2
3 **ISSUE:** BCUC Benchmark ROE

4
5 **QUOTE:** "The current BCUC benchmark ROE continues to be 8.75%."

6
7 **QUESTION:**

8
9 a) Please identify the most recent BCUC decision approving a BCUC benchmark
10 ROE of 8.75%. Please identify the date the decision was issued and relevant
11 paragraph(s) and page reference(s) regarding the BCUC benchmark ROE in the
12 response.

13
14 b) Is YEC aware of any generic cost of capital (GCOC) or equivalent proceedings
15 currently before the BCUC? If so, please provide further context.

16
17 **ANSWER:**

18
19 **(a)**

20
21 The current low-risk utility ROE benchmark at 8.75% was approved by the BCUC Order
22 G-75-13¹ effective January 1, 2013. The BCUC by its Order G-129-16² reaffirmed the
23 benchmark ROE at 8.75% and stated that it remains in effect until otherwise determined
24 by the BCUC.

25
26 **(b)**

27
28 Yukon Energy is aware that the BCUC issued a notice of Initiating a Generic Cost of
29 Capital Proceeding by letter dated January 18, 2021.

¹ 1 BCUC, Generic Cost of Capital, Order G-75-13 dated May 10, 2013, page 3, paragraph 2
https://www.bcuc.com/Documents/Proceedings/2013/DOC_34699_BCUC-GCOC-Stage1DecisionWEB.pdf
[accessed on February 12, 2021].

² 2 FortisBC Energy Inc. Application for its Common Equity Component and Return on Equity for 2016,
Order G-129-16 dated August 10, 2016, page 1, paragraphs 2 and 5
<https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/169143/index.do> [accessed on February 12,
2021].

- 1 However, it is unlikely the new benchmark ROE will be approved before YEC's 2021 GRA
- 2 proceeding is completed. The 2013 Generic Cost of Capital Proceeding was initiated in
- 3 February 2012 and final order by the BCUC was issued in May 2013, i.e., it took more
- 4 than a year to complete the review.

1 **REFERENCE:** **Application, Section 3.2, page 3-3**

2
3 **ISSUE:** **Fuel and Purchased Power**

4
5 **QUOTE:** “As reviewed in Section 2.3.2, Yukon Energy's annual fuel costs are
6 based on forecast hydro and thermal generation determined on a long-
7 term average basis. This analysis applies only to firm load
8 requirements.”

9
10 **QUESTION:**

- 11
12 a) Please confirm that the long-term average forecast hydro and thermal generation
13 used in the forecast includes industrial load. If not included, please explain.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Confirmed that the forecast 2021 firm load used to determine the 2021 long-term average
20 forecast hydro and thermal generation used in the Application forecast in Table 2.2
21 includes the forecast industrial load for 2021.

1 **REFERENCE:** Application, Section 2.3.2, page 2-11

2
3 **ISSUE:** Diesel and LNG Thermal Generation

4
5 **QUOTE:** “The forecast 2021 LTA thermal generation for the Application is 84.3
6 GW.h. The forecast for the test year is based on proposed updates to
7 the determination of LTA annual hydro availability for the current GRA
8 as outlined in Appendix 2.1...”

9
10 **QUESTION:**

- 11
12 a) Relative to LTA water flows, is YEC expecting water levels to be higher than LTA
13 for 2021 and therefore higher than LTA hydro generation for 2021? Please explain
14 why or why not.

15
16 **ANSWER:**

17
18 **(a)**

19
20 Based on available information at the time of drafting, YEC expects water levels to be
21 higher than LTA. Table 2.2 in the Application shows forecast ST 2021 hydro generation at
22 506.5 GWh, and shows LTA hydro generation for 2021 at the lower level of 452.4 GWh.
23 The ST forecast reflects conditions in the fall of 2020, following high inflows to Aishihik
24 and Mayo during the preceding summer that reversed the prior year’s low water
25 conditions.

26
27 As shown in prior years, water availability forecasts provided in the fall for the following
28 year are subject to review in following spring and again during the following summer – and
29 can display material changes as actual conditions unfold. For example, snowpack
30 measurements are not available until Q2; these measurements can have a significant
31 impact on the inflow expectations for the reservoirs.

1 **REFERENCE:** **Appendix A to Board Order 2018-10, paragraphs 76 and 77;**
2 **Application, Section 3.2, page 3-3; Application - Overview, pages**
3 **2 to 5; Application, Section 1.1, Need, Context and Proposed**
4 **Approach for 2021 GRA, page 1-3**

5
6 **ISSUE:** **Short-term Versus Long-Term Average Hydro Generation**
7 **Forecast**

8
9 **QUOTE:** From Appendix A to Board Order 2018-10:

10
11 “76. The Board recognizes that each method of forecasting, being LTA
12 or ST, has advantages and disadvantages for GRA purposes. As
13 submitted by YEC, during a period of favorable water conditions an ST
14 hydro generation forecast would have a lower revenue requirement
15 than one based on an LTA hydro generation forecast. The converse
16 holds for periods when water conditions are unfavorable. With ST hydro
17 generation forecasts, the impacts on revenue requirements, rate
18 changes and resulting bills will change with each GRA depending on
19 changes in ST water conditions and forecasts. LTA hydro generation
20 forecasts will tend to be more stable for revenue requirements from
21 GRA to GRA. However, items affected by this forecast may not be as
22 accurate or representative of current GRA circumstances. For the
23 current GRA, major differences in ratepayer bill impacts with ST versus
24 LTA hydro generation forecasts are likely to be limited if the current rate
25 stabilization mechanism is retained. The Board accepts that short-term
26 thermal generation may vary materially between GRAs due to changes
27 in actual water conditions. LTA hydro generation forecasts are based
28 on available historic annual water records as well as current grid
29 conditions and generation facilities to indicate ongoing average hydro
30 generation capability over a longer period of the hydro asset life.

31
32 77. Given the above-noted advantages and disadvantages of LTA and
33 ST hydro generation forecasts, the Board finds that, for purposes of this
34 proceeding, it will not use the ST forecast for forecasting levels of hydro
35 electric generation and thermal generation nor direct its use for future
36 GRAs. In determining the revenue requirements for these and future
37 test years, the Board is focusing on the reasonableness of the forecasts

1 and forecasting accuracy. Further, the onus is on YEC to adequately
2 explain any variance between actual results and its forecast amounts.
3 For these reasons, the Board directs YEC in future GRA filings to show
4 actual hydro and thermal generation results when comparing previous
5 and forecast test years.” (footnotes removed; underlining added)
6

7 From page 3-3 of the Application:
8

9 “Fuel and Purchased Power costs as set out in Table 3.2 for the 2021
10 test year increase to \$15.897 million (from \$2.677 million in 2018
11 approved), reflecting primarily both increased load and higher fuel
12 prices, as well as added purchased power cost [\$0.314 million] for
13 Independent Power Production (IPP).”
14

15 From page 2 of the Application:
16

17 “Yukon ratepayers have also experienced large bill increases in late
18 2019 and many are now experiencing ongoing disruptions due to the
19 COVID-19 pandemic.”
20

21 From page 1-3 of the Application:
22

23 “Yukon ratepayer bills – Concurrent with Yukon Energy’s dilemma,
24 Yukon ratepayers now are experiencing ongoing disruptions from the
25 impacts of COVID-19. Any material increases to ratepayer bills at this
26 time (and in the near future) would raise concerns.”
27

28 **PREAMBLE:** There have been instances in the past where LTA was not used to
29 determine YEC’s thermal generation forecast costs. Most recently, this
30 occurred when the Board directed YEC to use actual thermal costs for
31 the 2017 test year.
32

33 **QUESTION:**
34

35 If water levels and the concomitant hydro generation are expected to be higher in 2021,
36 for customer rate relief, should YEC utilize a ST hydro forecast thus reducing the upward

1 pressure of increased thermal generation costs for this test period? In the response,
2 please address the following:

3
4 a) For YEC's revenue requirement forecasts, the Board focuses on reasonableness
5 of the forecasts and the forecasting accuracy;

6
7 b) YEC, in the past, has stated that its LTA forecast cannot be retroactively verified;

8
9 c) If ST hydro forecasts are used, what the impact would be on required revenue;
10 and

11
12 d) The ongoing impacts of COVID-19 and related costs pressures on Yukon
13 ratepayers.

14
15 **ANSWER:**

16
17 **(a) through (d)**

18
19 YEC does not recommend using a short-term (ST) hydro forecast for the 2021 GRA as a
20 means for customer rate relief that reduces "the upward pressure of increased thermal
21 generation costs for this test period". The 2021 GRA already proposes specific measures
22 that will prevent any material increase in customer bills during 2021 in recognition of
23 ongoing impacts of COVID-19 and related cost pressures on Yukon ratepayers (see
24 Sections 1.1 and 4.5 of Application). Increased thermal generation costs outlined in the
25 Application are also already being fully funded by increased revenues from higher loads
26 and/or by Rider F adjustments for higher fuel prices (see Table 1-2 in Application).

27
28 Long-term (LT) hydro generation forecasts have been adopted to provide a consistent and
29 stable forecasting approach that avoids the uncertainties and instabilities associated with
30 ST hydro generation forecasts in the context of GRA rate setting procedures, with their
31 extended time periods required from preparing an initial GRA filing to the receipt of final
32 Board approval of a compliance filing. Rates based on short term hydro generation are
33 inherently more volatile; that is, any rate relief offered in 2021 due to excess water could
34 quickly become material rate increases in future years or financial burden to the utility for
35 a risk factor that is beyond its control when water conditions return to "normal" or below.

1 Experience (including extensive review during the 2017-18 GRA proceedings) has
2 demonstrated the inherent inaccuracy of ST hydro generation forecasts made in the
3 summer / fall of one year as regards water availability in the next calendar year. Outcomes
4 can and do change radically during any given summer period. Although LTA hydro
5 forecasts cannot be retroactively verified, their stability and predictability relative to ST
6 hydro forecasts has been well established.

7
8 The Board directed use of actual thermal results for the 2017 test year simply in
9 recognition that these results were already known at the time of the Board's decision in
10 December 2018.

11
12 Adoption of the 2021 ST hydro forecast developed around mid-2020 and provided in Table
13 2.2 of the Application would increase forecast test year hydro generation (and reduce
14 forecast test year thermal generation) by 54.046 GWh; based on the forecast 2021 fuel
15 prices in Table 3.2-1 and the assumed 90% LNG/ 10% diesel fuel mix, the resulting
16 revenue requirement reduction would approximate \$9.932 million or 64% of the
17 Application's forecast fuel costs of \$15.530 million and 90% of the Application's forecast
18 revenue shortfall (see Table 4.1 of Application). This reduction highlights the extent to
19 which test year forecast fuel costs become subject to high instabilities, with potentially very
20 wide ranging changes, as soon as ST hydro forecasts are considered for GRA rate setting
21 purposes. The ST revenue requirement reduction for 2021 from such a change would
22 establish with certainty the need for similarly large offsetting increases to future GRA
23 revenue requirements simply to restore LTA hydro generation forecast requirements.

1 **REFERENCE:** **Application - Overview, Summary of Requested Orders, pages 2**
2 **to 6**

3
4 **ISSUE:** **Low Water Reserve Fund (LWRF) Term Sheet**

5
6 **QUOTE:** “Yukon Energy acknowledges that it has been directed in Board Order
7 2019-08 to review and update the LWRF Term Sheet in this GRA, and
8 to provide any further views on its risk and ratepayer risks that YEC
9 considers relevant. Yukon Energy has been required, given COVID 19
10 conditions and other factors related to minimizing any bill impacts on
11 ratepayers, to focus first on completion and filing of its 2021 forecast
12 revenue requirement and rates Application. Yukon Energy is working
13 to complete and file an updated LWRF Term Sheet with the Board as
14 soon as feasible.”

15
16 **QUESTION:**

- 17
18 a) Without a LWRF term sheet, how is YEC able to determine its LTA thermal
19 generation requirements? Please explain.
20
21 b) Without a LWRF term sheet, how is YEC able to determine any transaction or
22 amounts with respect to the LWRF deferral account? Please explain.
23

24 **ANSWER:**

25
26 **(a)**

27
28 LTA thermal generation is generated based on the YECSIM long term forecasting model,
29 represented in the application by Table 2.1-1 in Appendix 2.1. Table 2.2 in Tab 2 includes
30 the LTA thermal generation forecast for the test year.
31

32 **(b)**

33
34 An updated LWRF term sheet, approved by the Board, is required to determine any
35 transactions or amounts with respect to the LWRF deferral account following the end of
36 the 2021 test year. These transactions do not affect the determination of revenue
37 requirement or rates in this application.

1 **REFERENCE:** Application, page 6; Application, LWRF, Section 3.6.3, Tab 3,
2 pages 3 30 to 3-31
3

4 **ISSUE:** Low Water Reserve Fund (LWRF)
5

6 **QUOTE:** “Yukon Energy has been required, given COVID 19 conditions and
7 other factors related to minimizing any bill impacts on ratepayers, to
8 focus first on completion and filing of its 2021 forecast revenue
9 requirement and rates Application. Yukon Energy is working to
10 complete and file an updated LWRF Term Sheet with the Board as soon
11 as feasible.”
12

13 **QUESTION:**
14

15 a) Please state when an updated LWRF Term Sheet will be made available. If a
16 precise date is not available, please provide YEC’s best estimate.
17

18 b) How can the Board or interveners test the reasonableness of the LWRF in the
19 absence of an updated term sheet? Please explain.
20

21 **ANSWER:**
22

23 **(a) and (b)**
24

25 Yukon Energy is working to provide an updated LWRF Term Sheet in March, along with
26 related LWRF Annual Reports for 2019 and 2020.
27

28 An updated Term Sheet is required for determining dollar impacts to the LWRF deferral
29 account when evaluating actual 2021 results as defined by the fund rules. The LWRF
30 Term Sheet, however, does not have any impact on the 2021 GRA revenue requirement
31 forecasts.

1 **REFERENCE:** Application, Tab 2, Table 2-2, page 2-17, lines 13-17; Application,
2 Tab 3, page 3-3, line 2
3

4 **ISSUE:** Diesel Generation
5

6 **QUOTE:** "The increase from 2018 to 2021 reflects higher production and labour
7 costs, including \$3.834 million costs for diesel rentals required to meet
8 the N-1 single contingency capacity planning criteria (no diesel rental
9 costs were included in the 2018 approved costs)."
10

11 **QUESTION:**
12

- 13 a) Within the context of forecast reductions in thermal generation from 2020 to 2021
14 as shown in Table 2-2, why is YEC forecasting an additional \$3.834 million for
15 rental of diesel generators?
16

17 **ANSWER:**
18

19 **(a)**
20

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

1 **REFERENCE: Application, Section 3.2, Fuel and Purchased Power, page 3-3**

2
3 **ISSUE: Thermal Generation Mix**

4
5 **QUOTE:** "The test year long-term average forecasts for hydro generation have
6 been updated to reflect new information, and forecast long-term
7 average thermal requirements for the test years are assumed to be
8 supplied with a combination of 90% LNG and 10% diesel generation,
9 the same ratio as approved in the 2018 GRA."

10
11 **QUESTION:**

- 12
13 a) Please provide the actual thermal generations ratios/percentages for each year
14 since YEC has been utilizing LNG as a fuel source.
15
16 b) In regard to the response to part (a), please explain how an LTA of 90% LNG and
17 10% diesel generation was derived and determined to be accurate for use in this
18 proceeding.
19
20 c) Does YEC take on all risk with respect to any changes between actual and forecast
21 results for changes in the thermal generation fuel ratios?
22

23 **ANSWER:**

24
25 **(a)**

26
27 Please see Table 1 below that shows actual thermal generations by source and
28 percentages for 2015 (the first year with partial LNG generation) through 2019, and
29 forecast for 2020 and 2021. Table 1 also shows annual thermal generation as a percent
30 of LTA thermal generation, highlighting the extent that annual hydro generation is below
31 or in excess of LTA hydro generation.

1

Table 1: Thermal Generation for 2015-2021 Years

Annual Thermal Generation - MWh	2015 Actual ²	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Diesel Generation	3,574	2,879	4,618	7,186	3,793	18,422	2,951
LNG Generation	1,295	3,251	9,856	30,130	66,065	52,778	27,309
Total Thermal ¹	4,868	6,131	14,474	37,316	69,858	71,199	30,260
Thermal Generation Source - %							
Diesel Generation	73%	47%	32%	19%	5%	26%	10%
LNG Generation	27%	53%	68%	81%	95%	74%	90%
Annual Thermal % of LTA		58%	103%	119%	276%	103%	36%

Notes:

1 Actual thermal generation reflects actual generation required for maintenance, capital, RFID and all other generation, e.g., peaking. Forecast Actual Generation includes peaking, maintenance (diesel of 0.198 GW.h in 2021, and LNG of 0 MW.h) and capital (0.234 GW.h diesel) requirements reflecting short-term hydro generation forecasts.

2 Partial year generation from LNG in 2015.

2

3

4 **(b)**

5

6 Since LNG was added as a generation source in 2015, Yukon Energy has used a split of
7 90% LNG and 10% diesel generation in GRA's based on the expected thermal mix
8 applicable to the LTA thermal generation estimates rather than basing the thermal mix on
9 the short-term water conditions that may occur in any specific year. The LTA thermal mix
10 is the ratio applicable to the LTA thermal forecast adopted for rate setting in GRAs.

11

12 The 90/10 LNG/diesel ratio was adopted based on expectation that LNG would be heavily
13 used during drought or low water conditions (i.e., LNG share would exceed 90%). This
14 very high usage tends to dominate the long-term thermal generation estimates over all
15 water conditions. That is, while diesel would be used for peaking, emergencies and other
16 specific uses such that diesel's share of thermal in many years with average or higher-
17 than-average water conditions may well significantly exceed 10%, the impact of high LNG
18 use in low water conditions favors the average mix of 90:10 on LTA basis.

19

20 This theory is proven out in in Table 1 above; the actual LNG generation was about 53%
21 of the total thermal generation in 2016, increasing to 68% in 2017, 81% in 2018 and 95%

1 in 2019.¹ This percentage has been below 90% when hydro generation was similar to or
2 in excess of LTA, and was above 90% in 2019 when hydro generation was well below
3 LTA.

4
5 As noted, higher LNG generation numbers in 2019 reflect water conditions materially
6 below LTA. For the 2020 full year forecast actual LNG is forecast to be about 74% of the
7 total thermal due to colder-than-normal weather (specifically January 2020 was colder
8 than normal weather) that resulted in high loads with diesel generation being required to
9 supply baseload energy as LNG units were running at max output. For the 2021 test year
10 actual LNG is currently expected to be about 90% of the total thermal.

11
12 The 90/10 ratio has been confirmed to be reasonable ratio for the 2021 test year based
13 on actual results for 2018 and 2019 [average for all thermal in 2018 and 2019 is 90% LNG
14 and 10% diesel]. YEC has no reason to believe there should be a change at this time to
15 the 90% LNG/10% diesel for the LTA thermal split purposes under LTA water conditions.

16
17 **(c)**

18
19 YEC does not take on all risk with respect to any changes between actual and forecast
20 results for changes in the thermal generation fuel ratios.

21
22 The “forecast” 90/10 LNG/diesel fuel mix in each GRA is intended to reflect LTA fuel mix
23 as reviewed in “b” above, and does not forecast actual fuel mix. In contrast, actual fuel mix
24 in any year reflects actual water availability and hydro generation, and can therefore vary
25 materially from the LTA fuel mix.

26
27 YEC’s final thermal generation costs for each fiscal year are determined through the
28 LWRF deferral account determinations after the end of the calendar year. YEC’s last
29 LWRF Term Sheet filed in December 2019 set YEC’s final fiscal year expense for the total
30 expected thermal generation (i.e., YEC expense after all transfers) to provide 90% LNG
31 and 10% diesel mix, subject to the constraint (when setting the LWRF based on actual
32 load) that the LNG share of any transfer into or out of the LWRF cannot exceed 100%. In
33 practice, this constraint could result in YEC’s final expense diesel share exceeding 10%.

¹ As noted on page 2-11 of the Application, the numbers slightly inflate diesel share due to inclusion of thermal generation for capital projects and RFID, i.e., LNG share was 83% of net thermal generation excluding capital and RFID loads in 2018 (versus 81% in Table 1) and 97% in 2019 (versus 95% in Table 1).

1 **REFERENCE: Application, Section 3.2, Fuel and Purchased Power, page 3-5**

2
3 **ISSUE: Forecast Thermal Costs – LNG**

4
5 **QUOTE:** “Forecast LNG delivered price to Yukon Energy's Whitehorse thermal
6 facility for the 2021 test year is \$0.4824 per litre, which reflects the
7 expected average delivered LNG cost. This forecast for LNG cost is
8 based on the results of a public competitive tender process completed
9 in late 2019 for liquefaction and shipping costs and current market price
10 for commodity value. Yukon Energy forecasts average efficiency for
11 LNG generation of 2.66 kW.h/litre, which is the average efficiency
12 based on actual results for 2019. The resulting forecast LNG cost is
13 \$0.1814/kW.h. The approved 2018 LNG price was \$0.1467/kW.h.”
14

15 **QUESTION:**

- 16
17 a) Please explain why a 2020 competitive tender process was not used to determine
18 the forecast delivered price.
19
20 b) Please provide a breakdown and reasons for the increase in LNG costs from
21 \$0.1467/kWh to \$0.1814/kWh.
22
23 c) Please explain why only a 2019 average efficiency was used for LNG generation.
24
25 d) Please include the fuel price forecasts for LNG and diesel from the Part 3 LNG
26 proceeding in 2014 and compare with actuals.
27

28 **ANSWER:**

29
30 **(a)**

31
32 The competitive tender process completed in 2019 was for 4 supply years commencing in
33 2020 and subject to minimum supply volumes. Prices for liquefaction and transport are
34 locked in for each year based on the winning bid. Commodity price fluctuates based on
35 an established market reference (NGX Alberta).

(b) and (c)

Please see Table 1 that provides a breakdown of LNG fuel cost components for 2017/18 GRA and 2021 GRA. The LNG fuel cost increase is mostly due to increase in transportation costs. Based on the competitive tender process completed in 2019, the prices for liquefaction remain unchanged from 2021 through 2023 [excluding the commodity price which fluctuates based on market price], while transportation cost reduces in 2023 by about 27% compared to the cost for 2021 [reduces to \$0.159/l in 2023 compared to \$0.218/l as shown in table below].

Table 1: LNG Fuel Cost Comparison

	2017/18 GRA \$/L	2021 GRA \$/L
Liquifaction [inc. commodity cost]	\$0.228	\$0.264
Transportation	\$0.149	\$0.218
	<u>\$0.377</u>	<u>\$0.482</u>
Efficiency, kW.h/litre	2.57	2.66
LNG fuel cost, \$/kW.h	\$0.1467	\$0.1814

Fuel efficiency for LNG and diesel for the 2021 GRA is in each case based on actual average results for 2019, which is the last full year with actual information at the time of filing of the application. The fuel efficiency for LNG improved from 2.57 kW.h/litre in 2017/18 GRA to 2.66 kW.h/litre in 2021 GRA. The forecast average efficiency of 2.66 kW.h/litre is the average efficiency based on actual results for 2019.

(d)

The Application for an Energy Project Certificate and An Energy Operation Certificate Regarding the Whitehorse Diesel-Natural Gas Conversion Project [LNG Part 3 application] filed on December 9, 2013 assumed LNG fuel cost at \$0.135/kW.h, including commodity cost at \$0.038/kW.h, liquefaction costs at \$0.053/kW.h and transportation cost at \$0.044/kW.h.

The transportation cost in the application assumed that the LNG haul from Calgary with A-Train with a cost of \$5.16/MMBtu which was based on a cost estimate of \$4.37/MMBtu plus approximately 18% increase for potential underutilization of equipment for initial YEC requirements from Calgary.

1 During the interrogatory process, YEC provided an update to the transportation costs to
2 reflect the need to secure LNG from FortisBC's LNG facility, higher assumed fuel
3 consumption per mile for the haul, higher hourly labour costs, increased unload time at
4 Whitehorse, and reduction in assumed operating days per year.¹ YEC's update to YUB-
5 YEC-1-4 filed March 27, 2014 estimated LNG delivered costs from the FortisBC LNG
6 facility in 2015 at \$0.156/kW.h assuming Tridem units for transportation.

7
8 For the 2021 GRA forecast cost of liquefaction is \$0.082/kW.h plus \$0.017/kW.h
9 commodity cost and \$0.082/kW.h transportation cost. In 2021 GRA the combined cost for
10 liquefaction and commodity at \$0.099/kW.h compared to \$0.091/kW.h in LNG Part 3
11 application and \$0.089/kW.h in 2017/18 GRA; while transportation cost increased to
12 \$0.082/kW.h in 2021 GRA compared to \$0.044/kW.h in LNG Part 3 application and
13 \$0.058/kW.h in 2017/18 GRA.

14
15 The diesel fuel cost in the LNG Part 3 application was \$0.246/kW.h compared to
16 \$0.2633/kW.h in 2017/18 GRA and \$0.2051/kW.h in 2021 GRA. As indicated in the 2021
17 GRA application the diesel fuel prices are as of July 1, 2020 and reflect lower fuel prices
18 during 2020 in response to oil market conditions and COVID-19.

¹ Response to YUB-YEC-1-44 during the review of the Application for an Energy Project Certificate and An Energy Operation Certificate Regarding Whitehorse Diesel-Natural Gas Conversion Project.

1 **REFERENCE:** Application, Section 3.2, Fuel and Purchased Power, page 3-6

2
3 **ISSUE:** Purchase Power Costs

4
5 **QUOTE:** "The purchase cost for the IPPs in 2021 is assumed at \$0.1583/kW.h
6 based on the latest approved thermal fuel cost for YEC in its 2017/18
7 GRA. Total IPP purchase cost is forecast at \$0.314 million for 2021."
8 (footnote removed)

9
10 **QUESTION:**

- 11
12 a) Why are the purchase costs from intermittent IPPs in 2021 based on the forecast
13 thermal fuel cost for YEC?
14
15 b) Given the IPPs currently in place, is the expected purchase of 1.983 GWh of
16 energy likely to occur? Please explain why or why not.
17
18 c) Has there been discussion of variable rates for IPPs that would recognize the
19 increased value of winter generation?
20

21 **ANSWER:**

22
23 **(a)**

24
25 Purchase prices applicable to IPPs are set according to applicable Standing Offer Rules.
26 The footnote removed from the quote explained that Standing Offer Rules, Section 42(a)
27 state that "the Base Fuel Price is to be equal to the YEC's average blended fuel price per
28 kWh for thermal generation most recently approved by the YUB before the date on which
29 the EPA takes effect." Accordingly, the purchase price for the IPPs in 2021 is assumed as
30 stated in the above quote.

31
32 Furthermore, section 3(2) of OIC 2019/25 as provided in Tab 11 of the Application provides
33 the same direction regarding the price paid by YEC for a kWh of electricity under an on-
34 grid electricity purchase price agreement; Section 4 (subsections 1 and 3) provide for
35 annual increases in the price in subsequent years at 50% of any increase in the CPI.
36 Section 2(1) of OIC 2019/25 directs that, in setting rates, the Board must allow the utility

1 to recover specific costs which include the cost of purchasing electricity under an electricity
2 purchase agreement.

3
4 **(b)**

5
6 YEC is not able to confirm that the forecast 2021 IPP purchase of 1.983 GWh of energy
7 is likely to occur. The first IPP project did not get completed in November 2020 as forecast
8 in the IPP agreement and as assumed in the Application. YEC has no control or
9 responsibility as regards when each of the two forecast IPP projects commences
10 production in 2021, or whether any other potential IPPs may be able to advance their plans
11 to commence production later in 2021.

12
13 **(c)**

14
15 The concept seasonal IPP rates was discussed in earlier Yukon government policy papers
16 related to potential IPP development. Current policy directions on IPP pricing for Standing
17 Offer Program projects do not include any provision for lower prices to apply during
18 summer periods.

REFERENCE: Application, page 5 and Section 3.6.2, Defined Benefit Pension
Deferral Account, page 3-29

ISSUE: Stabilization Mechanisms

QUOTE: From page 5:

“Defined Benefit Pension Deferral Account: Approval of defined benefit pension plan deferral account as set out in Section 3.6.2 that captures variances in contributions to the defined benefit pension plan from the cost included in the test year revenue requirements as a result of the required annual actuarial evaluations.”

From page 3-29:

“Yukon Energy is required to file updated actuarial valuation reports on an annual basis with valuation reports determining the required funding for the next year. The actual contributions for the year can vary from the forecast depending on market conditions and the performance of the pension plan assets. The proposed deferral account protects both the utility and ratepayers from variances in required contributions over the amounts included in test year revenue requirement. For the 2021 test year, the defined benefits pension plan cost is \$0.720 million.”

QUESTION:

- a) Please prepare a high-level outline of YEC’s history (including the relevant timeline and events) with respect to any previous use or request to use a defined benefit pension deferral account.
- b) Please explain why the “similar deferral account ... approved for [ATCO Electric Yukon] AEY by Board Order 2014-06” should apply in the circumstances of YEC. Please identify the similarities and differences between the “similar deferral account” approved for AEY in 2014 and the defined benefit pension deferral account proposed by YEC in the current GRA.
- c) Please clarify if the “required annual actuarial evaluation” was submitted by YEC and, if so, provide a reference to where details of the evaluation can be found in the current application. If not submitted, please provide the “required annual actuarial evaluation”.

1 d) Please provide historical details of YEC's "defined benefits pension plan cost" for
2 the years 2018-2020 on an approved and actual basis in comparison to YEC's
3 forecast 2021 cost of \$0.720 million. Please include any details respecting current
4 service payments from special payments.

5
6 e) Given there is an annual actuarial evaluation conducted, on what basis would there
7 be variances in required contributions over the amounts included in the test year
8 revenue requirement that would support deferral treatment as necessary?

9
10 f) What circumstances have changed recently such that YEC now considers a
11 defined benefit pension deferral account necessary?

12
13 g) Please provide details addressing both the requirement for and the specific
14 mechanics of YEC's proposed defined benefit pension deferral account including
15 proposals for a future true-up of the same.

16
17 **ANSWER:**

18
19 **(a)**

20
21 YEC has not previously requested nor used a defined benefit pension deferral account.

22
23 **(b)**

24
25 While YEC has not specifically reviewed the terms and conditions governing the AEY
26 pension plan, YEC believes the risks are similar based on the fact that the YEC plan was
27 inherited from ATCO as part of the termination of the management contract in 1997. Of
28 note, the YEC DB plan was closed to new members in 2001 while we understand the
29 ATCO plan continues to be available to new hires. Irrespective of that fact, the risks from
30 market fluctuations and the resultant impact on funding exists if the plan is closed or not.

31
32 **(c)**

33
34 Please see Attachment 1. Note this attachment is not the formal actuarial valuation from
35 2020 (see Attachment 2); however, YEC, as an IFRS-compliant public entity, uses IAS 19
36 as guidance for pension funding. Attachment 1 is the actuarial estimate of funding required

1 for 2020 based on IAS 19. YEC is seeking a deferral account to accumulate differences
2 from GRA approved funding v. future directions.

3
4 **(d)**
5

Fiscal Year	Pension Cost	
2018	\$657,984	Approved
2018	\$678,600	Actual
2019	\$605,900	Actual
2020	\$720,200	Forecast (per GRA)
2020	\$741,300	Actual

6
7 **(e)**
8

9 The GRA process essentially locks in the pension recovered from rates whereas the
10 funding requirements vary every year and the variance is beyond the utility's ability to
11 control.

12
13 **(f)**
14

15 As noted in the AEY application, current OSFI guidance has created a situation where
16 actuarial valuations are essentially required every year (unless solvency calculations
17 exceed 120%). This required has increased funding volatility year over year.

18
19 **(g)**
20

21 As discussed above, YEC is seeking a deferral account to absorb the differences between
22 the IAS 19 pension expenses as directed by the plan actuary. The accumulated
23 differences will be reviewed by the YUB at each GRA and balances will be refunded or
24 collected as necessary.

1 **REFERENCE: Application, Section 3, Revenue requirement**

2
3 **ISSUE: YEC Revenue Requirement**

4
5 **QUOTE:** Please revise Table 3.1, Table 3.3, Table 3.4, Table 3.5, Table 3.8, and
6 Table 3.9 to include 10 years of historical information on both an
7 approved and actual basis commencing with the year 2012.
8

9 **QUESTION:**

10
11 a) Please revise Table 3.1, Table 3.3, Table 3.4, Table 3.5, Table 3.8, and Table 3.9
12 to include 10 years of historical information on both an approved and actual basis
13 commencing with the year 2012.
14

15 **ANSWER:**

16
17 **(a)**

18
19 Please see YUB-YEC-1-36 Attachment 1 for requested information.

Table 3.1
Yukon Energy Revenue Requirement
(\$000)

	2012 Approved	Actual 2012	2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021 Proposed 2021	
Fuel and Purchased Power	\$ 2,316	\$ 827	\$ 3,200	\$ 3,878	\$ 1,569	\$ 2,756	\$ 2,159	\$ 2,460	\$ 2,677	\$ 5,348	\$ 6,211	\$ 11,874	\$ 13,153	\$ 15,897
Non-Fuel Operating and Maintenance	17,210	17,941	18,111	19,381	19,957	19,580	20,470	22,476	22,125	23,497	24,559	26,903	29,074	29,430
Depreciation and Amortization	7,927	8,225	8,604	9,500	7,783	8,690	7,816	10,848	11,141	11,104	11,053	11,007	12,489	13,125
Return on Rate Base	11,396	10,313	12,348	11,139	11,938	10,829	12,242	13,584	13,850	12,110	9,480	10,163	9,448	16,682
Revenue Requirement/Revenue	\$ 38,850	\$ 37,306	\$ 42,263	\$ 43,897	\$ 41,247	\$ 41,855	\$ 42,686	\$ 49,367	\$ 49,794	\$ 52,059	\$ 51,302	\$ 59,947	\$ 64,164	\$ 75,135

1 **REFERENCE: Application, Section 3.3, Non-Fuel Operating and Maintenance**
2 **(O&M) Expenses, pages 3-7 and 3-8**

3
4 **ISSUE: Non-labour and labour inflation rates**

5
6 **QUESTION:**

7
8 a) Please clarify if YEC applied or used an inflation rate (or escalation factor) in
9 arriving at its forecast non-labour O&M expenses for the year 2021. If confirmed,
10 please provide all support for the non-labour inflation rate used in YEC's 2021
11 forecast amounts (for example, provide excerpts from the most recent Yukon
12 Economic Outlook documentation) and identify which non-labour O&M expenses
13 the inflation rate was applicable to. If not confirmed, please explain YEC's method
14 for forecasting its non-labour O&M expenses for the year 2021.

15
16 b) Please provide the actual 2018-2020 non-labour inflation rates experienced by
17 YEC.

18
19 c) Please provide the actual 2020 labour inflation rate experienced by YEC and clarify
20 whether the labour costs shown on Table 3.3 (page 3-7) and included in the
21 forecast 2020 costs of \$12,727 reflect this inflation rate.

22
23 d) Please clarify if any collective bargaining agreements that will be settled in 2021
24 for the fiscal period 2020 are expected to be applied retroactively to January 2020
25 or some other date and, if so, explain if and how YEC has accounted for this
26 anticipated future liability for regulatory purposes.

27
28 e) Please confirm YEC's statement that the "forecast 2020 and 2021 labour rates
29 include estimated economic increments of 2%" means that 2019 actual labour
30 costs were inflated by 2% to arrive at 2020 forecast labour costs, followed by 2020
31 forecast labour costs being inflated by an additional 2% to arrive at 2021 forecast
32 labour costs. If not confirmed, please fully explain how the increments of 2% were
33 applied.

34
35 f) Please explain why a labour inflation rate of 2% remains reasonable for either of
36 the years 2020 or 2021 given the current economic conditions surrounding the
37 COVID-19 pandemic. Please clarify whether YEC's forecast labour inflation rate of

1 2% is consistent with Yukon Economic Outlook documentation. If so, please
2 provide the relevant excerpts from the most recent Yukon Economic Outlook
3 documentation for each of the years 2020 and 2021.

4
5 g) Please identify any additional costs or savings experienced by or actively sought
6 by YEC during 2020 as a result of the current economic conditions surrounding the
7 COVID-19 pandemic.

8
9 h) Referring to the response to part (g) above, are any additional costs or savings
10 experienced by or actively sought by YEC during 2020 as a result of the current
11 economic conditions surrounding the COVID-19 pandemic anticipated to continue
12 into the year 2021? If so, please identify and quantify the additional costs or
13 savings to YEC for the year 2021.

14
15 **ANSWER:**

16
17 **(a)**

18
19 YEC does not use a general inflation factor in arriving at its non-labour O&M forecasts.
20 YEC budget owners are given a blank template and they build up a budget based on their
21 experience, knowledge and expectations in the upcoming year. Budgets are submitted to
22 Finance and Senior Management, where they are vetted and adjusted as necessary.

23
24 **(b)**

25
26 As stated in (a), YEC did not use inflation rates in 2018-2020.

27
28 **(c)**

29
30 The actual 2020 labour inflation rate has not been determined due to the ongoing
31 collective bargaining agreement process applicable to the period commencing January 1,
32 2020. YEC expects this process to be completed in late 2021. The 2020 labour costs
33 shown on Table 3.3 of \$12,727 reflect an assumed inflation rate of 1.75% plus 0.25% for
34 other costs resulting from the collective bargaining process (e.g., performance increments)
35 for a total estimated annual increment of 2.00%.

1 **(d)**

2
3 As stated in response (c), YEC has assumed a total economic increment of 2.00%
4 resulting from the collective bargaining process. The collective bargaining process is for
5 the period commencing January 1, 2020, so YEC will calculate any differences in amounts
6 owing to/from employees retroactively, and adjust 2021 labour expense for this difference
7 (assuming the collective bargaining process is completed in 2021). There will be no
8 retroactive application of settled amounts into 2020.

9
10 **(e)**

11
12 The statement is confirmed.

13
14 **(f)**

15
16 Historically, YEC has benchmarked CBA annual increments against other local public
17 entity increases (e.g., Yukon Government, Yukon Hospital Corporation, Yukon University,
18 etc.). It is worth noting that the arbitrator has agreed with these benchmarks in each of the
19 last three CBA settlements. Yukon Economic Outlook documentation has historically not
20 been the basis for YEC economic increases decided by the arbitrator, so YEC does not
21 consider this applicable.

22
23 **(g)**

24
25 Significant additional costs as a result of the current economic conditions surrounding the
26 COVID-19 pandemic are included as RFID. Savings as a result of the current economic
27 conditions surrounding the COVID-19 pandemic include significantly reduced travel costs
28 for YEC employees.

29
30 **(h)**

31
32 YEC expects there to be both costs and savings that as a result of the current economic
33 conditions surrounding the COVID-19 pandemic continue into the year 2021. The amount
34 is not determinable.

1 **REFERENCE:** Application, Section 3.3, Non-Fuel Operating and Maintenance
2 (O&M) Expenses, pages 3-8 and 3-9

3
4 **ISSUE:** Labour Costs (Section 3.3.1)

5
6 **QUOTE:** "Table 3.4 shows that the total position count is forecast to increase by
7 9.90 positions since 2018 approved to 2021 test year.

8
9 At the historic staff level, employees were finding it difficult to keep pace
10 with increased demands, more so as additional assets are added and
11 increasing burden for planning and executing capital works. In recent
12 years overtime hours have increased creating additional workload and
13 adverse effect for the existing employees which in turn resulted in an
14 increase in employee turnover. The increase in employee turnover has
15 increased the recruiting and relocation costs for the forecast years."

16
17 "To combat the above issues, YEC is forecasting an increased
18 employee complement. The increase in employee complement has
19 resulted in significant decrease in forecast overtime costs for 2021.
20 Also, the increased employee complement in 2019 through 2021 is due
21 to an effort, where possible, to do more work internally as opposed to
22 hiring outside consultants and contractors. YEC has made a
23 conscience effort to limit increases to only those areas where required
24 as reviewed below."

25
26 **QUESTION:**

27
28 a) Please update Table 3.4 to include YEC's actual employee complement as of
29 December 31, 2020. Please include an explanation for any variances between
30 YEC's 2020 forecast 97.86 employee complement and 2020 actual employee
31 complement.

32
33 b) In light of the current economic conditions surrounding the COVID-19 pandemic,
34 does YEC anticipate an increase or decrease in employee turnover in 2021?

- c) Please provide YEC's employee turnover (number of employees resigned or retired) and vacancy rate on an actual basis for the years 2018-2020 and forecast basis for the years 2020 and 2021.
- d) Please prepare a table quantifying the "recruiting and relocation costs for the [2020 and 2021] forecast years" and compare these amounts to the recruitment and relocation costs experienced by YEC on an actual basis for the years 2018-2020.
- e) Please prepare a table quantifying the "forecast overtime costs for [2020 and 2021]" and compare this amount to the overtime costs (including both O&M and capital related) experienced by YEC on an actual basis for the years 2018-2020.
- f) Please prepare a table quantifying the costs of outside consultants and contractors on an actual basis for the years 2018-2020 and on a forecast basis for the years 2020-2021. In the response, please ensure that the type of consultant and contractor work being performed on behalf of YEC has been identified. (For example, the cost of the consultant and contractor work as related to O&M, capital, administrative, regulatory or other).

ANSWER:

(a)

Table 1 below represents Employee Complement History as presented in the Application updated for Actual 2020 results.

Table 1: Employee Complement History

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Actual 2020	Proposed 2021
President	4.16	5.14	4.82	4.01	4.01	4.16
First Nation Relations	-	-	-	-	0.50	1.00
Communications, Cust. Acctg.	1.00	1.00	1.00	3.10	3.10	4.60
Human Resources & Info. Mgmt.	5.25	5.27	5.34	5.32	5.30	5.25
Resource Planning and Environment	5.00	5.00	5.75	5.51	5.93	7.05
Finance, Cust. Acctg. & Purchasing	16.79	16.89	17.24	13.54	13.56	14.79
Operations	44.50	46.58	47.12	48.75	48.30	49.25
Engineering Services	15.00	13.03	15.16	15.63	15.72	15.50
Health & Safety	2.00	2.00	2.00	2.00	2.00	2.00
Total	93.70	94.91	98.44	97.86	98.41	103.60

1 There are no significant variances from Forecast 2020 to Actual 2020. The largest
2 variance of 0.50 is in First Nation Relations. YEC added this position to its Employee
3 Complement effective July 1, 2020; however, as of December 31, 2020, this position
4 remains vacant.

5
6 **(b)**

7
8 YEC does not forecast turnover and has no basis to assess the impact of the global
9 pandemic on the job markets that YEC is active in. YEC continues to plan and execute
10 recruitment efforts consistent with prior years.

11
12 **(c)**

13
14 YEC's employee turnover (number of employees resigned or retired) on an actual basis
15 for the years 2018-2020 is summarized in Table 2 below:

16
17 **Table 2: Employee Turnover: 2018-2020**

2018	5
2019	9
2020	6

18
19 YEC does not have a specific employee turnover forecast for 2021.

20
21 YEC's vacancy rate on an actual basis for the years 2018-2020 and forecast basis for the
22 years 2020 and 2021 is summarized in Table 3 below:

23
24 **Table 3: Vacancy Rate: 2018-2020**

Year	Vacancy Rate
Actual 2018	-6.05
Actual 2019	-9.91
Actual 2020	-9.30
Forecast 2020	-3.00
GRA 2021	-5.00

(d)

Recruiting and relocation costs are summarized in Table 4 below:

Table 4: Recruiting and Relocation Costs

	Actual	Forecast
2018	\$ 190,319.04	
2019	\$ 334,005.84	
2020	\$ 311,044.72	\$ 279,080.00
2021		\$ 211,260.00

(e)

Overtime costs are summarized in Table 5 below:

Table 5: Overtime Costs

	Actual	Forecast
2018	\$ 901,416	
2019	\$ 938,858	
2020	\$ 992,155	\$ 735,768
2021		\$ 760,960

(f)

The costs of outside consultants and contractors on an actual basis for the years 2018-2020 and on a forecast basis for the years 2020-2021 is summarized in Table 6 below:

Table 6: Costs for Outside Consultants and Contractors

(\$M)	Admin	O&M	Capital
2018 Actual	1.375	2.965	17.900
2019 Actual	1.358	2.520	17.124
2020 Actual	1.523	3.869	31.654
2020 Forecast	1.575	2.831	
2021 Forecast	1.532	2.942	

- 1 Capital project forecasts are not done on a cost-element basis, so we are unable to
- 2 provide a forecast for Capital outside consultants and contractors.

1 **REFERENCE: Application, Section 3.3.1, Non-Fuel Operating and Maintenance**
2 **(O&M) Expenses, pages 3-8 to 3-13**

3
4 **ISSUE: Labour Costs (Section 3.3.1)**

5
6 **QUESTION:**

- 7
- 8 a) Please clarify how many employees will report to YEC's proposed "1.00 position
9 increase in 2021 due to ... a Vice President, First Nation Relations." (page 3-10)
- 10
- 11 b) Please confirm whether "Yukon Energy's 5-Year Strategic Plan, published in 2019,
12 confirmed YEC's commitment to establishing mutually beneficial and strategic
13 partnerships with Yukon First Nations governments" (page 3-9) and is intended to
14 be subject to testing in the current GRA. If confirmed, please explain fully why this
15 is the case.
- 16
- 17 c) Please explain whether it is YEC's understanding that it is responsible for fulfilling
18 consultation obligations where they arise with respect to potential impacts on s. 35
19 rights (Section 35 of the Constitution Act, 1982).
- 20
- 21 d) Please elaborate on YEC's new position (Vice President, First Nation Relations)
22 and how it will expand YEC's current ability to move projects forward.
- 23
- 24 e) Given that the name for the "Finance, Customer Billing/Accounting and
25 Purchasing" category (page 3-11) continues to reference the words "Customer
26 Billing/Accounting," please clarify whether any "Customer Billing/Accounting"
27 personnel remain in the originating group after the 2020 transfer of 2.10 positions
28 to the "Communications, Customer Accounting" (page 3-10) category.
- 29
- 30 f) Referring to the categories identified in Table 3.4 (page 3-8) and including the
31 proposed "1.00 position increase in 2021 due to the addition of a new full-time
32 position, Senior Communications Advisor" (page 3-10), please clarify how many
33 communication personnel in total will be employed by YEC and in which Table 3.4
34 category or categories these employees reside.
- 35
- 36 g) Please clarify the role of YEC's communication personnel in relation to YEC's
37 internal versus external communication requirements.
- 38
- 39 h) Please quantify how many external communication issues, such as customer
40 complaints, were submitted to YEC for resolution during each of the years 2018-

1 2020. Of these submissions, please quantify how many were resolved in each year
2 by YEC and how many were forwarded to the YUB for resolution.

3

4 i) With respect to YEC's Resource Planning and Environment category, please
5 clarify what is referred to as the "backlog of planning work designation for
6 completion" (pages 3-10 and 3-11) for which YEC has proposed to add a two-year
7 resource planning engineer position to assist with. In the response, please also
8 clarify which capital projects have been delayed as a result of the referenced
9 planning work backlog.

10

11 j) With respect to YEC's Resource Planning and Environment category, please
12 clarify if YEC's "2020 10-Year Renewable Electricity Plan" (pages 3-10 and 3-11)
13 is intended to be considered by the Board in the current GRA. If confirmed, please
14 explain fully why this is the case. Please provide a reference to where YEC's
15 Electricity Plan has been provided in its application; otherwise, please submit a
16 copy of the report in response to this IR.

17

18 k) With respect to YEC's Resource Planning and Environment category, please
19 identify the priority initiatives recommended in the "2020 10-Year Renewable
20 Electricity Plan" (pages 3-10 and 3-11) which YEC has proposed to address by
21 adding a senior project manager. In the response, please also quantify how many
22 employees are currently engaged in any of the priority initiatives and whether any
23 are proposed to now report to the new senior project manager.

24

25 l) Please explain whether procurement personnel have historically been within the
26 "Finance, Customer Billing/Accounting and Purchasing" group and provide the
27 quantity of employees responsible for procurement in that or any other group up
28 to the year 2020. Will YEC's proposed "1.00 position increase ... of a new full-time
29 position, Procurement Administrator" (page 3-11) result in less work for those
30 employees previously responsible for procurement work up to the year 2020? If
31 so, please explain where has YEC incorporated the incremental benefits of hiring
32 a full-time procurement administrator in its revenue requirement.

33

34 m) In relation to YEC's procurement activities, please provide quantifiable evidence
35 that YEC has experienced "increased workload in the department due to greater
36 volume of high dollar projects" (page 3-11) during each of the years 2018-2020 on
37 an actual basis.

38

39 n) In relation to YEC's procurement activities, please explain why there are
40 "increasingly complex contracting strategies for some capital projects, including
41 the additional requirements of the First Nation procurement policy, which has
42 increased the complexity and administrative support required for large project

procurement.” (page 3-11) In the response, please confirm that it is the Yukon Government First Nation Procurement Policy being referred to, whether that policy applies to Yukon Energy, and also identify the additional requirements of YEC to follow that policy.

o) In relation to YEC’s procurement activities, please explain and provide context with respect to “the need to allow departmental management to concentrate on policy renewal and development and education for client managers new to YEC.” (page 3-11).

p) In relation to YEC’s operations, please confirm that the “1.00 position increase in 2018 due to the addition of a new full-time position, Maintenance Mechanic to address additional responsibilities (e.g., LNG assets)” was contemplated in YEC’s original LNG project business case. If confirmed, please provide a reference to the business case where an increase in employee complement was identified as being required.

q) In relation to YEC’s operations, please provide the per cent increase over 2020 actual plant operator personnel that the total 1.75 position increase in plant operators will represent. (page 3-12)

r) In relation to YEC’s engineering services, please confirm that the “1.00 position increase in 2020 ... of a new full-time position, Electric Engineer” (page 3-12) occurred on an actual basis during the year 2020.

s) Please provide YEC’s capital to maintenance allocation ratios on an actual basis for the years 2018-2020. (page 3.13)

ANSWER:

(a)

YEC is not proposing any direct reports to this position at this time. The VP will be the primary liaison with First Nations and will work through other departments as required depending on the nature of the issue (e.g., planning, engineering, operations, finance).

(b)

In this context, the reference to the 2019-24 strategic plan was intended to demonstrate the Corporation’s commitment to working with First Nations. It is self-evident that YEC

1 owes a duty to Yukon First Nations as a landowner and further, as a legal obligation under
2 various treaty agreements.

3
4 **(c)**

5
6 YEC is not directly responsible for fulfilling the Crown's duty to consult and accommodate
7 Yukon First Nations with respect to a potential impact on s. 35 rights. However, the Crown
8 has given effect to its duty to consult, in part, through the framework established under
9 YESAA, and YEC has duties as a proponent under that framework, including statutory
10 consultation obligations, with respect to the environmental and socio-economic
11 assessment of YEC projects. In addition, in certain circumstances, YEC may have further
12 consultation duties arising directly under the provisions of Yukon First Nation Final
13 Agreements (e.g., under Specific Economic Measures provisions included in Chapter 22).

14
15 **(d)**

16
17 Any significant project that occurs in the Traditional Territory of a Yukon First Nation
18 requires the proponent to engage and consult with that First Nation. In YEC experience,
19 the consultation process is most effective when an established relationship already exists
20 with the affected First Nation. The Vice President First Nation Relations will be responsible
21 for establishing and maintaining relationships with First Nations in Yukon Energy's service
22 area. As well, when a project is identified, the Vice President will lead the negotiations of
23 the benefits agreements thereby capitalizing on the relationship.

24
25 **(e)**

26
27 No Customer Billing/Accounting personnel remain in the group after the 2020 transfer. To
28 be clear, certain aspects of customer accounting is retained by the core Finance group
29 (e.g., account reconciliation, cash management) but staff who are responsible for direct
30 interactions with customers, account set up and maintenance, bill preparation and
31 distribution, account collection, etc. have transferred out of Finance.

32
33 **(f)**

34
35 There will be two communication personnel in total employed by YEC and both are in the
36 category labelled Communications, Cust. Acctg.

1 (g)

2
3 Yukon Energy communications personnel are responsible for developing and delivering
4 the Corporation's external communications and supporting company-wide internal
5 communications on key topics and projects. The latter can include writing and reviewing
6 company-wide messages, presentations, campaigns and other collateral.
7

8 (h)

9
10 Yukon Energy does not track all external issues and complaints in one central repository.
11 External issues and complaints are addressed and actioned by individual departments, as
12 required. Yukon Energy is not aware of how many external issues or complaints were
13 forwarded to the YUB.
14

15 In terms of specifics, YEC offers the following as indicative of increased work load:

- 16
- 17 • Weekly briefings for the Minister and YDC started in Q4 2019 and have continued
18 since.
19
 - 20 • We started tracking the number of media calls, Ask Steph (online) emails and
21 social media comments/questions we receive in 2020.
 - 22 o 84 media calls were received in 2020;
 - 23 o 44 Ask Steph inquiries in 2020;
 - 24 o More than 200 questions and comments on Facebook and Twitter in 2020;
 - 25
 - 26 • Table 1 below highlights the impact of additional duties with respect to increased
27 communications involvement in capital works and customer service.
28

29 **Table 1: Allocation of Manager of Communications Time, 2018-2020 (Year-to-date)**

Year	Communication Admin.	Customer Billing Admin.	Capital
2018	99.24%	0.0%	0.76%
2019	66.43%	0.0%	33.57%
2020	44.13%	15.53%	40.34%

1 Additionally, as a one-position department with critical responsibilities during unplanned
2 events, the Manager Communications is effectively on call 24/7, 365 days a year. The
3 extra position will help provide an additional resource for this important function.

4
5 **(i)**
6

7 The general challenge is that YEC is unable to advance concurrently, as required, all of
8 its projects given limited internal planning resources. The planning projects which are
9 currently designated for completion include the ones listed below. It's difficult to clarify
10 which projects have been delayed due to insufficient internal resources – all projects tend
11 to be adversely impacted in this situation, and YEC has had to address delays in dealing
12 with almost all of the active projects listed below. The concern looking forward is that the
13 upcoming work requirement is expected to be even more challenging than that
14 experienced to date.

- 15
16 • Aishihik Generating Station Water Use 25 Year License Renewal;
17
- 18 • Whitehorse Rapids Generating Station Water Use License Renewal;
19
- 20 • Mayo Generating Station Water Use License Renewal;
21
- 22 • Diesel Retirement Replacement;
23
- 24 • Southern Lakes Storage;
25
- 26 • Mayo Lake Storage Enhancement Project;
27
- 28 • Battery Energy Storage System;
29
- 30 • Pumped Storage;
31
- 32 • Southern Lakes Transmission Line; and
33
- 34 • Demand Side Management Programs.

1 (j)

2
3 YEC's "2020 10-Year Renewable Electricity Plan" is intended to be considered by the
4 Board in the current GRA in that it is included as a deferred cost Regulatory project added
5 to rate base, as disclosed in Section 5.3.2 of the Application (page 5-26) as well as in
6 Table 5.5. The Plan, however, generally addresses project planning for development
7 beyond the 2021 test year. Please see CW-YEC-1-36(a) Attachment 1 for a copy of the
8 10-Year Renewable Electricity Plan.

9
10 (k)

11
12 YEC anticipates the Senior Project Manager will lead the completion of the Southern
13 Lakes Transmission Line and Pumped Storage projects (each of which remain in WIP in
14 2021). Current employees are engaged on these projects on an ad hoc basis given limited
15 resource capacity, and the focus on securing federal funding before advancing either
16 project. YEC does not anticipate any employees will report to the new senior project
17 manager.

18
19 (l)

20
21 Procurement personnel have been within the "Finance, Customer Billing/Accounting and
22 Purchasing" group for many years (i.e., > 10 years). The number of full time equivalent
23 employees responsible for procurement in the group for year 2020 is 3.5. The addition of
24 the Procurement Administrator will not result in less work for other staff. YEC recognized
25 that the volume of purchasing was exceeding the capacity of the department to the point
26 where some projects were delayed due to backlogs in procurement. As well, procurement
27 volumes have increased (see (m) below) and other managerial tasks were not being
28 addressed on a timely basis (see (o) below).

29
30 (m)

31
32 See Table 1 below for the volume of purchase orders processed at YEC back to 2018,
33 demonstrating the greater volume of high dollar projects.

Table 1: Volume of Purchase Orders: 2018 to 2020

Fiscal Year	Count of PO Number	Sum of Originating Subtotal
2018	586	27,855,025.96
2019	630	33,480,891.75
2020	765	62,313,928.33

(n)

YEC has had to address, or is addressing, a number of complex procurements. This includes the following examples:

- BESS – new technology both for YEC and the Canadian industry, international vendors, long lead time;
- EAM – software acquisition, high dollar, US vendor, acquisition of licences implementation and post-go live support; and
- MMTP – high dollar, large number of contracts, federal funding requirements, large FN components.

YEC approved a First Nation Procurement Policy in 2016, although implementation has occurred gradually since that time. YEC was aware that YG was working on a similar policy since 2019. While YEC is not obligated to follow YG policy, the shareholder expects that our policy approach should not materially diverge from YG.

(o)

The department includes one manager who has responsibility for providing supervision and leadership to the team. In addition, this position is responsible for advising management on complex transactions, conducting market research, developing and maintaining long-term vendor relationships, policy update/development, procurement system access and functionality and training for client staff.

With respect to procurement policy, there is a recognized need to adapt current policy for external factors e.g., Canadian Free Trade Agreement, YG FN Procurement Policy. As

1 well, policies are over 10 years old and need to be updated for industry best practice and
2 general improvement for efficiency and effectiveness.

3
4 Training is becoming a critical issue as YEC has experienced significant turnover in recent
5 years. While the company has been successful at attracting skilled replacements, it is
6 normal for new project managers to require training on the specific rules of procurement
7 at YEC. Prior to the addition of an additional position, the manager was required to
8 participate in the preparation and management of procurement processes to the point
9 there was no time available to other matters as described.

10
11 **(p)**

12
13 The “1.00 position increase in 2018 due to the addition of a new full-time position,
14 Maintenance Mechanic to address additional responsibilities (e.g., LNG assets)” was not
15 specifically contemplated in YEC’s original LNG project business case. The position was
16 required to address the workload of all generation assets based on the workload at that
17 time, which changed from the time when the LNG business case was prepared. The
18 process to justify the additional position was done using a spreadsheet that assigned
19 annual tasks at each facility. This process determined the staff complement against the
20 work. The latest iteration of the work indicated a deficit in mechanical trades staff. With
21 the addition of the LNG facility there was an obvious lack of person hours to complete the
22 suggested maintenance.

23
24 **(q)**

25
26 The 1.75 position increase represents a 16% increase in plant operators.

27
28 **(r)**

29
30 Confirmed.

31
32 **(s)**

33
34 YEC’s capital to maintenance allocation ratios on an actual basis for the years 2018-2020
35 is provided in Table 2 below:

1

Table 2: Capital to Maintenance Allocation Ratios

	Capital	Maintenance
2018	14.7%	85.3%
2019	16.0%	84.0%
2020	18.2%	81.8%

2

1 **REFERENCE:** Application, Section 3.3.2, Production, pages 3-13 and 3-14

2
3 **ISSUE:** Production Costs – Diesel Rentals

4
5 **QUOTE:** “Diesel rentals [cost increase of \$3.834 million over 2018 approved
6 GRA]: Costs of mobile diesels to address dependable capacity
7 shortfalls (see Tab 2, section 2.4) is forecast to increase to \$3.834
8 million in 2021 as compared to actual 2018 costs of \$1.048 million and
9 no costs included as part of 2018 Approved costs. Forecast mobile
10 diesel costs are based on negotiated contracts with the vendor.”

11
12 **QUESTION:**

- 13
14 a) Please provide all quantitative evidence demonstrating a competitive supply for
15 YEC’s diesel rental costs on an actual basis for the period 2018-2020.

16
17 **ANSWER:**

18
19 **(a)**

20
21 2018/19

- 22 • YEC ran one-year public competitive tender process for 6 – 2 MW diesel
23 generators for placement at Whitehorse Rapids Generation Station for the winter
24 heating season (approximately 5 months).
25
26 • Two bids were received:

Vendor	Quote
Trinity Power	\$1,860,059
Finning Canada	\$1,557,881

- 27
28 • A contract was awarded to Finning Canada.

29
30 2019/20

- 31 • YEC ran a three year public competitive tender process for up to 8 – 2 MW units
32 for the season; annual renewals are at the discretion of YEC.

- 1 • Three bids were received; one bid was deemed non-compliant and was therefore
2 excluded from the price evaluation:
3

Vendor	Quote
United Rentals	\$3,706,685
Finning Canada	\$1,913,234

- 4
5 • Due to additional generation risk from low water in Mayo, YEC elected to rent one
6 additional 2 MW unit.
7

8 2020/21

- 9 • Based on forecast model, 17 – 2 MW units required for 20/21 heating season.
10
11 • 10 units placed in WRGS under the unit rates per 19/20 RFP; 7 units were placed
12 in Faro through a contract extensions with Finning Canada; unit rates for Faro units
13 were based on market conditions at the time.

1 **REFERENCE:** Application, Sections 3.3.3 and 3.3.4, Non-Fuel Operating and
2 Maintenance (O&M) Expenses, pages 3-14 to 3-16
3

4 **ISSUE:** Transmission and Distribution Brushing Allocations
5

6 **QUOTE:** “The major portion of the transmission cost variance relates to changes
7 in the annual brushing cost requirements and changes in the allocation
8 of brushing budgets between transmission and distribution lines. Table
9 3.6.1 provides further details on the brushing allocations.” (pages 3-14
10 and 3 15)
11

12 “The fluctuation results from changes in brushing allocations between
13 transmission and distribution lines. Table 3.6.1 provides further details
14 on the brushing allocations.” (page 3-16)
15

16 **QUESTION:**
17

18 a) Please identify and fully explain all reasons for the changes in “brushing allocations
19 between transmission and distribution lines” noted by YEC and referenced in the
20 above quotes.
21

22 b) Referring to Table 3.6.1 (page 3-15), please explain why YEC’s 2019 Actual
23 brushing costs were almost exclusively related to transmission brushing activities
24 (98%) as compared to a more typical 78-85% (transmission related) as observed
25 for the other years identified in the table.
26

27 **ANSWER:**
28

29 **(a)**
30

31 Brushing allocation is determined based on priority, planned work on infrastructure,
32 vegetation outage stats and growth rate.
33

34 **(b)**
35

36 The high allocation of funding in 2019 can be directly attributed to the transmission line
37 refurbishment (TLR) project where site access was a priority.

REFERENCE: Application, Section 3.3.5, General Operation and Maintenance, pages 3-16 and 3-17

ISSUE: General Operation and Maintenance

QUOTE: “Labour costs are forecast to decrease by \$0.017 million in 2020 from 2018 approved. Total forecast costs in the non-labour General O&M categories in 2021 are \$0.172 million higher than approved 2018 costs of \$1.219 million. Transportation expenses are forecast to increase \$0.051 million (10%) in 2021 over 2018 approved. Maintenance of Company Owned Properties is expected to increase \$0.090 million (18%) in 2021 over 2018 approved. SCADA Communication expenses are forecast to increase by \$0.031 million (15%) in 2021 under 2018 approved.”

QUESTION:

- a) Please provide variance explanations for all per cent changes between 2018 approved and 2021 forecast costs noted by YEC in the above quote.
- b) Please respond to part (a) on the basis of changes between 2020 and 2021 forecast costs.
- c) Please detail any measures to be taken by YEC to control or reduce its overall general operation and maintenance costs in 2021.

ANSWER:

(a)

Labour costs are forecast to decrease primarily due to a reduction in time allocated to Communications. Transportation expenses are forecast to increase primarily due to insurance and maintenance of an aging and larger fleet. Maintenance of Company Owned Properties is expected to increase primarily due to increased rental of land and buildings. SCADA Communications expenses are forecast to increase due to an increase in the cost of communication rentals.

1 **(b)**

2
3 Labour costs are forecast to increase primarily due to an increase in time allocated to
4 Fleet. Transportation expenses are forecast to increase primarily due to resumption of
5 more normal activities as the first half of 2020 was low due to decreased travel resulting
6 from the Covid-19 pandemic. Maintenance of Company Owned Properties is expected to
7 decrease primarily due to an overall general reduction in various Whitehorse costs.
8 SCADA Communications expenses are forecast to remain consistent with 2020.

9
10 **(c)**

11
12 YEC has an intense budget process where budget owners build a budget based on a
13 blank template. Budgets are scrutinized by Finance, Senior Management and the board
14 of directors. Budgets are adjusted as considered necessary.

1 **REFERENCE: Application, Section 3.3.6, Administration, pages 3-17 and page**
2 **3-18**

3
4 **ISSUE: Administration Costs**

5
6 **QUESTION:**

7
8 a) Please detail any measures taken by YEC to control or reduce its overall
9 administration costs forecast for 2021.

10
11 b) Please clarify whether YEC's forecast increase in general administration expense
12 related to new asset management software was contemplated in any related
13 business case and, if so, please provide a reference to the cost benefit analysis
14 conducted in that business case.

15
16 c) Please clarify why YEC's general administration expense forecast for 2021 is
17 anticipated to increase over 2020 forecast costs given the explanation for the
18 increase between 2018 and 2021 costs as noted in part (b) above.

19
20 d) Please explain why YEC's Board of Directors expenses have not decreased given
21 restrictions related to the COVID-19 pandemic and requirements to conduct
22 meetings virtually.

23
24 e) Please quantify the number of Board of Directors meetings held during the year
25 2020 on an actual basis and forecast for the year 2021.

26
27 f) Please describe the nature of and reason for any training proposed for YEC's
28 Board of Directors.

29
30 **ANSWER:**

31
32 **(a)**

33
34 YEC has an intense budget process where budget owners build a budget based on a
35 blank template. Budgets are scrutinized by Finance, Senior Management and the Board
36 of Directors. Budgets are adjusted as considered necessary.

1 **(b)**

2
3 The business case is reviewed in YUB-YEC-1-64, and includes consideration of managing
4 ongoing software management costs. The estimated ongoing annual costs start in 2021
5 and are used in the business case and NPV calculations.
6

7 **(c)**

8
9 The primary reason for the increase in general administration expense for 2021 over 2020
10 are the costs related to the new asset management software as noted in part (b), as the
11 system is to be implemented in 2021.
12

13 **(d)**

14
15 Travel cost was not a significant cost of the Board of Directors budget prior to the
16 pandemic; therefore, there is no significant savings on this budget due to pandemic
17 restrictions.
18

19 **(e)**

20
21 In 2020, YEC had 14 Board meetings and 24 Committee meetings. Of the 14 Board
22 meetings, 5 were scheduled and the other 9 were Special Meetings. YEC has scheduled
23 4 quarterly meetings, 2 special meetings for strategic planning and business plan approval
24 for 2021. There is a possibility that additional unscheduled meetings will be required for
25 time sensitive issues.
26

27 **(f)**

28
29 YEC's Board of Directors are looking at focusing their training on finance and oversight
30 for the Audit Committee (and possibly expanding to the full Board) for 2021. This is based
31 on the outcome of a Director Evaluation that was completed in 2020 and identified
32 oversight of financials and strategic priorities as a key focus area for the Board.

1 **REFERENCE:** Application, Section 3.3.7, pages 3-18 to 3-20

2
3 **ISSUE:** Insurance and Reserve for Injuries and Damages (RFID)

4
5 **QUOTE:** "Yukon Energy's costs for insurance in 2021 are forecast to increase
6 by \$0.392 million (38%) above approved 2018 costs of \$1.031 million,
7 and are based on the completed 2020 annual renewal process. Costs
8 in 2020 increased due to mid-year market rate adjustments (overall rate
9 increase of 25% on commercial package) and increased insured asset
10 value. Costs in 2021 increase primarily due to a full year impact of the
11 2020 rate increase [most of the costs for the 2021 fiscal year are
12 already locked by the insurance policy renewables in 2020 due to
13 insurance year cycle differences from YEC's fiscal year]. The market
14 rate increases experienced by YEC as part of 2020 renewals are
15 consistent with peer utilities in Canada."

16
17 "The large expense in 2020 reflect works required in Whitehorse hydro
18 generation facility penstock [about \$0.730 million], Whitehorse LNG
19 Unit #2 [\$0.4 million], LNG Vapourizer [\$0.3 million] and other small
20 projects. In 2021 test year, YEC is forecasting annual costs of \$0.411
21 million."

22
23 **QUESTION:**

- 24
25 a) Please provide the availability statistics for each of the LNG units by year since
26 inception.
27
28 b) In light of your response to part (a), please comment on the reliability of each of
29 the LNG units.
30
31 c) Please clarify whether the insurance year or renewal cycle has changed for either
32 YEC or its insurance company from those used in prior GRAs.
33
34 d) Please clarify whether YEC examined alternative insurance coverage from other
35 providers in order to keep insurance cost increases to a minimum. Please explain
36 all resources and alternatives YEC examined.

- 1 e) Please provide further details for each of the respective LNG-related RFID claims
2 comprising the \$1,598 thousand Forecast 2020 annual cost as noted in Table
3 3.11.1.
4
- 5 f) Please clarify whether YEC follows a policy for processing of claims against its
6 RFID account and, if so, please provide the policy or a reference to the most recent
7 version of the RFID policy by which YEC is guided.
8
- 9 g) Please explain the rationale for amortizing the \$2,121 thousand Forecast 2020
10 RFID balance over a period of five years, as opposed to any other period of time.
11
- 12 h) Please explain why YEC did not include 2020 forecast RFID charges in its
13 determination of a 10-year average annual charge as shown in Table 3.11 (page
14 3-19).
15
- 16 i) Please revise Table 3.11 and Table 3.11.1 to include an Actual 2020 column that
17 incorporates a 10-year average annual charge that incorporates 2020 actual
18 (annual charge) information.
19

20 **ANSWER:**

21
22 **(a)**

23
24 Please see Attachment 1 to this response.
25

26 **(b)**

27
28 Most of the issues with the LNG units relate to valve recession on the cylinder heads. YEC
29 is running the third version of the cylinder heads, as the OEM attempts to resolve the
30 problem. The majority of the costs associated with the valve recession have been covered
31 by the OEM.
32

33 In late Q4 2020, WG1 had a generator fault, the stator will need to be rewound. In Q2
34 2020 WG2 had extensive damage as a result of a valve failure.

1 (c)

2
3 Neither the insurance year nor renewal cycle has changed. Insurance periods start
4 approximately mid-year.

5
6 (d)

7
8 During 2020, YEC directed its broker to conduct a full marketing effort for YEC's property
9 insurance policy. The insurers on the program were selected in order to obtain the lowest
10 rate while still providing adequate coverage. Rate increases were compared with industry
11 peers to validate the market conditions experienced by YEC.

12
13 (e)

14
15 Further details for each of the LNG-related RFID claims are as follows:

- 16
17 • **LNG Vapourizer – [\$0.3 million]** – Three failures of the shell and tube heat
18 exchangers in the LNG storage and re-gas package significantly increased the risk
19 of failure of the vapourizer coil. This work involved the replacement of the coils with
20 an improved design in order to avoid an unexpected lengthy outage of the LNG
21 facility.
22
23 • **LNG Unit #2 [\$0.4 million]** – An exhaust valve failure in one of the cylinder heads
24 of LNG unit #2 resulted in damage to 16 power cylinders as well as two turbo
25 chargers. The extensive damage resulted in a complete block replacement, with a
26 portion of the costs being covered by the OEM.

27
28 (f)

29
30 The RFID Policy was most recently filed with the YUB as Appendix 3.1 in the 2012-13
31 General Rate Application. Annual appropriation was updated by the YUB as per Board
32 Order 2018-10 as part of the 2017-18 General Rate Application.

33
34 (g)

35
36 Amortization of the RFID opening balance over five years was selected as that is what the
37 YUB approved in the 2017-18 GRA.

1 **(h)**

2

3 YEC did not include 2020 forecast RFID charges in its determination of a 10-year average
4 annual charge as shown in Table 3.11 as this Table reflects 'actual' charges, not 'forecast'.

5

6 **(i)**

7

8 2020 actual RFID costs are not yet finalized due to ongoing 2020 year-end accounting
9 procedures.

KPI Report: Unit Status

02/23/2021 15:28

			2021-Q1 1287 hrs			2020-Q1,Q2,Q3,Q4 8784 hrs			2019-Q1,Q2,Q3,Q4 8760 hrs			2018-Q1,Q2,Q3,Q4 8760 hrs		
			AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED
			66.20%	Reliability 66.7%	0.5%	68.1%	Reliability 78.3%	10.2%	90.7%	Reliability 99.8%	9.1%	48.7%	Reliability 99.1%	20%
WHITEHORSE	THERMAL	WG1	-	100%	-	76%	8%	17%	88%	1%	11%	77%	2%	21%
		WG2	99%	-	1%	41%	57%	2%	93%	0%	7%	61%	-	39%
		WG3	100%	-	0%	87%	0%	12%	91%	0%	9%	8%	0%	0%

KPI Report: Unit Status

02/23/2021 15:28

			2017-Q1,Q2,Q3,Q4 8760 hrs			2016-Q1,Q2,Q3,Q4 8784 hrs			2015-Q1,Q2,Q3,Q4 8760 hrs		
			AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED
			56.1%	Reliability 99.8%	10.5%	62.8%	Reliability 99.9%	3.8%	63.3%	Reliability 99.4%	3%
WHITEHORSE	THERMAL	WG1	84%	0%	16%	95%	0%	5%	96%	0%	4%
		WG2	84%	0%	16%	93%	0%	7%	94%	1%	5%
		WG3	-	-	-	-	-	-	-	-	-

1 **REFERENCE:** Application, Section 4.4.2, pages 4-6 to 4-8

2
3 **ISSUE:** VGC and Alexco Fixed Charge

4
5 **QUOTE:** “Board Order 2018-04 also directs YEC to submit a limited scope
6 application to amend the firm mine rate within 60 days of the
7 Transmission Facilities Development Operation Date (Paragraph 57).
8 The Transmission Facilities Development Operation Date is forecast to
9 occur in late November 2020/early December 2020 when the
10 Transmission Facilities Development comes into service, connecting
11 the McQuesten Substation with a substation at Mayo. Yukon Energy’s
12 limited scope application to the Board to be filed when this development
13 comes into service is described in Appendix 4.3 based on forecast
14 costs and YEC’s approved 2018 GRA cost of capital.”

15
16 “The interim Fixed Charge for 2021 will also be subject to adjustment
17 and Board review and approval as part of YEC’s 2021 GRA. YEC
18 understands that the final Transmission Facilities Fixed Cost and an
19 adjusted Fixed Charge for VGC Group and Alexco for 2021 will be
20 determined subsequently based on YEC’s final compliance filing as
21 approved for the 2021 GRA (including actual costs as then known for
22 the relevant new facilities) and also based on adjustments as required
23 after 2021 year end to reflect actual MWh loads of VGC Group and
24 Alexco and any adjustments as needed for actual costs as then known
25 for the relevant new facilities.”

26
27 **QUESTION:**

- 28
29 a) Please clarify what YEC is requesting from the Board in the above quotes.
30 Specifically, is YEC asking the Board to approve an interim Fixed Charge for 2021
31 in the current proceeding and to determine the final Fixed Charge in a separate
32 application to be filed within 60 days of the Transmission Facilities Development
33 Operation Date?

1 **ANSWER:**

2
3 **(a)**

4
5 YEC is not asking the Board to approve the Fixed Charge for 2021 at this time.
6

7 The amended Transmission Facilities Fixed Cost application and related interim Fixed
8 Charge are required to be filed within 60 days of the Transmission Facilities Development
9 Operation Date, i.e., the date that YEC provides to VGC Group to confirm that the
10 Transmission Facilities Development has been completed and is in service to deliver Grid
11 Electricity to the Mine Facilities through the Mine Facilities Spur (all terms as defined in
12 the approved VGC Group PPA). This application, which is required to establish at that
13 time the adjusted Fixed Charge related to the amended Transmission Facilities Fixed
14 Cost, exists separate from the 2021 GRA application, and was therefore assumed not to
15 be part of the 2021 GRA application.
16

17 The Transmission Facilities Development Operation Date has been delayed to March
18 2021. YEC therefore now expects to file the amended Transmission Facilities Fixed Cost
19 application in March 2021, requesting an interim Fixed Charge adjustment effective May
20 1, 2021 in order to establish a necessary rate adjustment for VGC Group and Alexco as
21 soon as feasible. This filing will be based on the 2020-2021 to date forecast costs of the
22 new facilities and YEC's approved 2018 GRA cost of capital at 4.82%, i.e., these initial
23 adjustments do not include any changes related to YEC's 2021 GRA proposed cost of
24 capital.
25

26 The Transmission Facilities Fixed Cost and Fixed Charge for 2021 related to the
27 completed Transmission Facilities Development will be updated once the STATCOM is
28 commissioned and final costs are available, which will not occur until late 2021 after the
29 GRA is scheduled to be finalized. After the 2021 year end, adjustments will be made as
30 required by Section 7.7(c)(ii) of the approved VGC Group PPA to reflect actual 2021 MWh
31 loads of VGC Group and Alexco.

1 **REFERENCE:** **Application, page 5-23**

2
3 **ISSUE:** **Section 5.3.1.2, Demand Side Management**

4
5 **QUOTE:** “The context within which Yukon Energy has approached Demand Side
6 Management (DSM) has materially changed since the Board made the
7 following DSM related determination in Board Order 2018-10
8 (paragraph 482):

9
10 The Board is not persuaded that YEC should continue to operate DSM
11 projects. YEC has indicated the benefits of expanding the program and
12 submitted that its programs have met or exceeded key performance
13 indicators. However, the Board notes that the Yukon government has
14 DSM incentive programs in place, and the Board is of the view that it is
15 better to leave DSM projects to government, rather than having
16 ratepayers fund these projects. For these reasons, the Board is of the
17 view that continuation of DSM programs by YEC is not necessary.

18
19 Since that determination the Yukon Government has put in place a
20 Climate Change policy initiative called “Our Clean Future: A Yukon
21 Strategy for Climate Change, Energy and a Green Economy” which
22 emphasizes the importance of DSM as a valuable resource to reduce
23 the Yukon’s energy and capacity requirements. As part of that policy
24 the government fully expects Yukon Energy to pursue a cost-effective
25 DSM program.

26
27 Pursuant to this policy initiative and the Government’s expectations,
28 and further given DSM remains a cost-effective means of reducing
29 energy and capacity requirements, Yukon Energy has included in the
30 proposed 2021 rate base the expenditures for the programs and
31 activities as reviewed below. (footnotes removed)

32
33 **QUESTION:**

- 34
35 a) What is meant by the statement “the context within which Yukon Energy has
36 approached Demand Side Management (DSM) has materially changed”?

- 1 b) Given your response in part (a), how should the Board evaluate whether there is
2 a “material change” in the context (i.e., circumstances) since Board Order 2018-
3 10 was issued?
4
- 5 c) To the extent that the content of discussions can be disclosed, please describe
6 Yukon government discussions with YEC regarding the DSM programs YEC has
7 applied for in this proceeding, particularly in light of the Board’s finding in
8 paragraph 482 of Appendix A of Board Order 2018-10 that the continuation of DSM
9 programs by YEC was not necessary. Please also summarize any discussions on
10 scope, quantum, and timing of the applied-for DSM programs.
11
- 12 d) Please explain to what extent policy directions stated by Yukon Government in the
13 climate change policy initiative “Our Clean Future: A Yukon Strategy for Climate
14 Change, Energy and a Green Economy” are binding on the Yukon Utilities Board.
15 If these directions are not binding, please explain how the Yukon Utilities Board
16 should consider those policy directions in its review of YEC’s applied-for DSM
17 programs.
18
- 19 e) Please explain why policy initiatives supported by Yukon Government should be
20 funded by ratepayers through their utility bill, as opposed to through government
21 supported initiatives such as taxation or other means. In addition, please provide
22 YEC’s view on how the two options might differently affect low-income households.
23
- 24 f) Please explain how YEC considered rates and rate base provisions of the Public
25 Utilities Act in its proposal for demand-side management. In your response, please
26 specifically identify how the DSM programs are the property of a public utility used
27 or required to be used to provide service to the public.
28
- 29 g) On November 19, 2020, the Court of Appeal of Yukon heard an appeal regarding
30 Board Order 2019-05 (in which the Board dismissed YEC’s request to review
31 Board Order 2018 10) in relation to DSM costs. What impact, if any, is there on the
32 Board’s consideration of the applied-for DSM costs in this proceeding given that
33 the outcome of the Court of Appeal of Yukon’s decision on the appeal remains
34 outstanding?

1 h) Please explain YEC's management decision to include the DSM policy initiatives
2 in the current application rather than in its next GRA? Please explain why these
3 initiatives are required to be completed in 2021.

4
5 **ANSWER:**

6
7 **(a) through (f)**

8
9 Since the last rate application, the Yukon Government released a climate change strategy
10 – “Our Clean Future: A Yukon strategy for climate change, energy and a green economy”.
11 More specifically, YG drafted the action below in the policy:

12
13 53. Direct the Yukon Utilities Board to allow Yukon's public utilities to pursue cost-
14 effective capacity demand-side management measures.

15
16 This is a material change to how YEC approached DSM. The YG has clearly stated that
17 DSM is a valid supply option for Yukon utilities and that they expect YEC to actively
18 consider and implement prudent DSM programs. They also indicated their intention to
19 direct the YUB to support cost-effective programs administered by YEC and AEY.

20
21 In keeping with action item number 53 the YG enacted OIC 2021-16.

22
23 OIC 2021/16 directs the Board to include in rates provision to recover costs that a public
24 utility (i.e., YEC or AEY) reasonably incurs to provide or participate in a demand side
25 management program.

26
27 Based on YG's DSM policy and also considering growth in electrical load on the system,
28 Yukon Energy DSM planning was undertaken; this planning includes coordination with the
29 Yukon government's DSM programs to meet the overall policy objectives in a cost
30 effective manner.

31
32 DSM program costs of Yukon Energy have been approved by the Board in the past as
33 deferred costs that are included in rate base, consistent with the rate and rate base
34 provisions of the *Public Utilities Act* (“PUA”). The Board can continue to deal with these
35 costs in the future in the same manner.

1 **(g)**

2
3 YEC notes the Court of Appeal ruled on this proceeding on February 5, 2021 and the
4 appeal was dismissed. The Court of Appeal proceeding including the decision does not
5 affect the 2021 GRA Application as none of the costs that were covered by the appeal are
6 included in this Application.
7

8 **(h)**

9
10 As stated above, YG has publicly confirmed its support for utility-driven DSM programming
11 and further they indicated that they expect YEC to undertake such programing. Based on
12 YG's clear expectation (now confirmed by OIC 2021/16) and with the knowledge that a
13 significant capacity shortfall exists on the Yukon integrated system, YEC believed it was
14 timely and prudent to include these programming costs in the 2021 application.

1 **REFERENCE:** Application, Section 5.3.1.2, page 5-23, line 14

2
3 **ISSUE:** Effect of DSM on Energy and Capacity Requirements

4
5 **QUOTE:** "Since that determination the Yukon Government has put in place a
6 Climate Change policy initiative called "Our Clean Future: A Yukon
7 Strategy for Climate Change, Energy and a Green Economy" which
8 emphasizes the importance of DSM as a valuable resource to reduce
9 the Yukon's energy and capacity requirements. As part of that policy
10 the government fully expects YEC to pursue a cost-effective DSM
11 program." (footnote removed)

12
13 **QUESTION:**

- 14
15 a) Please provide any analysis or research compiled by YEC, or its program partners,
16 that supports the conclusion that DSM can reduce Yukon's energy and capacity
17 requirements.
18
19 b) Please provide any analysis YEC, or its program partners, has carried out
20 examining the effect of YEC's DSM projects to date on the energy and capacity
21 requirements for YEC and the associated cost savings compared to the costs of
22 the DSM programs.
23
24 c) Please comment on the potential effects on rates should DSM programs
25 administered by YEC lead to a significant decline in energy sales. In particular,
26 please provide YEC's view of whether it is possible for ratepayer-funded DSM
27 programs to lead to increased rates as a result of declining energy sales.
28
29 d) Please provide the results of any analysis carried out by YEC, or its program
30 partners, with respect to the ability of seasonal pricing to reduce peak energy and
31 capacity demand. If YEC has not carried out any such analysis, please explain
32 why.

1 **ANSWER:**

2
3 **(a) and (b)**

4
5 Yukon Energy in partnership with ATCO Electric Yukon and Yukon Government
6 completed a DSM Program Portfolio which was filed with the Yukon Utilities Board as part
7 of AEYs 2013-2015 GRA. This included a Conservation Potential Review, Market
8 Characterization, Implementation Plan, and Evaluation Measurement and Verification
9 Plan. The Conservation Potential Review was updated for Yukon Energy's 2016 Resource
10 Plan. DSM programs were again shown to be a cost effective resource and were included
11 in the recommended portfolio. These studies concluded the DSM can cost effectively
12 reduce Yukon's energy and capacity requirements.

13
14 A portion of the residential programs presented in this portfolio were launched to the
15 Yukon public. Progress reports and evaluations of the energy and capacity savings as well
16 as cost effectiveness of these programs in accordance with the filed Evaluation
17 Measurement and Verification Program were conducted and filed with the YUB. These
18 reports and evaluations clearly demonstrated DSM as a cost-effective energy and capacity
19 resource.

20
21 In Order 2014-06, the Board applied four standard cost-effectiveness measures for DSM
22 costs (collectively, the "InCharge Programs Prudency Measures"), namely the total
23 resource cost test (TRC), the program administration cost test (PAC), the rate-impact
24 measure test (RIM), and the participant cost test (PCT).¹ Program elements of the
25 residential non-government DSM portfolio that passed all four cost-effectiveness
26 measures for 2014 and 2015 were approved by the Board.

27
28 Evidence provided by Yukon Energy in the 2017/18 GRA indicated that the Approved
29 InCharge Programs met InCharge Programs Prudency Measures endorsed by the Board
30 in Order 2014-06 and were rate neutral for ratepayers. Specifically, Approved InCharge
31 Program development and delivery was reviewed in the 2017/18 Application at page 5-39
32 and 5-40. Figure 5-1 at page 5-40 provided a summary of energy savings and costs,
33 updated to the end of 2016 which noted that the programs achieved an overall RIM ratio
34 of 1.1 (1.0 shows the program is neutral from a utility rate impact perspective), and
35 achieved a very high PCT ratio (3.0) and high PAC ratio (9.4), demonstrating that the

¹ See Order 2014-06, Appendix A at pp. 94, 100-101.

1 programs are very beneficial to program participants and to utilities. Table 5-1 also showed
2 that the program achieved a high TRC ratio (3.1), showing that it also compares well
3 against other electricity resource options.

4
5 Evidence provided by Yukon Energy in the 2017/18 GRA also showed that the Approved
6 InCharge Programs elements were evaluated by a third party evaluation advisor in 2015
7 and 2016 which confirmed that the expenditures met or exceeded the above-noted
8 InCharge Programs Prudency Measures key performance indicators. The following were
9 specifically noted:

- 10
- 11 • The response to UCG-YEC-1-40 in that proceeding, provided the 2015 Interim
12 Evaluation Report by ICF Marbek; and the 2015-16 Evaluation Report by ICF
13 Marbek (actuals to end of July 2016).
 - 14
 - 15 • The evaluation reports were based on the Evaluation, Measurement and
16 Verification Plan filed with the YUB as an attachment to YUB-YECL-26(a) during
17 AEY's 2013-15 GRA².
 - 18
 - 19 • The energy savings and coincident peak demand reduction that have resulted from
20 the Approved InCharge Program were outlined in Table 2 of both the 2015 and
21 2015/16 Evaluation reports.³
 - 22
 - 23 • The response to YUB-YEC-1-80 (d) and (e) in YEC's 2017-18 GRA noted that the
24 cost benefit analysis provided by ICF Marbek was reviewed and approved by an
25 independent evaluator (Econoler).
 - 26

27 Reference to further supporting documentation that supports the conclusion that DSM can
28 reduce Yukon's energy and capacity requirements are provided below:

- 29
- 30 • Demand Side Management Plan including Program Portfolio, Conservation
31 Potential Review, Market Characterization and Working Group Guidelines.
32 [http://yukonutilitiesboard.yk.ca/pdf/YECL_2013-15_GRA_Part_2-](http://yukonutilitiesboard.yk.ca/pdf/YECL_2013-15_GRA_Part_2-DSM_plan.May_27_2013.pdf)
33 [_DSM_plan.May_27_2013.pdf](http://yukonutilitiesboard.yk.ca/pdf/YECL_2013-15_GRA_Part_2-DSM_plan.May_27_2013.pdf)

² YEC 2017/18 GRA proceeding, UCG-YEC-1-49(a).

³ YEC 2017/18 GRA proceeding, UCG-YEC-1-40(c).

- 1 • Program Implementation Plan http://yukonutilitiesboard.yk.ca/pdf/2013-08-08_YECL_Information_Responses.pdf
- 2
- 3
- 4 • Evaluation, Measurement and Verification Plan
- 5 http://yukonutilitiesboard.yk.ca/pdf/2013-08-08_YECL_Information_Responses.pdf
- 6
- 7
- 8 • inCharge Annual Reports including Program Evaluation Reports
- 9 http://yukonutilitiesboard.yk.ca/pdf/Reports/inCharge_Annual_Report_2017_FIN_AL.pdf
- 10
- 11 http://yukonutilitiesboard.yk.ca/pdf/Reports/2016_DSM_Annual_Report.pdf
- 12
- 13 • 2016 Resource Plan
- 14 http://yukonutilitiesboard.yk.ca/pdf/YEC_2017-18_GRA/Yukon_Energy_2016_Resource_Plan_Part_1.pdf
- 15
- 16 http://yukonutilitiesboard.yk.ca/pdf/YEC_2017-18_GRA/Yukon_Energy_2016_Resource_Plan_Part_2.pdf
- 17
- 18
- 19 • Conservation Potential Review Update
- 20 [https://yukonenergy.ca/media/site_documents/Appendix 5.20 Updates to Yukon Electricity Conservation and Demand Management Potential Review \(ICF 2016\).pdf](https://yukonenergy.ca/media/site_documents/Appendix_5.20_Updates_to_Yukon_Electricity_Conservation_and_Demand_Management_Potential_Review_(ICF_2016).pdf)
- 21
- 22
- 23

24 **(c)**

25

26 The RIM test as reviewed in Board Order 2014-06 (see response to (a) and (b) above)

27 recognizes and addresses the possibility that DSM programs may lead to significant

28 decline in energy sales that result in increased rates. As reviewed in response to (a) and

29 (b) above, Yukon Energy DSM programs were previously confirmed to pass the RIM test

30 and were rate neutral for ratepayers.

31

32 YEC anticipates that the targets for its ongoing DSM programs will emphasize capacity-

33 focused reductions rather than energy reductions. Capacity savings directly result in a

34 reduced requirement for temporary diesel rental units. These savings, in combination with

35 the fuel savings from any related energy savings, are expected to outweigh any potential

36 rate impacts driven by the reduction of sales.

1 (d)

2
3 YEC is aware that seasonal pricing can be an effective tool to reduce peak energy and
4 capacity demand. However, YEC has not proceeded with undertaking any detailed
5 analysis or assessments regarding implementation of seasonal pricing as a DSM
6 measure. As such, no analysis can be provided at this time.

7
8 While the 2017/18 GRA included forecast costs for a time-of-use rate structure and smart
9 grid study to assess the potential for a time-of-use rate structure and associated smart
10 grid – YEC did not proceed with undertaking this work. More specifically, in Order 2018-
11 10 the Board found that “YEC has not provided information that persuades the Board that
12 a study on smart grid and time-of-use rates is useful or needed. Accordingly, the Board
13 directs YEC to remove any forecast expenditures and cost recovery related to this project
14 in its compliance filing to this decision.”

15
16 Seasonal or time of use rates would drive a need to consider impacts on cost of service
17 (new rates/rate classes would require adjustments to COS study and alter results –
18 including possibly seeking to distinguish “winter” costs from “summer” costs); and YEC
19 would also need to consider the ability to implement a seasonal rate structure within rate
20 policy environment established by OIC 1995/90 and OIC 2018-220.

1 **REFERENCE:** Application, Tab 5, pages 5-1 to 5.6-1

2
3 **ISSUE:** Accuracy of Capital Project Forecasting

4
5 **PREAMBLE:** The Board wishes to evaluate the accuracy of YEC's project cost and
6 timeline forecasting and YEC's ability to control project costs.

7
8 **QUESTION:**

9
10 a) For all projects brought before the Board in YEC's 2008-09 GRA, 2012 GRA, 2016-
11 17 GRA and 2017-18 GRA, please provide a table showing the original forecast
12 cost and completion date provided to the Board and the final cost and completion
13 date.

14
15 b) Based on the information provided in response to part (a), please comment on the
16 accuracy of YEC's cost and timeline forecasts.

17
18 **ANSWER:**

19
20 **(a)**

21
22 Please see Table 1 that shows original forecast cost and completion dates for major
23 projects (with forecast GRA cost more than \$1 million) at the time projects were initially
24 proposed to be included in rate base for the three YEC GRAs during this time period
25 (2008/09 GRA, 2012/13 GRA and 2017/18 GRA), as well as actuals costs and completion
26 dates for these projects. In preparing this response YEC focused on major projects as
27 they represent most of the PP&E capital investments as well as providing the possibility
28 for review in the time available for responding to these IRs. For example, for the 2021 test
29 year about 91% of total PP&E capital spending is for major projects [91% for 2008 test
30 year, 47% for 2009 test year, 77% for 2012 test year, 70% for 2013 test year, 64% average
31 for 2017-2018 test years].

32
33 Please note that the cost information in column A is based on YEC's GRAs as requested
34 and will vary from the forecasts included in Part 3 applications, where applicable.

35
36 The costs in columns A and C are before contributions.

1 **Table 1: Major Projects Included in 2008/09, 2012/13 and 2017/18 GRAs [cost before contributions]**

	Included in GRA		Actuals		Note
	Total Cost, \$000	Completion Date	Total Cost, \$000	Completion Date	
	A	B	C	D	E
2008/09 GRA [note 1]					
Carmacks Stewart/Minto Spur Transmission Line Phase I	38,383	2008	40,343	2008	2008/09 GRA, pages 5-3 and 5-7
FD1 Re-Build	1,565	2008	1,674	2010	2008/09 GRA, pages 5-11
P126 WD3 Re-build	1,100	2008	1,370	2009	2008/09 GRA, pages 5-12
Sub-total	41,048		43,387		
2012/13 GRA					
Mayo B - Construction	116,588	2011	116,477	2011	2012/13 GRA, pages 5-5 and 5-6
Carmacks Stewart Transmission Line Stage 2	41,912	2011	41,912	2011	2012/13 GRA, pages 5-4 and 5-5
Aishihik Third Turbine Construction	13,817	2011	14,007	2011	2012/13 GRA, pages 5-6 through 5-9 [note 2]
Mayo Hydro - Substation Enhancements	10,153	2012	10,302	2012	2012/13 GRA, pages 5-9 through 5-11
Aishihik Generation Station Redundancy	6,365	2012	5,918	2011	2012/13 GRA, pages 5-14 through 5-16
Enterprise System	3,236	2012	2,983	2012/2017	2012/13 GRA, pages 5-19 through 5-21 [note 3]
Mayo Head Gate Repairs	1,334	2012	2,017	2012	2012/13 GRA, pages 5-11 through 5-14
Whitehorse Spillway Improvements	1,246	2012	1,548	2014	2012/13 GRA, pages 5-16 through 5-18
sub total	194,651		195,164		
2017/18 GRA					
AH Elevator Shaft Structural Steel Rehabilitation	10,116	2017	10,279	2017	2017/18 GRA, pages 5-7 and 5-8
Aishihik Electrical & Control Upgrades	2,511	2018	2,507	2019	2017/18 GRA, pages 5-8 through 5-11
Communications Upgrade	1,003	Dec, 2018	1,152	2019	2017/18 GRA, pages 5-12 through 5-14
Hydro Unit #WH4 Overhaul	4,291	2017	3,008	2018	2017/18 GRA, pages 5-15 and 5-16
LNG Plant	41,933	2016	41,933	2016	2017/18 GRA, pages 5-22 through 5-26
MH2 Overhaul	1,657	2018	1,645	2018	2017/18 GRA, pages 5-16 through 5-18
Wareham Spillway Gate Hoist Replacement	2,700	2015	2,700	2015	2017/18 GRA, pages 5-21
Whistle Bend Supply / Takhini Upgrade	11,383	2015	11,537	2015	2017/18 GRA, pages 5-22
T&D - Breaker Replacements	1,350	2018	1,278	2018	2017/18 GRA, pages 5-18 and 5-19 [Note 4]
sub total	76,946		76,039		
Total All Three GRAs	312,646		314,590		

2

Notes:

1. 2008/09 GRA also included a project to purchase Minto diesels at a cost of \$3.190 million. However, pursuant to the YUB's direction (para 207, Order 2009-08) the Minto diesels were removed from ratebase for the test years.
2. In 2012/13 GRA, page 5-9 YEC noted that "Yukon Energy is still attempting to resolve a number of issues including final deficiency work with the contractor which may impact costs but after the \$5 million contribution from the Yukon Government, the present estimate of the net rate base cost is approximately \$8.8 million." Please also see 2021 GRA, Appendix 5.1, page 5.1-8.
3. 2012/13 GRA, page 5-21 shows total projected cost at \$3.24 million. On that page YEC noted that the timing and scope of subsequent roll-outs will be dependent in part on the work done in Roll-Out #1. The cost of \$3.24 million included a portion of the project with \$2.486 million cost to be completed in 2012 and additional spending of \$0.750 million in 2012 and 2013 years. The project was partially completed in 2012 at a cost of \$2.486 million and remaining work through 2017 at total cost at \$0.495 million.
4. 2017/18 GRA included T&D - Breaker Replacements at a cost of \$1.350 million. As reviewed on page 5-16 of the 2021 GRA Application replacement of 5 medium voltage (34.5kV) breakers in YEC substations S150(4) and S176(1) was completed with a cost of \$0.798 million, including \$0.688 million spending in 2018. Separately, replacement of 7 high voltage (138kV) breakers in YEC substations at Aishihik Faro, Riverside and Takhini with cost of \$2.260 million was completed in 2019. The \$1.278 million spending in column C reflects spending of \$0.688 million for the first project and \$0.479 million for the second project as shown in Table 5.2-1.

1 (b)

2
3 Table 1 shows varying outcomes for different projects, as would be expected. Overall,
4 however, the capital cost and timeline forecasts in these three GRAs were reasonably
5 accurate.
6

7 1. **Capital costs** – Overall, actual major project capital costs across the three GRAs
8 were 100.6% of the capital costs included in the GRA rate base forecasts, i.e.,
9 actuals were very close to GRA forecast.

10 a. Actual results as a percentage of forecast varied by GRA, from 105.7% for
11 the 2008/09 GRA to 98.8% for the 2017/18 GRA.

12 b. Results are affected by many projects already being completed or largely
13 completed at the time of GRA filing. However, the largest project in the
14 table (Mayo B) was also basically completed within the budget forecast
15 before construction commenced. The spread in actual results as a
16 percentage of forecast for different projects ranges from 70% (Hydro Unit
17 #WH4 Overhaul) to 151% (Mayo Head Gate Repairs).
18

19 2. **Completion dates** – 13 of 20 (65%) of the major projects in Table 1 were
20 completed on or before the forecast completion year in the GRA, and another
21 (Enterprise System) had its major component completed on schedule and the
22 balance completed at less than forecast cost; together, these 14 projects
23 accounted for over 96% of the final completion costs for all projects in Table 1.

1 **REFERENCE:** Application, Tab 5.2.1, pages 5-5, 5-7, 5-8, 5-11, 5-13, 5- 15 to 5-19
2 and 5-32

3
4 **ISSUE:** Costs for Capital Works Projects Greater Than \$1 Million

5
6 **PREAMBLE:** In this section of its application, YEC outlined the costs for Capital
7 Works projects greater than \$1 million as follows:

- 8
9
10 • For the LNG Third Engine Project, YEC indicated that it spent
11 \$3.156 million in 2017, \$5.008 million in 2018 and \$0.097 million in
12 2019.
- 13 • For the N-1 Capacity Shortage Whitehorse Thermal Rental Site
14 Infrastructure Project, YEC indicated it spent \$0.227 million in 2018
15 and \$1.070 million in 2019.
- 16
17 • For the N-1 Capacity Shortage Faro Thermal Rental Site
18 Infrastructure Project, YEC indicated a forecast of \$2.037 million in
19 2020.
- 20
21 • For the Mayo – McQuesten Transmission Line Upgrade Project,
22 YEC indicated it spent \$0.501 million in 2019, indicated a forecast
23 of \$20.000 million in 2020 (offset by a \$15.274 million contribution)
24 and indicated a forecast of \$11.200 million in 2021 (offset by a \$8.4
25 million contribution).
- 26
27 • For the McQuesten Substation Project, YEC indicated it spent
28 \$0.123 million in 2018 and \$11.496 million in 2019 (offset by a
29 \$10.688 million contribution).
- 30
31 • For the Transmission Line Refurbishment Project, YEC indicated it
32 spent \$4.272 million in 2019.
- 33
34 • For the Transmission Line Refurbishment – L178 Project, YEC
35 indicated a forecast of \$1.3 million in 2021.

- For the Breaker Replacement Program Project, YEC indicated it spent \$0.479 million in 2018 and \$1.781 million in 2019.
- For the Replacement of the P125 Head Gate Project, YEC indicated it spent \$0.093 million in 2019, indicated a forecast of \$2.300 million in 2020 and indicated a forecast of \$3.500 million in 2021.
- For the WH2 Uprate Project, YEC indicated it spend \$3.044 million in 2019, indicated a forecast of \$1.693 million in 2020 and indicated a forecast of \$7.300 million in 2021.
- For the WH4 Uprate – Servomotor Replacement Project, YEC indicated it spent \$0.052 million in 2018, \$0.079 million in 2019, indicated a forecast of \$0.400 million in 2020 and indicated a forecast of \$1.000 million in 2021.

YEC stated it reflected these costs in Table 5.2.1 in its application, found from pages 5-32. It is not clear how YEC allocated these costs over the previous years and how it plans to allocate these costs in its forecasted years.

QUESTION:

- a) Please provide a cost breakdown for the projects provided in the preamble. More specifically, provide the activities conducted (or the activities YEC forecasts to conduct) and the cost amount allocated to each activity.

ANSWER:

(a)

Please see the following tables that provides cost breakdown by major activities for each project listed in the preamble. Due to nature as well as the stage of the projects [actuals vs forecast] the key activities are not the same for all projects.

Please note that the following tables reflect updated costs for 2020 based on preliminary actuals and/or forecasts for 2021:

- 1 • Table 6: N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure reflects
2 project preliminary actual costs. Please see response to CW-YEC-1-26 (b) that
3 provides explanation for higher actual costs.
4
- 5 • Table 7: Mayo – McQuesten Transmission Line Upgrade Project reflects project
6 preliminary actual costs for 2020 [\$3.014 million lower than the forecast] and
7 updated 2021 forecast [\$0.422 million lower than the forecast in the application].
8
- 9 • Table 8: Replacement of the P125 Head Gate Project reflects project preliminary
10 actual costs for 2020 [\$0.342 million lower than the forecast] as well as change in
11 scope for the project. The original scope of the project included work on WH1,
12 WH2 and WH3 headgates with total project cost at \$5.893 million, including about
13 \$3.5 million in 2021 for WH1 and WH3 headgates. YEC has now postponed work
14 on WH2 and WH3 headgates to 2022 and 2023, respectively. The revised cost in
15 Table 8 reflects removal of cost estimate for WH2 and WH3 headgates.
16
- 17 • Table 9: WH2 Uprate Project reflects project preliminary actual costs for 2020
18 [\$0.827 million lower than the forecast] and updated 2021 forecast [\$1.046 million
19 higher than the forecast in the application].
20
- 21 • Table 10: WH4 Uprate – Servomotor Replacement Project reflects project
22 preliminary actual costs for 2020 [\$0.146 million lower than the forecast].
23

24 Yukon Energy will reflect updated projects costs in the compliance filing.
25

26 Please also note that McQuesten Substation Project was built by Victoria Gold
27 Corporation and transferred to YEC, therefore, YEC does not have cost breakdown by
28 activities.

1 **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

2
3

4 **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

5
6
7

8 **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

9

1 **Table 4: Transmission Line Refurbishment – L178 Project, \$000**

Total Cost

Civil work	800.0
Installation	400.0
Materials	100.0

2 **Total** **1,300**

3

4 **Table 5: Breaker Replacement Program Project, \$000**

Total Cost

AFUDC	16.2
Equipment	949.0
Installation	658.2
Labour	283.2
Owner's Engineer	299.2
YEC Internal	54.2

5 **Total** **2,260**

6

7 **Table 6: N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure, \$000**

Total Cost

Engineering & Design	386.5
Materials	754.7
Installation & Construction	715.0
Internal Costs	417.7
Project Management	171.7

8 **Total** **2,446**

1	Table 7: Mayo – McQuesten Transmission Line Upgrade Project, \$000				
		2019	2020	2021	Total Cost
	<u>Mayo-McQuesten Transmission Line</u>				
	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
	<u>STATCOM</u>				
	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
2	Variance	0	-3,014	-422	-3,436

3					
4	Table 8: Replacement of the P125 Head Gate Project, \$000				
		2019	2020	2021	Total Cost
	Engineering, Project Mgmt & Internal Costs	93	94	50	237
	Installation Contractor	0	1,865	0	1,865
	Total	93	1,958	50	2,102
	Per 2021 GRA Application	93	2,300	3,500	5,893
5	Variance	0	-342	-3,450	-3,792

1

Table 9: WH2 Uprate Project, \$000

	2019	2020	2021	Total Cost
Owner's Engineer	167	213	732	1,112
Turbine & Generator	2,618	114	4,721	7,453
Internal Costs & Project mgmt	228	173	745	1,146
Balance of plant	32	366	436	834
Contingency & AFUDC	0	0	1,711	1,711
Total	3,044	866	8,346	12,256
Per 2021 GRA Application	3,044	1,693	7,300	12,038
Variance	-0	-827	1,046	218

2

3

4

Table 10: WH4 Uprate – Servomotor Replacement Project, \$000

	2018	2019	2020	2021	Total Cost
Servomotor supplier	0	0	142	576	718
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	1,000	1,385
Per 2021 GRA Application	52	79	400	1,000	1,531
Variance	0	0	-146	0	-146

5

1 **REFERENCE:** Application, Tabs 5.2.1.1 and 5.2.1.2, pages 5-5, 5-7 and 5-8

2
3 **ISSUE:** The LNG Third Engine, N-1 Capacity Shortage Whitehorse Thermal
4 Rental Site Infrastructure and N-1 Capacity Shortage Faro Thermal
5 Rental Site Infrastructure projects.
6

7 **QUOTE:** From page 5-5 of the Application:
8

9 “The LNG Third Engine Project provides a third natural gas-fired
10 generation unit of approximately 4.4 MW at the Whitehorse thermal
11 plant to help address the existing dependable capacity shortfall in a
12 cost effective manner. YEC is required to provide sufficient dependable
13 winter capacity to meet the single contingency capacity reliability
14 criterion, i.e., there is no acceptable “do nothing” option given the need
15 to maintain reliable service, and permanent solutions (rather than
16 relying on temporary options such as mobile diesel) are needed to
17 address an ongoing and growing dependable capacity shortfall.”
18 (footnote removed)
19

20 From page 5-7 of the Application:
21

22 “The [N-1 Capacity Shortage Whitehorse Thermal Rental Site
23 Infrastructure Project] involved the design of infrastructure to
24 accommodate temporary rented thermal generators at Whitehorse
25 substation to address the capacity shortfall projected under the N-1 for
26 2018/19 and 2019/20 winters.
27

28 In winter 2018/19 six temporarily rented 1.8 MW units were installed in
29 the proximity of S150 Whitehorse Rapids Substation. The 2019 project
30 included installation of two additional temporarily rented 1.8 MW units
31 in the area between P126 Whitehorse Diesel and S150 Whitehorse
32 Substation. The project scope included ... installation support
33 temporary seasonal diesel power generators to meet seasonal N-1 load
34 requirements and assist with meeting winter system peaks. Total
35 project cost was approximately \$1.298 million.”

1 From pages 5-7 to 5-8 of the Application:
2

3 "The [N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure]
4 involves the design and installation of temporary rental site electrical
5 infrastructure at Faro (870S) to ensure YEC can continue to meet its N
6 1 capacity planning requirements ... The project is expected to be
7 completed in 2020 at an estimated budget of \$2.037 million. The project
8 is on track for a mid-November 2020 in service date."
9

10 **QUESTION:**
11

- 12 a) Please provide the studies that were conducted showing the N-1 capacity criterion
13 was being violated prior to the development of the LNG Third Engine, N-1 Capacity
14 Shortage Whitehorse Thermal Rental Site Infrastructure and N-1 Capacity
15 Shortage Faro Thermal Rental Site Infrastructure projects.
16
- 17 b) Please provide the studies that were conducted to show that these projects met
18 the N-1 capacity criterion.
19
- 20 c) Given that the LNG Third Engine Project was required as a permanent solution to
21 meet the N-1 capacity criterion, please explain why YEC carried out the
22 Whitehorse Thermal Rental Site Infrastructure and Faro Thermal Rental Site
23 Infrastructure projects, which installed temporary infrastructure.
24
- 25 d) Given that the Whitehorse Thermal Rental Site Infrastructure and Faro Thermal
26 Rental Site Infrastructure projects involve temporarily rented generators and
27 temporary electrical infrastructure, please explain if YEC plans to implement a
28 permanent solution in the future to meet the N-1 capacity criterion. For example,
29 will the Battery Energy Storage System project discussed on page 5.1-5 of the
30 Application replace the need for these projects?
31
- 32 e) Please provide an update on the Faro Thermal Rental Site Infrastructure Project,
33 which had an in-service date of November 2020. Additionally, please indicate
34 whether work was carried out by YEC staff or consultants. If external consultants
35 were hired, please explain the competitive process that was followed.

1 **ANSWER:**

2
3 **(a), (b), (c), and (d)**

4
5 Section 2.4 of the Application provides details on the determination of the N-1 dependable
6 capacity shortfall for 2021 and other years, including the criteria established in this regard
7 in YEC's 2006 Resource Plan, updates carried out since that time, and the 2016 Resource
8 Plan assessment of the N-1 capacity shortfall that emerged at that time and was forecast
9 to grow until material new dependable capacity was developed. In January 2020, YEC
10 experienced record peak demands which increased forecast capacity requirements.

11
12 As summarized at page 2-15 of the Application, under the N-1 dependable capacity
13 criterion the N-1 capacity shortfall in 2021 without rented diesels is forecast at 25.75 MW
14 after including the LNG Third Engine new dependable capacity of 4.2 MW. Provision of 27
15 MW of rented diesels using the referenced diesel rental infrastructure at Whitehorse and
16 Faro is shown to result (in combination with the LNG Third Engine) with a surplus of
17 dependable capacity of approximately 1.25 MW for 2021. In summary, both the LNG Third
18 Engine and the rental diesels with related infrastructure were needed to meet the N-1
19 capacity criterion in 2021.

20
21 YEC's recent 10-Year Renewable Electricity Plan at Figure 17 and Table B3 provides a
22 Base Case forecast of the substantial annual N-1 capacity shortfall absent diesel rentals
23 that grows to 50 MW by 2035/36 with existing, committed and planned resources that
24 include the Battery Energy Storage System, Diesel Replacement and DSM program
25 projects. This updated resource plan includes proposed future renewable generation
26 projects (i.e., Atlin Hydro Expansion Project and Tutshi- Moon Pumped Storage) that
27 would provide permanent dependable capacity to remove this N-1 capacity shortfall (see
28 summary at Table D1 of the plan). For a copy of this plan, please see Attachment 1 to
29 CW-YEC-1-36(a). Even with this permanent solution, the diesel rental infrastructure will
30 continue to enable back-up diesel rental capability if required.

31
32 **(e)**

33
34 The Faro rental site was commissioned and in service December 1, 2020.

35
36 The construction of the site was primarily carried out by YEC staff. Construction support
37 was provided through existing vendor service contracts.

- 1 Engineering design and support was provided through an RFQ process, with the lowest
- 2 price qualified bidder awarded the contract.

1 **REFERENCE:** **Application, Tab 5.2.1.3, pages 5-8 to 5-10**

2
3 **ISSUE:** **The Mayo-McQuesten Transmission Line Upgrade Project**

4
5 **QUOTE:** From page 5-8 of the Application:

6
7 “The Mayo – McQuesten Transmission Line (MMTL) project involves
8 the construction of a new 138 kV framed transmission line from the
9 Mayo to McQuesten substations as well as the installation of electronic
10 voltage support equipment (Statcom) at Stewart Crossing South
11 substation that will improve overall reliability and power quality in the
12 system. The [Mayo – McQuesten Transmission Line Upgrade Project]
13 transmission will initially be operated at 69 kV.

14
15 The existing 69 kV transmission line from Mayo to Keno constructed by
16 the Northern Canada Power Commission (NCPC) in 1951 is at end of
17 life and in need of replacement. The transmission line has experienced
18 both reliability and power quality issues with an increasing number of
19 outages on the line affecting customers on a system wide basis. Key
20 requirements under the VGC Group PPA include development of the
21 McQuesten Substation plus new transmission to replace the existing
22 69 kV facilities between at least Mayo and McQuesten by
23 approximately summer of 2020.” (footnote removed)

24
25 From page 5-9 of the Application:

26
27 “Later stages will proceed only when loads in the area justify increasing
28 the operating voltage to 138 [kV], and when additional federal funding
29 becomes available ... Increased power transfer/ capacity will also
30 support economic development in central Yukon, as well as connection
31 of renewable energy sources such as hydro, wind and solar.”

32
33 “Effects assessment and stakeholder engagement development
34 activities for all project stages were undertaken in 2015 and 2016. As
35 reported during the 2017-18 GRA, all project permits were in place,
36 including the land use permit, access permits and highway permits. No

1 additional permitting was anticipated to be required.” (footnote
2 removed)

3
4 From page 5-10 of the Application:

5
6 “Decommissioning of the old 69 kV line is expected to occur between
7 November 2020 and December 2020. Substation construction at
8 Stewart Crossing commenced in August 2020 and is expected to be
9 completed by June 2021. An order has been placed for the Statcom
10 and it is in manufacturing. Statcom delivery is expected to occur by
11 August 2021, with installation in September 2021 and commissioning
12 completed by October 2021.”
13

14 **QUESTION:**

- 15
- 16 a) Please provide the reliability criteria YEC utilizes in assessing the viability of its
17 electric system (e.g. the thermal limit ratings and acceptable voltage range on
18 transmission lines).
19
- 20 b) Please provide and explain the studies that were conducted to show that the
21 existing 69 kilovolt (kV) transmission line had reliability and power quality issues.
22 For example, did YEC carry out a contingency analysis that showed this line
23 exhibited reliability criteria violations?
24
- 25 c) Please explain how often YEC carried out studies and assessed the reliability of
26 the existing 69 kV transmission line in the past.
27
- 28 d) Please explain why YEC proposed to install STATCOM in this project. Were any
29 other alternatives to STATCOM explored (e.g. static VAR compensators or
30 synchronous condensers)? If other alternatives were explored, please provide the
31 costs of these alternatives and the reasons these alternatives were dismissed.
32
- 33 e) Please provide the number and duration of outages experienced on the line in the
34 last 10 years, on a per annum basis, and the costs incurred due to these outages.

- 1 f) Please provide and explain the studies that were conducted to show the Mayo-
2 McQuesten Transmission Line Upgrade Project resolved reliability and power
3 quality concerns.
4
- 5 g) Please explain if any other alternative solutions were proposed and explored. If
6 applicable, please provide and explain the studies conducted on these alternatives
7 and provide the costs of these alternatives.
8
- 9 h) Given that YEC plans to operate this new line initially at 69 kV and future load will
10 need to justify an operating voltage of 138 kV, please explain why YEC considered
11 it prudent to spend capital on infrastructure designed for 138 kV.
12
- 13 i) Please explain if there were any concerns brought up during stakeholder
14 engagement sessions and if there are any outstanding concerns to date.
15
- 16 j) Please provide details on the selection process of contractors for this project,
17 including how contracts were awarded for this project.
18
- 19 k) Based on the information provided in page 5-10 of the Application, please provide
20 an update on the project. For example, did YEC decommission the old 69 kV line?
21

22 **ANSWER:**

23
24 **(a)**

25
26 Attachments 1 this response provides Transmission Line Design Criteria Stewart to Keno
27 Transmission Project 138 kV Transmission Lines which is relevant to the MMTL Project.
28 Attachment 2 provides YEC L170 Transmission Line – Clearance and Structural
29 Evaluation Criteria” – this document defines YEC’s evaluation criteria for all structures,
30 and is also relevant to the MMTL project.
31

32 **(b), (c) and (e)**

33
34 As noted in Tab 5, Section 5.21.3 of the Application, a new line from Mayo to the Keno
35 City region is required at this time to replace the end of life existing 69 kV line constructed
36 in the 1950’s. This line is in poor condition and there has been a significant degradation in

1 reliability. This was reviewed previously during the 2017 VGC Group PPA proceeding and
2 the 2017/18 GRA¹, and is also supported by data collected from inspections.

3
4 In the early 1990s, Yukon Energy noted that the line was significantly deteriorated and
5 needed to be rebuilt or abandoned due to safety and reliability concerns;² however, at the
6 time a rebuild could not be justified due to the closure of UKHM. As an alternative, minimal
7 capital improvements were undertaken at that time to maintain the line and ensure
8 continued service to existing non-industrial customers;³ and over the past 15+ years
9 transmission line repairs have been required on an ongoing basis to address reliability
10 concerns.

11
12 More specifically, the Stewart- Keno Transmission Line Project Proposal filed with YESAA
13 in 2015 noted⁴:

14
15 Transmission line repairs have been required over the past fifteen years to address
16 ongoing reliability concerns. Line reliability has also become a more significant
17 issue and line outages have increased, affecting customers on the Integrated Grid
18 (including local customers as well as customers as far away as Dawson City and
19 Whitehorse). For example, outages on the Mayo to Keno line have increased from
20 4 outages in 2012, to 6 outages in 2013, to 19 outages in 2014 to 20 outages (to
21 the end of Q3 2015) – outages for 2015 are forecast to be 27. Further, in 2011,
22 35% (or 188 of 535) of the structures on L250 failed the test and treat assessment
23 undertaken at that time and were considered unsafe to climb, limiting the
24 maintenance work that can be safely undertaken on these structures. The

¹ See for example, YEC's 2017 VGC Group PPA Application, section 4.3; and 2017/18 GRA Section 5.3.1.1; and response to YUB-YEC-1-78.

² The Yukon Energy 1992 Resource Plan notes "This line was built in 1952 with untreated native poles, which have long since rotted at ground level. Virtually every pole on this line has been stubbed (a small pole attached at ground level) or cribbed (a rock filled culvert or container added) over the last forty years. The line was identified as a severe safety hazard for Company employees and the general public."

³ In its 1992 Resource Plan, Yukon Energy noted that "it was recognized for many years, by both NCPC and YEC, that the Mayo-Elsa-Keno City transmission line urgently needed to be either re-built or abandoned." At the time, it was noted that "this project just could not continue to be deferred indefinitely," and "essential work had to be performed to ensure the safety of the line." The option of abandoning the transmission line was considered and discarded at the time for the following reasons: (1) Additional loads are also supplied from this line, via Keno City, CBC and NWTel tower sites, Silver Trail Lodge and a number of YTG Highways heat traces in culverts; and (2) The cost of diesel generation would be at least \$250,000 per annum based on approximately 2.5 kWh consumption at 10 cents per kWh by UKHM.

⁴ Stewart-Keno Transmission Line Project Proposal, Chapter 6, page 6-3.

remoteness of the line as well as terrain and access challenges also magnify the costs and difficulties involved in managing maintenance and reliability of this asset.

No power quality studies were performed for the existing 69kV transmission line due to the fact that the numerous outages were the assumed to be the cause of power quality issues experienced.

The following is noted regarding past inspections/ assessments for L250:

- A Line inspection was performed on L250 in 2002.
- A detailed Line inspection was performed on L250 in 2008.
- Wood pole test and treat was performed on the line on L250 in 2011.
- Outage statistics on L250 are updated as they occur.

Yukon Energy performs overhead line inspections and wood pole test and treat inspections to determine the condition of the line and poles. Outage reports are also reviewed annually to identify reliability issues.

See Table 1 below 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.

Table 1: Number and Duration of Outages: 2011 to 2020

Year	Unplanned Outages	Planned Outages	Total Outages	Outage Hours
2011	8	0	8	16.19
2012	4	0	4	5.91
2013	6	0	6	3.78
2014	14	5	19	126.24
2015	23	7	30	105.1
2016	9	1	10	0.6
2017	14	0	14	8.2
2018	4	3	7	9.62
2019	20	0	20	14.42
2020	1	3	4	4.19

(d)

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.

See Table 2 below for further details.

Table 2: Stewart Crossing Potential FACTS Solutions

	STATCOM	SVC	Synchronous Condenser	BESS plus STATCOM
Pros	Fastest response for reactive power support.	The most economical solution for reactive power support.	Provides frequency stability enhancement in addition to reactive power support. This may avoid predicted and future review/changes for frequency protection relays or RASs.	Potentially addresses frequency issues.
Cons	There are no cons associated with the STATCOM solution, for providing the required reactive power support	It is considered as a harmonic source, and doesn't have a quick response time compared to the STATCOM (e.g. flicker).	No-load running losses; may require additional maintenance when compared with the STATCOM or SVC solution.	Not commercially available. Would require custom design and assembly.
Relative Budgetary Cost *	1.0	0.90 - 0.95	1.4 – 2.0	Unknown. Costs would need to be determined via communication with the potential suppliers.
Other Notes	For low inertia systems, the addition of a STATCOM (as a solution for the deficient reactive power support) is a fix for only one issue. However, the wide swing of frequency may impact the evaluation of the required reactive power support.	This technology is fading in popularity. A STATCOM would be the preferred solution for reactive power support.	Synchronous condensers (synchs) are the solution for both reactive power deficiency and frequency instability. Synchs will provide long term operational easiness. They will also reduce or eliminate the need for future frequency RASs. YEC personnel have O&M synchronous condenser experience.	This solution would require significant research/study, consultation/coordination with suppliers, etc. which would result in additional time and cost for the project. Ongoing costs associated with battery life would need to also be considered.

NOTE: * The above relative budgetary costs are provided based on Teshmont's in-house information. Supplier input was not obtained.

(f), (g) and (h)

As noted in part (b) a new line from Mayo to the Keno City region is required to replace the end of life existing 69 kV line constructed in the 1950's. This fundamental requirement necessitated the project as a key element of the PPA as approved by the Board.

Please see Attachment 1 to this response which provides the Chimax Inc Transmission Line preliminary design report; and Attachment 2 which provides the Chimax Inc Transmission Line Scope Extension Report which reviews overall project cost comparisons between Mono Pole and H-Frame transmission structures.

As reported on and reviewed during the VGC Group PPA proceeding, an assessment was also carried out to determine the transmission upgrades required to supply the proposed Eagle Gold facility (EG) from the Yukon Energy Corporation (YEC) power system while providing acceptable service and reliability to EG and existing YEC customers. This study confirmed the system upgrades required (as provided for in the PPA), and the STACOM requirement as part of the overall system improvements.

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 was less than 10% (between 3.8% and 9.4%).

Table 3: Preliminary Cost Estimates SKTP

Voltage	L180				L250		
	138kV		69kV		138kV	69kV	
Pole Framing	H-Frame	Mono Pole	Mono Pole		H-Frame	Mono Pole	
Tangent Insulator Type	Suspension	Braced Post	Braced Post	Post	Suspension	Braced Post	Post
Fiber Configuration	OPGW	OPGW	OPGW	OPGW	OPGW	ADSS	ADSS
No. Structure	162	218	255	255	118	175	175
No. Pole	354	230	266	266	227	178	178
Cost Item							
Procurement	\$3,200,315.77	\$3,317,249.23	\$3,261,908.91	\$2,838,233.03	\$1,935,469.37	\$1,842,557.06	\$1,497,569.84
Construction	\$6,515,800.56	\$5,605,689.15	\$5,839,587.50	\$5,651,915.12	\$4,090,160.91	\$3,578,987.53	\$3,447,030.38
Engineering Support	\$68,790.00	\$83,910.00	\$93,900.00	\$93,900.00	\$56,910.00	\$72,300.00	\$72,300.00
Construction Management	\$950,400.00	\$950,400.00	\$950,400.00	\$950,400.00	\$799,000.00	\$799,000.00	\$799,000.00
Additional Cost Provision	\$281,029.86	\$399,254.44	\$447,979.30	\$447,979.30	\$159,717.42	\$301,112.00	\$301,112.00
Sub-Total	\$11,016,336.19	\$10,356,502.82	\$10,593,775.71	\$9,982,427.45	\$7,041,257.70	\$6,593,956.59	\$6,117,012.22
Contingency (10%)	\$1,101,633.62	\$1,035,650.28	\$1,059,377.57	\$998,242.75	\$704,125.77	\$659,395.66	\$611,701.22
Estimated Cost	\$12,117,969.81	\$11,392,153.10	\$11,653,153.28	\$10,980,670.20	\$7,745,383.47	\$7,253,352.25	\$6,728,713.44
cost per km	\$390,902.25	\$367,488.81	\$375,908.17	\$354,215.17			
Comparison							
Cost Differences		(\$725,816.71)	(\$464,816.53)	(\$1,137,299.61)		(\$492,031.22)	(\$1,016,670.03)
% Reduction		-5.99%	-3.84%	-9.39%		-6.35%	-13.13%
Assumptions:							
All mono pole embedments are based on 10% pole length plus 6ft (from grade). Actual embedment requirement will vary, require additional engineering in final design.							
For 138kV mono pole, average pole span is approximately 150m (cable galloping governed)							
For 69kV mono pole, average pole span is approximately 120m (cable galloping governed)							
Remarks:							
The increased structure count and combined with higher Braced Post Insulator cost, the mono pole option with braced post insulator would not provide significant saving compared with H-Frame structure. The reduced 69kV span allow utilization of post insulator which can significantly reduce the overall cost.							

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

- 2
- 3 1. For an increase in initial capital cost of between 4 % and 10% (for L-180 this would
- 4 amount to between \$0.5M and \$1.0M) from 69 to 138 kV.
- 5
- 6 2. The benefits of prebuilding to a 138 kV standard are an increase in the ultimate
- 7 line capacity of up to 400%.
- 8
- 9 3. The existing powerline is at its end of life and must be replaced in order to continue
- 10 to serve existing customers in this region and new industrial customers.
- 11
- 12 4. It is not possible to upgrade a 69 kV line to 138 kV design at a later date cost
- 13 effectively if at all.
- 14
- 15 5. The long term plan for any expansion to the Yukon's hydro grid is at the 138 kV
- 16 voltage level or higher due to the small incremental capital cost between 69 kV
- 17 and 138 kV.
- 18
- 19 6. Increase in reliability.
- 20

21 The selection of 138 kV vs 69 kV for this project was also addressed at some length during
22 the VGC PPA proceeding. It was noted that the VGC Group PPA default transmission
23 option defines a minimum priority development consistent with the SKTP planning to
24 provide 138 kV capability to facilitate potential future load and/or renewable resource
25 supply development in this region. Key features noted included the following:

- 26
- 27 • SKTP planning assessed transmission options, including 69 versus 138 kV
- 28 options, and concluded that the mono pole option with braced post insulators at 69
- 29 kV would not provide significant cost savings compared with the proposed H-
- 30 Frame structure and 138 kV when assessing costs for this new transmission.
- 31
- 32 • Further, proceeding to install a 69 kV transmission option with adequate upgrade
- 33 limited only for VGC Group and Alexco would maintain existing service, but ignore
- 34 the opportunity to strengthen and enhance the existing grid system to better
- 35 support future development opportunities in the region.

- The example of the existing relatively new 69 kV from Stewart Crossing to Mayo highlights the significant added costs to come back in future (as per the full SKTP proposal) to increase the capability of transmission to 138 kV after a new 69 kV line has been installed.

It is expected that reliability will improve through replacing a 66 year old transmission line (built in the 1950's) that is at end of life with a new transmission line that is installed using today's line design standards.

Once the line is in service, reliability will be tracked.

(i)

Attachment 1 summarizes concerns raised by members of the public as part of the public engagement process to support the development of the Project Proposal for the Stewart-Keno Transmission Line Project and how these concerns were addressed.

During construction – the following stakeholder engagement occurred:

- Virtual meetings with FNNND Council, Village of Mayo and Selkirk Development Corporation (designate for Selkirk First Nation) to discuss status of the project, COVID-19 safety plans and to determine any concerns with proceeding with the project during COVID-19 (no concerns were raised about proceeding with the project during COVID-19 so long as YEC followed strict project and community COVID-19 safety plans).
- Weekly Project Updates to contacts at the FNNND, Selkirk First Nation, Village of Mayo, Selkirk Development Corporation and NND Development Corporation. These started in June 2020 and have continued since.
- Monthly Project Updates prepared for Village of Mayo Council, FNNND Council and Selkirk First Nation Council. Emailed to each government's designates beginning in June 2020 and have continued since.
- One Newspaper ad that ran in the Yukon News in June 2020 to advise Yukoners that the project was moving forward.

- 1 • Project Newsletters mailed to residents in Mayo, Keno and Pelly with updates
2 about the project. Newsletters were distributed in June 2020, August 2020 and
3 February 2021.
- 4
- 5 • A virtual public meeting hosted on June 11, 2020 to discuss the project. Less than
6 five people attended.
- 7
- 8 • Project information is provided on YEC's website and in occasional social media
9 posts.

10
11 YEC received a complaint about ruts that were left in a resident's driveway by one of
12 YEC's contractors during construction. The complaint was addressed and repairs were
13 made to the driveway.

14
15 The Department of Environment, Government of Yukon also engaged YEC to discuss a
16 public complaint of construction-related disturbances to the Minto Creek Bridge
17 Interpretive Trail area. Yukon Energy prepared a restoration plan for consideration by YG
18 in this regard and expects to implement the restoration activities in the spring and summer
19 of 2021 as it conducts other post-construction clean-up activities along the transmission
20 line typical of such projects.

21
22 **(j)**

23
24 Contractors were selected through a competitive RFP process. Each of the contacts were
25 evaluated based on technical ability, price and the ability to provide FN opportunities.
26 Once the evaluation process was completed and successful bidder selected based on
27 total score, contract negotiations began, were finalized and signed.

28
29 **(k)**

30
31 The L180 Transmission line will be completed and fully energized in March 2021. Upon
32 energization of the new line, the old 69kV line will be decommissioned / removed with an
33 anticipated end date of April 2021.

Chimax Inc.

TRANSMISSION LINE DESIGN CRITERIA

**STEWART TO KENO TRANSMISSION PROJECT
138 kV TRANSMISSION LINES**



Yukon Energy Corporation

Prepared by: Edmund Kwong
December 12, 2017 (Rev-2)

Reviewed by: Raymond Leung
Approved by: Kevin Wong, P.Eng.

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1.0 Project Overview

Yukon Energy Corporation (YEC) is proposing to construct a 138kV transmission line from Stewart Crossing South (SCS) substation to Keno City (KC) substation. The overall transmission line and associated substation construction or modification is grouped as SKTL project.

1.1 Project Descriptions

The proposed 138kV transmission line route originates and travels north from SCS substation (S251) generally parallel existing L175 138kV transmission line to a point north of Stewart Crossing North (SCN). At this point the route turns east and parallels the existing L176 69kV transmission line to Mayo substation (S249). The transmission line will turn northeast to parallel the existing L250 69kV transmission line to KC substation (S257). A new substation at McQuesten (S258) will be constructed north of Halfway Lakes to convert voltage from 138kV to 69kV. The transmission line from S258 to S257 will be constructed for 138kV and energized at 69kV.

The existing L176 and L250 69kV transmission right of way is 60m wide which should accommodate 2 (two) parallel transmission line circuits.

The preliminary design will assess deviations from the YEC primary proposed route due to land use conflicts, environmental restriction, construction and maintenance access, geological restriction, etc.

2.0 Design Codes and Regulations

The design of the 138kV transmission line will be based on both deterministic approach as per CSA C22.3 No.1 (C22.3 No.1) “Overhead System” and reliability approach as per CSA C22.3 No.60826 (C22.3 No.60826) “Design Criteria of Overhead Transmission Lines”.

The conditions outlined in CSA C22.3 No.1 are minimum design requirements for both transmission and distribution overhead lines.

CSA C22.3 No.60826 outlines additional extreme weather conditions and design requirements for transmission line voltage exceeding 70kV (phase – phase voltage) as recommended in CSA C22.3 No.1 Section 10.

YEC has specified the design of the SKTL transmission lines to comply with Alberta Electrical Utility Code (AEUC) in addition to CSA code requirements. Chimax will also review and incorporate the relevant information and guidelines outlined in the Alberta Electrical System Operator (AESO) ISO Rules Section 502.2 “Bulk Transmission Line Technical Requirements”.

In addition to the Canadian overhead line design code, additional design codes and regulations will be followed for each transmission line component design. A full list of design codes and regulations is provided in Appendix B.

3.0 Meteorological (Climate) Data

3.1 Site Descriptions

The closest meteorological locations outlined in both C22.3 No.1 and C22.3 No.60826 is Dawson City.

3.2 Deterministic Approach Weather Case

CSA C22.3 No.1 Section 7 outlines the minimum deterministic weather loads shall be applied to each line components. C22.3 No.1 Annex C Figure C.1 indicates that the Yukon falls under CSA Medium A Loading condition which does not represent local observed ice loading situations. The CSA Heavy Loading is used for the previous CSTL and proposed transmission lines. Parameters are given in C22.3 No.1 Table 30 and are listed as follows:

Table 3.1

Conditions	Temperature (°C)	Horizontal Wind Loading (N/m ²)	Radial Ice	
			Thickness (mm)	Ice Density (kg/m ³)
CSA Heavy	-20	400	12.5	900

3.3 Reliability Approach Weather Cases

CSA C22.3 No.60826 is the Canadian adaptation of IEC 60826 “Design criteria of overhead transmission lines”, with implementation of appropriate Canadian variations and weather parameters. C22.3 No.60826 Table CA.1 listed 50 years return period (1/50) weather conditions for Canadian Locations. The mean annual maximum snow accumulation depths are provided in CSA C22.3 No.1 Table D.1. The ice, wind and snow depth parameters for the closest meteorological locations to the transmission line are listed below:

Table 3.2

Locations	Reference Average Minimum Temperature (°C)	Reference (1/50) Wind Speed (km/h)	Reference (1/50) Radial Ice		Mean Annual Maximum Snow Depth (m)
			Thickness (mm)	Ice Density (kg/m ³)	
Whitehorse (reference)	-43	85	10	900	0.4
Dawson City	-51	80	10	900	0.6

The ambient temperature for radial ice formation due to freezing precipitation is assumed at -10°C.

The reference wind and ice loading values given above are based on 1 in 50 year (1/50 return period) event.

3.3.1. Reference Ice Loadings

The reference ice loading listed in CSA C22.3 No.60826 does not reflect the occasionally observed rime ice condition on existing transmission line in Yukon. Additional ice loading of 51mm (2") rime ice (density of 350kg/m³) has been included in the design of the proposed transmission line.

The cable diameter factor and structure height factor according to C22.3 No.60826 Section 6.3.4.1 will be adjusted accordingly in PLS-Cadd model for site specific design.

3.3.2. Reference Wind Loading

The 1 in 50 return period reference wind loading is recommended for the design of the transmission line for capital cost minimization.

3.3.3. Combined Wind and Low Temperature

As per requirement under CSA C22.3 No.60826 Section 6.2.4 for span typically less than 200m, combination of minimum temperature with wind shall be included for reliability design load scenario. The combination shall be verified for reference average minimum temperature with 60% of design wind speed. The design wind speed for combination with minimum temperature is recommended to be 1 in 50 return period.

3.3.4. Combined Ice and Wind Loadings

The requirement of combination of the ice with wind is defined in CSA C22.3 No.60826 Section 6.4. The section outlines two ice and wind combinations as follows:

- Reduced Ice with High Wind - 85% Reference Ice with 60% Reference Wind (normal combined ice and wind)
- High Ice with Average Wind - 130% Reference Ice with 40% Reference Wind (extreme combined ice and wind with spatial factor)

The recommended level of reliability for ice loading combined with wind loading shall be 1 in 50 return periods.

4.0 Electrical Design Criteria

4.1 Code Clearances

4.1.1. Vertical and Horizontal External Clearances

4.1.1.1. Vertical Clearances

The minimum vertical ground clearance required for lowest cable is listed in C22.3 No.1 Table 2 (ground clearances), Table 3 (waterways), Table 9 (building, signs, fence, etc.) and Table 10 (bridges).

Segments of the proposed transmission lines are located at altitude between 1000 m to 1300 m above sea-level. According to C22.3 No.1 clause 5.3.1.1 (b), the required clearance shall be increased by 1% for each 100 m above of 1000 m. The designed high altitude clearance will be based on 3% increase of basic minimum clearance.

The minimum code specified clearance and recommended design values are summarized below:

Table 4.1 - 138kV (Maximum Voltage 155kV Ph-Ph) Vertical Ground Clearance

Clearance Descriptions	C22.3 No.1 Min. Clearance (m)	Mean Annual Snow Depth (m)	Survey Tolerance (m)	Const. Tolerance (m)	138kV Design Clearance (m)	138kV High Altitude Clearance (m)
Ground Clearance (CSA C22.3 No.1 Table 2)						
Vehicular Clearance (Vehicle Height <4.15m)	5.5	0.6	0.3	0.3	6.7	6.9
Non-Vehicular Clearance (Pedestrian / ATV)	4.0	0.6	0.3	0.3	5.2	5.4
Railroad Crossings	8.4		0.3	0.3	9.0	9.3
Waterway Crossings (CSA C22.3 No.1 Table 3)						
Class 1 (Vessel H ≤ 4.0 m)	6.7		0.6		7.3	7.5
Class 2 (Vessel H ≤ 6.0 m)	8.7		0.6		9.3	9.6
Class 3 (Vessel H ≤ 8.0 m)	10.7		0.6		11.3	11.7
Class 4 (Vessel H ≤ 10.0 m)	12.7		0.6		13.3	13.7
Class 5 (Vessel H ≤ 12.0 m)	14.7		0.6		15.3	15.8
Class 6 (Vessel H ≤ 14.0 m)	16.7		0.6		17.3	17.8
Features (CSA C22.3 No.1 Table 9 & Table 10)						
Buildings	4.2	0.6	0.3	0.3	5.4	5.6
Signs, Fences, etc.	4.2		0.3	0.3	4.8	5.0
Bridges	3.4	0.6	0.3	0.3	4.6	4.8
Ground Clearance (AEUC 2013 Table 5)						
Non-Vehicular Clearance (Pedestrian / ATV < 3.6m)	5.0	0.6	0.3	0.3	6.2	6.4
High Load Clearance (Vehicle Height <5.3m)	6.7		0.3	0.3	7.3	7.5

The C22.3 No.1 vertical clearances between cable crossings not supported by same structure are listed in C22.3 No.1 Table 13.

In addition to C22.3 No.1 wire crossing specification, Local Distribution Companies (YEC & AEY) should be consulted at each crossing for specific requirement during the final design.

Table 4.2 - Aerial Cable Crossing Vertical Clearance

Upper Cables	69kV (m)	138kV (m)
Lower Cables		
Communication	0.9	1.2
Secondary (<750V)	0.8	1.1
Distribution (>750V & ≤34.5kV)	0.9	1.2
Sub-Transmission (>44kV & ≤69kV)	1.1	1.4
138kV to 138kV		1.5
Limit of Approach		2.5

The wire crossing of the 138kV transmission lines will be designed based on the highest specified clearance requirement.

4.1.1.2. Horizontal Clearances

The horizontal cable clearance is defined for cable under conductor Blowout Wind condition as specified in C22.3 No.1 Section 5.2.7 & A5.2.7. The horizontal clearance requirements are specified in C22.3 No.1 Table 6 (Railroad), Table 9 (building, signs, fence, etc.), Table 10 (bridges) and Table 35 (flashover for tree pruning).

Table 4.3 – 138kV Horizontal Electrical Ground Clearance

Clearance Descriptions	C22.3 No.1 Min. Clearance	Survey Tolerance	138kV Design Clearance
	(m)	(m)	(m)
Railroads (CSA C22.3 No.1 Table 6)			
Main Tracks	3.5	0.3	3.8
Sidings	2.9	0.3	3.2
Features (C22.3 No.1 Table 9, Table 10 & Table 35)			
Buildings	2.6	0.3	2.9
Signs, Fences, etc.	2.6	0.3	2.9
Bridges	2.2	0.3	2.5
Tree Pruning	0.97	0.3	1.3

The specified horizontal conductor clearances are specified for locations where vertical clearances are not achieved.

In addition to conductor electrical clearance, minimum structure clearances in proximity to adjacent features are also governed by appropriate national, provincial and local bylaws.

Table 4.4 – Structural Clearance to Adjacent Facilities

Clearance Descriptions	Min. Clearance (m)
Railroads (C22.3 No.1 Table 7)	
Railroad Tracks	
Main Tracks	2.5
Sidings	1.9
Road Clear Zone Requirement	
Edge of Road	7.0
Edge of Highway	9.0

4.1.2. Electrical Clearances to Structures

Electrical clearance from energized conductors and hardware depends on maximum system voltage and switching surge ratio of the transmission system.

The minimum electrical clearances between phase conductors to supporting structure for voltage greater than 50kV phase-ground (<69kV phase-phase) are outside of the voltage range specified in C22.3 No.1. American National Electrical Safety Code (NESC – IEEE C2) shall be used to determine the electrical clearances between energized live parts and support structure components. As per NESC clause 235E1 for 138kV transmission lines, Table 235-6 shall provide the minimum clearance requirements. In addition, CSA C22.3 No. 1 Table A.1 provides flashover to ground distance based on typical switching surge factor.

Table 4.5.1 – 138kV Electrical Clearances to Structures

Clearance Descriptions	Minimum Clearance (m)
NESC Table 235-6 (290 Pa [6 psf] wind @ 15°C)	
Surface of Structure	0.81
Anchor Guys	
Inline Parallel Guys	1.79
Bisect & Offset Guys	1.10
CSA C22.3 No. Table A.1	
Switching Surge Flashover	0.97
Additional Clearance Consideration (RUS 1724E-200 Table 7-1)	
At Rest - No Wind	1.27
Extreme Hourly Wind	0.33

Table 4.5.2 – 138kV Electrical Design Clearances for Insulator Swing

Cable Conditions	Design Minimum Clearance (m)
Every Day Temperature	1.27
Blowout Wind (290 Pa wind @ 15°C)	0.97
-51°C	0.81
1/50 IEC Gust Wind	0.33

4.1.3. Lightning Performance and Shielding

The average structure height (ground to OPGW and OHGW) of the proposed transmission lines shall be below 92ft, the shielding angle of 30 degree, as per RUS 1724E-200 Table 8-3, was used for the determination of shieldwire and phase conductor separation.

Shielding angle of lightning protection by OPGW and OHGW shall be verified based on latest edition of IEEE Standard 1243 “Guide for Improving the Lightning Performance of Transmission Lines”. The ground flash design should either be based on historical data (when available) or IEEE Std. 1243 equation (2) or equation (3).

4.1.4. Grounding

Pole and shieldwire grounding shall be installed at every structure location. Unattached grounding system resistivity shall be 100 ohms or below. Grounding study shall be performed in final design phase to estimate number of ground rod(s) at each ground connection.

4.1.5. Galloping Conductors

Conductor and shield wire separations will be assessed for ice and wind galloping under the following conditions;

Table 4.6 – Galloping Conditions

Conditions	Temperature (°C)	Horizontal Wind Loading (Pa) [psf]	Radial Ice	
			Thickness (mm)	Ice Density (kg/m ³)
Galloping Swing	-5	95.7 [2]		
Galloping Ice	-5	95.7 [2]	12.7	900

An additional separation of 0.3m shall be provided between galloping ellipses for design buffer.

4.2 Clearance Buffers

The proposed design clearance buffers has been listed in each of the clearance categories

4.3 Structure Spotting Criteria

The preferred standard design span for proposed 138kV transmission lines to be 150m to 180m based on phase separation requirement under galloping conditions and maintaining reasonable structure height during extreme ice loading conditions. The actual design spotting will be based on above

consideration with right of way constraint and adjacent utilities provided in topographical survey utilizing PLS-Cadd 3D TIN terrain model.

4.4 Ampacity Rating Criteria

The phase conductor ampacity calculations are performed based on IEEE Std. 738-2013. C22.3 No.1 Section 3 “Rated ampacity” which outlines the basic ambient and cable conditions to be used for the ampacity calculation.

The ampacity calculations based on parameters outlined in Table 4.4.1 for selected phase conductor cable 266.8MCM ACSR (Partridge) and 397.5MCM ACSR (Ibis) are performed using PLS-Cadd embedded IEEE 738-2013 module. The PLS-Cadd program generated ampacity calculation outputs are given in Appendix F. The calculated continuous and limited thermal ratings for a single conductor are summarized below:

Table 4.7 – IEEE Std. 738 Ampacity Calculations

Parameters	CSA C22.3 No.1	AESO 502.2
Ambient Temperature	40°C	40°C
Case 1 – Maximum Thermal Rating (Maximum Conductor Temperature)	100°C	100°C
Case 2 – Operating Temperature 40 MW (44.5 MVA) x 1.25 OL @138 kV	240 A	240 A
Case 3 –Design Thermal Rating (Design Conductor Temperature)	75°C	75°C
Wind Speed	0.61 m/s (2 ft/s)	0.61 m/s (2 ft/s)
Wind Angle to Conductor	90°	90°
Conductor Latitude	63.6°	63.6°
Conductor Elevation (above sea level)	800m	800m
Conductor Direction (maximum solar heat)	E-W	E-W
Emissivity	0.5	0.6
Solar Absorption Coefficient	0.5	0.8

Table 4.8 – Conductor Continuous and Limited Thermal Ratings

Cable Conditions	CSA C22.3 No.1	AESO 502.2
Case 1 – Maximum Thermal Rating		
266.6 MCM 27/6 ACSR (Partridge)	484 A	475 A
397.5 MCM 27/6 ACSR (Ibis)	624 A	612 A
Case 2 – Operating Temperature		
266.6 MCM 27/6 ACSR (Partridge)	59.0°C	62.7°C
397.5 MCM 27/6 ACSR (Ibis)	54.9°C	58.9°C
Case 3 – Design Thermal Rating		

266.6 MCM 27/6 ACSR (Partridge)	361 A (62 MW @138 kV) (31 MW @69 kV)	341 A (58 MW @138 kV) (29 MW @69 kV)
397.5 MCM 27/6 ACSR (Ibis)	463 A (79 MW @138 kV) (39 MW @69 kV)	434 A (74 MW @138 kV) (37 MW @69 kV)

Based on above ampacity and conductor temperature data for the proposed 138kV transmission lines, the design conductor sag shall be based on conductor temperature of 75°C.

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5.0 Structural Design Criteria

5.1 Conductor and Conductor Support Hardware

The conductor and conductor supporting hardware shall be design and selected to withstand the required loadings as per requirement outlined in this section.

5.1.1. Conductor Tension Limits

CSA C22.3 No.1-2006 and CSA C22.3 No.60826 design codes are based on maximum allowable design tensions under various loading conditions. However, the latest edition of CSA C22.3 No.1-2010 has been revised to recommended maximum initial catenary for phase conductor.

5.1.1.1. Tension Limit (% Ultimate Tensile Strength)

C22.3 No.1-2006 Table 34 and Table 35 outlined the tension limit of phase conductor and galvanized steel wire as lightning protection wires (Table 35 has not been modified in the 2010 edition).

Table 5.1 – CSA C22.3 No.1-2006 Allowable Cable Tension Limits

Loading Conditions	AAC, ACSR and Aluminum Alloys Phase Conductors	Galvanized Steel Wires
Maximum tension under appropriate loading conditions	60%	60%
Maximum recommended initial unloaded (initial) tension at mean temperature (EDT)	35%	20%
Maximum recommended final unloaded (creep) tension at mean temperature (EDT)	25%	15%

Strength factor for reliability design are listed in C22.3 No.60826 Section 7. The standard values for strength coefficient of variation is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors and equivalent tension limits are given below:

Table 5.2 – CSA C22.3 No.60826 Allowable Cable Material Factors

Conductor & Shieldwire	Cable Material Factor		Support Design Strength Factor	Combined Allowable Material Factor
	COV	Factor		
Intact Load	3%	0.962	0.80	0.77
Failure Load	3%	0.962	0.90	0.87

5.1.1.2. Maximum Initial Cable Catenary

CSA C22.3 No.1-2010 edition section 8.7.3 “Wire tension limits” has been revised to provide additional safety for fatigue damage of conductors due to aeolian vibration. C22.3 No.1 2010 Table 33 provides the recommended catenary parameter for different span lengths.

As per CSTL design requirement, the catenary parameter requirement is consistent with maximum 15% cable UTS under -50°C. These requirements did impact the structure height requirement but provide reliability where large ranges of temperature variation can occur.

5.1.1.3. Recommended Cable Design Criteria

In consideration of various governing factors for cable design criteria, the follow conditions and criteria are used for the design of conductor and OPGW / OHGW;

Table 5.4 – Recommended Cable Design Criteria

Design Conditions	Cable Condition	Conductor	OPGW / OHGW
C22.3 No.1 CSA Heavy	Loaded	50% UTS	50% UTS
C22.3 No. 60826 Extreme Ice	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Gust Wind	Loaded	50% UTS	50% UTS
C22.3 No. 60826 Wind & Low Temp.	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Ice & Wind (High Wind)	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Ice & Wind (Low Wind)	Loaded	70% UTS	60% UTS
EDT	Initial	35% UTS	20% UTS
EDT	Creep	25% UTS	15% UTS
Catenary @ Mean Annual Min. Temp.	Initial	1500 m	1500 m
Min. Temperature (-50°C)	Creep	15% UTS	15% UTS

5.1.2. Insulators, Support Hardware and Conductor Accessories

Reliability design utilizes actual environmental loadings based on desired project return period to compare with reduced allowable material resistances.

The allowable material strength is dependent on material consistency and structure reliability requirement. Material strength factor for reliability design are listed in C22.3 No.60826 Section 7. The standard values for strength coefficient of variation is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors are summarized below;

Table 5.5 - CSA C22.3 No.60826 Cable and Hardware Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Insulators	5%	0.936	0.84	0.94	0.75	0.84
Hardware	5%	0.936	0.84	0.94	0.75	0.84

Despite C22.3 No.60826 outlines the allowable strength factors for insulator and hardware, manufacturers of insulator and hardware recommended the allowable strength for these items shall be 50% of the design tensile strength. The selection of insulators and conductor attachment hardware shall be based on manufacturer design limits, with exception of the high ice with average wind (130% Ice & 40% Wind) combination, the maximum insulator and hardware usage shall be 0.75.

5.2 Guys and Hardware

CSA C22.3 No.60826 clause 7.3.1 outlines the damage limit of steel guys and Table 18 provide material strength factor for grouted guy anchor design. The design of guy anchors shall be according to IEEE Std. 691 "IEEE Guide for Transmission Structure Foundation Design and Testing".

5.2.1. Guy Strand & Hardware

The maximum allowable guy cable and hardware tension shall be 0.75 (75%) ultimate tensile strength as per CSA C22.3 No.60826 Table 14.

5.2.2. Guy Anchors

The maximum design loadings for commercial available guy anchor shall be according to manufacturer recommended holding capacity. The material factor for grouted rock anchor shall be as follows;

Table 5.6 - CSA C22.3 No.60826 Allowable Rock Anchor Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Grouted Rock Anchor	10%	0.872	0.78	0.87	0.70	0.78

5.3 Structures

5.3.1. Load Factors

Deterministic approach is applied for designing transmission line components to withstand factored loads (vertical, transverse and longitudinal loads) under C22.3 No.1 conditions specific to the project area (see Table 3.1). The required overload factors are specified in C22.3 No.1 Section 7.4 to 7.9 and summarized in C22.3 No.1 Table 31.

Table 5.7 – CSA C22.3 No.1 Overload Factors for Limit State Design (Deterministic Approach)

Structure Type	Grade 2 Construction			Grade 1 Construction		
	Vertical	Trans.	Long.	Vertical	Trans.	Long.
Steel Components (crossarms, davit arms, braces, etc.)						
Tangent & Running Angle	1.15	1.10	1.00	1.30	1.20	1.10
Heavy Angle & Deadend	1.15	1.10	1.10	1.30	1.20	1.20
Wood Pole						
Tangent & Running Angle	1.50	1.30	1.00	2.00	1.90	1.20
Heavy Angle & Deadend	1.50	1.30	1.30	2.00	1.90	1.90

The allowable strengths for each transmission line structural component is calculated by PLS-Pole based on input material parameters, such as geometry, material yield strengths, mechanical properties of material type.

5.3.2. Strength Reduction Factors

The allowable material strength is dependent on material consistency and structure reliability requirement. Structural material strength coefficient of variation for steel component is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors are summarized below:

Table 5.8A - CSA C22.3 No.60826 Allowable Structural Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Steel Component	5%	0.936	0.84	0.94	0.75	0.84
Wood Component	15%	0.808	0.73	0.80	0.65	0.73

5.4 Design Loads

The design load cases for the proposed 138kV transmission lines shall be based on the climatic data outlined in Section 3.

5.4.1.1. *CSA Minimum Deterministic Load Case*

The minimum design loads for the proposed transmission lines shall be CSA Heavy Condition as per Table 3.1.

5.4.1.2. *Extreme Ice Load Cases*

The maximum extreme ice loadings shall be designed for 1 in 50 years return period reference data.

5.4.1.3. *Maximum Gust Wind Load Cases*

The maximum gust wind loadings shall be designed for 1 in 50 years return period reference.

5.4.1.4. *Combined Ice and Wind Load Cases*

Both combination of ice with wind loading conditions will be evaluated according to Section 3.3.4.

5.4.1.5. *Broken Wire and Unbalanced Ice Loads*

For tangent and running angle structures, since the application of braced post insulator had limited longitudinal load capability, the unbalanced longitudinal loading conditions are not considered.

5.4.1.6. *Containment Structures*

All dead end angle structures and double dead end containment structures shall be designed to withstand complete one sided cable loadings in addition to standard configuration loadings under all climatic conditions.

5.4.1.7. *Construction and Maintenance Loads*

Construction and maintenance load requirements are specified in C22.3 No.60826 Section 6.5.

The lifting components (such as lifting vent if required) during structure erection shall have minimum safety factor of 1.5 for planned control operation.

The safety factor for cable tension shall be 2.0 during cable stringing operation with 50% of the applied tension added as longitudinal load on all running angle structures.

5.5 Structure Design

The wood pole design shall be performed using PLS-Pole wood pole structural add-on application module. The PLS-Pole model shall include wood pole, steel crossarm, steel cross braces, insulators, guy cables, etc.

Attachment loadings will be generated by PLS-Cadd line design application using Method 4 “Structure Loads” calculations. Additional longitudinal loads for maintenance and construction scenario under every day temperature will be applied manually in PLS-Pole application.

5.6 Foundation Design

Transmission pole structures in this project are direct-embedded poles and shall be designed to resist the overturning moment, shear and axial loads generated from the design of pole structures using L-Pile caisson foundation application.

5.6.1. Moment Foundations

5.6.1.1. Design Philosophy

For direct-embedded method, the pole embedment length below the ground line shall be determined using an allowable lateral displacement approach. Horizontal subgrade reaction along the embedded length is determined based on borehole record information as per the geotechnical investigation report. Pole structure shall be designed to withstand the structural loading specified in other sections of this criteria document, and shall also be qualified to sustain the corresponding geotechnical loading to ensure structural integrity.

5.6.1.2. Deflection Limits

Pole recoverable deflection at ground line is limited to 25mm due to actual loading under normal weather condition, and 40mm due to actual loading under extreme weather condition. The soil input parameters for L-Pile application, such as friction angle for granular material and undrain strength for cohesive material, are deduced from site geotechnical report.

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Appendix A – Site Location Plan

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Appendix B – Code & Regulation List

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Appendix C – Cables and Insulators Catalogue Information

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Appendix D – Climatic Data Reference Data

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Appendix E – PLS-Cadd IEC 60826:03 Wind & Ice Adjustment Models

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IEC 60826:2003 Design Code – Input Parameter Definitions

IEC 60826:2003 Terrain Category

The information below applies only when the 'IEC 60826:2003' is selected in Criteria/Weather Cases or Criteria/Structure Loads.

Terrain Category

☐ A: Large stretch of water upwind, flat coastal areas

☒ B: Open country with very few obstacles, for example airports or cultivated fields with few trees or buildings

☐ C: Terrain with numerous small obstacles of low height (hedges, trees and buildings)

☐ D: Suburban areas or terrain with many tall trees

Static

Drag coefficient for iced wires (applies in presence of any ice thickness or load per unit length) 1.000

Summary of IEC Related Adjustments

Wire wind height adjust model set to IEC 60826:2003 does following:

- Wire and insulator wind speed adjusted by roughness factor K_r (terrain category).
- Wire wind speed adjusted for combined wind factor G_c (terrain category, attachment height)
- Insulator wind speed adjusted for combined wind factor G_t (terrain category, attachment height)
- Ice thickness adjusted by wire diameter factor K_d and by height factor K_h (sec. 6.3.4.1)

Wire gust response factor set to IEC 60826:2003 does following:

- Wire gust response factor adjusted for span factor G_l (span length)
- Wire gust response factor multiplied by drag coefficient for iced wires in presence of ice thickness or load per unit length.

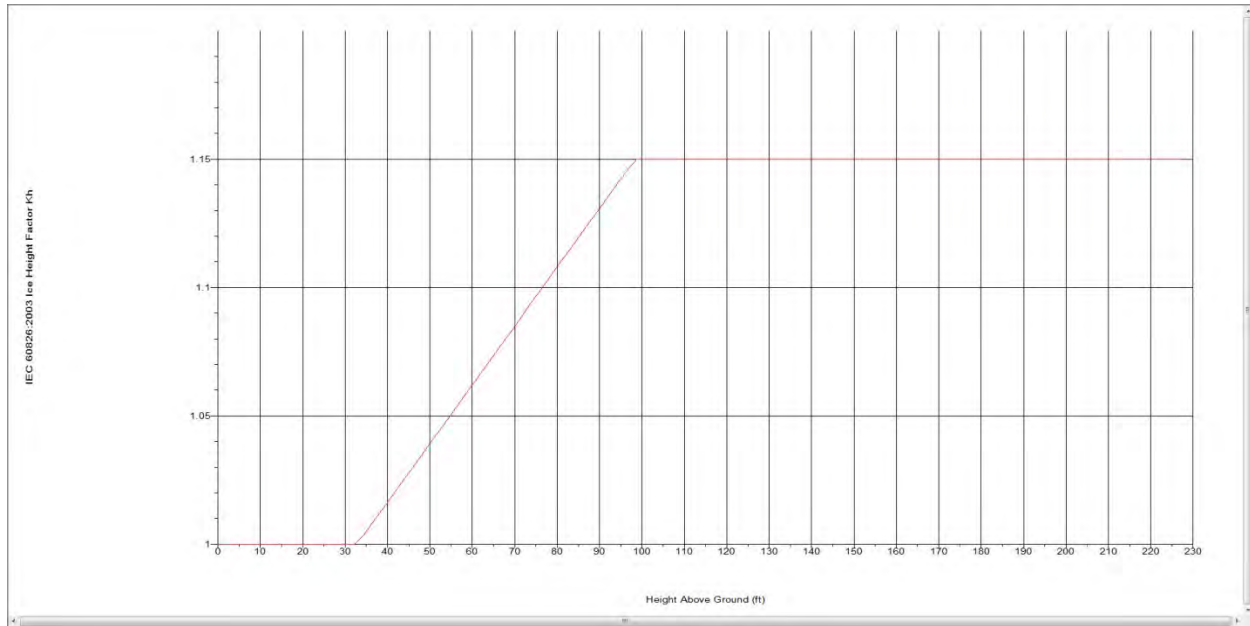
Structure wind load model set to IEC 60826:2003 does following:

- Structure wind speed adjusted by roughness factor K_r (terrain category)
- Structure wind adjusted for height. (done in PLS-POLE/TOWER)
- Structure wind adjusted for structure gust response factor. (done in PLS-POLE/TOWER)
- Drag coefficients adjusted as per IEC. (done in PLS-POLE/TOWER)
- Ice on structure increases vertical load but not wind load. (done in PLS-POLE/TOWER)

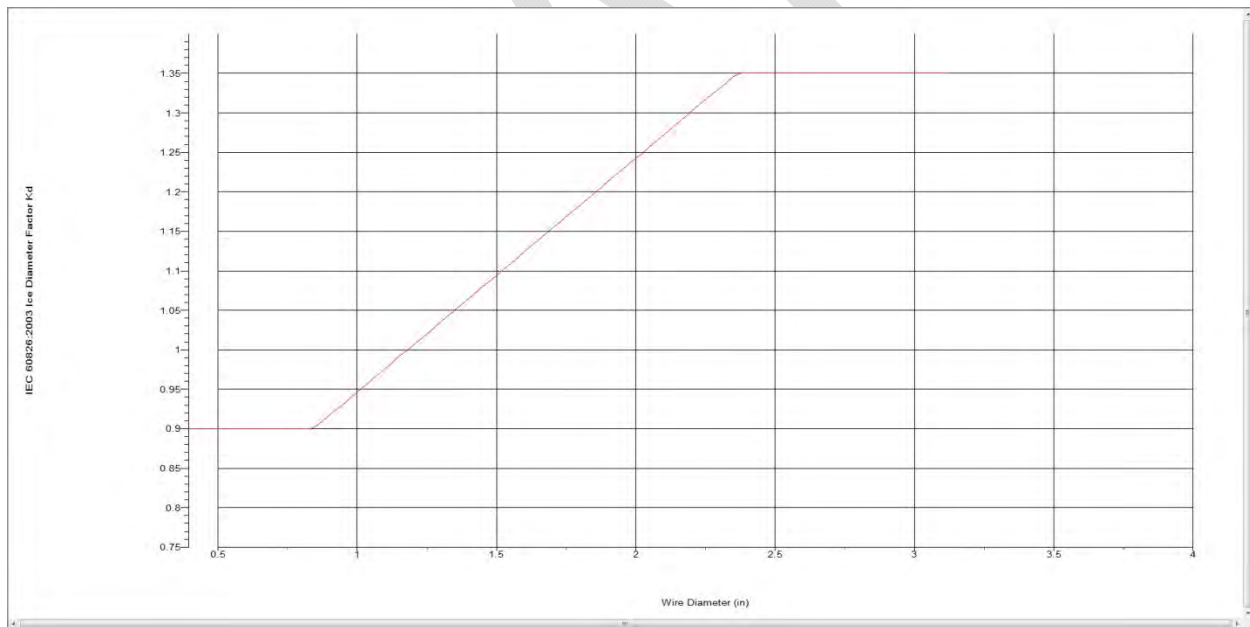
Notes on inputs to Criteria/Weather Cases:

- Wind pressure should be 10 minute average V_{rb} .
- Air density factor should include any correction factor for altitude.
- Ice should be ice load on a 30mm diameter conductor at 10m reference height.

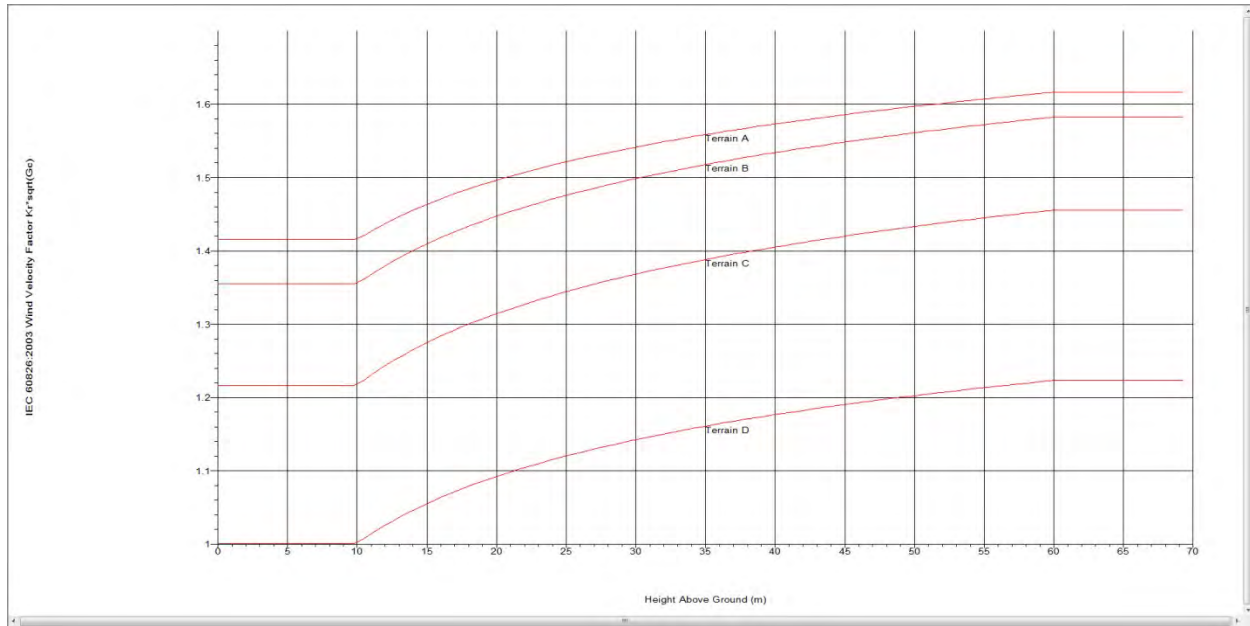
Show graphs of G_c , G_t , G_l , K_d and K_h OK Cancel



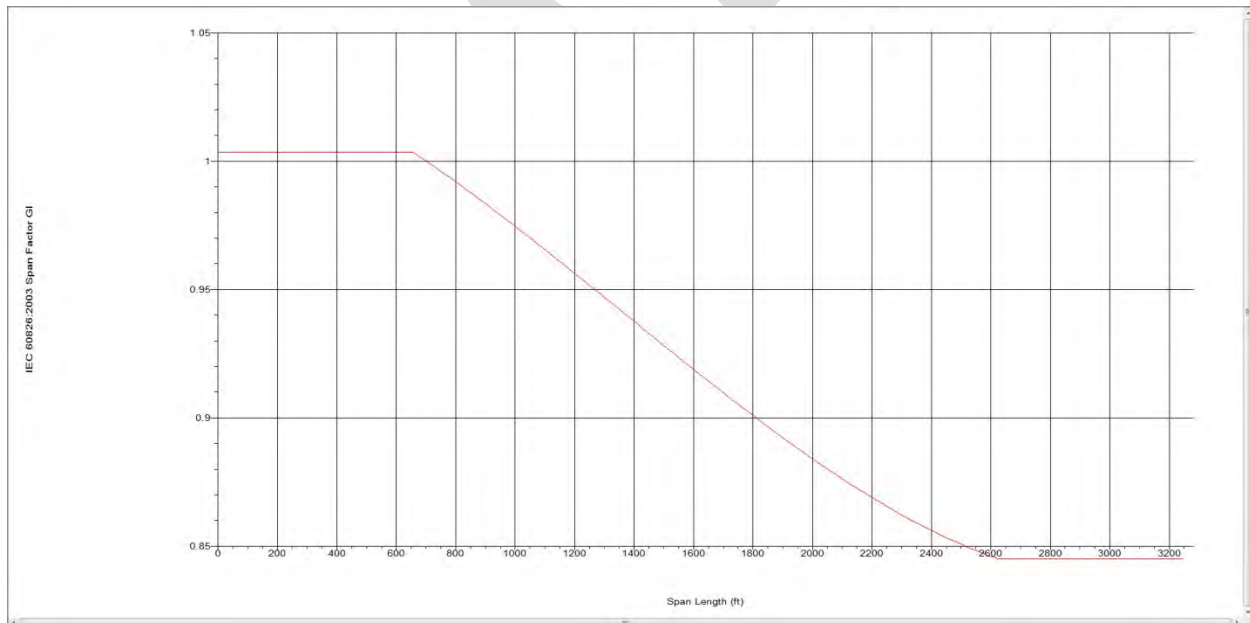
IEC Ice Height Factor (K_h) vs. Attachment Height



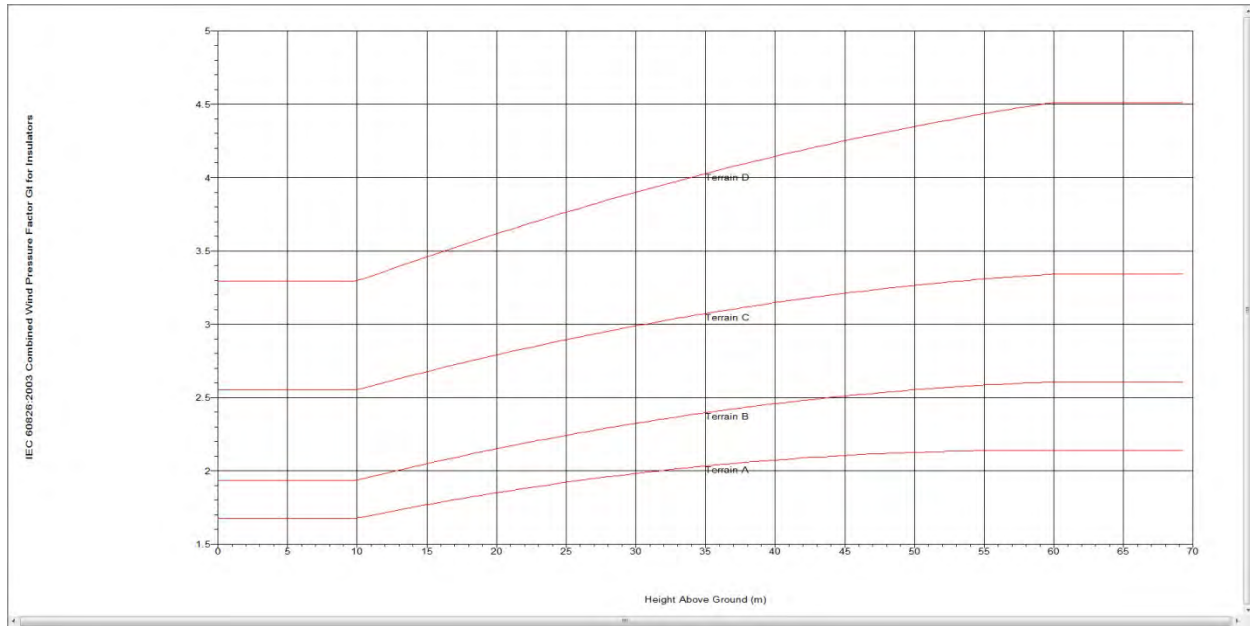
IEC Ice Diameter Factor (K_d) vs. Wire Diameter



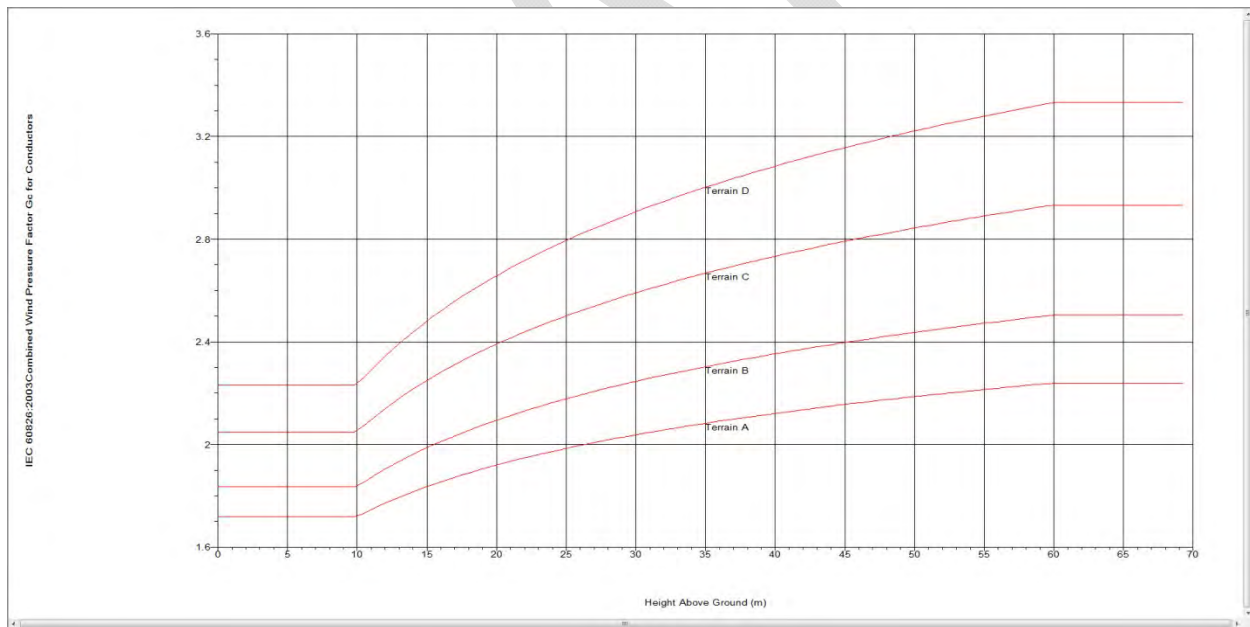
IEC Wind Velocity Factor ($K_r \cdot \sqrt{G_c}$) vs. Attachment Height



IEC Span Factor (G_I) vs. Span



IEC Combined Wind Pressure Factor (G_t) for Insulators vs. Attachment Height



IEC Combined Wind Pressure Factor (G_c) for Conductors vs. Attachment Height

Appendix F – IEEE Std. 738 Ampacity Calculation Program Output

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Evaluation Criteria

Re: ***YEC L170 Transmission Line – Clearance and Structural Evaluation Criteria***

1. General Description

The existing L170 138kV transmission line connects YEC Takhini switching station near Whitehorse and YEC Carmacks switching station at Carmacks. The L170 along with Carmacks to Stewart 138kV transmission lines (CSTL) (L173 Carmacks switching station to Minto Landing substation, L174 Minto Landing substation to Stewart Crossing South substation and L175 Stewart Crossing South substation to Stewart Crossing North switching station) provide the transmission grid tie between YEC southern operation area with northern operation area (Keno-Mayo-Dawson).

This document outlines the current governing design codes requirements for 138 kV transmission line clearance and structural criteria to be used in the evaluation of existing L170 structure compliance.

2. L170 Thermal Capacity & Conductor Temperature

The existing L170 has an operating capacity of 35MW with power factor of 0.93. The projected future capacity of L170 has been estimated to be 70MW. Based on power factor of 0.9, provide margin for flexibility, the calculated required ampacities are used in determination of the L170 conductor temperatures under different ambient temperatures and code reference conditions.

The CSTL 138kV transmission lines were designed with maximum conductor temperature of 75°C under both winter and summer conditions.

The phase conductor ampacity calculations are performed based on IEEE Std. 738-2013. The PLS-Cadd program generated ampacity calculation outputs are given in Appendix A.

Table 2.1 – IEEE Std. 738 Ampacity Calculations

Input Parameters	CSA C22.3 No.1	AESO 502.2	YEC Winter Operation	YEC Normal Operation	YEC Summer Operation
Ambient Temperature	40°C	40°C	10°C	15.6°C (60°F)	30°C
Wind Speed	0.61 m/s (2 ft/s)				
Wind Angle to Conductor	90°				
Conductor Latitude	61°				
Conductor Elevation (above sea level)	100m				
Conductor Direction (maximum solar heat)	E-W				
Emissivity	0.5	0.6	0.6	0.6	0.6
Solar Absorption Coefficient	0.5	0.8	0.8	0.8	0.8
Case 1 – Existing Thermal Loadings (35MW)	165 A				
Case 1 – Future Thermal Loadings (70MW)	330 A				
Case 3 – CSTL Design Conductor Temperature	75°C				

Table 2.2 – Conductor Continuous and Limited Thermal Ratings

Input Parameters	CSA C22.3 No.1	AESO 502.2	YEC Winter Operation	YEC Normal Operation	YEC Summer Operation
Ambient Temperature	40°C	40°C	10°C	15.6°C (60°F)	30°C
Case 1 – Conductor Temperature @ Existing Thermal Loadings (35MW)	54°C	57°C	28°C	33°C	48°C
Case 1 – Conductor Temperature @ Future Thermal Loadings (70MW)	71°C	75°C	44°C	50°C	65°C
Case 3 – Thermal Rating @ CSTL Design Conductor Temperature	358 A	337 A	500 A	474 A	399 A

3. Vertical Ground Clearance Criteria

In addition to compliance to CSA C22.3 No.1 “Overhead Systems”, YEC is mandated to conform with Alberta Electrical Utility Code (AEUC) under Yukon regulation. The minimum code specified clearance and recommended design values are summarized below:

Table 3.1 - 138kV (Maximum Voltage 155kV Ph-Ph) Vertical Ground Clearance

Clearance Descriptions	Code Ref. Min. Clearance	Mean Annual Snow Depth	Survey Tolerance	Const. Tolerance	Summer Design Clearance	Winter Design Clearance
	(m)	(m)	(m)	(m)	(m)	(m)
Ground Clearance (CSA C22.3 No.1 Table 2)						
Vehicular Clearance (Vehicle Height <4.15m)	5.5	0.6	0.3	0.3	6.1	6.7
Non-Vehicular Clearance (Pedestrian / ATV)	4.0	0.6	0.3	0.3	4.6	5.2
Railroad Crossings	8.4		0.3	0.3	9.0	9.0
Waterway Crossings (CSA C22.3 No.1 Table 3)						
Class 1 (Vessel H ≤ 4.0 m)	6.7		0.6		7.3	7.3
Class 2 (Vessel H ≤ 6.0 m)	8.7		0.6		9.3	9.3
Class 3 (Vessel H ≤ 8.0 m)	10.7		0.6		11.3	11.3
Class 4 (Vessel H ≤ 10.0 m)	12.7		0.6		13.3	13.3
Class 5 (Vessel H ≤ 12.0 m)	14.7		0.6		15.3	15.3
Class 6 (Vessel H ≤ 14.0 m)	16.7		0.6		17.3	17.3
Features (CSA C22.3 No.1 Table 9 & Table 10)						
Buildings	4.2	0.6	0.3	0.3	4.8	5.4
Signs, Fences, etc.	4.2		0.3	0.3	4.8	4.8
Bridges	3.4	0.6	0.3	0.3	4.0	4.6
Ground Clearance (AEUC 2013 Table 5)						
Non-Vehicular Clearance (Pedestrian / ATV < 3.6m)	5.0	0.6	0.3	0.3	5.6	6.2
Vehicular Clearance (Vehicle Height <4.15m)	5.5	0.6	0.3	0.3	6.1	6.7
High Load Clearance (Vehicle Height <5.3m)	6.7	0.6	0.3	0.3	7.3	7.9

4. Structural Loadings

CSA C22.3 No.1 (Overhead Systems) Design Loadings

CSA C22.3 No.1 Section 7 outlines the minimum deterministic weather loads shall be applied to each line components. C22.3 No.1 Annex C Figure C.1 indicates that the Yukon falls under CSA Medium A Loading condition which does not represent local observed ice loading situations. The CSA Heavy Loading is used for the previous CSTL and proposed transmission lines.

Table 4.1 - C22.3 No.1 Table 30 Deterministic Weather Loads

Conditions	Temperature (°C)	Horizontal Wind Loading (N/m ²)	Radial Ice	
			Thickness (mm)	Ice Density (kg/m ³)
CSA Medium A	-20	400	6.5	900
CSA Heavy	-20	400	12.5	900

CSA C22.3 No.60826 (Overhead Transmission Lines) Design Loadings

CSA C22.3 No.60826 is the Canadian adaptation of IEC 60826 “Design criteria of overhead transmission lines”, with implementation of appropriate Canadian variations and weather parameters. C22.3 No.60826 Table CA.1 listed 50 years return period (1/50) weather conditions for Canadian Locations. The mean annual maximum snow accumulation depths are provided in CSA C22.3 No.1 Table D.1. The ice, wind and snow depth parameters for the closest meteorological locations to the transmission line are listed below:

Table 4.2 - C22.3 No.60826 Table CA.1 Reliability Weather Reference Data

Locations	Reference Average Minimum Temperature (°C)	Reference (1/50) Wind Speed (km/h)	Reference (1/50) Radial Ice		Mean Annual Maximum Snow Depth (m)
			Thickness (mm)	Ice Density (kg/m ³)	
Whitehorse (reference)	-43	85	10	900	0.4
Dawson City	-51	80	10	900	0.6

The reference wind speed are based on 10 minutes average wind. Gust factor is applied in the PLS-Cadd program according the line configuration (typical factor of 1.6).

Ambient temperature for the corresponding wind and ice loadings are based on -10°C.

The reference ice loading listed in CSA C22.3 No.60826 does not reflect the occasionally observed rime ice condition on existing transmission line in Yukon. Additional ice loading of 51mm (2") rime ice (density of 350kg/m³) has been proposed for the evaluation of transmission line structure.



Figure 4.1 – Extreme Rime Ice on L174 (2011)

Table 4.3 - Recommended Design Load Combinations

Conditions	Temperature (°C)	Horizontal Wind Loading (km/h) [Pa]	Radial Ice	
			Thickness (mm)	Ice Density (kg/m ³)
CSA Heavy	-20	25.5 [400]	12.7	900
IEC Ice	-10	--	12.7	900
IEC Wind	-10	85 [425]	--	--
IEC Wind & Low Temp.	-24	51 [161]	--	--
IEC Low Ice & High Wind	-10	51 [161]	10.8	900
Extreme Min. Temp.	-51	--	--	--
YEC Rime Ice	-30	--	-51	350

Gust and height factor applied in PLS-Cadd program according to code specification.

Based on available information, the existing L170 designs are based on the following load combinations.

Table 4.4 – Existing L170 (1968) Design Load Combinations

Conditions	Temperature (°C) [°F]	Horizontal Wind Loading (Pa) [psf]	Radial Ice	
			Thickness (mm) [in]	Ice Density (kg/m ³)
Extreme Ice	-18 [0°F]	--	25.4 [1]	900
CSA Ice & Wind	-18 [0°F]	383 [8]	12.7 [1/2]	900
Extreme Wind	-18 [0°F]	574 [12]	--	--
Extreme Min. Temp.	-37 [35°F]	--	--	--

5. Recommendations

For the evaluation of existing L170 structures and replacement structure design, the ground clearance should be based on projected future capacity of 70MW. The clearance criteria should be as follows:

Table 5.1 Recommended Clearance Criteria

Conditions	Conductor Condition			Clearance (m)	
	Temperature (°C)	Wind (Pa)	Ice (mm)	Along ROW	Cross / Along Highway
YEC Summer (30°C Ambient)	65	--	--	6.1	7.3
YEC Winter (10°C Ambient)	45	--	--	6.7	7.9
Rime Ice	-20	--	50 mm @350 kg/m ³	--	7.9

The structural evaluation of existing L170 structural components are recommended to comply with following loading criteria:

Table 5.2 Recommended Loading Criteria for Existing Structural Components

Conditions	Conductor Condition			Adjustment Factors	
	Temperature (°C)	Wind (Pa)	Ice (mm)	Wind Height Factor	Wind Gust Factor
CSA Heavy	-20	400	12.7 @900 kg/m ³	1	1
Extreme Ice	-20	--	25.4 @900 kg/m ³	1	1
IEC Wind	-10	425	--	IEC 60826	IEC 60826
Extreme Minimum Temp.	-51	--	--	1	1

The design of replacement structures shall conform to all loading listed in Table 5.2 and the following additional requirement:

Table 5.3 Additional Loading Criteria for Replacement Components

Conditions	Conductor Condition			Adjustment Factors	
	Temperature (°C)	Wind (Pa)	Ice (mm)	Wind Height Factor	Wind Gust Factor
IEC Wind & Low Temp.	-24	161	--	IEC 60826	IEC 60826
IEC Low Ice & High Wind	-10	161	10.8 @900 kg/m ³	IEC 60826	IEC 60826
Rime Ice	-20	--	50 mm @350 kg/m ³	1	1

Appendix A - IEEE Std. 738-2013 Calculation Outputs

PLS-CADD Version 14.40x64 2:27:37 PM Tuesday, October 17, 2017

Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is 8.734 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

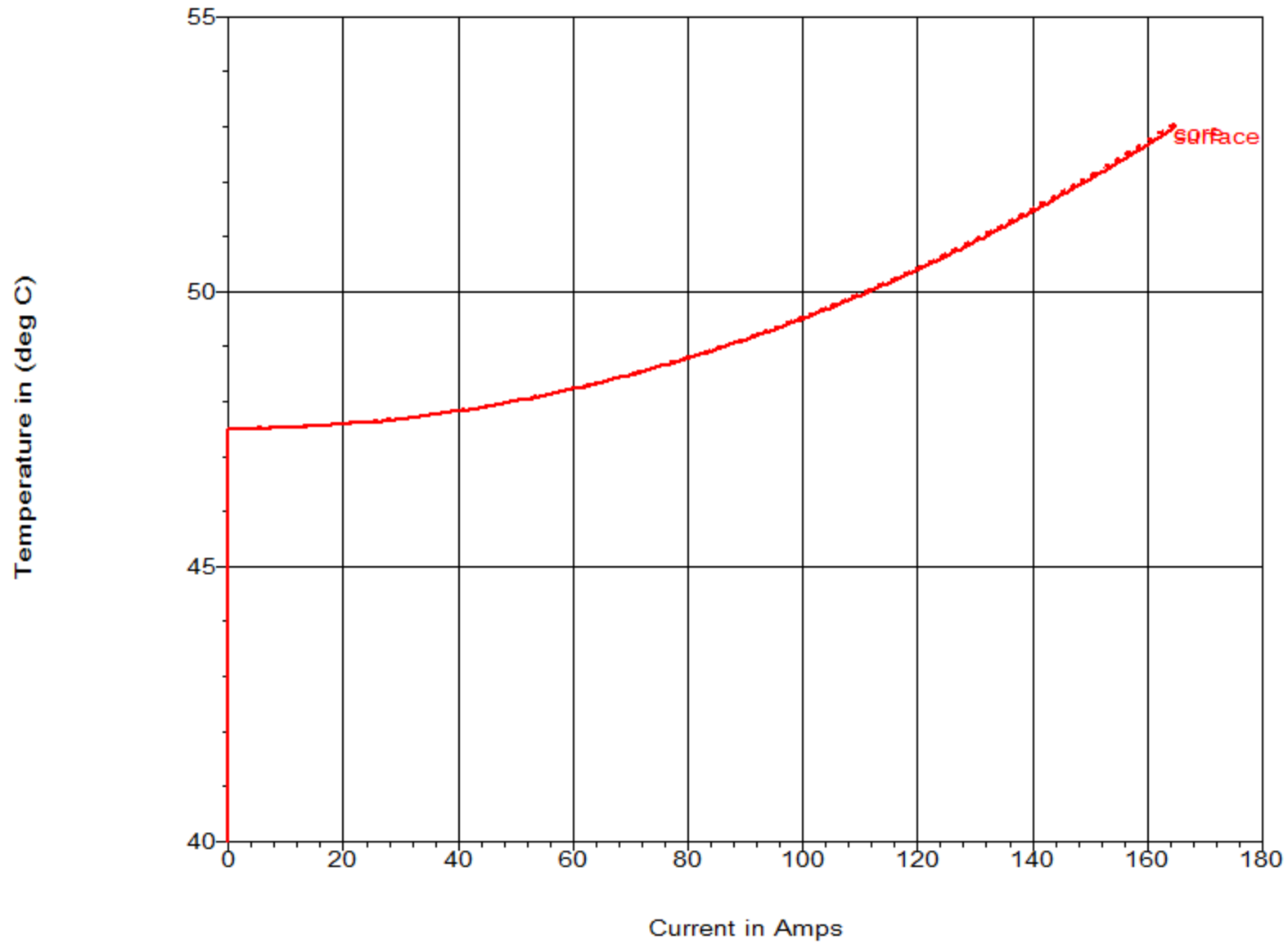
Radiation cooling is 2.469 (Watt/m)

Convective cooling is 12.723 (Watt/m)

Given a constant ac current of 165.0 amperes,

The conductor surface temperature is 53.0 (deg C)

The conductor core temperature is 53.1 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 14.40x64 2:39:32 PM Tuesday, October 17, 2017

Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is 8.734 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

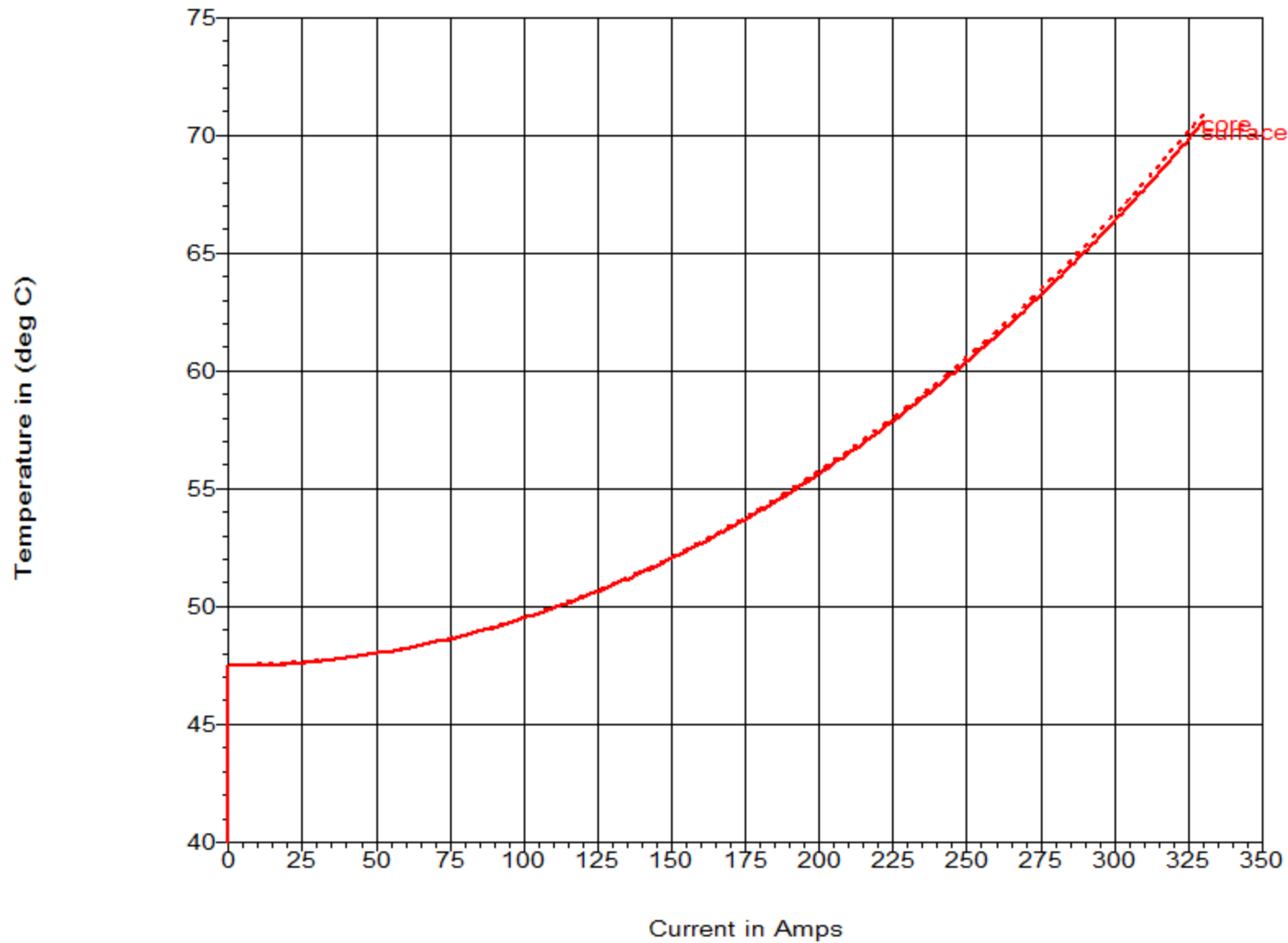
Radiation cooling is 6.304 (Watt/m)

Convective cooling is 29.875 (Watt/m)

Given a constant ac current of 330.0 amperes,

The conductor surface temperature is 70.6 (deg C)

The conductor core temperature is 70.9 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



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Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.5 and solar absorptivity is 0.5

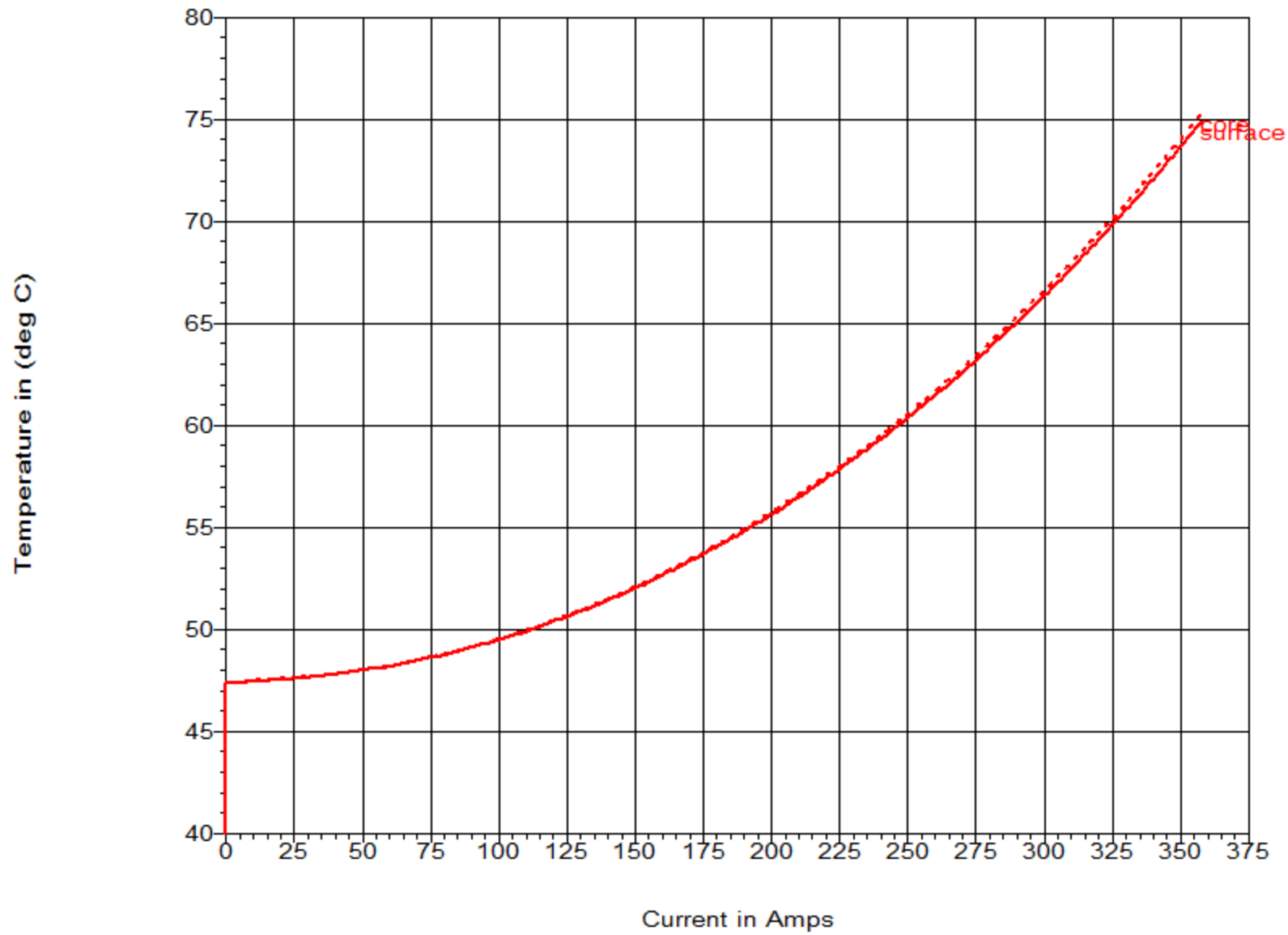
Solar heat input is 8.734 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

Radiation cooling is 7.366 (Watt/m)

Convective cooling is 34.188 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),

The steady-state thermal rating is 358.2 amperes



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Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

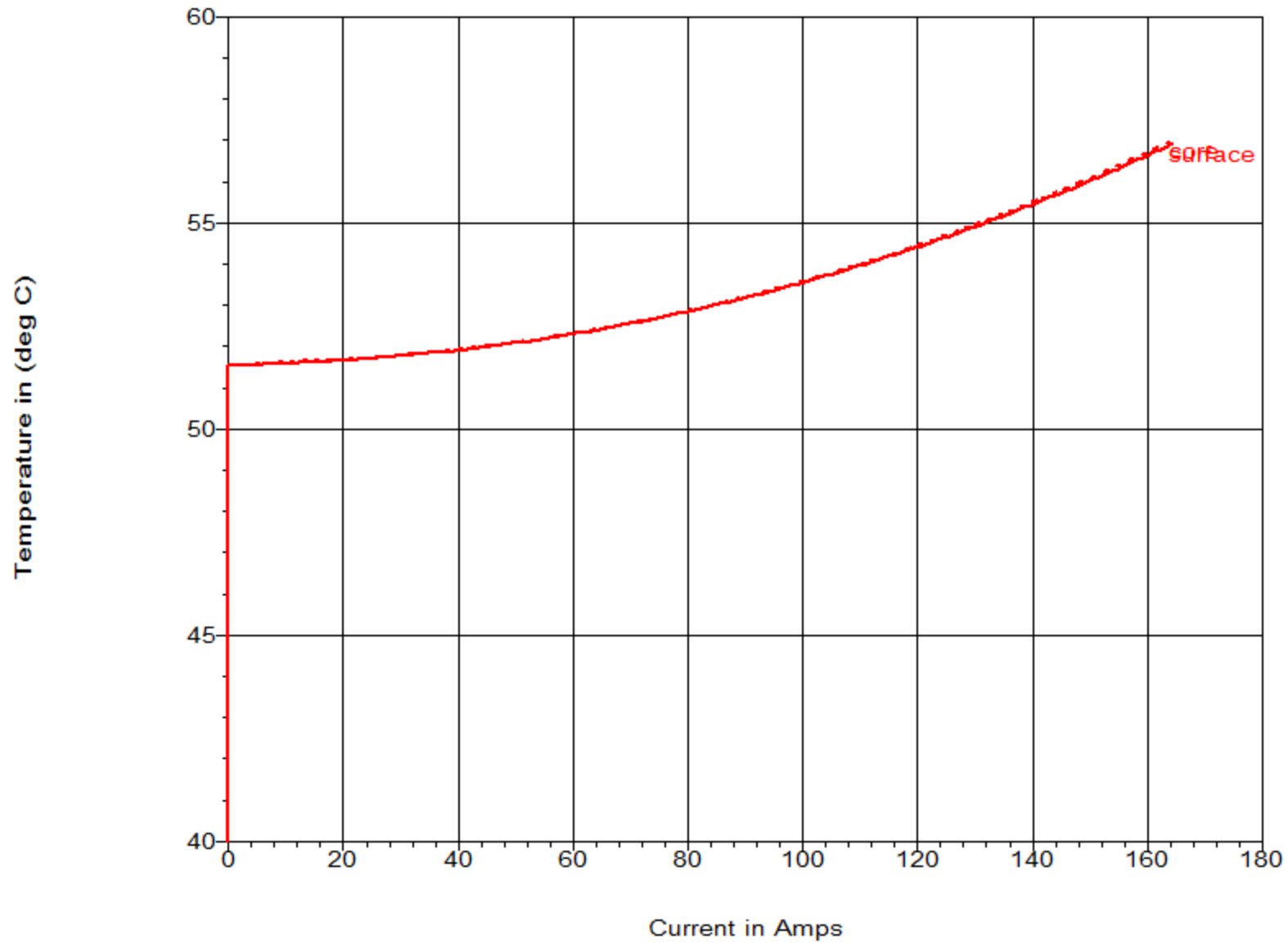
Radiation cooling is 3.934 (Watt/m)

Convective cooling is 16.582 (Watt/m)

Given a constant ac current of 165.0 amperes,

The conductor surface temperature is 57.0 (deg C)

The conductor core temperature is 57.0 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



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Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

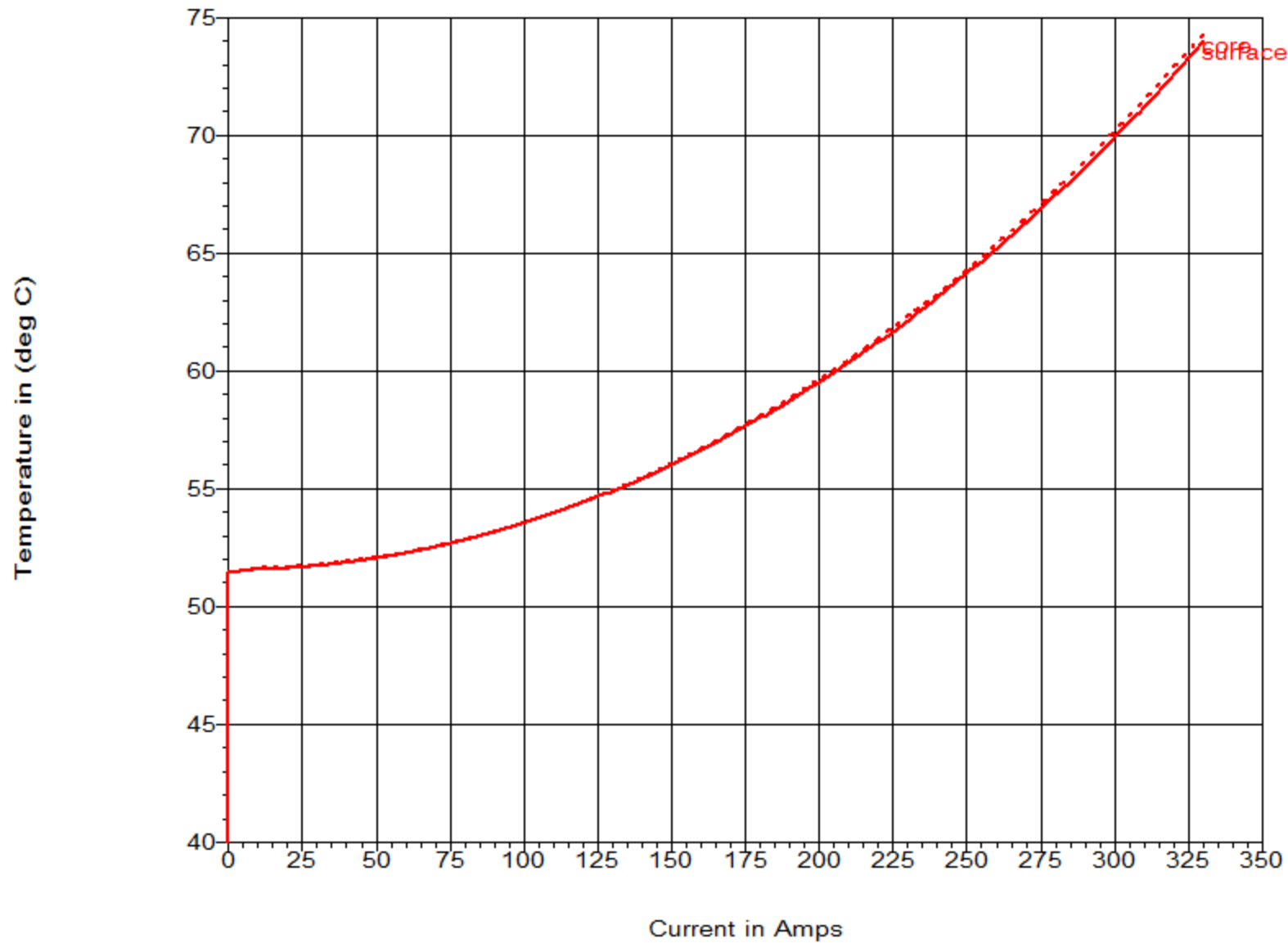
Radiation cooling is 8.540 (Watt/m)

Convective cooling is 33.191 (Watt/m)

Given a constant ac current of 330.0 amperes,

The conductor surface temperature is 74.0 (deg C)

The conductor core temperature is 74.3 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



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Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

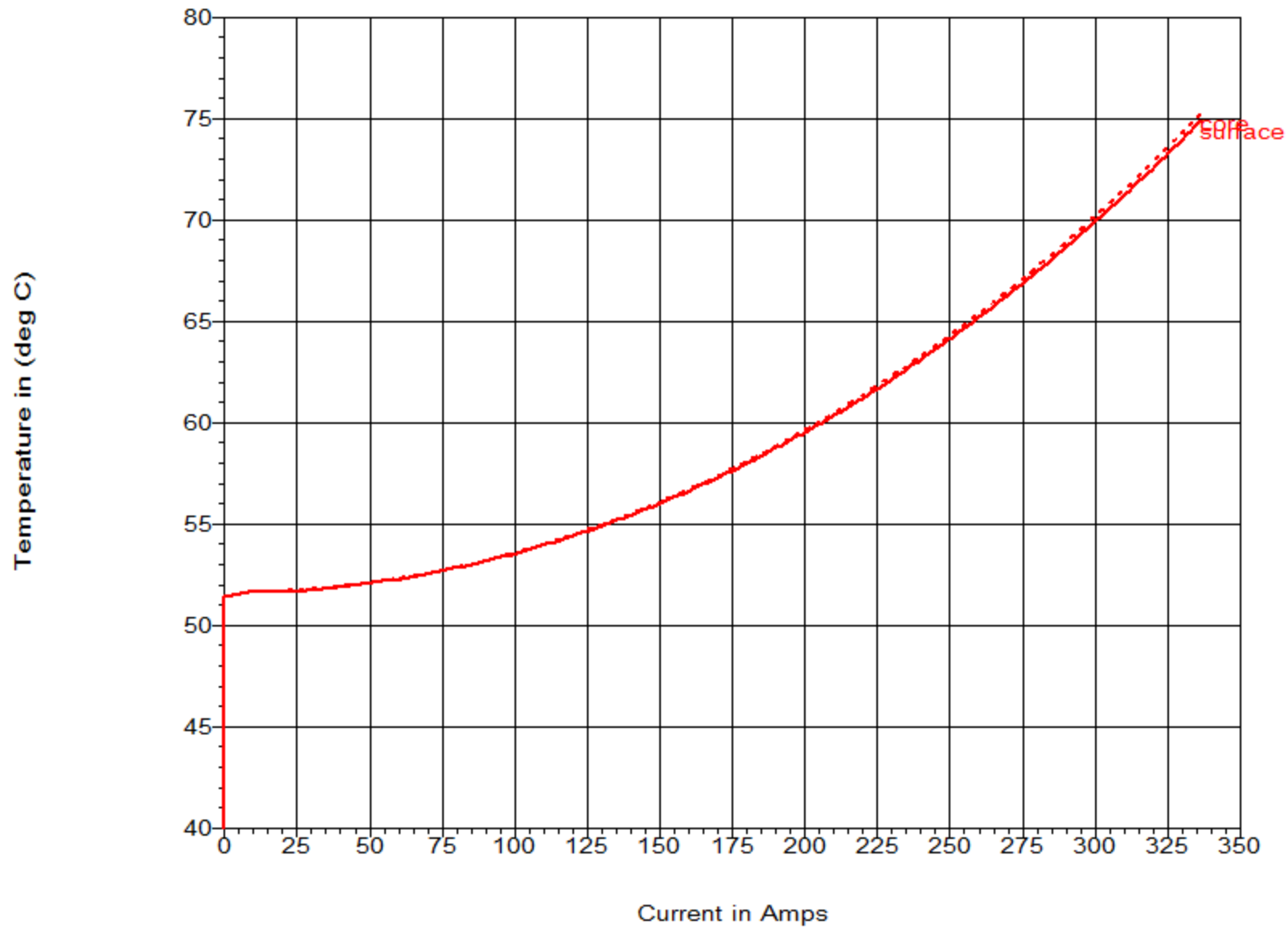
Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

Radiation cooling is 8.839 (Watt/m)

Convective cooling is 34.188 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),

The steady-state thermal rating is 337.1 amperes



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Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 10.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

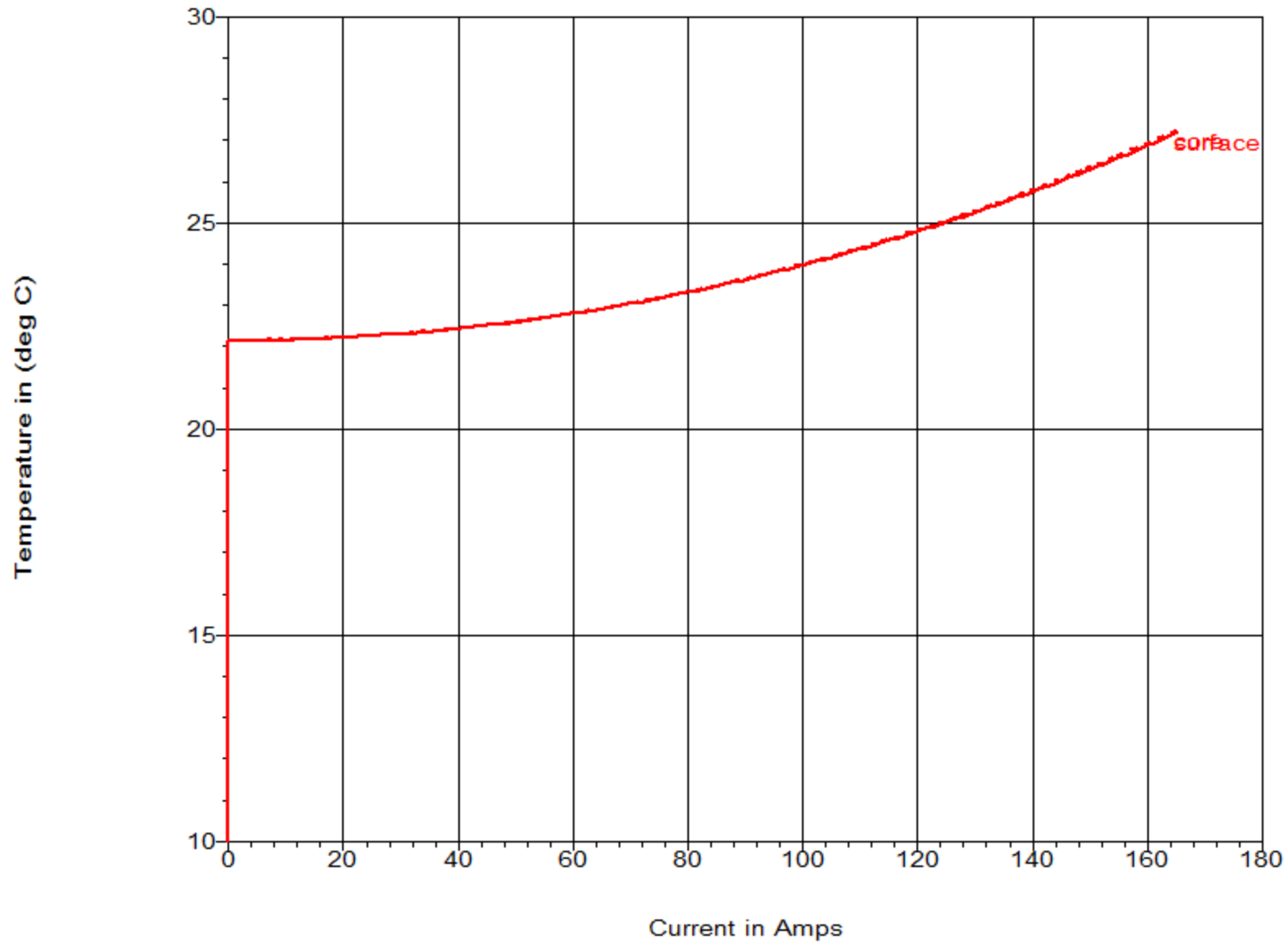
Radiation cooling is 2.976 (Watt/m)

Convective cooling is 16.870 (Watt/m)

Given a constant ac current of 165.0 amperes,

The conductor surface temperature is 27.2 (deg C)

The conductor core temperature is 27.3 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



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Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 10.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

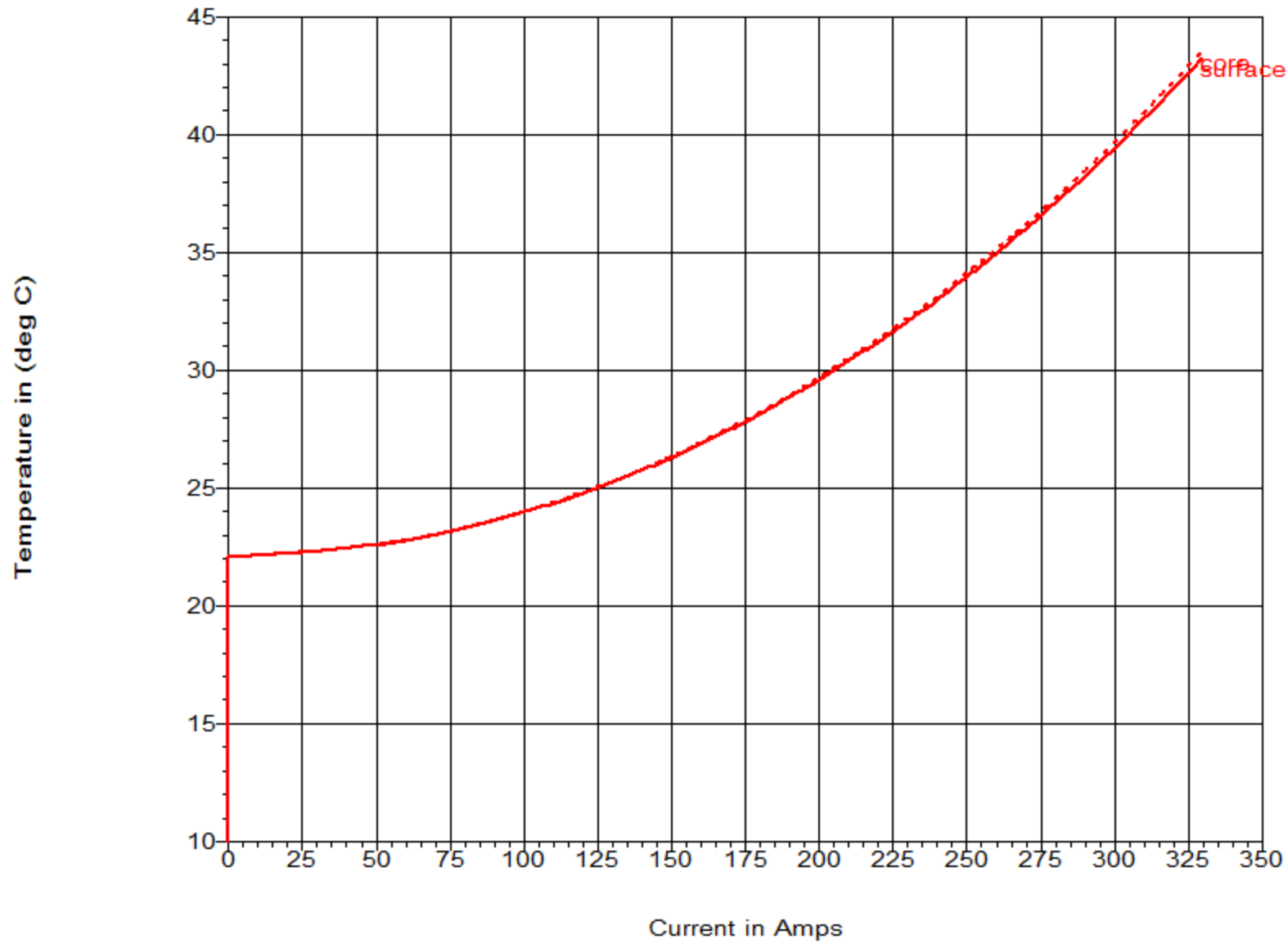
Radiation cooling is 6.272 (Watt/m)

Convective cooling is 32.648 (Watt/m)

Given a constant ac current of 330.0 amperes,

The conductor surface temperature is 43.3 (deg C)

The conductor core temperature is 43.6 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 14.40x64 3:09:19 PM Tuesday, October 17, 2017

Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 10.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

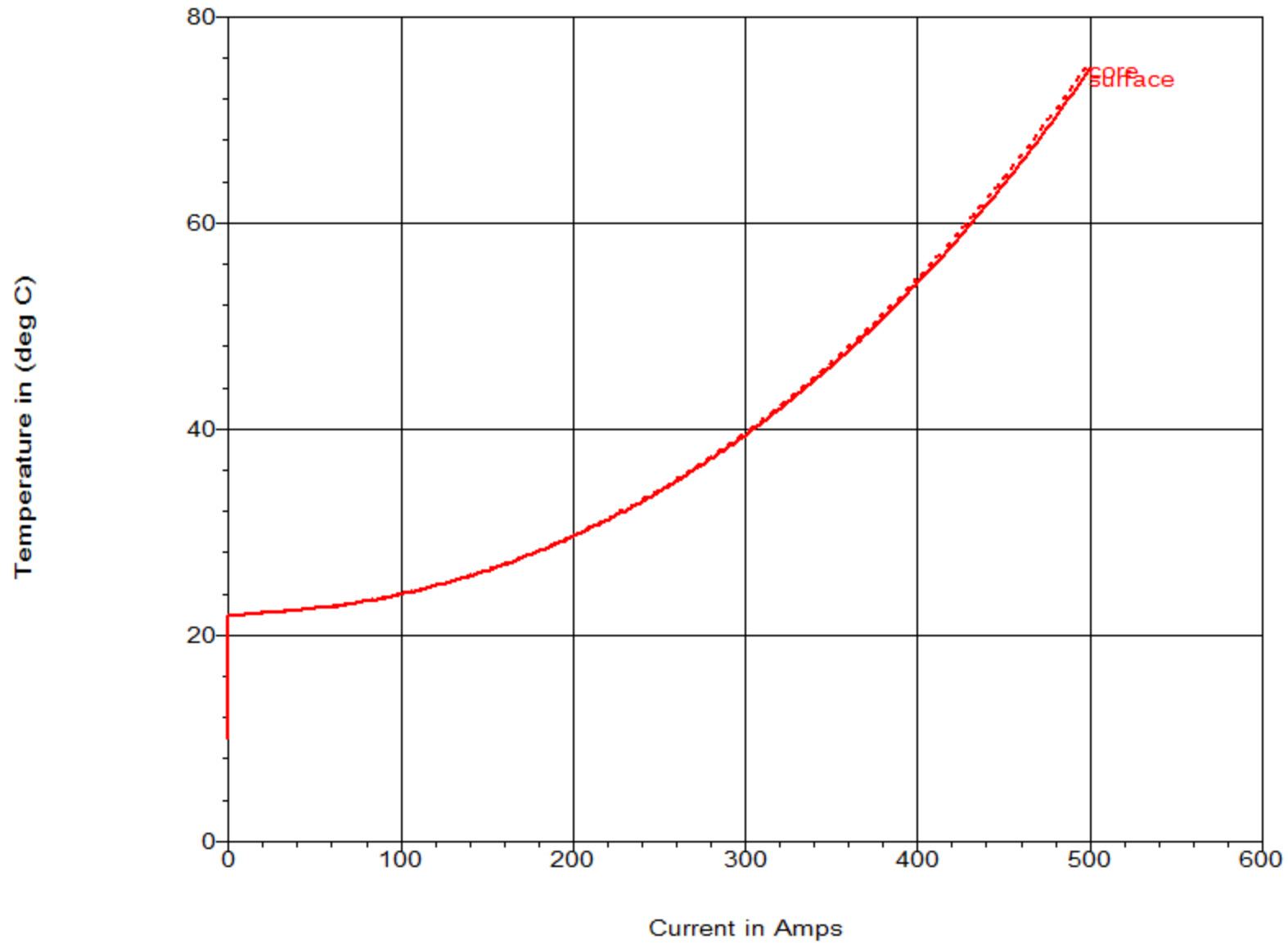
Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

Radiation cooling is 14.391 (Watt/m)

Convective cooling is 63.576 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),

The steady-state thermal rating is 500.1 amperes



PLS-CADD Version 14.40x64 3:13:17 PM Tuesday, October 17, 2017

Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 15.60 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

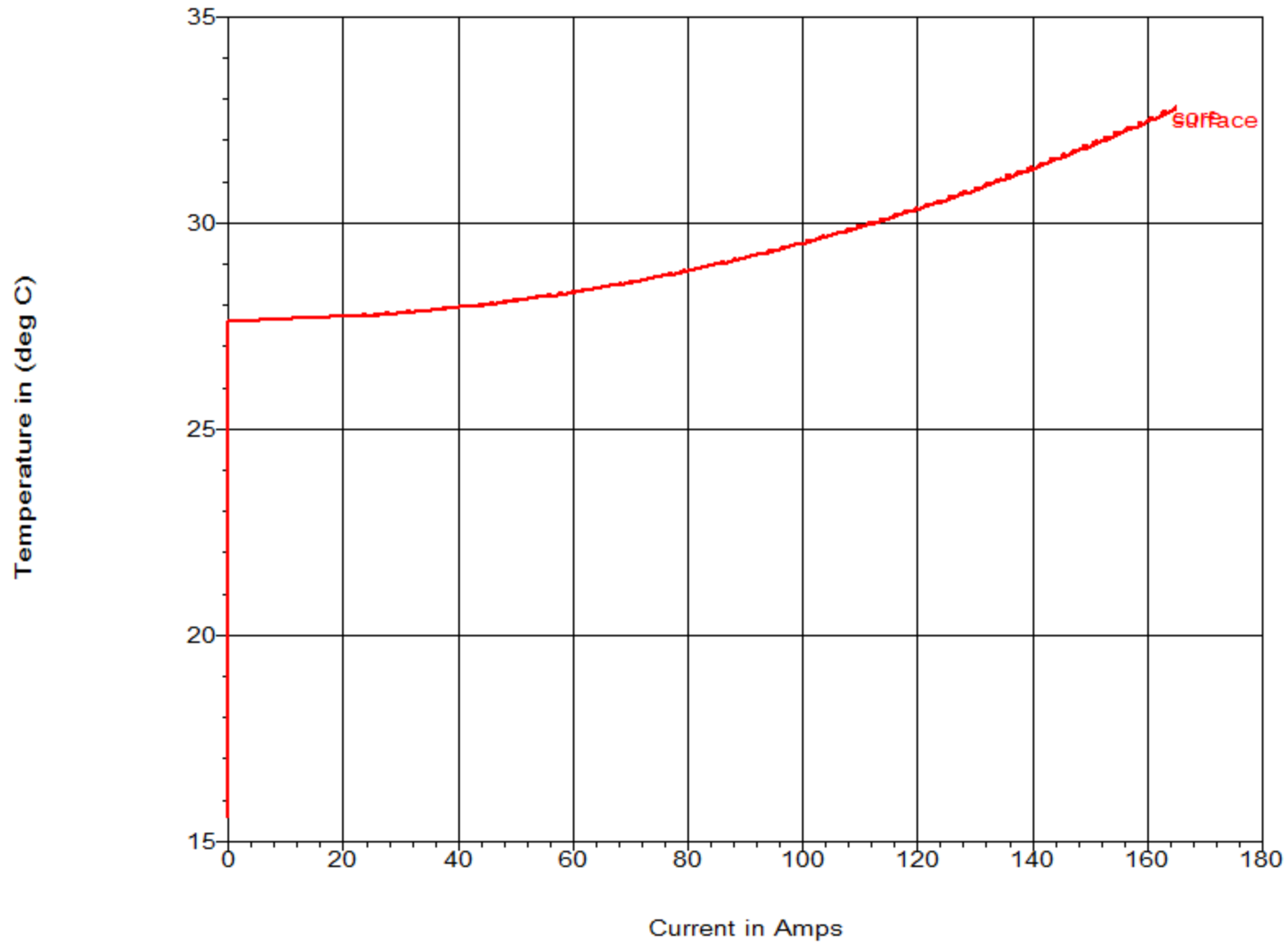
Radiation cooling is 3.143 (Watt/m)

Convective cooling is 16.818 (Watt/m)

Given a constant ac current of 165.0 amperes,

The conductor surface temperature is 32.8 (deg C)

The conductor core temperature is 32.8 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 14.40x64 3:14:35 PM Tuesday, October 17, 2017

Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 15.60 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

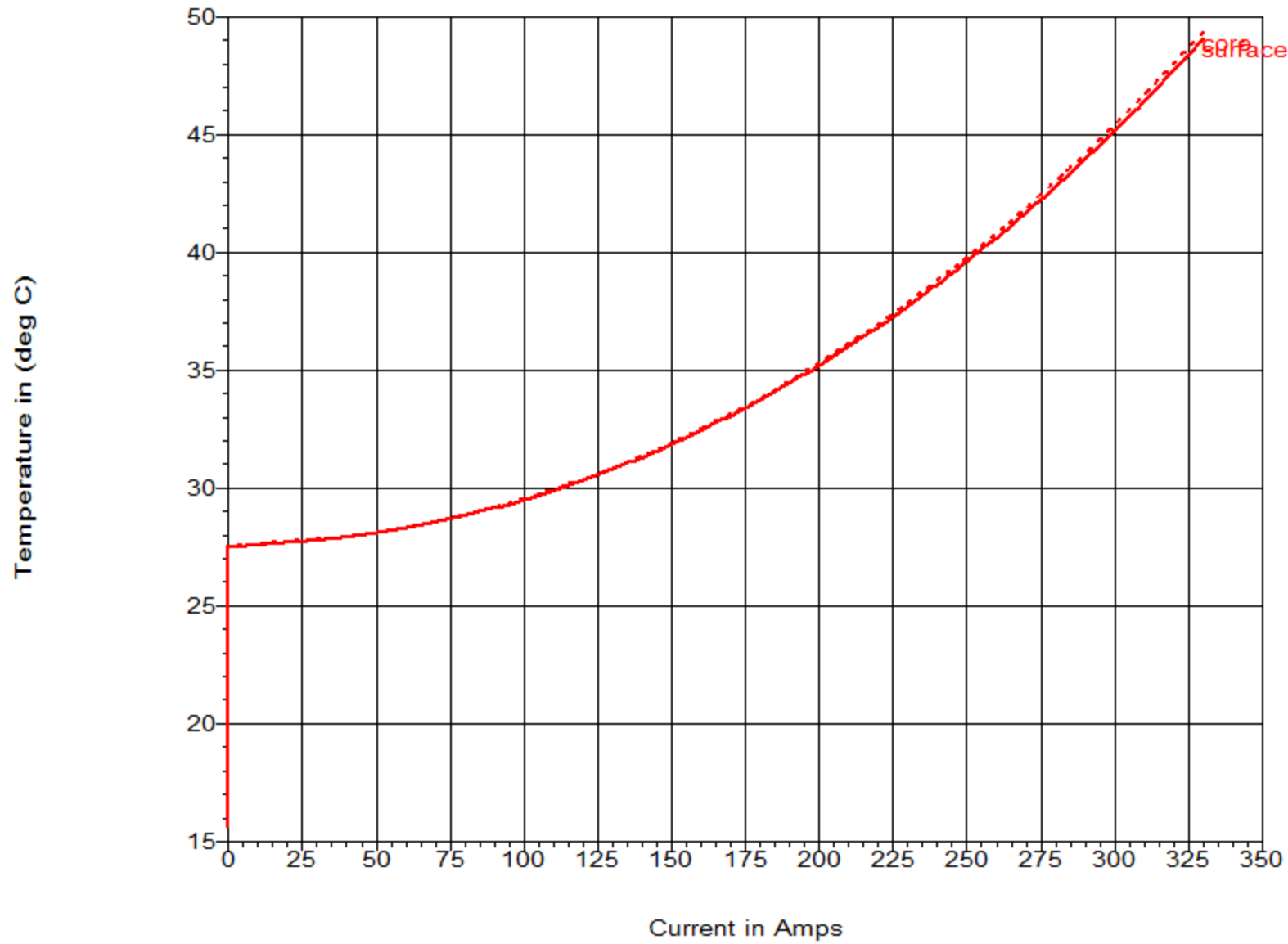
Radiation cooling is 6.667 (Watt/m)

Convective cooling is 32.779 (Watt/m)

Given a constant ac current of 330.0 amperes,

The conductor surface temperature is 49.1 (deg C)

The conductor core temperature is 49.4 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 14.40x64 3:10:14 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

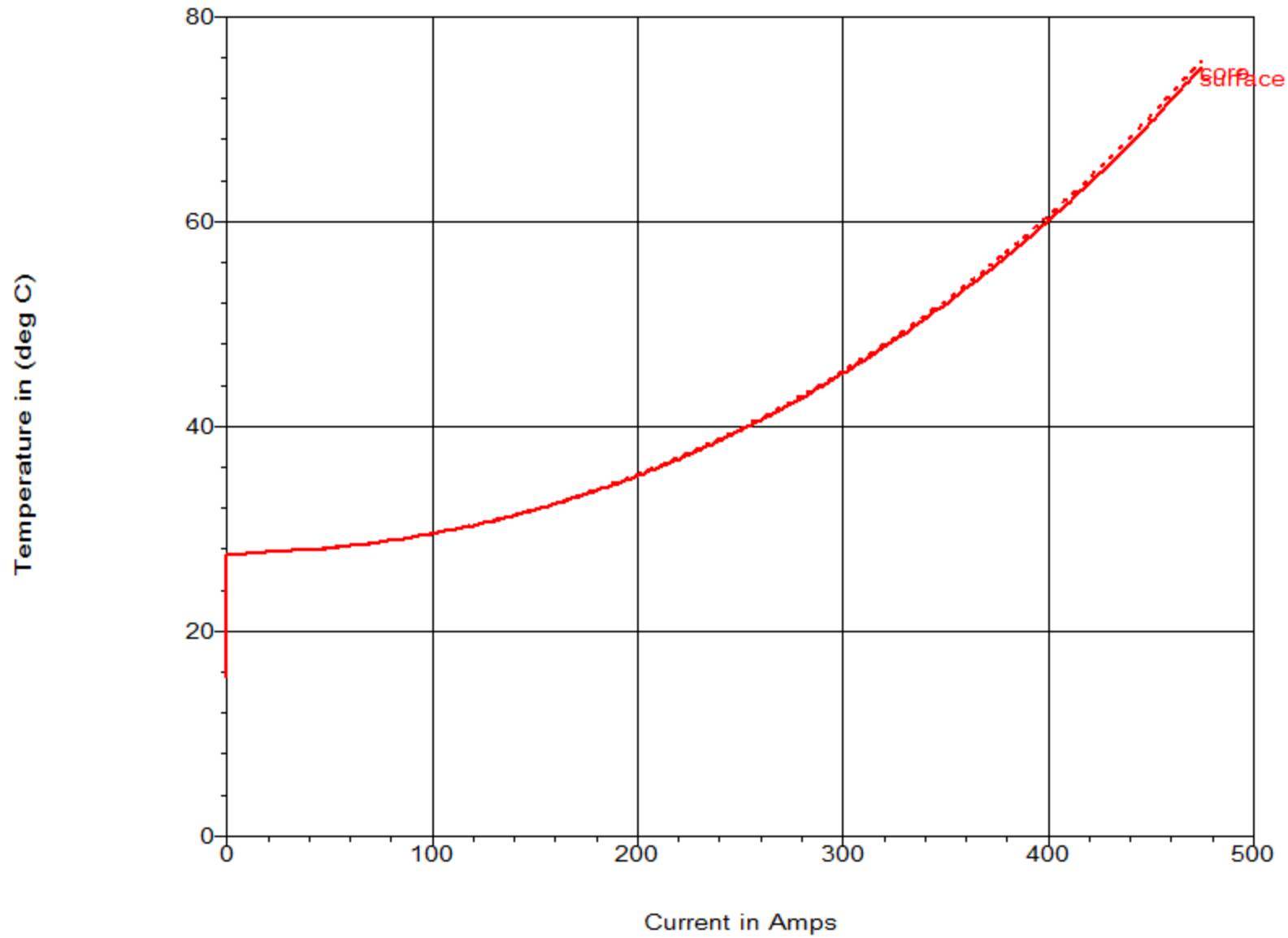
Air temperature is 15.60 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:

Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
and 0.2556 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)
Radiation cooling is 13.479 (Watt/m)
Convective cooling is 58.082 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 474.4 amperes



PLS-CADD Version 14.40x64 3:12:39 PM Tuesday, October 17, 2017

Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 30.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

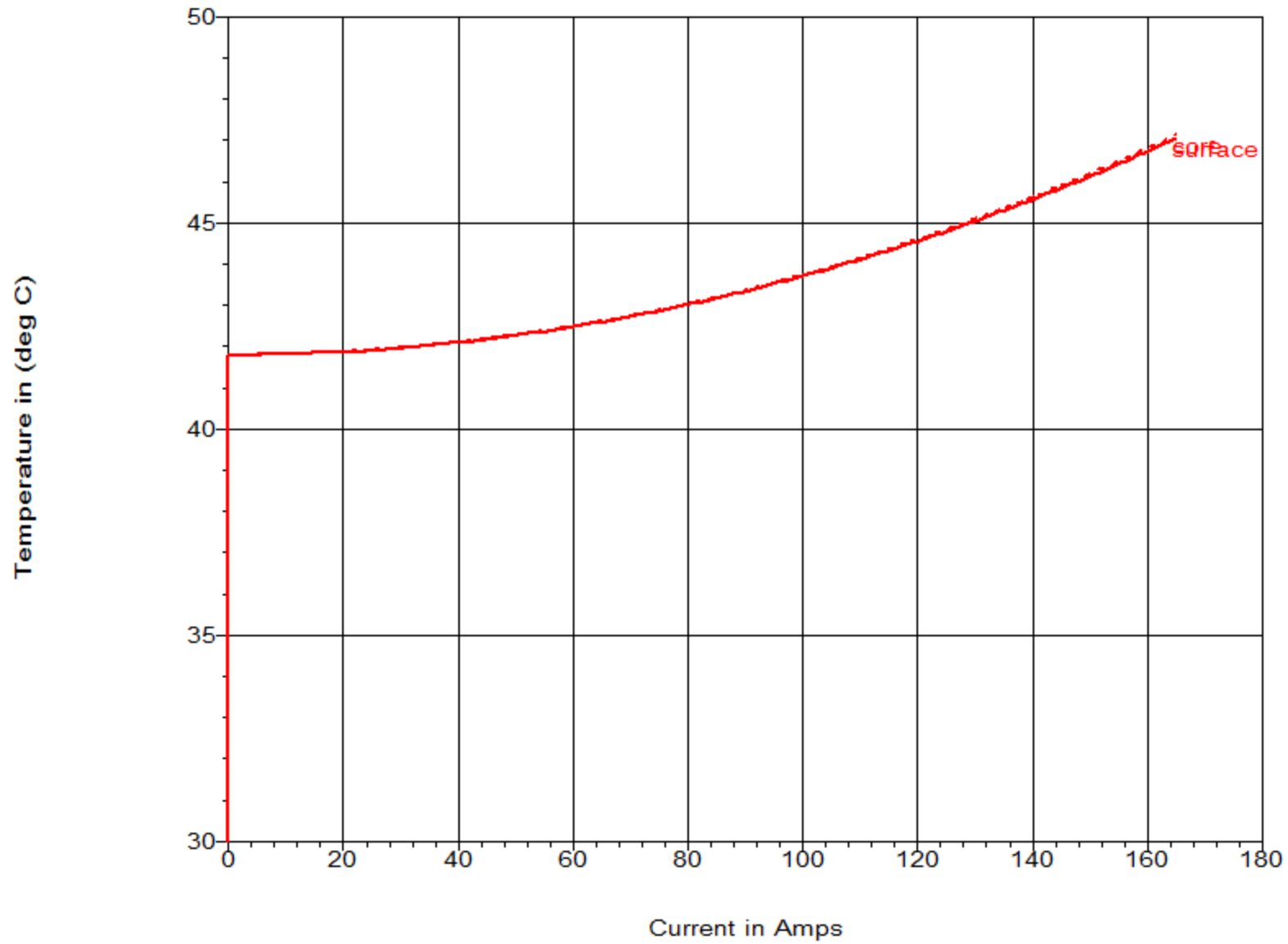
Radiation cooling is 3.600 (Watt/m)

Convective cooling is 16.690 (Watt/m)

Given a constant ac current of 165.0 amperes,

The conductor surface temperature is 47.1 (deg C)

The conductor core temperature is 47.1 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 14.40x64 3:11:53 PM Tuesday, October 17, 2017

Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 30.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

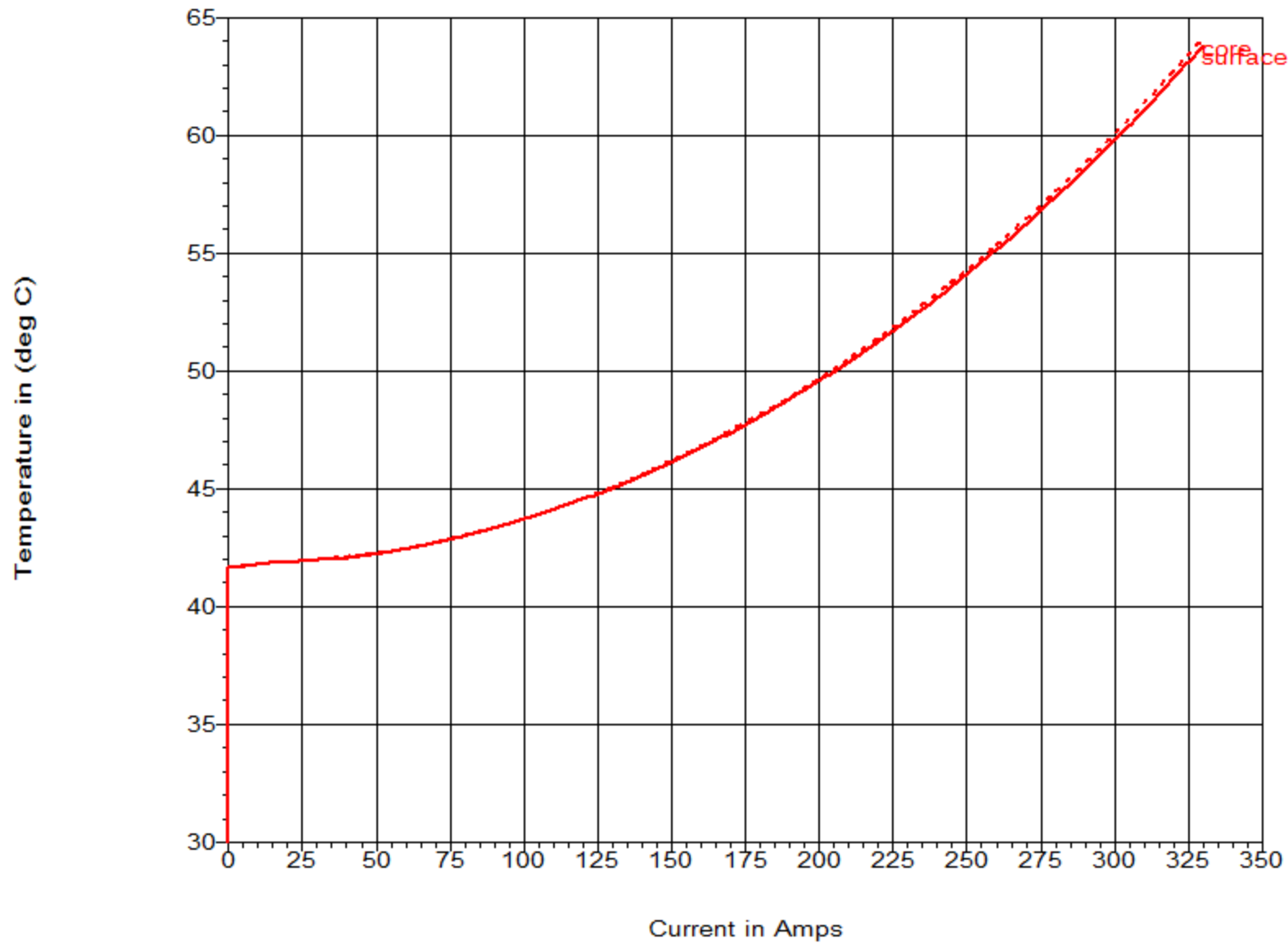
Radiation cooling is 7.744 (Watt/m)

Convective cooling is 33.056 (Watt/m)

Given a constant ac current of 330.0 amperes,

The conductor surface temperature is 63.8 (deg C)

The conductor core temperature is 64.1 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 14.40x64 3:11:12 PM Tuesday, October 17, 2017

Chimax Inc.

Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 30.00 (deg C)

Wind speed is 0.61 (m/s)

Angle between wind and conductor is 90 (deg)

Conductor elevation above sea level is 1000 (m)

Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)

Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)

Conductor latitude is 61.0 (deg)

Atmosphere is CLEAR

Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data

Conductor diameter is 1.631 (cm)

CORE STRANDS:

Diameter is 0.000 (mm)

Radial Thermal Conductivity is 2.00 (W/m-K)

Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)

and 0.2556 (Ohm/km) at 75.0 (deg C)

Conductor resistance is computed using average of core and surface temperatures.

Emissivity is 0.6 and solar absorptivity is 0.8

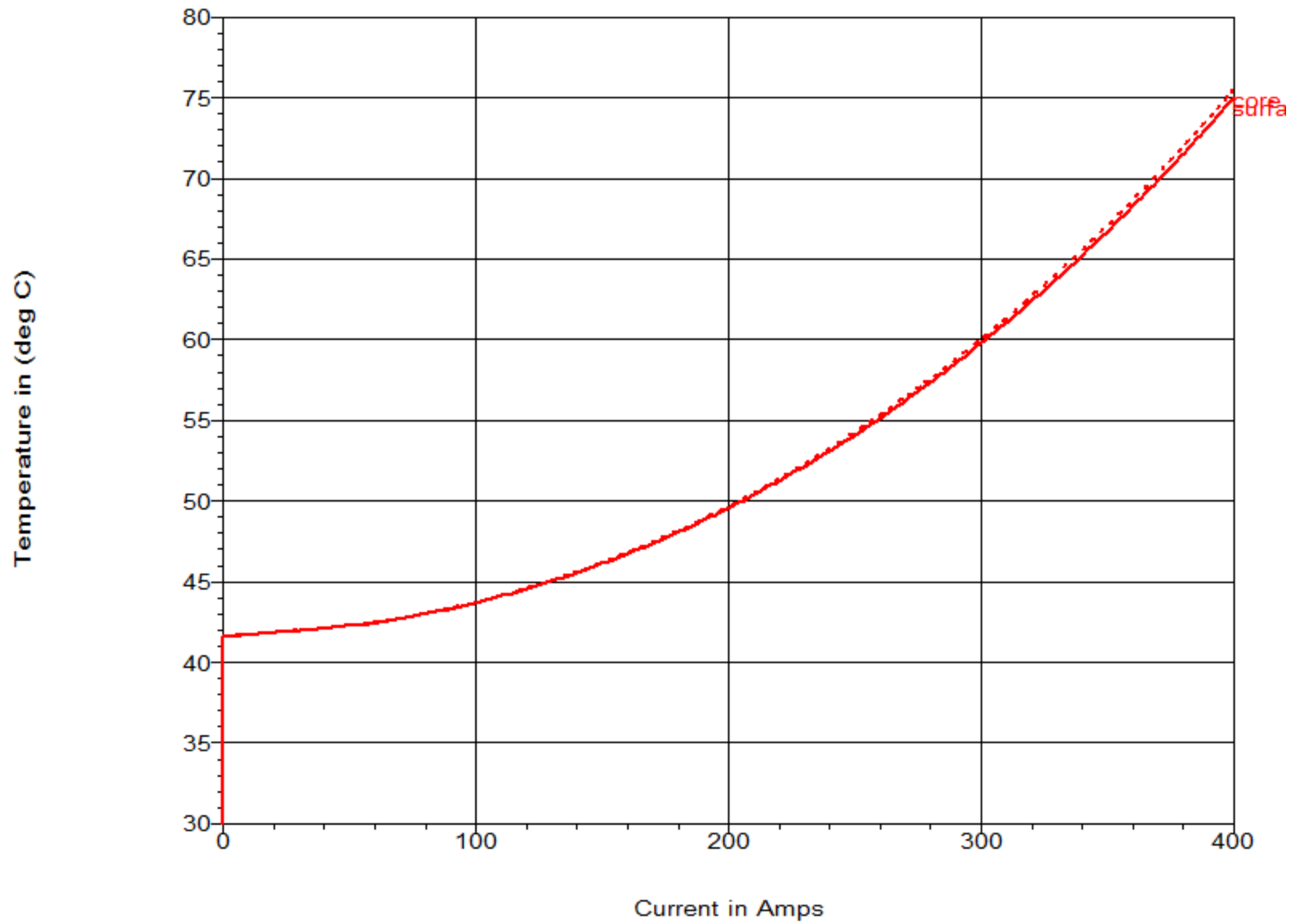
Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m²) - which was calculated)

Radiation cooling is 10.878 (Watt/m)

Convective cooling is 43.973 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),

The steady-state thermal rating is 399.8 amperes



Appendix B – Canada Climate Normal Data

- **Whitehorse**
- **Mayo**

Climate Normals 1981-2010 Station Data

Metadata including Station Name, Province, Latitude, Longitude, Elevation, Climate ID, WMO ID, TC ID

STATION_NAME	PROVINCE	LATITUDE	LONGITUDE	ELEVATION	CLIMATE_ID	WMO_ID	TC_ID
WHITEHORSE A	YT	60°42'34.200" N	135°04'07.800" W	706.2 m	2101300	71964	YXY

Legend

A = WMO "3 and 5 rule" (i.e. no more than 3 consecutive and no more than 5 total missing for either temperature or precipitation)

B = At least 25 years

C = At least 20 years

D = At least 15 years

1981 to 2010 Canadian Climate Normals station data

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Temperature													
Daily Average (°C)	-15.2	-12.7	-6.3	1	7.3	12.3	14.3	12.6	7.2	0.5	-9.4	-12.5	-0.1
Standard Deviation	6.5	4.7	3.5	2.3	1.5	1.3	0.9	1.4	1.6	1.8	4.8	4.7	3.3
Daily Maximum (°C)	-11	-7.7	-0.7	6.6	13.5	19.1	20.6	18.5	12.1	4.2	-6	-8.5	5.1
Daily Minimum (°C)	-19.2	-17.6	-11.9	-4.6	1	5.6	8	6.7	2.1	-3.2	-12.9	-16.5	-5.2
Extreme Maximum (°C)	9	11.7	11.7	21.8	34.1	34.4	32.8	31.6	26.7	19.3	11.7	10.6	
Date (yyyy/dd)	1977/26	1968/27	1979/22	2002/30	1983/30	1969/14	1951/09	1999/05	1942/03	2003/03	1970/02	2004/23	
Extreme Minimum (°C)	-52.2	-51.2	-40.6	-29.4	-12.9	-2.8	-0.5	-4.4	-19.4	-31.1	-41	-47.8	
Date (yyyy/dd)	1947/31	1968/02	1972/08	1986/10	2002/03	1971/03	1984/19	1948/25	1983/27	1982/28	2006/27	1942/19	
Precipitation													
Rainfall (mm)	0.3	0	0	1.2	14.3	32.4	38.1	35.5	29	8.8	1	0.4	160.9
Snowfall (cm)	25.4	18.3	14.8	7.2	2	0	0	0.3	4.7	18.6	27	23.5	141.8
Precipitation (mm)	17.8	11.8	10.3	7	16.3	32.4	38.1	35.8	33.3	23.2	20.1	16.3	262.3
Average Snow Depth (cm)	22	27	23	8	0	0	0	0	0	2	10	15	9
Median Snow Depth (cm)	22	27	23	8	0	0	0	0	0	0	10	15	9
Snow Depth at Month-end (cm)	26	25	18	1	0	0	0	0	0	5	13	18	9
Extreme Daily Rainfall (mm)	3.4	0.8	0.8	4.4	12.6	44.9	23.2	30.7	24.6	18.3	9.4	4.2	
Date (yyyy/dd)	1981/03	1984/04	1944/15	1983/30	2000/26	1985/27	1991/27	1948/01	1983/04	1970/02	1949/03	1981/18	
Extreme Daily Snowfall (cm)	14	16.7	27.2	16.6	12.2	12.7	0	8.6	21.6	15	14.6	27	
Date (yyyy/dd)	1968/03	1982/09	1967/08	2006/14	1942/04	1972/01	1942/01	1974/22	1956/27	1999/23	1978/23	1980/25	
Extreme Daily Precipitation (mm)	9.5	10.4	10.4	15.8	12.6	44.9	23.2	30.7	25.2	23.6	11.4	18.7	
Date (yyyy/dd)	1994/17	1952/28	1962/07	2006/14	2000/26	1985/27	1991/27	1948/01	1986/23	1970/02	1955/06	1980/25	
Extreme Snow Depth (cm)	86	94	94	66	38	0	0	3	20	21	52	69	
Date (yyyy/dd)	1972/30	1972/16	1972/01	1967/13	1972/01	1955/01	1955/01	1969/11	1956/28	1982/31	1978/25	1980/29	
Wind													
Speed (km/h)	13.4	13.7	13.2	12.8	12.6	11.6	10.8	11.3	13.2	14.2	13.9	14.6	12.9
Most Frequent Direction	S	S	S	S	S	S	S	S	S	S	S	S	S
Maximum Hourly Speed (km/h)	72	68	64	60	64	56	63	52	72	63	68	72	72
Date (yyyy/dd)	1962/09	1957/15	1953/14	1966/09	1965/06	1965/16	1959/30	1998/29	1967/17	1961/28	1962/18	1954/17	1954/17
Direction of Maximum Hourly Speed	SE	S	S	N	S	SE	E	S	S	SE	SE	S	S
Maximum Gust Speed (km/h)	100	106	93	89	85	90	91	84	101	97	106	97	106
Date (yyyy/dd)	1965/17	1964/19	1965/10	1965/16	1965/02	1963/26	1982/07	1960/11	1967/18	1958/01	1962/18	1960/14	1962/18
Direction of Maximum Gust	S	S	SW	N	S	W	SE	SE	S	S	SE	SE	SE
Days with Winds >= 52 km/h	1.5	1.2	0.5	0.4	0.1	0.1	0.1	0.2	0.7	0.8	1.1	1.2	7.6
Days with Winds >= 63 km/h	0.2	0.3	0.1	0.1	0	0	0	0.1	0.1	0.1	0.1	0.1	1

1981 to 2010 Canadian Climate Normals station data (Frost-Free)

	Frost-Free:	Code					
Average Date of Last Spring Frost	5-Jun	C					
Average Date of First Fall Frost	25-Aug	C					
Average Length of Frost-Free Period	80 Days	C					
Probability of last temperature in spring of (10%		25%	33%	50%	66%	75%	90%
Date	21-Jun	15-Jun	12-Jun	4-Jun	2-Jun	29-May	25-May
Probability of first temperature in fall of 0 °(10%		25%	33%	50%	66%	75%	90%
Date	10-Aug	22-Aug	24-Aug	30-Aug	3-Sep	4-Sep	14-Sep
Probability of frost-free period equal to or l 10%		25%	33%	50%	66%	75%	90%
Days	60	66	73	85	91	95	102

Climate Normals 1981-2010 Station Data

Metadata including Station Name, Province, Latitude, Longitude, Elevation, Climate ID, WMO ID, TC ID

STATION_NAME	PROVINCE	LATITUDE	LONGITUDE	ELEVATION	CLIMATE_ID	WMO_ID	TC_ID
*MAYO A	YT	63°37'00.000" N	135°52'00.000" W	503.8 m	2100700	71965	YMA
* This station meets WMO standards for temperature and precipitation.							

Legend

A = WMO "3 and 5 rule" (i.e. no more than 3 consecutive and no more than 5 total missing for either temperature or precipitation)

B = At least 25 years

C = At least 20 years

D = At least 15 years

1981 to 2010 Canadian Climate Normals station data

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Temperature													
Daily Average (°C)	-23.1	-17.9	-9.6	1	8.8	14.5	16.1	13.1	6.4	-2.7	-15.3	-19.9	-2.4
Standard Deviation	7.4	5.1	4.1	2.3	1.6	1.2	1	1.5	1.6	2.5	5.7	5.8	2.3
Daily Maximum (°C)	-18	-11.7	-2.9	7.2	15.2	21.4	22.8	19.5	12	1.2	-10.9	-14.7	3.4
Daily Minimum (°C)	-28.2	-24.1	-16.3	-5.2	2.2	7.5	9.4	6.7	0.9	-6.5	-19.7	-25.1	-8.2
Extreme Maximum (°C)	10.1	12.2	12.2	22.8	33.5	36.1	35.6	32.6	26.7	22.6	13.9	11.8	
Date (yyyy/dd)	1981/15	1968/27	1930/26	1976/29	1983/31	1969/14	1951/20	1999/06	1938/02	2003/03	1970/02	1999/23	
Extreme Minimum (°C)	-58.3	-62.2	-48.9	-41.1	-21.7	-3.9	-2.8	-10.6	-15.6	-36.7	-50.6	-57.8	
Date (yyyy/dd)	1947/28	1947/03	1951/05	1944/01	1964/11	2006/06	1928/23	1993/28	1946/28	1935/27	1950/26	1946/13	
Precipitation													
Rainfall (mm)	0.3	0	0.1	2.9	22.2	38.9	50.2	44.5	34.8	9.4	0.3	0.3	203.8
Snowfall (cm)	28.3	20.2	14.5	7.8	1	0.1	0	0.3	3.9	23	31.8	29.8	160.6
Precipitation (mm)	18.3	13	9.9	8.8	23.2	39	50.2	44.6	38.7	27	21.1	19.8	313.5
Average Snow Depth (cm)	31	38	34	15	0	0	0	0	0	3	14	23	13
Median Snow Depth (cm)	31	38	34	16	0	0	0	0	0	2	15	23	13
Snow Depth at Month-end (cm)	35	37	29	1	0	0	0	0	1	8	19	27	13
Extreme Daily Rainfall (mm)	4.2	0.3	14.5	20.3	25.4	34.6	29.2	31.8	23.6	12	6.6	5	
Date (yyyy/dd)	2009/20	1938/24	1947/17	1926/13	1939/26	2007/30	1976/14	1932/27	1959/19	1980/03	1947/22	1985/20	
Extreme Daily Snowfall (cm)	35.6	16.8	16	12.2	15	2.8	0	3.6	24.9	25.6	21	15.7	
Date (yyyy/dd)	1949/09	1974/07	1939/18	1964/01	1964/09	1992/07	1925/01	1984/28	1970/21	1982/25	2003/22	1958/15	
Extreme Daily Precipitation (mm)	35.6	16.5	16	21.6	25.4	34.6	29.2	31.8	23.6	22.4	16.3	15.7	
Date (yyyy/dd)	1949/09	1965/12	1939/18	1928/29	1939/26	2007/30	1976/14	1932/27	1959/19	1958/04	1966/04	1958/15	
Extreme Snow Depth (cm)	81	109	117	94	28	0	0	0	20	41	64	71	
Date (yyyy/dd)	2004/19	1967/24	1967/04	1967/01	1964/01	1934/18	1955/01	1955/01	1993/26	1982/26	1956/20	1958/31	
Wind													
Speed (km/h)	5	6.2	9.3	8.8	8	6.3	5.3	5.1	6.2	7.9	6.1	5.3	6.6
Most Frequent Direction	N	N	N	N	N	N	N	N	N	N	N	N	N
Maximum Hourly Speed (km/h)	42	43	42	56	42	64	42	50	43	72	43	50	72
Date (yyyy/dd)	1973/01	1979/02	1966/28	1965/18	1965/25	1961/12	1961/13	1984/26	1977/22	1962/27	1978/26	1998/26	1962/27
Direction of Maximum Hourly Speed	N	N	NE	NE	SW	S	W	N	N	S	N	N	S
Maximum Gust Speed (km/h)	69	74	65	126	70	117	65	74	65	67	67	61	126
Date (yyyy/dd)	1981/19	1986/26	1994/04	2002/20	1985/31	1998/14	1985/01	1998/02	1977/22	1989/07	1999/01	1980/14	2002/20
Direction of Maximum Gust	S	S	SE	W	E	E	W	S	N	S	SW	S	W

1981 to 2010 Canadian Climate Normals station data (Frost-Free)

	Frost-Free:	Code
Average Date of Last Spring Frost	26-May	C
Average Date of First Fall Frost	26-Aug	C
Average Length of Frost-Free Period	91 Days	C
Probability of last temperature in spring of 0 10%	25%	33%
Date	23-Jun	12-Jun
Probability of first temperature in fall of 0 °C 10%	25%	33%
Date	29-Jul	5-Aug
Probability of frost-free period equal to or le: 10%	25%	33%
Days	47	62

**YESAA Project Proposal
October 2015**

Stewart-Keno City Transmission Project

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Interests and Concerns Raised by Members of the Public and Areas where Feedback from Public Engagement Activities was considered in the Environmental and Socio-economic Assessment Process

Issue	Interest/Concern Raised	Response
Project Description and Transmission Line Route	New line segment between Mayo and Keno City should limit frequency of crossing over the highway.	This was a consideration in the routing of the new transmission line between Mayo and Keno City. See Chapter 6, Section 6.3.3.
	New line should avoid crossing properties as it enters Keno City substation (Mayo to Keno City Line Segment).	See Chapter 6, Section 6.3.3.
	Concern regarding the potential for the new line to encroach on existing private property as distance between existing centre line and private property line is limited.	See mitigation discussed in Chapter 7, Section 7.3.3.2 (Private and Commercial Land Use).
	Special care and attention was requested for a buried water line near McGuinty Creek along the proposed route.	See mitigation discussed in Chapter 7, Section 7.3.3.2 (Private and Commercial Land Use).
	Concern regarding avoidance of historic signage and engine on Alexco parcel near Keno City.	See mitigation discussed in Chapter 7, Section 7.3.3.2 (Private and Commercial Land Use). See also Chapter 6, section 6.3.3.
	Interest in the types of poles being used to replace the line segment between Mayo and Keno City.	An H-Frame configuration is planned with use of mono-pole or double circuit design provided in specific areas to mitigate adverse impacts on private property or other interests.
Substations	Interest in the potential locations for the substations.	Project Description, Chapter 6, Section 6.3.3.1 describes alternatives locations for substation.

**YESAA Project Proposal
October 2015**

Stewart-Keno City Transmission Project

Issue	Interest/Concern Raised	Response
Safety and Reliability	New line should limit the frequency and duration of power outages for customers (Mayo to Keno City Line Segment).	See Chapter 6, Project Description. The Project will improve the transmission grid infrastructure in central Yukon between Stewart Crossing and Keno City, and reinforce and strengthen the grid between Stewart Crossing and Mayo ensuring continued safe and reliable service.
	Concern regarding power outages during line construction.	In the event that substantial power outages are anticipated, generators will be put in place to reduce impacts of outages to hours (not days).
	Concern regarding potential for stray electricity coming off the new line given it will be operated at a higher voltage.	Due to the size of the line this concern is not an issue.
Transformer Upgrades	Concern regarding replacement of existing transformers that were considered insufficient to meet existing power needs of two customers along the route northeast of Mayo.	The Project will also provide updated transformer infrastructure for service to specific properties near the Minto Bridge and Halfway Lakes.
	Interest in new opportunities to access grid power and associated costs.	The cost of a new transformer and distribution line is borne by the customer. However, the Yukon Government's Rural Electrification Program may provide some financing assistance. A 69kV step-down transformer may cost between \$100,000 and \$150,000 (a 138 kV step-down transformer would cost slightly more). Ten distribution poles (100 m apart) would cost on the order of \$15,000.

**YESAA Project Proposal
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Stewart-Keno City Transmission Project

Issue	Interest/Concern Raised	Response
Project Costs	Concern regarding how the Project will be funded; and impact of Project costs and potential cost over-runs on ratepayers.	Funding by the Yukon Government through Yukon Development Corporation (YDC), rather than by Yukon Energy, will allow the system improvement to be completed without any adverse cost impacts on electrical rates. Yukon Energy does not have any specific information regarding how the Yukon Government or YDC plans to finance the Project at this time, but understands a number of funding options are being considered.
	Concern regarding extreme cost of the Project when there are only a handful of customers in Keno; suggestion to decommission the line and turn on the diesels in the communities. Suggestion that money could be used more strategically.	See Chapter 6, Section 6.3.3. Moving existing customers from grid generation to thermal (diesel) generation is not consistent with the goals of Yukon government's Energy Strategy for Yukon or the Climate Change Action Plan. Removal of the line would also likely limit potential future industrial growth in this area of longstanding mining activity, which could have an adverse impact on potential economic growth in Yukon. It would also limit future renewable generation development in this area for connection to the Yukon grid.
	Concern over how the government is funding the Project.	Yukon Energy understands that the government is considering a number of funding options.

**YESAA Project Proposal
October 2015**

Stewart-Keno City Transmission Project

Issue	Interest/Concern Raised	Response
	Concern over building public infrastructure to potentially support uncertain and future private development. Suggest that mining companies should pay for their own infrastructure. Concern regarding the high cost of substations for industrial purposes.	See Chapter 6, Section 6.3. The Project will reinforce and strengthen the grid between Stewart Crossing and Mayo, and replace and remove deteriorated and 'end of life' transmission infrastructure between Mayo and Keno City, ensuring continued safe and reliable service and facilitating future economic development within the territory. See also discussion in Chapter 5, Section 5.4 which outlines the current industrial customer investment policy as approved by the YUB. This reduces the risk of adverse cost impacts to other utility ratepayers from new capital costs needed to connect a new major industrial customer and focuses on maximizing potential industrial customer investment to new transmission facilities developed to extend service to them as well as to retain direct assignment of annual capital-related transmission costs for existing facilities, where appropriate.
Employment Opportunities	Queries regarding who would be hired to do line work.	Line work will be put out to competitive and open tender.
	Interest in construction employment opportunities, including local contractors (brushing, clearing, substation crews).	Line work will be put out to competitive and open tender. Brushing contracts have been tendered separately in the past. Yukon Energy would like to understand the capacity of local residents have for this type of work in order to maximize Project benefits to local residents and Yukoners in general.
	Interest in environmental contracts.	There are not likely to be any other environmental contracts at this time; however, Yukon Energy is pursuing potential heritage work.
	Interest in local economic benefits. YEC should have a policy that supports using local companies and businesses for their infrastructure projects and should consider local businesses during tender process.	Yukon Energy will endeavour as part of the remaining project planning, procurement and construction stages to maximize benefits to local businesses.

**YESAA Project Proposal
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Stewart-Keno City Transmission Project

Issue	Interest/Concern Raised	Response
	Interest in the location of construction camps and potential opportunities for local businesses.	Decisions have not yet been made regarding the number of camps or camp locations. Camp location would very likely be located on private property.
Consultation	Interest in consultation/engagement process and how individuals could participate in the planning and assessment process so that their views could be discussed.	See discussion included in Section 4.3 and Section 4.4 of this Chapter regarding methods of communication for the public engagement process.
Project Schedule	Interest in overall Project schedule (YESAB submissions, construction, operation).	See Chapter 6, Section 6.5 for overall Project schedule.
Biophysical Environment	Concern regarding important small mammal habitat area.	See Chapter 7, Section 7.2.3.3.
	Interest in impact collisions related to migratory birds.	See Chapter 7, Section 7.2.3.4.
	Request to avoid Community Ecological Monitoring Plots.	See Chapter 7, Section 7.3.3.2.
	Include a vegetative buffer between roadway and transmission line.	See mitigation discussion in Chapter 7. A vegetative buffer is being provided to the extent feasible.
	Concern over past construction practises regarding waste materials and garbage along the ROW.	There will be environmental monitoring and adequate oversight. Yukon Energy will ensure its EMS is applied.
	Concern regarding ground disturbance along the ROW including permafrost melting, soil erosion and drainage.	See mitigation measures described in Chapter 7. Ground disturbance will be minimized through avoidance of poor terrain, where possible, and other mitigation measures as described in Chapter 7.
Heritage	Concern over heritage or historic sites of value along the proposed route.	See Chapter 7, Section 7.3.3.5. A Heritage Resources Impact Assessment has been completed. Yukon Energy's Heritage and Culture EWP will be followed during construction.

**YESAA Project Proposal
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Stewart-Keno City Transmission Project

Issue	Interest/Concern Raised	Response
Timber Salvage	NND and local community residents (Mayo and Keno City) noted importance of access to fuel wood.	The Timber Salvage Plan has been prepared as part of the submission.
	Queries regarding whether hand clearing or machinery would be used.	See Chapter 7 and Timber Salvage Plan provided as Appendix 6C. In areas of low salvageable timber and extensive permafrost the wood will likely be mulched and left as ground cover. In conventional terrain areas it will be slashed and burned.
	Interest in access to usable salvaged poles.	Yukon Energy will offer opportunities for salvage/use of decommissioned poles where appropriate.
Future Development	Concern over whether Mayo will still be serviced with new infrastructure if mining activities become productive in the future.	Mayo will still be serviced with new infrastructure if mining activities become productive in the future.
	Interest in renewable energy projects, specifically the potential power from future wind projects on Ferry Hill to be fed into the system.	Consideration, via data collection, is being given to the feasibility of the Ferry Hill power source. See also Chapter 6, Section 6.3. The proposed improvements to the integrated system will extend Yukon's existing 138 kV grid from Stewart Crossing to Mayo and the Keno City area, addressing continued reliability concerns, and also facilitating connection to the integrated grid of potential future customers and sources of renewable energy in this region that require a higher voltage power line with greater capacity.
	Interest in fibre optic cable providing faster internet speeds being included in this Project.	See Project Description provided in Chapter 6. Fibre optic cable will be for utility usage only.

1 **REFERENCE:** Application, Tab 5.2.1.4, page 5-13

2
3 **ISSUE:** McQuesten Substation Project

4
5 **QUOTE:** "Total cost estimated for the McQuesten Substation during the VGC
6 PPA proceeding were \$8.529 million (assuming no need for a Step
7 Down transformer)..."

8
9 "YEC has received an asset contribution from VGC Group valued at
10 \$10.688 million, and has incurred a net cost of \$0.931 million (related
11 to added facilities to enable future 138 kV service operation if
12 required)." (footnote removed)

13
14 **QUESTION:**

- 15
16 a) Please explain in what circumstances YEC would require a step-down transformer
17 in this substation and the likelihood of such a transformer in the near future.
18
19 b) Please explain the assets included in the \$10.688 million contribution amount and
20 whether this amount will equate to future 138 kV service operation, if required.
21

22 **ANSWER:**

23
24 **(a)**

25
26 YEC would require a step down transformer if the line from Stewart Crossing substation
27 to McQuesten substation was energized at 138kV. The likelihood of installing the step
28 down transformer is unknown at this time.
29

30 **(b)**

31
32 The assets included in the \$10.688 million asset contribution from VGC Group include
33 substation assets and all related ancillary components that VGC Group was responsible
34 for funding, i.e., all capital costs related to the McQuesten Substation development except
35 for costs to enable operation at 138 kV voltage. Accordingly, this amount is not related to
36 future 138 kV service operation, if required.

The VGC Group PPA provides for VGC Group to recover from YEC the incremental fees, costs and expenses associated with the McQuesten Substation, as initially developed, being able to operate at 138 kV voltage ("YEC McQuesten Substation Costs" as specified in Schedule B of the VGC Group PPA). YEC McQuesten Substation Costs as included in Schedule B of the VGC Group PPA are summarized in the Table below, and are YEC's net cost related to this facility.

Table B-2: YEC McQuesten Substation Costs

S258 McQuesten & S249 Mayo	YEC
Construction	\$ 605,931
Supervision	\$ 36,000
Site Prep (Civil works)	\$ 325,350
Foundations	\$ 174,081
Structure and Bus Work	\$ 8,000
Electrical / Telecontrol / Telecom	\$ 62,500
Material	\$ 240,036
Switch Yard	\$ 132,770
Major Equipment	\$ 87,266
Delivery	\$ 20,000
Commissioning	\$ -
On-site	
Owner's Costs	\$ -
Overall owner's costs	
Subtotal	\$ 845,967
Contingency (10%)	\$ 84,597
TOTAL	\$ 930,563

1 **REFERENCE:** Application, Tab 5.2.1.5, pages 5-13 to 5-14

2
3 **ISSUE:** Transmission Line Refurbishment Project

4
5 **QUOTE:** "YEC's 138 kV Whitehorse-Aishihik-Faro (WAF) transmission system
6 was constructed in the late 1960's and early 1970's, and plays a critical
7 role linking key hydro generation sources to load centres in Whitehorse
8 and on the northern grid. Recent studies as well as a detailed line
9 assessment in 2017 indicated that key components of the WAF system
10 were at end of life, in poor condition, and required replacement."

11
12 "Specifically, certain components of these lines had begun to exhibit
13 higher failure rates. Based on these events, YEC commissioned
14 external asset assessments of the key backbone lines on the integrated
15 system as noted above. These assessments indicated that a large
16 number of cross arms and insulators are at end of life with a high risk
17 of failure." (footnote removed)

18
19 **QUESTION:**

- 20
21 a) Please provide and explain the studies (including the detailed line assessment
22 conducted in 2017) that were conducted to show that key components of the WAF
23 transmission system were at end of life, in poor condition and required
24 replacement. For example, what reliability criteria were violated, and were
25 contingency analyses performed?
26
27 b) Please explain how often YEC carried out studies and assessed the reliability of
28 the WAF transmission system in the past.
29
30 c) Please explain which components of the system began exhibiting higher failure
31 rates and whether this system experienced any outages. If so, please provide the
32 number and duration of outages experienced in the last 10 years, on a per annum
33 basis, and the costs incurred due to these outages.

1 **ANSWER:**

2
3 **(a)**

4
5 The requested studies are provided in the following attachments:

6
7 **Attachment 1** provides the “Transmission Line Overhead Facilities Condition Assessment
8 Technical Specification and Project Management Requirements.” The document defines
9 the requirements for inspection and condition assessment of Yukon Energy Corporation’s
10 (YEC) overhead transmission line assets and notes as follows in the Overview:

11
12 The intent of transmission line inspection and condition assessment is to ensure
13 that sufficient information is available to support ongoing operations and
14 maintenance of these assets, plan for maintenance upgrades in the future, and
15 address immediate maintenance issues that may affect reliability or availability. In
16 general, the transmission line inspection will assess the present condition of each
17 structure and piece of hardware associated with the line, as well as noting possible
18 foundation, clearance, and vegetation issues related to the line. The line patrol will
19 also involve identifying original structure location relative to its replacement
20 structure. A photo record of each structure and associated foundation and of every
21 defect recorded will be part of the inspection and assessment work. Inspection
22 crews are required to install missing structure tags in the field as necessary, the
23 structure tags will be supplied by YEC.

24
25 Following collection of field data, the inspection results, record of defects and
26 repair priorities is to be summarized in the supplied excel worksheet.

27
28 The excel worksheet is provided as **Attachment 2**.

29
30 Other studies undertaken that show that key components of the WAF transmission study
31 were at end of life, in poor condition or required replacement are summarized below.
32 Generally, cross-arms, insulation and the shell thickness of the poles were the main
33 components of concern.

- 34
35 • **Attachment 3** provides the Powertech Labs Inc. assessment of “Failure Analysis
36 and Condition Assessment Tests on Suspension Insulators from Yukon Energy
37 138 kV Transmission Line”. As noted in the report, Yukon Energy sent seventy-

1 eight insulators that had been removed from a failed wood pole 138 kV
2 transmission structure (it burned) to Powertech for determination of the root cause
3 of the fire and to assess the condition of all insulators removed from the same
4 structure. A series of test were carried out on the insulators. The Powertech report
5 notes in summary that “if the condition of these insulators is typical of the insulators
6 in this transmission line it is recommended that all insulators that are marked with
7 “Made in England 1968” or “Buller’s England 1968” be replaced. Any live line work
8 done on these transmission lines should take into account there is a significant risk
9 that there are punctured insulators and there may be insulators with low
10 mechanical strength in the insulator strings being work on.”
11

- 12 • **Attachment 4** provides PowerTech “Condition Assessment and Evaluation of
13 Type ASX Cross Arms”. A condition assessment and evaluation of in-service
14 crossarms from a 138 kV transmission line operated by Yukon Energy was
15 performed by Powertech Labs, to determine the remaining load carrying capacity
16 of the crossarms, and whether they still meet both historical and upgraded modern
17 design load requirements. The crossarms were from angled tangent structures, in
18 which the angle of the crossarms is approximating that of the sloping terrain. The
19 report noted that “Given the high probability of not meeting design vertical loads
20 and the age of the crossarms (close to 50 years old), as well as evidence of failure
21 in service, it is recommended that the replacement of these crossarms should be
22 initiated to mitigate the risk of failure in service”. The following priorities were
23 suggested:
 - 24 o Long spans should be given priority for replacement over short spans;
 - 25 o Crossing structures should be given priority over non-crossing structures;
 - 26 and
 - 27 o For all spans, those structures in which knots and checks are noted around
28 connection points should be given priority over structures in which these
29 features are not seen.
30
- 31 • **Attachment 5** provides “Condition Assessment and Evaluation of 138 kV Wood
32 Cross Arms”. Wood crossarms utilized in single crossarm H-frame structures from
33 an existing 138 kV transmission line were supplied by Yukon Energy Corporation
34 for full scale mechanical testing and flexural testing. The crossarms of the
35 transmission line are scheduled to be replaced by steel crossarms, the testing was
36 undertaken to assess the existing structural integrity of the crossarms and their
37 serviceability with respect to updated design criteria for the line, and gauge the

1 immediacy of the replacement program. The report notes, “Based on the test
2 results, it can be stated that the existing single wood crossarms do not meet the
3 updated design criteria for the line. The design criteria itself takes into account load
4 factors in combination with worst case climate load scenarios. From the reliabilities
5 obtained against the unfactored design load, it is seen that the probability of any
6 immediate failures of existing crossarms is low.” It was recommended that the
7 replacement program of steel crossarms begin as soon as operational
8 practicability dictates, and be guided as follows:

- 9 o Long spans should be given priority for replacement over short spans;
- 10 o Crossing structures should be given priority over non-crossing structures;
- 11 o For all spans, those structures in which knots and checks are noted around
12 connection points should be given priority over structures in which these
13 features are not seen.

14
15 **(b)**

16
17 YEC established the first Test and Treat in 2009. Tests and treat is a process that
18 determines the pole shell thickness above and below grade, treats cavities and eliminates
19 insect infestations. Detailed line assessments occur on the various transmission lines at
20 approximately 10-year intervals. The first was in 2003, and the latest was in 2018.

21
22 **(c)**

23
24 Cross-arms, insulation and the shell thickness of the poles were the main components of
25 concern. For further details see Attachments 3, 4 and 5 to part (a) of this response.

26
27 Please see Table 1 below for number and duration of outages on L170 and L171 over the
28 past 10 years. Outage data is not available for L172.

29
30 Total costs related to outages are as follows:

- 31
32 • L170 total cost to respond to outages (planned and unplanned) are \$313,500, with
33 an average annual cost (2012-2020) of \$34,800; additionally, capital investment in
34 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; and
- 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.

Table 1: Number and Duration of Outages L170: 2011 to 2020

2011-2020 L170 Planned and Unplanned Line Outages				
Year	Unplanned Outages	Planned Outages	Total Outages	Outage Hours
2011	3	0	3	5.23
2012	1	0	1	0.31
2013	3	0	3	1.35
2014	3	5	8	5.35
2015	4	1	5	4.95
2016	6	0	6	5.14
2017	5	11	16	10.13
2018	2	1	3	3.67
2019	2	2	4	9.73
2020	5	5	5	23.46

1

Table 2: Number and Duration of Outages L171: 2011 to 2020

2011-2020 L171 Planned and Unplanned Line Outages

Year	Unplanned Outages	Planned Outages	Total Outages	Outage Hours
2011	2	0	2	0.74
2012	0	0	0	0
2013	0	0	0	0
2014	0	3	3	0.2
2015	0	3	3	0.83
2016	1	0	1	1.47
2017	1	4	5	36.67
2018	2	1	3	181.75
2019	2	1	3	382.87
2020	1	0	1	0.3

2



Yukon Energy

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Transmission Line Overhead Facilities Condition Assessment

Technical Specification and Project Management Requirements

REVISION LOG:

Revision #	Revision Date	Amendment
0	2016-Sep-09 th	Release for Detailed Line Assessment – (RFP 2016-044)
1	2016-Oct-06 th	Release for Detailed Line Assessment – L171 (Field Work)
2	2016-Dec-16 th	Remove GPS requirements for Detailed Line Assessment 2017

1. OVERVIEW

This document defines the requirements for inspection and condition assessment of Yukon Energy Corporation's (YEC) overhead transmission line assets.

The intent of transmission line inspection and condition assessment is to ensure that sufficient information is available to support ongoing operations and maintenance of these assets, plan for maintenance upgrades in the future, and address immediate maintenance issues that may affect reliability or availability. In general, the transmission line inspection will assess the present condition of each structure and piece of hardware associated with the line, as well as noting possible foundation, clearance, and vegetation issues related to the line. The line patrol will also involve identifying original structure location relative to its replacement structure. A photo record of each structure and associated foundation and of every defect recorded will be part of the inspection and assessment work. Inspection crews are required to install missing structure tags in the field as necessary, the structure tags will be supplied by YEC.

Following collection of field data, the inspection results, record of defects and repair priorities is to be summarized in the supplied excel worksheet. All data including hard and soft copies of all field inspection check sheets, line assessment summary spreadsheets, notes, tailboards and photo record (soft-copy only) are to be returned to YEC following completion of the transmission line inspection.

1.1. LINE GENERAL INFORMATION

YEC's 138kV transmission line network consists primarily of wood pole H-Frame type transmission structures. Some of the newer lines and replacement structures make use of steel crossarms and steel cross-braces. Insulation is a mix of porcelain dating to 1968, toughened glass, and composite.

1.1.1. L171 (Aishishik Generation - Takhini Substation)

L171 is a 129km transmission line built in 1976 to connect Aishihik power generation to Whitehorse. L171 is comprised of ~611 structures.

L172 (Riverside Substation – Takhini Substation)

L172 was part of the L170 original line built from Whitehorse (Riverside) to Faro Mining community in 1970. Later, Takhini substation was built and the L170 structures #1 - #112 became their own line, L172. L172 is 25km long, with ~112 structures.

L169 (L172 tap – McIntyre Substation)

L169 was built to connect the 138kV L172 to McIntyre Substation in 1980. L169 is 6.5 km long with ~30 structures.

1.1.2. L170 (Takhini Substation – Carmacks Airport Sub)

L170 is 152 km transmission line built in 1970, and has maintained its Line designation from the original build to the Carmacks area. L170 is comprised of ~723 structures.

1.1.3. L178 (Carmacks Airport Sub – Faro Mine)

L178 was part of the L170 original line built from Whitehorse (Riverside) to Faro Mining community in 1970. L178 is 190km from Carmacks Airport Sub to the Faro Mine and is comprised of ~832 structures.

1.2. GROUND PATROL SCOPE OF WORK

The scope of work for this assessment project consists of the following aspects:

1. Complete ground patrol and structure condition assessment and accurate recording of field data. Assess urgency of associated maintenance actions.
2. Produce photographic record of each structure, structure foundation, and all visible defects.
3. Note and photo record vegetation along Right of Way (ROW).
4. Install missing structure tags where required.
5. Provide all equipment and supplies required to perform the assessment in a safe, professional manner including: quads; trailers; vehicles; fuel; hand tools; binoculars; GPS enabled camera; computers; safety and communications equipment; food; accommodations, and so on. (YEC will supply structure tag kit).
6. Project management, tracking, and reporting of progress.
7. Support YEC QA/QC process and checks.
8. Compile results into final report including line assessment summary spreadsheet and provide to YEC.

1.3. YUKON ENERGY RESPONSIBILITIES

1. Supply plan and profile drawings of the line to be inspected.
2. Supply number tags and plates for replacement of missing structure tags.
3. Co-ordination of pre-job safety review between the Contractor and YEC personnel.
4. Perform contractor orientation and QA/QC checks to ensure quality of returned data matches specification and expectations.
5. Responsive support from YEC SCC to track and support daily operations (daily check-in and check-out).

2. FACILITIES INSPECTION PATROL REQUIREMENTS

2.1. STRUCTURE CONDITION ASSESSMENT

A structure by structure ground patrol, on foot where difficult terrain prevents ATV access, examination of each structure on the line (including PT-Substation structural components and take off structures from main substations) is the primary goal of this project.

Each aspect of the structure is to be identified, inspected, and the condition recorded. Any associated visual defects and deficiencies are to be identified and recorded. Each deficiency is to be categorized on a YEC defined maintenance priority scale, reflecting the urgency of need for repair.

2.1.1. Structure (STR)

Each structure is to be visually inspected to establish the general condition of the structure framing. The structure type is to be identified and recorded. General structure straightness and condition is to be noted and recorded.

Each component shall be visually inspected for condition and defect, including poles, cross-arms, insulators, hardware, armor-rod, conductor, guys and anchors.

2.1.2. Poles (POL)

Pole height, class, species, date stamp, general external condition, evidence of ant infestation and any external visual damage including burns, woodpecker holes and mechanical damage are to be identified, noted and recorded as part of the patrol finding.

Internal testing of poles is not included as part of the scope of the patrol inspection. Separate inspection program will determine the pole structural adequacy.

2.1.3. Foundation (FDN)

The condition of structure foundations is to be examined, the type of foundation is to be recorded, and visual deficiencies such as leaning structures, inadequate backfill, sloughing, soft-rot and other problems are to be identified, noted and recorded.

2.1.4. Guys and Anchors (G&A)

The number, type, configuration, general condition of the guy and anchor shall be noted and recorded. Visual damage of the guy wire and hardware shall be noted and categorized for maintenance priority. Anchor surface condition shall be inspected to determine the state of the anchor performance. Any anchor deficiency shall be noted, recorded and categorized for maintenance priority.

2.1.5. Cross Arm (XRM)

Type of cross arm, steel or wood, general external condition, visual damage including cracks, burns, bow, bend, twist, sloping grain, rust are to be identified, noted and recorded as part of the patrol finding. Cross arms before road or trail crossings are to be noted with key words ' road crossing' in the comment section.

2.1.6. Cross Brace (XBR)

Type of cross brace, steel or wood, general external condition, visual damage including cracks, bow, twist, grain, rust are to be identified, noted and recorded as part of the patrol finding.

2.1.7. Insulators (INS)

The colour (grey or brown) and type (ceramic or composite) of the insulators on each structure are to be noted during the inspection patrol, as this will date the age of the insulator. The condition of the insulator and any defects including staining, rust, cement bulging, burn marks, chips, cracks, misalignment, defective pins, etc, are to be identified, noted and recorded as part of the inspection.

2.1.8. Vibration Damper (VIB)

The type and number of vibration damper on each span shall be noted and recorded as part of the inspection.

2.1.9. Aerial Marker (AMK)

The type and number of aerial marker, general condition, visual damage including gun shot, broken marker, colour fading are to be identified, noted and recorded as part of the inspection.

2.1.10. Conductor and Shield Wire (C&S)

The condition of conductor between structures is to be visually assessed and any visible damage, such as loose or broken strands, bird caging, gunshot damage or other types of damage is to be recorded. Any damage to overhead shield wire, where it exists (typically only near substations) should be noted as well. The presence of in-line splices is to be noted as part of the inspection, and the key words 'auto sleeve' added to the comment field.

A span of conductor will be identified by the name of the structure behind it. For example the span between structures L170-455 and L170-456 is to be recorded as span L170-455.

2.1.11. Grounding and Bonding (G&B)

The condition of grounding wires and connections are to be visually assessed. Any missing connections, broken wires, missing guards, signs of tracking or burning are to be noted.

Bonding of hardware in presence of shield wire or metal cross arm is to be inspected for any visible damage, loose or missing connections.

2.1.12. Hardware (HDW)

All hardware and attachments are to be inspected in detail. Any deficiencies, including damaged, worn, missing, decayed, loose, miss-aligned or incorrectly installed items are to be identified, noted and recorded. Deficiencies are to be categorized on a YEC defined relative priority scale, reflecting the urgency of need for repair.

2.1.13. Vegetation on Right of Way (VEG)

Vegetation in the span following the structure (in the direction of the structure with the next highest number) is to be assessed, and the average height estimated. Any trees in danger of falling on the Line will be noted.

2.1.14. General Comments (GRL)

Any access issues to the structure should be recorded here.

2.2. EQUIPMENT CONDITION CODES AND MAINTENANCE PRIORITY CODES

All deficiencies noted are to be categorized as to equipment condition as well as the maintenance priority. Condition and Priority Codes are defined on a YEC defined priority scale reflecting the relative urgency for repair.

Equipment Data Collection Codes¹, Equipment Condition Codes, and Maintenance Priority Codes are supplied in the Appendix.

The Condition (general) and Maintenance Priority Codes to be assigned to deficiencies found in the field are summarized in the table below.

2.2.1. YEC Transmission Line Condition Codes (General Summary)

YEC has supplied specific equipment condition codes for each aspect of a transmission in the Appendix.

In general, condition codes are assigned as per the following pattern.

G	Good Condition – No Visible Defects (Will Last Next 10 Years) No maintenance necessary. Re-inspect at next cycle (Priority Code of 5).
F	Fair Condition – Visible Defects Not Critical. Requires Maintenance, Adjustment, Repair at next opportunity, or Ongoing Monitoring (Priority Code of 4 or 5 would be appropriate depending on the defect).
P	Poor Condition – Replace or Repair Required. Priority Code of 1, 2, or 3 would be appropriate depending on the defect.
M	Missing – Replace Missing Item (Priority Code of 1, 2 or 3 would be appropriate depending on the missing component).
O	Other Condition – Specify.
N/A	Not Applicable

¹ Abbreviations used to identify different types of each structure aspect found in Appendix A.

2.2.2. *YEC Transmission Line Maintenance Priority Codes*

- 1 Indicates a very serious system reliability or public safety problem. Repairs or modifications should be made immediately (probably within 1 to 2 days). Contact YEC T&D Leadhand as soon as possible (ASAP).
- 2 Indicates a reliability or safety problem which is serious enough it should be rectified in the not too distant future (possibly within 3 months). Condition is serious enough that it would probably be dealt with prior to the next scheduled routine maintenance.
- 3 Indicates a concern which should be corrected, but is minor enough that it could be rectified as part of a planned maintenance program (possibly within the next 1 to 5 years).
- 4 Indicates a concern which is minor enough it would only be corrected if convenient to do so. Corrections would only be made if other work were being done in the same area or on the same pole.
- 5 Indicates a comment which is recorded for information only – no corrective action is required.

2.3. NOTE AND RECORD VEGETATION GROWTH IN THE ROW DURING GROUND PATROL

The Contractor is to document and record in general terms the predominant type and height of vegetation in the cleared ROW for each span (e.g. mixed willow / poplar to 3m). The intent is for YEC to confirm brushing plans in the coming years, and to manage any danger tree or clearance issues which have arisen between clearing cycles. The Contractor is to make note of any danger trees (or potential danger trees) threatening the transmission line. Digital photos are to be taken to support the observations of general vegetation condition and danger trees.

2.4. REPLACE MISSING STRUCTURE TAGS DURING GROUND PATROL

The Contractor will be required to re-install missing structure tags with a YEC Supplied structure tag kit during the ground patrol.

2.5. PHOTO RECORD

For each structure, a baseline of four digital photos is required, showing the entire structure and foundation from each quadrant; Front, Left, Back and Right side. Example; L170-000963-FRNT, L170-000963-LEFT, L170-000963-BACK, L170-000963-RGHT.

For ground patrol, additional images will be taken to show specific details of the structure to illustrate any concerns or deficiency, if necessary.

The Contractor will be required to supply his own photographic equipment for this project. Photos taken must have an accurate time/date stamp and GPS location Data inserted in the picture by the camera. The digital images shall be in JPEG format. Images shall have a minimum resolution of 3 megapixels.

Two copies of the photo record shall be provided to YEC in a photo directory on separate USB keys. Photos are to be saved with proper orientation, such that no further rotation is needed. Photos shall be titled in accordance with the following system:

- L170-xxxxxx-aaa-xx
 - L170 indicates line number
 - xxxxxx indicates structure number (Six characters required: Leading zeros are needed for effective database sorting e.g. S91 is not acceptable; S000091 is acceptable).
 - aaa-xx 3 digit alpha code to indicate which aspect of the structure;

STR - Structure	INS - Insulator	G&B - Grounding and
POL - Pole	VIB - Vibration Damper	Bounding Defect
FDN - Foundation	AMK - Aerial Marker	HDW – Hardware
G&A - Guy & Anchor	C&S – Conductor &	VEG – Vegetation
XRM - Cross-Arm	Shield Wire	GRL - General Comments
XBR - Cross-Brace		

and 2 digit numeric code for different images of the same detail.

- Examples
 - L170-000963-STR-01.JPG Line 170, Structure 963, Structure defect image 01
 - L170-000963-FDN-01.JPG Line 170, Structure 963, Foundation defect img 01
 - L171-0062_7-XRM-01.JPG Line 171, Structure 62/7, Cross Arm defect img 01

3. FINAL REPORT

A draft of the final report detailing the condition of the transmission line is to be submitted within 10 working days of the completion of the transmission line assessment. Upon YEC's approval of the draft, the final hard copy of the report shall be submitted to YEC within 10 working days.

YEC retains rights to all field and summary data, photos and records collected during the course of inspection.

The final report will consist of the following;

- A summary describing the general condition of the line and significant findings or discussion of difficulties encountered.
- Hard copies of the field inspection check sheets, sorted by line and structure.
- Hard copies of daily tailboards by field crew, in chronological order.
- A base excel line assessment summary spreadsheet complete with all assessment information². This spreadsheet will be, sorted by structure number, containing all the findings and notes of the field assessment, including:
 - Inspection data, condition codes and related comments.
 - Defects noted, related priority code, and photo reference.
 - Structure photo references (minimum 4).
 - Notes regarding minor maintenance work performed in the field (eg. structure tags).
 - Height of vegetation growth for each span.
 - Location of old structure relative to existing, where structure has been replaced.
 - Road crossings spans.
- Summary of structure issues which require attention, sorted by priority.
- Separate summary of issues, sorted by aspect category (first) and then by priority.

² Format supplied by YEC and is intended for conversion to a database by YEC.

- The complete photographic record of the line, by structure, including photos of all defects (soft-copy only).

The Contractor is responsible for all computer hardware and software required to record data and compile the line assessment summary spreadsheet, as well as the integrity of all data until the project is complete and all reports have been submitted to, and accepted by, YEC. During the project, data backups, security, and storage are the responsibility of the Contractor.

Two hard copies of the final report are to be submitted to YEC in separate binders, with sections logically separated by tabs. Two soft copies of the final report are to be submitted on separate USB keys in both PDF and native formats. These submissions are to include copies of field inspection check sheet forms and copies of daily tailboards and weekly progress updates. Two soft copies of the Photo Record on separate USB memory sticks will be submitted to YEC. Hard copy photo prints of structures and defects are not required.

The Contractor will submit a draft report to YEC for review prior to publishing the final report. YEC will review the draft report and advise the Contractor, within 7 working days, whether the report is acceptable or whether deficiencies exist. If changes are needed, the Contractor shall remedy any deficiencies and re-submit the final report within a further 10 working days.

4. PROJECT MANAGEMENT, SAFETY PLANNING, AND GENERAL INFORMATION

4.1.

The YEC project manager will implement the following Q/A Q/C checks with the contractor's cooperation, to ensure returned data accurately captures the condition of equipment in the field, and that expectations between YEC, the contractor, and the inspection team are aligned.

1. Prior to Field inspection, YEC will review the inspection specification and expectations with the inspection field team. This will occur immediately following safety and environmental orientation at the project kick-off with the contractor.
2. Field Audit on Day 1 Week 1: YEC will accompany the contractor on the entire first day of field inspection and oversee the quality of data collection as performed by the contractor meets YEC expectations.
3. Field Audit on Day 3 Week 1: The contractor will complete inspections on the second day without YEC oversight. YEC will randomly select at minimum one structure from the second day of inspection for field audit to confirm the quality of collected data.
4. The contractor is to return to YEC all inspection data collected over the course of a week by the end of day Sunday. This is to support field inspection, and is not to be considered as the final report or complete inspection data package deliverable to be supplied at the end of the project.
5. Field Audit Week 2: The contractor will submit weekly field data for YEC review at the end of the first week of inspection. YEC will randomly select a structure from Week 1 inspection for field audit to confirm the quality of collected data.
6. Field Audit Week 3: The contractor will submit weekly field data for YEC review at the end of the second week of inspection. YEC will randomly select a structure from the week prior inspection for field audit to confirm the quality of collected data. YEC will confirm tailboards with the crew in the field.
7. Field Audit on returned data: Once the contractor has processed the first batch of field data into the summary spreadsheet, YEC will select a structure from the data set and perform a field audit to confirm the summary spreadsheet condition data matches the structure in the field.
8. Ongoing Q/A Q/C checks: Every two weeks for the duration of the project, YEC will perform at least one structure inspection audit to compare contractor collected data with a field structure.

4.2. ACCESS

YEC will supply known, existing access points, which YEC uses for planned maintenance activities. However, for inspection purposes without heavy equipment (e.g ATV or foot

access), any publicly accessible access point may be used. The exception is private property or First Nations Settlement Land Parcels.

Crossing of private property land parcels without the landowners' permission is not permitted. It is incumbent on the Contractor to pre-arrange access over private land where it may be necessary.

First Nations Settlement Land is to be respected as private property. YEC will engage the first nation and work to arrange for access across settlement land parcels for the Contractor before field work begins, and may require the Contractor's input in this regard. YEC advises that the FN may impose access restrictions.

Access roads may not be modified or altered, nor may new accesses be created.

YEC will provide maps showing line plan view, which will identify the transmission line route and structure locations, road ROW, known access points for YEC maintenance purposes, private surveyed land parcels and First Nation settlement land.

Regardless of land title or ownership, YEC expects that the crew performing field work will act in a professional manner, not leave behind litter or waste, and treat land and residents living near or along the transmission line with respect.

Access to substations (some PT Substations are fenced) is not expected. If needed, access arrangements shall be made with YEC System Control Center (SCC).

4.3. DAILY CHECK-IN AND CHECK-OUT

The Contractor will be required to check-in with the YEC System Control Centre (SCC) at the beginning of each day, indicating the section of line that is planned to be patrolled during that day, and the hours of work planned.

The Contractor will be required to check-out with SCC at the end of each working day.

4.4. PROJECT TRACKING

The Contractor shall supply a weekly project update to the YEC project manager overseeing inspection. The weekly report is due by the end of day Sunday, and will include:

- Project report of structures inspected in the past week
- Field data from the previous weeks inspection work, to support and facilitate YEC QA/QC checks.
- Structures/sections scheduled for inspection in the week ahead.
- Notable difficulties encountered.
- Notable deficiencies and critical defects encountered requiring immediate attention.
- Any change to forecast completion date as a result of progress to date.

4.5. CRITICAL DEFECTS

The YEC Lead-hand T&D is to be called as quickly as possible and notified of critical field issues found during the ground patrol which require immediate attention to avoid failure of the line.

In all circumstances, the initial call to YEC Lead-hand T&D is to be followed up with an email within five working days. The email will indicate;

- Where: Line and structure number
- When: The problem was first noticed
- What: Nature of the problem
- Photograph

4.6. SAFETY PLANNING / COMMUNICATIONS

The Contractor is required to develop and present to YEC before beginning field work, a comprehensive safety plan for their work including: Tailboards and job plans, communications equipment, emergency contact information, MSDS sheets where applicable, PPE and safety equipment, and training appropriate to the work being done.

The inspection Contractor is required to comply with all YEC Health, Safety and Environmental requirements and policies, Yukon OH&S requirements, environmental regulation and reporting requirements, as well as any additional H&S requirements as deemed necessary by the Contractor as part of the Contractor's Health and Safety Plan.

All field personnel are required to complete YEC Health, Safety, and Environmental orientations prior to beginning field work. Environmental portion includes awareness of bird nesting habits and fish bearing streams.

A joint safety review / orientation meeting between YEC, the Contractor, and all workers involved in the project, will be conducted by the YEC project manager before any field work is carried out. Radio communication with YEC repeaters is not reliable along all sections of transmission line. It is suggested that the Contractor not plan to depend on the YEC radio repeater network for communications during this project.

The Contractor will make provision to supply their own satellite phone for each crew in the field for the duration of the field work. The YEC System Control Centre must be able to contact the field crew(s) while they are working in the field. When working on YEC property/ROW, SCC should be the first line of contact for the Contractor in an emergency.

Appendix A - Abbreviations For Transmission Line Master Inspection Form

Structure Information (STR)

Structure Number Sxxxxxx

L170, L172, L178 - Structure Type:

A / AX	Tangent Structure 0° to 3°
B	Angle Structure 3° to 12° 30'
BS	Angle Structure 3° to 12° 30' for Side Slope Locations
C	Angle Structure (Str. 1244) Angle 12° 48' Left
CS	Permanent Structure (Str. 1208) Angle 12° 48' Left
D	Angle Structure 30° to 60°
DS	Angle Structure 30° to 60° for Side Slope Locations
E	Angle Structure 0° to 90°
ES	Angle Structure 0° to 90° for Side Slope Locations
F	Transposition Structures
G	Uplift Structure Tangent 0° to 3°
AG / AGX	Tangent Structure 0° to 3° with OHGW
EG	Angle Structure Deadend 0° to 90° with OHGW
AXS	Tangent Structure for Sloping Locations (Snowshed structures)

L171 – Structure Type:

Type H	Tangent Structure: 0° - 1°
Type HG	Tangent Structure: 1° - 3°
Type HW	Tangent Structure with OHG (Unguyed Structures)
Type HWG	Tangent Structure with OHG (with Side Guys 1° to 3° line angle)
Type HWX	Tangent Structure with OHG (with longitudinal guys – dead end of OHG)
Type T	Transposition Structure
Type 3A	Angle Structure: 3° - 15°
Type 3AS	Sidehill Tangent Structure
Type 3B	Angle Structure: 15° - 30°
Type 3C	Angle Structure: 30° - 45°
Type 3D0	Dead End Angle Structure: 0° to 1°
Type 3D10	Dead End Angle Structure: 1° to 10°
Type 3D90	Dead End Angle Structure: 10° to 90°
Type 3DW10S	Dead End Structures with OHGW: 0° - 10° Slack Span
Type 3DW90S	Dead End Structures with OHGW: 10° to 90° Slack Span
Type 3DW90	Dead End Structures with OHGW: 10° to 90°

Number Tag:

G	Number Tag in Good Condition
P	Number Tag in Poor Condition (replace during inspection)
M	Number Tag Missing (replace during inspection)

Structure Straightness

G	Structure Straightness in Good Condition
LT	Structure Leaning in Transverse Direction (Left or Right) e.g. structure leaning sideways perpendicular to line
LL	Structure Leaning in Longitudinal Direction (Forward or Back) e.g. structure leaning toward either ahead or back along the line

Wood Pole (POL)

Pole Class and Height

L	Left Pole (As seen when looking down the Line ³)
C	Center Pole
R	Right Pole

1/80 Denote Class 1 80ft pole

Species (Code according to CSA O15-2015 Clause 6.5.3)

Cedar	
WC	Western Red Cedar
Fir	
DF	Douglas Fir
Pine	
LP	Lodgepole Pine
RP	Red Pine
SP	Southern Yellow Pine

Date Stamp 68 (for 1968)

Pole Condition

E	Pole in Excellent Condition (Like New)
G	Pole in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering, light cracking along wood grains
F	Pole in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. moderate to heavy weathering, minor groundline rotting, deep cracks along wood grains, minor insect / animal damage, small woodpecker hole, etc.
P	Pole in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. severe groundline rotting, cracks perpendicular to wood grains, large woodpecker hole with opening larger than 4 inches, etc.
O	Other Condition – Specify

POL Maintenance Comments

In addition to noting the pole condition;

- Note bird nests on pole tops.
- Record distance and direction to old Pole stubs from existing, where structure has been replaced.
- Record quantity and size of Wood Pecker Holes (WPH) openings
 Size: - Small <2"
 - Medium 2-4"
 - Large >4"

³ As seen while facing the structure being inspected, with your back towards lower number structures. Looking toward the end of the line with the highest structure number.

Pole Foundation (FDN)

Foundation Type

D	Direct buried - no stub
S1D	Direct buried - one stub
S2D	Direct buried - two stubs
S3D	Direct buried - three stubs
TC	Timber crib filled with rocks - no stub
S1TC	Timber crib filled with rocks - one stub
C	Culvert filled with rocks - no stub
S1C	Culvert filled with rocks - one stub

Ground Type

SO	Soil
SW	Swamp
R	Rock

Foundation Condition

S	Foundation Stable
U	Foundation Unstable (Require Maintenance) e.g. pole base sinking (tilted structure), large void surrounding pole, pole base heaving, water pond surrounding pole base, etc.

Guys & Anchors (G&A)

Configuration g/a number of guys / number of anchors

Guy & Anchor Condition

NA	Not Available (Not Require As Per Framing)
G	Guy & Anchor in Good Condition – No Visible Defects
F	Guy & Anchor in Fair Condition – No Visible Defects (Adjustment Performed During Inspection) e.g. guy tension adjustment, preform snapped shut, etc.
P	Guy & Anchor in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. bended anchor rod, anchor out of alignment with guy wire, broken anchor or wire, anchor movement (shifted/pulled/exposed), significant corrosion, etc.
M	Guy & Anchor Missing (Require Replacement)
O	Other Condition – Specify

Cross arm (XRM)

Cross arm Type

ST	Steel Cross arm
WD	Wood Cross arm

Cross arm (Wood) Condition

E	Cross arm in Excellent Condition (Like New)
G	Cross arm in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering.
F	Cross arm in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. moderate to heavy weathering, lightly bowed or twisted, bird nesting, etc.
P	Cross arm in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. broken, split, surface rot, deep cracking along wood grains, cracks perpendicular to wood grains, wood grain of cross arm sloped (not parallel to arm), excessive knots, heavily bowed or twisted, burned, etc.
O	Other Condition – Specify

Cross arm (Steel) Condition

E	Cross arm in Excellent Condition (Like New)
G	Cross arm in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering (discoloration)
F	Cross arm in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. minor rusting on attachment holes, lightly bowed or twisted, burned, etc.
P	Cross arm in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. bended, damaged, rusting along entire cross arm, heavily bowed or twisted, etc.
O	Other Condition – Specify

XRM Maintenance Comments

In addition to noting the cross arm condition;

- Use key words 'road crossing' where next span crosses road or trail.
- Where the structure has multiple cross arms, record condition and maintenance priority code based on the worst cross arm condition in both the 'Front' and 'Back' sets. Use comment field to record condition of remaining cross arms.

Cross Brace (XBR)

Cross Brace Type

ST	Steel Cross Brace
WD	Wood Cross Brace

Cross Brace (Wood) Condition

E	Cross Brace in Excellent Condition (Like New)
G	Cross Brace in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering.
F	Cross Brace in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. moderate to heavy weathering, lightly bowed or twisted, bird nesting, etc.
P	Cross Brace in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. broken, split, surface rot, deep cracking along wood grains, cracks perpendicular to wood grains, sloping grain, heavily bowed or twisted, burned, etc.
O	Other Condition – Specify

Cross Brace (Steel) Condition

E	Cross Brace in Excellent Condition (Like New)
G	Cross Brace in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering (discoloration)
F	Cross Brace in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. minor rusting on attachment holes, lightly bowed or twisted, burned, etc.
P	Cross Brace in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. bended, damaged, rusting along entire brace, heavily bowed or twisted, etc.
O	Other Condition – Specify

Insulators (INS)

Insulator Type

BP	Brown Porcelain
GP	Grey Porcelain
TG	Toughen Glass
EP	Epoxy / Composite
MX	Mixed

Fitting Type

BS	Ball-Socket End Fittings
CT	Clevis-Tongue End Fittings

Count i Number of Insulator Units

Insulator Visible Condition (Porcelain / Glass)

G	Insulators in Good Condition – No Visible Defects (Will Last Next 10 Years)
F	Insulators in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. light pollution contamination, minor rust stains on skirt, light rust on caps, foreign object lodged, etc.
P	Insulators in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. heavy pollution, moderate to severe rust on caps, tracking or flash marks, gunshot damage, chipped or cracked bell skirt, shattered or missing bell skirt, rusty pin, crushed socket, insulator not hanging straight, burn marks, bulged porcelain, etc.
O	Other Condition – Specify

Insulator Visible Condition (Polymer)

G	Insulators in Good Condition – No Visible Defects (Will Last Next 10 Years)
F	Insulators in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. light pollution contamination, minor rust stains on skirt, etc.
P	Insulators in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. heavy pollution, tracking or flash marks, gunshot damage, broken skirt (missing pieces of skirt), moderate to heavy rusting of end fittings, etc.
O	Other Condition – Specify

Vibration Damper (VIB)

Vibration Damper v/Type Number Per Phase on Each Span / Damper Type

Vibration Type

SB	Stockbridge Dampers – two small weights suspended by short cable.
HX	Helix Spiral Dampers – pre-form grip section, followed by widening spirals.

Aerial Marker (AMK)

Marker Condition

NR	Not Required
G	Aerial Marker in Good Condition – No Visible Defects (Will Last Next 10 Years)
P	Aerial Marker in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. broken aerial marker, severe color fading, gunshot damage, etc.
M	Aerial Marker Missing (Require Replacement)

Conductor & Shield Wire (C&S)

Cable Condition

G	Cables in Good Condition – No Visible Defects (Will Last Next 10 Years)
F	Cables in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. bird cage, minor outer strands breakage, etc.
P	Cables in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. severe strand breakage, burned, severe corrosion, etc.
O	Other Condition – Specify

C&S Maintenance Comments

In addition to noting the conductor and shield wire condition;

- Use key words 'auto sleeve' where next span has splice in conductors.

Grounding & Bonding (G&B)

G&B Condition

- G Ground and Bond Wires in Good Condition – No Visible Defects (Will Last Next 10 Years)
- F Ground and Bond Wires in Fair Condition - Specify Visible Defects (Require Maintenance)
e.g. light discoloration at contact point, loose connections, damaged guard, etc.
- P Hardware in Poor Condition – Specify Visible Defects (Recommend Replacement)
e.g. moderate to heavy discoloration, severe wearing (reduce effective thickness), broken connections, signs of tracking, burn marks on pole, etc.
- O Other Condition – Specify

Hardware (HDW)

Hardware Condition

- G Hardware in Good Condition – No Visible Defects (Will Last Next 10 Years)
- F Hardware in Fair Condition – Specify Visible Defects (Require Maintenance)
e.g. light rusting at contact point, loose hardware, etc.
- P Hardware in Poor Condition – Specify Visible Defects (Recommend Replacement)
e.g. moderate to heavy rusting, severe wearing (reduce effective thickness), deformation, missing hardware, missing retaining cotter pin, etc.
- O Other Condition – Specify

Right of Way Vegetation (VEG)

Species

P/A	Poplar / Aspen
B	Birch
W	Willow
S/P	Spruce / Pine
O	Other – Specify

Vegetation Density

LD	Low Density – Maintenance Vehicle Can Travel Along
MD	Medium Density – ATV Can Travel Along Easily
HD	High Density – ATV Can Travel Along with Difficulty

Vegetation Height h ft Highest vegetation along ROW

Clearance Concern

N	No Vegetation Clearance Issue (Within Next 10 Years)
Y	Vegetation Clearance Violation (Within Next 10 Years)

Danger Tree

N	Not Present
Y	Danger Tree Present

Danger Tree Height d ft Danger Tree Height

Vegetation Comments List Vegetation Concern on Each Line

Priority

1	Indicates a very serious system reliability or public safety problem. Repairs or modifications should be made immediately (probably within 1 to 2 days). Contact YEC T&D Leadhand as soon as possible (ASAP).
2	Indicates a reliability or safety problem which is serious enough it should be rectified in the not too distant future (possibly within 3 months). Condition is serious enough that it would probably be dealt with prior to the next scheduled routine maintenance.
3	Indicates a concern which should be corrected, but is minor enough that it could be rectified as part of a planned maintenance program (possibly within the next 1 to 5 years).
4	Indicates a concern which is minor enough it would only be corrected if convenient to do so. Corrections would only be made if other work were being done in the same area or on the same pole.
5	Indicates a comment which is recorded for information only – no corrective action is required.

General (GRL)

GRL Additional Comments

- Record any issues with structure access.

Structure Maintenance Concern

Maintenance Comments List Individual Defect on Each Line

Photo Number Reference Photo for Each Individual Defect

Aspect Category

STR	Structure Defect	VIB	Vibration Damper Defect
POL	Wood Pole Defect	AMK	Aerial Marker Defect
FDN	Foundation Defect	C&S	Conductor & Shield Wire Defect
G&A	Guy & Anchor Defect	G&B	Grounding & Bonding Defect
XRM	Cross arm Defect	HDW	Hardware Defect
XBR	Cross Brace Defect	VEG	Vegetation in Right of Way
INS	Insulator Defect	GRL	General – Any Additional Notes

Priority

- 1 Indicates a very serious system reliability or public safety problem. Repairs or modifications should be made immediately (probably within 1 to 2 days). Contact YEC T&D Leadhand as soon as possible (ASAP).
- 2 Indicates a reliability or safety problem which is serious enough it should be rectified in the not too distant future (possibly within 3 months). Condition is serious enough that it would probably be dealt with prior to the next scheduled routine maintenance.
- 3 Indicates a concern which should be corrected, but is minor enough that it could be rectified as part of a planned maintenance program (possibly within the next 1 to 5 years).
- 4 Indicates a concern which is minor enough it would only be corrected if convenient to do so. Corrections would only be made if other work were being done in the same area or on the same pole.
- 5 Indicates a comment which is recorded for information only – no corrective action is required.

1 **REFERENCE:** Application, Tab 5.2.1.6, pages 5-15 to 5-16

2
3 **ISSUE:** Transmission Line Refurbishment – L178 Project

4
5 **QUOTE:** “Outages on the L178 currently trip at S164 (Takhini Substation) and
6 can result in an outage on the Takhini-Carmacks L170 transmission
7 line. Failure to complete this element of the refurbishment project would
8 increase the risk of component failure on L178 resulting in a split in the
9 North-South grid and significant thermal generation costs in the
10 northern grid to maintain supply to all customers.”

11
12 “The \$1.3 million budget will cover the work done in 2021, which is only
13 a portion of the full L178 transmission line refurbishment forecast to
14 cost \$8.3 million (costs to be brought into rate base each year as each
15 year’s work is completed).”

16
17 **QUESTION:**

- 18
19 a) Please provide the number and duration of outages on transmission line L178
20 experienced in the last 10 years, on a per annum basis, and the costs incurred due
21 to these outages.
22
23 b) Please explain when YEC expects this project to be completed.
24
25 c) What is the expected annual frequency and duration of outages due to component
26 failure on L178 if this project is not completed? What costs would YEC continue to
27 incur if the project is not completed? Given the expected frequency and duration,
28 please estimate the additional annual costs resulting from the need for additional
29 thermal generation due to those outages.
30

31 **ANSWER:**

32
33 **(a)**

34
35 The number and duration of outages on transmission line L178 experienced in the last 10
36 years are summarized in Table 1 below.

Table 1: Number and Duration of Outages – 2011 to 2020

Year	Unplanned Outages	Planned Outages	Total Outages	Outage Hours
2011	2	0	2	18.31
2012	2	0	2	1.49
2013	1	0	1	0.19
2014	3	8	11	17.25
2015	4	3	7	5.66
2016	5	5	10	8.5
2017	6	14	20	32.05
2018	6	2	8	69.42
2019	6	0	6	70.15
2020	10	4	14	78.14

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 2020.¹

(b)

Not known at this time; remaining works will be allocated to future fiscal periods as resources and priorities warrant.

(c)

There is an expected annual outage frequency due to component failure of 2 – 5 failures per year increasing with the age of the line. Outage duration can be anywhere from 1 day to a week or more depending heavily on access. Access is much more of an issue in an unplanned event.

Unplanned repairs cost substantially more. A helicopter charge of \$3500 – \$7000 is typical on L178 just to locate the failure that caused the outage. In a planned scenario crews are on site with materials and civil work complete.

Diesel costs during summer conditions to run the town of Faro are approximately \$300/hour. It usually takes at least 24 hours to respond and complete a repair on a simple

¹ New financial software implemented in late 2013.

1 failure with reasonably good access. A difficult repair with challenging access could take
2 up to a week or more. Consequently, diesel cost per event would likely be in the range of
3 \$7,200-\$36,000.

4
5 On planned maintenance projects Civil & Mob costs would normally be divided over many
6 structures. In an unplanned failure, Civil & Mob costs for a challenging repair can easily
7 be \$25,000 - \$40,000 or more for a single structure. The type of failure could be a broken
8 cross arm or structure. A failure in easily accessed locations would have a civil cost usually
9 of \$10,000 or less.

10
11 Labour and Equipment and Travel cost for the onsite structure repair are about \$16,500
12 for a 12 hour work day during the regular work week. 1 – 2 days of full crew for onsite and
13 preparation/monitoring

14
15 In summary, an unplanned repair estimated cost per event can be from \$35,000 to
16 \$110,000. With historical 2-5 failures on this line, the costs may range between \$70,000
17 to \$550,000 annually. It is noted that the line is aging and the repair costs continue to
18 increase, and YEC expects higher failure rates if the identified issues are not addressed.
19 L178 is geographically located in difficult terrain that provides challenging access to the
20 structures. Depending on the location of the problem, costs and repair durations can
21 escalate quickly.

22
23 It is also noted that L178 line protection is not as secure or advanced as the other lines
24 mostly due to the lack of a breaker at Carmacks where the line splits. This protection
25 scheme under certain conditions results in faults on L178 impacting the whole system by
26 splitting the grid at Takhini and Minto substations. This results in significantly more
27 customer outages and longer restoration durations.

28
29 A challenging repair in winter would leave a substantial amount of generation unavailable
30 to support grid requirements.

1 **REFERENCE:** Application, Tab 5.2.1.7, page 5-16

2
3 **ISSUE:** Breaker Replacement Program Project

4
5 **QUOTE:** "The project involves replacement of twelve aging circuit breakers in
6 various substations throughout the Yukon, including the replacement of
7 five 34.5 kV Medium Voltage (MV) and five 138 kV High Voltage (HV)
8 breakers. Many of the breakers are 40 years old, replacement parts are
9 not available and any damage to aging components could result in
10 lengthy outages to implement repairs or eventual replacement of a
11 breaker, impacting system reliability. Restricted operation of some
12 breakers and non-routine maintenance are becoming increasingly
13 frequent."

14
15 "Replacement of 7 high voltage (138kV) breakers in YEC substations
16 at Aishihik Faro, Riverside and Takhini: this was initiated in 2018 and
17 was to be completed in 2019. The high voltage breaker replacement
18 program was completed in 2019 with a total cost of \$2.26 million."
19 (footnote removed)

20
21 **QUESTION:**

22
23 a) Please explain how often YEC tested the breakers involved in this project to
24 assess their reliability in the past 40 years and how often maintenance work was
25 required. If possible, please provide the number of times maintenance was
26 conducted on these breakers in the last 10 years, on a per annum basis, and the
27 cost of this maintenance work.

28
29 b) YEC stated that five HV breakers were being replaced in one instance of its
30 application and that seven HV breakers were being replaced in another instance.
31 Please confirm the correct number of HV breakers being replaced in this project.

1 **ANSWER:**

2
3 **(a)**

4
5 Testing frequency of breakers is every 5 years. Costs for the testing are largely labour
6 with a small material component. YEC tests on average 5 breaker per year at a cost of
7 \$5000 per breaker, total cost \$25,000.

8
9 It should be noted that these breakers were 40 years old, spare parts were not available,
10 and any failure of aging components may have led to lengthy outages to repair.

11
12 **(b)**

13
14 Seven breakers were replaced in this project.

1 **REFERENCE:** Application, Tab 5.2.1.8, pages 5-17 to 5-18

2
3 **ISSUE:** Replacement of the P125 Head Gate Project

4
5 **QUOTE:** "The P125 Hydro Plant originally commissioned in 1958 ... The
6 headgates at the P125 plant are located above the plant at the water
7 intake structure ... To date, the headgates have never been
8 overhauled."

9
10 "An external engineering firm (SNC Lavalin) performed tests and
11 structural assessments of the P125 headgates in 2019 that indicate that
12 the headgates can no longer be relied upon for emergency closure or
13 for single device isolation. The gates were tested, in a controlled
14 situation, to determine if they would close during emergency conditions
15 and two out of the three gates did not close. This failure could result in
16 a unit runaway / over-speed that could potentially cause severe
17 damage to the unit as well as the plant."

18
19 "The scope of the project includes the removal of existing headgates,
20 design and installation of new headgates and control systems, and
21 refurbishment of the headgate hoist mechanism. YEC tendered and
22 proceeded with work on the WH2 headgate in 2020 ... It is expected
23 that the WH2 headgate will be completed in 2020 at a forecast cost of
24 \$2.3 million."

25
26 "... is assessing team capacity to complete replacement and
27 refurbishment of the gates and related infrastructure for units WH1 and
28 WH3 in 2021 ... and that the WH1 and WH3 headgates will be
29 completed in 2021 at a forecast cost of \$3.5 million."

30
31 **QUESTION:**

- 32
33 a) Please explain how often YEC tested out the headgates at the P125 Hydro Plant
34 in the past to assess their reliability and how often maintenance work was required.
35 If possible, please provide the number of times maintenance was conducted on
36 the headgates in the last 10 years, on a per annum basis, and the cost of this
37 maintenance work.

1 b) Please provide the tests, structural assessments and any other studies conducted
2 to show that the headgates could no longer be relied upon.

3
4 c) Please provide and explain the studies conducted to mitigate the concerns brought
5 on by the existing headgates. For example, how was the design of new headgates
6 and control systems carried out, and how was the preferred solution reached?
7 Please describe the results of the assessment in which it was determined that work
8 on the WH2 headgate needed to be carried out before work on the WH1 and WH3
9 headgates.

10
11 d) Please indicate whether work for the WH2 headgate was completed in 2020. Did
12 YEC staff complete this portion of the project, or was an external consultant
13 required? If an external consultant was required, please provide details on the
14 selection process of the contractor and how costs were awarded.

15
16 e) Please provide an update on the work currently completed for the WH1 and WH3
17 headgates. For example, what objectives have been met so far, and is YEC
18 expecting this portion of the project to be completed by 2021? Additionally, will
19 YEC complete this portion of the project, or will an external consultant be required?

20
21 **ANSWER:**

22
23 **(a)**

24
25 The head gates are used annually during the hydro planned maintenance. There is annual
26 maintenance on the hoist motors (grease/oil) and regular pulley inspections. Cost for this
27 maintenance is less than \$5,000.

28
29 **(b)**

30
31 Please see Attachment 1 and Attachment 2 to this response which provides reports from
32 SNC regarding the inspection and assessment of the P125 Headgates.

33
34 **(c)**

35
36 Studies determined that the P125 Headgates are not certifiable for Single Device Isolation.
37 Tests determined the headgates could not close fully in an emergency. Additional

1 concerns were the reliability of the hoist and controls. The new gates, hoist controls and
2 refurbished hoist addressed each of these concerns. WH2 was selected to be done first
3 because of the upcoming WH2 Uprate and the need for reliable means of isolation.

4
5 The P125 Headgate Assessment report is provided Attachment 1 to YUB-YEC-1-56(b).
6 The inspection report from SNC regarding the inspection and assessment of the P125
7 Headgates is provided as Attachment 2 of YUB-YEC-1-56(b).

8
9 **(d)**

10
11 The WH2 Headgate Project was completed in 2020. The work was carried out by a prime
12 contractor selected through an RFP process.

13
14 The RFP was issued and posted publicly through MERX. Two bids were received and
15 were evaluated. A best value approach was taken with points awarded based on the
16 following criteria: technical, cost and FN content. The Proponent with the highest total
17 score was recommended.

18
19 **(e)**

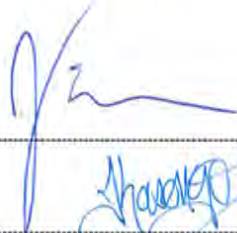
20
21 YEC will complete the preliminary design and tendering of the WH1 and WH3 headgate
22 in 2021 for project completion in 2022. YEC will engage an engineering firm for assistance
23 with this process.

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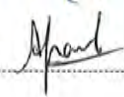
OWNER: Yukon Energy Corporation

PROJECT: WH2 Uprate Project



PREPARED BY: Josh Vines Signature: 

REVIEWED BY: Cyril Kasongo Signature: 

APPROVED BY: Abhishek Pandey Signature: 

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REVISION INDEX

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1.0 INTRODUCTION

1.1 General

Yukon Energy Corporation's (YEC) P125 hydroelectric generating station was constructed in 1958 on the Yukon River in Whitehorse, Yukon Territory. The original plant included two double-regulated Kaplan turbine-generators (WH1 and WH2) each with a capacity of 5.8 MW. The powerhouse was extended in 1969 to add a third 8.4 MW propeller type unit (WH3). The power intakes for the three units are located at the end of a 600 m long approach channel located on the left side of the dam and spillway. Three penstocks connect the power intakes to the powerhouse.

The intake structure includes stoplogs and emergency closing headgates for each unit. One set of stoplogs is available to isolate any one of the three units. Each unit has an emergency closing headgate and dedicated wire-rope hoist. Headgates for units WH1 and WH2 were installed in 1958 with the original construction, while the third intake was left otherwise blocked. The third headgate (for unit WH3) was added in 1969 along with the addition of the third turbine-generator unit. Since their original installation it is understood that the headgates have not undergone any major maintenance or repair works. The headgates are intended to provide isolation for safe work downstream, and to close against flow in case of emergency.



Photograph 1 - WH1 Headgate Inspection Position

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The WH2 turbine-generator unit is to be refurbished and “uprated” in year 2021. As part of its mandate as Owner’s Engineer for the WH2 Uprate Project, SNC-Lavalin Inc. (SLI) was asked to review the condition of balance-of-plant equipment related to the WH2 unit and define the scope for required upgrades. This work identified that a detailed assessment of the headgates was required. The three intakes are identical apart from age and minor design differences of the WH3 headgate. As such, the scope for headgate assessment was extended to include the WH1 and WH3 intake headgates.

Inspections of the three headgates were completed by SLI and YEC in May and June 2019. Following the inspections, SLI analysed stresses in the headgates with consideration of the as-found conditions of each gate. This technical report documents the results of the inspections and analysis and makes recommendations based on the findings.

1.2 Purpose

The objective of the assessment is to verify if the P125 headgates and hoists are fit for purpose in their current condition, and to define the scope of work required to either refurbish and/or replace equipment as necessary. Where appropriate, the assessment considers the estimated costs for both refurbishment and replacement options.

1.3 Key Parameters

WH1 / WH2 Headgates:	
Design/Manufacture	Dominion Bridge
Gate type	Fixed-Wheel Vertical Lift
Year of manufacture	1958
Fabrication method	Riveted
Height – Clear opening	4.11 m
Height – To lintel seal	4.15 m
Width – Clear opening	3.81 m
Width – Seal to seal	3.94 m
Width – Wheel to wheel	4.18 m
Elevation of sill	641.91 m
Original design maximum head	10.67 m
Normal operating maximum head*	11.19 m
Material	ASTM A36
Gate mass (including concrete ballast)	8050 kg

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WH1 / WH2 Headgate Hoists:	
Design/Manufacture	Dominion Bridge
Hoist type	Wire-rope
Capacity	12700 kg
Hoisting speed	2.1 m/min
Lowering speed	3.4 m/min
Power supply	550 V / 3 ph. / 60 Hz
Rated motor capacity	5.6 kW
Control panel voltage	125 VDC

* Units are routinely operated at heads that exceed the original design values.

WH3 Headgate:	
Design/Manufacture	Dominion Bridge
Gate type	Fixed-Wheel Vertical Lift
Year of manufacture	1969
Fabrication method	Welded
Height – Clear opening	4.11 m
Height – To lintel seal	4.15 m
Width – Clear opening	3.81 m
Width – Seal to seal	3.96 m
Width – Wheel to wheel	4.18 m
Elevation of sill	641.91 m
Original design maximum head	10.67 m
Normal operating maximum head*	11.19 m
Material	ASTM A36
Gate mass (including concrete ballast)	8050 kg
WH3 Headgate Hoist:	
Design/Manufacture	Dominion Bridge
Hoist type	Wire-rope
Capacity	13600 kg
Hoisting speed	1.2 m/min
Lowering speed	3.0 m/min

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Power supply	550 V / 3 ph. / 60 Hz
Rated motor capacity	3.7 kW
Control panel voltage	115 VAC

* Unit is routinely operated at heads that exceed the original design values.

1.4 Reference Documents

Document Number	Title
TK1081.B2.W9.27	Specification for Headgate and Stoplog Equipment
NCP 9879	Intake – General Layout
E51563	WH1 / WH2 Headgate Assembly Drawing
E52304	WH1 / WH2 Headgate Hoist Assembly Drawing
M0186-1	WH3 Headgate Assembly Drawing
M0187-L1	WH3 Headgate - Details
M0188	WH3 Headgate Hoist Assembly Drawing
Memo – J Vines to G Dunbrack, June 24 2019	P125 / WH2 Headgate Inspection
Memo – C Kasongo to G Dunbrack, Aug 09 2019	P125 / WH1, WH3 Headgate Inspection

2.0 METHODOLOGY

The following sections describe the methods used in the various aspects of the headgate assessment.

2.1 Condition Assessment

Inspections of all three headgates were completed in May and June of 2019. The headgates were raised to their highest position possible using their wire rope hoists. Gate inspections included:

- Cleaning of headgates
- Visual inspection of gate structural steel and connections
- Dimensional measurements
- Corrosion pitting measurements
- Visual inspection and measurement of rivet condition

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- Visual inspection of one-wheel bushing condition (WH2 gate only)
- Ultrasonic thickness measurements
- Magnetic particle inspections

Gate guides were inspected by YEC using a remote operated vehicle, with video recording.

The headgate hoists were visually inspected and observed during operation.

Notes, photographs, and measurement results from the inspections were recorded and documented in memoranda.

2.2 Gate Stress Analysis

Calculations were prepared to estimate the normal stress in the structural elements of the headgates in their current condition. The calculations consider the measured thickness of structural elements and ultrasonic checks were completed during the inspections. A reservoir level of 653.1 m is assumed in the analysis based on the maximum normal operating range observed at P125. At this stage, the analysis does not consider seismic or flood conditions, as it is only preliminary. A more detailed analysis should be done at the next stage.

The analysis was performed using the allowable stress method, with the allowable tensile stress defined as 60% of yield strength and the allowable shear stress defined as 2/3 of the allowable tensile stress. These limits are within the normal range of allowable stresses used in the industry, as summarized in the following table.

Standard	Allowable Tensile Stress
P.F. Erbisti, Design of Hydraulic Gates (2014)	68% S_y
ASME Boiler and Pressure Vessel Code	67% S_y
CAN/CSA S16	60% S_y
DIN 19704-1976	60% S_y
BC Hydro Design Standard H2124/H2676	54% S_y
US Army Corps of Engineers EM 1110-2-2105	50% S_y

S_y = Yield strength

Where possible, the allowable stress was defined based on material test results. For WH1 and WH2 this was done based on a coupon sample tested in 2010. Material test data was not available for the WH3 headgate so a minimum yield strength based on the ASTM standard (A36) was assumed.

Calculations included:

- Bending stress, shear stress and deflection in horizontal girders according to methods of Erbisti (2014)
- Skinplate stress according to DIN 19704 – 1976

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- Vertical end-girder bending and shear stress approximated as a simply supported beam
- Wheel contact stresses according to Erbisti (2014)
- Wheel axle shear stress assuming simple support
- Wheel bushing stress according to Erbisti (2014)

Stress in the skinplate was calculated with plate thickness determined by the UT measurements and also with consideration of reduced thickness due to area-averaged pitting corrosion depth.

2.3 Hoist Analysis

Calculations were prepared to check the adequacy of the hoist capacity and to verify the wire rope loads are acceptable. The estimate of hoist loads included the calculation of buoyancy, wheel friction, seal friction, and hydraulic downpull. Wheel friction and seal friction calculations were based on the methods presented in Erbisti (2014).

The hydraulic downpull was approximated based on a simplified method presented in Erbisti (2014) wherein a downpull factor (k) is multiplied by the product of the gate cross-sectional area and the hydrostatic pressure on the gate. The k-factor was assumed at 0.2 based on a review of gate lip designs and model test data presented by Erbisti.

The capacity of the wire rope was checked against the required hoisting loads. The wire rope strength was taken from the Machinery's Handbook according to the rope type specified on the hoist assembly drawings.

3.0 RESULTS

3.1 Condition Assessment Results

The results of the headgate inspections were presented in memoranda (see Section 1.4 herein). In summary, the WH1 and WH2 headgates were found to have significant corrosion on the skinplate (primarily the upstream side), the webs of horizontal girders, and somewhat less corrosion on vertical end-girders. Although the thickness of the skinplate was found to be greater than as shown in the drawings, corrosion pitting on the skinplate was measured to depths exceeding 4 mm. The heads of rivets were found to have varying levels of corrosion, with some rivet heads in good condition and others heavily corroded. The shaft of rivets inspected were found to have no corrosion. Wheels and wheel bushings were found to be in good condition. The dimensions of the gate were found to match the design drawings, with the exception of the skinplate thickness. Magnetic particle inspections did not identify any cracks in the areas inspected, including rivet hole locations, drainage holes in horizontal girder webs, wheel axle holes in vertical end-girders, and in the inspected wheel bushing pin.

In comparison, the WH3 headgate was found to be in much better condition. The extent of inspection was limited to the top section of the gate, as a result of the limit switches on the hoist limiting travel. However, from inspection of the top section it was found that there was much less corrosion than the WH1 and WH2 headgates. Again, the skinplate thickness was found to exceed what is shown on the design drawings. Welds, to the

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extent that they could be visually inspected, appeared to be in good condition. Wheels appeared in good condition although were found to not turn as easily as those on the other headgates. Measured dimensions were found to match the design drawings, with the exception of the skinplate thickness. Magnetic particle inspections did not find any cracks in the areas inspected.

The gate guides of WH2 appeared from the ROV videos to be in good condition. Some roughness due to corrosion appears to be present, although it is difficult to quantify from the video. The condition of guides on WH1 and WH3 could not be clearly ascertained from the videos, but they are expected to be in similar condition.

The wire ropes of all three gate hoists were observed to have some corrosion and wear. It is not clear from the available maintenance history whether the ropes have been replaced since the original installation. The gearbox of the WH2 hoist was inspected and the gears found to be in good condition. Greasing points on all three hoists showed signs of recent greasing and maintenance staff report that regular greasing is part of normal maintenance schedules. Operation of the wire rope hoists was observed to be smooth and trouble-free. The local control panels for all three gate hoists are using outdated technology and are expected to be at or beyond their design life.

3.2 Gate Stress Analysis Results

The main results of the stress analysis for the headgates are summarized in the following table. Where multiple elements (girders, skinplate sections, etc.) were evaluated the maximum calculated stresses are shown. Although the WH3 headgate was found to have little corrosion, a nominal reduction in thickness of 0.5 mm was assumed to be conservative.

Description	Percent of Allowable Stress			
	WH1 / WH2 Headgates		WH3 Headgate	
	Original Plate Thickness	Thickness After Corrosion	Original Plate Thickness	Thickness After Corrosion
Horizontal girder – Bending	74%	n/a	92%	n/a
Horizontal girder – Shear	38%	65%	48%	54%
Skinplate stress	139%	172%	148%	162%
Vertical end-girder – Bending	55%	n/a	58%	n/a
Vertical end-girder – Shear	25%	n/a	29%	n/a
Wheel contact stress	56%	n/a	56%	n/a

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Description	Percent of Allowable Stress			
	WH1 / WH2 Headgates		WH3 Headgate	
	Original Plate Thickness	Thickness After Corrosion	Original Plate Thickness	Thickness After Corrosion
Wheel axle shear	16%	n/a	16%	n/a
Wheel bushing	35%	n/a	35%	n/a
Rivet tension	66%	n/a	n/a	n/a
Rivet shear	89%	n/a	n/a	n/a

The summary table shows that most elements of the gates are within allowable stress limits, except the skinplates which have stresses far exceeding the allowable stress. After consideration of thickness reduction due to corrosion, the stress in the WH1/WH2 skinplates slightly exceeds the tested yield strength of the material.

3.3 Hoist Analysis Results

The hoist load calculations found a maximum hoist load of approximately 15,600 kg, which exceeds the rated capacity of the hoists. This hoist load is estimated for the condition of lifting the gates to their filling position when the downstream water passage is dewatered. As noted in Section 2.3, the hydraulic downpull on the gates is approximated according to a simplified method, therefore there is some uncertainty in the estimated maximum hoist load.

The capacity of the wire ropes was found to have a factor of safety of 4.6 over the calculated maximum hoist load. Industry standard requires a minimum factor of safety of 5.0.

4.0 DISCUSSION

4.1 Refurbishment / Replacement Options

Due to the extensive corrosion pitting damage observed on the WH1 and WH2 headgates refurbishment is not seen as a practical option. Extensive welding work would be required to repair the corrosion pitting damage. Additional stiffeners would need to be added to reduce the skinplate stress. Due to the condition of rivets all the rivets would need to be removed and replaced by welded fabrication. With such extensive work a careful program of dimensional control would need to be put in place. As such, there is no advantage seen in refurbishing these gates as compared to replacing them.

The WH3 headgate was found to be in good condition and therefore refurbishment is possible. The high stresses found in the skinplate can be addressed by the addition of vertical stiffeners midway between the existing vertical stiffeners. This would lower the skinplate stresses into the allowable range. Refurbishment would include sandblasting and recoating the gate.

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Based on the video inspections it is expected that the embedded guides for all three gates can be refurbished. Work should include detailed inspection and measurement, followed by machining if/as necessary to achieve typical flatness and verticality.

Refurbishment of all three headgate hoists is possible. Wire ropes should be replaced with new wire ropes, which would provide an increased safety factor due to improvements in wire rope strength since the original equipment was supplied. Other hoist components can be dismantled, cleaned and greased. Gearbox oil should be drained, gears cleaned, and refilled with oil.

The local controls for all three wire rope hoists should be replaced with modern control systems. Instrumentation (limit switches) on the hoists should be replaced due to age.

4.2 Cost Estimates

The costs for the refurbishment (where appropriate) and replacement of the equipment were estimated by scaling from recent projects and similar market quotations recently obtained. In some cases the costs were estimated by SNC and YEC based on calculated quantities and estimated unit rates and labour. Budgetary quotations were requested from vendors but none were able to provide the estimates at time of reporting due to seasonal resource limitations. The cost estimates are summarized in the following table.

Equipment	Refurbish Cost	Replace Cost
WH1 and WH2 Headgates	n/a	\$465,900
WH3 Headgate	\$150,000	\$233,000
Embedded Parts Repair x3	\$656,300	n/a
Wire rope hoists c/w controls x3	\$645,600	\$855,000

The accuracy of the estimates is at the level of an AACE Class 4 estimate.

4.3 Outage Costs

It will be necessary to shut down the units while work is being done on the headgates and hoists. As such, consideration was given to the evaluation of outage costs (lost generation) for the refurbishment and replacement options. Gate refurbishment options would require removal of the gate(s) to a shop for a period of time during which the respective unit must be out of service. In comparison, gate replacement options would require shorter duration outages since the new gate would be ready to install earlier.

Refurbishment of the WH1 and WH2 headgates is not practical as mentioned in Section 4.1, therefore associated outage costs will not be evaluated.

It is understood that there are times of the year when the WH3 generating unit is not typically used and therefore outage costs are insignificant (no lost generation). If the work is planned for a period of time when the unit is not scheduled for operation, then the outage costs do not need to be considered in the evaluation of options.

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It is anticipated that refurbishment of the headgate hoists would be completed during the same outage as the gate refurbishment/replacement work. As such, the costs of outage do not factor into the decision to refurbish or replace the hoists.

4.4 Engineering Costs

An estimate of engineering hours was used to establish a budget for engineering related to the headgate works. This would include detailed tender design and analysis, drafting, preparation of procurement specifications, tender support, review of vendor shop drawings and submittals. For replacement of all three headgates plus refurbishment of the hoists and upgrades of the controls, the engineering costs are estimated as follows:

Mechanical Engineering Hours	400
Electrical Engineering Hours	210
PM / Administrative Hours	120
Total Cost	\$85,000

If the WH3 headgate is refurbished rather than replaced then an additional 250 mechanical engineering hours would be required. The total cost in that case would be \$114,000.

4.5 Shop Inspection and Field Inspection Costs

In case YEC wishes to engage an engineering consultant or a third party to carry out shop inspections and field inspections, for installation and commissioning, the associated costs are estimated as under:

Hours for Mechanical Inspections	160
Hours for Electrical Inspections (including commissioning supervision)	60
PM / Administrative Hours	40
Expenses (travel and stay)	\$14,000
Total Cost	\$45,000

The hours and expenses for inspections are tentative and based on initial planning for replacement/refurbishment works. These costs can be confirmed after YEC's planning for inspections is determined and schedule for replacement/refurbishment works is firmed up.

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5.0 CONCLUSION AND RECOMMENDATIONS

The assessment has shown that the stresses in all three headgate skinplates are far beyond the acceptable limits. As such, the headgates should not be relied upon to isolate the water passages for the purpose of worker access. If personnel access in the water passage is required then the stoplogs must be used, or the headgates could be safely used at a reduced water level (approximate elevation 649 m).

Refurbishment of the WH1 and WH2 headgates is not practical due to the extent of corrosion. These gates should be replaced.

The wire rope hoists can be effectively refurbished (and local controls replaced) for a lower cost than replacement with new hoists. As such, this option is preferred over providing completely new wire rope hoists.

The WH3 gate could either be refurbished or replaced. This then yields two options for the project scope: **Option A** would include refurbishment of the WH3 headgate and **Option B** would consider replacement of the WH3 headgate. Both options would include replacement of the WH1 and WH2 headgates, refurbishment of all three wire rope hoists, and replacement of the local control panels. The costs are summarized as follows:

Scope Item	Option A	Option B
WH1 and WH2 Headgates – Replacement	\$465,900	\$465,900
WH3 Headgate	\$150,000	\$233,000
Embedded Parts Repair x3	\$656,300	\$656,300
Wire rope hoists c/w new controls x3 - Refurbishment	\$645,600	\$645,600
Engineering	\$114,000	\$85,000
Shop Inspection and Field Inspection Costs	\$45,000	\$45,000
Total Cost	\$2,076,800	\$2,130,800

The cost estimates above are Class 4 estimates and exclude all owner's costs, taxes, bonds, risk, contingency and other indirect costs.

The costs for the two options are within 5% of each other. It is worth noting that although Option A is less expensive, there is more risk involved. Risks would include the potential of finding the gate to be in worse condition than expected when it is fully removed from the slot, and the risk that extended duration of in-shop gate refurbishment would result in delays to the outage period.

Additionally, replacement of the WH3 headgate will result in a longer service life for the equipment when compared with refurbishment. Option B appears favourable, considering that the cost estimates for both options are close in value, and it involves less risk of cost and schedule variation and may result in a longer service life.

Further evaluation should be done to obtain more certainty on costs for the two options by obtaining budget quotations from several vendors. That work can be done in parallel with the engineering required to support the final procurement activities.

1 **REFERENCE:** Application, Tab 5.2.1.9, pages 5-18 to 5-19

2
3 **ISSUE:** WH2 Uprate Project

4
5 **QUOTE:** “Whitehorse Hydro #2 (WH2) was commissioned in 1958 and is one of
6 the three units installed at P125. It is a Kaplan Turbine unit with nominal
7 rating of a 5.8 MW and is currently operating with the original runner,
8 rotor, stator and windings from 1958. WH2 asset health has been
9 declining due to its age, and there is an increased risk of failure and
10 related unplanned outages and costs. Specifically, the generator has
11 exceeded a typical winding life of 40 years; and issues have been
12 identified with oil leaks at the runner blade to hub seals and with
13 possible voids in the concrete behind the draft tube liner. In the
14 circumstances, it was considered prudent to rewind the generator in
15 order to mitigate these risks and their potential reliability and cost
16 implications. External studies also determined that unit efficiency would
17 be improved with a new runner of modern design.” (emphasis added)

18
19 “In 2017, Hatch completed an economic assessment of various uprate
20 options at the Whitehorse Rapids Generating Station (WRGS). The
21 report concluded that the uprating of the WH1 or WH2 units would be
22 the most cost-effective option and provide the best payback of the
23 WRGS hydro units. Management selected the uprating of WH2 over
24 WH1 since there are existing known issues with the WH2 governor, and
25 the uprating project would resolve these issues.”

26
27 “The project is planned to be implemented over a three year period
28 (2019 21), and is expected to add 6.4 GWh/yr additional hydraulic
29 generation to the grid [starting in the third quarter of 2021]. The project
30 is also expected to increase dependable capacity of WH2 by 0.94
31 MW... YEC contracted Litostroj Power to undertake the runner
32 fabrication with the following concurrent activities planned for 2020:
33 governor fabrication, balance of plant civil construction; balance of plant
34 P&C design completion, relace of balance of plant request for proposal,
35 and delivery of materials to Whitehorse.”

1 **QUESTION:**

- 2
- 3 a) Please explain how often YEC carried out tests on WH2 in the past to assess its
- 4 reliability and how often maintenance work was required. If possible, please
- 5 provide the number of times maintenance was conducted on WH2 in the last 10
- 6 years, on a per annum basis, and the cost of this maintenance work. For example,
- 7 how many times did YEC rewind the generator?
- 8
- 9 b) Please indicate if any unplanned outages have occurred with WH2. If confirmed,
- 10 please provide the number and duration of these outages in the last 10 years, on
- 11 a per annum basis, and the costs incurred due to these outages.
- 12
- 13 c) Please provide the external studies showing that unit efficiency would be improved
- 14 with a new runner of modern design, and explain the improvements found with this
- 15 design. Additionally, please indicate which consultant carried out these studies,
- 16 and provide details on the selection process of the contractor and how costs were
- 17 awarded.
- 18
- 19 d) Please provide Hatch's economic assessment of the various uprate options at the
- 20 Whitehorse Rapids Generating Station, and provide the costs of all the uprate
- 21 options explored in this assessment.
- 22
- 23 e) Please provide further detail on YEC's choice of uprating WH2 over WH1. For
- 24 example, what process was carried out to determine that WH2 required uprating
- 25 over WH1? Did YEC conduct technical meetings with its staff or carry out an
- 26 assessment comparing issues between both assets?
- 27
- 28 f) Please provide an update on the work currently completed for this project. Is YEC
- 29 currently on schedule with this project?
- 30

31 **ANSWER:**

32

33 **(a)**

34

35 YEC carries out annual scheduled maintenance and testing on WH2.

1 A major overhaul was completed in 2016 at a cost of \$686,764. The generator has never
2 been rewound since it was put into service in 1958. All major components of WH2 are
3 original.

4
5 There is also annual maintenance work scheduled for 2-3 weeks per year. Average costs
6 for this work is \$80,000-\$100,000 depending on discoveries (cavitation). YEC historically
7 performs 10 year major overhauls on the major hydro assets.

8
9 **(b)**

10
11 Please see Attachment 1 to this response which provides WH2 KPIs from YTD back to
12 2015. The forced outage rate is very low. Costs would be difficult to provide due to the
13 very low failure rate. Costs are captured in the general O&M accounts.

14
15 **(c)**

16
17 Please see also YUB-YEC-1-57(d) Attachment 1 which provides the Hatch study. Section
18 3 of this report outlines the benefits of replacing the runner as well as some of the other
19 improvements that are being made to the WH2 Unit. Assessments for WH1 are applicable
20 to WH2 as noted in the report.

21
22 Issues with existing unit performance are noted in Section 3.1. More specifically, the
23 section notes issues with oil leakage at the runner blade to hub seals and with possible
24 voids in the concrete behind the draft tube liner. Section 3.1 notes efficiency tests were
25 conducted on WH1 in 2009 by Hydro Power Performance Engineering, Inc. (HPPE) for
26 the KGS Group. Turbine flow was measured using flow meters installed at the intake. The
27 tests indicated performance as follows:

- 28
29 • Peak turbine efficiency = 88.1%;
30
31 • Peak efficiency flow = 23 m³/s;
32
33 • Efficiency at full load = 82.3%;
34
35 • Full load flow = 39.5 m³/s; and
36
37 • Full load turbine output = 5.74 MW at 18 m net head.

Figure 3-2 of the report shows the efficiency of the existing turbine based on the testing done by HPPE, the efficiency of a modern state of the art turbine derived from model test information, and the estimated efficiency of the WH1 turbine with a new runner and possible stay vane modifications. The efficiency curve for the existing turbine is for the optimum wicket gate – runner blade relationship. The estimated increase in efficiency with a new runner is approximately 4%. Figure 3-2 also shows the estimated turbine performance for a new runner with a 10% increase in flow. The increase in energy and capacity for the various uprate options are discussed in Section 7.

Hatch was awarded the work to undertake the study noted through a competitive RFP process. Proposals were evaluated based on technical and organization competence and price; and demonstrate the best value for price submitted.

(d)

Please see the Hatch study provided as Attachment 1 to this response. The costs for each option assessed in the Hatch study are provided in Table 10-1 of the attached (excerpted below). Assessments for WH1 are applicable to WH2.

Option	Uprated Unit	Increased Turbine Flow (Y/N)	Load Scenario	Avoided Thermal Generation (MWh/yr)	Avoided Thermal Capacity (MW)	Capital Cost (\$M)	Cost Incl. Disassembly & Install (Y/N)	Cost Incl. Generator Rewind (Y/N)	NPV 30 years (\$M)	B/C ratio 30 years	Simple Payback Period (Years)	Discounted Payback Period (Years)
1-1	WH1	N	1	559	0.09	1.99	Y	N	0.21	1.11	19 yrs	28 yrs
1-1A	WH1	N	1	559	0.09	1.78	N	N	0.41	1.23	17 yrs	24 yrs
1-3	WH1	N	3	932	0.16	1.99	Y	N	0.98	1.52	12 yrs	15 yrs
1-3A	WH1	N	3	932	0.16	1.78	N	N	1.18	1.69	11 yrs	13 yrs
1-4	WH1	N	4	1491	0.23	1.99	Y	N	1.18	1.61	12 yrs	14 yrs
1-4A	WH1	N	4	1491	0.23	1.78	N	N	2.26	2.29	9 yrs	9 yrs
2-1	WH3	N	1	47	0.01	2.58	Y	N	-2.43	0.04	No Payback	No Payback
2-1A	WH3	N	1	47	0.01	1.18	N	N	-1.06	0.09	No Payback	No Payback
2-4	WH3	N	4	430	0.07	2.6	Y	N	-1.61	0.36	>45 yrs	>45 yrs
2-4A	WH3	N	4	430	0.07	1.2	N	N	-0.23	0.80	20 yrs	>45 yrs
3-1	WH4	N	1	395	0.05	4.26	Y	Y	-2.84	0.30	No Payback	No Payback
3-1A	WH4	N	1	395	0.05	2.30	N	N	-1.16	0.47	37 yrs	No Payback
4-1	WH1	Y	1	488	0.15	4.78	Y	Y	-2.68	0.43	No Payback	No Payback
4-1A	WH1	Y	1	488	0.15	2.74	N	N	-0.68	0.75	27 yrs	No Payback
4-4	WH1	Y	4	1879	0.40	4.78	Y	Y	0.28	1.06	14 yrs	23 yrs
4-4A	WH1	Y	4	1879	0.4	2.74	N	N	2.23	1.85	9 yrs	10 yrs
5-1	WH4 - K	N	1	1583	0.70	10.38	Y	Y	-6.18	0.39	42 yrs	No Payback
5-4	WH4 - K	N	4	47	1.00	10.4	Y	Y	1.20	1.12	14 yrs	23 yrs
6-1	WH1 & 2	N	1	795	0.09	3.97	Y	N	-0.95	0.75	27 yrs	No Payback

1 **(e)**

2
3 WH2 was selected over WH1 because the energy output of WH2 is higher based on the
4 plant configuration. That is, WH2 produces more energy because it exhausts mid-stream;
5 WH1 exhausts against the bank of the river which creates a loss of efficiency. Otherwise,
6 the units are essentially identical units. Additionally, WH2 was having a problem with its
7 governor, i.e., the WH2 governor was having issues with MW control and resolution was
8 required.

9
10 **(f)**

11
12 Design and manufacturing are complete and the site work is currently underway. YEC is
13 currently on schedule with the WH2 Uprate.

KPI Report: Unit Status

02/22/2021 10:48

			2021-Q1 1259 hrs		2020-Q1,Q2,Q3,Q4 8784 hrs			2019-Q1,Q2,Q3,Q4 8760 hrs			2018-Q1,Q2,Q3,Q4 8760 hrs	
			AVAILABLE	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	PLANNED
			99.1%	0.9%	41.2%	Reliability 42.8%	1.6%	92.8%	Reliability 100%	7.1%	61.2%	38.8%
WHITEHORSE	THERMAL	WG2	99%	1%	41%	57%	2%	93%	0%	7%	61%	39%

KPI Report: Unit Status

02/22/2021 10:48

			2017-Q1,Q2,Q3,Q4 8760 hrs			2016-Q1,Q2,Q3,Q4 8784 hrs			2015-Q1,Q2,Q3,Q4 8760 hrs		
			AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED
			84.2%	Reliability 99.9%	15.7%	93.2%	Reliability 99.9%	6.7%	93.8%	Reliability 98.9%	5.1%
WHITEHORSE	THERMAL	WG2	84%	0%	16%	93%	0%	7%	94%	1%	5%

1 **REFERENCE:** Application, Tab 5.2.1.10, pages 5-19

2
3 **ISSUE:** WH4 Uprate – Servomotor Replacement Project

4
5 **QUOTE:** “The project involves detailed design, procurement and installation of
6 two new Servomotors for Whitehorse Hydro Unit 4 (WH4) wicket gate
7 operation. Implementation will increase the output of the WH4 unit by
8 allowing full range of operation of the wicket gates; this enhancement
9 adds additional hydraulic generation of 0.9 GWh/year.”

10
11 “Contracts with [ANDRITZ Hydro] (OEM), L&S Electric (to review
12 documentation and develop a governor commissioning plan) and Hatch
13 (owners engineer) have been finalized. Procurement has not yet been
14 undertaken for testing services and installation of a lifting device.”

15
16 “Final design is nearing completion and manufacturing is expected to
17 commence in Q3 2020 ... Delivery of the Servos is expected by January
18 2021. Contractor mobilization and installation, testing and
19 commissioning is expected to occur in June 2021. The project is
20 expected to be in service in June 2021.”

21
22 **QUESTION:**

23
24 a) Please indicate the year in which the existing servomotors were installed and the
25 expected service life at the time of installation.

26
27 b) Please explain why YEC decided to pursue this project. For example, were there
28 reliability issues with the existing servomotors? Did the existing servomotors cause
29 reliability issues with WH4? If outages were experienced at WH4 due to the
30 servomotors, please provide the number and duration of outages in the last 10
31 years, on a per annum basis, and the costs incurred due to these outages.

32
33 c) If there were reliability issues with the servomotors, please explain how often YEC
34 carried out tests in the past to assess reliability of the servomotors. If possible,
35 please provide the number of times maintenance was conducted on the
36 servomotors in the last 10 years, on a per annum basis, and the cost of this
37 maintenance work.

1 d) Please explain how the enhancement proposed in this project adds additional
2 hydraulic generation.

3
4 e) Please provide details on the selection process of contractors (specifically
5 ANDRITIZ Hydro, L&S Electric and Hatch) for this project, including how contracts
6 were awarded for this project.

7
8 f) Please provide an update on the work currently completed for this project. Is YEC
9 currently on schedule with this project? For example, has final design and
10 manufacturing been completed and is the project still expected to be in service in
11 June 2021?

12
13 **ANSWER:**

14
15 **(a)**

16
17 Servo motors are original (1984). The expected service life at time of installation is not
18 known.

19
20 **(b)**

21
22 Yukon Energy's (YEC) 10 Year Renewable Electricity Plan has confirmed that the
23 Corporation faces an existing and forecast shortfall in renewable energy until such time
24 that significant new sources of supply are sourced from the Atlin Hydro Expansion and the
25 Moon Lake Pump Storage projects.

26
27 A number of smaller scale supply projects, including the replacement of servo-motors on
28 YEC's Whitehorse Hydro #4 (WH4) hydro unit (also referred to as the 'WH4 Upgrading
29 Project') are included in the 10 Year Renewable Electricity Plan, in order to provide
30 incremental sources of renewable energy in the short to medium term. The primary benefit
31 of the project is a 0.8 MW increase in maximum output of WH4, resulting in an estimated
32 gain in energy production of 0.9 GWh/yr. at average hydro conditions. The estimated
33 Levelized Cost of Energy (LCOE) of this energy gain is \$0.065/kWh under the base case
34 load forecast, and \$0.051/kWh under the high load case. This project LCOE compares
35 favourably to the economics of both existing and new thermal and renewable generation
36 options. Secondary benefits include reduced stress levels in the servo-motors, governor
37 and wickets gates/operating ring which will increase reliability and safety during operation.

1 **(c)**

2
3 The current servo motors were not meeting IEEE code in terms of operation and reliability.

4
5 The servo motor is a hydraulic ram that requires little maintenance other than oil and filter
6 changes. The issue with the servo motor on WH4 is not related to frequent failures. The
7 servo is not capable (underpowered) enough to allow the hydro unit to operate at 100%
8 gate opening. The unit if brought to 100% gate opening would be unable to close the
9 wicket gates.

10
11 **(d)**

12
13 YEC's WH4 unit is currently limited to 92% gate opening as a result of undersized servo-
14 motors. This limitation results in a reduction of the unit output as compared to the
15 nameplate rating. The proposed project involves replacement of the servo-motors with
16 spring assisted servo-motors that will augment the force provided by the high pressure
17 hydraulic unit (HPU) and overcome the gate stalling issue experienced beyond 92%
18 stroke. The governor gate position limiter will be removed and the WH4 unit will be re-
19 commissioned with the capability to operate at 100% gate opening. The ability to operate
20 at %100 gate opening will increase Energy and Capacity of the unit.

21
22 **(e)**

23
24 ANDRITZ Hydro and L&S were selected because they are the Original Equipment
25 Manufacturers (OEM) for the equipment. The OEMs have all proprietary drawings,
26 manuals and expert / familiar staff to perform the modifications that other manufacturers
27 simply would not have. Hatch was selected through an RFP process.

28
29 **(f)**

30
31 Final design and manufacturing are complete and the project is expected to be completed
32 by June 2021.

1 **REFERENCE:** Application, Tab 5.3.1, pages 5-21 to 5-25 and 5-35 to 5-42

2
3 **ISSUE:** Costs for Deferred Projects Greater Than \$1 Million

4
5 **PREAMBLE:** In this section of its application, YEC outlined the costs for the Aishihik
6 Generating Station Three-Year Licence Renewal and Demand Side
7 Management projects, which were deferred projects incurring costs
8 greater than \$1 million. For the Aishihik Generating Station Three Year
9 Licence Renewal Project, YEC indicated that it spent \$0.805 million in
10 2019 and \$0.200 million in 2020. For the Demand Side Management
11 Project, YEC indicated that it spent \$0.833 million in 2019, forecasted
12 spending \$0.375 million in 2020 and forecasted spending \$0.894
13 million in 2021. YEC stated that it reflected these costs in Tables 5.3 to
14 5.6 in its application, found from pages 5-35 to 5-42. It is not clear how
15 YEC allocated these costs over the previous years and how it plans to
16 allocate these costs in its forecasted years.

17
18 **QUESTION:**

- 19
20 a) Regarding the Aishihik Generating Station Three-Year Licence Renewal Project,
21 please provide a cost breakdown of the \$0.805 million and \$0.200 million spent in
22 2019 and 2020 respectively. More specifically, provide the activities conducted and
23 then the cost amount allocated to each activity.
24
25 b) Regarding the Demand Side Management Project, please provide:
26
27 i. a cost breakdown of the \$0.833 million spent in 2019, a description the
28 activities conducted and the cost amount allocated to each activity; and
29
30 ii. a cost breakdown of forecasted spending on \$0.375 million and \$0.894
31 million in 2020 and 2021 respectively, a description of the activities YEC
32 forecasts to conduct and the cost amount allocated to each activity.

ANSWER:

(a)

Please see Table 1 below.

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

(b)

(i)

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.

(ii)

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
<i>Contributions (PeakSmart funding)</i>	<i>\$ (215,000)</i>
Total Net Project Cost	\$ 600,000

- 1 Net of contributions, the updated costs for 2020/2021 are \$691,545 as compared with
- 2 \$904,000 in the Application.

1 **REFERENCE:** Application, Tab 5.3.1.2, page 5-23, line 14; Our Clean Future: A
2 Yukon Strategy for Climate Change, Energy and a Green
3 Economy, page 45
4

5 **ISSUE:** Demand Side Management (DSM)
6

7 **QUOTE:** From page 5-23 of the Application:
8

9 “Since that determination the Yukon Government has put in place a
10 Climate Change policy initiative called “Our Clean Future: A Yukon
11 Strategy for Climate Change, Energy and a Green Economy” which
12 emphasizes the importance of DSM as a valuable resource to reduce
13 the Yukon’s energy and capacity requirements. As part of that policy
14 the government fully expects YEC to pursue a cost-effective DSM
15 program.” (footnote removed)
16

17 From page 45 of Our Clean Future: A Yukon Strategy for Climate
18 Change, Energy and a Green Economy:
19

20 **“ACTIONS**

21 H26. Provide direction to the Yukon Utilities Board in 2020 to allow
22 Yukon’s public utilities to partner with the Government of Yukon to
23 pursue cost-effective demand-side management measures (YDC)
24

25 H27. Establish a partnership between the Government of Yukon, YEC
26 Corporation and ATCO Electric Yukon by 2021 that will collaborate on
27 the delivery of energy and capacity demand-side management
28 programs (EMR & YEC)”
29

30 **QUESTION:**
31

- 32 a) Please provide copies of any written communication from the Yukon Government
33 directing YEC to deliver DSM programs.
34
- 35 b) Please provide references to any act, regulation or order in council since the Board
36 issued Order 2018-10 directing YEC to deliver DSM programs or directing the
37 Board to allow YEC to recover the costs of such programs through its rates.

1 **ANSWER:**

2

3 **(a) and (b)**

4

5 Please see OIC 2021-16 which added section 10 to OIC 1995/90, and response to YUB-
6 YEC-1-46 (a to f).

1 **REFERENCE:** Application, Tab 5.3.1.2, page 5-24, line 18

2
3 **ISSUE:** Pilot DSM Program

4
5 **QUOTE:** "YEC faces a capacity shortage under the single contingency (N-1)
6 planning criterion. With this capacity planning context, and mindful of
7 the policy context outlined in the Yukon Government's Climate change
8 strategy, YEC has pursued a pilot program testing internet connected,
9 wifi enabled demand response technology designed to control
10 residential baseboard and hot water heating during winter peak periods
11 to help reduce system peak and reduce reliance on thermal generation
12 such as diesel or natural gas.

13
14 The objective of the program is to: evaluate the technical feasibility of
15 the demand response technology; model and test the peak shifting
16 effect of the pilot; test the reliability of the peak shifting effects of the
17 pilot; and evaluate customer acceptance of the demand response
18 events.

19
20 The project is managed by YEC with funding support from Atco Electric
21 Yukon (AEY), Yukon Development Corporation (YDC) and Natural
22 Resources Canada (NRCan). Project expenditures of \$0.809 million
23 (\$0.434 million in 2019 and \$0.375 million in 2020) are to be included
24 in rate base, offset by contributions of \$0.365 million in 2019, are
25 amortized over 10 years."

26
27 **QUESTION:**

28
29 a) Please provide a detailed description of the components of this pilot project. For
30 example, in which areas of Yukon is the project being conducted, and how many
31 customers are included in the pilot? Please provide the forecasted and actual costs
32 to date allocated to each component.

33
34 b) Please provide details of the funding amounts provided by AEY, YDC and NRCan,
35 including a description of how YEC and AEY determined the relative amounts to
36 be contributed by each party.

1 c) Please provide the information and assumptions on which this pilot project is
2 based, including but not limited to:

- 3 i. quantity of and electrical demand of the installed water heaters;
4
5 ii. percentage of water heaters that could be taking part in the final project;
6
7 iii. estimated demand of the water heaters during peak demand periods;
8
9 iv. average lifespan of water heaters being used in the pilot program
10 compared to the typical household water heater;
11
12 v. the cost of the equipment, including installation cost, included in the pilot;
13
14 vi. description of any incentives offered to the participating ratepayers;
15
16 vii. potential security concerns for participants' wireless internet systems
17 and measures being implemented to address those concerns; and
18
19 viii. estimated frequency and duration of disconnections or service calls
20 resulting from the new equipment and YEC's proposed measures to
21 manage such events.
22

23 d) Please provide any analysis carried out by YEC or its program partners comparing
24 the proposed program to direct incentives paid to customers who take their own
25 steps to reduce demand or shift peak demand. If no such analysis has been done,
26 please explain why.
27

28 e) Please provide the results of analysis performed by YEC or its program partners
29 examining the costs and benefits of the project relative to any alternatives
30 considered.
31

32 **ANSWER:**
33

34 **(a)**
35

36 The Residential Demand Response Pilot will install internet-connected, wifi-enabled
37 electric baseboard thermostats and hot water tank controllers in the homes of residential

1 electrical customers anywhere on the Yukon Integrated System. The thermostats and hot
2 water tank controllers will be used to temporarily lower the temperature set-point of the
3 homes heat and hot water during a period of peak demand to lower the demand on the
4 grid.

5
6 1000 thermostats and 400 hot water tank controllers will be installed as part of the pilot
7 across 400 Yukon residences.

8 The actual costs to the end of 2020 are \$269K in equipment, \$149K in labour, \$512 in
9 professional services and \$8K in expenses. The forecast remaining costs to complete the
10 pilot are \$68K labour and \$414 professional services, including ongoing licensing and
11 support.

12
13 **(b)**

14
15 AEY is providing \$300,000, YDC is providing \$250,000 and NRCan is providing \$650,000.
16 The funding amounts with AEY and YDC were reached through discussion with these
17 organizations. NRCan offers up to 50% of eligible costs in for the demonstration stream
18 of their Smart Grid funding stream.

19
20 **(c)**

21
22 **(i)**

23
24 Controllers are being installed on 400 hot water tanks as part of this pilot. The electrical
25 demand of a standard residential hot water tank is estimated to be an average of
26 4.5kW/unit.

27
28 **(ii)**

29
30 No projection has been made as to how many total hot water tanks could take part if this
31 pilot is transitioned into a full program.

32
33 **(iii)**

34
35 As the heating elements of the 400 hot water tanks participating in the pilot are at various
36 stages of heating, it is assumed that these tanks would contribute 400kW to the peak
37 demand (1kW/unit).

1 **(iv)**

2
3 Controllers are being installed on customers' existing typical hot water tanks. Accordingly,
4 the average lifespan of the hot water tanks in the program are the same as a typical hot
5 water tank. YEC does not have detailed data on this expected lifespan at this time.
6

7 **(v)**

8
9 The total cost of equipment for this pilot is \$269,000 and installation costs are \$134,000.
10

11 **(vi)**

12
13 There are no financial incentives being paid to participants of the pilot.
14

15 **(vii)**

16
17 There was a potential security concern that records of a participant's hot water use and
18 heating could be accessed and constitute a personal privacy breach. For this reason, the
19 supplier of the controllers used in the pilot program were evaluated on the cyber security
20 of their systems and care has been taken to protect any personal information of
21 participants in the program design.
22

23 **(viii)**

24
25 It is expected that service calls or disconnections of a customer's heating or hot water are
26 extremely infrequent. In the case that a participant experiences a heating or hot water
27 emergency, a local electrical contractor is kept on retainer to respond. Participants are
28 provided with the contractor's contact information as part of the program.
29

30 **(d)**

31
32 This particular pilot was pursued by YEC due to the funding opportunities from NRCAN,
33 AEY and YDC largely offsetting the program costs, enabling learnings from the pilot to be
34 applied to future DSM programs at far less than the full project cost. The analysis and
35 design of other DSM programs, such as direct incentives to customers, will now be
36 advanced given OIC 2021/16 directions enabling YEC to recover through rates the costs
37 reasonably incurred to provide or participate in a demand side management program.

1 **(e)**

2

3 YEC has not performed any analysis of this project relative to alternatives. As discussed
4 in (d) this pilot was pursued as funding was available to do so.

1 **REFERENCE:** Application, Tab 5.3.1.2, page 5-25, line 9

2
3 **ISSUE:** LED Streetlight Retrofit Program

4
5 **QUOTE:** "In addition to the program's specifically developed in response to the
6 Yukon Governments Climate Change initiative, the Board also noted in
7 Order 2018-10 (Para 481) that it "considers that retrofitting streetlights
8 at end of life with LED lights were prudent expenditures. Any LED
9 installations that are not end-of-life conversions must not be included in
10 YEC's rate base." The 2017/18 GRA outlined the basis for the LED
11 Streetlight Replacement program noting that YEC decided to move
12 forward with the retrofit of streetlight assets with LEDs. Streetlights in
13 downtown Dawson and Mayo were retrofit in 2016 with plans to retrofit
14 the remaining streetlights in Faro, Mendenhall and Champagne in
15 2018. As illustrated in Table 5.3, \$0.273 million was added to rate base
16 in 2018." (footnote removed)

17
18 **QUESTION:**

- 19
20 a) Please confirm that all costs added to rate base in 2018 for LED streetlight retrofits
21 were for retrofitting streetlights that were at end of life. If not confirmed, please
22 explain.
23
24 b) If part (a) is not confirmed, please separate the \$0.273 million into amounts for
25 end-of-life retrofitting and retrofitting of streetlights that were not at end of life.
26
27 c) Please confirm that YEC has not added any amounts to rate base for streetlight
28 retrofitting in 2019 and 2020 and does not propose to do so in 2021. If not
29 confirmed, please explain.
30
31 d) Are there any remaining streetlights that have not been retrofitted to LEDs? If so,
32 please estimate the percentage of streetlights that have not been retrofitted, the
33 cost of retrofitting the remaining streetlights, and outline YEC's planned timeline
34 for doing so.

1 **ANSWER:**

2
3 **(a) and (b)**

4
5 For clarity, the transfer to rate base in 2018 for \$0.273 million was not all related to the
6 streetlight replacement program. The costs breakdown further as follows:

8	inCharge Program Delivery	\$0.180
9	Streetlight Change Outs	<u>\$0.093</u>
10		<u>\$0.273</u>

11
12 inCharge program delivery is the cost to deliver the programs approved by the YUB in
13 Order 2014-06. As a historical DSM cost, this amount will be written off the accounts of
14 YEC and ratepayers will bear no burden.

15
16 Not all of the streetlights retrofit were end-end-of-life. As described in response to YUB-
17 YEC-1-81 in the 2017/18 GRA, YEC believes these assets are at or near end of life. This
18 is assumed as the majority of the asset value is historical cost transferred by community
19 i.e. YEC has no visibility on the value of the lamp head separate from the rest of the
20 structure – pole, wiring, civil improvements, etc. Based on past experience with installation
21 costs, YEC estimates \$0.006 million in undepreciated capital costs from streetlights
22 replaced. YEC proposes to write off this amount from the streetlight PP&E accounts.

23
24 **(c)**

25
26 Costs were added in 2020 for the environmental disposal of the old HPS streetlight heads
27 (\$0.008 million).

28
29 **(d)**

30
31 There are some high-powered highway lights that have not been retrofit. These lights
32 were not retrofit as the business case of the energy savings did not justify the LEDs
33 required for this application.

1 **REFERENCE:** Application, Tab 5.3.2, page 5-26, line 15; Appendix A to Board
2 Order 2018-10: Reasons for Decision, paragraphs 515 and 516
3

4 **ISSUE:** Deferred Costs for Projects Between \$100,000 and \$1 Million
5

6 **QUOTE:** From Application page 5-26:
7

8 "Mayo and Aishihik Hydro Climate Change Study (\$0.638 million in
9 2020 for expenditures from 2017 to 2020)..."
10

11 "Transmission Access Road Program Study (\$0.133 million in 2020 and
12 \$0.200 million in 2021)..."
13

14 From Appendix A to Board Order 2018-10:
15

16 "515. For the Mayo and Aishihik climate change study, YEC spent
17 \$121,530 prior to 2017 and forecast \$160,000 for each of 2017 and
18 2018. This project will deliver research and modelling to better
19 understand how climate change will impact the Aishihik and Mayo
20 drainages to help inform inputs to YEC's generation model..."
21

22 516. In response to a UCG IR, YEC indicated that the 35 years of data
23 inflows into YECSIM reflect what was recorded over the 35 years,
24 including any climate change impacts relevant to those years. Given
25 YEC's statement that its YECSIM model includes climate change
26 impacts, the Board finds that YEC has not adequately demonstrated
27 that it is necessary to engage in a separate study specifically on climate
28 change impacts. Accordingly, the Board finds there is no justification
29 for this project and directs YEC to remove these costs from its revenue
30 requirement for each of 2017 and 2018 and not recover the 2016 costs.
31 The Board directs YEC further to reflect this finding in its compliance
32 filing." (emphasis added; footnotes removed)
33

34 **QUESTION:**
35

- 36 a) Please justify the costs for the Mayo and Aishihik Hydro Climate Change Study in
37 this application, given that the Board directed YEC to remove costs associated

1 with studies on climate change impact in the previous application. Why should the
2 \$0.638 million incurred for this study be approved and put into rate base?

3

4 b) Please provide a breakdown of the \$0.333 million incurred for the Transmission
5 Access Road Program Study. More specifically, please provide the activities
6 conducted by YEC and the cost allocated to each activity.

7

8 **ANSWER:**

9

10 **(a)**

11

12 The Mayo and Aishihik Climate Change Study as concluded in 2020 was required to
13 develop an understanding of future climate change impacts on YEC's hydrological system
14 and its hydroelectric generation.

15

16 Costs incurred on this project were not included in 2017-18 forecast revenue requirement
17 or rates (i.e., YEC forecast in that application that these costs would remain in WIP).

18

19 Now that these costs are included in the forecast revenue requirement under the present
20 application it is important to emphasize why this study is crucial to YEC's understanding
21 of how its hydro facilities may be impacted by climate change. The information before the
22 Board in Order 2018-10 did not adequately reflect why YEC pursued this study.

23

24 At a strategic level, Canadian utilities have focused significant attention on understanding
25 the potential long-term impacts of climate change on energy supply, and also on
26 developing strategies to adapt to the expected impacts of climate change in order to
27 mitigate potential impacts to utility operations and ratepayers. As an example, a key
28 requirement of the Canadian Electricity Association's *Sustainable Electricity Company*
29 designation, which YEC achieved in 2016, is the development of a utility-specific climate
30 change adaptation plan. As a hydro-based utility, YEC's focus is first to understand the
31 expected long term impact of Climate Change on its hydro resources, which it critical to
32 long term resource planning, risk mitigation and the development of any required
33 adaptation plans.

1 In Board Order 2018-10, the Board stated:

2
3 “YEC indicated that the 35 years of data inflows into YECSIM reflect what was
4 recorded over the 35 years, including any climate change impacts relevant to those
5 years. Given YEC’s statement that its YECSIM model includes climate change
6 impacts, the Board finds that YEC has not adequately demonstrated that it is
7 necessary to engage in a separate study specifically on climate change impacts.”
8

9 The YECSIM model data only reflects any impacts due to climate change observed to
10 date by incorporating 35 years of actual historical data. However, the model does not
11 predict or account for the expected future impact of climate change on the inflows. Further,
12 as the timing of impacts of climate change can vary, a 35-year historical dataset does not
13 necessarily adequately reflect the near-term impacts to be expected from climate change.
14

15 The future impact of climate change includes changes in the expected amount of
16 precipitation (rain and snow), as well as the impact of glacier melt on the hydrological
17 systems. These impacts directly affect the expected long-term water availability for
18 hydroelectric generation. This is a key assumption for long-term resource planning. The
19 future effects of climate change on hydro availability is a critical variable to evaluate when
20 conducting long-term resource planning for the Yukon Interconnected System. Further,
21 understanding the potential range of event severity due to climate variability is critical for
22 understanding future impacts to system reliability and generation availability.
23

24 The project scope included development of a supplemental model, Hydrotel, which
25 produces inflow forecasts that incorporate not only historical actual data, but also future
26 climate change predictions. These predictions can be used in conjunction with YECSIM
27 to understand the long-term generation limitations or behaviour due to future climate
28 change impacts. The project scope was also updated to include an assessment of climate
29 change and glacial melt impact on the Upper Yukon River, enabling the Hydrotel model to
30 be used to forecast expected climate change impacts on all three of YEC’s hydroelectric
31 generation facilities.
32

33 The project was also partially funded by NSERC, which lessened the costs incurred by
34 YEC to achieve the project objectives.

1 (b)

2
3 The Transmission Access Road Program Study includes the following key phases of
4 activities:

- 5
6 1. Phase 1 activities were focused on completion of a desktop GIS study;
7
8 2. Phase 2 activities will focus on field work to confirm the findings of the desktop
9 study undertaken in Phase 1; and
10
11 3. Phase 3 includes final reporting to tie the results of desktop GIS study and
12 subsequent field work together.
13

14 Phase 1 activities were completed by Tetra Tech in 2020 at a total cost of \$87,526. Phase
15 2 and Phase 3 activities planned for 2021 have been deferred to 2022.

1 **REFERENCE:** Application, Tab 5.4.1.1, page 5-28, line 11 and page 5-30, line 10

2
3 **ISSUE:** Enterprise Asset Management (EAM) System Purchase and
4 Implementation Project

5
6 **QUOTE:** “YEC is undertaking a multi-year process to develop and implement a
7 formal Physical Asset Management Managed System (PAMMS) that
8 will align its practices with the ISO 55000 standard for physical asset
9 management (see Appendix 5.1 for further details on the Asset
10 Management Framework). A key part of the PAMMS initiative is the
11 selection and implementation of an Enterprise Asset Management
12 (EAM) solution suited to the needs of the company. (footnote removed)

13
14 The existing Computerized Maintenance Management System
15 (CMMS) does not meet YEC’s current or future asset management
16 needs. An EAM system is an enterprise level software application that
17 enables an organization – particularly an asset intensive organization
18 – to manage and optimize its assets throughout the entire asset
19 lifecycle including asset needs identification, asset investment planning
20 and prioritization, advanced asset maintenance management and
21 asset performance tracking.” (page 5-28)

22
23 “Total costs to complete the project are currently estimated at \$4.938
24 million. The project is expected to be fully implemented in early 2021.”
25 (page 5-30)

26
27 **QUESTION:**

- 28
29 a) Please provide a business case for the enterprise asset management system
30 project, including the cost benefit analysis that could be used for a performance
31 measure.
32
33 b) Please explain why the existing Computerized Maintenance Management System
34 does not meet YEC’s current or future asset management needs.
35
36 c) Please provide a cost breakdown of the \$4.938 million estimated, specifically the
37 activity that will be completed and the cost amount allocated to that activity.

1 d) Please explain if any other alternatives were explored by YEC in meeting its asset
2 management needs and, if so, provide the costs of those alternatives.

3
4 e) Please provide an update on the work currently completed for this project. Is YEC
5 currently on schedule with this project?

6
7 **ANSWER:**

8
9 **(a)**

10
11 The average estimated NPV for the EAM project is \$2.87 million over a period of 10 years.¹
12 A detailed NPV analysis is provided as Attachment 1 to this response.² Savings from
13 anticipated tangible benefits are as summarized in the table below. A description of
14 tangible and intangible benefits of the Project are summarized in the discussion that
15 follows.

¹ Assuming weighted average cost of capital of 4.82%; inflation rate of 2.0%; implementation cost allocation of \$3.56 million in 2020 and \$275,000 in 2021; estimated O&M costs and realized benefits for 10 years from 2021 to 2031, increasing from 2021 onwards from 0% in 2020; 40% in 2021; 80% in 2022 and 100% 2023 onwards.

² The total project cost is \$ 4.6 million. The NPV evaluation used a project cost of \$3.7 million which was at that time the cost looking forward, excluding costs incurred/ committed to date. The increase of \$0.9 million is covered by the NPV result.

Table 1: Anticipated Tangible Benefits Summary

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

Tangible Benefits:

- **Productivity Gains:** 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 industry³ has shown that wrench time can increase between 10 – 40% as a result of improvement in maintenance capabilities that are enabled by an EAM. YEC supervisors in respective groups estimate a 10 – 15% productivity improvement for electrical technicians and a 15 – 20% improvement for mechanical technicians. YEC estimates a productivity improvement range of 12 – 25% once all asset classes are fully deployed in the EAM by the end of 2021.
- **Improved Inventory Management and Procurement:** Because of integration of work with material requirements, better inventory visibility will result in forward planning of work and materials will enable YEC to source materials with longer lead times taking advantage of existing contractual agreements that are in place. Other electric utilities have estimated savings of 0.5 - 3% as a result of better contract management for purchases.

³ Source: Booz & Company.

- 1 • **Improved Reliability – Extended Asset Life:** The use of an EAM system for
2 planned maintenance requirements and scheduling can extend asset life and
3 maintain a record of asset health. Organizations that have implemented EAM have
4 reported reductions in long term asset costs of up to 5% by extending asset life.
5 YEC is estimating an expected improvement of 2 – 3% on useful asset life as a
6 result of asset life optimization.
7
- 8 • **Improved Reliability – Reduced Diesel Consumption:** Improved asset
9 maintenance practices are expected to result in reduced outages and therefore a
10 reduction in thermal consumption for backup power during restorations. A
11 reduction of 20 – 30% in controllable outages and related thermal costs could be
12 realized.
13
- 14 • **Improved Reliability – Revenue Recovery:** Utilizing the EAM to enable improved
15 preventative maintenance before the point of asset failure is expected to reduce
16 controllable outage events that cause customers to lose power, by 20 – 30%. This
17 will result in additional revenue from the sale of energy otherwise not delivered.
18
- 19 • **Warranty Claims:** The EAM will record and track warranty periods for assets and
20 parts that are placed into service. Should installed assets or parts require
21 corrective work orders, the EAM will flag when those parts are still under warranty,
22 and eligible for a warranty claim reimbursement. This is expected to increase
23 successful warranty claims by 100 – 200%.
24

25 **Intangible Benefits:**

- 26
- 27 • **Process Improvement – Standardized Processes:** The EAM standardizes
28 workflows, processes, and procedures related to the entire asset lifecycle;
29 transitioning this knowledge from individuals into institutional knowledge retention.
30 Particularly valuable is knowledge related to proactive maintenance strategies.
31
- 32 • **Availability and Retention of Information:** The EAM will improve access and
33 availability of information (ad hoc and personal documents, corporate documents,
34 etc.), gathered from currently disparate locations into an organized 'single source
35 of truth'.

- 1 • **Contributions to Safety:** Safety procedures can be attached to work orders;
2 ensuring recorded completion of Job Safety Analysis (JSA) procedures and forms,
3 all contributing to a reduced risk of injury.
4
- 5 • **Improved Decision Making:** Improved access to detailed, complete data sets on
6 the assets of the Corporation, which can inform better decision making.
7
- 8 • **Increased Compliance with Regulatory Requirements:** The EAM will serve as
9 the system of record for compliance work fulfilling regulatory requirements. These
10 centralized data sets can be queried for trends or data points that support YEC's
11 rate applications. The EAM will unlock a holistic view of capital projects that will
12 better inform and justify deferral and renewals.
13
- 14 • **Improved Accountability:** Transparent workflows enable simple work order
15 delegation, and managers can easily track the status of work orders. This improves
16 accountability and supports quality control audits.
17
- 18 • **Increased Accuracy in Performance Measurement:** Enabling management to
19 track and report on various performance measures, and trends over time. High
20 value reports can be consolidated into dashboards tailored by audience.
21

22 **(b)**
23

24 While YEC's current CMMS allows YEC to track cost and raise reactive work orders, it
25 has significant shortcomings and is not capable of planning and executing planned
26 preventative maintenance work requiring coordinated scheduling of materials and labour
27 requirements, tracking asset condition and criticality, nor does it support the end worker
28 by making equipment records and history easily available.
29

30 In 2017, a preliminary market study and RFI were carried out by YEC and Hatch. To
31 assess suitability of Key2Act's (YECs existing CMMS) to support YEC's long term
32 strategic needs, Key2Act was invited to complete the RFI that was distributed to the other
33 viable vendors. As noted, the self-assessment requests that the vendors confirm and
34 demonstrate compliance to a series of functional requirements by answering yes/no and
35 providing details on how their solution addresses each requirement. While Key2Act did
36 not explicitly answer No to any questions, they did leave 14/44 responses blank, citing
37 reasons such as "possibly with configuration" and "likely through customization" with no

1 additional detail. Specifically, Key2Act was unable to confirm compliance to the following
2 functional requirements detailed in Attachment 1 to this response: F1, F2, F5, F15, F17,
3 F18, F19, F20, F22, F25, F36, F39, F43, and F44.

4
5 When contrasted with the other vendor responses which provided substantial detail as to
6 how they would address each requirement, Key2Act's responses illustrate a lack of
7 understanding of this domain.

8
9 Additionally, interviews were held with YECs operational, engineering, and IT staff in which
10 they were asked about their experiences with Key2Act. The interviews identified that the
11 solution falls short of meeting YEC's current requirements which has resulted in the
12 development of several stop-gap in-house solutions, and significant duplication of effort.
13 It was also identified that the YEC staff have no confidence in Key2Act's ability to enhance
14 their system to meet YEC's needs.

15
16 Based on the results of the self-assessment and the interviews with YEC staff, it was
17 apparent that the Key2Act solution was not only incapable of supporting YEC's long term
18 strategic objectives but that it is also not meeting their current operational needs. For this
19 reason, Key2Act was not invited to submit costing to enhance their system to meet YEC's
20 needs nor were they asked to participate in the solution demonstrations.

21
22 **(c)**

23
24 Please see Table 1 below for a breakdown of EAM costs.

Table 1: EAM Implementation Cost Breakdown

Cost Item	Forecast at Completion (\$million)
Vendor Selection & Project Initiation	0.809
Application Software Licences	0.578
System Implementation	1.575
Hardware and Facilities	0.390
Internal Resources	0.462
Additional Data Loading (2021)	0.250
Change Management	0.114
Project Management	0.340
Subtotal	4.518
Contingency	0.118
Total Project costs	\$4.636

Note there is a \$0.302 million variance from the GRA forecast of \$4.93 million. This is due to an error in the GRA forecast for this project.

(d)

Yes. Other software alternatives were explored. A preliminary market survey of EAM solutions was conducted in 2017. An RFI was distributed to 27 vendors in order to better understand the costs associated with implementation and integration.

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.

(e)

YEC is expecting to go live with the EAM project on March 15, 2021. YEC is currently on schedule with this project.

APPENDIX D – DETAILED NET PRESENT VALUE ANALYSIS

NPV Analysis of EAM Deployment

Assumptions

Year 1 Implementation %	80%
Year 2 Implementation %	20%
Year 1 Benefits Captured	40%
Year 2 Benefits Captured	80%
Year 3 Benefits Captured	100%
Year 4 and beyond	100%
IRR	4.82%
Inflation %	2%

	NPV	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Costs													
One Time Implementation	(\$3,646,589)	(\$3,560,000)	(\$275,000)										
On-going Support	(\$1,528,024)		(\$166,260)	(\$169,585)	(\$172,977)	(\$176,436)	(\$179,965)	(\$183,564)	(\$187,236)	(\$190,980)	(\$194,800)	(\$198,696)	(\$202,670)
Total Costs	(\$5,174,613)	(\$3,560,000)	(\$441,260)	(\$169,585)	(\$172,977)	(\$176,436)	(\$179,965)	(\$183,564)	(\$187,236)	(\$190,980)	(\$194,800)	(\$198,696)	(\$202,670)
Benefits													
Low Estimated Benefits	\$5,597,013		\$ 265,498	\$ 541,615	\$ 690,559	\$ 704,370	\$ 718,458	\$ 732,827	\$ 747,483	\$ 762,433	\$ 777,682	\$ 793,235	\$ 809,100
Average Estimated Benefits	\$8,049,074		\$ 381,812	\$778,897	\$993,094	\$1,012,956	\$1,033,215	\$1,053,879	\$1,074,957	\$1,096,456	\$1,118,385	\$1,140,753	\$1,163,568
High Estimated Benefits	\$10,501,135		\$ 498,127	\$ 1,016,180	\$ 1,295,629	\$ 1,321,542	\$ 1,347,973	\$ 1,374,932	\$ 1,402,431	\$ 1,430,479	\$ 1,459,089	\$ 1,488,271	\$ 1,518,036
Costs - Benefits													
Low Estimate Cost Benefit	\$422,400	(\$3,560,000)	(\$175,762)	\$372,030	\$517,582	\$527,934	\$538,492	\$549,262	\$560,248	\$571,453	\$582,882	\$594,539	\$606,430
Average Estimate Cost Benefit	\$2,874,461	(\$3,560,000)	(\$59,448)	\$609,312	\$820,117	\$836,520	\$853,250	\$870,315	\$887,721	\$905,476	\$923,585	\$942,057	\$960,898
High Estimate Cost Benefit	\$5,326,522	(\$3,560,000)	\$56,867	\$846,595	\$1,122,652	\$1,145,105	\$1,168,008	\$1,191,368	\$1,215,195	\$1,239,499	\$1,264,289	\$1,289,575	\$1,315,366

Figure 1: 10 Year Cost Benefits Projection for EAM Project

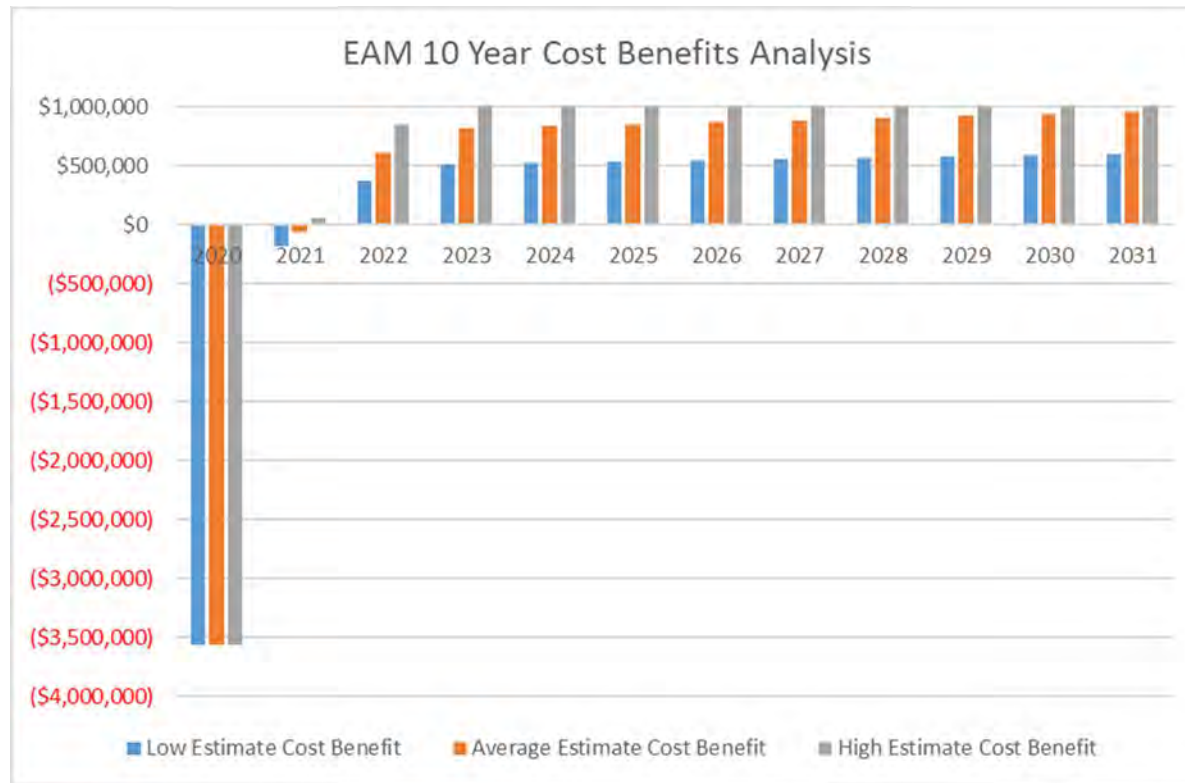


Table 4-1: Functional Requirements

#	Requirement	Description
F1	Alignment with ISO55000, 55001, and 55002	The system should be capable of managing the assets from concept to disposal.
F2	Base CMMS Functionality	The system should be capable of performing the basic maintenance functions for work order planning, execution, closing, and history.
F3	Asset Register	The system should provide a robust asset register.
F4	Critical Asset Identification	The system should enable the assignment of criticality to equipment to be used for prioritization.
F5	Management of Change (MoC) capabilities	The system should be capable of tracking and recording all changes made to equipment, procedures, and work orders by user and time stamp.
F6	Pending work back log	The system should be capable of monitoring the backlog of work to allow for prioritization of scheduling, and to make sure no high priority work is missed.
F7	ContractorProject Work Management	The system should be capable of supporting projects: tracking for schedule, costs and completion as well as history.
F8	KPIs and Reports	The system should support any required reports or KPIs.
F9	Material and Procurement Management	The system should be capable of performing Material management and procurement or integrating with existing systems.
F10	InventorySpares management	The system should be capable of tracking and managing inventory (and spares) as well as attaching parts to work orders and setting levels and allowing automatic reordering.
F11	Mobile Device Support	The system should have a robust mobile device capability to allow execution of work and recording of all required details by the technicians using it.
F12	Standard jobs & task lists	The system should enable common, repeated tasks (either PM or common repairs) to be created and saved including parts and special requirements then can be used when work is required without the need to keep recreating it.
F13	Reliability and related analysis	The system should be capable of tracking and storing the information required to perform reliability analysis.
F14	Asset Equipment History	The system should track all equipment history, work completed, schedule, and costs (for use with reliability and budgeting).
F15	Compatibility with condition monitoring system	The system should be capable of performing condition monitoring through Scada and others systems, with the ability use this information for reliability, and schedule generation.
F16	Manage PM and PdM work procedures	The system should support PM and PdM work procedures (and association to work orders).
F17	PM optimization including Reliability Analysis	The system should be capable of tracking the history of the PMs so it can be analyzed to see if the right work is being done at the right time.

#	Requirement	Description
F18	Support for failure modes and effects analysis (FMEA) and reliability centered maintenance (RCM)	The system should support FMEA and RCM or provide a mechanism to import these analyses from external sources for inclusion in reliability work.
F19	Track and differentiate non-recurring work failures and break downs	The system should monitor break in or break down work for use in reliability analysis.
F20	Track corrective maintenance results against PM and CBM	The system should be capable of tracking corrective maintenance results vs PM and CBM. This is used for PM optimization to ensure the right work is being created by the PM and PdM work orders. If the PM and PdM is being done but no corrective work is being generated these PMs and PdM may need to be adjusted.
F21	Track recurring work types - PM and PdM	The system should be capable of tracking recurring work types. This is used for the reliability functions of the PMs and PdMs. May signal a need for deeper investigation like RCM.
F22	Support for Asset Health Index Calculations	The system should be capable of using the RCA, FMEA and history to provide assets health index calculations.
F23	Work Order Management	Break out of CMMS function
F24	Work Close Out and Feed Back	Break out of CMMS function
F25	Work Order Routing	Break out of CMMS function
F26	Work Planning	Break out of CMMS function
F27	Work Scheduling and Resource Balancing	Break out of CMMS function
F28	Document Management	The system should provide a mechanism for attaching and managing documents. This can be through integration with external document management systems or native functionality within the system.
F29	Decision Analytics	This is part of the reliability functions and IDS functions. The reliability side can predict the life of the equipment and repairs will need to be made. This is information that will also be used by and IDS function to calculate costing.
F30	Asset and project views for business cases for both asset-based and needs-based projects	Part of the decision analytics
F31	Configurable for workflows, policies and processes	This requirement is to ensure the IDS system can facilitate the workflows for approvals and execution to align with the policies and processes of the organization.
F32	Ease of integration	This requirement is to ensure the IDS system can be integrated with the organizations other systems e.g. Finance.
F33	Method of "What if" analysis for investment analysis	The system should provide a mechanism for performing What-if analysis and scenario generation for investment and maintenance decisions.
F34	Asset management planning tools/approach	The system should provide all of the required tools for asset planning through its entire life cycle.
F35	System Architecture options	This requirement aims to establish the vendor solution systems architecture to ensure compatibility with other systems in the organization.
F36	Risk calculation evaluation	The system should support reliability and risk calculations, and analysis
F37	Ease of Customization	The system should be easily configured (and re-configured) to meet the organization's needs.
F38	Ease of use: implementation effort	This requirement aims to understand the effort involved in implementing the system.

#	Requirement	Description
F39	Hardware Support (if applicable)	This requirement aims to establish whether hardware support is part of the offering.
F40	Reporting and Ad-hoc Queries	The system should be support ad-hoc reporting and analytics.
F41	User Customizable Dashboards	The system should support user configurable dashboards.
F42	Financial Software Integration	The system should be capable of integrating with the existing financial information system.
F43	GIS Software Integration	The system should provide a mechanism to overlay EAM data on a GIS layer (through integration or native functionality).
F44	Scada Software Integration	The system should be capable of integrating with the existing Scada system.

REFERENCE: Application, Appendices 5.1 to 5.6

ISSUE: Forecasted Dates Provided for Projects and Studies in These Appendices

PREAMBLE: In the descriptions for the projects and studies, YEC provided the forecasted completion date. For example, YEC indicated that the forecasted completion date for the Dawson Voltage Conversion was 2022.

QUESTION:

- a) For each project or study mentioned in Appendices 5.1 to 5.6, please indicate whether it is still viable for completion on the forecasted date. If not, please explain the reasons for delays on projects.

ANSWER:

(a)

Please see the summary provided below.

Table 1: Summary of projects/ Studies in Appendix 5.1 to Appendix 5.6

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
Appendix 5.1: Capital Projects >\$1 M Not Impacting Rate Base			
Dawson Voltage Conversion	2023/24	Yes	2020 and 2021 and 2022 are planning years due to significant amount of outages required and project complexity. We expect the project to be in service in 2023
MHO (Mayo A) Generating Station Slope Stability	2022	No	This project will be completed in 2023 as part of a suite of projects to take advantage of mobilization and demobilization costs as well as other synergies that exist.
Replacement of Mayo A Surge Chamber	2023	Yes	

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
Stop Log Crane WH Main Spillway	2022	Yes	
Asset Management framework	2022	Yes	
Battery Energy Storage System	2022	Yes	
Pumped Storage	2028	No	Monitoring activities 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.
Southern lake transmission line	2028	Yes	
Whitehorse Interconnection	2022	Yes	
Appendix 5.2: Capital Projects >\$100,000 and <\$1 M Added to Rate Base			
Dam Safety Program	2021	Yes	
Dam Safety Recommendations	2019, 2020	2019 Yes, 2020 No	As a result of the high water levels, work identified could not be completed. The work will be reprioritized and included in the 2021 DSR action plan.
P126 Boil off gas heat exchanger	2019	Yes	Completed
Wareham Gate Heater	2020	Yes	
Wareham Gate Refurbishment	2020	No	Higher than normal water levels in 2020 resulted in this project to be deferred until 2022. Investments to date will be held in WIP through 2021.
Whitehorse Diesel System Grounding for Generators	2020	Yes	
WH1 and WH2 Design and Installation of Dewatering system	2019	Yes	
WH4 Ventilation	2021	No	Engineering will be finalized in 2021 for installation in 2022.
Alexco Mobile Substation	2020	No	Alexco has had delays in selecting substation location and will not receive the substation

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
			until March 2021. This has delayed the in service date.
Line 177 Re Route	2021	Yes	
Minto Mine Substation - NGR	2019	Yes	
Protection and Control Program	2021	Yes	Scope has been reduced in 2021 to allow for additional planning and estimating of activities in 2022 and beyond.
Transmission Line Access	2019, 2020	2019 yes, 2020 No	Activities planned for 2020 were deferred as a result of additional planning required to develop and prioritize the plan moving forward. Activities will resume in 2022. The spending for the project to date will be held in WIP until it is completed.
Van Gorda Substation	2019	Yes	
WAF Transmission Upgrades	2019	Yes	
Customer Extensions	2019, 2020, 2021	Yes	
L355 Voltage Regulator	2020	Yes	
System Improvements for Eagle Gold Mine	2019	Yes	
Communication Upgrades	2019	Yes	
Building Upgrades	2019, 2020	Yes	
Compact Digger Truck	2021	Yes	
Crane Replacement/ Refurbishment	2020, 2021	Yes	
Mayo Earthworks	2020	Please see the note	Preliminary engineering work was done in 2020. Further studies and engineering are required. Also being planned as part of a larger suite of projects to take advantage of synergies and reduce Mob and Demob costs. Any cost spent in 2020 will be held in WIP until the project is completed [potentially in 2022/23].
Mobile Office Unit – IT	2021	Yes	
Vehicle Purchases	2019,2020,2021	Yes	

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
FD7 Overhaul	2021	No	Pricing for overhaul has been significantly higher than expected. Business case being performed in 2021 to determine if replacement is more cost effective than refurbishment. Any spending for 2021 business case will be held in WIP and reflected in GRA compliance filing.
Decommissioning on WD3	2019	Yes	
Site Restoration Transmission Lines	2019	Yes	
Appendix 5.3: Deferred Project >\$1 M Not Added to Rate Base			
Aishihik Generating Station Long Term Year Water Use License Renewal	2022	Yes	
Whitehorse Rapids Generating Station Water Use Licence Renewal	2025	Yes	
Diesel Retirement Replacement	2023/24	Yes	
Southern Lakes Enhanced Storage Project	2023	Yes	
Mayo Lake Storage Enhancement Project – Including Mayo Lake Outlet Dredging	2023	Yes	
Appendix 5.4: Deferred Projects >\$100,000 and <\$1 M Added to Rate Base			
IPP Standing Offer Program Implementation	2019	Yes	
Mt Sumanik Wind Feasibility Studies	2020	Yes	
WH2 uprate Engineering	2021	Yes	
Building Condition Reports 2020-2024	2021	Yes	
Business Continuity Plan	2021	Yes	
Mayo and Aishihik Hydro Climate Change	2020	Yes	

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
PMF Flood Study	2021	Yes	
Transmission Access Road Program Study	2020, 2021	2020 Yes, 2021 No	2020 will be closed separately. The planned additional phases for 2021 have been deferred to 2022/23 and will be in WIP at end of 2021. YEC is looking at a GIS project in the future and want to ensure that the data collected is compatible with the system of choice.
Whitehorse Diesel Rental Substation improvements	2021	Yes	
10-Year Renewable Electricity Plan	2020	Yes	
Atlin Hydro EPA Preparation	2020	No	2021
Dam Safety Review	2020	No	Project will be completed in 2021, impacts from COVID-19 and high water levels prevented completion in 2020. All assessments are completed and drafts reports submitted.
Appendix 5.5: Deferred Studies >\$100,000 <\$1 M Not Impacting Rate Base			
EV Infrastructure Project	>2021	Not specified	Given the delays in the rollout of the electric vehicles contemplated in Yukon Government's strategy from the original draft in November 2019, the project is not required to be completed in 2021 and has been delayed.
P125 Trash rack Study	2021	No	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
Appendix 5.6: Intangible Assets >\$100,00 <\$1 M Added To Rate Base			
ERP System Upgrades	2020	Yes	

1 **REFERENCE:** Application, Appendix 5.1-1, page 5.1-2

2
3 **ISSUE:** Dawson Voltage Conversion Project

4
5 **QUOTE:** "Dawson City's two 4.16 kV distribution feeders have reached their
6 practical operating limits, resulting in frequent power outages, constant
7 voltage flicker, and longer fault clearing times. Teshmont Consultants
8 LP conducted a site visit to assess the entire 4.16 kV distribution
9 system to identify protection issues, potential voltage levels,
10 transformer utilization and power flow. The primary issues facing the
11 Dawson distribution system were noted as follows ..."

12
13 "Teshmont recommended converting the operating voltage of the
14 Dawson City distribution system from 4.16 kV to 12.47 kV in a single
15 stage. Increasing the voltage immediately improves the capacity on the
16 existing conductors, reduces fault current at the primary, reduces
17 voltage drops and decreases energy losses."

18
19 **QUESTION:**

- 20
21 a) Please indicate the year in which these two feeders were installed and the
22 expected service life of the feeders at the time installation.
23
24 b) Please explain how often YEC carried out tests on these feeders in the past to
25 assess their reliability and how often maintenance work was required. If possible,
26 please provide the number of times maintenance was conducted on these feeders
27 in the last 10 years, on a per annum basis, and the cost of this maintenance work.
28
29 c) Please provide the number and duration of outages resulting from the two Dawson
30 City distribution feeders for each of the last 10 years, on a per annum basis, and
31 the costs incurred due to these outages.
32
33 d) Please provide the assessments conducted by Teshmont Consultants LP. Were
34 any other alternatives explored for mitigating the issues on the Dawson distribution
35 system?

ANSWER

(a)

The F1 Breaker was installed in 1978; and the F2 breaker was installed in 1976. The expected service life is 40 years for the wire, pole and insulators.

(b)

These breakers receive 10 year inspections. The estimated cost is \$3,500 for this testing. The other feeder assets (i.e., transformers, poles) are typically run to failure. It is noted that studies and engineering are continuing in 2021 and 2022 that will include further data collection and analysis to support the project justification. The project will not be in service until 2023.

(c)

Attachment 1 to this response provides the outage list for F1 and F2. Table 1 below summarizes the total number of outages and duration.

Table 1: Number and Duration of Outages

Year	Total Outages	Outage Hours
2011	8	4.36
2012	11	2.87
2013	12	26.95
2014	7	2.46
2015	20	10.43
2016	12	5.31
2017	21	11.59
2018	9	6.96
2019	25	26.46
2020	19	11.34
	144	108.73

Cost associated with the individual outages would be onerous. Studies and engineering are continuing in 2021 and 2022 that will include further data collection and analysis to support the project justification. The project is not planned to be in service until 2023.

27 (d)

28
29 Please see Attachment 1 to this response for the assessment provided by Teshmont LP.

30
31 The Dawson Voltage conversion project is set to be in-service in 2023. Temporary
32 measures have been implemented such as increasing the breaker trip settings and fuse
33 sizes, which leads the system to experience different types of issues such as brownouts.
34 An interim solution has been implemented which includes a partial voltage conversion to
35 12.47 kV which has relieved the load on Dome area. A voltage conversion to 24.94 kV
36 was not considered due to the excessive costs.



YEC Outage Reporting with Parameters

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations	Feeder/Line	Start DateTime	End DateTime						
2011	Qtr 1	2011-0019	Jan 23, 2011	Segs: 2	Dawson (603) Wet Snow			0.62	270	153.0	YUB		
				Dawson	Dawson (Feeder 1)	1/23/2011 2:13:00 AM	1/23/2011 2:44:00 AM	0.52	135	69.7		T	12.47Kv
				Dawson	Dawson (Feeder 2)	1/23/2011 2:13:00 AM	1/23/2011 2:50:00 AM	0.62	135	83.2		T	12.47Kv
		2011-0022	Mar 22, 2011	Segs: 2	Dawson (503) Defective Equipment/Material			0.78	270	209.2	YUB		
				Dawson	Dawson (Feeder 1)	3/22/2011 2:23:32 PM	3/22/2011 3:10:07 PM	0.78	135	104.8		T	12.47Kv
				Dawson	Dawson (Feeder 2)	3/22/2011 2:23:32 PM	3/22/2011 3:09:57 PM	0.77	135	104.4		T	12.47Kv
		Tot Qtr:2						2.68	540	362.2			
	Qtr 2	2011-0048	Jun 27, 2011	Segs: 1	Dawson (400) Lightning			0.10	422	40.4	YUB		
				Dawson	Dawson (Feeder 1)	6/27/2011 4:06:05 PM	6/27/2011 4:11:50 PM	0.10	422	40.4		T	12.47Kv
		Tot Qtr:1						0.10	422	40.4			
	Qtr 3	2011-0004	Aug 25, 2011	Segs: 1	Dawson (202) Transmission Inadvertent			0.60	439	263.5	YUB		
				Dawson	Dawson (Feeder 2)	8/25/2011 12:19:04 PM	8/25/2011 12:55:05 PM	0.60	439	263.5		T	12.47Kv
		2011-0008	Sep 29, 2011	Segs: 1	Dawson (806) Commissioning Error			0.09	439	39.8	YUB		
				Dawson	Dawson (Feeder 2)	9/29/2011 12:05:01 PM	9/29/2011 12:10:27 PM	0.09	439	39.8		T	12.47Kv
		Tot Qtr:2						0.69	878	303.3			
	Qtr 4	2011-0012	Nov 10, 2011	Segs: 2	Dawson (806) Commissioning Error			0.14	861	115.3	YUB		
				Dawson	Dawson (Feeder 1)	11/10/2011 11:34:46 AM	11/10/2011 11:42:09 AM	0.12	422	51.9		T	12.47Kv
				Dawson	Dawson (Feeder 2)	11/10/2011 11:34:46 AM	11/10/2011 11:43:26 AM	0.14	439	63.4		T	12.47Kv
		2011-0015	Dec 05, 2011	Segs: 2	Dawson (603) Wet Snow			0.20	861	165.2	YUB		
				Dawson	Dawson (Feeder 1)	12/5/2011 12:41:00 AM	12/5/2011 12:52:00 AM	0.18	422	77.4		T	12.47Kv
				Dawson	Dawson (Feeder 2)	12/5/2011 12:41:00 AM	12/5/2011 12:53:00 AM	0.20	439	87.8		T	12.47Kv
		2011-0017	Dec 25, 2011	Segs: 2	Dawson (603) Wet Snow			0.13	861	104.5	YUB		
				Dawson	Dawson (Feeder 1)	12/25/2011 2:05:38 PM	12/25/2011 2:12:29 PM	0.11	422	48.2		T	12.47Kv
				Dawson	Dawson (Feeder 2)	12/25/2011 2:05:38 PM	12/25/2011 2:13:20 PM	0.13	439	56.3		T	12.47Kv
		Tot Qtr:3						0.89	2,583	385.0			
	Tot Yr: 8							4.36	4,423	1,091.0			

Report generated: 2/22/2021 1:45:53 PM

Year	Quarter	Id	Date	(Code) Description			Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations		Feeder/Line	Start DateTime	End DateTime						
2012	Qtr 1	2012-0010	Mar 30, 2012	Segs: 2	Dawson	(302) Broken Branch			0.14	857	120.5	YUB		
				Dawson	Dawson (Feeder 1)		3/30/2012 1:47:30 PM	3/30/2012 1:55:43 PM	0.14	420	57.5		T	12.47Kv
				Dawson	Dawson (Feeder 2)		3/30/2012 1:47:30 PM	3/30/2012 1:56:09 PM	0.14	437	63.0		T	12.47Kv
		2012-0022	Jan 01, 2012	Segs: 2	Dawson	(603) Wet Snow			0.20	861	166.6	YUB		
				Dawson	Dawson (Feeder 1)		1/1/2012 5:33:18 PM	1/1/2012 5:44:17 PM	0.18	422	77.2		T	12.47Kv
				Dawson	Dawson (Feeder 2)		1/1/2012 5:33:18 PM	1/1/2012 5:45:31 PM	0.20	439	89.4		T	12.47Kv
		2012-0023	Jan 02, 2012	Segs: 2	Dawson	(603) Wet Snow			0.20	861	166.4	YUB		
				Dawson	Dawson (Feeder 1)		1/2/2012 8:26:02 AM	1/2/2012 8:37:21 AM	0.19	422	79.6		T	12.47Kv
				Dawson	Dawson (Feeder 2)		1/2/2012 8:26:02 AM	1/2/2012 8:37:54 AM	0.20	439	86.8		T	12.47Kv
		2012-0024	Jan 03, 2012	Segs: 2	Dawson	(603) Wet Snow			0.16	861	131.0	YUB		
				Dawson	Dawson (Feeder 1)		1/3/2012 1:39:20 AM	1/3/2012 1:48:13 AM	0.15	422	62.5		T	12.47Kv
				Dawson	Dawson (Feeder 2)		1/3/2012 1:39:20 AM	1/3/2012 1:48:42 AM	0.16	439	68.5		T	12.47Kv
		Tot Qtr:4							1.36	3,440	584.6			
	Qtr 3	2012-0001	Sep 04, 2012	Segs: 2	Dawson	(506) Other Equipment Failure			0.08	861	61.9	YUB		
				Dawson	Dawson (Feeder 1)		9/4/2012 5:38:56 AM	9/4/2012 5:42:55 AM	0.07	422	28.0		T	12.47Kv
				Dawson	Dawson (Feeder 2)		9/4/2012 5:38:56 AM	9/4/2012 5:43:34 AM	0.08	439	33.9		T	12.47Kv
		2012-0002	Sep 05, 2012	Segs: 2	Dawson	(300) Tree Contacts			0.12	861	107.1	YUB		
				Dawson	Dawson (Feeder 1)		9/5/2012 6:11:14 PM	9/5/2012 6:18:42 PM	0.12	422	52.5		T	12.47Kv
				Dawson	Dawson (Feeder 2)		9/5/2012 6:11:14 PM	9/5/2012 6:18:42 PM	0.12	439	54.6		T	12.47Kv
		2012-0003	Sep 12, 2012	Segs: 2	Dawson	(300) Tree Contacts			0.12	861	96.9	YUB		
				Dawson	Dawson (Feeder 1)		9/12/2012 11:11:10 PM	9/12/2012 11:17:40 PM	0.11	422	45.7		T	12.47Kv
				Dawson	Dawson (Feeder 2)		9/12/2012 11:11:10 PM	9/12/2012 11:18:10 PM	0.12	439	51.2		T	12.47Kv
		Tot Qtr:3							0.62	2,583	266.0			
	Qtr 4	2012-0004	Oct 25, 2012	Segs: 1	Dawson	(300) Tree Contacts			0.08	401	33.1	YUB		
				Dawson	Dawson (Feeder 1)		10/25/2012 12:53:55 PM	10/25/2012 12:58:52 PM	0.08	401	33.1		T	12.47Kv
		2012-0005	Dec 10, 2012	Segs: 2	Dawson	(603) Wet Snow			0.29	861	245.6	YUB		
				Dawson	Dawson (Feeder 1)		12/10/2012 6:04:33 AM	12/10/2012 6:21:27 AM	0.28	422	118.9		T	12.47Kv
				Dawson	Dawson (Feeder 2)		12/10/2012 6:04:33 AM	12/10/2012 6:21:52 AM	0.29	439	126.7		T	12.47Kv
		2012-0006	Dec 11, 2012	Segs: 3	Dawson	(205) Other Loss of Supply			0.02	1,283	18.8	YUB		

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations	Feeder/Line	Start DateTime	End DateTime						
2012	Qtr 4	2012-0006	Dec 11, 2012	Dawson	Dawson (Feeder 2)	12/11/2012 10:30:06 AM	12/11/2012 10:31:12 AM	0.02	439	8.0		T	12.47Kv
				Dawson	Dawson (Feeder 1)	12/11/2012 10:30:06 AM	12/11/2012 10:30:53 AM	0.01	422	5.5		T	12.47Kv
				Dawson	Dawson (Feeder 1)	12/11/2012 10:31:12 AM	12/11/2012 10:31:57 AM	0.01	422	5.3		T	12.47Kv
		2012-0008	Dec 12, 2012	Segs: 2	Dawson (603) Wet Snow			0.11	861	86.4	YUB		
				Dawson	Dawson (Feeder 1)	12/12/2012 5:23:19 PM	12/12/2012 5:30:07 PM	0.11	422	47.8		T	12.47Kv
				Dawson	Dawson (Feeder 2)	12/12/2012 5:23:19 PM	12/12/2012 5:28:35 PM	0.09	439	38.5		T	12.47Kv
		Tot Qtr:4						0.90	3,406	383.8			
	Tot Yr: 11							2.87	9,429	1,234.4			
2013	Qtr 1	2013-0001	Jan 13, 2013	Segs: 2	Dawson (603) Wet Snow			0.24	861	197.4	YUB		
				Dawson	Dawson (Feeder 2)	1/13/2013 11:34:41 PM	1/13/2013 11:48:55 PM	0.24	439	104.1		T	12.47Kv
				Dawson	Dawson (Feeder 1)	1/13/2013 11:34:41 PM	1/13/2013 11:47:57 PM	0.22	422	93.3		T	12.47Kv
		2013-0002	Jan 15, 2013	Segs: 2	Dawson (603) Wet Snow			0.11	861	92.9	YUB		
				Dawson	Dawson (Feeder 2)	1/15/2013 11:49:36 AM	1/15/2013 11:56:04 AM	0.11	439	47.3		T	12.47Kv
				Dawson	Dawson (Feeder 1)	1/15/2013 11:49:36 AM	1/15/2013 11:56:05 AM	0.11	422	45.6		T	12.47Kv
		2013-0003	Jan 19, 2013	Segs: 2	Dawson (603) Wet Snow			0.22	861	151.8	YUB		
				Dawson	Dawson (Feeder 2)	1/19/2013 11:12:00 AM	1/19/2013 11:20:00 AM	0.13	439	58.5		T	12.47Kv
				Dawson	Dawson (Feeder 1)	1/19/2013 11:15:00 AM	1/19/2013 11:28:16 AM	0.22	422	93.3		T	12.47Kv
		Tot Qtr:3						1.03	2,583	442.2			
	Qtr 2	2013-0005	Jun 04, 2013	Segs: 2	Dawson (300) Tree Contacts			0.16	861	130.8	YUB		
				Dawson	Dawson (Feeder 1)	6/4/2013 11:37:46 AM	6/4/2013 11:47:21 AM	0.16	422	67.4		T	12.47Kv
				Dawson	Dawson (Feeder 2)	6/4/2013 11:38:41 AM	6/4/2013 11:47:21 AM	0.14	439	63.4		T	12.47Kv
		2013-0006	Jun 04, 2013	Segs: 1	Dawson (802) Protection Setting			0.08	422	35.4	YUB		
				Dawson	Dawson (Feeder 1)	6/4/2013 2:00:03 PM	6/4/2013 2:05:05 PM	0.08	422	35.4		T	12.47Kv
		2013-0007	Jun 05, 2013	Segs: 2	Dawson (802) Protection Setting			12.09	861	10,404.9	YUB		
				Dawson	Dawson (Feeder 1)	6/5/2013 9:35:41 AM	6/5/2013 9:40:33 PM	12.08	422	5,098.2		T	12.47Kv
				Dawson	Dawson (Feeder 2)	6/5/2013 9:35:41 AM	6/5/2013 9:40:58 PM	12.09	439	5,306.7		T	12.47Kv
		Tot Qtr:3						24.56	2,144	10,571.1			
	Qtr 3	2013-0011	Jul 02, 2013	Segs: 2	Dawson (300) Tree Contacts			0.13	861	107.0	YUB		
				Dawson	Dawson (Feeder 2)	7/2/2013 5:15:01 PM	7/2/2013 5:22:19 PM	0.12	439	53.4		T	12.47Kv

Year	Quarter	Id	Date	(Code) Description			Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage	
				Locations		Feeder/Line	Start DateTime	End DateTime							
2013	Qtr 3	2013-0011	Jul 02, 2013	Dawson	Dawson (Feeder 1)			7/2/2013 5:15:01 PM	7/2/2013 5:22:38 PM	0.13	422	53.6		T	12.47Kv
		2013-0012	Aug 08, 2013	Segs: 1	Dawson	(808) Other Human Element				0.11	439	47.4	YUB		
				Dawson	Dawson (Feeder 2)			8/8/2013 11:42:53 AM	8/8/2013 11:49:22 AM	0.11	439	47.4		T	12.47Kv
		2013-0013	Aug 11, 2013	Segs: 1	Dawson	(300) Tree Contacts				0.19	439	83.3	YUB		
				Dawson	Dawson (Feeder 2)			8/11/2013 2:33:02 PM	8/11/2013 2:44:25 PM	0.19	439	83.3		T	12.47Kv
		2013-0015	Sep 08, 2013	Segs: 1	Dawson	(300) Tree Contacts				0.17	439	73.2	YUB		
				Dawson	Dawson (Feeder 2)			9/8/2013 8:04:05 AM	9/8/2013 8:14:05 AM	0.17	439	73.2		T	12.47Kv
		2013-0016	Sep 08, 2013	Segs: 2	Dawson	(0) Unknown				0.11	861	88.5	YUB		
				Dawson	Dawson (Feeder 1)			9/8/2013 6:52:37 PM	9/8/2013 6:58:16 PM	0.09	422	39.7		T	12.47Kv
				Dawson	Dawson (Feeder 2)			9/8/2013 6:52:37 PM	9/8/2013 6:59:17 PM	0.11	439	48.8		T	12.47Kv
		2013-0017	Sep 24, 2013	Segs: 2	Dawson	(0) Unknown				0.30	861	193.3	YUB		
				Dawson	Dawson (Feeder 1)			9/24/2013 4:34:09 PM	9/24/2013 4:42:43 PM	0.14	422	60.3		T	12.47Kv
				Dawson	Dawson (Feeder 2)			9/24/2013 4:33:12 PM	9/24/2013 4:51:23 PM	0.30	439	133.0		T	12.47Kv
		Tot Qtr:6									1.36	3,900	592.7		
	Tot Yr: 12									26.95	8,627	11,606.0			
2014	Qtr 2	2014-0033	Apr 15, 2014	Segs: 2	Dawson	(503) Defective Equipment/Material	Outage caused by a failed Governor PLC for WH4.		0.20	857	161.0	YUB			
				Dawson	Dawson (Feeder 1)			4/15/2014 2:59:50 AM	4/15/2014 3:10:24 AM	0.18	420	74.0		T	4200V
				Dawson	Dawson (Feeder 2)			4/15/2014 2:59:50 AM	4/15/2014 3:11:47 AM	0.20	437	87.0		T	4200V
		2014-0038	May 02, 2014	Segs: 1	Dawson	(500) Equipment Failure	WH4 tripped off at 19.6MW while testing under CSP 14-115. After investigation it was foug that the governor PLC failed. CPU in PLC was replaced.		0.07	439	30.0	YUB			
				Dawson	Dawson (Feeder 2)			5/2/2014 2:49:21 PM	5/2/2014 2:53:27 PM	0.07	439	30.0		T	4200V
		2014-0040	May 18, 2014	Segs: 1	Dawson	(100) Scheduled Outage	Planned power outage to replace C Phase hot tap in Alley between 6th and 7th Avenues.		1.03	439	451.4	YUB			
				Dawson	Dawson (Feeder 2)			5/16/2014 11:48:13 AM	5/16/2014 12:49:55 PM	1.03	439	451.4		T	12.47Kv

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage		
				Locations		Feeder/Line	Start DateTime							End DateTime	
2014	Qtr 2	2014-0049	Jun 24, 2014	Segs: 2	Dawson	(300) Tree Contacts		Outage caused by a tree on L178 at structure 1318 just passed Drury Creek Campground. Note: The area where the tree contacted the power line was an area identified and was contracted by Ace Vegetation to be cleared this summer.		0.12	861	100.4	YUB		
				Dawson	Dawson (Feeder 1)		6/24/2014 4:14:00 PM	6/24/2014 4:21:00 PM	0.12	422	49.2		T	4200V	
				Dawson	Dawson (Feeder 2)		6/24/2014 4:14:00 PM	6/24/2014 4:21:00 PM	0.12	439	51.2		T	4200V	
		Tot Qtr:4						1.71	2,596	742.9					
	Qtr 3	2014-0081	Aug 04, 2014	Segs: 2	Dawson	(503) Defective Equipment/Material		System was split at S255-52-2 and L170-89-481 for GOI 14-240. Faro was on diesel generation. Carmacks was seperated from the grid and placed on AEY diesel generation. SCC was tying Faro and Mayo together via S255-52-2 when the Northern grid collapsed due to high voltage. After investigation it was found that the breaking resistors in Mayo were non operational and 1.1 MVAR Reactor was open in Mayo. December 05/2014 update; Michael Tilbrook informed SCC that the breaking resistors are now operational and the 1.1 MVAR Reactor is now closed.		0.14	861	116.3	YUB		
				Dawson	Dawson (Feeder 1)		8/4/2014 12:14:00 PM	8/4/2014 12:21:49 PM	0.13	422	55.0		T	4200V	
				Dawson	Dawson (Feeder 2)		8/4/2014 12:14:00 PM	8/4/2014 12:22:23 PM	0.14	439	61.3		T	4200V	
		2014-0085	Aug 12, 2014	Segs: 2	Dawson	(400) Lightning		Possibly a lightning strike as lightning and generally poor weather was reported at the time of the outage.Faro, Mayo and Dawson were seperated at S255. L170 was isolated at the time for structure/repair/replace.		0.12	861	101.5	YUB		
				Dawson	Dawson (Feeder 1)		8/12/2014 7:12:00 PM	8/12/2014 7:18:51 PM	0.11	422	48.2		T	4200V	
				Dawson	Dawson (Feeder 2)		8/12/2014 7:12:00 PM	8/12/2014 7:19:17 PM	0.12	439	53.3		T	4200V	
		Tot Qtr:2							0.51	1,722	217.8				
		Qtr 4	2014-0194	Dec 06, 2014	Segs: 1	Dawson	(203) Generation Inadvertent		WH4 Tripped - PLC failure		0.25	459	115.9	YUB	
	Dawson				Dawson (Feeder 2)		12/6/2014 10:07:58 PM	12/6/2014 10:23:07 PM	0.25	459	115.9		T	12.5Kv	
	Tot Qtr:1								0.25	459	115.9				
	Tot Yr: 7								2.46	4,777	1,076.6				

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage	
				Locations	Feeder/Line	Start DateTime	End DateTime							
2015	Qtr 1	2015-0027	Jan 16, 2015	Segs: 2	Dawson	(603) Wet Snow	12cm of heavy wet snow with 22k winds at the time of the outage.		0.64	906	575.1	YUB		
				Dawson	Dawson (Feeder 1)		1/16/2015 2:35:36 AM	1/16/2015 3:13:19 AM	0.63	447	281.0		T	4200V
				Dawson	Dawson (Feeder 2)		1/16/2015 2:35:36 AM	1/16/2015 3:14:03 AM	0.64	459	294.1		T	4200V
		Tot Qtr:1							1.27	906	575.1			
	Qtr 2	2015-0098	May 14, 2015	Segs: 2	Dawson	(503) Defective Equipment/Material	Split Cross Arm on structure along L177. Insulator pulled free and contacted Guywire.		0.42	906	281.3	YUB		
				Dawson	Dawson (Feeder 1)		5/14/2015 1:26:06 PM	5/14/2015 1:38:12 PM	0.20	447	90.1		T	4200V
				Dawson	Dawson (Feeder 2)		5/14/2015 1:26:06 PM	5/14/2015 1:51:05 PM	0.42	459	191.1		T	4200V
		2015-0099	May 21, 2015	Segs: 1	Dawson	(506) Other Equipment Failure	DD5 tripped on Low coolant level. P158 52-F2 and S250 52-2 tripped on U/F.		0.13	459	61.5	YUB		
				Dawson	Dawson (Feeder 2)		5/21/2015 2:24:03 PM	5/21/2015 2:32:05 PM	0.13	459	61.5		T	4200V
		2015-0102	May 29, 2015	Segs: 2	Dawson	(400) Lightning	Lightning storm at time of outage. Dawson power restored using Dawson Diesel generation.		0.88	906	714.1	YUB		
				Dawson	Dawson (Feeder 1)		5/30/2015 6:40:30 AM	5/30/2015 7:22:05 AM	0.69	447	309.8		T	4200V
				Dawson	Dawson (Feeder 2)		5/29/2015 11:40:30 PM	5/30/2015 12:33:21 AM	0.88	459	404.3		T	4200V
		2015-0121	Jun 08, 2015	Segs: 2	Dawson	(400) Lightning	Reports of lightning between Dawson and Stewart North. Comms for P158 and S250 went down immediately. Dawson PLT called in to reset RTU - COMMS restored. Once COMMS restored, SCC was able to restore Dawson back to grid power.		0.21	906	187.3	YUB		
				Dawson	Dawson (Feeder 1)		6/8/2015 9:13:20 PM	6/8/2015 9:25:30 PM	0.20	447	90.6		T	4200V
				Dawson	Dawson (Feeder 2)		6/8/2015 9:13:20 PM	6/8/2015 9:25:58 PM	0.21	459	96.6		T	4200V
		2015-0139	Jun 25, 2015	Segs: 2	Dawson	(103) Maintenance	Planned power outage for YEC Electrician and Orbis under CSP 15-253 to change the PLC program and test run the Diesels.		0.55	906	500.3	YUB		
				Dawson	Dawson (Feeder 1)		6/25/2015 3:00:50 AM	6/25/2015 3:33:58 AM	0.55	447	246.8		T	4200V
				Dawson	Dawson (Feeder 2)		6/25/2015 3:00:50 AM	6/25/2015 3:33:58 AM	0.55	459	253.5		T	4200V
		2015-0141	Jun 24, 2015	Segs: 2	Dawson	(901) Wildlife (Bird/Animal)	Northern grid outage caused by a Raven that was discovered in 870S.		0.30	906	270.2	YUB		
				Dawson	Dawson (Feeder 2)		6/24/2015 8:20:16 AM	6/24/2015 8:38:27 AM	0.30	459	139.1		T	4200V
				Dawson	Dawson (Feeder 1)		6/24/2015 8:20:16 AM	6/24/2015 8:37:52 AM	0.29	447	131.1		T	4200V

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage		
				Locations		Feeder/Line	Start DateTime							End DateTime	
2015	Qtr 2	2015-0142	Jun 24, 2015	Segs: 2	Dawson	(203) Generation Inadvertent	Grids were seperated for L170 test and treat repairs. FD1 was on line because YEC Employee had a clearance to make changes to the P158 PLC which had all Dawson Diesels off line. FD1 tripped off causing a Dawson power outage. Cause was a valve cage cooling hi temp alarm.		0.27	906	205.4	YUB			
				Dawson	Dawson (Feeder 2)		6/24/2015 2:20:55 PM	6/24/2015 2:37:01 PM	0.27	459	123.2		T	4200V	
				Dawson	Dawson (Feeder 1)		6/24/2015 2:20:55 PM	6/24/2015 2:31:57 PM	0.18	447	82.2		T	4200V	
		2015-0143	Jun 25, 2015	Segs: 2	Dawson	(203) Generation Inadvertent	MBH1 tripped off line at 4.3MW. Alarms on MBH1 were, MBH1 non drive end thrust bearing pad #1 Hi temp alarm and MBH1 86M1 Lockout.		0.19	906	169.0	YUB			
				Dawson	Dawson (Feeder 1)		6/25/2015 9:34:53 AM	6/25/2015 9:45:50 AM	0.18	447	81.6		T	4200V	
				Dawson	Dawson (Feeder 2)		6/25/2015 9:34:53 AM	6/25/2015 9:46:19 AM	0.19	459	87.5		T	4200V	
		Tot Qtr:8							5.27	6,801	2,389.0				
		Qtr 3	2015-0157	Jul 13, 2015	Segs: 2	Dawson	(400) Lightning	Lightning Strike was the cause. Rain and Thunderclouds reported in the area. S250 57-1 grounding switch closed and had to be opened.		0.25	906	225.3	YUB		
					Dawson	Dawson (Feeder 1)		7/13/2015 3:38:50 PM	7/13/2015 3:53:27 PM	0.24	447	108.9		T	4200V
	Dawson				Dawson (Feeder 2)		7/13/2015 3:38:50 PM	7/13/2015 3:54:03 PM	0.25	459	116.4		T	4200V	
	2015-0158		Jul 17, 2015	Segs: 2	Dawson	(808) Other Human Element	MH2 Tripped due to hi bearing temperature at 07:12:11. At 07:11:15 there was an MH2 MW Hi Alarm @ 2.70MW as well as 5 Mayo Penstock Hi level alarms between 07:04 and 07:05 that gave the SCC Operator indication that there was an over load issue with MH2.		0.16	906	129.1	YUB			
				Dawson	Dawson (Feeder 1)		7/17/2015 7:12:30 AM	7/17/2015 7:19:48 AM	0.12	447	54.4		T	4200V	
				Dawson	Dawson (Feeder 2)		7/17/2015 7:12:30 AM	7/17/2015 7:22:16 AM	0.16	459	74.7		T	4200V	
	2015-0159		Jul 17, 2015	Segs: 2	Dawson	(400) Lightning	There were reports of lightning storms in the area at the time of the outage. S256 L177A LED occurred alarm , L177 inst trip Alarm, L177A LED Zone 1Fault , L177A LED ground fault alarm , L177A LEDPhase A alarm, L177A LED 50 trip Alarm, L177B LED trip Alarm , L177B LED A Phase trip alarm , L177B BPhase trip alarm. L176 A freq hi 61.7, L177 A Phase B to Ground Voltage Lo , L177B LED Zone 1 fault alarm .		0.18	906	161.8	YUB			
				Dawson	Dawson (Feeder 1)		7/17/2015 6:13:32 PM	7/17/2015 6:23:57 PM	0.17	447	77.6		T	4200V	
				Dawson	Dawson (Feeder 2)		7/17/2015 6:13:32 PM	7/17/2015 6:24:32 PM	0.18	459	84.1		T	4200V	
	2015-0167	Jul 26, 2015	Segs: 2	Dawson	(400) Lightning	There were reports of lightning storms in the area at the time of the outage. Diesel DD3 tripped twice as soon as they tried to close P158-52-EF locally.		0.18	906	160.5	YUB				

Report generated: 2/22/2021 1:45:53 PM

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations	Feeder/Line	Start DateTime	End DateTime						
2015	Qtr 3	2015-0167	Jul 26, 2015	Dawson	Dawson (Feeder 2)	7/26/2015 5:49:55 PM	7/26/2015 6:00:50 PM	0.18	459	83.5		T	4200V
				Dawson	Dawson (Feeder 1)	7/26/2015 5:49:55 PM	7/26/2015 6:00:15 PM	0.17	447	77.0		T	4200V
		2015-0181	Aug 10, 2015	Segs: 1	Dawson	(400) Lightning	Walter Tindal placed S250 SC1 on line Lightning is suspected as a storm was reported at the time of the outage. System went back together without incident Bevon Keefer assisted in restoration. DD2 and DD3 stayed on line (Grids Seperated) Feeder 1 stayed closed.		0.14	459	64.0	YUB	
				Dawson	Dawson (Feeder 2)	8/10/2015 7:08:25 PM	8/10/2015 7:16:47 PM	0.14	459	64.0		T	4200V
		2015-0183	Aug 20, 2015	Segs: 2	Dawson	(304) Off-ROW Tree	Suspect tree on the line approx. 170km east of Carmacks. Mike Sage flew the line from Carmacks and discovered an off-ROW tree on the line. Mike removed tree. SCC was able to tie the grids back together at S164. L178 isolated and Faro mine site being fed from FD7.		0.30	906	271.1	YUB	
				Dawson	Dawson (Feeder 1)	8/20/2015 3:25:28 AM	8/20/2015 3:43:10 AM	0.30	447	131.9		T	4200V
				Dawson	Dawson (Feeder 2)	8/20/2015 3:25:28 AM	8/20/2015 3:43:40 AM	0.30	459	139.2		T	4200V
		2015-0189	Sep 06, 2015	Segs: 2	Dawson	(503) Defective Equipment/Material	There was a false fire alarm in P158. This false fire alarm resulted in all Dawson Diesel units locking out and tripped Feeder 1 and Feeder 2.		0.30	906	234.5	YUB	
				Dawson	Dawson (Feeder 1)	9/6/2015 11:23:00 AM	9/6/2015 11:36:00 AM	0.22	447	96.8		T	4200V
				Dawson	Dawson (Feeder 2)	9/6/2015 11:23:00 AM	9/6/2015 11:41:00 AM	0.30	459	137.7		T	4200V
		2015-0193	Sep 15, 2015	Segs: 2	Dawson	(806) Commissioning Error	WH1 tripped offline due to manual input of gate limit. SCC manually entered a gate limit of '99' which was the same value already targeted. Lead Electrician deducted an error in the PLC programming caused the gate to shut when it should not have.		0.10	906	86.6	YUB	
				Dawson	Dawson (Feeder 1)	9/15/2015 1:26:48 PM	9/15/2015 1:32:52 PM	0.10	447	45.2		T	4200V
				Dawson	Dawson (Feeder 2)	9/15/2015 1:26:48 PM	9/15/2015 1:32:13 PM	0.09	459	41.4		T	4200V
		2015-0195	Sep 29, 2015	Segs: 2	Dawson	(304) Off-ROW Tree	Wind gusts up to 70k knocked tree onto power line along L178.		0.13	906	110.0	YUB	
				Dawson	Dawson (Feeder 2)	9/29/2015 9:51:29 AM	9/29/2015 9:59:01 AM	0.13	459	57.6		T	4200V
				Dawson	Dawson (Feeder 1)	9/29/2015 9:51:29 AM	9/29/2015 9:58:31 AM	0.12	447	52.4		T	4200V
		Tot Qtr:9						3.18	7,707	1,443.0			
	Qtr 4	2015-0199	Oct 02, 2015	Segs: 2	Dawson	(503) Defective Equipment/Material	AH3 tripped due to faulty solenoid for the TIV.		0.29	906	256.5	YUB	
				Dawson	Dawson (Feeder 1)	10/2/2015 7:57:53 PM	10/2/2015 8:14:30 PM	0.28	447	123.8		T	4200V
				Dawson	Dawson (Feeder 2)	10/2/2015 7:57:53 PM	10/2/2015 8:15:14 PM	0.29	459	132.7		T	4200V

Year	Quarter	Id	Date	Locations		(Code) Description	Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
					Feeder/Line	Start DateTime	End DateTime							
2015	Qtr 4	2015-0221	Nov 13, 2015	Segs: 1	Dawson	(603) Wet Snow	Heavy snow was reported in the area at the time of this outage. Lineman suspects line slap from snow falling off the power lines. The grid was tied back together at 11:41:49.		0.15	459	67.2	YUB		
				Dawson	Dawson (Feeder 2)		11/13/2015 8:29:42 AM	11/13/2015 8:38:29 AM	0.15	459	67.2		T	4200V
		Tot Qtr:2							0.71	1,365	323.7			
	Tot Yr: 20								10.43	16,779	4,730.9			
2016	Qtr 1	2016-0007	Jan 15, 2016	Segs: 2	Dawson	(911) Other foreign Interference	Elevator repair personnel hit the emergency stop button for AH1. AH1 tripped off line with approximately 11.5MW of load.		0.18	906	150.1	YUB		
				Dawson	Dawson (Feeder 1)		1/15/2016 9:17:13 AM	1/15/2016 9:27:43 AM	0.18	447	78.2		T	4200V
				Dawson	Dawson (Feeder 2)		1/15/2016 9:17:13 AM	1/15/2016 9:26:37 AM	0.16	459	71.9		T	4200V
		2016-0008	Jan 18, 2016	Segs: 2	Dawson	(601) Extreme Wind	50K winds and heavy snow were reported at the time of this outage.		0.31	906	279.1	YUB		
				Dawson	Dawson (Feeder 1)		1/18/2016 9:41:50 PM	1/18/2016 10:00:04 PM	0.30	447	135.8		T	4200V
				Dawson	Dawson (Feeder 2)		1/18/2016 9:41:50 PM	1/18/2016 10:00:34 PM	0.31	459	143.3		T	4200V
		2016-0010	Jan 25, 2016	Segs: 2	Dawson	(604) Ice/Icing	Suspect power line slap due to the heavy frost/ice built up on the lines. Mild weather reported which caused frost/ice to fall off the lines.		0.42	906	378.3	YUB		
				Dawson	Dawson (Feeder 1)		1/25/2016 6:37:06 PM	1/25/2016 7:01:59 PM	0.41	447	185.4		T	4200V
				Dawson	Dawson (Feeder 2)		1/25/2016 6:37:06 PM	1/25/2016 7:02:19 PM	0.42	459	192.9		T	4200V
		Tot Qtr:3							1.78	2,718	807.6			
	Qtr 2	2016-0092	Jun 30, 2016	Segs: 2	Dawson	(400) Lightning	Heavy lightning and rain reported at the time of the outage.		0.13	906	113.3	YUB		
				Dawson	Dawson (Feeder 2)		6/30/2016 6:58:00 PM	6/30/2016 7:05:45 PM	0.13	459	59.3		T	4200V
				Dawson	Dawson (Feeder 1)		6/30/2016 6:58:00 PM	6/30/2016 7:05:15 PM	0.12	447	54.0		T	4200V
		Tot Qtr:1							0.25	906	113.3			
	Qtr 3	2016-0095	Jul 11, 2016	Segs: 2	Dawson	(400) Lightning	Thunder/lightning storm at the time of the outage.		0.18	906	158.1	YUB		
				Dawson	Dawson (Feeder 1)		7/11/2016 6:45:30 PM	7/11/2016 6:55:45 PM	0.17	447	76.4		T	4200V
				Dawson	Dawson (Feeder 2)		7/11/2016 6:45:30 PM	7/11/2016 6:56:11 PM	0.18	459	81.7		T	4200V
		2016-0099	Jul 12, 2016	Segs: 2	Dawson	(400) Lightning	Thunder/lightning storm Territory wide was the cause of this outage.		0.49	906	337.2	YUB		
				Dawson	Dawson (Feeder 1)		7/12/2016 5:59:10 PM	7/12/2016 6:14:29 PM	0.26	447	114.1		T	4200V
				Dawson	Dawson (Feeder 2)		7/12/2016 5:59:10 PM	7/12/2016 6:28:20 PM	0.49	459	223.1		T	4200V

Year	Quarter	Id	Date	(Code) Description			Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations		Feeder/Line	Start DateTime	End DateTime						
2016	Qtr 3	2016-0104	Jul 14, 2016	Segs: 2	Dawson	(400) Lightning	Thunder and lightning storm at the time of the outage.		0.17	906	148.6	YUB		
				Dawson	Dawson (Feeder 1)		7/15/2016 7:44:40 PM	7/15/2016 7:54:00 PM	0.16	447	69.5		T	4200V
				Dawson	Dawson (Feeder 2)		7/15/2016 7:44:40 PM	7/15/2016 7:55:00 PM	0.17	459	79.0		T	4200V
		2016-0105	Jul 15, 2016	Segs: 2	Dawson	(503) Defective Equipment/Material	WH4 Tripped off line at 17.5MW. Cause of the trip was a loose wire on the governor. Loose wire was cold soldered and reconnected.		0.17	906	147.6	YUB		
				Dawson	Dawson (Feeder 1)		7/15/2016 1:51:44 AM	7/15/2016 2:01:00 AM	0.15	447	69.0		T	4200V
				Dawson	Dawson (Feeder 2)		7/15/2016 1:51:44 AM	7/15/2016 2:02:00 AM	0.17	459	78.5		T	4200V
		2016-0107	Jul 15, 2016	Segs: 2	Dawson	(400) Lightning	Severe thunder and lightning storm at the time of the outage.		0.24	906	209.8	YUB		
				Dawson	Dawson (Feeder 1)		7/15/2016 8:06:15 PM	7/15/2016 8:19:53 PM	0.23	447	101.6		T	4200V
				Dawson	Dawson (Feeder 2)		7/15/2016 8:06:15 PM	7/15/2016 8:20:24 PM	0.24	459	108.2		T	4200V
		Tot Qtr:5							2.21	4,530	1,001.3			
	Qtr 4	2016-0138	Nov 29, 2016	Segs: 2	Dawson	(605) Other Adverse Weather	Strong blowing winds mixed with heavy snow fall at the time of the outage.		0.23	906	205.2	YUB		
				Dawson	Dawson (Feeder 2)		11/29/2016 7:59:08 PM	11/29/2016 8:13:02 PM	0.23	459	106.3		T	4200V
				Dawson	Dawson (Feeder 1)		11/29/2016 7:59:08 PM	11/29/2016 8:12:24 PM	0.22	447	98.8		T	4200V
		2016-0140	Dec 12, 2016	Segs: 1	Dawson	(802) Protection Setting	After short investigation it was discovered the breaker settings were set too low. Changed settings from non breaker to hi load setting. Feeder #1 closed and held.		0.09	447	39.7	YUB		
				Dawson	Dawson (Feeder 1)		12/12/2016 12:14:20 PM	12/12/2016 12:19:40 PM	0.09	447	39.7		T	4200V
		2016-0143	Dec 30, 2016	Segs: 2	Dawson	(603) Wet Snow	Heavy snowfall with strong winds were the cause of this outage.		0.27	906	238.9	YUB		
				Dawson	Dawson (Feeder 1)		12/30/2016 12:55:47 AM	12/30/2016 1:11:27 AM	0.26	447	116.7		T	4200V
				Dawson	Dawson (Feeder 2)		12/30/2016 12:55:47 AM	12/30/2016 1:11:45 AM	0.27	459	122.1		T	69Kv
		Tot Qtr:3							1.07	2,259	483.8			
	Tot Yr: 12								5.31	10,413	2,405.9			
2017	Qtr 1	2017-0006	Jan 17, 2017	Segs: 2	Dawson	(706) Other Adverse Environment	Aishihik Plant slowly began to shed load until all three Aishihik units were taken off line. This event was caused by a complete ice build up on the intake - warm weather caused ice to weaken along power canal and eventually break off and plug up intake. Divers and steamer truck needed to remove ice/debris from trashracks. Minto Mine placed on their back up diesel generators until Aishihik plant brought back to service.		0.38	906	342.8	YUB		

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations	Feeder/Line	Start DateTime	End DateTime						
2017	Qtr 1	2017-0006	Jan 17, 2017	Dawson	Dawson (Feeder 1)	1/17/2017 7:34:53 AM	1/17/2017 7:57:13 AM	0.37	447	166.4		T	4200V
				Dawson	Dawson (Feeder 2)	1/17/2017 7:34:51 AM	1/17/2017 7:57:55 AM	0.38	459	176.5		T	4200V
		2017-0007	Feb 01, 2017	Segs: 2	Dawson	(808) Other Human Element	System split at the time of this outage for a structure repair along L178. Voltage spiked when closing in S255-52-2, picking up all of L178 as well as to L170-89-481. It was later determined that the GOI point that was used (L178-89-481) created too many MVAR's as it was later decided that L170-89-754A should have been the GOI point (Less line voltage). Also, as voltage increased rapidly SCC tried to lower voltage with S251 Tap Changer. Tap changer adjusted in wrong direction.		0.31	906	277.3	YUB	
				Dawson	Dawson (Feeder 1)	2/1/2017 11:16:41 AM	2/1/2017 11:34:47 AM	0.30	447	134.8		T	4200V
				Dawson	Dawson (Feeder 2)	2/1/2017 11:16:41 AM	2/1/2017 11:35:18 AM	0.31	459	142.4		T	4200V
		2017-0010	Feb 18, 2017	Segs: 2	Dawson	(501) Electrical Failure	WAFMD system wide outage. Mayo and Haines Jct. were the only locations left with power. WH4 tripped at 18.9MW. After investigation it was determined that a control circuit failed on the exciter.		0.23	906	209.4	YUB	
				Dawson	Dawson (Feeder 1)	2/18/2017 3:08:16 PM	2/18/2017 3:21:57 PM	0.23	447	101.9		T	4200V
				Dawson	Dawson (Feeder 2)	2/18/2017 3:08:16 PM	2/18/2017 3:22:19 PM	0.23	459	107.5		T	4200V
		2017-0014	Feb 28, 2017	Segs: 2	Dawson	(501) Electrical Failure	AH2 tripped on over voltage. After investigation it was determined that AH2 tripped due to all 11 brushes on one of the slip rings being damaged (5 severely). The cause may be due to contamination of fiberglass dust and access to perform regular checks on the Aishihik units.		0.11	906	96.6	YUB	
				Dawson	Dawson (Feeder 1)	2/28/2017 2:47:56 PM	2/28/2017 2:53:56 PM	0.10	447	44.7		T	4200V
				Dawson	Dawson (Feeder 2)	2/28/2017 2:47:53 PM	2/28/2017 2:54:40 PM	0.11	459	51.9		T	4200V
		Tot Qtr:4						2.04	3,624	926.1			
	Qtr 2	2017-0031	Apr 22, 2017	Segs: 2	Dawson	(304) Off-ROW Tree	This outage affected the Northern grid. After flying the lines (L170 and L178) a tree was discovered on L178 across from Little Salmon campground between structures 1166 and 1167. Heavy winds were witnessed/reported at the time of this outage.		0.67	906	367.4	YUB	
				Dawson	Dawson (Feeder 1)	4/22/2017 12:00:54 PM	4/22/2017 12:09:02 PM	0.14	447	60.6		T	4200V
				Dawson	Dawson (Feeder 2)	4/22/2017 12:00:54 PM	4/22/2017 12:41:00 PM	0.67	459	306.8		T	4200V
		2017-0061	Jun 22, 2017	Segs: 2	Dawson	(400) Lightning	The Outage was likely due to Lightning. The Canadian Lightning Danger Map was showing extreme strikes throughout Northern Yukon. Dawson had a Fire Rating of High. Dawson PLT patrolled the line before SCC closed in on Hunker and S250 52-1.		0.26	906	233.9	YUB	

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations	Feeder/Line	Start DateTime	End DateTime						
2017	Qtr 2	2017-0061	Jun 22, 2017	Dawson	Dawson (Feeder 1)	6/22/2017 7:23:40 PM	6/22/2017 7:38:52 PM	0.25	447	113.2		T	4200V
				Dawson	Dawson (Feeder 2)	6/22/2017 7:23:40 PM	6/22/2017 7:39:26 PM	0.26	459	120.6		T	4200V
		2017-0062	Jun 25, 2017	Segs: 2	Dawson	(400) Lightning	Heavy thunder and lightning reported at the time of this outage. PLT's dispatched to fly L178 and L170. Nothing discovered.		0.30	906	262.9	YUB	
				Dawson	Dawson (Feeder 1)	6/25/2017 4:22:30 PM	6/25/2017 4:39:07 PM	0.28	447	123.8		T	4200V
				Dawson	Dawson (Feeder 2)	6/25/2017 4:22:30 PM	6/25/2017 4:40:41 PM	0.30	459	139.1		T	4200V
		2017-0065	Jun 27, 2017	Segs: 2	Dawson	(205) Other Loss of Supply	AH1 tripped due to thrust bearing high temperature alarm. This trip is under investigation.		0.04	906	34.0	YUB	
				Dawson	Dawson (Feeder 1)	6/27/2017 12:19:19 PM	6/27/2017 12:21:33 PM	0.04	447	16.6		T	4200V
				Dawson	Dawson (Feeder 2)	6/27/2017 12:19:17 PM	6/27/2017 12:21:33 PM	0.04	459	17.3		T	4200V
		Tot Qtr:4						1.97	3,624	898.1			
	Qtr 3	2017-0094	Jul 25, 2017	Segs: 2	Dawson	(400) Lightning	Major Lightning/Thunder storms Territory wide. Outage caused by lightning strike in Minto area.		0.05	934	45.9	YUB	
				Dawson	Dawson (Feeder 1)	7/25/2017 7:46:23 PM	7/25/2017 7:49:29 PM	0.05	466	24.1		T	4200V
				Dawson	Dawson (Feeder 2)	7/25/2017 7:46:23 PM	7/25/2017 7:49:11 PM	0.05	468	21.8		T	4200V
		2017-0095	Aug 03, 2017	Segs: 1	Dawson	(503) Defective Equipment/Material	WH4 speed signal failed, WH4 secondary speed device failed which caused the unit to trip off line and shut down.		0.14	468	66.7	YUB	
				Dawson	Dawson (Feeder 2)	8/3/2017 7:40:18 AM	8/3/2017 7:48:51 AM	0.14	468	66.7		T	4200V
		2017-0097	Aug 08, 2017	Segs: 2	Dawson	(802) Protection Setting	S251T1 protection settings at 14MVA, due to lack of gen available on the southern grid we were generating heavy from the north this caused the protection setting on S251 T1 to trip on over current The cause of the second August 8th outage occurred during the system restoration from the loss of WH4. Northern thermal and hydro generation used to replace the lost generation from WH4 exceeded the protection settings of a transformer located at Stewart Crossing. The transformer protection settings are lower than the transformer capacity. The protection settings will be review and changed.		0.28	934	258.1	YUB	
				Dawson	Dawson (Feeder 1)	8/8/2017 7:25:01 AM	8/8/2017 7:41:36 AM	0.28	466	128.8		T	4200V
				Dawson	Dawson (Feeder 2)	8/8/2017 7:25:01 AM	8/8/2017 7:41:36 AM	0.28	468	129.3		T	4200V
		2017-0098	Aug 08, 2017	Segs: 1	Dawson	(503) Defective Equipment/Material	WH4 shed around 4MW of load as unit was being brought off line due to speed sensing issues. This caused P158 52-F2 and S250 52-2 to trip on U/F.		0.27	468	127.5	YUB	
				Dawson	Dawson (Feeder 2)	8/8/2017 4:30:17 PM	8/8/2017 4:46:38 PM	0.27	468	127.5		T	4200V

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Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage		
				Locations		Feeder/Line	Start DateTime							End DateTime	
2017	Qtr 3	2017-0099	Aug 09, 2017	Segs: 1	Dawson	(506) Other Equipment Failure	At 04:16:38 AH2 tripped offline. The Upper guide bearing temp trip (80c) alarm came in and the unit locked out. All Main breakers were closed at 05:42:25 and load pickups were completed shortly after 07:00. Restoration was done with Whitehorse Diesels and AH2, after it was inspected.		0.23	468	109.7	YUB			
							The cause of the August 9th outage was a high temperature bearing trip on Aishihik unit 2 (AH2). AH2 was placed on line on Aug 8th to eliminate the thermal being used to replace WH4 generation. The unit had been inspected after being on line for an hour with no issues found. The bearing over heated due to a clogged cooling water supply to the bearing.								
			Dawson	Dawson (Feeder 2)		8/9/2017 4:16:38 AM	8/9/2017 4:30:42 AM	0.23	468	109.7		T	4200V		
		2017-0103	Sep 13, 2017	Segs: 2	Dawson	(0) Unknown	S256-52-2 tripped. Attempted a close on S256-52-2, which held. DD2 failed to synch on line and P158-52-EF had to be closed locally.		0.32	934	286.9	YUB			
					Dawson	Dawson (Feeder 1)		9/13/2017 12:50:26 PM	9/13/2017 1:09:50 PM	0.32	466	150.7		T	4200V
			Dawson	Dawson (Feeder 2)		9/13/2017 12:50:26 PM	9/13/2017 1:07:54 PM	0.29	468	136.2		T	4200V		
		Tot Qtr:6							1.91	4,206	894.9				
	Qtr 4	2017-0115	Oct 17, 2017	Segs: 1	Dawson	(103) Maintenance	Planned outage to Dawson City Customers to set power poles under work order # C17045.		2.09	468	976.4	YUB			
					Dawson	Dawson (Feeder 2)		10/17/2017 4:00:04 AM	10/17/2017 6:05:15 AM	2.09	468	976.4		T	4200V
		2017-0116	Oct 19, 2017	Segs: 1	Dawson	(103) Maintenance	Planned isolation for Dawson City Customers fed from Feeder #1. Isolation needed to set power poles.		1.89	466	880.6	YUB			
					Dawson	Dawson (Feeder 1)		10/19/2017 4:00:04 AM	10/19/2017 5:53:27 AM	1.89	466	880.6		T	4200V
		2017-0118	Oct 30, 2017	Segs: 2	Dawson	(0) Unknown	AH2 tripped on a 86M Mechanical lockout. No cause determined.		0.21	934	192.9	YUB			
					Dawson	Dawson (Feeder 1)		10/30/2017 11:19:38 AM	10/30/2017 11:31:53 AM	0.20	466	95.1		T	4200V
					Dawson	Dawson (Feeder 2)		10/30/2017 11:19:36 AM	10/30/2017 11:32:08 AM	0.21	468	97.8		T	4200V
		2017-0127	Nov 21, 2017	Segs: 2	Dawson	(604) Ice/Icing	Heavy frost built up on the power lines. Very windy at the time of the outage. Line slap from frost coming off the power lines most likely the cause.		0.15	934	136.2	YUB			
					Dawson	Dawson (Feeder 1)		11/21/2017 4:22:57 PM	11/21/2017 4:31:24 PM	0.14	466	65.6		T	4200V
					Dawson	Dawson (Feeder 2)		11/21/2017 4:22:57 PM	11/21/2017 4:32:00 PM	0.15	468	70.6		T	4200V

Year	Quarter	Id	Date	(Code) Description				Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations		Feeder/Line	Start DateTime	End DateTime							
2017	Qtr 4	2017-0128	Nov 21, 2017	Segs: 2	Dawson	(802) Protection Setting		After restoration of the outage at 16:22 S250 RT1 did not go back to normal setpoint automatically. It was at step 9 and should have been step 7. Local lineman changed steps and voltages all returned to normal. Feeder 1 and Feeder 2 both tripped on under voltage.	0.23	934	177.4	YUB			
				Dawson	Dawson (Feeder 1)		11/21/2017 5:34:34 PM	11/21/2017 5:43:44 PM	0.15	466	71.2		T	4200V	
				Dawson	Dawson (Feeder 2)		11/21/2017 5:34:34 PM	11/21/2017 5:48:11 PM	0.23	468	106.2		T	4200V	
		2017-0129	Nov 24, 2017	Segs: 1	Dawson	(808) Other Human Element		Orbis was working on protection relays and settings in Minto landing and caused S253-52-2 to open on undervoltage. An incident report will be completed	0.13	468	58.5	YUB			
				Dawson	Dawson (Feeder 2)		11/24/2017 4:59:03 PM	11/24/2017 5:06:33 PM	0.13	468	58.5		T	4200V	
		2017-0131	Dec 10, 2017	Segs: 2	Dawson	(301) Falling Tree		Tree on the line discovered near Little Salmon area. Faulty indications to S164-52-1 and S164-52-2 delayed restoration to Faro and tying the grid back together.	0.25	934	220.8	YUB			
				Dawson	Dawson (Feeder 2)		12/10/2017 4:13:25 AM	12/10/2017 4:28:12 AM	0.25	468	115.3		T	4200V	
				Dawson	Dawson (Feeder 1)		12/10/2017 4:13:25 AM	12/10/2017 4:27:00 AM	0.23	466	105.5		T	4200V	
		Tot Qtr:7								5.66	5,138	2,642.9			
	Tot Yr: 21									11.59	16,592	5,362.0			
2018	Qtr 1	2018-0009	Feb 07, 2018	Segs: 2	Dawson	(501) Electrical Failure		Protection and Systems Engineer: Based on what tripped I am about 90% sure that it was the T1 protection that operated. When it operates, it also trips the R1 lockout relay (along with the 52-5 lockout relay, the SC1 lockout relay, and the high-speed grounding switch). The reactor protection only trips the reactor lockout relay, not the rest. Furthermore, the last event logs that I did see from the relay (from November 2017) showed the overcurrent protection on T1 picking up and dropping out multiple times under non-fault conditions. There are some setting changes waiting to be applied that would increase the pickup slightly.	0.21	934	192.0	YUB			
				Dawson	Dawson (Feeder 1)		2/7/2018 12:12:37 PM	2/7/2018 12:24:42 PM	0.20	466	93.8		T	4200V	
				Dawson	Dawson (Feeder 2)		2/7/2018 12:12:37 PM	2/7/2018 12:25:12 PM	0.21	468	98.1		T	4200V	
		Tot Qtr:1								0.41	934	192.0			

Year	Quarter	Id	Date	Locations		(Code) Description	Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
						Feeder/Line	Start DateTime	End DateTime						
2018	Qtr 2	2018-0023	Apr 10, 2018	Segs: 2	Dawson	(501) Electrical Failure	TIV closed resulting in AH1 shutdown. After investigation it was determined that the TIV had a stuck Electrical Actuated valve. When looking at the PLC program it showed that a bit called the TIV open_command_latch was not getting turned on. The request for an open should cause this latch to happen. This command is blocked only by a TIV Alarm or a TIV Close command. When operating the TIV it was noted that it immediately went into alarm and then cleared after the TIV fully traveled. This happened in both directions (open or Close). Further investigation showed that at least one of the Atco electrically operated valves was stuck causing a Fail to open Alarm thus allowing water flow when it should not and without the Open Latch signal the TIV was able to drift off of its fully open state. I will try to get the signal from the Open latch bit indicating to our SCADA System for a short term solution. I believe we need to look into some stronger type of operating valves to insure that after sitting for a few months the control power will be strong enough to move the valve. Minto Mine left on their own dieswel generation until Aishihik problem resolved.		0.24	934	219.5	YUB		
				Dawson	Dawson (Feeder 1)		4/10/2018 3:52:46 PM	4/10/2018 4:06:42 PM	0.23	466	108.2		T	4200V
				Dawson	Dawson (Feeder 2)		4/10/2018 3:52:46 PM	4/10/2018 4:07:02 PM	0.24	468	111.3		T	4200V
		2018-0025	Apr 24, 2018	Segs: 1	Dawson	(506) Other Equipment Failure	Operator was switching storage tanks to accommodate LNG truck offload. The send out tank switched to the storage tank and units tripped on low gas pressure. Operations Coordinator working with GP Strategies to rectify problem.		0.13	468	62.4	YUB		
				Dawson	Dawson (Feeder 2)		4/24/2018 7:48:00 AM	4/24/2018 7:56:00 AM	0.13	468	62.4		T	4200V
		2018-0044	May 30, 2018	Segs: 2	Dawson	(400) Lightning	Lightning strike near Callison Substation was cause. Also, Lineman reported burnt transformer and a blown fuse. Replaced transformer and re-fused.		0.19	934	154.4	YUB		
				Dawson	Dawson (Feeder 1)		5/30/2018 7:31:51 PM	5/30/2018 7:40:13 PM	0.14	466	65.0		T	4200V
				Dawson	Dawson (Feeder 2)		5/30/2018 7:31:51 PM	5/30/2018 7:43:19 PM	0.19	468	89.4		T	4200V

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage	
				Locations		Feeder/Line	Start DateTime							End DateTime
2018	Qtr 2	2018-0075	Jun 20, 2018	Segs: 2	Dawson	(304) Off-ROW Tree		Lost everything on the Northern Grid except Mayo Townsite. MH1 was the only hydro generator online and very overloaded to the point of cycle degradation. L250 fault tripped S249 52-4 and S249 52-5 which effectively disconnected MBH0 from the rest of the grid. Dawson islanded for restoration. The system was delivering very poor power quality to Minto Mine and Faro couldn't synch to the grid due to low Hz. Only MH1 was online. SCC dumped Minto Mine to regain Hz and opened S249 89-17 to bridge back and regain MBH1 for generation. Minto Mine remains on their own diesel power. A leaning structure was found and believed to be the cause. After investigation a tree had fallen onto the structure and caused it to lean. Rick Brooker and Daniel Lafleur dismantled the structure and SCC energized using MBH1. S253 52-1 and 52-2 deadbus closes didn't work. Matt O'Brien closed breakers locally.	0.47	934	416.2	YUB		
				Dawson	Dawson (Feeder 2)		6/20/2018 11:43:18 AM	6/20/2018 12:08:24 PM	0.42	468	195.8		T	12.47Kv
				Dawson	Dawson (Feeder 1)		6/20/2018 11:43:18 AM	6/20/2018 12:11:41 PM	0.47	466	220.4		T	4200V
		Tot Qtr:4							1.83	3,270	852.5			
	Qtr 3	2018-0082	Jul 24, 2018	Segs: 2	Dawson	(501) Electrical Failure		WH3 tripped on an 86E Electrical Fault. The cause of the 86e was	1.77	934	1,645.0	YUB		
				Dawson	Dawson (Feeder 1)		7/24/2018 6:32:07 PM	7/24/2018 8:17:32 PM	1.76	466	818.7		T	4200V
				Dawson	Dawson (Feeder 2)		7/24/2018 6:32:07 PM	7/24/2018 8:18:03 PM	1.77	468	826.3		T	4200V
		2018-0085	Jul 27, 2018	Segs: 1	Dawson	(301) Falling Tree		Earlier today S255-52-1 tripped. Outages in Faro and along L178 were experienced. SCC was just informed that Whitehorse PLT flew the line and the all clear was given to SCC to reenergize the power line. After closing S255-52-1 it tripped immediately. Whitehorse PLT flew the line again and discovered a tree was discovered on the power line just north of Drury Creek. As it was getting too late to remove the tree, L178 was isolated from North of Drury Creek to Faro for the night. The next day (July 28) the tree was removed and L178 was reenergized.	0.19	468	87.1	YUB		
				Dawson	Dawson (Feeder 2)		7/27/2018 8:35:19 PM	7/27/2018 8:46:29 PM	0.19	468	87.1		T	4200V

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations	Feeder/Line	Start DateTime	End DateTime						
2018	Qtr 3	2018-0100	Sep 12, 2018	Segs: 2	Dawson	(911) Other foreign Interference	Contractors washing the building at the time all five Dawson Diesel units locked out and both Feeder 1 and Feeder 2 tripped. After investigation by YEC Electrician, he stated " my assumption is that the water from the sprinkler system must have some how got a low pressure. There is a valve which is labeled inspectors test that may have been used. The only two thing that will trip all units and feeders are the emergency shutdown button or the sprinkler system(not the fire alarm). This has happened a few times in the past.	0.35	934	293.5	YUB		
				Dawson	Dawson (Feeder 1)	9/12/2018 2:23:51 PM	9/12/2018 2:45:07 PM	0.35	466	165.2		T	4200V
				Dawson	Dawson (Feeder 2)	9/12/2018 2:23:51 PM	9/12/2018 2:40:18 PM	0.27	468	128.3		T	4200V
		Tot Qtr:3						4.34	2,336	2,025.6			
	Qtr 4	2018-0117	Nov 13, 2018	Segs: 2	Dawson	(304) Off-ROW Tree	Heavy snow and strong winds in the north (Carmacks to Faro). PLT noticed outside ROW trees heavily weighted down by snow. Possible tree contact on L178 may be cause of outage as no other possible cause reported.	0.20	934	179.0	YUB		
				Dawson	Dawson (Feeder 1)	11/13/2018 7:34:00 PM	11/13/2018 7:45:00 PM	0.18	466	85.4		T	4200V
				Dawson	Dawson (Feeder 2)	11/13/2018 7:34:00 PM	11/13/2018 7:46:00 PM	0.20	468	93.6		T	4200V
		Tot Qtr:1						0.38	934	179.0			
	Tot Yr: 9							6.96	7,474	3,249.2			
2019	Qtr 1	2019-0020	Mar 08, 2019	Segs: 2	Dawson	(506) Other Equipment Failure	Outage due to loss of WGO plant generation. Manually Pressure build idle tank @ 30,000L and swap tanks manually until process issues are sorted out.	0.12	934	101.2	YUB		
				Dawson	Dawson (Feeder 1)	3/8/2019 6:04:00 PM	3/8/2019 6:11:00 PM	0.12	466	54.4		T	4200V
				Dawson	Dawson (Feeder 2)	3/8/2019 6:04:00 PM	3/8/2019 6:10:00 PM	0.10	468	46.8		T	4200V
		Tot Qtr:1						0.22	934	101.2			
	Qtr 2	2019-0043	May 31, 2019	Segs: 1	Dawson	(203) Generation Inadvertent	WG3 tripped off with a transmission oil low level.	0.17	468	77.6	YUB		
				Dawson	Dawson (Feeder 2)	5/31/2019 11:49:54 AM	5/31/2019 11:59:51 AM	0.17	468	77.6		T	4200V
		2019-0048	Jun 08, 2019	Segs: 2	Dawson	(400) Lightning	Caused by lightning strike in Dawson area. Lots of lightning strikes reported at the time of the outage. Outage duration prolonged due to COMMS issues in the North.	0.42	934	388.4	YUB		
				Dawson	Dawson (Feeder 1)	6/8/2019 7:33:00 PM	6/8/2019 7:57:50 PM	0.41	466	192.9		T	4200V
				Dawson	Dawson (Feeder 2)	6/8/2019 7:33:00 PM	6/8/2019 7:58:04 PM	0.42	468	195.5		T	4200V

Year	Quarter	Id	Date	(Code) Description			Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations		Feeder/Line	Start DateTime	End DateTime						
2019	Qtr 2	2019-0062	Jun 30, 2019	Segs: 2	Dawson	(400) Lightning	Multiple lightning strikes.		1.12	934	1,011.8	YUB		
				Dawson	Dawson (Feeder 1)		6/30/2019 2:15:51 PM	6/30/2019 3:18:37 PM	1.05	466	487.5		T	4200V
				Dawson	Dawson (Feeder 2)		6/30/2019 2:15:51 PM	6/30/2019 3:23:04 PM	1.12	468	524.3		T	4200V
		2019-0064	Jun 25, 2019	Segs: 1	Dawson	(400) Lightning	Lightening Strike.		2.22	468	1,037.4	YUB		
				Dawson	Dawson (Feeder 2)		6/25/2019 1:20:00 PM	6/25/2019 3:33:00 PM	2.22	468	1,037.4		T	4200V
		Tot Qtr:4							5.38	2,804	2,515.2			
	Qtr 3	2019-0077	Jul 22, 2019	Segs: 2	Dawson	(400) Lightning	S164 L170 Zone 2 Phase distance 21A 175km @ 340A 20:55:59 Suspected lightning. Possible two lightning events. One at 20:49:15 near Minto Landing and one at 20:55:59 near L170.		0.26	934	223.4	YUB		
				Dawson	Dawson (Feeder 1)		7/22/2019 8:49:16 PM	7/22/2019 9:02:14 PM	0.22	466	100.7		T	4200V
				Dawson	Dawson (Feeder 2)		7/22/2019 8:49:16 PM	7/22/2019 9:05:00 PM	0.26	468	122.7		T	4200V
		2019-0085	Aug 06, 2019	Segs: 1	Dawson	(101) Customer Requested	GOI 19-497 return to normal Install Openers		0.05	466	23.0	YUB		
				Dawson	Dawson (Feeder 1)		8/6/2019 2:40:00 AM	8/6/2019 2:42:58 AM	0.05	466	23.0		T	4200V
		2019-0086	Aug 06, 2019	Segs: 1	Dawson	(101) Customer Requested	GOI 19-497 planned outage to install switch		0.11	466	52.7	YUB		
				Dawson	Dawson (Feeder 1)		8/6/2019 1:56:34 AM	8/6/2019 2:03:21 AM	0.11	466	52.7		T	4200V
		2019-0087	Aug 07, 2019	Segs: 1	Dawson	(101) Customer Requested	G O I 19_499 start switching at 2 am installed grounds for work being done on the Caisiar BLDG		3.35	466	1,561.1	YUB		
				Dawson	Dawson (Feeder 1)		8/7/2019 2:00:00 AM	8/7/2019 5:21:00 AM	3.35	466	1,561.1		T	4200V
		2019-0090	Aug 06, 2019	Segs: 2	Dawson	(301) Falling Tree	A tree fell on the line – Broke insulators and cross arms – had to operate several local breakers to get the Hospital and as many customers back on the grid as possible		3.80	934	1,792.0	YUB		
				Dawson	Dawson (Feeder 2)		8/6/2019 2:35:46 PM	8/6/2019 6:23:35 PM	3.80	468	1,777.0		T	4200V
				Dawson	Dawson (Feeder 1)		8/6/2019 3:13:05 PM	8/6/2019 3:15:01 PM	0.03	466	15.0		T	4200V
		2019-0100	Aug 29, 2019	Segs: 1	Dawson	(503) Defective Equipment/Material	Feeder 1 isolation Required to fix Gang Switch S7905		0.04	466	18.0	YUB		
				Dawson	Dawson (Feeder 1)		8/29/2019 12:42:00 AM	8/29/2019 12:44:19 AM	0.04	466	18.0		T	4200V

Year	Quarter	Id	Date	(Code) Description		Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage					
				Locations		Feeder/Line	Start DateTime							End DateTime				
2019	Qtr 3	2019-0101	Aug 28, 2019	Segs: 1	Dawson	(103) Maintenance	PP 34 S7905 gang switch center phase had a hot spot on arcing horn. Isolated feeder 1 and potential test and installed grounds open and close gang switch.		1.55	466	722.3	YUB						
				Dawson	Dawson (Feeder 1)		8/28/2019 11:47:00 PM	8/29/2019 1:20:00 AM	1.55	466	722.3		T	4200V				
		2019-0104	Sep 17, 2019	Segs: 1	Dawson	(103) Maintenance	IBEX doing porcelain cutout replacement on feeder one starting in alley behind 2 ave and queen street to Harper street pp 55 pp52 pp50 pp all 3 phase transformer		1.00	50	50.0	YUB						
				Dawson	Dawson (Feeder 1)		9/17/2019 7:30:00 AM	9/17/2019 8:30:00 AM	1.00	50	50.0		T	4200V				
		2019-0109	Sep 14, 2019	Segs: 2	Dawson	(506) Other Equipment Failure	The cause of the trip was a momentary loss of 24vdc power supply to the Dawson plant, "fire alarm panel B." In Figure 1, a loss in 24vdc to relays FFT, FET1, and FET2 will cause a trip to be sent to F1, F2, DD1, DD2, DD3, DD4, and DD5.		0.15	934	136.8	YUB						
							Dawson	Dawson (Feeder 2)		9/14/2019 10:41:07 AM	9/14/2019 10:49:26 AM	0.14	468	64.9		T	4200V	
							Dawson	Dawson (Feeder 1)		9/14/2019 10:41:07 AM	9/14/2019 10:50:23 AM	0.15	466	72.0		T	4200V	
		2019-0110	Sep 18, 2019	Segs: 1	Dawson	(103) Maintenance	; Ibex porcelaine cut out change on feeder 2		2.00	61	122.0	YUB						
				Dawson	Dawson (Feeder 2)		9/18/2019 9:30:00 AM	9/18/2019 11:30:00 AM	2.00	61	122.0		T	4200V				
		2019-0111	Sep 18, 2019	Segs: 1	Dawson	(103) Maintenance	Dawson feeder 1 cut out replacement on 3 phase bank		1.00	61	61.0	YUB						
							Dawson	Dawson (Feeder 1)		9/18/2019 5:00:00 PM	9/18/2019 6:00:00 PM	1.00	61	61.0		T	4200V	
		2019-0112	Sep 18, 2019	Segs: 1	Dawson	(103) Maintenance	Ibex porcelaine cut out replacement Dawson feeder 2 residential		3.00	53	159.0	YUB						
							Dawson	Dawson (Feeder 2)		9/18/2019 1:30:00 PM	9/18/2019 4:30:00 PM	3.00	53	159.0		T	4200V	
		Tot Qtr:12								16.70	5,357	4,921.4						
		Qtr 4	2019-0123	Nov 06, 2019	Segs: 2	Dawson	(802) Protection Setting	S250-52-1 switch was in Dawson Protection Mode causing S250-52-2 to trip at lower settings		0.97	934	887.7	YUB					
								Dawson	Dawson (Feeder 1)		11/5/2019 3:43:55 PM	11/5/2019 4:40:00 PM	0.93	466	435.6		T	4200V
								Dawson	Dawson (Feeder 2)		11/5/2019 3:43:55 PM	11/5/2019 4:41:53 PM	0.97	468	452.1		T	4200V
			2019-0124	Nov 05, 2019	Segs: 2	Dawson	(802) Protection Setting	S250-52-1 switch was in Dawson Protection Mode causing S250-52-2 to trip at lower settings		0.25	934	224.3	YUB					
	Dawson							Dawson (Feeder 2)		11/5/2019 12:44:57 PM	11/5/2019 12:59:03 PM	0.24	468	110.0		T	4200V	
	Dawson							Dawson (Feeder 1)		11/5/2019 12:44:57 PM	11/5/2019 12:59:40 PM	0.25	466	114.3		T	4200V	
	2019-0131		Nov 19, 2019	Segs: 1	Dawson	(603) Wet Snow	Local Lineman reports lots of snow on lines. Suspect line slap.		0.29	466	136.0	YUB						
							Dawson	Dawson (Feeder 1)		11/19/2019 6:32:40 PM	11/19/2019 6:50:11 PM	0.29	466	136.0		T	4200V	

Year	Quarter	Id	Date	(Code) Description			Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations		Feeder/Line	Start DateTime	End DateTime						
2019	Qtr 4	2019-0132	Nov 20, 2019	Segs: 2	Dawson	(603) Wet Snow	Heavy snowfall in the area. Suspected line slap		0.15	934	130.4	YUB		
				Dawson	Dawson (Feeder 1)		11/20/2019 8:53:03 AM	11/20/2019 9:01:03 AM	0.13	466	62.1		T	4200V
				Dawson	Dawson (Feeder 2)		11/20/2019 8:53:03 AM	11/20/2019 9:01:48 AM	0.15	468	68.2		T	4200V
		2019-0133	Nov 20, 2019	Segs: 2	Dawson	(603) Wet Snow	Heavy snowfall in the area.		0.12	934	110.3	YUB		
				Dawson	Dawson (Feeder 1)		11/20/2019 12:23:07 PM	11/20/2019 12:30:02 PM	0.12	466	53.7		T	4200V
				Dawson	Dawson (Feeder 2)		11/20/2019 12:23:07 PM	11/20/2019 12:30:22 PM	0.12	468	56.5		T	4200V
		2019-0136	Nov 21, 2019	Segs: 2	Dawson	(604) Ice/Icing	Thick Frost on the lines		0.11	934	103.5	YUB		
				Dawson	Dawson (Feeder 1)		11/21/2019 1:41:22 PM	11/21/2019 1:47:47 PM	0.11	466	49.8		T	4200V
				Dawson	Dawson (Feeder 2)		11/21/2019 1:41:22 PM	11/21/2019 1:48:15 PM	0.11	468	53.7		T	4200V
		2019-0137	Nov 25, 2019	Segs: 2	Dawson	(604) Ice/Icing	lines in Dawson are all thick covered with Snow and Frost		0.26	934	240.9	YUB		
				Dawson	Dawson (Feeder 1)		11/25/2019 3:50:23 AM	11/25/2019 4:05:39 AM	0.25	466	118.6		T	4200V
				Dawson	Dawson (Feeder 2)		11/25/2019 3:50:23 AM	11/25/2019 4:06:04 AM	0.26	468	122.3		T	4200V
		2019-0138	Nov 25, 2019	Segs: 2	Dawson	(604) Ice/Icing	Heavy frost buildup on power lines. Frost falling off causing line slap.		0.12	934	110.5	YUB		
				Dawson	Dawson (Feeder 1)		11/25/2019 10:24:26 AM	11/25/2019 10:31:32 AM	0.12	466	55.1		T	4200V
				Dawson	Dawson (Feeder 2)		11/25/2019 10:24:26 AM	11/25/2019 10:31:32 AM	0.12	468	55.4		T	4200V
		Tot Qtr:8								4.16	7,004	1,943.6		
	Tot Yr: 25								26.46	16,099	9,481.4			
2020	Qtr 1	2020-0004	Jan 31, 2020	Segs: 2	Dawson	(604) Ice/Icing	Breaker opened at Stewart North @ 14:20. Cause likely related to snow loading on the lines, reset all alarms in control room, opened S250-57-1, reset express feeder, and put sync condenser S250-52-SC1 online.		0.13	939	123.4	YUB		
				Dawson	Dawson (Feeder 1)		1/31/2020 2:18:24 PM	1/31/2020 2:26:04 PM	0.13	429	54.8		T	4200V
				Dawson	Dawson (Feeder 2)		1/31/2020 2:18:24 PM	1/31/2020 2:26:28 PM	0.13	510	68.6		T	4200V
		2020-0007	Feb 07, 2020	Segs: 2	Dawson	(203) Generation Inadvertent	Comms failure led to system wide cascade event Tripped Minto and requested Eagle transfer to their own generation. Minto made decision to stay on their own generation for the night.		1.67	939	1,354.0	YUB		
				Dawson	Dawson (Feeder 1)		2/7/2020 7:42:29 PM	2/7/2020 8:52:58 PM	1.17	429	504.0		T	4200V
				Dawson	Dawson (Feeder 2)		2/7/2020 7:42:29 PM	2/7/2020 9:22:29 PM	1.67	510	850.0		T	4200V

Year	Quarter	Id	Date	(Code) Description			Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations		Feeder/Line	Start DateTime	End DateTime						
2020	Qtr 1	2020-0008	Feb 13, 2020	Segs: 2	Dawson	(203) Generation Inadvertent	WH4 trip (excitor problems)		0.15	939	139.6	YUB		
				Dawson	Dawson (Feeder 1)		2/13/2020 2:00:31 PM	2/13/2020 2:09:09 PM	0.14	429	61.7		T	4200V
				Dawson	Dawson (Feeder 2)		2/13/2020 2:00:31 PM	2/13/2020 2:09:41 PM	0.15	510	77.9		T	4200V
		Tot Qtr:3							3.40	2,817	1,617.0			
	Qtr 2	2020-0011	Apr 07, 2020	Segs: 1	Dawson	(203) Generation Inadvertent	High LEL during offload at LNG Facility tripped all three WG units and all four on line YM rental units.		0.17	510	88.0	YUB		
				Dawson	Dawson (Feeder 2)		4/7/2020 8:37:18 AM	4/7/2020 8:47:39 AM	0.17	510	88.0		T	4200V
		2020-0018	May 29, 2020	Segs: 2	Dawson	(503) Defective Equipment/Material	Fire pump testing in P158 proved that the bypass switch for the fire system is not working correctly. Dan entered an equipment issue for this.		0.04	939	33.4	YUB		
				Dawson	Dawson (Feeder 1)		5/29/2020 8:22:54 AM	5/29/2020 8:24:50 AM	0.03	429	13.8		T	4200V
				Dawson	Dawson (Feeder 2)		5/29/2020 8:22:54 AM	5/29/2020 8:25:12 AM	0.04	510	19.5		T	4200V
		Tot Qtr:2							0.24	1,449	121.3			
	Qtr 3	2020-0028	Jul 05, 2020	Segs: 2	Dawson	(400) Lightning	Lightening strike L171		0.47	939	434.0	YUB		
				Dawson	Dawson (Feeder 1)		7/5/2020 7:06:44 PM	7/5/2020 7:33:34 PM	0.45	429	191.9		T	4200V
				Dawson	Dawson (Feeder 2)		7/5/2020 7:04:50 PM	7/5/2020 7:33:19 PM	0.47	510	242.1		T	4200V
		2020-0029	Jul 11, 2020	Segs: 2	Dawson	(301) Falling Tree	Tree on L178.		0.60	939	560.9	YUB		
				Dawson	Dawson (Feeder 1)		7/11/2020 2:03:04 PM	7/11/2020 2:38:26 PM	0.59	429	252.9		T	4200V
				Dawson	Dawson (Feeder 2)		7/11/2020 2:03:04 PM	7/11/2020 2:39:18 PM	0.60	510	308.0		T	4200V
		2020-0032	Jul 25, 2020	Segs: 2	Dawson	(400) Lightning	Heavy lightning storm reported at the time of the outage.		0.19	939	171.0	YUB		
				Dawson	Dawson (Feeder 2)		7/25/2020 2:52:52 PM	7/25/2020 3:03:58 PM	0.19	510	94.4		T	4200V
				Dawson	Dawson (Feeder 1)		7/25/2020 2:52:52 PM	7/25/2020 3:03:35 PM	0.18	429	76.6		T	4200V
		2020-0035	Jul 27, 2020	Segs: 2	Dawson	(400) Lightning	Lightning was reported in the area at the time of the outage. No other cause reported/discovered.		0.17	939	156.2	YUB		
				Dawson	Dawson (Feeder 1)		7/27/2020 7:09:44 PM	7/27/2020 7:19:31 PM	0.16	429	70.0		T	4200V
				Dawson	Dawson (Feeder 2)		7/27/2020 7:09:44 PM	7/27/2020 7:19:53 PM	0.17	510	86.3		T	4200V
		2020-0037	Jul 30, 2020	Segs: 1	Dawson	(100) Scheduled Outage	Planned power outage under GOI 20-416.		0.11	429	47.8	YUB		
				Dawson	Dawson (Feeder 1)		7/30/2020 1:00:11 AM	7/30/2020 1:06:52 AM	0.11	429	47.8		T	4200V
		Tot Qtr:5								2.92	4,185	1,369.8		

Year	Quarter	Id	Date	(Code) Description			Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
				Locations		Feeder/Line	Start DateTime	End DateTime						
2020	Qtr 4	2020-0061	Oct 26, 2020	Segs: 2	Dawson	(601) Extreme Wind	Strong southerly winds at +90kmph knocked down many trees in southern Yukon causing damage to power lines, transformers and PT's.		0.49	939	445.4	YUB		
				Dawson	Dawson (Feeder 1)		10/26/2020 2:54:58 PM	10/26/2020 3:22:39 PM	0.46	429	197.9		T	4200V
				Dawson	Dawson (Feeder 2)		10/26/2020 2:54:58 PM	10/26/2020 3:24:05 PM	0.49	510	247.5		T	4200V
		2020-0068	Nov 15, 2020	Segs: 2	Dawson	(203) Generation Inadvertent	Vaporizer on LNG skid tripped off due to low gas temp, cut fuel to WG0 and tripped the units. S249-52-10 did not close on SCADA commands, Mayo PLT. needed to close in locally.		0.24	939	223.8	YUB		
				Dawson	Dawson (Feeder 1)		11/15/2020 4:00:27 PM	11/15/2020 4:14:32 PM	0.23	429	100.7		T	4200V
				Dawson	Dawson (Feeder 2)		11/15/2020 4:00:27 PM	11/15/2020 4:14:56 PM	0.24	510	123.1		T	4200V
		2020-0069	Nov 17, 2020	Segs: 2	Dawson	(506) Other Equipment Failure	Cause was S250-T1MVA exceeded.		0.50	939	465.8	YUB		
				Dawson	Dawson (Feeder 1)		11/17/2020 6:16:42 PM	11/17/2020 6:46:28 PM	0.50	429	212.8		T	4200V
				Dawson	Dawson (Feeder 2)		11/17/2020 6:16:42 PM	11/17/2020 6:46:28 PM	0.50	510	253.0		T	4200V
		2020-0072	Dec 02, 2020	Segs: 2	Dawson	(301) Falling Tree	This was the 6th tree caused outage along L178 this year. Tree discovered just north of Little Salmon.		0.13	939	124.2	YUB		
				Dawson	Dawson (Feeder 1)		12/2/2020 3:51:40 AM	12/2/2020 3:59:36 AM	0.13	429	56.7		T	4200V
				Dawson	Dawson (Feeder 2)		12/2/2020 3:51:40 AM	12/2/2020 3:59:36 AM	0.13	510	67.4		T	4200V
		2020-0073	Dec 04, 2020	Segs: 2	Dawson	(304) Off-ROW Tree	Outage currently under investigation. No cause discovered. Possibly a tree contact as it was very windy and snowing.40-60km/hr. Note that Minto Mine breaker S254-52-F1 tripped not S254-52-TR (S254-52-F1 not in database. Had to use S254-52-TR for outage tracking purposes). Also, had to enterS258-52-3 breaker for Eagle Gold		0.25	939	227.5	YUB		
				Dawson	Dawson (Feeder 1)		12/4/2020 10:53:16 AM	12/4/2020 11:07:26 AM	0.24	429	101.3		T	4200V
				Dawson	Dawson (Feeder 2)		12/4/2020 10:53:16 AM	12/4/2020 11:08:07 AM	0.25	510	126.2		T	4200V
		2020-0074	Dec 14, 2020	Segs: 2	Dawson	(501) Electrical Failure	The three LNG units tripped, as a result the Breakers at P158, S250 and Mayo opened and YM10 and YM13 tripped. The reason for the LNG trip is under investigation. After further investigation it was determined that a ground fault on WG1 resulted in all three LNG units tripping off line.		0.13	939	115.2	YUB		
				Dawson	Dawson (Feeder 2)		12/14/2020 7:17:46 AM	12/14/2020 7:25:20 AM	0.13	510	64.3		T	4200V
				Dawson	Dawson (Feeder 1)		12/14/2020 7:17:46 AM	12/14/2020 7:24:53 AM	0.12	429	50.9		T	4200V
		2020-0078	Dec 22, 2020	Segs: 2	Dawson	(604) Ice/Icing	Heavy frost/snow accumulation on L177 causing line slap.		0.13	939	114.4	YUB		

Year	Quarter	Id	Date	(Code) Description			Comment		OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage	
				Locations		Feeder/Line	Start DateTime	End DateTime							
2020	Qtr 4	2020-0078	Dec 22, 2020	Dawson	Dawson (Feeder 1)			12/22/2020 4:58:09 PM	12/22/2020 5:06:00 PM	0.13	429	56.1		T	4200V
				Dawson	Dawson (Feeder 2)			12/22/2020 4:58:09 PM	12/22/2020 5:05:00 PM	0.11	510	58.2		T	4200V
		2020-0079	Dec 26, 2020	Segs: 2	Dawson	(501) Electrical Failure		S253-521 had lost its SF6 as burst disc had ruptured. This had happened the night before. Through testing the breaker was determined to be the fault.		0.26	939	218.0	YUB		
				Dawson	Dawson (Feeder 1)			12/26/2020 4:46:29 PM	12/26/2020 5:02:09 PM	0.26	429	112.0		T	4200V
				Dawson	Dawson (Feeder 2)			12/26/2020 4:46:29 PM	12/26/2020 4:58:57 PM	0.21	510	106.0		T	4200V
		2020-0081	Dec 20, 2020	Segs: 2	Dawson	(604) Ice/Icing		Suspected line slap due to frost built up on L177 power lines.		0.46	939	294.0	YUB		
				Dawson	Dawson (Feeder 1)			12/20/2020 10:39:02 AM	12/20/2020 11:06:29 AM	0.46	429	196.3		T	4200V
				Dawson	Dawson (Feeder 2)			12/20/2020 10:39:02 AM	12/20/2020 10:50:32 AM	0.19	510	97.7		T	4200V
		Tot Qtr:9								4.77	8,451	2,228.3			
	Tot Yr: 19								11.34	16,902	5,336.4				
2021	Qtr 1	2021-0004	Jan 18, 2021	Segs: 2	Dawson	(604) Ice/Icing		Windy and wet snow at the time of the outage. Also lots of frost built up on power lines. Possible line slap.		0.08	939	66.8	YUB		
				Dawson	Dawson (Feeder 1)			1/18/2021 5:09:54 PM	1/18/2021 5:13:50 PM	0.07	429	28.1		T	4200V
				Dawson	Dawson (Feeder 2)			1/18/2021 5:09:57 PM	1/18/2021 5:14:30 PM	0.08	510	38.7		T	4200V
		Tot Qtr:1							0.14	939	66.8				
	Tot Yr: 1								0.14	939	66.8				
Tot All:145									108.88	112,454	45,640.5				

1 **REFERENCE: Application, Appendix 5.1, page 5.1-3**

2
3 **ISSUE: MH0 (Mayo A) Generation Station Slope Stability Project**

4
5 **QUESTION:**

6
7 a) Please provide a cost breakdown of the \$1,500,000 cost for this project. More
8 specifically, identify the activities YEC forecasts to conduct and the cost amount
9 allocated to those activities.

10
11 **ANSWER:**

12
13 **(a)**

14
15 This project has been deferred to 2023 to allow for further engineering and planning.

1 **REFERENCE:** Application, Appendix 5.1, page 5.1-3

2
3 **ISSUE:** Replacement of Mayo A Surge Chamber Project

4
5 **QUOTE:** "The Mayo A surge chamber is at end life and must be replaced before
6 there is a catastrophic failure. An engineering study is being undertaken
7 in 2021 to determine solutions and further work is forecast in 2022."
8

9 **QUESTION:**

10
11 a) Please indicate the year in which the Mayo A surge chamber was installed and the
12 expected service life at the time of installation.

13
14 b) Please explain how often YEC carried out tests on this chamber in the past to
15 assess its reliability and how often maintenance work was required. If possible,
16 please provide the number of times maintenance was conducted on this chamber
17 in the last 10 years, on a per annum basis, and the cost of this maintenance work.

18
19 c) Please describe the nature of the catastrophic failure that could occur in the Mayo
20 A surge chamber.

21
22 d) Please provide details on the engineering study that will be conducted on the
23 chamber.
24

25 **ANSWER:**

26
27 **(a)**

28
29 The surge chamber was Installed in 1952. Expected service life unknown.
30

31 **(b)**

32
33 A reliability test was performed in 2018; annual maintenance consists of visual inspection
34 and confirmation of heating functionality prior to winter.

1 Maintenance was performed twice (2019/2020)

- 2
- 3 • The 2019 cost was \$142; and
- 4
- 5 • The 2020 cost was \$21,212.
- 6

7 **(c)**

8

9 The nature of the catastrophic failure that could occur is unknown.

10

11 **(d)**

12

13 An engineering study will be completed to determine options and a recommendation for

14 the replacement of the surge chamber.

1 **REFERENCE:** Application, Appendix 5.1, page 5.1-4

2
3 **ISSUE:** Stop Log Crane WH Main Spill Way Project

4
5 **QUOTE:** "The stop log crane at the Whitehorse hydro main spill way is critical
6 infrastructure that is required for installing stop logs, including in
7 emergency situations. Furthermore, cranes are subject to annual
8 inspection by regulation. The stop log crane is aging and is
9 experiencing a number of issues. Several structural fasteners are
10 showing signs of rusting and possible fatigue ... Due to the age and
11 design of this unit, any parts required to facilitate this repair will have to
12 be independently sourced and/or manufactured."
13

14 **QUESTION:**

- 15
16 a) Please indicate the year in which the stop log crane was installed and the expected
17 service life at the time of installation.
18
19 b) Please clearly describe what work will be done, as part of this project in 2021, that
20 is covered by the \$200,000 cost. Are further costs, beyond the \$200,000 in 2021,
21 anticipated in the near future for the stop log crane?
22

23 **ANSWER:**

24
25 **(a)**

26
27 The estimated installation date is 1958 as part of the original infrastructure. The expected
28 service life of an exterior crane is 20 years.
29

30 **(b)**

31
32 Assessment and engineering work will be completed in 2021 and has yet to begin. This
33 information will be used for project planning and estimating. The crane replacement
34 project will commence in 2022.

1 **REFERENCE:** Application, Appendix 5.1, page 5.1-4

2
3 **ISSUE:** Asset Management Framework Project

4
5 **QUOTE:** "YEC is proceeding in a staged manner. Asset Management
6 Framework costs to the end of 2019 were \$2.064 million, with \$1.560
7 million of forecast expenditures in 2020 and \$1.196 million of forecast
8 expenditures in 2021. Project costs will remain in WIP at the end of
9 2021 as activities for the 5-year program remain ongoing in 2022. Costs
10 for EAM system purchase and implementation are addressed
11 separately (see Section 5.4.1)."

12
13 **QUESTION:**

- 14
15 a) Please confirm that this is a separate project from and in addition to the Enterprise
16 Asset Management (EAM) in Section 5.4.1.1 in the Application. (IR 66) Why are
17 they separated into two projects?
18
19 b) Please explain why it costs \$4.82 million to develop a framework for managing
20 capital assets.
21
22 c) Please provide a cost breakdown for this project. More specifically, provide the
23 activities YEC has included in its forecasts and the cost amount allocated to those
24 activities.
25
26 d) Please provide the results of analysis performed by YEC examining the costs and
27 benefits of this project, including a comparison to any alternatives considered by
28 YEC for this project.
29

30 **ANSWER:**

31
32 **(a)**

33
34 EAM implementation is a separate project from Asset Management Framework (AMF) and
35 PAMMS.

1 The AMF project involves development of a governance model as it applies to lifecycle
2 management of YEC assets cradle to grave. It is aligned with ISO 55000, the international
3 standard on Asset Management, and involves the development of a managed system.
4 This system includes policy, processes, procedures pertaining to the management of
5 assets. Attachment 1 to this response provides the ISO 55000 standard.

6
7 The EAM tool is a component of the AMF. The EAM projects is a software tool project
8 primarily used for planning maintenance work at YEC.

9
10 **(b)**

11
12 The objective of this 5-year project is to develop and implement a formal Asset
13 Management Framework at YEC. Project deliverables include the following activities:

- 14
15 • Implementation of an AMF and governance model consisting of policies,
16 procedure, and process;
- 17
18 • Completion of the asset hierarchy and naming convention;
- 19
20 • Asset data collection;
- 21
22 • Maintenance philosophy, and methodology;
- 23
24 • Refinement, Development and documentation of Maintenance Manuals
25 (Maintenance plans and instructions);
- 26
27 • Development of Asset Management Plans (AMPs) which include YEC's hydro,
28 protection and control, diesel, substation, dam, transmission, and distribution
29 assets;
- 30
31 • Maintenance Repair and Operations (MRO) parts warehousing process and
32 procedure development and implementation;
- 33
34 • Organizational change management procedures and processes; and
- 35
36 • Project management methodologies, processes and procedures.

1 (c)

2
3 Please see the cost breakdown provided in the table below.
4

Asset Management Project Budget March 2018	
Subject Area	Total
Strategy and Planning	\$ 58
Whole Life Cost Justification	\$ 81
Lifecycle Delivery	\$ 3,015
Asset Information	\$ 645
Organizaion and People	\$ 228
Risk and Review	\$ 422
Project Management and Overhead	\$ 426
Subtotal	\$ 4,875
Contingency	\$ 608
Total	\$ 5,482

5
6
7 (d)

8
9 There was no formal cost/ benefit analysis or NPV business case study performed on the
10 Asset Management Framework (AMF) project as the benefits are qualitative.

11
12 Successful execution of the proposed the AMF project is expected to deliver the following
13 benefits to YEC:

- 14
15
 - Organizational sustainability;
 - 16 • Knowledge transfer;
 - 17 • Operational Efficiencies;
 - 18 • Long Term Capital Planning certainty;
 - 19 • Regulatory Approval certainty;
 - 20 • Managing the risk of project deferral; and
 - 21 • Continuous improvement.

22

23 These benefits are discussed in further detail below.

1 **Organizational Sustainability**

2 Without a managed system, strategic items that are implemented are typically on
3 someone's desktop or filed away where other employees have little to no access. A
4 managed system prevents this, and information is stored and managed in a structure,
5 such that any one employee can leave the company and the information is available and
6 managed.

7
8 **Knowledge capture / lasting change**

9 The outcome of the development of the AMF (collaboratively developing and documenting
10 roles and responsibilities, processes, and procedures) establishes documented business
11 practices for YEC and ensures that the AMF becomes a persistent part of the culture and
12 is resilient to potential risks such as turnover of key staff.

13
14 **Operational Efficiencies**

15 Utilities that have implemented Asset Management programs based on the ISO 55000
16 standard have achieved operational savings in the range of 15-25%¹. While Management
17 has not quantified the expected cost savings that will result from implementation of the
18 proposed Asset Management framework, savings are expected to arise from of the
19 following:

- 20
- 21 • Efficiency improvements in the planning and execution of maintenance work;
22
 - 23 • Capital efficiency improvements through the prioritization of investments according
24 to asset criticality, condition and risk;
25
 - 26 • Optimization of relative expenditures on operating costs (e.g., maintenance) vs
27 capital expenditures (asset refurbishment or replacement); and
28
 - 29 • Efficiency improvements from improved availability and management of
30 documentation and data related to assets.

¹ 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.

1 **Long Term Capital Planning certainty**

2 The proposed Asset Management program will deliver comprehensive data and
3 supporting analysis on the condition of YEC's key assets, which will be used to support
4 and justify YEC's long term Sustaining Capital plans and associated long term financing
5 requirements. This data is critical for the evaluation of YEC's future capital needs by the
6 YEC Board, Shareholder and Yukon Government.

7
8 **Regulatory Approval certainty**

9 Information on the condition of key assets can be used to demonstrate the prudence of
10 YEC's Sustaining Capital investments to the Yukon Utilities Board (YUB). This results in
11 YEC's ability to deliver on its Capital Program consistently.

12
13 **Managing the risk of project deferral**

14 Upon project completion YEC will have information at hand to make well informed decision
15 about an asset. Also, the maintenance program will be improved such that the overall
16 lifecycle of an asset is longer than expected. This results in a flatter Capital program over
17 a longer period of time, extending asset life as well as a reduction in equipment failures.

18
19 **Continuous improvement**

20 A managed system, by definition, deploys a Plan, Do, Check and Act process. The
21 process, when followed, reviews existing systems, identifies improvement opportunities
22 and where cost effective, defines actions to ensure that the "Status Quo" is challenged.
23 This process is significant and allows an organization to become more efficient in its
24 operations.

1 **REFERENCE:** Application, Appendix 5.1-2, page 5.1-5; Appendix A to Board
2 Order 2018 10: Reasons for Decision, paragraph 463

3
4 **ISSUE:** Battery Energy Storage System Project

5
6 **QUOTE:** From Appendix 5.1-2, page 5.1-5:

7
8 “In Order 2018-10 regarding the 2017/18 GRA the Board noted its view
9 that the estimated costs for 4 MW of battery storage did not compare
10 favourably on a dollar per MW basis with the LNG third engine or the
11 20 MW thermal plant. Further, concern was noted that the technology
12 was not tested, and shown demonstrated benefits, in northern climates.
13 Given the costs and unproven nature of the technology in a northern
14 environment, the Board determined the project was not viable and
15 absent NRCan funding it was risky to undertake the project.” (footnote
16 removed)

17
18 From Appendix A to Board Order 2018-10:

19
20 “Further, the Board is of the view that, at this time, the technology used
21 for battery storage has not been tested in northern climates such as
22 Yukon and has not been shown to provide the benefits outlined by YEC
23 in such jurisdictions. The Board finds that, given the costs and unproven
24 nature of the technology in a northern environment, the project is not
25 viable. If YEC did not have funding from NRCan, it was risky to
26 undertake the project, considering that even the initial costs in the test
27 years are forecast at over \$9 million dollars. For these reasons, the
28 Board finds that expenditures on such a project are not warranted. As
29 a result, the Board denies the inclusion of costs associated with the
30 battery energy storage project in the revenue requirement for the test
31 years and directs YEC to reflect this finding in its compliance filing.”

32
33 **QUESTION:**

- 34
35 a) Please provide the results of analysis performed by YEC examining the costs and
36 benefits of the project relative to any alternatives considered by YEC.

1 b) Please identify how YEC has addressed the Board's concerns in Board Order
2 2018-10 with respect to the project's viability, benefits and expenditures.

3
4 c) If this project is approved by the Government of Yukon in 2021, please provide the
5 current estimate of when YEC intends to add costs related to this project to its
6 proposed rate base, e.g., in a future GRA.

7
8 **ANSWER:**

9
10 **(a), (b) and (c)**

11
12 The Battery Energy Storage System (BESS) project is planned to come into service in the
13 latter part of 2022. It will remain in WIP during 2021 and not affect 2021 GRA revenue
14 requirement.

15
16 The BESS project has been designated in OIC 2020/180 as a "regulated project" under
17 Part 3 of the Public Utilities Act, and the Minister has referred to the YUB for review the
18 YEC Application for an energy project certificate and an energy operation certificate for
19 this project. The Board's review and report to the Minister will be completed before YEC
20 undertakes any final commitments to proceed with this project.

21
22 Yukon Energy addressed the Board's concerns regarding this project through feasibility
23 assessment by Hatch Engineering of the technology application in the Yukon climate and
24 securing \$16.5 million of federal grant funding towards development of this project as
25 described in the GRA section referenced in this question.

26
27 The BESS will provide 7.2 MW dependable capacity [reduction of four diesel rentals] to
28 reduce Yukon Energy's need to rely on rental of diesel generators during the winter
29 months to address N-1 capacity shortfalls. The BESS will also provide other benefits,
30 including: an operating reserve that reduces thermal generation requirements; enhanced
31 blackstart capability; opportunities for diesel-peak shifting; and other system benefits.
32 These benefits are forecast in the Part 3 Application to result in net ratepayer savings
33 when compared to the use of diesel rentals which would be necessary should the Project
34 not proceed, i.e., over the life of the Project the net present value (2022\$) of the net YEC
35 costs is \$27.751 million compared to the net present value of benefits of \$40.426 million
36 for reduced diesel rental costs and reduced thermal generation fuel costs (see a copy
37 below of Table 4-3 from the Part 3 Application). This indicates the BESS project will benefit

Yukon ratepayers (present value savings of \$12.676 million). The BESS is expected to assist in YIS grid stability and reduce thermal generation and GHGs – benefiting both the environment and Yukon ratepayers.

Table 1: Annual Ratepayer Impacts from BESS (20 MW/ 40 MWh)
[Copy of Table 4-3 from YEC's Part 3 Application for the BESS Project]

	BESS Annual Costs (\$000)				BESS Annual Savings (\$000)				Net Annual Ratepayer Savings (Costs) (\$000)
	Annual Capital Cost	Annual Operating Cost [excl. recharging]	Annual Net Recharging Cost [15% return loss plus 3% idling loss]	Total Annual Costs	Avoided Diesel Rental Costs	Annual Savings from Operating Reserve Use	Annual Savings from Peak Shifting	Total Annual Savings	
	A	B	C	D=A+B+C	E	F	G	H=E+F+G	I=H-D
\$000									
Year 1	\$1,530	\$652	\$82	\$2,264	\$1,216	\$1,125	\$11	\$2,351	\$87
Year 2	\$1,492	\$665	\$84	\$2,240	\$1,265	\$1,147	\$11	\$2,423	\$182
Year 3	\$1,454	\$678	\$85	\$2,217	\$1,315	\$1,170	\$11	\$2,496	\$280
Year 4	\$1,416	\$691	\$87	\$2,194	\$1,368	\$1,193	\$11	\$2,573	\$379
Year 5	\$1,378	\$704	\$89	\$2,171	\$1,423	\$1,217	\$12	\$2,651	\$481
Year 6	\$1,340	\$717	\$91	\$2,148	\$1,480	\$1,242	\$12	\$2,733	\$585
Year 7	\$1,302	\$731	\$92	\$2,126	\$1,539	\$1,267	\$12	\$2,817	\$691
Year 8	\$1,264	\$745	\$94	\$2,104	\$1,600	\$1,292	\$12	\$2,904	\$801
Year 9	\$1,226	\$759	\$96	\$2,082	\$1,664	\$1,318	\$12	\$2,994	\$912
Year 10	\$1,189	\$774	\$98	\$2,061	\$1,731	\$1,344	\$13	\$3,088	\$1,027
Year 11	\$1,151	\$789	\$100	\$2,040	\$1,800	\$1,371	\$13	\$3,184	\$1,144
Year 12	\$1,113	\$804	\$102	\$2,019	\$1,872	\$1,398	\$13	\$3,284	\$1,265
Year 13	\$1,075	\$820	\$104	\$1,999	\$1,947	\$1,426	\$13	\$3,387	\$1,388
Year 14	\$1,037	\$835	\$106	\$1,978	\$2,025	\$1,455	\$14	\$3,493	\$1,515
Year 15	\$999	\$851	\$108	\$1,959	\$2,106	\$1,484	\$14	\$3,604	\$1,645
Year 16	\$961	\$868	\$111	\$1,939	\$2,190	\$1,514	\$14	\$3,718	\$1,779
Year 17	\$923	\$885	\$113	\$1,920	\$2,278	\$1,544	\$15	\$3,836	\$1,916
Year 18	\$885	\$902	\$115	\$1,902	\$2,369	\$1,575	\$15	\$3,958	\$2,057
Year 19	\$847	\$919	\$117	\$1,884	\$2,463	\$1,606	\$15	\$4,085	\$2,201
Year 20	\$810	\$937	\$120	\$1,866	\$2,562	\$1,638	\$15	\$4,216	\$2,350
NPV	\$16,318	\$10,147	\$1,286	\$27,751	\$22,647	\$17,612	\$167	\$40,426	\$12,676

Notes:

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

1 **REFERENCE:** Application, Appendix 5.1, page 5.1-6

2
3 **ISSUE:** Pumped Storage

4
5 **QUOTE:** "Federal funding was identified as a critical requirement for this project
6 to keep the project affordable for customers and to minimize risks."
7

8 **QUESTION:**
9

- 10 a) Does YEC have an estimate of the total cost for this project, if completed? If so,
11 please provide a cost breakdown of the costs for this project. More specifically,
12 provide the activities YEC forecasts to conduct and the cost amount allocated to
13 those activities. If not, please explain why not.
14
- 15 b) Has YEC identified potential federal funding for this project? If so, please provide
16 an overview of the funding YEC hopes to obtain and the status of efforts to do so.
17
- 18 c) Please provide the results of analysis performed by YEC examining the costs and
19 benefits of the project relative to any alternatives considered by YEC.
20
- 21 d) Please comment on how an isolated electrical system running out of generation
22 capacity can benefit over the short, medium and long term from energy storage
23 within the isolated system.
24
- 25 e) Given the inefficiencies of storage systems and the current operating frequencies
26 and duration for thermal generation in the Yukon, please comment on whether it
27 is reasonable to use thermal generation to charge a storage facility.
28

29 **ANSWER:**
30

31 **(a)**
32

33 As outlined in the 10-Year Renewable Electricity Plan, the total cost for the Moon Lake
34 Pumped Storage is estimated to be \$280,000,000. A breakdown of the cost estimate can
35 be found in Appendix F, Table 4.1 of the 10-Year Renewable Electricity Plan. [This Plan
36 is provided in Attachment 1 to CW-YEC-1-36(a).]

1 **(b)**

2
3 YEC is working with Yukon government and the First Nations whose Traditional Territory
4 the project is located on to secure Federal funding for the work required in the planning
5 phase of the Moon Lake project. An application has been submitted for initial funding for
6 project planning, but no confirmation has been received to date on its approval status from
7 the Federal government. Material work on the project will not be undertaken until Federal
8 funding is secured for these activities.

9
10 **(c)**

11
12 The 10-Year Renewable Electricity Plan analyzed a number of alternative resources to
13 meet the Yukon's energy and capacity demands. The Moon Lake pumped storage project
14 with federal funding has the most competitive Levelized Cost of Capacity (LCOC)
15 compared to alternatives, as reviewed in Table 3 in the 10-Year Renewable Electricity
16 Plan (see response to "a" above). Dependable capacity was the key element needed in
17 resources to address the capacity shortfall and expected load growth, while providing
18 additional benefits of seasonal energy storage.

19
20 **(d)**

21
22 The proposed pumped storage would enable the YIS to secure renewable dependable
23 capacity sufficient to remove the sizeable N-1 dependable capacity shortfall forecast for
24 the medium and long-term that would otherwise require reliance on rental and/or new
25 permanent thermal generation capacity. The project would also utilize summer surplus
26 renewable energy on the YIS, and (through the related transmission development)
27 enhance prospects for sale of surplus renewable summer energy to the Skagway cruise
28 ship tourist activity. Key factors related to pumped storage and YIS summer surplus
29 renewable energy include the following:

- 30
- 31 • Today YEC has excess water in summer at WGS and have to spill;
 - 32
 - 33 • It is forecast that YEC will have 40 GWh of SOP IPP energy added to the grid,
 - 34 and all of the summer energy related to these IPPs is expected to increase spill
 - 35 at Whitehorse dam; and

- Pumped storage will utilize this summer surplus and enable it to be redeployed to the winter, directly reducing thermal generation requirements.

(e)

YEC does not anticipate recharging the pumped storage system with thermal energy but would instead use surplus wind, solar and summer Whitehorse generation (which is currently spilled). Moon Lake is also expected to provide inflows and energy generation. Having a seasonal pumped storage facility would allow Whitehorse Generating Station to run at 100% capacity in the summer and shift this energy to the winter, reducing the thermal requirements in the Yukon.

REFERENCE: Application, Appendix 5.1, page 5.1-7

ISSUE: Southern Lakes Transmission Line and Whitehorse Interconnection Projects

QUESTION:

- a) Does YEC have an estimate of the total costs for these two projects, if completed? If so, please provide cost breakdowns for the projects. More specifically, provide the activities YEC forecasts to conduct and the cost amount allocated to those activities. If not, please explain why not.

ANSWER:

(a)

As stated in the 10-Year Renewable Electricity Plan, the full cost of the Southern Lakes Transmission Line project is estimated at \$166,000,000. The methodology for creating this cost estimate for the transmission project is presented in Section 3 of the Transmissions Options Evaluation Study, completed for the 2016 Resource Plan.¹ Specifically, Options 4 and 10, presented in Table 4 of this study. The full cost of the Whitehorse Interconnection Project is estimated to be \$7.7 million, for the components as shown in the table below.

Element	Cost Estimate
Whitehorse S150 & P126 Upgrades	\$3 million
L151 Reroute	\$0.5 million
Riverside Substation S171 Upgrades	\$3.5 million
Subtotal:	\$7 million
Contingency (10%)	\$0.7 million
Total Interconnection Upgrades Cost:	\$7.7 million

¹ For further details see the following:

[https://yukonenergy.ca/media/site_documents/Appendix_5.21_Transmission_Options_Evaluation_\(Midgard_2016\).pdf](https://yukonenergy.ca/media/site_documents/Appendix_5.21_Transmission_Options_Evaluation_(Midgard_2016).pdf)

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-1

2
3 **ISSUE:** Dam Safety Program Project

4
5 **QUOTE:** “A full dam safety review (DSR) is performed every 5 years by an
6 external consultant as recommended by the Canadian Dam
7 Association (CDA) ... Spending in 2021 is required to address 2020
8 DSR outcomes and priorities identified for 2021. Some of the high
9 priority items that will be addressed include:

- 10
11
 - Wareham dam spillway design
12
13
 - Warning and danger signage around the six dams
14
15
 - Public safety around Marsh Lake”
16

17 **QUESTION:**

- 18
19 a) Please confirm that the \$300,000 cost for 2021 is for the work included in the bullet
20 list. If confirmed, please break down the \$300,000 cost into the three projects.
21
22 b) Please explain what “public safety around Marsh Lake” entails.
23
24 c) Is the cost of performing the dam safety review included in YEC’s revenue
25 requirement? If so, please provide a reference to where that is described in YEC’s
26 Application.
27
28 d) Was a competitive process used to retain an external consultant to perform the
29 review? If not, why not? If so, please describe the process, including the number
30 of quotes or proposals received and details of the successful vendor.

1 **ANSWER:**

2
3 **(a)**

4
5 The \$300,000 cost is broken out as follows:

- 6
7 • Warning/danger signage - \$50,000;
- 8
9 • Public safety around Marsh Lake - \$150,000;
- 10
11 • Emergency Preparedness Plan and Operational MS - \$25,000; and
- 12
13 • Canyon Lake control structure repairs - \$75,000.

14
15 **(b)**

16
17 The work includes the development of a public safety plan, signage and safety boom
18 installation.

19
20 **(c)**

21
22 Yes, Dam Safety Program cost is included in the 2021 test year revenue requirements as
23 part of rate base. No amortization expense is included for 2021 test year as the project is
24 forecast to be closed by end of 2021.

25
26 The project is listed in Appendix 5.2: Capital Projects >\$10,000 and < \$1 million added to
27 Rate Base and also included in Table 5.2-1 "Projects Included in 2021 Rate Base".

28
29 **(d)**

30
31 A competitive RFP process was initiated. Eight proposals were received evaluated and
32 awarded based on total score based on best overall proposal which included evaluating
33 technical ability and price. Ecora Engineering was selected as the successful proponent.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-2

2
3 **ISSUE:** Dam Safety Recommendations 2017-18

4
5 **QUOTE:** “2019 spending included required maintenance around the Marsh Lake
6 control structure, and replacement of Whitehorse piezometers; while
7 planned 2020 activities include replacement of the Mayo Lake Dam
8 wood planking, Wareham Dam seismic upgrades, and the
9 implementation of a public safety plan at the Marsh Lake control
10 structure.”

11
12 **QUESTION:**

- 13
14 a) Please provide a cost breakdown for 2019 and 2020 spending by the work items
15 listed in the quote above.
16
17 b) Please explain why each of the work items listed in the quote above were required
18 to be done in 2019 and 2020.
19
20 c) Was the work scheduled to be done in 2020 completed? If not, please explain why
21 and provide an update on the status of the work.
22

23 **ANSWER:**

24
25 **(a)**

26
27 A breakdown of 2019 and 2020 spending is outlined in the table below.

	2019 (+)	2019 (+)	2020 (+)
	Total Cost (+)	Cust Connect Contract (+)	Total Cost (+)
P16-026) Dam Safety Recommendations - (-)	272,274.92		124,011.21
(C18053) Dam Safety Recommendations -Closed	172,735.64		
(C19601) DSR-WH Spillway Drainage -Closed	560.66		.00
(C19602) DSR-Marsh Lake Sheet Pile Isla -Closed	3,521.28		
(C19603) DSR-Marsh Lake Boat Lock -Closed	3,214.03		
(C19604) DSR-Mayo Replace Wall Planking -Open	24,377.73		3,405.32
(C19605) DSR-Wareham Dam 2007 Seismic -Open	23,164.62		38,988.33
(C19606) DSR-P125 Stability of stoplogs -Closed	76.82		
(C19607) DSR-Aishihik GS Contingency Pl -Closed	2,999.61		
(C19608) DSR-Aishihik CLCS Non-Conforma -Closed	3,735.98		
(C19609) DSR-WH Embankmt Piezometer Rep -Closed	3,804.16		
(C19610) DSR-EPP/OMS and Other Support -Closed	25,323.16		42,803.25
(C19611) DSR-Owner Cost -Closed	6,978.60		
(C19612) Dam Safety Management Program -Closed	977.86		3,475.35
(C19613) Dam Safety Inspection -Closed			35,338.96
(C19614) WRGS Seismic Study -Closed	804.77		

The total actual spend for 2020 was \$124,011 (compared to the forecast of \$0.300 million in the GRA). The remainder was to be applied to the Mayo Wall Planking construction, the Wareham Dam Seismic Upgrades construction, and the Public Safety Plan. The Mayo Wall Planking and the Wareham Dam Seismic Upgrades were deferred due to the high water levels in both Mayo Lake and Wareham Lake. The Public Safety Plan was deferred until the completion of the 2020 Dam Safety Review.

These 3 projects are identified as part of Dam Safety Review and will be completed.

(b)

Items listed for 2019/2020 were generated from Dam Safety Inspection (performed yearly) and the Dam Safety Review of 2015.

(c)

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.

- 1 Wareham Dam Seismic Upgrades were also not completed due to high water levels. This
- 2 work will now be completed as part of other Wareham Dam projects currently being
- 3 planned.
- 4
- 5 Public Safety Plan was not completed due to the fact that YEC is waiting for results from
- 6 the 2020 Dam Safety Review for inclusion into the Public Safety Plan.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-2

2
3 **ISSUE:** P126 LNG Boil-Off Gas Heat Exchanger Project

4
5 **QUOTE:** "Prior to decommissioning of the Mirrlees diesel generators, LNG boil
6 off gas was piped to P126 and burned in the P126 plant boiler and/or
7 dissipated through the WD1 jacket water heat exchanger. With
8 retirement and removal of the three Mirrlees gensets at the Whitehorse
9 Diesel Plant (P126) there was a requirement to replace this heat
10 dissipation function and to design, supply and install a new heat
11 exchanger at the plant to dissipate extra heat from the combustion of
12 LNG boil off gas. Work related to the installation of the heat exchanger
13 included hiring an owners engineer to prepare design, drawings and
14 specifications for the new heat exchanger, piping, a new pump with
15 VFD, and a temperature sensing device, and provide mechanical and
16 electrical drawings and technical specifications for equipment and
17 piping installation for tendering the construction work."
18

19 **PREAMBLE:** The Board requires additional information regarding how removal of the
20 Mirrlees generators necessitates a new heat dissipation function and
21 heat exchanger.
22

23 **QUESTION:**

- 24
25 a) Were the P126 plant boiler and WD1 jacket water heat exchanger removed or
26 decommissioned when the diesel generators were decommissioned?
27
28 b) Please explain why removal of the diesel generators necessitates installation of a
29 new heat exchanger.
30

31 **ANSWER:**

32
33 **(a)**

34
35 P126 boiler was not removed. WD1 Jacket and water heat exchanger were removed when
36 the diesel generators were decommissioned.

1 **(b)**

2

3 New heat exchanger was installed to dissipate heat from the boil off gas from the LNG
4 site. The diesel cooling system previously dissipated heat prior to removal.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-2

2
3 **ISSUE:** Wareham Gate Heating Project

4
5 **QUOTE:** "The Wareham Gate Heating project replaced an old and ineffective
6 heating system on both Wareham Spillway Gates. The new system is
7 designed to keep both spillway gates operational through the winter.
8 Passing flows during outages and times of high inflows is a critical
9 function of the spillway."

10
11 **QUESTION:**

- 12
13 a) Please indicate the year in which the original heating system was installed and the
14 expected service life at the time of installation.
15
16 b) Please describe the frequency and duration of periods during which the Wareham
17 spillway gates were out of operation during the winter over the last ten years, on a
18 per annum basis.
19
20 c) Please describe the effect of those periods on available capacity.

21
22 **ANSWER:**

23
24 **(a)**

25
26 The original heating system was installed in circa 1990. The expected service life is
27 unknown.

28
29 **(b)**

30
31 Due to the extreme cold weather at Mayo keeping the gates operational is problematic.
32 Prior to the repair of the gate heat and installation of the bubbler system in 2015 the spill
33 gates required steaming at least 1-2 times per year to keep them operational.

1 (c)

2

3 There is no effect on available capacity.

4

5 The installation of the Mayo B facility (2011) required an increase to the Wareham forebay
6 level, i.e., the layout of the penstock to Mayo B instituted a higher Wareham forebay level
7 to run one or both units¹. The higher operating forebay reduces the time to start spilling if
8 the hydro is shutdown; and the higher forebay requirements have required increased
9 availability and operability of the Wareham spill gates. Additional gate heat and sealing of
10 the gates was required to accomplish this.

¹ The high point in the penstock (PI2) limits the variations in the forebay.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-4

2
3 **ISSUE:** WH4 Ventilation

4
5 **QUOTE:** "The WH4 plant is overheating during the summer. Given that YEC is
6 adding additional capacity to the WH4 hydro unit with new servo motors
7 in 2021, removing the restriction placed on output by the overheating
8 issue will enable the extra capacity to be used reliably throughout the
9 year."

10
11 **QUESTION:**

12
13 a) Please describe the work to be done as part of this project and break down the
14 \$750,000 cost to the work items comprising this project. In your response, provide
15 any assumptions on how the \$750,000 cost was derived.

16
17 b) Please describe the frequency and duration of outages at WH4 resulting from
18 overheating over the last ten years, on a per annum basis.

19
20 **ANSWER:**

21
22 **(a)**

23
24 The project was forecast to be completed in 2021. It will now be completed in 2022 and
25 therefore will not be part of the test year revenue requirement. A breakdown of project
26 costs is not available at this time.

27
28 **(b)**

29
30 Outages were avoided by limiting the output. Summer output was limited to ~80% due to
31 the overheating.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-7

2
3 **ISSUE:** L355 Voltage Regulator Project

4
5 **QUOTE:** "Atco Electric Yukon (AEY) has reported low voltage levels (below CSA
6 standards) at the AEY Haines Junction substation, which is supplied
7 from Aishihik via distribution line L355. The project identified the voltage
8 profile of L355, determined the appropriate location and settings of
9 voltage regulators, and completed all installation and commissioning
10 work.

11
12 **QUESTION:**

13
14 a) Please explain the frequency at which AEY is experiencing low voltage levels.

15
16 b) Please provide the voltage levels prescribed in CSA standards and the voltage
17 levels experienced at the Haines Junction substation.

18
19 **ANSWER:**

20
21 **(a)**

22
23 The low voltages at the AEY Haines Junction substation occur during periods of high load.
24 Most frequently during the winter months.

25
26 **(b)**

27
28 The nominal voltage at the point of sale and purchase should not vary by more than +/-
29 6% as per CAN3-C235-83 (reaffirmed in 2015). On two previous occasions, the incoming
30 voltage to the Haines Junction substation has dipped as low as 6.4% and 10% below
31 nominal.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-9, footnotes

2
3 **ISSUE:** Building Upgrades

4
5 **QUOTE:** “⁷There are many exterior works, including roofing, heat trace, metal or
6 wood cladding, structural or building envelope work or windows and
7 doors. A variety of work is required to be done on staff housing, offices
8 and plants.
9 ⁸ Numerous Heating Ventilation and Air Conditioning (HVAC) issues
10 have been identified. The intent is to group the HVAC work
11 requirements into annual tenders seeking contractor to do works within
12 the communities required.
13 ⁹ Flooring issues identified relate to removal of worn carpeting or
14 sealing of foundation flooring to alleviate any potential radon into the
15 workplace.
16 ¹⁰ A majority of electrical panels are at end of life or currently overloaded
17 and need to be replaced.
18 ¹¹ A stepdown transformer is required for the Aishihik office plant as the
19 existing one has exceeded its life expectancy.”
20

21 **QUESTION:**

- 22
23 a) Please provide the costs for the work items listed in footnote 7 and explain why
24 each is necessary.
25
26 b) Please describe the issues and problems with the existing HVAC systems and
27 equipment and the proposed remedies and forecast cost of those remedies.
28
29 c) Please provide and comment on the results of any testing done for radon in YEC’s
30 buildings and the forecast cost of replacing flooring in those buildings.
31
32 d) Are the electrical panels currently experiencing problems or issues leading to
33 safety concerns or excessive maintenance costs? Please explain.
34
35 e) Please provide the estimated cost of replacing the panels.

1 f) Is the existing stepdown transformer currently experiencing problems or issues
2 leading to safety concerns or excessive maintenance costs? Please explain.

3
4 g) Please provide the estimated cost of replacing the stepdown transformer.

5
6 **ANSWER:**

7
8 **(a)**

9
10 Exterior Works planned for 2019 included replacement of metal cladding and joint sealers
11 at two offices and a hydro plant, roofing replacement at a staff house and office trailer,
12 and the installation of an ice melt system in the concrete ramp at the WH4 hydro plant.
13 The roofing replacement of the Faro staff house was completed during Q3; other planned
14 work was deferred to 2020 due to the need for further investigation, contractor availability,
15 or further inspection determined the work not to be required and it was removed from the
16 scope.

17
18 Total costs incurred in 2019 for exterior work was \$11,989.

19
20 **(b)**

21
22 The consultant identified number of HVAC units that were at end of lifecycle. YEC deemed
23 it prudent to proactively replace these now, rather than waiting for them to breakdown.
24 Run-to-failure is not a principled approach to managing this class of asset. This equipment
25 is critical during heating season so any failures in winter would likely entail higher costs
26 for call-outs, overtime, etc.

27
28 Planned HVAC Retrofits for 2019 involved the replacement of furnaces, boilers,
29 ventilation, or fan coils at a number of locations including offices, generation plants, and
30 staff houses. HVAC work was completed in Q4 at the Aishihik plant, Dawson and Faro
31 offices, Mayo staff house, Kulan warehouse, and Whitehorse IT & drafting trailers. Total
32 costs allocated to HVAC work in 2019 were \$68,709.

1 **(c)**

2
3 Radon testing results did not indicate any areas high zone for radon. The flooring works
4 being undertaken consequently do not relate to radon but relate to the end of life of the
5 existing product in place.
6

7 Flooring Replacement was completed as planned at the main office and a staff house in
8 Dawson. The quotes for replacement of the carpet in the Whitehorse main office came in
9 higher than expected, however, this was offset by removing the flooring replacement in
10 the electrician's trailer from the scope of work. Work planned for 2020 includes flooring
11 replacement at staff houses in Faro and Mayo.
12

13 Total costs allocated to flooring work in 2019 was \$86,014.
14

15 **(d)**

16
17 Some panels are reaching end of life and some are fully loaded requiring a larger panel
18 installation. Works identified within BCR were to be addressed internally if possible. The
19 panels that were replaced were deemed priority for load and life cycling purposes.
20

21 **(e)**

22
23 The estimated cost for replacing the panels was \$18,250.
24

25 **(f)**

26
27 An internal inspection was undertaken and it was determined that this stepdown
28 transformer is not currently overloaded, will not be taking on any more load and could
29 have significant useful life remaining if not operated at a high load. Although it is
30 exceeding its life expectancy the transformer will be monitored and replaced when it starts
31 showing signs of failure or requires additional load.
32

33 **(g)**

34
35 The cost estimate to replace the stepdown transformer in 2013 was \$9,800.

1 **REFERENCE:** **Application, Appendix 5.2, page 5.2-9**

2
3 **ISSUE:** **Compact Digger Truck**

4
5 **QUOTE:** “The purchase of a 4 to 5 ton chassis compact digger truck for use in
6 Dawson will substantially decrease risks for workers and ensure
7 greater efficiency in day to day work; including providing improvements
8 in outage response times. Servicemen currently use an attachable
9 bucket that goes on the side of the digger boom for many types of work
10 from street light maintenance, service work, trouble call response, and
11 new construction. The bucket is heavy and difficult to attach/detach. In
12 a trouble call scenario this can also be time consuming and increase
13 trouble call response time leading to frustration and potential unsafe
14 working conditions.”

15
16 **QUESTION:**

- 17
18 a) On average, how many times per year is the bucket attached to and removed from
19 the digger boom, how many service personnel does it typically take to attach the
20 bucket, and how long does it typically take to do so?
21
22 b) Please use the answers to part (a) to estimate the annual incremental cost of not
23 purchasing a new digger truck.
24
25 c) In the past five years, have any injuries or safety concerns been reported by
26 service personnel as a result of having to attach the bucket? If so, please explain.
27
28 d) Please provide the models and website links (with purchase prices) for the models
29 of compact digger trucks being considered. Please also include YEC’s comments
30 on which model(s) are preferable and why.

1 **ANSWER:**

2
3 **(a)**

4
5 It is practice to remove the bucket if the boom is to be used for lifting. This can include
6 being used for poles, transformers, and wire. Frequency of removing and re-attaching the
7 bucket to the digger boom can range from multiple times per day to just a few times per
8 week depending on the tasks being completed. It is estimated that there can be between
9 250 and 400 change overs per year.

10
11 Dawson PLT's are often in a working alone situation due the district requirements. This
12 can lead to the bucket being attached/re-attached by one PLT. This can be difficult to do
13 as the bucket alone weighs over 100 lbs and can be difficult to handle. Slippery conditions
14 can also add a degree of difficulty to this work.

15
16 For one person working alone this can take 15-20 minutes, and with two people it can take
17 about 10 minutes. The digger takes about twice as long to set up as does a compact
18 bucket truck.

19
20 **(b)**

21
22 Two separate options to purchasing a new digger truck are noted: (1) renting a bucket
23 truck; and (2) continuing to operate in the same manner:

- 24
25 1. **Rental Option:** YEC could rent bucket truck for the busy season at a cost of
26 \$5000-6000 a month for 6 months. This would total about \$30,000 - \$36,000 per
27 year. However, rentals are difficult to procure locally and would likely need to be
28 mobbed/ de-mobbed from a southern province. Mob cost are about \$6000 each
29 way.
30
31 2. **Status Quo:** This option would result in more pressure on, and maintenance for,
32 the Whitehorse large bucket truck. YEC would continue to incur unnecessary travel
33 costs, over time and contractor use. The bucket truck travels to Dawson an
34 estimated 10 times per year, a round trip of 1,064 km. Having the compact bucket
35 truck in Dawson would not eliminate all of these trips but would increase the
36 capacity of Dawson PLT's and greatly reduce trips to Dawson. The closest bucket
37 truck is in Whitehorse which leaves us more exposed to outages in Dawson.

1 (c)

2
3 No Injuries have been recorded in the past five years.

4
5 (d)

6
7 YEC has received information from four vendors regarding the purchase of a compact
8 bucket truck. Table 1 that follows provides a comparison of the information received.
9 Attachment 1 provides the information and specs received from each vendor.

- 10
11 • In comparing the four units YEC has concluded that the Altec AT41M (rank #1)
12 would be the best selection for YEC. Altec is a reputable name when it comes to
13 bucket trucks. It is the same make of the bucket YEC currently owns (smaller
14 model). The AT41M has the best work height of all the comparable units. The rear
15 two step access makes the bucket very accessible. The truck is a “single Cab”
16 which keeps the overall length short and is ideal for the alley ways in Dawson. This
17 truck comes ready to work with all necessary boom testing, strobe lights and
18 compartment lights. The price of this unit is \$187,975. This unit will be ready in
19 June which is months sooner than the Versalift below.

- 20
21 • The next most comparable unit is the Versalift VST 40-I (rank #2). This truck comes
22 on the same chassis and the base price is \$167,500. Although this unit is \$20k
23 lower cost it does not have all of the features of the Altec AT41M and will require
24 upgrades to be ready for work (e.g., inadequate strobes, no compartment lighting,
25 no go light).

26
27 YEC will release a public RFP in 2021 to ensure optimal pricing and fit for service.

1

Table 1: Summary of Options Reviewed & Vendor Information

Bucket Truck Comparison				
Model	AT41M - Altec	LTM40 Terex Hi_Ranger	ETI ETC40MH	VST40-I Versalift
Supplier	Altec BC	Commercial BC	Falcon equipment BC	Custom truck Alberta
Price	\$187,975	\$261,000	\$209,000	\$167,500
Condition	New	New	New	New
Ready Date	Jun-21	late to end of year 2021	Available now	Fall 2021
		Truck Spec		
Chasis	Ford 550	Ford 550 super cab	Ford 550 super cab	Ford 550
4X4	yes	yes	yes	yes
HP	330	330	330	330
Transmission	AUTO	AUTO	AUTO	AUTO
Engine	6.7L power stroke diesel	6.7L power stroke diesel	6.7L power stroke diesel	6.7L power stroke diesel
GVWR	19,500 LBS	19,500 LBS	19,500 LBS	19,500 LBS

Unit Spec				
Boom	Altec model AT41M telescopic articulating aerial device with continuous rotation and ISO-Grip insulating system at boom tip	New Terex Hi-Ranger LTM40 Articulating / Telescoping Aerial Device	2019 ETI ETC40MH Continuous Rotation/ Fiberglass Inner Boom	Versalift VST-40-I, Insulated 40Ft. 4 In Telescopic Aerial Platform Lift, 360 Degree Continuous Rotation Including Slip Rings
Working Hieght	45.8 ft	44.5 ft	44'10"	45.4 ft
Side Reach	30.1 feet	30.7 ft	27'5"	30'2"
Material handling	jib/winch, hydraulically articulating, top mounted, round	Top mount, Removable Jib /Winch	Hydraulic Jib and Winch Package	Hydraulic Dual Arm Articulating Jib Pole And Winch Package
Lifting eye capacity	1000Lbs	800Lb	1000lbs	Jib up to 1000 lb
Elevator	No	No	No	No
Platform	Single 1-Man Platform, Fiberglass, 24" x 30" x 42", End Mount, 180 Degree Rotation	One (1) person, end mounted Platform 24 x 30 x 42:	24x30	1 man Side Mounted Closed Heavy-Duty One-Step 24 In. X 30 In. X 42 In.
Platform Steps	2	Includes one outside access step with slip-resistant surface.	2	Cable Access Step At Rear And Side Access.
Platform cover	yes	yes	yes	yes
Platform Liner	yes 50 kv rating	yes 50 kv rating	yes	Yes
Hydraulic tool outlet	1 set	2 sets	1 set	1 set
Engine start/stop	yes	yes	yes	yes
Out Riggers	Modified A-frame primary outriggers with fixed shoes and safety interlock system	Model 438506 Standard Duty Low Profile A-Frame Outriggers:	A-frame shaped between cab and body	Sub Frame Mounted Main A-Frame Outriggers With Pivot Feet,

Body / other				
Body (lots of detail in spec's)	Standard altec fiber glass body details in W.O documents	Brand FX BFXB 84T Line Body with C2 Walk-Up Details in W.O	steel standard	Dakota Bodies 132" Long X 40" High X 94" Wide Service Body:
Hitch	T-60 style pintle hitch	Assumed...	Assumed	Typical hitch reciever
Out rigger pads	Wood outrigger pads	Wood outrigger pads	Dica compisite	Compisite
Bin Lights	Complete LED FMVSS lighting package	LED Flexglo Compartment Lighting * Top & Sides of Doors	Light in every compartment with master switch in cab	none
More strobe light	4-Corner strobes, amber LED	Truck-Lite 60122Y LED amber oval strobe light offering dual or quad flashing patterns.		none
Strobe light	Strobes, amber LED, with brush guard, installed on post at front of body,	Amber strobe light with 6" lens and mounting bracket.	Amber strobe on post at DS	Strobes in Grill
Light bar	none	Strip LED lighting mounted in loadbed both sides Extruded aluminum drip rails mounted above lighting	none	none
Trailer plug	6-Way trailer receptacle, pin type	6-Way trailer receptacle, pin type	6-Way trailer receptacle, pin type	6-Way trailer receptacle, pin type
Search Light	Go Light	Golight Stryker Search Light	no	no
	Secondary stowage system	Prowatt 3000 Inverter	7	
		Aluminum ladder rack mounted on the street side compartment top		No Hose Cover

2



January 19, 2021

Company: Yukon Energy

Customer Contact: Matt Noseworthy

Altec Account Manager: Richard Merinsky 604-358-0148

Unit / Body Specifications

- Altec model AT41M telescopic articulating aerial device with continuous rotation and ISO-Grip insulating system at boom tip
 - working height: 45.8 ft
 - side reach: 30.1 ft
- Single one man platform, 180 degree rotation
- Material handling jib/winch, hydraulically articulating, top mounted, round
- Two (2) platform steps
- Platform cover
- Platform liner
- One set of hydraulic tool outlets at the boom tip
- Engine start/stop with secondary stowage system
- Jib stick, 36 in L, non-extension dependent, non-certified
- Modified A-frame primary outriggers with fixed shoes and safety interlock system
- Temperature Sight Gauge
- Small aerial service body with side access, 29 inch long tailshelf
- T-60 style pintle hitch
- Wood outrigger pads
- Complete LED FMVSS lighting package
- 4-Corner strobes, amber LED
- Strobes, amber LED, with brush guard, installed on post at front of body, one (1) each side
- 6-Way trailer receptacle, pin type
- Secondary stowage system
- Standard Altec warranty: one (1) year parts, one (1) year labor, ninety (90) days travel and limited lifetime structural.

Chassis Specifications

- Ford F550
 - 4x4 drivetrain
 - 84 inch CA
 - 6.7L Power Stroke diesel
 - 330 HP engine rating
 - Automatic transmission
 - GVWR 19,500 lb

Options

FOB Surrey, BC

Quick-turn Unit - Delivery June 2021

Price: \$ 187,975.00
Options: \$ 0
Delivery: \$ FOB Surrey, BC
Total: \$ 187,975.00
(Excluding Taxes)



Quote Number: 826303 - 1
Altec, Inc.

January 19, 2021
Our 92nd Year

Ship To:
Yukon Energy

Bill To:

Attn:
Phone:
Email:

Altec Quotation Number: 826303 - 1
Account Manager: Richard Merinsky
Technical Sales Rep:

<u>Item</u>	<u>Description</u> <u>Unit</u>	<u>Qty</u>
1.	Altec Model AT41M Articulating Telescopic Aerial Device with a fiberglass upper boom and fiberglass insulator in the articulating arm and proportional joystick upper controls. Built in accordance to ALTEC's standard specifications and to include the following features: A. Ground to Bottom of Platform Height: 40.8 feet at 7.3 feet from centerline of rotation (12.45 m at 2.21 m) B. Working Height: 45.8 feet (13.96 m) C. Maximum reach to edge of platform with Upper Boom Non- overcenter: 30.1 feet (at 17.3 feet platform height) D. Upper boom extension: 110 inches E. Continuous rotation F. Articulating Arm: Articulation is from -3 to 82 degrees. Insulator provides 19 inches of isolation. G. Compensation System: By raising the articulating arm only, the telescopic boom maintains its relative angle in relation to the ground. The work position is achieved through a single function operation. H. Upper Boom: Articulation is from -25 to 85 degrees. The fiberglass section provides a minimum of 10.9 inches of isolation in the upper boom (when retracted and 42.3 inches when extended). I. Platform leveling is achieved by a hydraulic master-slave leveling system. This lifetime system is very low maintenance. J. The dielectrically tested, insulating upper control system includes the following boom tip components that can provide an additional layer of secondary electrical contact protection. Control Handle: A single handle controller incorporating high electrical resistance components that is dielectrically tested to 40 kV AC with no more than 400 microampers of leakage. The control handle is green in color to differentiate it from other non-tested controllers. The handle also includes an interlock guard that reduces the potential for inadvertent boom operation. Auxiliary Control Covers: Non-tested blue silicon covers for auxiliary controls. Control Console: Non-tested non-metallic control console plate. Boom Tip Covers: Non-tested non-metallic boom tip covers. The covers are not	1

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UTILITY EQUIPMENT AND BODIES SINCE 1929



Quote Number: 826303 - 1
Altec, Inc.

<u>Item</u>	<u>Description</u>	<u>Qty</u>
	dielectrically tested, but they may provide some protection against electrical hazards.	
K.	Hydraulic system: Open center (full pressure), maximum flow 6 GPM, maximum operating pressure 3,000.	
L.	Dielectric rating: Category C, 46 kV and below	
M.	Unit is painted with a powder coat paint process which provides a finish-painted surface that is highly resistant to chipping, scratching, abrasion and corrosion. Paint is electrostatically applied to the inside as well as outside of fabricated parts then high temperature cured prior to assembly ensuring maximum coverage and protection.	
N.	Manuals: Two (2) Operator's and two (2) Maintenance/ Parts manuals containing instructional markings indicating hazards inherent in the operation of an aerial device.	
O.	Unit meets or exceeds ANSI 92.2 standards.	
2.	Pedestal	1
3.	Single 1-Man Platform, Fiberglass, 24" x 30" x 42", End Mount, 180 Degree Rotation	1
4.	No Platform Elevator	1
5.	Platform Mounted Single Handle Controls	1
6.	Material Handling Jib/Winch, Hydraulically Articulating, Top Mounted, Round (ARM Jib)	1
7.	One (1) Platform Step - located on the side of the platform nearest the elbow in the stowed position	1
8.	Platform Cover - soft vinyl, 24 x 30 inches (610 x 762 mm)	1
9.	Platform Liner, 24 x 30 x 42 inches (610 x 762 x 1067 mm), 50 kV Rating	1
10.	Hydraulic Tool Circuit at Platform: One set of quick disconnect couplings at the boom tip for open center tools.	1
11.	Engine Start/Stop & Secondary Stowage System: 12 VDC powered motor and pump assembly for temporary operation of the unit in a situation wherein the primary hydraulic source fails. Electric motor is powered by the chassis battery. This feature allows the operator to completely stow the booms, platform, and outriggers. Secondary Stowage & Start/Stop is activated with an air plunger at the platform or momentary switch at the lower control station and outriggers.	1
12.	Jib Stick, 36" L, non-extension, non certified, grey in color	1
13.	Slip Ring: Required for engine start/stop, secondary stowage system, and throttle control options	1
14.	Outriggers, Primary, Modified A-Frame With Integrated Subbase, 30"-34" Chassis Height, Electric Interlock, No Valves On Legs, 114" Spread, Fixed Shoe (AT37/41 M/ME/P/PE/S/SE)	1
15.	Winch load line swivel hook	1
16.	Altec Unit Powder Painted White	1

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And Opportunity of Serving You

UTILITY EQUIPMENT AND BODIES SINCE 1929



Quote Number: 826303 - 1
Altec, Inc.

<u>Item</u>	<u>Description</u>	<u>Qty</u>
<u>Unit & Hydraulic Acc.</u>		
17.	Scuff Pad, 24" x 30", No Step (For use with Platform Liner)	1
18.	Electric Outrigger Controls for one (1) set of outriggers, drive hydraulic outrigger control valves. Durable weather proof sealed electronic switches mounted in aluminum boxes located at the rear of the unit unless otherwise specified.	1
19.	Steel Reservoir, 15 gallon capacity, triangular, 17" L x 17" W x 24" H, and includes breather caps and dipsticks	1
20.	Temperature Sight Gauge	1
21.	HVI-22 Hydraulic Oil (Standard).	25
22.	Standard Pump For PTO	1
23.	Electric Shifted PTO	1
24.	Standard PTO/Transmission Functionality for Small Ford and Dodge Chassis	1
<u>Body</u>		
25.	Altec LGSS-132-84 (81) Low-Side General Service Body With Step:	1
A.	Steel Body	
B.	Steel Structural Channel Crossmembers And Smooth Floor With Ladder-Style Understructure	
C.	132" Body Length	
D.	94" Body Width	
E.	40" Body Compartment Height	
F.	20" Body Compartment Depth	
G.	24" From Body Floor To Compartment Tops	
H.	Finish Paint Entire Body Altec White	
I.	Undercoat Applied Under The Body	
J.	5.5" Drop-In Wooden Cargo Retaining Board At Rear Of Body	
K.	5.5" Drop-In Wooden Retaining Board At Top Of Side Access Step	
L.	Stainless Steel Rotary paddle Latches With Locks	
M.	Gas Props On All Vertical Doors	
N.	Chains On All Horizontal Doors	
O.	Standard Master Body Locking System	
P.	Hotstick Shelf Extending Full Length Of Body On Streetside	
Q.	Two (2) Hotstick Brackets Installed On Streetside.	
R.	One Chock Holder On Each Side of Body With Retaining Lip In Fender Panel	
S.	1st Vertical (SS) - 34" W - One (1) Outrigger Housing And Two (2) Adjustable Shelves With Removable Dividers On 4 Inch Centers	
T.	2nd Vertical (SS) - 24" W - Two (2) Adjustable Shelves With Removable Dividers On 4 Inch Centers	
U.	1st Horizontal (SS) - 50" W - One (1) Fixed Shelf With Removable Dividers On 4 Inch Centers On Bottom of Compartment	
V.	Rear Vertical (SS) - 24" W - Six (6) Locking Swivel Hooks On An Adjustable Rail (1-4-1)	
W.	1st Vertical (CS) - 34" W - One (1) Outrigger Housing And Two (2) Adjustable Shelves With Removable Dividers On 4 Inch Centers	

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And Opportunity of Serving You

UTILITY EQUIPMENT AND BODIES SINCE 1929



Quote Number: 826303 - 1
Altec, Inc.

<u>Item</u>	<u>Description</u>	<u>Qty</u>
X.	2nd Vertical (CS) - 24" W - Gripstrut Access Steps With Two (2) Sloped Grab Handles, Vented Battery Storage	
Y.	1st Horizontal (CS) - 50" W - One (1) Adjustable Shelf With Removable Dividers On 4 Inch Centers And One (1) Fixed Shelf With Removable Dividers On 4 Inch Centers On Bottom Of Compartment	
Z.	Rear Vertical (CS) - 24" W - Six (6) Locking Swivel Hooks On An Adjustable Rail (1-4-1)	
AA.	Body Floor Cut-Out For AT41M/ME/P/PE Aerial Device Near Front Of Body	
AB.	Steel Tailshelf, 29" L x 94" W, With Rear Cross Storage And Drop Down Doors	

Body and Chassis Accessories

26.	ICC (Underride Protection) Bumper Installed At Rear	1
27.	Combination 2 Ball (10 000 LB MGTW) and Rigid Pintle Hitch (16 000 LB MGTW with 3 000 LB MVL), 4-Bolt, Buyers BH82000	1
28.	Set Of Eye Bolts for Trailer Safety Chain, installed one each side of towing device mount.	1
29.	Rigid Step Mounted Beneath Side Access Steps (Installed To Extend Approx. 2" Outward)	1
30.	Platform Rest, Rigid with Rubber Tube	1
31.	Boom Rest for a Telescopic Unit	1
32.	Wood Outrigger Pad, 19" x 19" x 2.5", With Rope Handle	2
33.	Outrigger Pad Holder, 20" L x 20" W x 5" H, Fits 19.5" x 19.5" x 4" And Smaller Pads, Bolt-On, Bottom Washout Holes, 3/4" Lip Retainer	2
34.	Pendulum Retainers For Outrigger Pad Holders	2
35.	Mud Flaps With Altec Logo (Pair)	1
36.	Wheel Chocks, Rubber, 9.75" L x 7.75" W x 5.00" H, with 4" L Metal Hairpin Style Handle (Pair)	1
37.	Slope Indicator Assembly (Pair) For Machine With Outriggers	1
38.	Safety Harness & 4.5 FT Lanyard (Medium To X-large)	1
39.	Driveaway Safety Kit	1
40.	Vinyl manual pouch for storage of all operator and parts manuals	1

Electrical Accessories

41.	Lights and reflectors in accordance with FMVSS #108 lighting package. (Complete LED, including LED reverse lights)	1
42.	4-Corner Strobes, Amber, LED, Two (2) Surface Mounted Lights In Grille, Two (2) Round Lights At Rear	1

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Quote Number: 826303 - 1
Altec, Inc.

<u>Item</u>	<u>Description</u>	<u>Qty</u>
43.	Remote Spot Light, LED, Permanent Mount with Wireless Dash Mounted Controls and Programmable Wireless Remote	1
44.	Strobe Beacon, Amber LED, With Brush Guard, Installed On Post At Front Of Body, One (1) Each Side (Standard) (Federal Signal #420221-02)	1
45.	Dual Tone Back-Up With Outrigger Motion Alarm	1
46.	PTO Hour Meter, Digital, with 10,000 Hour Display	1
47.	6-Way Trailer Receptacle (Pin Type) Installed At Rear	1
48.	Ford Upfitter Switches (Supplied with Chassis)	1
49.	Power Distribution Module Is A Compact Self-Contained Electronic System That Provides A Standardized Interface With The Chassis Electrical System. (Includes Operator's Manual)	1
50.	Install secondary stowage system.	1
51.	Install Remote Start/Stop system in Final Assembly.	1
52.	Install Outrigger Interlock System	1
53.	Heavy Duty Secondary Stowage Pump	1
54.	PTO Indicator Light Installed In Cab	1
<u>Finishing Details</u>		
55.	Powder Coat Unit Altec White	1
56.	Finish Paint Body Accessories Above Body Floor Altec White	1
57.	Altec Standard; Components mounted below frame rail shall be coated black by Altec. i.e. step bumpers, steps, frame extension, pintle hook mount, dock bumper mounts, D-rings, receiver tubes, accessory mounts, light brackets, under-ride protection, etc. Components mounted to under side of body shall be coated black by Altec. i.e. Wheel chock holders, mud flap brackets, pad carriers, boxes, lighting brackets, steps, and ladders.	1
58.	Additional Black Undercoating, Applied per Altec Standard	1
59.	Apply Non-Skid Coating to all walking surfaces	1
60.	English Safety And Instructional Decals	1
61.	Vehicle Height Placard - Installed In Cab	1
62.	Placard, HVI-22 Hydraulic Oil	1
63.	Dielectric test unit according to ANSI requirements.	1
64.	Stability test unit according to ANSI requirements.	1
65.	Focus Factory Build	1

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Quote Number: 826303 - 1
Altec, Inc.

<u>Item</u>	<u>Description</u>	<u>Qty</u>
66.	Inbound Freight	1
67.	Stock Unit	1
68.	Stock Unit Sold To Customer	1
<u>Chassis</u>		
69.	Altec Supplied Chassis	1
70.	2022 Model Year	1
71.	Ford F550	1
72.	4x4	1
73.	84 Clear CA (Round To Next Whole Number)	1
74.	Regular Cab	1
75.	Chassis Cab	1
76.	Chassis Color - White	1
77.	Chassis Wheelbase Length - 169	1
78.	Ford 6.7L Power Stroke Diesel	1
79.	330 HP Engine Rating	1
80.	Ford Torqshift 10-Speed Automatic Transmission (w/PTO Provision)	1
81.	GVWR 19,500 LBS	1
82.	7,500 LBS Front GAWR	1
83.	14,706 LBS Rear GAWR	1
84.	225/70R19.5 Front Tire	1
85.	225/70R19.5 Rear Tire	1
86.	Hydraulic Brakes	1
87.	Park Brake In Rear Wheels	1
88.	Ford E/F250-550 Single Horizontal Right Side Exhaust	1
89.	63C - Aft Axle Frame Extension	1
90.	98R - Operator Commanded Regeneration (OCR)	1
91.	No Idle Engine Shut-Down Required	1
92.	50-State Emissions	1

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UTILITY EQUIPMENT AND BODIES SINCE 1929



Quote Number: 826303 - 1
Altec, Inc.

<u>Item</u>	<u>Description</u>	<u>Qty</u>
93.	Clean Idle Certification	1
94.	Ford 40 Gallon Fuel Tank (Rear)	1
95.	Ford 7.2 Gallon DEF Tank (Mid Mount)	1
96.	AM/FM Radio	1
97.	Bluetooth	1
98.	Air Conditioning	1
99.	Cruise Control	1
100.	Keyless Entry	1
101.	Power Door Locks	1
102.	Power Windows	1
103.	Tilt Steering Wheel	1
104.	Block Heater	1
105.	Limited Slip Rear Axle	1
106.	Power Mirrors with Heated Glass	1
107.	Trailer Brake Controller (Factory Installed)	1
108.	Vinyl Split Bench Seat	1

Additional Pricing

109.	Standard Altec Warranty: One (1) year parts warranty, one (1) year labor warranty, ninety (90) days warranty for travel charges, limited lifetime structural warranty	1

Altec Industries, Inc.

BY _____

Hannah Elizabeth Bridges

Notes:

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UTILITY EQUIPMENT AND BODIES SINCE 1929



Commercial
591 Chester Road
Delta, British Columbia
Phone: (604) 526-6126
Fax: (604) 526-1746

Quotation

Customer: Yukon Energy – Sample Spec

Quote Date:

Contact:
Phone:
Email:

Salesperson: Adam Lowe

QUANTITY	DESCRIPTION	Quote Number: Sample
	AERIAL DEVICE	
1	One (1) New Terex Hi-Ranger LTM40 Articulating / Telescoping Aerial Device providing a working height of 44.5 ft (13.6 m) and a side reach of 30.7 ft (9.4 m) with a platform. Unit will be mounted behind the cab. Design Criteria: * Design criteria is in accordance with current industry and engineering standards applicable and accepted for structural and hydraulic design. Platform Leveling: * Leveling is provided by a master/slave cylinder system. * A control a both the upper and lower control is provided. Upper Controls: * "Control-Plus" single stick controller (4-function) * Non-metallic control handle * Dielectrically tested for limited secondary protection between the valve and handle. * May provide limited secondary protection for operator depending on condition and cleanliness. * Not rated for electrical protection, although it may provide limited secondary protection. * Not intended to replace safe work practices or primary protection such as cover-up and personal protection equipment. * Enable lever must be actuated before operation. * Controls lower boom lift, upper boom lift, boom extension and rotation. Insulated Engine Stop / Start: * Controlled from platform and lower control station. Lower Control: * Individual control levers are located in an accessible location on the turntable. * The lower controls activate boom lift, boom extension, platform leveling, and rotation. * An upper/lower control selector provides override of platform controls, along with an emergency stop. Lower Boom: * Constructed of high strength, rectangular steel tube with a rectangular bi-axial epoxy resin filament wound, high strength fiberglass insert providing an insulation gap of 12 inches. * The lower boom articulation is from -5 to 90 degrees. Upper Boom: * Aerial device upper boom is constructed of high strength steel. * The upper boom has an articulation of -20 to 80 degrees * A boom rest with a cam style tie down strap is provided. Second Section Boom: * The second section boom is constructed of high strength filament wound fiberglass.	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Extension of the second section is accomplished by a hydraulic cylinder. * The upper boom has a total insulation gap of 14 inches retracted and 61 inches extended for end mount platform. * (Note: Side mount platform will be reduced by 12 inches.) * Tapered non-metallic rollers mounted at the end of the second section boom support the fiberglass boom under load minimizing scratches and abrasions. The sides of the fiberglass boom are supported and guided by non-metallic rollers to reduce tracking. Lower Boom Cylinder: * Single, threaded end gland design, double acting hydraulic lift cylinder equipped with integral holding valves. Upper Boom Cylinder: * A double acting hydraulic lift cylinder equipped with integral holding valve is provided. Extension Cylinder: * The boom cylinder is of threaded end gland design. * The cylinder is equipped with integral holding valves to prevent creep and hold the boom in position in the event of hose failure. Boom Interlock: * To operate the boom the outriggers must be extended. Pedestal: * The pedestal is of welded high-strength steel construction. * The pedestal top plate is machined from a single piece of plate. * The top plate bearing surface is pre-machined and inspected after weld to provide a flat mounting surface for the rotation bearing. Turntable: * The turntable is constructed of side plates with an offset configuration to provide maximum strength. * The steel bottom plate has provisions for attaching the outer race of the rotation bearing. Continuous Unrestricted Rotation: * A hydraulic rotary manifold provides a rotating oil distribution system for continuous and unrestricted rotation. * One 3/8 inch hydraulic port is available for options. * Self-locking worm gear rotation drive is provided and equipped with bi-directional motor. * A 7/8 inch external hex shaft allows for manual rotation. * A minimum 4-channel electric collector ring is provided. Rotation Bearing: * The rotation bearing is a heavy-duty "shear ball" bearing with external gear teeth utilizing polished alloy steel balls. * Both the inner and outer races are made from high-strength alloy steel and are heat treated to provide maximum life. * High strength grade 8 bolts attach the inner and outer races to the pedestal and turntable. ANSI & CSA Rating: * Aerial device is designed as a Category C machine and is dielectrically tested and rated for operation up to 46,000 volts AC per ANSI/SIA A92.2-2009 and CSA C225-10. Hydraulic System: * Full pressure, open center hydraulic system. * A 20 gallon external hydraulic oil reservoir is provided with a 60 mesh filler screen, baffles, 100 mesh suction screen with bypass, clean out access hole, dip stick and shut off valve. * A spin on type 10 micron return line filter is provided. * A relief is also provided. * Hydraulic hoses are equipped with permanent type fittings. Miscellaneous: * All metallic components of the complete aerial device are prime painted. * The fiberglass upper boom, boom inserts, platforms, and covers are white. * Two complete manuals providing operation and maintenance procedures, and a replacement parts listing.	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Warning decals provided with unit.	
1	Pedestal * Sized for F550 Super cab Chassis	
1	Platform 24 x 30 x 42: * One (1) person, end mounted, fiberglass platform with a rated capacity up to 400 lbs. * Includes one outside access step with slip-resistant surface. * A safety harness with lanyard.	
1	Hydraulic Platform Rotator: * For end mount platform. * Allows 180-degrees hydraulic rotation and is controlled at the upper controls.	
1	Insulated Platform Liner with Step for 24" x 30" x 42" Platform: * Tested at 50 KV AC.	
1	Vinyl Platform And Control Cover For 24" x 30" Platform: * Waterproof with internal elastic cord around edge and external elastic cord around control cover.	
1	Dual Hydraulic Tool Outlets At Platform With Flow Control: * Installed at the platform to accommodate two open center hydraulic tools. * Provides 5 GPM at 2250 psi at engine idle.	
1	Auxiliary Power: * Allow the operation of any function for a time period limited by the battery life. * Includes 12 volt electric motor for use on a 12 volt chassis. Note: This includes a switch for activation at pedestal for electric or air function.	
1	Platform Rest Saddle with a padded rest. * Provides platform support during road travel	
1	Top mount, Removable 800 lb. Jib/Winch * Levels with platform. * Hydraulic articulation from -20 to 70 degrees. * 51" load radius from the platform shaft. * Manual extension 17". * Maximum jib capacity of 800 lb. * Includes up to 65' of 3/8" winch rope and hook. * Low profile stowed position of 16" and the boom can still utilize its full range of motion down to -40 degrees. * Poppet valve protection of fiberglass boom. Stops boom operation if jib contacts fiberglass boom. * Jib/winch is removable and comes with ship loose socket to store the jib/winch when removed (placed during installation) * King post attached to jib. Low profile socket when jib removed to minimize interference and overall height.	
1	Model 438506 Standard Duty Low Profile A-Frame Outriggers: * Hydraulic double acting outriggers including integral holding valves. * 135.8 " Spread pin to pin and 147.8 " to outside of pads at 3.1 " penetration and 32 " frame height. * 7 " x 12 " Stabilizer pads.	
1	Control For 1-Set Of Outriggers (Open center systems): * Recessed at rear of truck each side for ease of view for outrigger placement. * Includes switches and alarm for outrigger in motion alarm.	
1	Mounting Kit: * Behind cab mount for use with (1) set of outriggers and tie plates.	
1	SAG Light opening in outrigger leg for 1 set of Outriggers: * Includes wiring and switch. * Opening only, no light.	
1	Sight Gauge With Thermometer:	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Mounted within an aluminum body to protect sight tube. * Installed on end of hydraulic oil reservoir. * Thermometer has a range of 0-300 degrees Fahrenheit.	
1	Pump for systems requiring 8 gallons per minute: *Fixed displacement vane pump providing 5 gallons per minute at 950 engine rpm and 8 gallons per minute at 1370 engine rpm with a 98% PTO. * Typically used for transmissions required an elevated speed for PTO operation. Note: LTM product 6 gallons per minute at 900 engine RPM.	
1	Metric and Imperial Load Chart	
	UTILITY BODY	
1	Brand FX BFXB 84T Line Body with C2 Walk-Up – 53130-0007 * Overall Pack Length 132" * Overall Width 94" * Floor Width 58" * Overall Height 48 1/2" * Mounting Height: 30" * Pack Depth 18" * Stainless Steel Hinges and Slam Locks * Vinyl Covered S/S cable door stops * Non Skid Compartment Tops * Full length Aluminum Drip Rail * Clear Vinyl Rock Guards * Automotive grade Bubble gasket * One piece Molded Doors with Automotive finish both sides * Recessed Door Jambs * Flow through Ventilation System * Hot-stick Door Street Side Street Front Compartment * (5) Locking Swivel Hooks 2-1-2 mounted high * (5) Locking Swivel Hooks 2-1-2 mounted Low * Outrigger Cutout Street Front Compartment #2 * 3 Adjustable Shelves with Dividers * Dri-Dek Compartment Liner Street Horizontal Compartment * 1 Adjustable Shelf * Dri-Dek Compartment Liner Street Rear Compartment * 3 Adjustable Shelves * Dri-Dek Compartment Liner Curb Side Front * 3 Adjustable Shelves with Dividers * Dri-Dek Compartment Liner * Outrigger Cutout Curb Front #2 * Walk-Up Stairs – Grip-strut * Access to Deck Curb Horizontal * Fixed Shelf on either side of three pull-out drawers * Fixed Shelf on bottom with Dividers	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Dri-Dek Compartment Liner Curb Rear Compartment * (5) Locking Swivel Hooks 2-1-2 mounted high * (5) Locking Swivel Hooks 2-1-2 mounted Low * Dri-Dek Compartment Liner LED Flexglo Compartment Lighting * Top & Sides of Doors Wheel Well Liners – Aluminum. Fully covering Fiberglass in front, behind and on top of Wheel Wells * Extends under Verticals by 3 inches Wheel Chock Holders * Mounted Curbside at Fenders Aluminum ladder rack mounted on the street side compartment top	
	INSTALLATION & ACCESSORIES	
1	Install Aerial Device Behind Cab And Install All Associated Components: * Final test and inspect completed unit including stability and dielectric testing per manufacturers requirements, ANSI/SIA A92.2-2001 and CSA C225-10.	
1	Hose and fittings to connect the hydraulic system from the oil reservoir to the pump and unit.	
1	Miscellaneous Shop Supplies.	
1	Commercial Custom Aerial Boom Rest * Heavy Gauge Steel Construction	
2	Stainless Steel Grounding Point * 3/4" Stainless Steel round bar * Welded to bottom of outrigger leg	
1	Outrigger controls protection cover * Controls to be enclosed with Aluminum box to protect them from tire and road debris	
30	Hydraulic Oil * ESSO Univis HVI 13	
1	Power take off, 6-bolt, with indicator light for automatic transmission.	
1	Relocate factory DEF Tanks * Required procedure on Ford F550 chassis	
1	Rear towing Recovery Eyes 50,000 pound capacity - used in pairs only * Closed eye 1 1/2" diameter hole * Material - 1" 50,000 PSI steel * One (1) Left & One (1) Right - vertical orientation * Mounted directly to frame rail * 5" W X 16" L * Engineered rating - see 2285-1	
1	Heavy Duty Aluminum Checker Plate Deck	
4	Deck "D" Rings * Welded to cross members * Flush mount	
1	Aluminum Tail Shelf * Checker plate top surface	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Aluminum grab handle mounted on top surface	
1	Vise bracket that fits vertical in a pocket. * 2 inch receiver * Mounted at curb side of Tailshelf	
1	Set chassis parameters * Programming of the Multi-Plex circuits * Writing the programming for the ECU * Program Throttle and PTO * Program Stop/Start * Program all safety controls.	
1	License Plate Lamp * LED * Meets SAE J587 * Complete with bracket	
1	VMAC Throttle Commander * Maintains rpm over engine torque loads * 12-Volt activated * 3 preset programmable rpm settings	
1	Wired-Rite system for chassis.	
1	Truck-Lite LED 7-lamp DOT Lighting Package: * Complies with CMVSS 108 * Includes required lights, junction box and wiring harness	
1	Golight Stryker Search Light * Wireless Remote Controlled Operation * 370° Rotation x 135° Tilt * 500,000 Candle Power, 5.5 Amps * UV Ray and Saltwater Resistant * Integrated 12V DC High-Torque Motors * Weatherproof for Land and Sea Applications * Waterproof Remote Transmitters * R.F. Programmable Super Heterodyne Receiver * 5-Year Limited Warranty * Mounted on hood of vehicle	
2	Amber strobe light with 6" lens and mounting bracket. * Mounted on Boom rest behind Cab * 360 degree visibility	
2	Truck-Lite 60122Y LED amber oval strobe light offering dual or quad flashing patterns. * Flush mounted at rear of body * Switched in Cab	
2	Strip LED lighting mounted in loadbed both sides Extruded aluminum drip rails mounted above lighting	
1	Back-up alarm to sound when the vehicle is shifted into reverse.	
1	Prowatt 3000 Inverter is designed for high power and industrial applications. Its high surge output is ideal for heavy-duty loads or multiple smaller AC loads. It can often be used in place of a generator for large intermittent loads. Product Features * 3000 watts maximum, 5000 watt surge capability * Built-in LED display for DC volts and amps * Supports addition of external AC outlets	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Single GFCI receptacle for safe operation and hardwire AC connections * Heavy duty terminals for trouble-free battery connection * Includes ON/OFF remote switch * Two year warranty	
1	400 Amp fuse Product Features * DC rated, UL listed high current Class-T fuse * Protective clear removable cover protects against inadvertent contact * Dual post design to reduce arcing * Easy to change, user replaceable fuses	
1	Battery Interconnect * 12V * 100 Amp * Uni-Directional /w aux start	
2	Duplex GFI Outlet * Mounted in NEMA 4 Junction Box	
1	Inverter/Battery Cable Package * Required to connect the Vehicle Batteries with the Inverter * Includes all necessary Hardware	
1	Bin Heater mounted in SS2 – with switch in cab Engine coolant type – provide air access via 3" holes to SS1 & Hot stick shelf.	
1	Paint completed Unit one solid colour (white) * Aerial unit powder coated Terex White * Fiberglass service body to be white Gelcoat * Cargo area to be coated with spray-on non-slip coating * Side pack tops to non-slip coated * Front surface of outriggers to be coated with spray on coating * Body under carriage, rear hitch assembly and bottom side of front outrigger sub frame to be undercoated with petroleum based coating	
2	Level indicator, inclinometer, +/- 5 Degrees.	
2	Mud Flap * Plain Black - 24" x 30" * Includes mounting hardware	
1	One pair of anti-sail brackets for mud flaps.	
1	Cone Holder * Deck Mounted.	
2	Outrigger Pads - wood * 24" x 24" x 2"	
2	Outrigger Pad Holder * For Single Outrigger Pads - 24" X 24" * Mounted under body in close proximity to the Outriggers	
2	Wheel Chock * Standard Rubber Type	
1	DOT Triangle Reflector Kit.	
1	First Aid Kit – BC Level 1 * Ship loose.	

QUANTITY	DESCRIPTION	Quote Number: Sample
2	5lb ABC Fire Extinguisher * Includes mounting bracket. *Ship loose – customer to install	
1	CMVSS Inspection. * Scale Ticket * Road Test * Fuel Truck.	
1	Dielectric Testing to CSA Standards * Fibreglass Boom Sections only * Auxiliary Jibs not included	
1	Stability Testing to CSA standards * Weight studies will be provided for customer approval prior to start of assembly.	
1	Orientation of Completed Unit with Customer * This is for the customers personnel * Certified Trainer reviews the operation of the new unit with crew * Safety items are discussed * Maintenance schedules are discussed * Classroom discussion followed up with a hands on Orientation Session * Orientation is performed on Customers Site * Up to one day in length.	
1	Chassis (Customer Supplied) * Quote is based on clear frame back of cab, customer supplied chassis. * Quote does not include any modification to chassis including but not limited to suspension modifications, axle relocation, relocation of batteries, air brake components, fuel tanks or other items not covered by this quotation. * Prior to order we required a detailed chassis specification provided by original manufacturer to confirm suitability of vehicle.	
	CHASSIS	
1	Ford F550 Super Cab 4x4 Chassis * 84" CA * 6.7 Liter Diesel Engine * 6 speed Automatic Transmission * 4.88:1 ratio differential * 19,500 GVWR * Customer supplied Specifications	

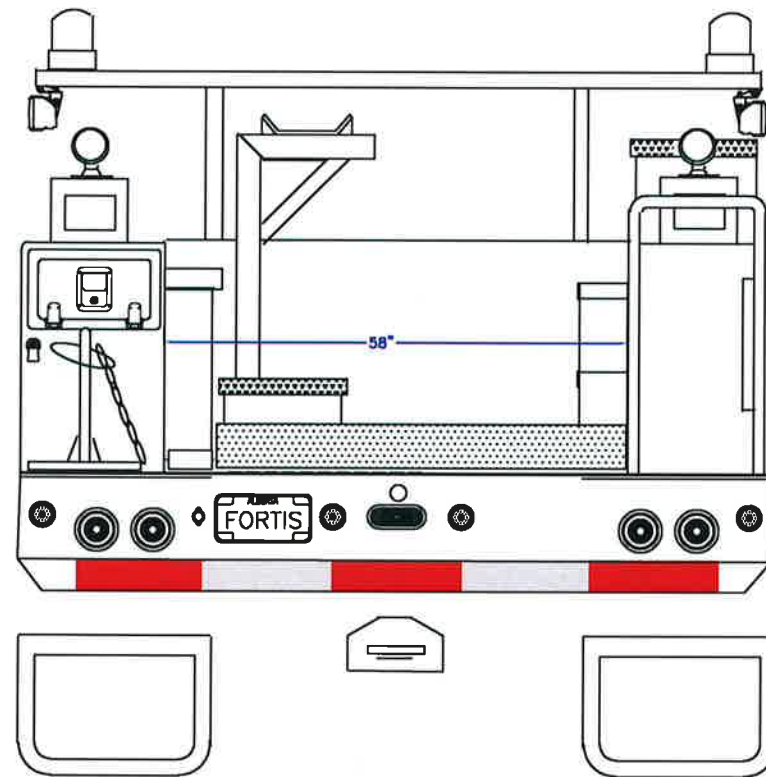
Budgetary price per unit: \$261,000.00

Customer must fill out the information below before the order can be processed...

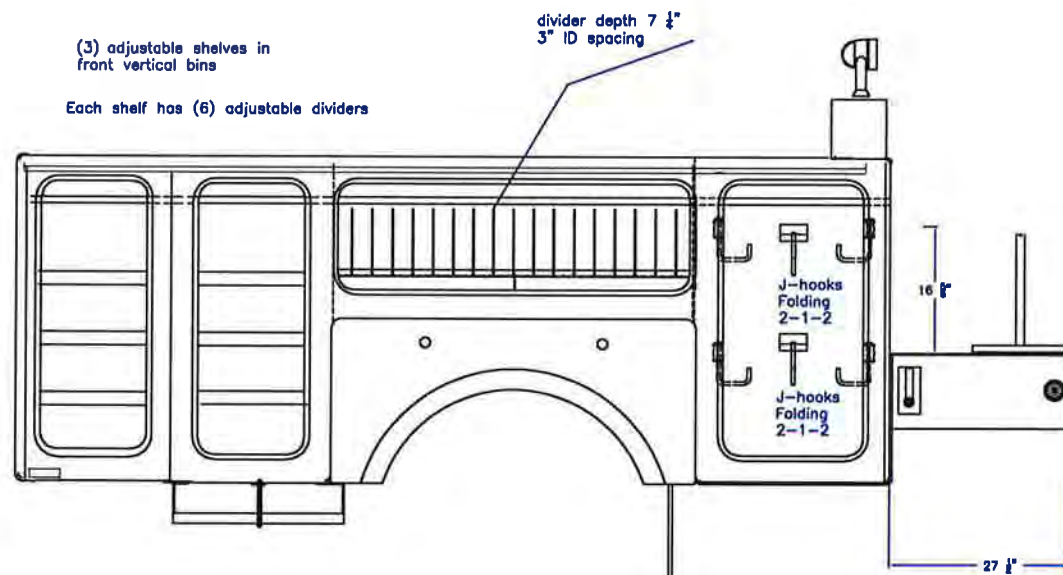
Accepted by:	
Date:	
P.O. number:	

- ◆ Quote is valid for 15 days from date of quote.
- ◆ All prices are in Canadian Funds.
- ◆ Quoted price does not include any applicable taxes.
- ◆ Terms are Due upon Receipt unless prior credit arrangements are made at the time of order.
- ◆ FOB Yukon.

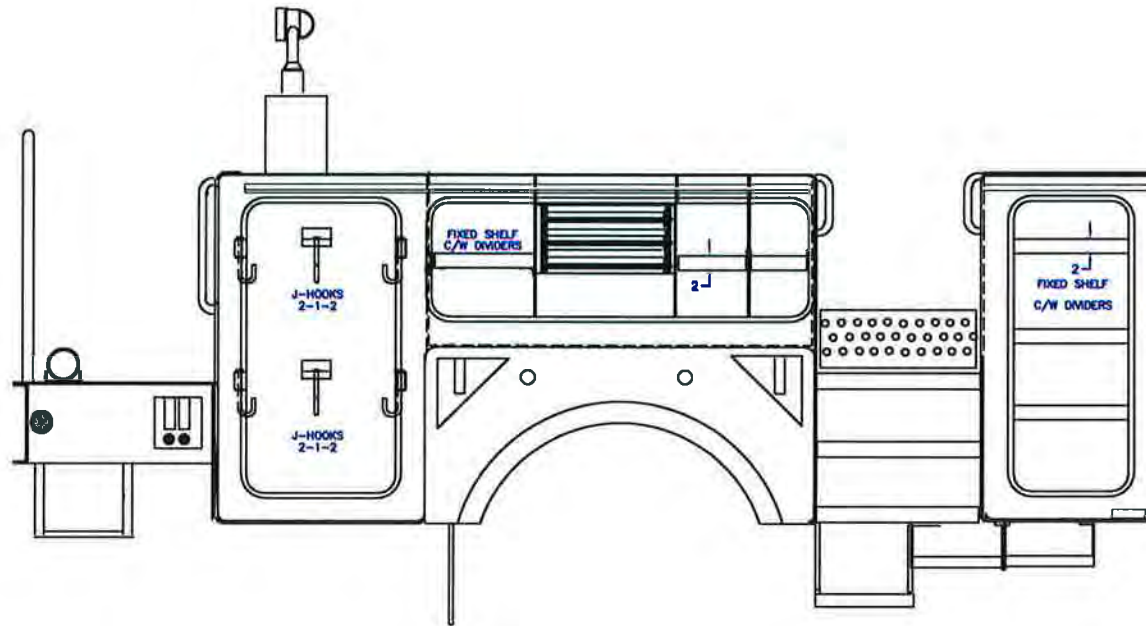
- ◆ Please note if chassis is furnished, it is as a convenience and terms are Net Due on Receipt of Chassis.



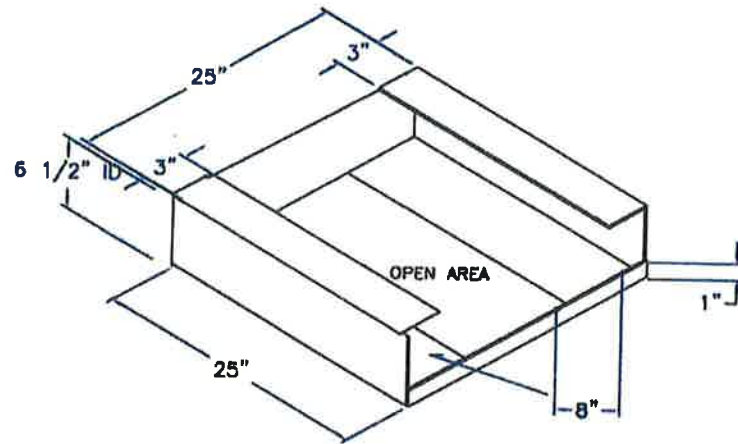
REAR VIEW 84" C-A
Nov. 21 / 19



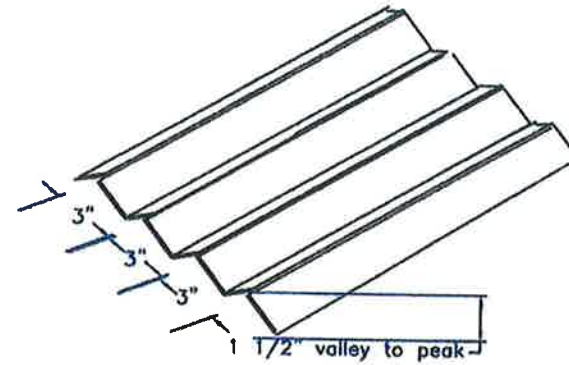
STREET SIDE
Nov. 25/19



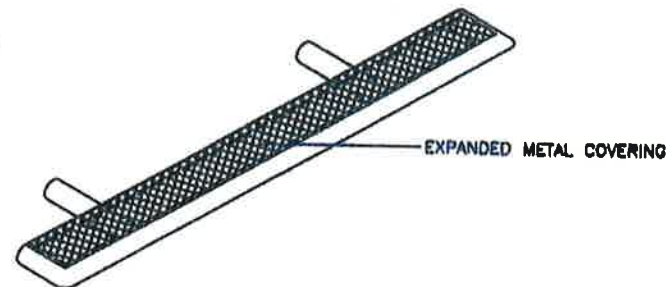
CURB SIDE
Nov. 21/19



OUTRIGGER PAD HOLDER
3/16" Aluminum

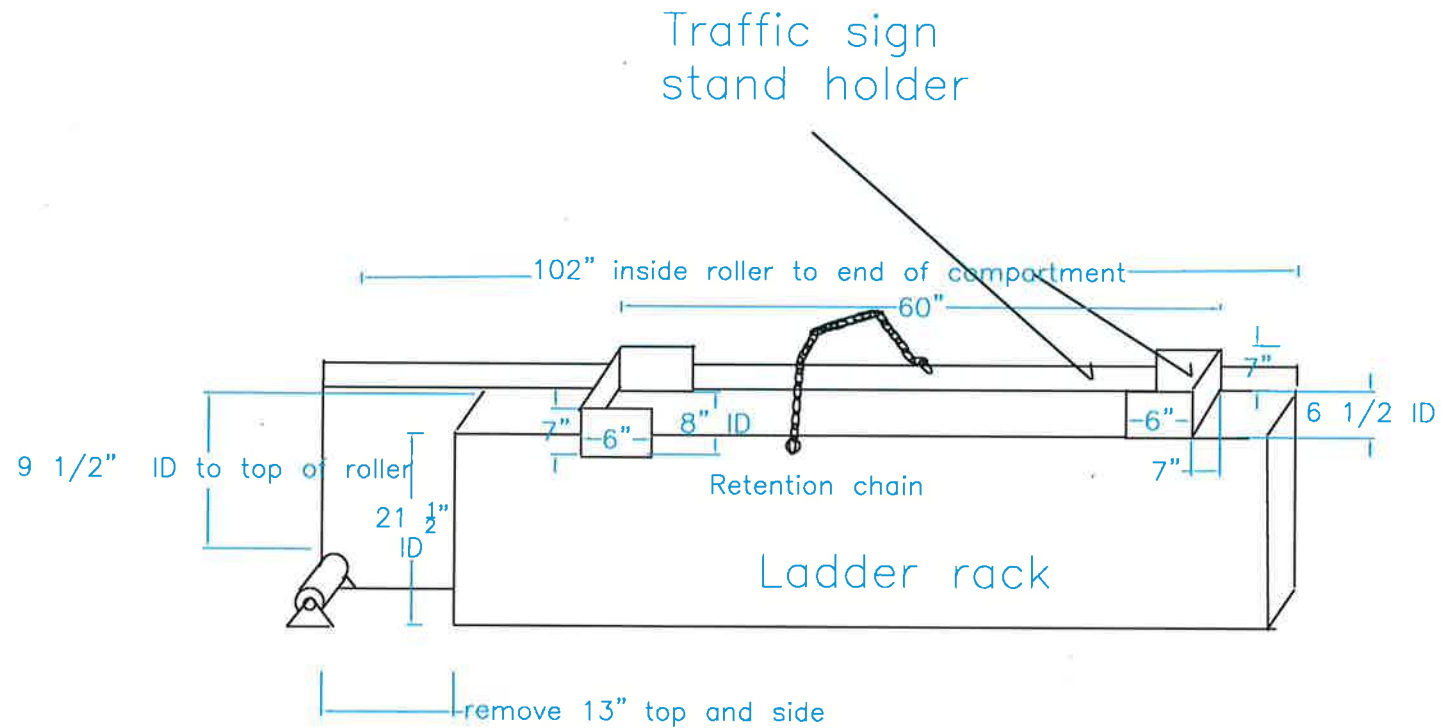


STREETSIDE HOTSTICK TUBE TRAY
1/8" Aluminum



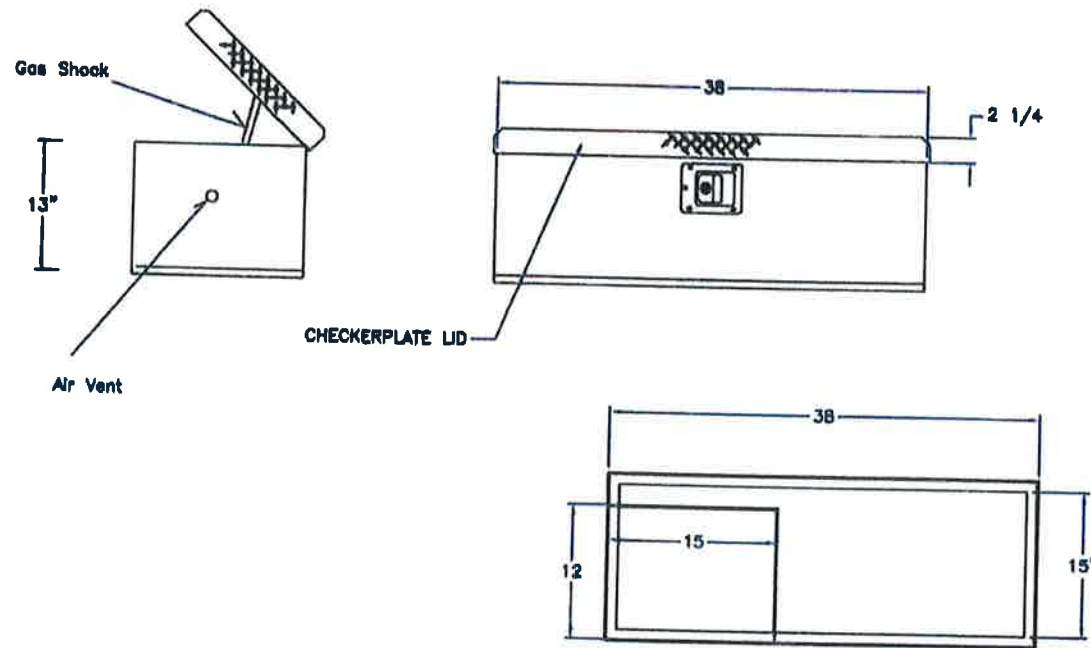
RUNNING BOARDS

Drawing #1
Nov. 10 / 17



Drawing #2

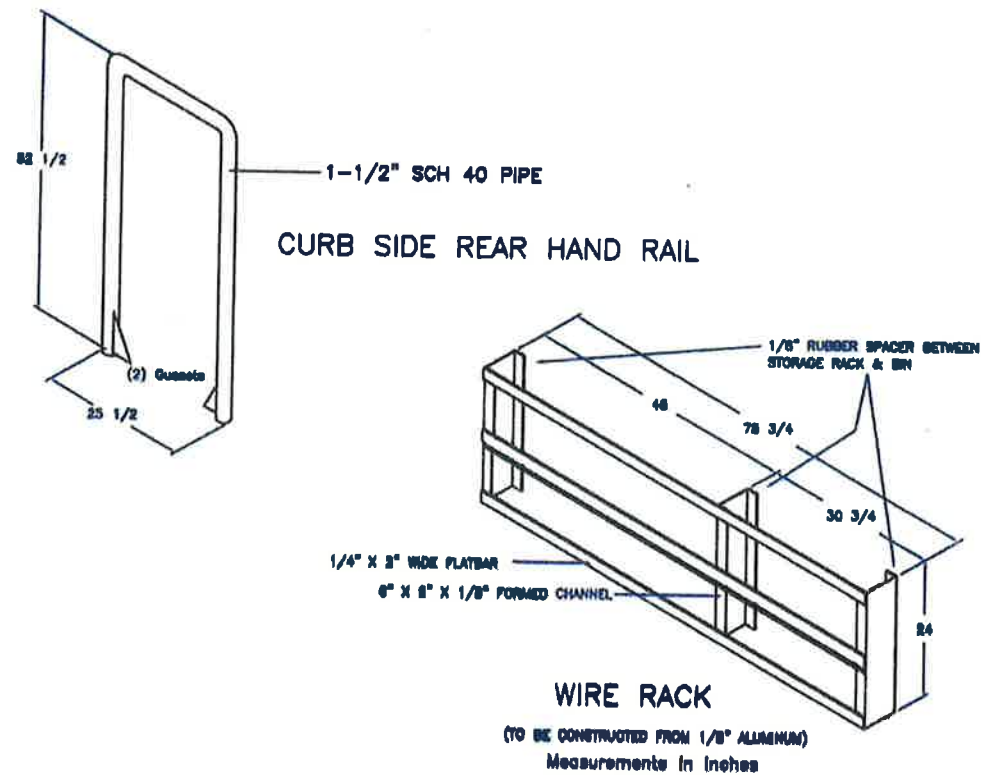
Oct. 29 / 18
Revised March 03 / 2019



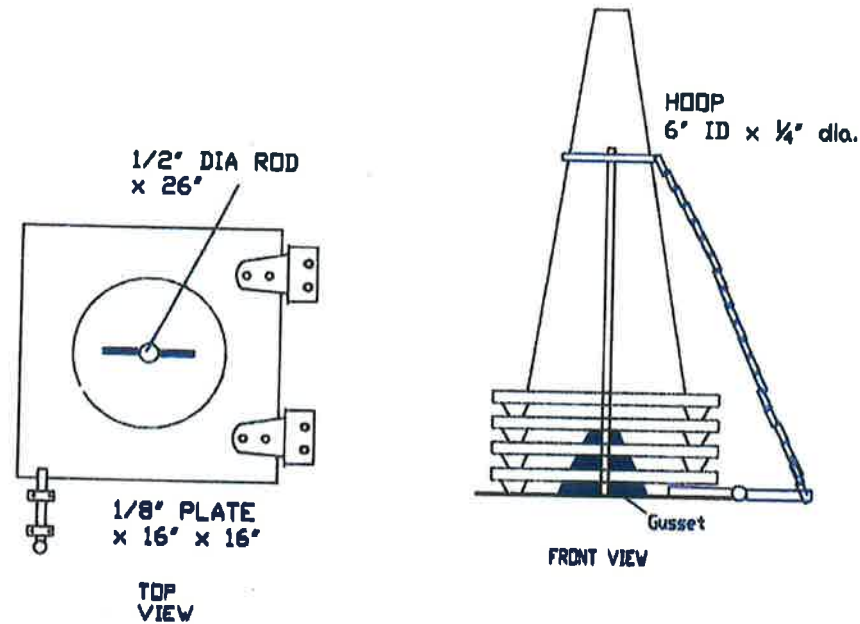
Chain saw Box
1/8" ALUMINUM

Drawing# 3

Nov. 10 /17

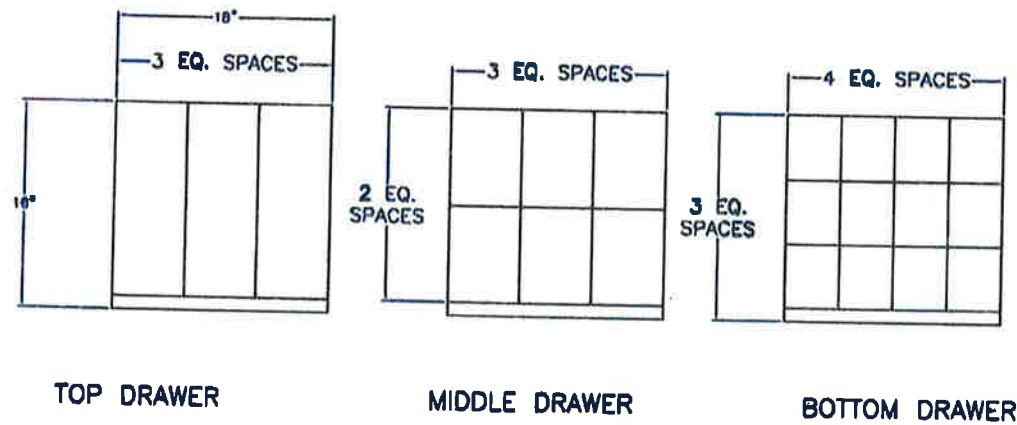


Drawing #4
 Nov. 09 / 17



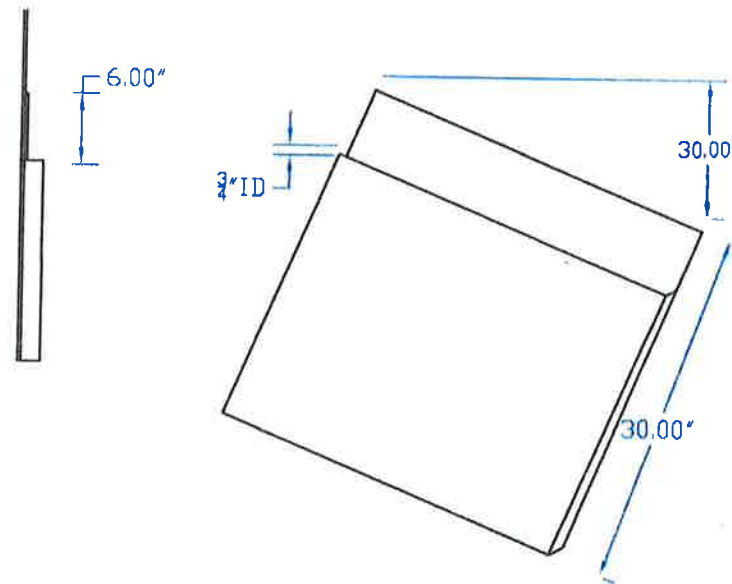
Cone Holder

Drawing #5
Nov. 10 / 17

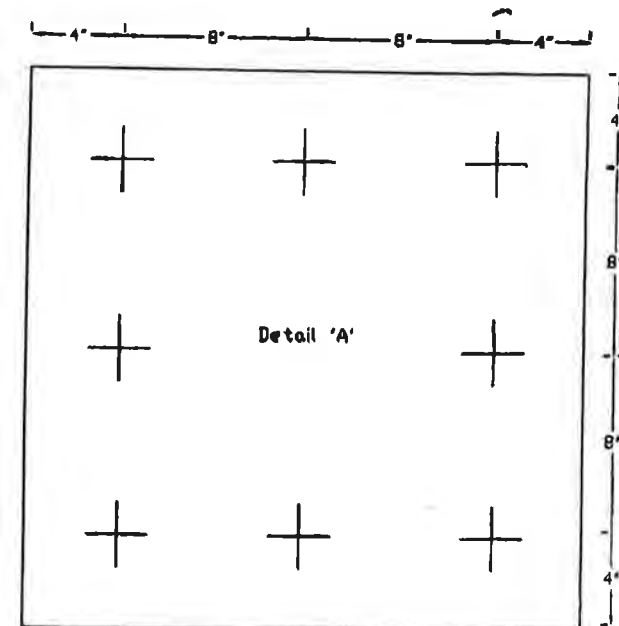
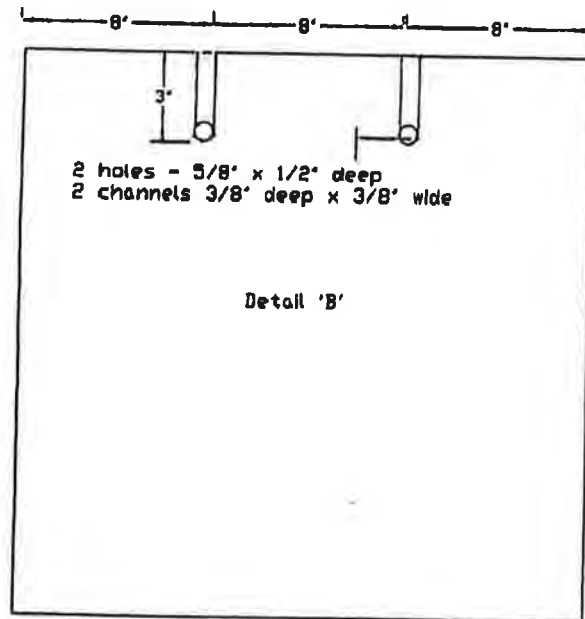


Drawer height 3"

Drawing #6
Nov. 09 / 17

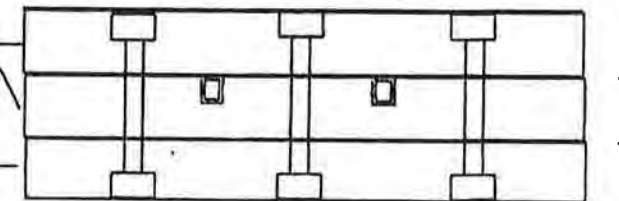


Drawing# 7
Envelope sign holder
Aug. 16, 2017
rev. May 16, 2018

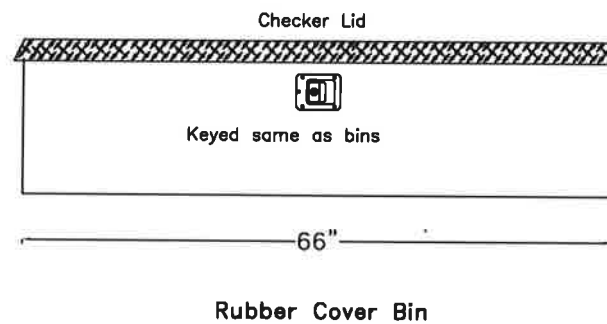
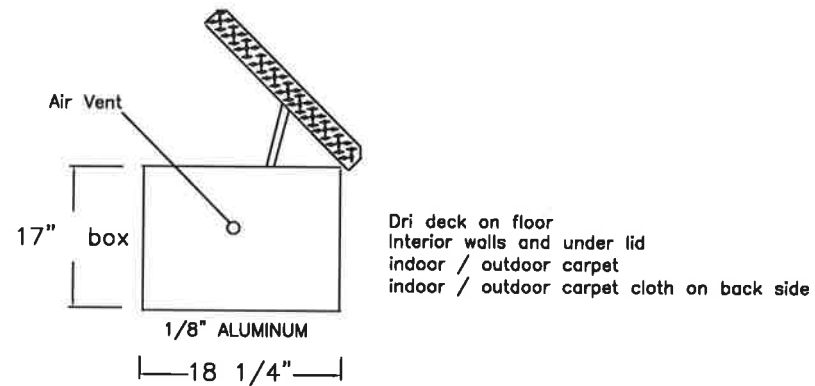


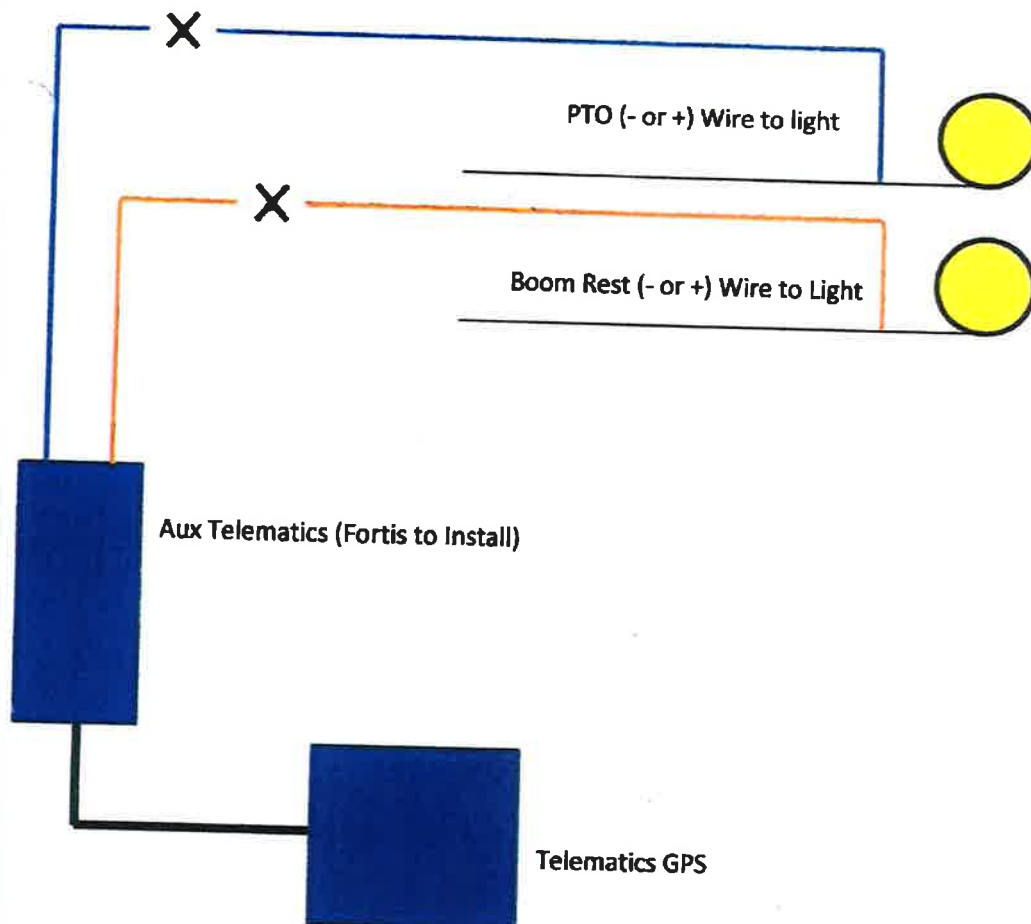
Requirements

- 2 - 1" x 24" x 24" plywood with 8 holes, centered as in Detail 'A'.
Drill 8 holes 9/16" x depth of plywood.
- 1 - 1" x 24" x 24" plywood drilled and channeled as in detail 'B'.
Then drill 8 holes 9/16" x depth of plywood as in detail 'A'.
- 8 - Hex Bolts 1/2" by 2 3/4".
- 1 - Piece of rope, 3/8" with knots at each end. Long enough to press knot into each hole run up channel and leave approximately 11" outside for a handle.
- All pieces of wood to be glued together.
- All weathered sides of wood to have Thompsons Weather Seal applied.



OUTRIGGER PADS
rev. 10/25/2000





Supply 2 wires for boom out of rest wiring and PTO engaged wiring

PTO engaged wiring shall be supplied as a **BLUE** wire off the ground or positive wire from the PTO IQ light on the dash. Run wire to the OBD reader area, Fortis Techs will make connection to Telematics; ensure that wire is labeled "**Telematics PTO**".

Boom out of rest wiring shall be supplied as an **ORANGE** wire off the ground or positive wire from the Boom out of rest IQ light in the dash. Run wire to the OBD reader area, Fortis Techs will make connection to Telematics; ensure that wire is labeled "**Telematics boom out of rest**".

Our Telematics system can run on both positive and ground signals



CHASSIS SPECS & BODY SPECS

Cab And Chassis:

Ford F-550 4X4 Cab And Chassis With A CA Of 84"
GVWR: 19,500 Lbs.
6.7L 4V OHV Power Stroke V8 Turbo Diesel Engine
Torqshift 6-Speed Automatic Transmission
4.88 Limited Slip Axle.
Air Conditioning.
Engine Block Heater
225/70RX19.5G BSW Traction Tires.
Radio: AM/FM Stereo Includes 4 Speakers.
HD Vinyl 40/20/40 Slit Bench Seat
Trailer Brake Controller
Operator Commanded Regeneration
Painted Oxford White.

Dakota Bodies 132" Long X 40" High X 94" Wide Service Body:

30 Inch Aluminum Tread Plate Platform Extension
LED Lighting Package Installed In Tail Shelf.
Cable Access Step At Rear And Side Access.
Two (2) Chrome Grab Handles At Side Access And
Two (2) Pool Type Grab Rails At Rear Tail Shelf.
Wheel Chock Storage And Outrigger Pad Holders.
Push/Pull Rod Lock System
40" High Street Side Compartments As Follows
1st Vertical: Two (2) Adjustable Shelves With Dividers And Cutout For Outrigger
2nd Vertical: Two (2) Adjustable Shelves With Dividers
Horizontal: One (1) Removable Shelf With Dividers
Rear Vertical: Two (2) Adjustable Shelves With Dividers
Hot Stick Shelf With Rear Access Door.
40" High Curbside Compartments As Follows
1st Vertical: Two (2) Adjustable Shelves With Dividers And Cutout For Outrigger
2nd Vertical: Grip Strut Access Steps To Bed Area With Removable Composite Side Gate.
Horizontal: One (1) Adjustable Shelf With dividers
Rear Vertical: Five (5) fixed material hooks 1-3-1

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DISCLAIMER: Specifications are believed to be correct, but may contain errors and/or omissions.
Pictures are representative and may not be identical.

Versalift VST-40-MHI Aerial Ford F550 4x4

EQUIPMENT SPECS

Versalift VST-40-I, Insulated 40Ft. 4 In Telescopic Aerial Platform Lift, 45Ft. 4 In Working Height With A Horizontal Reach Of 30 Ft.2 In. To Include The Following Items:

Standard Platform Capacity Of 400 Lbs
Right Hand Single Stick Control.
Hydraulic Platform Rotator.
Hydraulic Dual Arm Articulating Jib Pole And Winch Package For Up To 1,000 Lbs.
Capacity, Including Insulated Jib Pole
360 Degree Continuous Rotation Including Slip Rings
Six GPM Open Center Hydraulic System With A 3000 PSI Operating Pressure
Side Mounted Telescopic Upper Boom Allows Low Stowing Of Platform.
ANSI A92.2 Requirements For Category C 46KV And Below.
Chassis Insulating System (Fiberglass Lower Boom Insert) Providing 12 In. Insulation Gap And Including Accommodations To Bridge Insulation Gap For Testing
Per ANSI 92.2
Electrogard And Inner Boom Finished With White Urethane Paint Over A White Gel Coat.
Non-Lube Bearings Used Throughout.
One Set Of Hydraulic Tool Outlets With Pressure Limit Valve. Valve Can Be Adjusted From 1000 To 2500 PSI.
Sub Frame Mounted Main A-Frame Outriggers With Pivot Feet, Two Control Valves, And A Selector Valve.
Outrigger Boom Interlock System For Main Outriggers
Integral Reservoir With A 17-Gallon Capacity And Dual Sight Gauges.
Side Mounted Closed Heavy-Duty One-Step 24 In. X 30 In. X 42 In.
Fiberglass Platform Including Platform Liner And Vinyl Cover.
Individual Full Pressure Controls At The Turret Actuate All Boom Functions And Is Equipped With A Selector Valve To Override Upper Controls
12 Volt DC Backup Pump Providing Power To All Boom Functions.
2 speed Throttle Control.
Start/Stop at upper controls
Safety Harness And Lanyard
Two Operator Manuals And Service Manuals

• PRICE: \$167,500.00 CAD Plus applicable taxes

• Ex Works: Calgary, Alberta

QUOTE NUMBER: Yukon Energy

EXPIRATION DATE: Jan 31, 2021

VST-36/40/47/52-I

Insulated Articulated/Telescopic Aerial Device

- **WORKING HEIGHT:** Up to 56 ft 6 in (17.2 m)
with Standard Pedestal
- **HORIZONTAL REACH:** Up to 30 ft 9 in (9.4 m)
- **PLATFORM CAPACITY:** Up to 600 lbs (272 kg)
- **JIB CAPACITY (Optional):** Up to 1000 lbs (454 kg)

**MORE
PAYLOAD
THAN THE
COMPETITION**

**JIB & WINCH
OPTIONAL**

**TruGuard®
STANDARD**



VST-40-I shown with Material Handling option.

VERSALIFT®

**LOWER TRUE
COST OF
OWNERSHIP**

7601 Imperial Drive | Waco, Texas 76712 | 254.399.2100 | VERSALIFT.com

VST-36/40/47/52-I

Insulated Articulated/Telescopic Aerial Device



GENERAL SPECIFICATIONS:

(Based on 40 in Frame)

	VST-36-I	VST-40-I	VST-47-I	VST-52-I
Horizontal Reach	26 ft 2 in (8.0 m)	30 ft 2 in (9.2 m)	30 ft 9 in (9.4 m)	30 ft 4 in (9.3 m)
Maximum Platform Capacity	600 lbs (272 kg)	600 lbs (272 kg)	600 lbs (272 kg)	600 lbs (272 kg)
Inner Boom Extension	79 in (2.0 m)	103 in (2.6 m)	103 in (2.6 m)	53 in (1.35 m)
Outer/Inner Boom Articulation	-25° to +85°	-25° to +85°	-25° to +85°	-25° to +85°
Lower Boom Articulation	0° to +87°	0° to +87°	0° to +84°	0° to +84°
Rotation	360° Continuous	360° Continuous	360° Continuous	360° Continuous

WITH STANDARD PEDESTAL:

Height to Bottom of Platform	36 ft 4 in (11.1 m)	40 ft 4 in (12.3 m)	46 ft 10 in (14.3 m)	51 ft 6 in (15.7 m)
Working Height	41 ft 4 in (12.6 m)	45 ft 4 in (13.8 m)	51 ft 10 in (15.8 m)	56 ft 6 in (17.2 m)
Stowed Travel Height	10 ft 6 in (3.2 m)	10 ft 6 in (3.2 m)	11 ft 0 in (3.4 m)	11 ft 6 in (3.5 m)

INSULATION GAP:

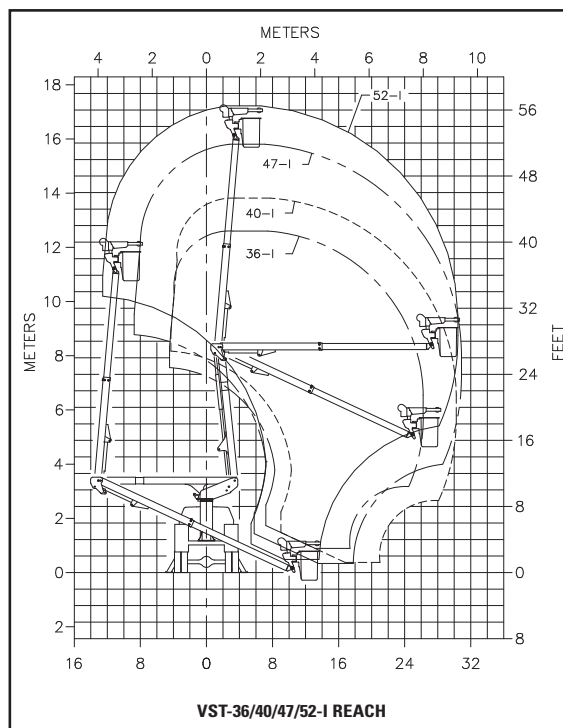
Upper Boom Fully Retracted	46 in (1.2 m)	46 in (1.2 m)	52 in (1.3 m)	64 in (1.6 m)
Upper Boom (Extended 12+ inches)	46 in (1.2 m)	46 in (1.2 m)	64 in (1.6 m)	64 in (1.6 m)
Lower Boom	12 in (305 mm)	12 in (305 mm)	12 in (305 mm)	12 in (305 mm)

HYDRAULIC SYSTEM:

Operating Pressure	3000 psi (207 bar)
Flow Rate	6 gpm (22.7 lpm)
System Type	Open Center

OPTIONS:

- Auxiliary Outriggers
- Second Set of Tool Power Ports
- Platform Elevator
- Various Pedestal Heights
- Automatic Boom Latch
- Backup 12-Volt Pump
- Hydraulic Jib/Winch (Reduces Platform Capacity 100 lbs)
- Jib up to 1000 lb (454 kg) capacity



Note: Specifications on units may vary or change without prior notification due to option selections.

REV. 03/20

VERSALIFT is a leading manufacturer of bucket trucks, digger derricks and cable placers. Customers in the electric utility, telecommunications, forestry and sign, light & traffic industries experience a lower true cost of ownership by choosing Versalift. Our equipment is engineered to be lighter, while keeping the designs simple, which provides advantages like less unscheduled maintenance, greater payloads and ease of maintenance. Versalift has the lowest recall rate in the industry making it the smarter and most reliable choice. Versalift aerial lifts are the only units to feature the patented TruGuard® safety system, which provides additional protection to linemen in the bucket. Versalift is a Time Manufacturing Company, and together with Aspen Aerials has more than 1,400 employees worldwide.

REV. 03/19



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FALCON

LOCATION: **SURREY, BC**

CLASSIFICATION: **FALCON DEMO**

FALCONEQUIP.COM



2019 FORD F-550

TRANSMISSION: Automatic
ENGINE: 6.7L 4 Valve OHV Power
Stroke Diesel
KMS: 10
GVW: 19,500 lbs
WHEELBASE: 192"

T2265

VIN #: IFDOX5HT7KEG25813

2019 ETI ETC40MH

Material Handler
45' Working Height
30' Ground to Bottom of Bucket
27' 5" Side Reach with End Mount Bucket
Hydraulic Jib and Winch Package
Continuous Rotation/ Fiberglass Inner Boom
Hoses Inside Boom Are Contained in a Cat Trac
400 lb Bucket Capacity/ 18 Gallon Oil Reservoir
Light in every compartment with master switch in cab
Backup Alarm and camera

\$209,000.00

FALCON

March 4, 2021

Page 1

Prepared for: Mr. Monty Smith
Office: 604-888-5066

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)
Price Level: 930



Client Proposal

Prepared by:
Chenn Bergen
Office: 604-532-9921
Quote ID: MontyX5H
Date: 08/15/2019



March 4, 2021

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass, Surrey, British Columbia, V3S7R2
Office: 604-532-9921 | Fax: 604-530-2525

Prepared for: Mr. Monty Smith



Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia |
V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Warranty

Standard Warranty

Basic

Distance	37,283 miles	Months	36 months

Powertrain

Distance	62,139 miles	Months	60 months

Corrosion Perforation

Distance	Unlimited miles	Months	60 months

Roadside Assistance

Distance	62,139 miles	Months	60 months

Accessories

Distance	37,283 miles	Months	36 months

Prices and content availability as shown are subject to change and should be treated as estimates only. Actual base vehicle, package and option pricing may vary from this estimate because of special local pricing, availability or pricing adjustments not reflected in the dealer's computer system. See salesperson for the most current information.

Prepared for: Mr. Monty Smith



Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia |
V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

As Configured Vehicle

Code	Description	MSRP
Base Vehicle		
X5H	Base Vehicle Price (X5H)	\$61,249.00
Packages		
663A	Order Code 663A <i>Includes:</i> - Cloth 40/20/40 Split Bench Seat w/Recline - Includes fold down centre armrest with 2 cupholders, lift up centre-seat with locking storage, powerpoint, driver's side manual lumbar and 4-way adjustable driver and passenger headrests. - Radio: Premium AM/FM Stereo w/MP3 Player - Includes 7 speakers, digital clock and SiriusXM satellite radio with 6 month prepaid subscription. - SYNC Communications & Entertainment System - Voice-activated. Includes USB port, 911 Assist, steering wheel mounted controls and microphone in headliner.	N/C
Powertrain		
99T	Engine: 6.7L 4V OHV Power Stroke V8 Turbo Diesel B20 <i>Includes transmission mounted live drive and stationary mode PTO, 27 litre (7.2 gallon) plastic urea tank, exhaust brake, B20 capability, urea gauge and intelligent oil life monitor.</i> <i>Includes:</i> - Dual 78-AH 750 CCA Batteries - Rapid-Heat Supplemental Cab Heater - Dual Extra Heavy-Duty Alternators (Total 377-Amps) - 4.2" LCD Display in Centre-Stack	\$9,450.00
44W	Transmission: TorqShift 6-Speed Automatic <i>(6R140). Includes SelectShift and tow/haul mode.</i>	N/C
X8L_	4.88 Axle Ratio w/Limited Slip w/99T/68M	N/C
68M	GVWR: 8,845 kgs (19,500 lbs) Payload Package <i>Includes upgraded frame, upgraded rear-axle, low deflection/high capacity rear springs and 14,706 lbs. max rear GAWR. Note: See Super Duty Supplemental Reference Manual for further details on GVWR.</i>	\$700.00
Wheels & Tires		
TGK	Tires: 225/70Rx19.5G BSW Max Traction #2 <i>Includes 4 traction tires on the rear and 2 traction tires on the front. Not recommended for over the road applications; could incur irregular front tire wear and/or NVH. Optional spare is BSW traction #2.</i>	\$320.00
64D	Wheels: 19.5" Forged Polished Aluminum	\$820.00

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Prepared for: Mr. Monty Smith



Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia |
V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

As Configured Vehicle (cont'd)

Code	Description	MSRP
<i>Includes Ford oval centre hub ornaments.</i>		
Seats & Seat Trim		
3	Cloth 40/20/40 Split Bench Seat w/Recline <i>Includes fold down centre armrest with 2 cupholders, lift up centre-seat with locking storage, powerpoint, driver's side manual lumbar and 4-way adjustable driver and passenger headrests.</i>	Included
Other Options		
PAINT	Monotone Paint Application	STD
192WB	192" Wheelbase	STD
213	4x4 Electronic-Shift-On-The-Fly <i>Includes auto-manual locking hubs and rotary control located on instrument panel</i>	\$200.00
98R	Operator Commanded Regeneration (OCR)	\$290.00
18A	Upfitter Interface Module <i>Includes the UIM pre-installed and interface cables (2- 3' blunt cut cables with connectors). Note: The Upfitter Interface Module (UIM) is an electronic control module that provides output signals for aftermarket equipment (such as lift buckets, cranes, motors, salt spreaders, snow plows, etc.) via customer programmable logic based on switch inputs and vehicle CAN bus messages. The operation of such equipment is limited to the load parameters of the UIM. The UIM does not come pre-programmed for use. It must be configured by the upfitter for aftermarket equipment. The UIM provides output signals only, and is not intended to directly power any aftermarket device. Customer must use external relays to drive any equipment. Ford Motor Company is not responsible for debugging or verifying the function of the customer created UIM program files. It is the responsibility of the upfitter to ensure proper function of the software created to complete their upfit.</i>	\$400.00
41P	Transfer Case Skid Plates	\$200.00
43C	110V/400W Outlet <i>Includes 1 in-dash mounted outlet.</i>	\$250.00
18B	Platform Running Boards	\$490.00
585	Radio: Premium AM/FM Stereo w/MP3 Player <i>Includes 7 speakers, digital clock and SiriusXM satellite radio with 6 month prepaid subscription. Includes: - SYNC Communications & Entertainment System Voice-activated. Includes USB port, 911 Assist, steering wheel mounted controls and microphone in headliner.</i>	Included
166	Carpet Delete <i>Replaced with black flooring.</i>	N/C

Interior Colors

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Prepared for: Mr. Monty Smith



Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia |
V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

As Configured Vehicle (cont'd)

Code	Description	MSRP
3S_02	Medium Earth Grey	N/C
Primary Colors		
Z1_01	Oxford White	N/C
SUBTOTAL		\$74,369.00
Destination Charge		\$1,900.00
TOTAL		\$76,269.00

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Prepared for: Mr. Monty Smith



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08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia |
V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Pricing Summary - Single Vehicle

MSRP

Vehicle Pricing

Base Vehicle Price	\$61,249.00
Options & Colours	\$13,120.00
Upfitting	\$0.00
Destination Charge	\$1,900.00

Subtotal	\$76,269.00

Pre-Tax Adjustments

Description

Air Excise Tax	\$100.00

Total	\$76,369.00

Customer Signature

Acceptance Date

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Prepared for: Mr. Monty Smith



Prepared by: Chenn Bergen
08/15/2019

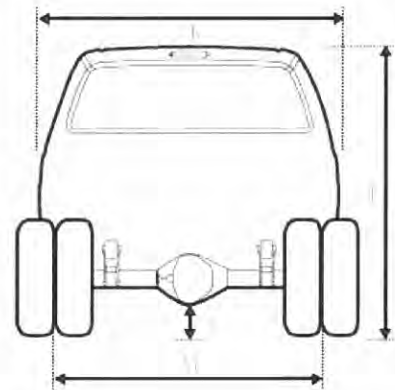
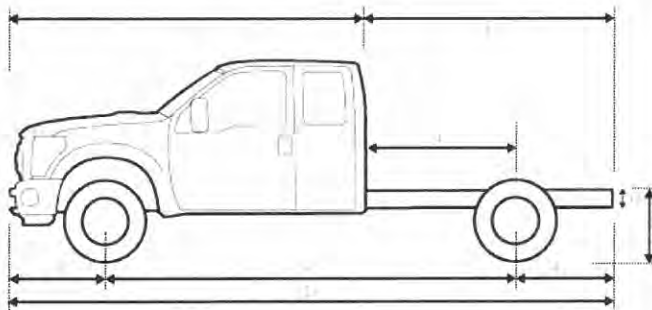
Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia |
V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Vehicle Dimension and Performance Summary

Performance predictions in this report represent an estimate of vehicle performance based on standard operating conditions. Variations in customer equipment, load configuration, ambient conditions, and/or operator driving techniques can cause significant variations in vehicle performance. These values are not representative of results that may be shown in actual dynamometer tests. This report should therefore be used as a guide for comparative vehicle performance.



Dimensions

A	Front of Bumper to Front Axle	38.30 in.
B	Front Bumper to Back of Cab (BBC)	146.30 in.
C	Wheelbase (WB)	192.00 in.
D	Overall Length (OAL)	277.40 in.
E	Back of Cab to Rear Axle (CA)	84.00 in.
F	Back of Cab to End of Frame	131.20 in.
G	Rear Axle to End of Frame (AF)	47.20 in.
H	Frame Section Height	N/A
I	Rear Frame Height Unloaded	34.30 in.
I	Rear Frame Height Loaded	28.60 in.
J	Cab Height	81.80 in.
K	Body Width	80.00 in.
L	Maximum Ground Clearance	N/A
L	Minimum Ground Clearance	8.20 in.
M	Front Tread	74.80 in.
M	Rear Tread	74.00 in.

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Prepared for: Mr. Monty Smith



Prepared by: Chenn Bergen
08/15/2019

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V3S7R2

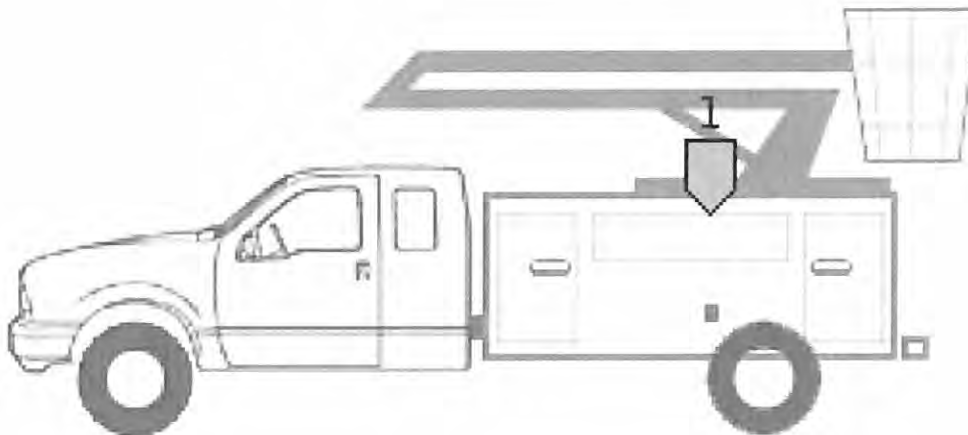
2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Vehicle Dimension and Performance Summary (cont'd)

Body Specs

Truck body style:	Aerial Device
Cab to body gap:	3.00 in.
Body length:	10.70 ft
Body tare weight:	3,460 lbs
Body width:	96 in.
Body height from ground:	120 in.
Centre gravity (from front):	64.10 in.



Weight

GVW	Front Axle	Rear Axle	Totals
Chassis	5,009 lbs	3,381 lbs	8,390 lbs
Body	306 lbs	3,154 lbs	3,460 lbs
Occupants Weight	600 lbs	300 lbs	900 lbs
1 Max Payload - (Max Payload)	585 lbs	6,165 lbs	6,750 lbs
TOTAL	6,500 lbs	13,000 lbs	19,500 lbs

Ratings	Front Axle	Rear Axle	GVWR
GAWR	6,500 lbs	14,706 lbs	19,500 lbs
Wheels/Tires	7,500 lbs	15,000 lbs	
Suspension	6,500 lbs	15,000 lbs	
Axle	7,000 lbs	14,706 lbs	
Legal Axle Limit	0 lbs	0 lbs	

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Prepared for: Mr. Monty Smith



Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia |
V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Vehicle Dimension and Performance Summary (cont'd)

Start, Grade and Speed

Start	Ratio	Desired	Calculated
Start grade capability in 1st gear	3.97	15.00 %	42.71 %
Start grade capability in reverse	3.13	15.00 %	33.62 %
Grade	Ratio	Desired	Calculated
Maximum grade in 4th gear	1.15	3.00 %	13.00 %
Maximum grade in 5th gear	0.86	3.00 %	9.71 %
Maximum grade in 6th gear	0.67	3.00 %	7.63 %
Speed		Desired	Calculated
Top Speed (level grade)		75 mph	88 mph
<i>To meet your requirement you need a maximum axle ratio of 5.74</i>			
Top Speed on 3.0% grade		55 mph	
<i>To meet your requirement you need a maximum of 122 hp</i>			
Cruise Speed		60 mph	65 mph
Engine RPM at desired cruise speed			2,121 rpm

Variables in Use

Rear axle ratio:	4.88/4.88	Governed RPM:	3,120 rpm
Tire size:	225/70R19.5 (645 rev/mile)	Frontal Area:	40.44 Sq.Ft.
Gross Vehicle Weight (GVW):	19,500 lbs	Cruising RPM	2,300 rpm
Clutch engagement torque:	375 ft.lbs.	Worst road surface	Typical Highway
Torque conversion ratio:	1.90	Final Drive Ratio:	0.67
Peak engine torque:	750 ft.lbs.	Drag Coefficient	0.80
Engine Power:	330 hp @ 2,600 rpm		

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Prepared for: Mr. Monty Smith



Prepared by: Chenn Bergen
 08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia |
 V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

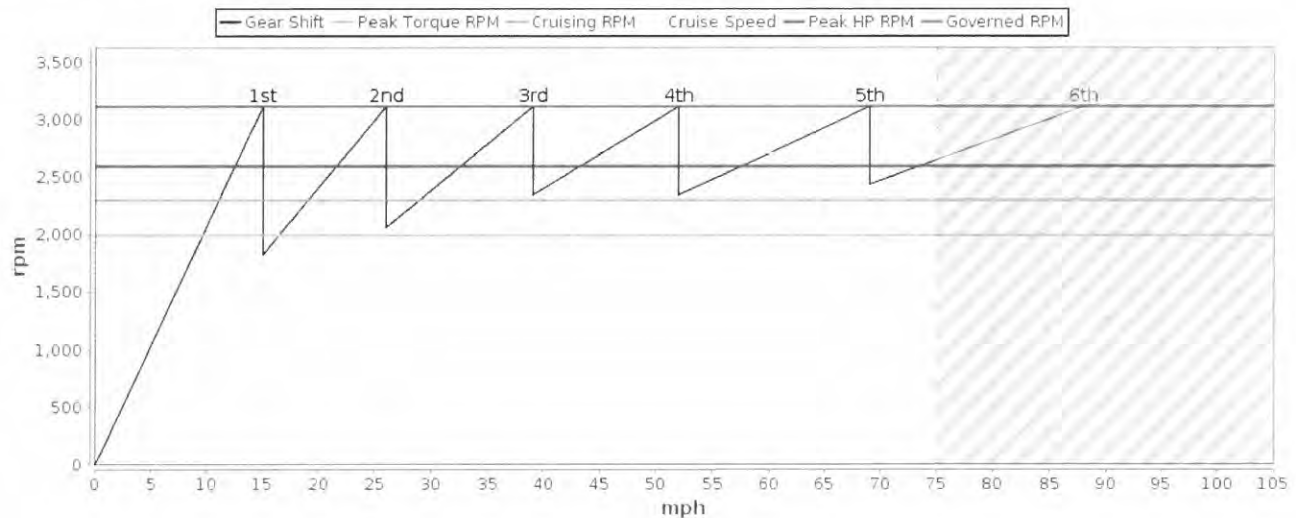
Vehicle Dimension and Performance Summary (cont'd)

Shift Chart

Shift Chart displays mathematical geared speed.

Diesel engines use Governed RPM for shift points.

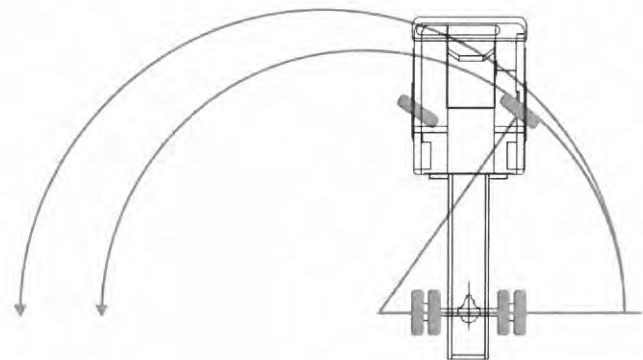
Gas engines use Peak Torque RPM for shift points.



Turning Radius

Turning Radius

27.10 ft



Prices and content availability as shown are subject to change and should be treated as estimates only. Actual base vehicle, package and option pricing may vary from this estimate because of special local pricing, availability or pricing adjustments not reflected in the dealer's computer system. See sales@yukonenergy.com for the most current information.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-9

2
3 **ISSUE:** Crane Replacement/Refurbishment

4
5 **QUOTE:** “During an annual crane inspection, three YEC cranes (Aishihik service
6 building, P127 powerhouse, & P127 stop log hoist) were identified as
7 needing significant structural, electrical, and mechanical repairs in
8 order remain in acceptable working condition. 2020 spending will
9 provide for a detailed assessment of each crane to determine an
10 engineered plan for replacement or refurbishment as required. Actual
11 construction activities are planned for 2021.”

12
13 **QUESTION:**

- 14
15 a) Are the cranes being repaired or replaced with mobile or fixed cranes? If they are
16 mobile cranes, how many mobile cranes does YEC have available at the specified
17 locations? Please comment on the possibility of other cranes being used in place
18 of the cranes to be repaired or replaced.
19
20 b) Please explain what is entailed in the assessments of the cranes, who will carry
21 out the assessments and why the assessment of three cranes will cost \$165,000.
22
23 c) Please confirm that the \$400,000 forecast cost for 2021 is the estimated cost to
24 repair or replace all three cranes. If not confirmed, please explain.
25
26 d) What is the estimated full replacement cost of the three cranes?
27
28 e) When did the three cranes enter service, and what is their expected service life?
29

30 **ANSWER:**

31
32 **(a) and (e)**

33
34 To clarify, the three cranes in the quote provided refer to the following equipment:

1 These two cranes entered service on the following dates:

- 2
- 3 • Whitehorse Spillway: 1958 (capacity: 20t);
- 4
- 5 • P127 (WH4) Whitehorse Powerhouse crane: 1984 (capacity: 80T); and
- 6
- 7 • Aishihik Powerhouse: 1975 (capacity: 38t/5t).
- 8

9 The typical life span on all crane hoists is 20-25 years. With major overhauls, the typical
10 lifespan can potentially extend by an additional 20-25 years (and the process can be
11 repeated). The steel and the concrete structure itself has a typical lifespan of 50 years and
12 a major overhaul can be undertaken to extend its life.

13

14 Fixed cranes are proposed. YEC currently has 25 mobile cranes, however, the lifting
15 capacity of mobile cranes is far less than the fixed cranes.¹

16

17 **(b)**

18

19 The value reported in the GRA for 2020 was a forecast; actual work completed resulted in
20 an actual value of \$155,296. 2020 Crane works included asset assessment and capital
21 corrective works. The assessment work was conducted on three cranes:

- 22
- 23 • WH4 Powerhouse Crane;
- 24
- 25 • WHS Whitehorse Spillway Crane, and
- 26
- 27 • Aishihik Service Building Crane.
- 28

29 Total value of assessment work was \$51,750. The scope of the assessment work is as
30 follows:

¹ The lift capacity of service truck cranes is about 2,000 lbs at 3 ft. radius. Large PLT trucks have greater capacity and can lift up to 20,000 lbs. YEC Digger Derricks in Mayo, Dawson and Whitehorse have this capacity.

1 **WHS Spillway Crane Whitehorse:**

- 2
- 3 • **Structural Assessment:** Measurement of structural members; Engineer
- 4 assessment of structural members, welds, joints, bolts and rivets; Determination
- 5 of current crane capacity and life cycle stage.
- 6
- 7 • **Mechanical Assessment:** Examination of gearing, couplings, drive trains, and
- 8 power transfer systems (involving disassembly).
- 9
- 10 • **Electrical/Controls Assessment:** Engineer assessment of controls, motors,
- 11 switching, wiring etc.; Testing of electric motors and panels; Determination of
- 12 current condition and life cycle stage.
- 13

14 **WH4 Powerhouse Crane – Whitehorse**

- 15
- 16 • **Structural Assessment:** Measurement of structural members; Engineer
- 17 assessment of structural members, welds, joints, bolts and rivets; Determination
- 18 of current crane capacity and life cycle stage.
- 19
- 20 • **Mechanical Assessment:** Servicing of internal couplings (disassembly required).
- 21
- 22 • **Electrical Assessment** Disassembly and internal inspection of resistor cubicles
- 23 and panels.
- 24

25 **Aishihik Service Building Crane**

- 26
- 27 • **Mechanical Assessment:** Disassembly and inspection of internal couplings,
- 28 gearcase.
- 29

30 As the contractor was on site already, YEC had them address a number of deficiencies
31 on the cranes. The value of this work was \$103,500 and included repair/replacement of
32 various components:

- 33
- 34 • Braking systems;
- 35
- 36 • Cables;

- 1 • Electrical components; and

- 2
3 • Control systems.

4
5 Additionally, the repair scope included addressing recommendations on the inspection of
6 numerous mobile cranes at YEC (\$30,000). Both the inspections and repair works were
7 completed by Kone Crane.

8
9 **(c)**

10
11 No. The \$400k is for Major capital repairs including:

- 12
13 • An engineered assessment on replacement of the Whitehorse Stop Log crane;
14
15 • Retrofit to the Aishihik Service Building Crane Auxiliary Hoist Drum Replacement;
16 and
17
18 • A 5 Ton Electric Chain Hoist Replacement for the Aishihik surge chamber unit that
19 is damaged and non-serviceable.

20
21 These major works are approximately 80% of the total budget. The remaining \$80k of
22 budget relates to addressing safety considerations for other cranes.

23
24 **(d)**

25
26 Unknown at this time; cost will be based on an engineered solution, followed by an RFP
27 cost estimate and review.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-9

2
3 **ISSUE:** Mayo Earthworks Project

4
5 **QUOTE:** "A number of issues at and around the Mayo Hydro facilities have been
6 identified. These include slope instability and erosion issues near
7 access roads (Mayo A, Mayo B, and Wareham dam), both powerhouse
8 buildings, surge tank, and both substations. During 2019 a complete
9 site inventory of civil issues was undertaken to identify and prioritize
10 issues. The inspection highlighted several required projects to improve
11 roads, make culvert installations and secure embankments. 2020
12 spending developed a detailed work plan for identified issues including
13 a geotechnical assessment, topographic survey, detailed engineering
14 design (including drawings and specifications), construction
15 methodology, and project scope, schedule & budget development."
16

17 **QUESTION:**

- 18
19 a) Please confirm that 2020 spending was only on development of the work plan for
20 the Mayo earthworks project. If not confirmed, please explain.
21
22 b) When does YEC propose to undertake the works required to remediate the
23 identified issues and what is the estimated cost of those works?
24
25 c) Please describe the safety issues and or threats to infrastructure caused by the
26 issues identified.
27

28 **ANSWER:**

29
30 **(a)**

31
32 Spending was only on the work plan for the Mayo Earthworks project. Please see
33 response to YUB-YEC-1-65.
34

35 **(b)**

36
37 The project will begin in 2022 and stretch in 2023. Costs not identified as of yet.

1 (c)

2

3 Current issues are: erosion at edges of roads that will increase hazards for drivers; and
4 erosion of slopes that cause landslides that could increase and potentially impact access
5 safety or equipment.

1 **REFERENCE: Application, Appendix 5.2, page 5.2-10**

2
3 **ISSUE: New Mobile Office Unit – IT**

4
5 **QUOTE:** “The existing IT trailer houses five offices and a closed storage space.
6 It is aging and requires additional O&M support each year. The project
7 involves replacement of the aging, undersized IT trailer with a larger
8 unit able to accommodate eight office spaces and storage. Additional
9 office spacing would allow for staff expansion as a less costly solution
10 than building onto the main building.”
11

12 **QUESTION:**

- 13
14 a) What was the original cost of the existing IT trailer, when did it enter service and
15 what was its expected service life?
16
17 b) How many YEC personnel currently use the IT trailer, and what is the typical
18 number of personnel occupying the trailer at any time?
19
20 c) What is the estimated annual O&M cost associated with the IT trailer, and what is
21 the estimated annual O&M if a new trailer is purchased?
22

23 **ANSWER:**

24
25 **(a)**

26
27 YEC is unable to locate the original cost of the existing IT trailer or the original expected
28 service life. According to the Atco tag on the building, the unit was factory constructed in
29 1991.
30

31 **(b)**

32
33 Excluding Covid-19 pandemic limitations, five employees normally occupy this space on
34 a full-time basis, with an additional one employee using it on a part-time basis.

1 (c)

2

3 The estimated annual O&M cost associated with the IT trailer is \$8,500. The estimated
4 annual O&M on a new trailer would be expected to be less than \$8,500.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-10

2
3 **ISSUE:** Vehicle Purchases

4
5 **QUOTE:** "Fleet vehicles were historically replaced at regular intervals based
6 simply on age and mileage. YEC has recently adopted a replacement
7 policy that considers more comprehensive criteria when assessing
8 specific vehicles to be replaced each year. The forecast amounts for
9 2019 include the purchase of pickup trucks with service bodies,
10 including a 2 tonne mechanical operator's vehicle (the current 1 tonne
11 vehicles did not have sufficient chassis to do the work safely), and
12 forecast 2020 acquisitions focused on vehicles based in Dawson and
13 Mayo due to the higher cost of local repair services. 2021 costs are to
14 replace aging/ high mileage vehicles that are incurring greater O&M
15 costs to maintain."
16

17 **QUESTION:**

18
19 a) For each of the last five years (actual) and 2021 (forecast), please provide the
20 number of vehicles replaced and the average age and average mileage of those
21 vehicles.
22

23 b) Please provide YEC's estimate of the average annual maintenance cost of
24 vehicles in its fleet based on the number of years the vehicle has been in service,
25 beginning at one year and ending with the age of the oldest vehicle replaced in the
26 last five years.
27

28 **ANSWER:**

29
30 **(a)**

31
32 Please see the table below for the requested information:

YEC Vehicle Replacement 2017-2021				
Year	# of Vehicles replaced (additional vehicle(s) added to fleet)	Average Mileage of vehicles replaced	Average Age of vehicle being replaced (Years)	Notes
2017	2 (2)	216683	10	Added 2 additional vehicles to inventory - Digger Truck & Pool vehicle. Blown Transmission in PLT truck reduced Average age of vehicle being replaced
2018	1 (1)	197465	11	Added 1 additional vehicle to inventory - PLT's vehicle
2019	3	182003	13.6667	Ambulance (unit # 54) was replaced driving up average age
2020	4 (1)	211172	9.25	Added 1 additional vehicle to inventory - Electrician's vehicle
2021	6	196126	11.2	Unit # 113 being replaced due to rollover/writeoff accident, not factored in averages. Please note Average mileage will increase before replacement vehicles are obtained

(b)

The question is unclear; the table below shows annual maintenance cost by vehicle category: ≥ 1 ton and < 1 ton as well as the number of units in the fleet during that year. The cost per unit for >1 T shows more variability, in part due to the nature of the equipment. This category includes large utility equipment such as bucket trucks, crane trucks and diggers. By their nature, the maintenance requirements of the attached equipment, i.e., cranes can be variable with respect to timing and amount. Cranes are required by law to be inspected by certified inspectors and the recommendations of the inspector must be complied with or the unit will be tagged out from service.

1

	2016		2017		2018		2019		2020	
	Maintenance Cost	# units	Maintenance Cost	# units	Maintenance Cost	# units	Maintenance Cost	# units	Maintenance Cost	# units
Service Vehicles > 1T	\$83,855	25	\$146,892	26	\$146,428	26	\$222,068	27	\$146,340	27
Service Vehicles < 1T	\$58,860	26	\$65,535	27	\$57,722	27	\$59,125	27	\$75,603	28

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-10

2
3 **ISSUE:** Water Improvement Upgrades

4
5 **QUOTE:** "The cooling water and potable water systems in the YEC main
6 corporate office have experienced pre-mature piping failure and select
7 cooling coil leaks for at least the past 10 years. An external engineering
8 firm was engaged to assess the current systems and provide
9 recommendations to address the issues. The project will implement
10 those recommendations including the installation of a particulate filter,
11 a VFD drive for the existing pump, a heat exchanger, new cooling water
12 piping and valves, and fan coil drip pans with leak detection."
13

14 **QUESTION:**

- 15
16 a) What was the cause of the problems experienced with the office water systems?
17 Please describe how the proposed work will prevent similar problems in the future.
18

19 **ANSWER:**

20
21 **(a)**

22
23 An assessment was undertaken by Stantec in 2019 to assess the identified failures related
24 to the cooling water and potable water systems in the YEC main corporate office. This
25 identified two potential reasons for the failures: (1) the first was that the well water is
26 possibly slightly corrosive towards the piping (not likely to form scale in the piping); and
27 (2) the second is that excessive flow velocities are present in sections of the piping.
28

29 Work completed to address these concerns included the following:

- 30
31 • New pex piping;
32
33 • New filtration system from well water to building;
34
35 • Installation of lead/standby pumps with integral variable speed drives and sensors
36 self-modulating to meet pressure set points;

- 1 • Installation of chemical pot feeder;
- 2
- 3 • Revising control valves to 3rd floor fan coils; and
- 4
- 5 • Supplying of VFD and Pressure sensor for domestic water.

1 **REFERENCE: Application, Table 5.2-1, page 5-33**

2
3 **ISSUE: Other Projects Under \$100K**

4
5 **QUESTION:**

- 6
7 a) Please provide more details on the “Other projects under \$100K” line item in Table
8 5.2.1. What were these projects associated with? Why were they required?
9

10 **ANSWER:**

11
12 **(a)**

13
14 Projects under \$100k include various small projects under the generation, transmission,
15 distribution and general plant and equipment functions. Detailed business cases are
16 typically not provided for these projects in the GRA application given small cost magnitude
17 within the forecast capital costs for the test year, i.e., collectively all such small projects in
18 Table 5.2-1 account for \$915k in 2021 forecast capital works (with 71% under “General
19 Plant & Equipment”).
20

21 The following is noted regarding the nature of the projects:
22

- 23 • **Generation** – Includes small projects that relate to maintenance of generation
24 facilities such as insulation, water level sensor upgrades, stairways, etc.
25
26 • **Transmission** – Includes small projects that relate to maintenance of transmission
27 facilities such as substation protection and control minor upgrades.
28
29 • **Distribution** – Includes small projects that relate to maintenance of distribution
30 facilities including distribution upgrades and land management and easement
31 project.
32
33 • **General Plant and Equipment** – The majority of projects under general plant have
34 annual blanket costs such as operations tools and equipment, fencing upgrades,
35 IT equipment and replacements, etc.

1 **REFERENCE:** Application, Appendix 5.2, page 5.2-11

2
3 **ISSUE:** FD7 Overhaul Project

4
5 **QUOTE:** "Faro Diesel #7 (FD7) is located at the Faro Diesel Plant and uses as 12
6 cylinder Caterpillar Model 3612 diesel engine as its prime mover
7 (vintage 1992). The unit was used when purchased by YEC from a
8 mining operation; however, the complete service history for the unit is
9 not known (YEC has registered 28,624 operating hours). A conditional
10 assessment for the engine was undertaken in 2016 by MPR Associates
11 and a follow-up inspection was undertaken by Finning in May 2016. The
12 inspection focused on items identified in the MPR report and included a
13 more fulsome mechanical inspection that included: removal,
14 measurement and inspection of piston/ rings; inspection of camshaft
15 segments and filter assemblies; measurement of heads and valves and
16 connect rod bearings. One cylinder lining was found cracked and
17 replaced during the inspection. Due to the significant wear found on the
18 inspected parts, it was recommended that a complete overhaul of the
19 unit be undertaken."

20
21 **QUESTION:**

- 22
23 a) Please indicate the number of hours FD7 was in operation for the last 10 years.
24
25 b) If the overhaul is completed as proposed, does YEC expect the annual operating
26 hours for the unit to increase, decrease or stay the same? Please explain.
27
28 c) What is the estimated purchase and installation price to completely replace FD7?
29
30 d) Were any alternatives to this project considered? If not, please explain why not. If
31 so, please provide details of the results of this consideration.
32
33 e) Please provide a breakdown of the work proposed to be done on FD7 and the
34 estimated cost of each component.

ANSWER:

(a)

Please see Table 1 below which provides FD7 running hours for the past 10 years. This also provides for 2014 to 2020 the hours available for operation.

Table 1: FD7 Running Hours and Hours Available for Operation

Year	Running Hours	Available for Operation
2011	573.40	
2012	263.60	
2013	599.20	
2014	204.60	8,705.94
2015	208.90	8,589.79
2016	114.50	8,433.76
2017	202.40	8,390.61
2018	173.40	8,176.99
2019	496.50	8,671.70
2020	427.30	8,721.54
2021 to date	66.73	
Total	3,330.53	59,690.33

(b)

With the overhaul complete the annual operating hours for the unit are expected to stay the same.

YEC's dispatch utilizes renewable energy first on the generation dispatch. YEC Faro generation is lower than LNG, rentals, Whitehorse and Dawson thermal assets in the stacking order. FD7 provides community backup during unplanned events as well as planned maintenance work.

(c)

Replacement cost for FD7 is estimated at \$4-5 million.

1 (d)

2
3 The option for a replacement unit has been considered and will be reviewed through a
4 business case assessment. Discoveries during OH's are a project risk and do increase
5 the cost to repair. The condition of the block may necessitate a replacement of the
6 component (block) resulting in a substantial increase in cost. These costs can equal or
7 exceed the replacement cost.

8
9 (e)

10
11 As indicated in response to YUB-YEC-1-65, pricing for this overhaul was significantly
12 higher than expected when the GRA forecast was prepared. Therefore, a business case
13 is being performed in 2021 to determine if replacement is more cost effective than
14 refurbishment. Any spending for 2021 business case will now be held in WIP and reflected
15 in GRA compliance filing.

16
17 The original work proposed to be done on FD7 in the GRA included disassembly of engine;
18 cleaning and inspection of all parts and components and reassembly of engine, including:

- 19
20 • Installation of all must-do parts¹ (includes main, rod, & cam bearings);
21 • Exchange components including:
22 o Cylinder Heads;
23 o Turbocharger Complete;
24 o Cylinder Liners;
25 o Pistons (Including Rings, Retainers, Pins, Bearing shafts);
26 o Fuel Injectors;
27 o water, oil and fuel lines;
28 o valve train;
29 o air lines;
30 o instrument panel and wiring (where applicable);
31 o front & rear gear train; and
32 o aftercooler and exhaust.

33
34 The OH quote is high level and does not provide individual component costs.

¹ "Must-Do Parts" are seals, gaskets, bearings, plugs, pins, springs and other minor parts necessary in a standard complete in-frame overhaul.

1 **REFERENCE:** Application, Appendix 5.1, page 5.1-1 and Appendix 5.3, page 5.3-
2 1

3
4 **ISSUE:** Projects Not Impacting Rate Base and Deferred Projects

5
6 **QUOTE:** “Appendix 5.1 provides project summaries for capital projects with
7 spending over the period from 2019 to 2021 exceeding \$1 million that
8 remain in WIP at the end of 2021 (and therefore do not affect the 2021
9 GRA revenue requirement).”

10
11 “Deferred expenditure test year spending on major projects (i.e.,
12 expenditures over \$1 million) retained in WIP is focused on projects
13 required to address sustaining capital requirements (i.e., required to
14 replace, repair or enhance/ improve components of the existing system
15 to ensure continued reliability, safety and environmental or regulatory
16 compliance), investments to ensure sufficient dependable capacity for
17 the integrated grid, and continued planning expenditures to meet other
18 potential future generation and transmission requirements.”

19
20 **QUESTION:**

- 21
22 a) Please explain why there are two different appendixes (5.1 and 5.3) for projects
23 held in WIP and what the purpose of each of those appendixes is.
24
25 b) Please confirm that no costs for projects listed in Appendix 5.1 and Appendix 5.3
26 have been added to YEC’s rate base or revenue requirement for 2021. If not
27 confirmed, please explain and provide a breakdown of all costs for these projects
28 that YEC is proposing to add to rate base.
29
30 c) Please explain the rationale for YEC’s “Not Impacting Rate Base” and “Deferred
31 Projects” categories. At some point, will YEC put the costs of projects currently
32 listed as “Not Impacting Rate Base” into the rate base?
33
34 d) Please provide YEC’s capitalization policy.

1 **ANSWER:**

2
3 **(a) through (c)**

4
5 Appendices 5.1 and 5.3 review Major Projects (i.e., projects with forecast costs exceeding
6 \$1 million) for PPE (Appendix 5.1) and deferred costs (Appendix 5.3) that are forecast to
7 remain in WIP during the 2021 test year. The purpose of these appendices is to clearly
8 identify major projects with costs that will not affect forecast test year rate base and
9 therefore do not require detailed review at this time for the purpose of the 2021 GRA
10 Application. Accordingly, it is confirmed that no costs for projects listed in these
11 appendices have been added to rate base or revenue requirement for 2021.

12
13 The rationale generally for the “Not Impacting Rate Base” category is to identify clearly
14 project costs that are not added to rate base or revenue requirement for 2021. It is
15 expected that the costs for projects in WIP will at some point after 2021 (e.g., when brought
16 into service or closed) be brought into rate base.

17
18 To clarify further, information on individual projects with costs that remain in WIP is
19 provided in separate appendices for each category (Appendix 5.1 for Major Projects that
20 are capital works, Appendix 5.3 for Major Projects that are deferred studies, and Appendix
21 5.5 for deferred studies with costs between \$100,000 and \$1 million).

22
23 **(d)**

24
25 Please see Attachment 1 to this response. The policy is unchanged from the version
26 reviewed during the 2017/18 proceeding.

	Finance Accounting Practice FX-Appendix	DEPARTMENT:		
		All		
		INQUIRIES TO:		
		Finance		
		TOPIC:		
		Property, Plant and Equipment Definitions		
		ISSUED:		
		January 1, 2021		
		REVIEW DATE:		
		January 1, 2024		
		APPROVED BY:		
		Chief Financial Officer		

1.0 Purpose

To provide detailed definitions for various Property, Plant and Equipment (PP&E) terminologies.

2.0 Definitions

1. **Property, plant and equipment** are identifiable tangible assets that meet all of the following criteria:

- are held for use in the production or supply of electrical services, for administrative purposes, or for the development, construction, maintenance or repair of other property, plant and equipment;
- have been acquired, constructed or developed with the intention of being used on a continuing basis for longer than one year;
- are not intended for sale in the ordinary course of business (i.e. goods purchased for resale),
- have a cost greater than \$1,000.

2. **Acquisition Costs**

- The cost of an item of property, plant and equipment includes the purchase price and other acquisition costs such as options costs when an option is exercised, brokers' commissions, installation costs, site preparation costs, freight, brokerage and duty charges, transportation insurance costs, , acceptance and commissioning costs.
- The cost of an item of property, plant and equipment that is acquired, constructed, or developed over time includes carrying costs directly attributable to the acquisition, construction, or development activity such as interest costs. For a rate-regulated asset, the cost includes the directly attributable AFUDC allowed by the Yukon Utilities Board (YUB) (see 10.)

3. **Units of Property** represent the main units of equipment or property contained within each PP&E category. A unit of property is defined as that which is independently operational, readily separable and useful in its own right. Examples include dam, turbine, wood pole structures, conductors, transformers, regulators, circuit breakers, diesel engines and hydro generators.

(refer to GP Users Manual for Property, Plant and Equipment for additional information)

4. **Components of Units** represent the associated parts or items making up units of property. Components must be in service to be considered for capitalization. Examples include transformer bushings, voltage regulator bushings, fuel pumps, cross arms, guys or insulators.
5. **Betterment** is an upgrade and/or enhancement that extends the life of a capital asset or increases its functionality or service potential without replacement of a complete unit. Betterment relates to such additions to the asset that increase its useful life, results in reliability and/or quality improvements, increase in previously assessed physical output or service capacity, reduces operating costs by a substantial and quantifiable amount over a period of at least three years or reduces financial liability, environmental or safety risks. Overhaul and maintenance of machinery and equipment are not betterment expenditures.
6. **Maintenance costs** incurred to maintain the service potential of an item of property, plant or equipment are repairs and must be expensed.

Note: If a cost has the attributes of both a repair and betterment, the portion considered a betterment should be capitalized.
7. **Overhauls** are routinely conducted on diesel, wind and hydro production units. Major overhauls extend the useful life of the unit and minor overhauls maintain the efficient and effective operations of the unit. Costs associated with major overhauls are capitalized and depreciated, while costs associated with minor overhauls are expensed in the period in which they are incurred. (refer to FX-002 Overhauls for additional information)
8. **Allowance for Funds Used During Construction (AFUDC)** is imputed interest that is applied to capital projects during construction. It is intended to cover the cost of financing a capital project during the period of construction. AFUDC ceases when an item of property, plant and equipment is substantially complete and ready for productive use. Determining when an asset, or a portion thereof, is substantially complete and ready for productive use requires consideration of the circumstances and operating functions.
(refer to FX-004 AFUDC for additional information)
9. **Asset retirements** – when assets reach the end of their useful life they are retired from service.
10. **Salvage** - is any recovery associated with the retirement of an asset from service including any proceeds received from the sale of the retired asset.

- 11. *Net Salvage*** – is proceeds received from salvage less any costs incurred to remove or dismantle assets retired from service.
- 12. *Disposals*** – assets are said to be disposed of when they are sold, destroyed, lost, abandoned, or expropriated. Disposals require the approval of the Chief Financial Officer.

1 **REFERENCE:** Application, Appendix 5.3, page 5.3-2

2
3 **ISSUE:** Aishihik Generating Station (AGS) Long-Term Water Use Licence
4 **Renewal Project**

5
6 **QUOTE:** “The planned long term AGS Water Use Licence renewal project and
7 related costs were initially reviewed as part of the 2017/18 GRA. At that
8 time, it was noted that the total forecast budget for the project was
9 \$3.569 million spread over five years (2015-2019) ... The deferred
10 costs forecast in the Application include spending in WIP increasing
11 from \$4.957 million at the end of 2018 to \$7.918 million by the end of
12 2021. The project is forecast to be complete by the end of 2022.”

13
14 **QUESTION:**

- 15
16 a) Please break down the \$7.918 million cost for this project into the various
17 components of the project and provide a description of why each component is
18 necessary for the project to proceed.
19
20 b) Please explain why the total cost of this project has increased from \$3.569 million
21 in the 2017-18 GRA to \$7.918 million in the current application.
22
23 c) Please provide a description of each new cost item and each cost item that has
24 increased since the previous GRA, along with a description of why the new cost
25 item or the increased cost is necessary.
26
27 d) Please include an explanation of why YEC’s initial cost estimate was less than half
28 of the current estimate and the measures YEC has implemented or plans to
29 implement to improve its ability to forecast the costs of projects like this.
30
31 e) Please describe the actions YEC has taken throughout the duration of this project
32 and the actions YEC plans to implement moving forward to control and minimize
33 the costs of this project.

ANSWER:

(a)

The \$7.918 million cost noted in Appendix 5.3 of the Application provided forecast project costs to the end of 2021, including 2020 forecasts. These costs now need to be updated to reflect revised forecast costs for 2020, 2021 and 2022.

As set out in Table 1 below – costs forecast to the end of 2021 are now expected to be \$0.871 million higher than forecast in the Application. See Table 2 (response to (b) and (c) below) for updated forecast costs to the end of 2022.

Table 1: Project Costs - 2018 WIP to 2021 WIP

	2018 WIP Actual Cost	2019 Actual Cost	2020 Actual Cost	Forecast 2021	Total
Project Management	\$276,268	\$1,247	\$152,946	\$200,000	\$630,461
CAFN Compensation & Stakeholder Engagement	\$705,319	\$2,373	\$1,012,811	\$350,000	\$2,070,503
Impact Assessment Studies	\$3,748,543	\$94,741	\$406,438	\$ -	\$4,249,722
Early Monitoring	\$ -	\$226,900	\$258,049	\$65,000	\$549,949
Permitting processes	\$40,218	\$182,847	\$303,625	\$325,000	\$851,690
Aishihik Advisory Committee	\$186,851	\$4,648	\$4,935	\$ -	\$196,434
Future AFUDC*	\$ -	\$ -	\$ -	\$240,000	\$240,000
Project Total:	\$4,957,199	\$512,755	\$2,138,804	\$1,180,000	\$8,788,758

*Note: Previous AFUDC accruals for actuals 2018WIP, 2019 and 2020 are embedded within each category total

Set out below are descriptions of the various cost components (and why they are necessary for the project is as follows):

- Project management costs are primarily YEC internal costs related to work on planning and executing the project. These costs are required to move the project forward and coordinate the various working groups and deliverables.

- 1 • CAFN Compensation and stakeholder engagement costs are related to the
2 following:

- 3
4 1. Engagement with the CAFN, including funding the Champagne and
5 Aishihik Community Advisory Committee (CACAC);
6 2. Compensation to the CAFN to be approved by the Yukon Water Board;
7 3. Negotiation costs to reach a reconciliation agreement with the CAFN;
8 4. Capacity funding to CAFN to support participation in the project technical
9 review and development of the Monitoring and Adaptive Management Plan
10 and
11 5. Public engagement activities.

12
13 YEC deemed it prudent to engage the CAFN at the beginning of the current water
14 use license renewal process, given that the facility is located within the CAFN's
15 traditional territory. The objective of engagement was to increase participation by
16 the CAFN in the water use relicensing regulatory process, increasing collaboration
17 between YEC and CAFN and reducing the risk of conflict and/or adversarial legal
18 action during the formal regulatory proceedings.

- 19
20 • Impact assessment studies costs are related to the planning and execution of the
21 environmental and social impact assessment studies in preparation for the YESAB
22 and Yukon Water Board applications. These costs are required to be able to
23 prepare the Project Proposal for the YESAB Designated Office and develop a
24 Monitoring & Adaptive Management Plan for the Yukon Water Board application.
25
26 • Early monitoring costs are related to early monitoring carried out to address issues
27 relevant to CAFN, YESAB and regulators (including requirements from 3-year
28 license to support 25-year renewal).
29
30 • Permitting process costs are required to complete the regulatory activities which
31 are mandatory to achieve the primary objective of the project (obtaining a 25-year
32 water use license for the facility). They include: 1) the project proposal to the Yukon
33 Environmental and Socio-economic Assessment Board (YESAB); 2) regulatory
34 application to the Department of Fisheries and Oceans (DFO); and 3) regulatory
35 application to the Yukon Water Board (YWB).

- 1 • Aishihik Advisory Committee (AAC) costs related to funding the activities of the
2 AAC from 2015 to 2018. The AAC's role was to provide ongoing advice and
3 feedback as Yukon Energy and CAFN developed the necessary regulatory
4 applications. In addition, the AAC worked to reconcile potential opposing interests
5 and values of the YEC, CAFN, external stakeholders, and public related to the use
6 of Aishihik Lake.

7
8 **(b), (c), (d) and (e)**

9
10 As noted, the \$7.918 million cost provided in Appendix 5.3 of the Application relates to
11 forecast costs only to the end of 2021. Appendix 5.3 noted that the project is now forecast
12 to be complete by end of 2022.

13
14 Table 2 below compares:

- 15
16 (a) the forecast cost breakdown provided during the 2017/18 GRA¹ to complete the 25-
17 year licence renewal; and
18 (b) the updated forecast costs to complete this project by the end of 2022.

19
20 The updated forecast costs of \$9,388,758 to complete the project include 2020 and 2021
21 costs that are \$0.871 million higher than the forecast reviewed in Appendix 5.3 of the 2021
22 GRA (see Table 1 above) plus \$600,000 forecast costs for 2022 (the 2021 GRA did not
23 provide any forecast for this project's costs after 2021).

¹ The response to YUB-YEC-1-77(a) in the 2017-18 GRA proceeding provided a cost breakdown for \$3.149 million, excluding compensation costs to CAFN. Table 2 includes the added \$0.42 million (as required for the \$3.569 million 2017-18 GRA forecast) under CAFN Compensation and Stakeholder Engagement.

1 **Table 2: 2017/18 GRA Forecast compared to Updated Forecast to end of 2022 –**
2 **Aishihik Relicensing Project Costs**

	Forecast cost to end of 2022	2017/18 GRA Forecast Cost Sept, 2015 budget	Variance	Cost Drivers
Project Management	\$730,460	\$553,000	\$177,460	Additional project management required to provide project management services over extended project timeline and coordinate/attend increased number of technical subgroups.
CAFN Compensation & Stakeholder Engagement	\$2,145,503	\$804,000	\$1,761,083	\$500,000 Chemi Narrows compensation payment (requirement from 2002 relicensing process, adjusted to this compensation in the Three Year Licence) was not included in initial budget. Significant additional engagement and collaboration requirements beyond those anticipated in the initial budget, including increased capacity funding for CAFN.
Impact Assessment Studies	\$4,249,722	\$1,759,000	\$2,490,722	Additional studies and technical work beyond that anticipated in the initial budget. drove higher costs, particularly during shared study planning process with CAFN plus added costs due to extended time for studies.
Early Monitoring	\$564,949	\$-	\$564,949	Engagement with CAFN and YG revealed requirement for early monitoring programs (as well as requirements from 3-year license to support 25-year renewal) not anticipated in the initial budget. Some items raised for consideration or requested by external parties to be part of the MAMP were required to be piloted to ensure commitments over long term are effective and achievable. In order to address assessment and permitting risk, elements initiated to evaluate impact for

				the long-term license requirements.
Permitting processes	\$1,001,690	\$300,000	\$701,690	Collaborative approach with external parties as directed in Three Year Licence drove an increase in the MAMP scope. Specific information on the MAMP is required for the Water Board; accordingly, scope increases drove additional supporting technical work to complete the processes.
Aishihik Advisory Committee	\$196,434	\$153,000	\$43,434	Increased scope of committee activities per input from committee members; Additional accrual of AFUDC due to project extended timeline.
2021 & 2022 AFUDC	\$500,000	\$-	\$500,000	Additional accrual of AFUDC due to project extended timeline and increased budget.
Project Total:	\$9,388,758	\$3,569,000	\$6,239,338	

Explanation as to why the total cost has increased as described in Table 2, and why the initial cost estimate provided in the 2017-18 GRA was less than half the current estimate, requires review of the context for the 2017-18 GRA forecast including Champagne and Aishihik First Nations' (CAFN) historic grievances relating to the facility and other key factors affecting the relicensing of the Aishihik Generating Station.

Background re: 2017-18 Cost Forecast

The 2017-18 GRA filing addressed a project that was to remain in WIP for the test years and therefore did not affect the revenue requirement during the test years. When the GRA was filed in June 2017, the relicensing process was still at an early stage of development. The forecast cost provided in the GRA reflected a preliminary budget approved by the YEC Board in September 2015.

However, the 2017-18 GRA filing noted that the last Aishihik licence renewal (2002) cost approximated \$8.791 million. That cost reflected protracted processes related to stakeholder engagement, first nation compensation, environmental assessment, and the Yukon Water Board. These processes underscored major issues CAFN had with the Aishihik facility dating back well before Yukon Energy acquired these assets from Canada in 1987.

1 The initial 2015 budget assumed that these issues would not once again cause similar
2 protracted time and cost problems if a shared work plan approach for the relicensing
3 assessment studies was adopted between Yukon Energy and CAFN (and other
4 stakeholders).

5
6 In that regard, the 2017-18 GRA filing recognized that the Aishihik hydro facility has had
7 long term impacts on CAFN, that Yukon Energy and CAFN were working in partnership
8 on proposed terms and conditions for the new Aishihik water license, and that in January
9 of 2016 Yukon Energy and CAFN entered into a Protocol Agreement which established
10 shared objectives, procedures and governance of the new relationship.

11
12 During the 2017/2018 GRA Application process, when YEC forecast the project to be
13 completed by the end of 2019 (when the then existing water use licence expired), YEC
14 identified in YUB-YEC-1-77 that the forecast costs could not be accurately estimated at
15 the time given the material uncertainties relating to the First Nation and regulatory issues
16 surrounding this project. This was clearly articulated as follows:

17
18 “Largely due to the known increased quantum and scope of the impact assessment
19 studies required for the project proposal to YESAB, as well as the funding of the
20 CACAC and CAFN traditional knowledge project, the project is expected to exceed
21 the initial budget of \$3.569 million. Due to unknown costs related to potential
22 increase in the scope of regulatory proceedings, and compensation to the CAFN,
23 the final project cost cannot be accurately estimated at this time. YEC will continue
24 to monitor the development of costs related to unknowns and adjust the budget
25 accordingly.”
26

27 Experience during 2017 through 2018 confirmed that the uncertainties and issues
28 surrounding this project since its inception remained. It became evident during this time
29 that considerably more time and costs would be required than forecast in the initial budget.
30 This experience revealed amongst other things the challenges that CAFN and YEC faced
31 in trying to carry out the shared work plan.

32
33 As reviewed below - because of these difficulties and other related matters --, Yukon
34 Energy had to suspend its 25 year relicensing project in early 2019 in order to secure a
35 three year licence renewal while reconciliation discussions between the Yukon
36 government and CAFN relating to amongst other things CAFN’s historical grievances were
37 ongoing.

1 **Overview of Key Factors for Cost & Schedule Change**

2
3 In summary, the two key factors accounting for the added time and cost requirements for
4 this project are:

- 5
- 6 • The long-standing concerns of Champagne and Aishihik First Nations (CAFN) with
7 regard to this facility's origins and ongoing impacts; and
 - 8
9 • The Yukon Government's decision by early 2019 to engage in negotiation of an
10 agreement with CAFN to address issues of concern including reconciliation.
- 11

12 Overlaying the above key factors is the critical importance of the AGS facility (and its
13 successful relicensing) for the Yukon Integrated System and the strong interest that Yukon
14 Energy has in establishing an improved long-term relationship with CAFN. See Appendix
15 A to this response for summary of the key features of the Aishihik facility.

16
17 ***CAFN's Longstanding Concerns***

18
19 Yukon Energy was aware of CAFN's long standing and ongoing concerns related to the
20 AGS. These concerns were front and center in the 2002 renewal process and they have
21 not abated.

22
23 To try to deal with these issues -- at the start of the current AGS relicensing in 2016 --
24 Yukon Energy and CAFN worked together to develop a shared work plan for the AGS long
25 term licence renewal through implementation of a Protocol Agreement.

- 26
- 27 • Through the Protocol Agreement the parties agreed to work together, on a without
28 prejudice basis, to pursue common objectives for the AGS Water Licence renewal.
 - 29
30 • The Protocol Agreement (2016) did not expand CAFN's rights under the Final
31 Agreement, but it confirmed that CAFN retained the right to participate freely in the
32 regulatory review and Government consultation processes (i.e., under YESAA and
33 the *Waters Act*) and to oppose any or all parts of what may be proposed.
 - 34
35 • The shared work planning process provided a framework for extensive
36 engagement with CAFN and other relevant stakeholders that commenced in 2016
37 and extended throughout the Project planning phase until the fall of 2018. This

1 included Yukon Energy and CAFN working jointly to direct the consulting team
2 regarding the Project work plan and schedule, including the scope of the baseline
3 studies, a structured decision making process to jointly attempt to determine a
4 preferred operating regime, and the opportunity to review and comment on initial
5 Project Proposal draft documentation.

- 6
7 • The shared work planning process under the Protocol Agreement ended in
8 October 2018 as the parties were unable to obtain consensus regarding the
9 operating range for Aishihik Lake. Due to the impending licence renewal deadline
10 Yukon Energy proceeded with preparing and filing a YESAA Project Proposal that
11 reflected key elements of Water Use Licence HY99-011. CAFN indicated that it
12 was not in agreement with Yukon Energy's decision to move ahead with its
13 preferred operating alternative.

14
15 The above experience between 2016 and the end of 2018 resulted in a greatly expanded
16 and prolonged impact assessment study and CAFN engagement processes that delayed
17 initiation of required YESAA evaluation and subsequent permitting activities. YEC
18 attempted to move ahead by the start of 2019 with its 25-year YESAA Project Proposal –
19 but - as outlined below - work on this project had to be deferred to address a three-year
20 short-term relicensing project.

21 22 ***Yukon Government Reconciliation Discussions – Three Year Licence***

23
24 Yukon Energy brought forward the AGS Relicensing Project Proposal in February 2019
25 for a three-year renewal term. This was done to allow the YG and YEC to engage with
26 CAFN on reconciliation related issues including historic grievances CAFN had with the
27 Aishihik facility and to avoid a lapse in Yukon Energy's water use licence for the AGS and
28 termination of Yukon's encumbering rights related to this project under the CAFN Final
29 Agreement.²

30
31 The three year licence approved by the Yukon Water Board in early 2020 outlined a
32 number of additional regulatory requirements for the 2020-2022 period that have driven
33 added costs for completion of the long-term relicensing project. The regulatory
34 requirements included: additional collaborative monitoring and studies during the three

² Due to delays in filing the YESAA Project Proposal to accommodate Yukon Government discussions with Champagne and Aishihik First Nations (CAFN), Yukon Energy had to address material risks that the regulatory review timelines could extend beyond 2019.

1 year licence; development of a collaborative downstream monitoring and adaptive
2 management plan; and reporting on collaboration with CAFN and other parties in relation
3 to the required monitoring and adaptive management specified in the licence.

4
5 After the three year licence renewal was secured in early 2020, Yukon Energy engaged
6 in a further collaborative process with CAFN and YG to develop a Monitoring and Adaptive
7 Management Plan (MAMP) for the long-term licence renewal. Concurrently, CAFN, YG
8 and Yukon Energy continue to work on concluding a reconciliation agreement to address
9 long-standing issues of mutual interest. These activities were also not anticipated in the
10 initial September 2015 project budget, and result in further material schedule extensions
11 and cost increases.

12
13 At the time of filing this IR response, negotiations for the reconciliation agreement have
14 substantively progressed, but have yet to be concluded.

15
16 In summary, the use of a collaborative process with CAFN from 2016 to 2018, prior to the
17 2019 filing and over 2020 and 2021 has led to very material increases in effort and related
18 costs to date and a significantly longer process than originally envisioned.

19
20 The only way to reduce costs would have been to reduce the level of collaboration with
21 CAFN regarding the relicensing process and avoid the 3-year renewal requirement by
22 completing the 25-year relicensing proposal in accordance with the initial schedule.
23 However, in the context of the Water Use Licence and a Yukon government led agreement
24 process with CAFN related to this project and other outstanding issues, this was not
25 feasible – and any such option would not have had any assurance that the end result
26 would have secured the required licence.

27
28 YEC plans to conduct a comprehensive ‘lessons learned’ analysis prior to the initiation of
29 similar future relicensing projects in order to increase the estimation of project costs by
30 increasing the accuracy of estimated technical effort and engagement requirements.

Appendix A: Importance of AGS for the Yukon Integrated System

The Aishihik Generating Station (AGS) is a critical asset for the Yukon Integrated System (YIS); and ensuring that the regulatory instruments required for its ongoing operation are sustained is an essential requirement and responsibility for Yukon Energy.

- The AGS provides the only material annual storage in the Yukon and load following power, after non-dispatchable generation resources (e.g., any existing wind or run-of-river hydro generation facilities) have been utilized.
- Under long-term average water conditions, the AGS supplies approximately 25% of the total annual YIS generation – and about 40% of annual YIS winter generation concentrated in the months from November through May when peak YIS loads occur and run-of-river hydro supplies are constrained.
- The AGS also provides 37 MW of dependable capacity³ to the YIS, which is more than one quarter of Yukon Energy's maximum generation capacity.
- Cessation or reduction of AGS operation would require that the current generation capability of AGS be replaced with some other source of energy that could be relied upon during the winter months. No such renewable alternative is in place today.
- Prior to planning, permitting and development of any new alternative generation capability, including renewable supply options, YEC would need to rely on existing thermal generation to replace the energy supplied currently by the AGS. Reliance on thermal generation to replace AGS hydro generation would have ongoing and very significant added generation operation costs (for fuel and non-fuel O&M) as well as added GHG emissions.⁴

³ Dependable capacity, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history.

⁴ Implications are discussed at a high level in Appendix 6C of YEC's 2020 YESAB Project Proposal, which provides estimates of added capital and O&M costs as well as added GHG emissions associated with an alternative (Alternative 7) that removes AGS storage capability as proposed by CAFN and limits operating to the pre AGS Aishihik Lake LSL and FSL levels, i.e., the high added capital costs (+\$100 million), O&M costs (~\$12 million per year long-term average for thermal generation) and GHG emissions (+32 kt/year CO₂e long-term average) for this alternative compared with the existing licence under 2021 grid loads and grid configuration which still retains run-of-river hydro generation benefits from the AGS.

- 1 • Yukon Energy assessments also indicate that the 37 MW of AGS dependable
2 capacity would also likely need to be replaced with new thermal generation
3 capacity in order to maintain dependable winter supply capability, which would
4 require time for planning and permitting and a capital cost for new thermal
5 generation capacity in excess of \$100 million (a significantly higher capital cost
6 would be required for similar new dependable renewable capacity even if such an
7 alternative was available in the near to medium term).

8
9 In light of the above considerations, renewal of the AGS water use licence under terms
10 substantially similar to the 2002 water use licence has been (and continues to be)
11 considered the only reasonable option for Yukon Energy to pursue at this time.

1 **REFERENCE:** Application, Appendix 5.3, page 5.3-3

2
3 **ISSUE:** Whitehorse Generating Station Water Use Licence Renewal
4 Project

5
6 **QUOTE:** "The existing water use licence for the Whitehorse Rapids Generating
7 Station (WRGS) expires at end of 2025 and must be renewed in order
8 to ensure ongoing, lawful operation of the WRGS hydro facilities. This
9 is a multi-year project to renew the existing long-term project
10 authorizations for the WRGS Hydro Plants and associated
11 infrastructure. Project activities include conducting required baseline
12 studies (e.g. environmental, socio-economic, engineering), and
13 undertaking environmental and socio-economic effects assessment,
14 First Nation engagement and consultation, other stakeholder
15 engagement as required to submit a YESAA project proposal to the
16 Whitehorse Designated Office. Project activities will also include
17 completing the YESAA review process, the water use renewal process
18 with the Yukon Water Board, and Fisheries Act Authorization (DFO)
19 regulatory process."

20
21 **QUESTION:**

- 22
23 a) Is the \$260,000 cost for 2021 the full expected cost of this project? If not, please
24 provide the full expected cost of this project along with a breakdown of that cost
25 into individual cost components. Please also include a description of why each cost
26 component is a necessary part of the project.
27
28 b) What measures is YEC undertaking to ensure that the cost of this project does not
29 increase by a similar magnitude as the costs for the Aishihik licence renewal?
30
31 c) What efforts have been made to streamline planning work for the Southern Lakes
32 Enhanced Storage to avoid duplication with this water licence renewal project?

1 **ANSWER:**

2
3 **(a)**

4
5 No. The estimated cost of the full project is approximately \$5,000,000. A detailed workplan
6 and budget will be developed as part of the project initiation work in 2021.
7

8 **(b)**

9
10 YEC plans to conduct a “lessons learned” exercise regarding the Aishihik licence renewal
11 to identify areas for improvement and lessons to apply to the Whitehorse generating
12 station renewal.
13

14 **(c)**

15
16 The scope of the assessment and permitting for the Southern Lakes Enhanced Storage
17 Project will include an examination primarily of the storage component of the Whitehorse
18 Rapids Generating Station operations. The subsequent water use licence renewal for the
19 whole facility and operations, including an extension to the term of the project
20 authorizations, will have a broader scope. It is expected that most of the issues that will
21 be examined during the assessment and permitting for the Enhanced Storage Project will
22 be able to stand as evidence for the assessment and permitting for the long-term licence
23 renewal and will effectively limit the scope of the water use licence renewal project to
24 primarily those things that were not otherwise assessed during the Enhanced Storage
25 Project just a few years earlier. Accordingly, it is anticipated that redundancy will be
26 minimized and the scope of the water relicensing project will be reduced via the work done
27 on the Enhanced Storage Project.

1 **REFERENCE:** Application, Appendix 5.3, page 5.3-3 to 5.3-4

2
3 **ISSUE:** Diesel Retirement Replacement Project

4
5 **QUOTE:** “The 2016 Resource Plan identified a dependable capacity shortfall for
6 the Yukon Integrated System under its single contingency (N-1)
7 capacity reliability criterion that approximates 6 MW in 2017, increasing
8 to 10-11 MW by 2019. YEC is required to provide sufficient dependable
9 winter capacity to meet the single contingency capacity reliability
10 criterion, i.e., there is no acceptable “do nothing” option given the need
11 to maintain reliable service and to address an ongoing and growing
12 dependable capacity shortfall.

13
14 The 2016 Resource Plan identified a new 20 MW greenfield diesel plant
15 as one of the preferred options for addressing the dependable capacity
16 shortfall gap in a cost effective manner in the near term. The YUB
17 reviewed planning for the project during the 2017/18 GRA, and noted it
18 was not persuaded that the project was the only way to address the
19 predicted capacity shortfall, and that YEC should not proceed with the
20 project without a detailed business case that considers the alternatives
21 to the project.

22
23 Following the Board’s direction in Order 2018-10, YEC proceeded with
24 the additional work as required to evaluate project alternatives. This
25 included identifying and evaluating a number of options for a new 20
26 MW thermal plant. In October 2019, it was determined that considering
27 the results of the technical, environmental and socio- economic
28 research, as well as public feedback, YEC would focus potential
29 options to add or replace capacity at existing generation facilities on an
30 incremental basis as diesel engines are retired.

31
32 This includes consideration of the following near term activities:

- 33
34 • Installation of 5 MW of thermal capacity at the Whitehorse Diesel
35 Plant (P126);

- Replacement of 5.1 MW of diesel to be retired at the Faro Diesel Plant with a 5 MW diesel unit;
- Retirement of the existing 2.5 MW of diesel capacity in Dawson City with installation of 2.5 MW of diesel capacity at the Callison Substation.

Efforts in 2020 have focused on preliminary engineering and finalizing a procurement strategy, defining vendor contracts and milestones, and updating the overall project schedule.

The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from \$0.041 million at the end of 2018 to \$6.395 million by the end of 2021. Dependable capacity from these projects is expected to be available by winter 2023/24. In the interim, YEC will continue to rent diesel generators each winter to ensure an adequate supply of back-up power in case of an emergency.”

QUESTION:

- a) Is the \$6.395 million estimate for the end of 2021 the full estimated cost of this project? If not, please provide the full estimated cost.
- b) Please provide a breakdown of the \$6.395 million into the various components of this project, including a description of why each component is required.
- c) Please provide the results of the analysis YEC carried out to compare the costs and benefits of the various alternatives considered in response to the Board’s finding that it “requires a detailed evaluation of alternatives to this project included in the business case.”

ANSWER:

(a)

The full cost of the project is estimated to be \$45 million.

(b)

Subsequent to the submission of the Application the project cost for 2021 has been adjusted to \$1,920,000 based on updated project planning. This change will be reflected in YEC's Compliance Filing.

A breakdown of all actual costs from 2018 WIP to 2020, and forecast 2021 costs, is shown in Table 1 below.

Table 1: Estimated Project Costs

	Actuals - 2018WIP	Actuals - 2019	Actuals - 2020	2021 Forecast
Feasibility Engineering	\$6,775	\$349,724	\$238,654	\$-
Preliminary Engineering & Procurement	\$-	\$-	\$86,101	\$1,100,000
Assessment & Permitting	\$-	\$20,541	\$78,166	\$220,000
Public & First Nations Engagement	\$-	\$98,764	\$-	\$50,000
Project Management	\$33,897	\$78,758	\$50,914	\$500,000
AFUDC	\$334	\$6,437	\$21,947	\$50,000
Total	\$41,006	\$554,224	\$475,783	\$1,920,000

(c)

The use of a 20 MW greenfield thermal plant as the reference point for comparison was originally based on the findings of the 2016 Resource Plan, which included a 20 MW greenfield diesel plant in the recommended portfolio to address the forecast N-1 dependable capacity shortfall on the Yukon Integrated System (YIS). The initial analysis did not assess options (including requirements) involving replacement and/or addition of diesel units at existing plant facilities on the YIS, and assumed a need to rely primarily on new thermal generation to address the N-1 dependable capacity shortfall.

Ongoing Yukon Energy review and consultation on 20 MW plant options, including potential addition of units at the Whitehorse diesel plant, indicated a wide range of concerns regarding development of a new large greenfield diesel plant – as well as higher costs and uncertainties if similar scaled development was to be focused at the existing Whitehorse diesel plant. The resultant reconsideration of the new thermal generation recommended in the 2016 Resource Plan led to increased reliance on short-term diesel rentals to address the near-term capacity shortfall and provide time to assess a wider range of options.

1 Ongoing review of YEC diesel facilities at Faro, Dawson and Mayo indicated site-specific
2 requirements and opportunities that needed to be addressed when assessing optimum
3 overall new diesel unit planning on the YIS to address forecast N-1 dependable capacity
4 shortfalls. For example, assessments indicated a potential need to relocate diesel capacity
5 required at Dawson and Mayo for reasons unrelated to the N-1 dependable capacity
6 deficit, with resultant opportunities in each case (including planned retirement of two units
7 at Dawson in 2023) to provide cost-effective new diesel capacity to the YIS. Recent studies
8 also highlighted opportunities to provide new cost-effective incremental diesel capacity at
9 the existing Faro diesel plant where a unit is planned to be retired in 2023. The Whitehorse
10 diesel plant also provides ongoing opportunities to replace the three retired Mirrlees diesel
11 units.

12
13 Updated resource plans also separately identified potential renewable generation options
14 that could significantly reduce the need to rely primarily on new thermal generation to
15 address the forecast N-1 dependable capacity shortfall.

16
17 Based on the above reviews, the 2016 Resource Plan has now been superseded by
18 YEC's 10 Year Renewable Electricity Plan, which includes the development of 12.5 MW
19 of replacement diesel capacity at three different existing plant sites (Faro, Dawson and
20 Whitehorse) in the recommended portfolio of projects as well as planning for potential
21 development of a major pumped storage dependable capacity option and a near-term Atlin
22 Hydro Expansion dependable capacity project. Therefore, the development of a new 20
23 MW greenfield thermal plant is no longer a relevant option for current planning given the
24 Corporation's current business plan as reflected in the 10 Year Renewable Electricity Plan,
25 i.e., developing 20 MW of new thermal generation today would be inconsistent with
26 consideration of the renewable pumped storage option combined with the Atlin Hydro
27 Expansion project.

28
29 The 12.5 MW of diesel retirement replacement now being planned involves three separate
30 diesel plant projects, each with its own cost prudence assessment based on plant site
31 requirements and options. Economic assessment for each facility focuses on levelized
32 cost of capacity (LCOC) for each option, given the need to provide dependable capacity
33 that is not expected to have material long term average levels of thermal energy
34 generation. Ongoing cost experience with rented diesels provides a benchmark to assess
35 an option to development of new permanent diesel replacement capacity.

1 **REFERENCE:** Application, Appendix 5.3, page 5.3-4

2
3 **ISSUE:** Southern Lakes Enhanced Storage Project (Marsh Lake Storage
4 Project)

5
6 **QUOTE:** “Forecast MLSEP project costs and actual expenditures were reviewed
7 in detail in the 2012/13 and the 2017/18 GRAs. The 2012/13 GRA,
8 identified the project as a relatively small project, with earliest in-service
9 assumed in 2014 (first full year 2015) at a capital cost (2010\$) of \$10.5
10 million, with mitigation design (shoreline erosion and surface water)
11 expected to comprise about one-half of this total cost (actual costs for
12 mitigation were stated in the 2012/13 GRA as an item that at that time
13 could not be known with any certainty). In the 2017/18 GRA, forecast
14 total project costs increased to \$15.377 million (\$9.795 million forecast
15 for effects assessment; \$0.300 million forecast for YESAA assessment
16 and permitting; and \$7.127 million forecast for mitigation
17 implementation).
18

19 “YEC completed an additional round of engagement in 2019 to confirm
20 the level of support for the project. This included engagement with local
21 residents in the Southern Lakes area, and Yukoners generally; as well
22 as a further round of First Nations engagement to confirm the position
23 of the affected First Nations (Carcross/Tagish First Nation, Kwanlin Dun
24 First Nation and Ta’an Kwach’an Council). Prior to the end of 2020,
25 YEC will make a determination regarding whether to advance the
26 project to the YESAA assessment phase.
27

28 The deferred costs forecast in the Application assumes that the project
29 continues, with spending in WIP increasing from \$7.319 million at the
30 end of 2018 to \$9.379 million by the end of 2021. Potential in service
31 for the Project is 2023.”
32

33 **QUESTION:**

- 34
35 a) Please provide an update on the status of this project including but not limited to
36 the outcome of First Nations and public engagement and YEC’s decision on
37 whether to proceed with this project.

1 b) If YEC is proceeding with this project, please provide:

- 2
- 3 i. updated cost forecasts along with detailed explanations for any cost
- 4 increases relative to the forecast provided in 2017-18;
- 5
- 6 ii. a detailed work plan for completion of the project, including timing for
- 7 individual components of the project;
- 8
- 9 iii. a breakdown of the costs forecast for the various work components
- 10 comprising the project, including all plans for shoreline erosion and
- 11 property owner septic upgrades and other mitigations;
- 12
- 13 iv. steps YEC is taking to prevent cost increases for the project; and
- 14
- 15 v. results of analysis performed by YEC examining the costs and benefits of
- 16 the project relative to any alternatives considered by YEC.
- 17

18 **ANSWER:**

19

20 **(a)**

21

22 In 2019 and early 2020 YEC conducted a final round of public engagement regarding the

23 project. Based on the results of this engagement and the estimated economics of the

24 project, YEC's Board of Directors decided to advance the project into the next stage:

25 preparing a proposal to submission to the YESAA Designated Office.

26

27 **(b)**

28

29 **(i)**

30

31 The current total project cost estimate is \$17.1 million.

32

33 **(ii)**

34

35 The current workplan as outlined below includes collaboration with impacted First Nations

36 who contribute to the development of the Monitoring & Adaptive Management Plan and

- 1 conducting required fieldwork such as the Heritage Resources Impact Assessment. This
- 2 workplan will inform the finalization of the overall project timeline.

ID	Task/Milestone	2021				2022				2023				2024				2025			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	Advance FN benefits and Compensation Agreements																				
2	Advance Monitoring and Adaptive Management Plan																				
4	Prepare YESAA Project Proposal																				
5	Fisheries Baseline Fieldwork																				
6	Heritage Resources Impact Assessment Fieldwork																				
3	Update Project Economics																				
7	Go/No-Go Decision - Stagegate 3																				
8	Proceed Through YESAA																				
9	Prepare and Proceed Through Water Use Licence Amendment																				
#	Go/No-Go Decision - Stagegate 4																				
#	Procure & Implement Mitigation/Monitoring Measures																				
#	Implement Increased Storage Range																				
#	Public, Stakeholder & First Nations Engagement (Ongoing)																				
Optional timing shown for Tasks 10 and 11 in case assessment, permitting, and/or mitigation installation exceed initial schedule estimates.																					

- 3
- 4
- 5 (iii)
- 6 The estimated cost components are provided in the table below.

(\$000's)	Forecast Total Project Costs
Concept Definition & Baseline Studies (2009-2012)	4,305
Preliminary Effects Assessment (2013-2014)	1,229
Mitigation Design & Consultation (2015-2020)	2,234
Additional Engagement & Assessment Prep (2020-2021)	1,314
Assessment & Permitting	800
Project Implementation (Mitigation construction)	7,200
Total Estimated Project Costs	17,082

(iv)

YEC is working to confirm mitigation plans for impacted properties and refine estimates to ensure costs are fully understood before moving forward with the project. Using a stagegate approach to assess a “go” or “no go” decision after more information is known from the results of the YESAA assessment will enable a decision to be made regarding the project with refined information on the economics.

(v)

An updated analysis of the Project economics was completed in early 2020 using the estimated Project costs available at the time. The added water storage is forecast to produce an additional ~6.5 GWh/year of winter energy, which would reduce thermal generation costs for ratepayers.

From an economic perspective, the Project provides energy at a levelized cost of \$0.17/kWh over an economic life of 25 years (WACC of 5.9%) which compares favorably to the marginal cost of thermal generation (blend fuel price of \$0.184/kWh in 2021 GRA forecast).

Given the favorable economics of the SLESP, the Project was included in the recommended project portfolio from both the 2016 Resource plan and the 2020 10 Year

- 1 Renewable Electricity Plan, as a near term project to increase the support of cost effective
- 2 winter energy on the YEC system.

1 **REFERENCE:** Application, Appendix 5.3, page 5.3-6

2
3 **ISSUE:** Mayo Lake Storage Enhancement Project

4
5 **QUOTE:** “In 2018, Northwest Hydraulic Consultants (NHC) was retained to
6 provide a technical assessment regarding whether sediment
7 remediation steps in the Mayo Outlet Channel were feasible and cost
8 effective. This assessment determined that removal of a coffer dam
9 remnant in the outlet channel would improve flow in the near term and,
10 through scouring activity, could potentially also remove the sediment
11 from the channel; if required, as a next step, dredging the channel
12 upstream of the coffer dam could improve hydraulic benefit for power
13 generation. YEC has subsequently proceeded with preparing a YESAA
14 assessment for the project (including the two-phase outlet channel
15 work) which is targeted to be filed with the Mayo Designated Office
16 before the end of 2020.

17
18 The deferred costs forecast in the Application assume that the project
19 continues, with spending in WIP increasing from \$3.373 million at the
20 end of 2018 to \$4.621 million by the end of 2021. Provided licencing
21 processes commence in late 2020/early 2021, potential in service of
22 the amended licence would be in 2023. Work to remove the coffer dam
23 remnant would then proceed as a separate project.”

24
25 **QUESTION:**

- 26
27 a) A detailed work plan for completion of the project, including timing for individual
28 components of the project;
29
30 b) A total forecast costs for the project and a breakdown of the costs forecast for the
31 various work components comprising the project;
32
33 c) Steps YEC is taking to prevent cost increases for the project; and
34
35 d) Results of analysis performed by YEC examining the costs and benefits of the
36 project relative to any alternatives considered by YEC.

ANSWER:

(a)

The estimated work plan for completion of the project is shown below. This is subject to FNNND's confirmation of ability to complete review as proposed.

Task	Proposed Completion Date
Assessment and Permitting	
Baseline Studies	Ongoing
YESAA Assessment	
Project Proposal reviewed by FNNND completed	March 1, 2021
FNNND Chief & Council reconfirmation of support to submit	March 15, 2021
File of YESAA Project Proposal	March 31, 2021
Issuance of Decision Document ¹	November 18, 2021
Water Use Licence	
File Water Use License Amendment Application	June 1, 2021
Receipt of amended Water Use License ²	March 2022
Fisheries Act Authorization	
File Request for Fisheries Act Authorization	June 30, 2021
Receipt of Fisheries Act Authorization ³	July 2022
Consultation and Engagement	
Consultation and Engagement with FNNND ⁴	Ongoing through assessment and permitting
Engineering	
Boat Ramp Extension Design	December 2021
Construction and Implementation	
Boat Ramp Extension	May 2022
Phase 1 Dredging (Cofferdam Removal)	August 2022
Phase 2 Dredging (if required) ⁴	2025/2026

Assumptions:

1. Assuming a DO filing no later than March 31, 2021 and that the DO will take maximum time at each stage.
2. Assuming a filing to the Yukon Water Board for a Water Use License amendment no later than June 1, 2021.
3. Assuming a filing to Fisheries and Oceans Canada no later than June 30, 2021.
4. Phase 2 Dredging is dependent on the results of the Phase 1 Dredging. Following the Phase 1 Dredging, two to three years of monitoring will be conducted to monitor results of Phase 1 Dredging and determine if Phase 2 Dredging is required.

1 (b)

2
3 The total forecast costs to project completion are shown below.
4

Task	Forecast at Completion
Planning (Pre-YESAA)	\$4.5M
Assessment & Licensing	\$500k
Phase 1 Dredging	\$1.1M
Phase 2 Dredging (if required)	\$6.5M to \$9.7M
Overall Project Total	\$6.1M to \$15.8M

5
6 (c)

7
8 YEC continues to employ project management practices to manage budget and scope,
9 including review of project costs and benefits at each stage of decisions.
10

11 (d)

12
13 An economic analysis has examined the project value based on a capital investment
14 amortization period of 45 years and 65 years, across several project scenarios. Three
15 scenarios were run for each of the project added storage ranges (0.5 m and 1 m) with
16 different Phase 2 dredging disposal options, and for each of the 45 year and 65 year
17 project life assumptions. The project life is based on the durability of the proposed
18 dredging and the expected frequency of the future channel dredging:
19

- 20 • A 65 year project life is based on the fact that the control structure has existed
21 since the early 1950s (approximately 70 years) and that this duration would be a
22 reasonable estimate of the expected life of the proposed dredging.
23
- 24 • A more conservative case uses a shorter, 45-year project life in the instance that
25 dredging is required more frequently.
26

27 The 2019 estimated levelized cost of energy (LCOE) for the matrix of cases is presented
28 below. As can be seen from the results, the project has a competitive LCOE under even
29 the most conservative of the scenario (45 year project life, 0.5 m storage range extension)
30 when compared to the marginal cost of natural gas generation (approximately \$0.18/kWh).
31 Updated LCOE analysis will be provided for the 2021 regulatory submissions.

Project Life	Added Storage Assumption (m)	LTA Added Winter Energy (GWh/yr)	Phase 1 Dredging Only LCOE (\$/kWh)	Phase 1 + Phase 2 Dredging LCOE (\$/kWh)	
				Lake Disposal	Land Disposal
45 years	0.5	~3.7	\$0.05	\$0.11	\$0.13
	1	~6.3	\$0.03	\$0.07	\$0.08
65 years	0.5	~3.7	\$0.05	\$0.09	\$0.11
	1	~6.3	\$0.03	\$0.06	\$0.07

1

1 **REFERENCE:** Application, Appendix 5.4, page 5.4-2

2
3 **ISSUE:** IPP Standing Offer Program Implementation

4
5 **QUOTE:** "YEC and ATCO Electric Yukon (AEY) are responsible for
6 implementing the Yukon Government's Independent Power Producers
7 (IPP) Policy ... The project is to be closed in 2020 with total
8 expenditures of \$232,039 to be amortized over five years. The Standing
9 Offer Program (SOP) was developed based on the model used in
10 British Columbia and required development of the following key
11 documents: (1) SOP Program Guide; (2) SOP Program Rules; (3) SOP
12 Application Process; (4) SOP Application Form; (5) Interconnection
13 Standards; and (6) Electricity Purchase Agreement Template."
14

15 **QUESTION:**

- 16
17 a) Please provide a summary of the legislative requirements, any policy directives or
18 government directives which support the statement "YEC and ATCO Electric
19 Yukon (AEY) are responsible for implementing the Yukon Government's
20 Independent Power Producers (IPP) Policy".
21
22 b) Please explain what YEC means when they say the project will be "closed" in 2020.
23 Does this mean it will be completed, cancelled or put on hold?
24
25 c) Please provide a copy of the documentation for the British Columbia model used
26 by YEC as well as the "key documents" listed in the quote above.
27
28 d) Please provide a breakdown of the project components comprising the \$232,039.

1 **ANSWER:**

2
3 **(a)**

4
5 The referenced statement simply reflects the direction by YG in the IPP policy that YEC
6 and AEY are the two public utilities responsible for implementing all contracts and
7 connections with IPPs as required to implement the Yukon Government's IPP Policy.¹
8

9 **(b)**

10
11 In this instance, the term "closed" means that the project will be completed.
12

13 **(c)**

14
15 Please see Attachment 1 to this response which provides relevant documents for the YEC
16 SOP program. Attachment 2 to this response provides documentation for the British
17 Columbia model that is available from BC Hydro's website.
18

19 **(d)**

20
21 Please see Table 1 below for the actual cost breakdown for project components, which
22 include an increase in actual over forecast of \$50k. The following is noted:
23

- 24 1. ATCO's Legal costs to develop the Standing Offer Program rules were cost
25 shared.
26
27 2. DLA Piper provided legal services to YEC regarding review the SOP Rules,
28 development of the Electricity Purchase Agreement template, development of
29 systemic responses to address initial inquiries from three early SOP applicants;
30 and developing additional documents to support the EPA such as a Lenders
31 Consent Agreement.

¹ Yukon's IPP Policy is available at the following link: <https://yukon.ca/sites/yukon.ca/files/emr/emr-yukon-independent-power-production-policy.pdf>.

1 3. Teshmont developed the System Interconnection Guidelines which is a
2 foundational technical document providing guidance and requirement to the SOP
3 proponent to connect to the grid.

4
5 4. Info session food reflects costs for an information session for interested IPP
6 Proponents held on April 25, 2019.

7
8

Table 1: IPP Standing Offer Program Implementation Costs

ATCO Electric Yukon - PO	154,949.64
DLA Piper (Canada) LLP	76,984.88
Teshmont Consultants LP	36,985.00
AFUDC	10,244.82
Info Session Food	528.38
Labour	224.51
Orbis Engineering Field Service Ltd.	139.32
	<u>\$ 280,056.55</u>

9

1 **REFERENCE:** **Application, Appendix 5.4, page 5.4-3**

3 **ISSUE:** **Mt. Sumanik Wind Feasibility Studies**

5 **QUOTE:** “From 2016 to 2017, the project work consisted mostly of data collection
6 and management, as well as evaluating upgrades to the power system
7 for the monitoring equipment which experienced difficulties. In 2018
8 work was conducted to repair the laser of the Lidar unit as the
9 equipment was malfunctioning... The need for YEC to directly conduct
10 resource wind monitoring and site assessments has since been
11 eliminated due to the high likelihood that future wind resources will be
12 developed by Independent Power Producers. As such, the project was
13 decommissioned in 2020 with total expenditures of \$775,581 to be
14 amortized over five years.”

16 **PREAMBLE:** **YEC incurred \$694,427 in 2018, \$31,155 in 2019 and \$50,000 in**
17 **2020.**

19 **QUESTION:**

- 21 a) Please confirm that the cost to repair the laser of the Lidar unit was included in the
22 2018 costs, provide the exact cost of this repair and provide a breakdown of any
23 other costs incurred in that year.
- 25 b) Please provide a breakdown of the costs for the wind feasibility projects incurred
26 for 2019 and 2020.
- 28 c) Please explain how YEC determined that it was not required to conduct wind
29 monitoring and site assessments. For example, did it engage in meetings with
30 Independent Power Producers who expressed interest in wind development?

1 **ANSWER:**

2
3 **(a) and (b)**

4
5 Confirmed that cost to repair the laser of the Lidar unit was included in the 2018 costs.
6 Please see Attachment 1 to this response for breakdown of 2018 costs, as well as of 2019
7 and 2020 actual costs. The following are noted with regard to this information:

- 8
9 • The Application's costs shown for 2018, as stated at pages 5.4-2 and 5.4-3, include
10 all costs incurred prior to 2018; and
11
12 • The 2020 costs in Attachment at \$25,005 are actual costs (and differ from the
13 \$50,000 forecast cost in the Application due to the cost for removing the unit being
14 much lower than had been forecast).

15
16 **(c)**

17
18 Wind was not identified as a required resource in the 10-Year Renewable Electricity Plan,
19 given its provision of intermittent renewable energy and no dependable capacity (which is
20 currently at a shortfall). As YEC is not pursuing any wind projects, wind monitoring and
21 site assessments are unnecessary at this time. It is expected wind energy will be provided
22 from the Independent Power Producer Standing Offer Program. Proponents of this
23 program are responsible for all development costs for their projects, including wind
24 monitoring and site assessments.

2018 Mt Sumanik Costs

Task/Cost type

AFUDC	\$14,537.47
Communication	\$1,219.39
Consultants	
Subscription: Land permit	\$150.00
YEC internal labour: includes project management and site visits and maintenance	\$10,318.73
Propane	\$1,750.52
Materials and supplies: Includes Lidar repair (\$28,793.6)	\$31,658.90
Shipping: Lidar and equipment for repair	\$4,257.36
Travel to site	\$12,349.64

TOTAL 2018 COST **\$76,242.01**

2019 Mt Sumanik Costs

Task/Cost type

AFUDC	\$16,804.38
Communication	\$480.00
Consultants - Hatch wind data assessment	\$11,790.00
Subscription: Land Permit	\$150.00
YEC internal labour: includes project management and site visits and maintenance	\$1,640.00
Propane	\$270.00
Materials and supplies	
Shipping	
Travel to site	\$20.23

TOTAL 2019 COST **\$31,154.61**

2020 Mt Sumanik Costs

Task/Cost type

AFUDC	\$18,221.41
Communication	\$480.00
Consultants	
Subscription: Land Permit	
YEC internal labour: includes project management and site visits and maintenance	\$1,402.94
Propane	
Materials and supplies	\$234.96
Shipping	
Travel to site	\$4,666.00

TOTAL 2020 COST **\$25,005.31**

1 **REFERENCE:** Application, Appendix 5.4, pages 5.4-3 to 5.4-4 and footnote 1,
2 page 5.4-3
3

4 **ISSUE:** WH2 Uprate Engineering
5

6 **QUOTE:** From pages 5.4-3 to 5.4-4 of the Application:
7

8 “See Section 5.2.1.10 for a full description and business case for
9 completing the WH2 Uprate Project before the end of 2021.”
10

11 From page 5.4-3, footnote 1 of the Application:
12

13 “1 By end of 2021 WH2 Uprate Engineering costs will be transferred to
14 Property, Plant and Equipment and added to WH2 Uprate total cost
15 [amortized over 72 years starting in 2022].”
16

17 **QUESTION:**
18

19 a) Please explain why costs for the WH2 Uprating Engineering study are not included
20 in the costs for the WH2 Uprate Project, which is classified as a Capital Works
21 project.
22

23 b) Is a 72-year amortization period typical for projects of this nature? If not, please
24 explain why such an amortization period was chosen for this project.
25

26 **ANSWER:**
27

28 **(a)**
29

30 WH2 Uprate Engineering costs included under Table 5.6 of Tab 5 are part of WH2 Uprate
31 project as indicated in the footnote #1 to Appendix 5.4 and note #2 to Table 5.6 in Tab 5.
32 This project has a separate project number and the spending maintained separately from
33 other capital expenditures for the WH2 Uprate project. Therefore, it was presented under
34 Table 5.6, deferred costs.
35

36 There is no impact to the revenue requirement or requested rate increases as the project
37 is amortized starting in 2022.

1 **(b)**

2

3 The amortization rate was mis-quoted. A 72 year life applies to hydro structures, asset
4 class 1615-200. The proper asset class is 1615-506 – Waterwheels, Turbines and
5 Generators with an expected life of 60 years. There is no impact to the revenue
6 requirement request in this application as this project will not enter service until 2022 (i.e.,
7 outside the test year).

1 **REFERENCE:** Application, Appendix 5.4, page 5.4-4

2
3 **ISSUE:** Building Condition Reports 2020-2024

4
5 **QUOTE:** "YEC is moving from a crisis management model (e.g. waiting for a
6 furnace to fail in the middle of winter), towards a preventive
7 maintenance schedule (identifying life cost cycling of a furnace) for all
8 YEC-owned buildings. This change in approach can provide material
9 cost savings. Building condition reports are required to formally
10 document the structure and fabric of a property, describe the
11 construction of the building and its current condition, and outline work
12 required, timing and costs for completion."
13

14 **QUESTION:**

- 15
16 a) Please explain YEC's rationale for implementing a crisis management model
17 originally.
18

19 **ANSWER:**

20
21 **(a)**

22
23 Prior to having a full wide Building Condition Reports (BCRs) in 2013 by Golder
24 Engineering maintenance was very reactive in nature. There was no proper structured
25 capture of property management, hence the terminology of Crisis Management, which
26 implies repairs were being done as required. The cost implications saved by having
27 detailed BCRs in place allows for life cycle management of equipment and replacement
28 of required building components in a timely fashion to avoid expensive "right now" repair
29 call-outs for individual items.

1 **REFERENCE:** Application, Appendix 5.4, page 5.4-6

2
3 **ISSUE:** Whitehorse Diesel Rental Substation Improvements

4
5 **QUOTE:** "The project is to be closed in 2021 with total expenditures of
6 \$100,000 to be amortized over 45 years."

7
8 **QUESTION:**

9
10 a) Is a 45-year amortization period typical for projects of this nature? If not, please
11 explain why such an amortization period was chosen for this project.

12
13 **ANSWER:**

14
15 **(a)**

16
17 Yes. A 45 year amortization period is typical for projects of this nature.

1 **REFERENCE:** Application, Appendix 5.5, page 5.5-1

2
3 **ISSUE:** Deferred Studies Between \$100,000 and \$1 Million Not Impacting
4 Rate Base

5
6 **PREAMBLE:** YEC included the expenditures for the EV Infrastructure Project and
7 P125 Trashrack Study, forecasted at \$200,000 for each study in 2021.

8
9 **QUESTION:**

- 10
11 a) Please confirm that the \$200,000 for each project will not be added to rate base in
12 this GRA. Please explain if there are plans to include costs for these projects in
13 future GRAs.

14
15 **ANSWER:**

16
17 **(a)**

18
19 Confirmed. These projects are not forecast to be included in rate base in the test year.

20
21 See YUB-YEC-1-101 for further information regarding status of the EV Infrastructure
22 Project; the response notes YEC has chosen to defer this project to a future year, as it is
23 expected to take several years for the rollout of electric vehicles to take place at a larger
24 scale in Yukon. YUB-YEC-1-102 provides further information regarding status the trash
25 rack study.

26
27 Costs for the above studies would be included in a subsequent GRA for prudence review
28 by the Board after the studies have been completed.

1 **REFERENCE:** Application, Appendix 5.5, page 5.5-1

2
3 **ISSUE:** Deferred Studies, EV Infrastructure Project, Electric Vehicle
4 Charging Stations

5
6 **QUOTE:** "The Yukon government 'Our Clean Future: A Yukon Strategy for
7 Climate Change, Energy and a Green Economy' includes a number of
8 actions to encourage the adoption of electric vehicles in Yukon, and the
9 construction of public electric vehicle charging stations. The Yukon
10 Government is forecasting 5,000 electric vehicles in the Yukon by 2030.
11 YEC must be proactive in undertaking infrastructure upgrades and
12 improvements to accommodate the anticipated increased demand on
13 the electrical grid due to this planned growth. Strategy development will
14 assess the potential impact of electric vehicles on the Yukon electrical
15 system and identify a path forward for YEC to meet these challenges.
16 Not addressing this could result in unforeseen costs and reactionary
17 programs."

18
19 **QUESTION:**

20
21 a) Please provide a breakdown of the forecasted \$200,000 for this project. More
22 specifically, provide the activities YEC is planning to engage in and provide the
23 cost allocated to each activity. Does YEC foresee any customer contributions
24 related to costs for this project?

25
26 b) Please provide your preliminary view on whether the Capital Works projects
27 discussed in this application will defer or eliminate infrastructure upgrades related
28 to electric vehicle charging station growth.

29
30 c) How many electric vehicle charging stations have been installed by the Yukon
31 Government and YEC?

32
33 d) What rate schedule(s) apply to these charging stations and how are these
34 revenues accounted for in YEC's Application?

35
36 e) Please include details of the quantities of energy supplied through and any
37 revenues for YEC resulting from the charging stations.

1 f) In YEC's view, why is it reasonable for system demand to be increased and the
2 charges recovered through rates when the benefits of the charging stations would
3 only accrue to those who own electric vehicles?
4

5 **ANSWER:**
6

7 **(a) to (f)**
8

9 Subsequent to the submission of the Application, YEC has chosen to defer this project to
10 a future year, as it is expected to take several years for the rollout of electric vehicles to
11 take place at a larger scale in Yukon. The Compliance Filing will be adjusted to reflect this
12 decision. This change has no impact on the forecast revenue requirement for the 2021
13 test year, i.e., Appendix 5.5 includes only projects forecast to remain in WIP.

1 **REFERENCE:** Application, Appendix 5.5, page 5.5-1

2
3 **ISSUE:** P125 Trashrack Study

4
5 **QUOTE:** "The P125 intake is becoming blocked with debris and frazil ice. These
6 blockages are currently being removed manually by divers and plant
7 operators. This results in multiple outages each year to address
8 blockages. Not addressing this issue will mean continued outages and
9 requirement for divers to address the issue manually. A track [sic] rack
10 must be installed that can permanently address the variety of debris
11 encountered at the intake. The study will confirm the deck structural
12 capacity and other details such as power supply and trash rack
13 geometry."
14

15 **QUESTION:**

16
17 a) Please provide the number and duration of outages caused by the debris and frazil
18 ice blockage in the last 10 years, on a per annum basis, and the costs incurred for
19 these outages.
20

21 b) Please provide a breakdown of the forecast \$200,000 for this project. More
22 specifically, provide the activities YEC is planning to engage in and provide the
23 cost allocated to each activity.
24

25 **ANSWER:**

26
27 **(a)**
28

29 Yukon Energy is in the process to complete the Trashrack Study. The initial observations
30 for the 2018 and 2019 year was Yukon Energy had an average of 6 days of plant outages
31 for cleaning out the trashrack. Based on this estimate, crane cost in addition to potential
32 energy gains from the having the trashrack partly blocked in between cleanings, initial
33 estimates show that the trashrack cleaner is potentially economic and should be studied.
34 Also, having a trashrack cleaner would help to lower the risk of frazil ice blockages on
35 WH1,2,3,4, in the early winter, which leads to system instability. During the full study, all
36 potential benefits will be reviewed and the last 10 years of history will be included.

1 **(b)**

2

3 Costs for the project include \$100,000 for detailed design, \$30,000 for project
4 management, and \$70,000 for procurement and selection of vendor(s).

1 **REFERENCE:** Application, Appendix 5.6, page 5.6-1

2
3 **ISSUE:** ERP System Upgrades

4
5 **QUOTE:** "Given YEC's role as the primary generator of electricity for an isolated
6 grid, it is critical to maintain a modern and robust Enterprise Resource
7 Planning (ERP) system. ERP system refers to a type of software that
8 organizations use to manage day-to-day business activities such as
9 accounting, procurement, project management, maintenance
10 management and supply chain operations. Best practice is to update
11 systems regularly to ensure that the systems are up to date. The project
12 involves upgrades to the ERP system components to the
13 recommended latest stable versions. System experts are contracted to
14 help with individual components as these are critical systems and YEC
15 has no inhouse expertise."
16

17 **QUESTION:**

- 18
19 a) Please explain the implications of not upgrading the ERP system components to
20 the recommended latest stable versions.
21
22 b) Please explain how often YEC has updated the ERP system in the last 10 years
23 and provide the cost of these upgrades.
24
25 c) Please provide YEC's analysis comparing the expected benefits of this project to
26 the forecast costs. Please include an explanation of cost savings or cost
27 avoidances that have been or are expect to be realized.
28

29 **ANSWER:**

30
31 **(a)**

32
33 There are many implications of not upgrading the ERP system components to the
34 recommended latest stable versions, including the following:

- 35
36 • **Lack of support** - You can no longer get support when calling up vendors as they
37 will only support clients with up-to-date stable systems.

- 1 • **Security concerns because security patches cannot be installed** - Security
2 holes have been identified and these need the latest versions to be fixed.

- 3
4 • **System instability** - Older protocols are no longer supported; YEC can no longer
5 get client applications (i.e., Internet explorer 8).

6
7 **(b)**

8
9 Prior to the upgrade in 2020, YEC has updated the ERP system once in 2016 at a cost of
10 \$66,000.

11
12 **(c)**

13
14 Due to the nature of the implications indicated in part (a), a financial cost/benefit analysis
15 is not considered necessary.

1 **REFERENCE: Application, Tab 7 schedules, Schedule 4, page 7-8**

2
3 **ISSUE: Cost of Capital Calculation**

4
5 **QUESTION:**

- 6
7 a) Please confirm that cell G58 of Schedule 4 should equal cell N25 of Schedule 7. If
8 not confirmed, please explain and provide the calculation of the value in cell G58.
9
10 b) Please confirm that cell M56 of Schedule 4 should equal cell M60 multiplied by cell
11 K56. If not confirmed, please explain and provide the calculation of the value in
12 cell M56.
13
14 c) Please confirm that cell M58 of Schedule 4 should equal cell M60 multiplied by cell
15 K58. If not confirmed, please explain and provide the calculation of the value in
16 cell M58.
17
18 d) Please confirm that cell M60 of Schedule 4 should yield the same value as the sum
19 of cells M56 and M58. If not confirmed, please explain. If confirmed, please explain
20 why it does not yield the same value and correct if necessary.
21
22 e) If any of parts (a), (b), (c) and (d) are confirmed, please provide the corrected
23 schedules along with an explanation of any changes to YEC's revenue
24 requirement or rates resulting from the corrections.
25

26 **ANSWER:**

27
28 **(a) through (e)**

29
30 Minor edits to Tab 7 schedules are noted below and then responses are provided to the
31 specific questions.
32

33 YEC identified that the number in line 20 of Schedule 4 [cell G58 in the excel file] was not
34 correctly linked. YEC also revised the calculations for cells M56 and M58 to use the
35 capitalization ratios in Schedule 4, column K in the excel file to avoid impact of rounding
36 of decimal points [the overall impact to the revenue requirement is less than \$300].

1 Please see YUB-YEC-1-104(e) Attachment 1 for revised version of Tab 7 schedules.
2 Please note that there is no impact to the requested rate increase from the above
3 adjustments.

4
5 With regard to the specific questions, the following responses are provided:

6
7 **(a)**

8
9 Not confirmed. Cell G58 of Schedule 4 is mid-year 2021, and cell N25 of Schedule 7 is
10 only year end 2021.

11
12 **(b), (c) and (d)**

13
14 Confirmed.

15
16 **(e)**

17
18 See Attachment 1 to this response.

Yukon Energy Corporation
Computation of Rate Base
(\$000s)

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Property, Plant and Equipment							
2	Year end balance	S.3 L.4	612,436	615,387	642,738	677,309	738,663	738,663
	Deduct:							
3	Accumulated depreciation (note 1)	S.3 L.8	163,053	160,541	172,426	185,389	198,334	198,970
4	Construction-in-progress	S.3 L.12	7,620	4,491	8,088	10,796	37,389	37,389
5	Disallowed assets	S.3 L.11	2,193	2,193	1,989	1,785	1,582	1,582
6	Miscellaneous reserves	S.3 L.16	7,808	7,249	6,231	4,849	4,655	5,012
7	Total deductions		180,674	174,474	188,735	202,820	241,960	242,953
	Add:							
8	Deferred study costs and Intangible assets (note 2)	S.3 L.59	41,695	30,118	32,133	37,884	44,400	44,400
9	Less: Studies and Intangible Assets in Progress	S.3 L.60	29,498	18,930	20,881	26,065	29,972	29,972
10	Total additions		12,198	11,188	11,252	11,819	14,428	14,428
	Net plant in Service							
11	Current year-end balance	S.3 L.62	443,960	452,101	465,255	486,307	511,131	510,138
12	Previous year-end balance		446,777	446,782	452,101	465,255	486,307	486,307
13	Mid-year balance		445,368	449,441	458,678	475,781	498,719	498,223
14	Mid-year regulatory deferral		3,879	3,805	3,009	2,484	2,732	2,732
15	Working capital	S.2 L.8	5,344	5,617	5,935	6,592	6,985	7,141
16	Gross Rate Base		454,592	458,864	467,622	484,858	508,436	508,096
	Deduct:							
	Contributions for extensions (PP&E)							
17	Current year-end balance		201,232	199,527	211,719	228,231	257,031	257,031
18	Contributions in WIP		-	603	385	776	20,776	20,776
19	Current year-end balance in-service		201,232	198,924	211,333	227,455	236,255	236,255
20	Accumulated amortization of contributions		35,976	34,536	39,276	44,306	48,767	48,767
21	Net current year-end balance in-service		165,256	164,387	172,057	183,149	187,488	187,488
22	Previous year-end balance		168,967	168,967	164,387	172,057	183,149	183,149
23	Mid-year balance		167,112	166,677	168,222	177,603	185,319	185,319
24	Net Rate Base	S.5 L.1	287,480	292,186	299,399	307,255	323,117	322,777

Note 1: Including Reserve for Future Removal and Site Restoration

Note 2: Planning and Study costs, Relicensing, Dam Safety costs, Vegetation Management and Intangible Assets. Net of contributions.

Schedule 2
November 2020

Yukon Energy Corporation
Computation of Allowance for Working Capital
(\$000s)

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Operating and maintenance	S.5 L.5	23,715	27,794	29,784	37,653	41,119	43,863
2	Taxes other than income	S.5 L.6	708	671	673	739	750	750
3	Non-allowable expenses		(100)	(99)	(166)	(95)	(120)	(120)
4	Cash operating expenses		24,323	28,366	30,290	38,298	41,748	44,492
5	27/365		1,799	2,098	2,241	2,833	3,088	3,291
6	Inventory (three year average)		3,703	3,697	3,837	3,913	4,014	4,014
7	GST Impact on working capital	S.2A L.11	(158)	(178)	(143)	(154)	(117)	(164)
8	Working capital	S.1 L.19	5,344	5,617	5,935	6,592	6,985	7,141

Yukon Energy Corporation
Effect of GST on Working Capital
(\$000s)

Schedule 2A
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Expenses subject to GST		42,084	37,733	53,916	69,534	99,535	102,279
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		2,104	1,887	2,696	3,477	4,977	5,114
4	Day Factor		14	14	14	14	14	14
5	Recoverable portion of GST impact		81	72	103	133	191	196
6	Revenue subject to GST		49,794	52,059	51,302	59,947	64,164	75,135
7	GST blended rate (2009 GRA)		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
8	GST payable		2,490	2,603	2,565	2,997	3,208	3,757
9	Day factor		35	35	35	35	35	35
10	Payable portion of GST impact		239	250	246	287	308	360
11	Net impact of GST on working capital	S.2 L.7	(158)	(178)	(143)	(154)	(117)	(164)

Yukon Energy Corporation
Continuity Schedule of Property, Plant and Equipment, Deferred Costs and Intangible Assets
(\$000s)

Schedule 3
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
Property, Plant and Equipment								
1	Balance at beginning of year		598,756	598,756	615,387	642,738	677,309	677,309
2	Net Increases to PPE (Table 5.1)		13,680	20,189	29,259	34,571	61,354	61,354
3	Retirements, disposals and adjustments		-	(3,559)	(1,908)	-	-	-
4	Balance at end of year	S.1 L.2	612,436	615,387	642,738	677,309	738,663	738,663
Accumulated depreciation								
5	Balance at beginning of year		150,857	150,857	160,541	172,426	185,389	185,389
6	Depreciation expense	S.6 L.7	12,196	12,185	12,677	12,963	12,945	13,581
7	Retirements, disposals and adjustments		-	(2,501)	(791)	-	-	-
8	Balance at end of year	S.1 L.3	163,053	160,541	172,426	185,389	198,334	198,970
Deductions from PP&E:								
9	Disallowed assets		2,746	2,746	2,746	2,746	2,746	2,746
10	Accum. Disallowed depreciation		(553)	(553)	(757)	(961)	(1,164)	(1,164)
11	Net Disallowed	S.1 L.5	2,193	2,193	1,989	1,785	1,582	1,582
12	Construction-in-progress	S.1 L.4	7,620	4,491	8,088	10,796	37,389	37,389
Miscellaneous Reserves								
13	Fire Insurance Reserve		4,704	4,704	4,442	4,180	3,918	3,918
14	Reserve for Injuries and Damages		(1,035)	(1,419)	(1,002)	(2,121)	(2,053)	(1,697)
15	Reserve for Future Removal and Site Restoration		4,139	3,963	2,790	2,790	2,790	2,790
16	Total Miscellaneous Reserves	S.1 L.6	7,808	7,249	6,231	4,849	4,655	5,012
17	Total Deductions		17,621	13,933	16,308	17,431	43,626	43,983
18	Net Property, Plant and Equipment for Rate Base		431,762	440,913	454,003	474,489	496,703	495,710
Add:								
19	Deferred study costs and Intangible assets (net of contributions)							
20	Feasibility Studies							
21	Opening balance		18,499	18,499	17,798	16,841	16,791	16,791
22	Additions		14,127	1,091	866	1,819	7,370	7,370
23	Amortization		(1,838)	(1,791)	(1,824)	(1,869)	(2,272)	(2,272)
24	Year-end balance		30,788	17,798	16,841	16,791	21,889	21,889
25	Relicensing							
26	Opening balance		6,604	6,604	8,447	10,123	11,970	11,970
27	Additions		1,544	2,359	2,102	2,148	1,745	1,745
28	Amortization		(515)	(515)	(427)	(301)	(368)	(368)
29	Year-end balance		7,633	8,447	10,123	11,970	13,347	13,347
30	Dam Safety							
31	Opening balance		118	118	89	59	345	345
32	Additions		-	-	-	315	-	-
33	Amortization		(30)	(30)	(30)	(30)	(93)	(93)
34	Year-end balance		89	89	59	345	252	252
35	Vegetation Management							
36	Opening balance		1,994	1,994	1,772	1,551	1,329	1,329
37	Additions		-	-	-	-	-	-
38	Amortization		(222)	(222)	(222)	(222)	(222)	(222)
39	Year-end balance		1,772	1,772	1,551	1,329	1,108	1,108
40	Intangibles							
41	Opening balance		1,859	1,859	1,684	2,339	6,000	6,000
42	Additions		79	308	1,215	4,239	495	495
43	Amortization		(478)	(482)	(560)	(578)	(749)	(749)
44	Year-end balance		1,460	1,684	2,339	6,000	5,746	5,746
45	DSM							
46	Opening balance		990	995	1,253	1,319	1,510	1,510
47	Additions		-	350	210	375	894	894
48	Amortization		(110)	(92)	(144)	(184)	(228)	(228)
49	Year-end balance		880	1,253	1,319	1,510	2,176	2,176
50	Hearing Reserve							
51	Opening balance		(1,026)	(1,026)	(926)	(99)	(61)	(61)
52	Additions		155	155	883	93	-	-
53	Amortization		(55)	(55)	(55)	(55)	(55)	(55)
54	Year-end balance		(926)	(926)	(99)	(61)	(116)	(116)
55	Total Deferred Costs and Intangible Assets							
56	Opening balance		29,038	29,043	30,118	32,133	37,884	37,884
57	Additions		15,906	4,262	5,276	8,989	10,504	10,504
58	Amortization		(3,248)	(3,187)	(3,261)	(3,239)	(3,987)	(3,987)
59	Year-end balance	S.1 L.8	41,695	30,118	32,133	37,884	44,400	44,400
60	Less: Working in Progress	S.1 L.9	29,498	18,930	20,881	26,065	29,972	29,972
61	Total Net Deferred Costs and Intangible Assets for Rate Base		12,198	11,188	11,252	11,819	14,428	14,428
62	Total Net PP&E, Deferred Costs and Intangible Assets for Rate Base	S.1 L.11	443,960	452,101	465,255	486,307	511,131	510,138
63	Other Regulatory							
64	Opening balance		3,868	3,863	3,746	2,272	2,696	2,696
65	Additions		318	141	(1,209)	670	500	500
66	Amortization		(295)	(258)	(266)	(246)	(428)	(428)
67	Year-end balance		3,891	3,746	2,272	2,696	2,768	2,768
68	Total Net PP&E, Deferred Costs and Intangible Assets		447,850	455,847	467,527	489,004	513,899	512,900

Yukon Energy Corporation
Calculation of Depreciation Expense for 2021
(\$000s)

Schedule 3A
November 2020

Description	Cost at 2020 Year End	2021 Additions	Cost at 2021 Year End	Existing Depreciation Rate (Years)	2021 Existing Forecast Depreciation	Proposed Depreciation Rate (Years)	2021 Proposed Forecast Depreciation
Land							
Hydraulic Production	444.9	0.0	444.9	0	0.0	0	0.0
Diesel Production	27.7	0.0	27.7	0	0.0	0	0.0
Main Transmission Facilities	576.9	0.0	576.9	0	0.0	0	0.0
Distribution System	17.8	0.0	17.8	0	0.0	0	0.0
General Plant	548.0	0.0	548.0	0	0.0	0	0.0
Rights	128.8	0.0	128.8	50	1.6	50	1.6
Depreciation Study Differences					0.0		0.0
Total Land	1,744.0	0.0	1,744.0		1.6		1.6
Hydro Plant							
Structures and Improvements	37,647.8	17,068.5	54,716.3	72	522.9	72	522.9
Buildings and Improvements	10,278.7	0.0	10,278.7	40	257.0	40	257.0
Reservoirs, Dams, and Waterways	173,561.2	300.0	173,861.2	103	1,685.4	103	1,685.4
Overhaul	6,712.1	0.0	6,712.1	10	671.2	10	671.2
Waterwheels, Turbines & Generation	26,904.6	0.0	26,904.6	85	309.9	60	439.0
Accessory Electric Equipment	27,364.1	750.0	28,114.1	45	608.0	40	684.0
Accessory Digital Equipment	837.9	0.0	837.9	20	41.9	20	41.9
Misc Power Plant Equipment	11,791.4	25.0	11,816.4	30	393.0	30	393.0
Fencing	107.1	0.0	107.1	30	2.7	30	2.7
Depreciation Study Differences					-307.6		-140.5
Total Hydro Plant	295,205.0	18,143.5	313,348.5		4,184.4		4,556.6
Diesel Production							
Structures and Improvements	1,562.4	0.0	1,562.4	72	21.7	72	21.7
Buildings and Improvements	466.1	0.0	466.1	55	8.5	55	8.5
Fuel Holders, Products, and ACC	1,688.5	0.0	1,688.5	25	41.6	40	26.0
Generating Equipment and Prime	14,596.8	0.0	14,596.8	40	635.2	40	635.2
Overhaul	2,962.8	580.0	3,542.8	5	592.6	5	592.6
Minto Generating Equipment	243.5	0.0	243.5	12	26.1	12	26.1
Accessory Electric Equipment	9,018.9	0.0	9,018.9	45	199.7	45	199.7
Misc Power Plant Equipment	1,837.7	0.0	1,837.7	30	59.2	30	59.2
Depreciation Study Differences					-80.6		-70.2
Total Diesel Production	32,376.6	580.0	32,956.6		1,503.9		1,498.7
Wind Turbine							
Wind Turbine	0.0	0.0	0.0	0	0.0	0	0.0
Total Wind Turbine	0.0	0.0	0.0		0.0		0.0
Main Transmission Facilities							
Poles and Fixtures	86,010.6	12,855.0	98,865.6	65	1,323.2	50	1,720.2
Brushing	14,082.3	0.0	14,082.3	50	281.6	60	234.7
Survey Costs	4,380.7	0.0	4,380.7	50	238.7	60	198.9
Overhead Conductors / Poles	20,561.3	0.0	20,561.3	50	411.2	60	342.7
Overhead Conductors / Towers	278.0	0.0	278.0	50	5.6	60	4.6
Substation Equipment	81,331.5	300.0	81,631.5	54	1,512.8	45	1,815.3
Substation Buildings	1,536.2	0.0	1,536.2	55	27.9	55	27.9
Substation Fences	274.5	0.0	274.5	20	13.4	30	8.9
Depreciation Study Differences					-53.4		-79.6
Total Main Transmission Facilities	208,455.0	13,155.0	221,610.0		3,761.1		4,273.7
Sub Transmission Lines							
Poles and Fixtures	4,579.6	0.0	4,579.6	45	100.0	50	90.0
25Kv Minto Spur- Structure	2,646.1	0.0	2,646.1	12	0.0	12	0.0
Brushing	41.6	0.0	41.6	50	0.8	60	0.7
Brushing Minto	432.5	0.0	432.5	12	0.0	12	0.0
Survey costs	0.0	0.0	0.0	50	0.0	60	0.0
Survey costs Minto	95.1	0.0	95.1	12	0.0	12	0.0
Overhead Conductors	1,840.4	0.0	1,840.4	45	40.7	60	30.5
Underground Conductors / Conduit	83.9	0.0	83.9	45	1.9	45	1.9
Overhead Conductors Minto	920.7	0.0	920.7	12	0.0	12	0.0
Substation Equipment	8,013.6	0.0	8,013.6	40	200.3	45	178.1
Substation Equipment Minto	7,111.2	0.0	7,111.2	12	74.6	12	74.6
Depreciation Study Differences					-27.4		-45.8
Total Sub Transmission Lines	25,764.8	0.0	25,764.8		391.0		330.0

Yukon Energy Corporation
Calculation of Depreciation Expense for 2021
(\$000s)

Schedule 3A
November 2020

Description	Cost at 2020 Year End	2021 Additions	Cost at 2021 Year End	Existing Depreciation Rate (Years)	2021 Existing Forecast Depreciation	Proposed Depreciation Rate (Years)	2021 Proposed Forecast Depreciation
Distribution System							
Poles and Fixtures	9,798.1	649.1	10,447.1	35	280.1	40	245.1
Brushing	44.8	0.0	44.8	50	0.9	50	0.9
Survey costs	619.4	0.0	619.4	50	17.7	50	17.7
Overhead conductors - Poles	268.2	0.0	268.2	35	7.7	50	5.4
Overhead Costs	2,117.4	0.0	2,117.4	40	52.9	40	52.9
Underground Services	385.2	0.0	385.2	40	9.6	40	9.6
Underground Conduit	40.5	0.0	40.5	40	1.0	40	1.0
Wind Monitoring Equipment	0.0	0.0	0.0	0	0.0	0	0.0
Meters	312.6	0.0	312.6	30	8.6	16	16.1
Meter Equipment	288.4	0.0	288.4	30	9.2	16	17.2
Substation Equipment	1,287.2	0.0	1,287.2	40	30.3	40	30.3
Substation Buildings	64.8	0.0	64.8	55	1.2	55	1.2
Substation Fences	100.3	0.0	100.3	20	5.0	30	3.3
Street Lights	591.6	0.0	591.6	40	13.8	40	13.8
Line Transformers	4,051.1	0.0	4,051.1	40	98.9	35	113.0
Sentinel Lights	36.4	0.0	36.4	30	1.2	30	1.2
Depreciation Study Differences					-27.6		1.3
Total Distribution System	20,005.9	649.1	20,654.9		510.5		530.1
Building and Other Equipment							
Survey Costs Land	4.3	0.0	4.3	50	0.1	50	0.1
Structures and Improvements (Hydro)	2,791.6	0.0	2,791.6	40	69.4	50	55.5
Building and Improvements	10,632.1	125.0	10,757.1	55	193.3	50	212.6
Office Furniture and Equipment	1,877.4	25.0	1,902.4	20	47.2	20	47.2
Communication Site Towers	19.3	0.0	19.3	30	0.6	40	0.5
Communication Site Fences	64.1	25.0	89.1	20	3.2	30	2.1
Computer Hardware	2,063.4	230.0	2,293.4	5	188.7	7	134.8
Computer Software	0.0	0.0	0.0	5	0.0	5	0.0
Tool and Instruments	2,157.5	490.0	2,647.5	20	84.4	20	84.4
Wind Monitoring Equipment	14.3	0.0	14.3	20	0.7	15	1.0
Communication Equipment	5,615.6	100.0	5,715.6	20	234.1	20	234.1
Company Owned Houses / Land	59.0	0.0	59.0	30	1.7	40	1.3
Company Owned Houses	2,132.4	230.0	2,362.4	30	22.8	40	17.1
Depreciation Study Differences					-29.0		-19.0
Total Building and Other Equipment	27,431.1	1,225.0	28,656.1		817.1		771.6
Transportation							
Utility Vehicles	371.6	30.0	401.6	7	29.3	8	25.6
Sedans and Stationwagons	137.8	0.0	137.8	7	9.4	11	6.0
Trucks & Pole Trailer	11.0	0.0	11.0	31	0.4	25	0.4
Pole Trailers > 10,000 Lbs	53.7	0.0	53.7	25	1.7	25	1.7
Trucks 3/4 to 2 Ton	3,378.4	580.0	3,958.4	10	242.4	9	269.3
Trucks > 3 Ton	1,459.8	185.0	1,644.8	20	58.4	20	58.4
Foremost	1,003.9	0.0	1,003.9	25	40.2	20	50.2
Depreciation Study Differences					-0.7		19.3
Total Transportation	6,416.1	795.0	7,211.1		381.0		431.0
Critical Spares							
Critical Spares	1,193.6	0.0	1,193.6	0	0.0	0	0.0
Total Critical Spares	1,193.6	0.0	1,193.6		0.0		0.0
LNG Production							
Structures and Improvements	6,184.7	0.0	6,184.7	72	85.9	72	85.9
Fuel Holders	13,200.7	0.0	13,200.7	32	412.5	60	220.0
Generator	20,891.0	0.0	20,891.0	40	522.3	40	522.3
Overhaul	343.3	180.0	523.3	2	171.4	2	171.4
Accessory Electric Equipment	3,655.9	0.0	3,655.9	45	81.2	45	81.2
Misc Power Plant Equipment	2,850.6	35.0	2,885.6	30	95.0	30	95.0
Fence	779.7	0.0	779.7	30	26.0	30	26.0
Depreciation Study Differences					0.0		-14.0
Total LNG Production	47,905.9	215.0	48,120.9		1,394.4		1,187.9
Total	666,498.0	34,762.5	701,260.5		12,944.9		13,581.1

Yukon Energy Corporation
Cost of Capital Calculation
(\$000s)

Schedule 4
November 2020

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio		Mid Year Rate Base	Mid Year Cost Rate	Return
2018 GRA Compliance								
1	Long-Term debt	S.11 L.18	172,472	60.0%		172,473	2.23%	3,844
2	Common Stock	S.7 L. 8	115,005	40.0%		115,007	8.70%	10,006
3	Total	S.5 L.3	287,477	100.0%		287,480	4.82%	13,850
2018 Actual								
7	Long-Term debt	S.11 L.18	159,362	57.4%		167,813	2.58%	4,336
8	Common Stock	S.7 L. 8	118,109	42.6%		124,373	6.25%	7,773
9	Total	S.5 L.3	277,471	100.0%		292,186	4.14%	12,110
2019 Actual								
10	Long-Term debt	S.11 L.18	170,377	58.6%		175,532	2.71%	4,757
11	Common Stock	S.7 L. 8	120,229	41.4%		123,867	3.81%	4,723
12	Total	S.5 L.3	290,606	100.0%		299,399	3.17%	9,480
Existing 2020								
10	Long-Term debt	S.11 L.18	179,873	59.6%		183,023	2.92%	5,339
11	Common Stock	S.7 L. 8	122,093	40.4%		124,232	3.88%	4,824
12	Total	S.5 L.3	301,966	100.0%		307,255	3.31%	10,163
Existing 2021								
16	Long-Term debt	S.11 L.18	193,756	60.0%		193,870	2.81%	5,446
17	Common Stock	S.7 L. 8	129,171	40.0%		129,247	3.10%	4,002
18	Total	S.5 L.3	322,927	100.0%		323,117	2.92%	9,448
Proposed 2021								
					Deemed Ratio			
19	Long-Term debt	S.11 L.18	193,505	59.8%	60.0%	193,666	2.81%	5,447
20	Common Stock	S.7 L. 8	130,088	40.2%	40.0%	129,111	8.70%	11,235
21	Total	S.5 L.3	323,593	100.0%	100.0%	322,777	5.17%	16,682

Yukon Energy Corporation
Utility Revenue Requirement
(\$000s)

Schedule 5
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Net rate base	S.1 L.24	287,480	292,186	299,399	307,255	323,117	322,777
2	Average Rate of return on rate base		4.82%	4.14%	3.17%	3.31%	2.92%	5.17%
3	Utility income	S.8 L.1	13,850	12,110	9,480	10,163	9,448	16,682
4	Utility expenses							
5	Operating and maintenance (note 1)	S.6 L.3	23,715	27,794	29,784	37,653	41,119	43,863
6	Taxes other than income	S.6 L.4	708	671	673	739	750	750
7	Amortization of deferred costs	S.6 L.5	3,543	3,500	3,582	3,540	4,471	4,471
8	Reserve for Injuries and Damages	S.6 L.6	479	479	479	479	479	835
9	Depreciation	S.6 L.7	12,196	12,185	12,677	12,963	12,945	13,581
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(4,394)	(4,377)	(5,002)	(5,291)	(4,723)	(4,723)
11	Disallowed depreciation		(204)	(204)	(204)	(204)	(204)	(204)
12	Donations		(100)	(99)	(166)	(95)	(120)	(120)
13	Total utility expenses		<u>35,943</u>	<u>39,949</u>	<u>41,822</u>	<u>49,784</u>	<u>54,716</u>	<u>58,453</u>
14	Revenue Requirement	S.6 L.1	<u>49,794</u>	<u>52,059</u>	<u>51,302</u>	<u>59,947</u>	<u>64,164</u>	<u>75,135</u>

Note 1: Includes fuel expenses and purchased power.

Yukon Energy Corporation
Statement of Earnings
(\$000s)

Schedule 6
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Revenues (note 1)	S.5 L.14	49,794	52,059	51,302	59,947	64,164	75,135
2	Operating expenses							
3	Operating and maintenance	S.10 L.15	23,715	27,794	29,784	37,653	41,119	43,863
4	Taxes other than income	S.5 L.6	708	671	673	739	750	750
5	Amortize deferred costs		3,543	3,500	3,582	3,540	4,471	4,471
6	Reserve for Injuries and Damages	S.5 L.8	479	479	479	479	479	835
7	Depreciation	S.3 L.8	12,196	12,185	12,677	12,963	12,945	13,581
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(4,394)	(4,377)	(5,002)	(5,291)	(4,723)	(4,723)
9	Total		<u>36,247</u>	<u>40,252</u>	<u>42,192</u>	<u>50,083</u>	<u>55,040</u>	<u>58,777</u>
10	Operating income		13,546	11,807	9,110	9,864	9,124	16,359
11	Other income							
12	Allowed for Funds Used	S.8 L.2	542	539	648	831	1,269	1,269
13	Miscellaneous (note 2)	S.8 L.3	(515)	(824)	(951)	(508)	(307)	(327)
14	Total		<u>28</u>	<u>(284)</u>	<u>(304)</u>	<u>323</u>	<u>961</u>	<u>941</u>
15	Other expenses							
16	Interest expense	S.8 L.4	4,431	5,583	6,124	9,663	5,631	5,631
17	Total		<u>4,431</u>	<u>5,583</u>	<u>6,124</u>	<u>9,663</u>	<u>5,631</u>	<u>5,631</u>
18	Net earnings	S.8 L.8	<u>9,142</u>	<u>5,939</u>	<u>2,683</u>	<u>524</u>	<u>4,454</u>	<u>11,669</u>

Note 1: Includes revenues from sales and other revenues.

Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

Yukon Energy Corporation
Statement of Retained Earnings
(\$000s)

Schedule 7
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Balance at beginning of year		60,775	61,366	67,653	65,606	66,983	69,153
	Add:							
2	Net earnings	S.6 L.18	9,142	5,939	2,683	524	4,454	11,669
3	IFRS Comprehensive Income Adjustment		1,660	348	(1,859)	853	-	-
4	Balance at end of year before dividend		<u>71,577</u>	<u>67,653</u>	<u>68,477</u>	<u>66,983</u>	<u>71,437</u>	<u>80,821</u>
	Less:							
5	Common Dividends (note 1)		<u>10,414</u>	<u>-</u>	<u>2,871</u>	<u>-</u>	<u>-</u>	<u>3,623</u>
6	Balance at end of year		<u>61,163</u>	<u>67,653</u>	<u>65,606</u>	<u>66,983</u>	<u>71,437</u>	<u>77,198</u>
	Shareholder's Equity							
7	Common shares		54,036	53,600	53,600	57,998	61,924	57,998
8	Retained earnings		<u>61,163</u>	<u>67,653</u>	<u>65,606</u>	<u>66,983</u>	<u>71,437</u>	<u>77,198</u>
9	Total		<u>115,200</u>	<u>121,253</u>	<u>119,206</u>	<u>124,981</u>	<u>133,361</u>	<u>135,196</u>

Note:

1. YDC equity injection/dividend estimates required in order to maintain 60/40 debt to equity ratio.

Yukon Energy Corporation
Reconciliation of Utility Income to Net Earnings
(\$000s)

Schedule 8
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Utility Income (Return on Rate Base)	S.5 L.3	13,850	12,110	9,480	10,163	9,448	16,682
	Add:							
2	Allowance for funds used	S.6 L.12	542	539	648	831	1,269	1,269
3	Other income (expenses)	S.6 L.13	(515)	(824)	(951)	(508)	(307)	(327)
			<u>13,878</u>	<u>11,825</u>	<u>9,176</u>	<u>10,486</u>	<u>10,409</u>	<u>17,624</u>
	Less:							
4	Interest - long-term	S.6 L.17	4,431	5,583	6,124	9,663	5,631	5,631
5	Donations	S.5 L.12	100	99	166	95	120	120
6	Disallowed costs	S.5 L.13	-	-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	204	204	204	204	204	204
			<u>4,735</u>	<u>5,886</u>	<u>6,494</u>	<u>9,962</u>	<u>5,955</u>	<u>5,955</u>
8	Net earnings	S.6 L.18	9,142	5,939	2,683	524	4,454	11,669

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues
(\$000s)

Schedule 9
November 2020

Line No.	Description	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
1	Residential					
2	Customers	1,635	1,689	1,730	1,756	1,780
3	Sales in MWh	13,719	15,626	15,384	16,730	16,210
4	MWh sales per customer	8.4	9.3	8.9	9.5	9.1
5	Revenue (\$000s)	2,016	2,262	2,262	2,413	2,384
6	Cents per KWh	14.7	14.5	14.7	14.4	14.7
7	General Service					
8	Customers	489	506	517	516	514
9	Sales in MWh	25,436	27,171	29,148	32,250	32,323
10	MWh sales per customer	52.0	53.7	56.4	62.5	62.9
11	Revenue (\$000s)	4,054	4,490	4,833	5,351	5,388
12	Cents per KWh	15.9	16.5	16.6	16.6	16.7
13	Industrial					
14	Sales in MWh	32,193	36,910	27,286	64,856	102,904
15	Revenue (\$000s)	3,952	4,378	3,673	7,260	11,535
16	Cents per KWh	12.3	11.9	13.5	11.2	11.2
17	Street lights					
18	Sales in MWh	214	224	168	168	168
19	Revenue (\$000s)	56	87	82	82	82
20	Cents per KWh	26.0	39.1	48.8	48.8	48.8
21	Space lights					
22	Sales in MWh	12	11	10	10	10
23	Revenue (\$000s)	3	3	3	3	3
24	Cents per KWh	22.5	29.2	26.7	28.1	26.6
25	Total Company - Firm Retail and Industrial					
26	Customers	2,125	2,195	2,247	2,272	2,293
27	Sales in MWh	71,573	79,941	71,997	114,013	151,614
28	Revenue (\$000s)	10,081	11,221	10,853	15,108	19,392
29	Cents per KWh	14.1	14.0	15.1	13.3	12.8
30	Wholesale sales					
31	Sales in MWh	314,700	332,270	331,495	351,775	343,537
32	Revenue (\$000s)	26,114	27,572	27,507	29,190	28,507
33	Cents per KWh	8.3	8.3	8.3	8.3	8.30
34	Total Company - Firm					
35	Sales in MWh	386,273	412,212	403,491	465,788	495,151
36	Revenue (\$000s)	36,194	38,792	38,360	44,298	47,899
37	Cents per KWh	9.4	9.4	9.5	9.5	9.7
38	Secondary					
39	Sales in MWh	2,059	258	0	0	0
40	Revenue (\$000s)	115	20	0	0	0
41	Cents per KWh	5.6	7.6	7.6	0.0	0.0
42	Total Company					
43	Sales in MWh	388,332	412,470	403,492	465,788	495,151
44	Revenue (\$000s)	36,310	38,812	38,360	44,298	47,899
45	Cents per KWh	9.4	9.4	9.5	9.5	9.7
46	Rider J	13,231	13,329	13,842	15,289	15,897
47	Post-GRA Reconcil Req'd					
48	GRA Increase Req'd				0	10,971
49	Total Sales of Power	49,541	52,141	52,203	59,588	74,767
50	Other Revenues	253	-82	-901	359	369
51	Total Revenues	49,794	52,059	51,302	59,947	75,135

Schedule 10
November 2020

Yukon Energy Corporation
Summary of Operating and Maintenance Expenses
(\$000s)

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Utility operations							
2	Production		5,930	7,755	8,402	9,871	10,909	10,909
3	Transmission and distribution		3,445	2,835	2,767	3,215	3,187	3,187
4	General		1,615	1,746	1,921	1,695	1,770	1,770
5	Administration and general		8,917	8,966	9,201	9,603	10,557	10,557
6	Insurance		1,031	1,046	1,117	1,299	1,423	1,423
7	Sub-total		<u>20,938</u>	<u>22,347</u>	<u>23,407</u>	<u>25,684</u>	<u>27,845</u>	<u>27,845</u>
8	Donations		100	99	166	95	120	120
9	Sub-total		<u>100</u>	<u>99</u>	<u>166</u>	<u>95</u>	<u>120</u>	<u>120</u>
10	O&M not including fuel and							
11	purchased power		<u>21,038</u>	<u>22,447</u>	<u>23,574</u>	<u>25,779</u>	<u>27,965</u>	<u>27,965</u>
12	Fuel		2,638	5,295	6,153	11,814	12,787	15,530
13	Purchased power		39	53	57	60	367	367
14	Sub-total		<u>2,677</u>	<u>5,348</u>	<u>6,211</u>	<u>11,874</u>	<u>13,153</u>	<u>15,897</u>
15	Total operating and maintenance	S.6 L.3	<u>23,715</u>	<u>27,794</u>	<u>29,784</u>	<u>37,653</u>	<u>41,119</u>	<u>43,863</u>
Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:								
16	Reserve for Injuries and Damages		479	479	479	479	479	835
17	Property Taxes		708	671	673	739	750	750
18	less: Donations		<u>(100)</u>	<u>(99)</u>	<u>(166)</u>	<u>(95)</u>	<u>(120)</u>	<u>(120)</u>
19	O&M per Table 3.3 (Tab 3)		<u>22,125</u>	<u>23,497</u>	<u>24,559</u>	<u>26,903</u>	<u>29,074</u>	<u>29,430</u>

Schedule 10A
November 2020

Yukon Energy Corporation
Summary of Labour Costs
(\$000s)

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Total FTEs	Tab 3, Table 3.4	93.7	94.9	98.4	97.9	103.6	103.6
2	Total Labour Costs		14,394	14,173	14,131	15,420	16,148	16,148
3	O&M Labour Costs	Sum Lines 5-9	11,932	12,083	11,863	12,727	13,310	13,310
4	Labour Costs to Capital		2,461	2,090	2,268	2,694	2,838	2,838
	Labour Costs							
5	Production		4,131	4,455	4,467	4,995	4,931	4,931
6	Transmission		635	526	545	659	674	674
7	Distribution		856	801	625	617	629	629
8	General		395	351	391	343	378	378
9	Administration		5,916	5,949	5,835	6,113	6,699	6,699
10	Total Labour		<u>11,932</u>	<u>12,083</u>	<u>11,863</u>	<u>12,727</u>	<u>13,310</u>	<u>13,310</u>

Yukon Energy Corporation
Summary of Cost of Long - Term Debt
(\$000s)

Schedule 11
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
General Purpose Long-Term Debt Balance								
1	YDC Mayo B Flexible Term Debt		19,542	19,542	19,205	18,868	18,531	18,531
2	TD Bank Swap (2.69%)		8,991	8,991	8,623	8,245	7,858	7,858
3	Minto Decommissioning Reserve		2,684	2,710	2,769	2,800	2,816	2,816
4	YDC \$5.5M Debt (2.40%)		5,505	5,505	5,505	5,505	5,505	5,505
5	YDC \$92.5M Debt (2.40%/2.83%)		77,723	77,723	74,039	70,356	66,672	66,672
6	YDC \$21.0M Debt (2.21%)		18,466	18,466	17,627	16,788	15,948	15,948
7	YDC \$12.1M Debt (2.10%)		12,136	12,136	12,136	12,136	12,136	12,136
8	TD Bank Swap (3.665%)		21,940	23,406	22,811	22,194	21,554	21,554
9	New 2018 Debt-2018 True Up (2.15%)		5,776	0	0	0	0	0
10	TD Bank Swap (2.899%)		0	0	6,688	6,498	6,303	6,303
11	YDC \$2.9M Debt (2.899%)		0	0	2,871	2,871	2,871	2,871
12	New 2020 Debt-2019 True Up (2.19%)		0	0	0	8,760	8,760	8,760
13	New 2020 Debt-2020 True Up (2.19%)		0	0	0	12,450	12,450	12,450
14	New 2021 Debt-2021 True Up (2.19%)		0	0	0	0	18,638	18,135
15	Current year-end balance		172,763	168,479	172,274	187,471	200,041	199,539
16	Previous year-end balance		172,181	150,244	168,479	172,274	187,471	187,471
17	Mid Year		172,472	159,362	170,377	179,873	193,756	193,505
Interest Costs								
18	YDC Mayo B Flexible Term Debt		334	771	690	1,049	1,030	1,030
19	TD Bank Swap (2.69%)		247	247	237	227	217	217
20	Minto Decommissioning Reserve		24	45	59	31	16	16
21	YDC \$5.5M Debt (2.40%)		132	132	132	132	132	132
22	YDC \$92.5M Debt (2.40%/2.83%)		1,954	1,954	1,865	1,984	1,886	1,886
23	YDC \$21.0M Debt (2.21%)		427	427	408	390	371	371
24	YDC \$12.1M Debt (2.10%)		255	255	255	255	255	255
25	TD Bank Swap (3.665%)		472	287	848	826	803	803
26	New 2018 Debt-2018 True Up (2.15%)		0	0	0	0	0	0
27	TD Bank Swap (2.899%)		0	0	81	191	186	186
28	YDC \$2.9M Debt (2.899%)		0	0	42	83	83	83
29	New 2020 Debt-2019 True Up (2.19%)		0	0	0	79	192	192
30	New 2020 Debt-2020 True Up (2.19%)		0	0	0	0	273	273
31	New 2021 Debt-2021 True Up (2.19%)		0	0	0	0	0	0
32	Total Cost of Interest		3,844	4,118	4,618	5,247	5,443	5,443
33	Mid-Year Cost of Debt		2.23%	2.58%	2.71%	2.92%	2.81%	2.81%

1 **REFERENCE: Application, Tab 7 schedules, Schedule 9, page 7-13**

2
3 **ISSUE: Revenues**

4
5 **QUESTION:**

6
7 a) Please explain how the revenue figures in rows 5, 11, 15, 19, 23 and 32 are
8 calculated.

9
10 b) Please provide references to where the calculation(s) for part (a) are explained in
11 the Application.

12
13 **ANSWER:**

14
15 **(a) and (b)**

16
17 The revenues at existing rates are calculated as follows:

- 18
19 • The revenues at existing rates for YEC retail customers [lines 5, 11, 19 and 23,
20 Schedule 9] are calculated based on forecast energy sales for the test year
21 multiplied by average revenue per kW.h sales. The average revenues per KW.h
22 sales are determined based on actual base rate revenues for last five years, 2015
23 through 2019 as shown below [please note the numbers are subject to rounding]:

24
25 o Average base rate revenues per kW.h for residential customers at 14.71
26 cents/kW.h [by way of example AEY's 2016-17 GRA Compliance Filing
27 average revenue per kW.h at 14.10 cents/kW.h].

28
29 o Average base rate revenues per kW.h for general service customers at
30 16.67 cents/kW.h [by way of example AEY's 2016-17 GRA Compliance
31 Filing average revenue per kW.h at 16.33 cents/kW.h].

32
33 o Average base rate revenues per kW.h for streetlight and space light at
34 38.44 cents/kW.h and 27.18 cents/kW.h respectively.

- 1 • For wholesales [line 15, Schedule 32] – the revenues at existing rates are
2 calculated based on forecast sales for the test year [343,537 MW.h] multiplied by
3 the existing wholesales rate [8.298 cents/kW.h].
4
- 5 • For industrial customers [line 15, Schedule 9] the revenues at existing rates are
6 calculated based on:
7 o Forecast energy sales for the test year multiplied by existing energy rates,
8 including fixed Rider F;
9
- 10 o Forecast peak demand multiplied by existing demand rate; plus
11
- 12 o Fixed Charge revenues based on assumed new Fixed Charges.¹
13

14 Forecast sales and revenues are described in Section 2.2 of the Application and Table
15 2.1. Additional details on the calculations have been provided above.

¹ At the time of preparation of the Application YEC forecasted the new Transmission Facilities Development coming into service connecting the McQuesten Substation with a substation at Mayo in late November 2020/early December 2020 triggering new Fixed Charges effective January 1, 2021 as outlined in section 4.4.2 of the Application and Appendix 4.3. Based on this assumption the existing rate revenues for industrial customers in the Application used Fixed Charge at \$35,734/month effective January 1, 2021 [subject to a separate application] compared to \$8,402/month existing Fixed Charge. However, the in service date for the new Transmission Facilities Development is delayed. YEC will adjust the existing rate revenues for industrial customers in Compliance Filing.

1 **REFERENCE: Application, Tab 7 schedules, Schedule 11, page 7-16**

2
3 **ISSUE: Interest Costs**

4
5 **QUESTION:**

6
7 a) Please explain why there is no interest cost in cell N46 of Schedule 11 for new
8 2021 debt-2021 true up.

9
10 **ANSWER:**

11
12 **(a)**

13
14 The GRA assumes the new long-term debt for 2021 is issued in late 2021 to finance the
15 capital projects and maintain 60/40 debt to equity ratio. Therefore, no interest expense is
16 calculated for the 2021 new debt [the interest expense assumed to start in January 2022].

REFERENCE: Application, Section 3.4, Rate base, page 3-22; and Tab 7, Schedule 2A, page 7-4

ISSUE: Working Capital

QUOTE: “The balance of the change in net rate base from mid-year 2018 approved to mid-year 2020 reflects increased working capital (\$1.8 million increase in 2021 forecast over 2018 approved of \$5.3 million).”

Schedule 2A from page 7-4:

Yukon Energy Corporation Effect of GST on Working Capital (\$000s)							Schedule 2A November 2020	
Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast	
							Existing 2021	Proposed 2021
1	Expenses subject to GST		42,084	37,733	53,916	69,534	99,535	102,279
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		2,104	1,887	2,696	3,477	4,977	5,114
4	Day Factor		14	14	14	14	14	14
5	Recoverable portion of GST impact		81	72	103	133	191	196

QUESTION:

- a) Please provide a complete reference to any Tab 3, Tab 5, Tab 7 or other schedule that can be used for the same purpose of clearly arriving at the YEC's Line No. 1 “Expenses subject to GST” for all years indicated.

ANSWER:

(a)

Please see Table 1 for the requested information.

Table 1: Expenses Subject to GST for Working Capital Calculation Purposes

Line No		Actual 2018	Actual 2019	Forecast 2020	Forecast		References
					Existing 2021	Proposed 2021	
1	Feasibility Studies	17,798	16,841	16,791	21,889	21,889	Schedule 3, Line 24
2	Relicensing	8,447	10,123	11,970	13,347	13,347	Schedule 3, Line 29
3	Dam Safety	89	59	345	252	252	Schedule 3, Line 34
4	Intangibles	1,684	2,339	6,000	5,746	5,746	Schedule 3, Line 44
5	DSM	1,253	1,319	1,510	2,176	2,176	Schedule 3, Line 49
6	Hearing Reserve	-926	-99	-61	-116	-116	Schedule 3, Line 54
7	Other Regulatory Deferred Costs	3,746	2,272	2,696	2,768	2,768	Schedule 3, Line 67
8=Sum(1:7)	Total Deferred Costs	32,092	32,855	39,251	46,061	46,061	
9	Annual Change in Deferred Costs	1,180	763	6,396	6,810	6,810	
10	Annual amortization added back	4,316	4,298	4,192	4,951	4,951	Note 1
11=9+10	Total Additions to Deferred Costs for Working Capital Purposes	5,496	5,060	10,589	11,761	11,761	
12	Property, Plant and Equipment Cost Year End Balance	615,387	642,738	677,309	738,663	738,663	Schedule 3, Line 4
13	Annual Change	16,631	27,351	34,571	61,354	61,354	
14	Remove AFUDC	539	648	831	1,269	1,269	Note 2
15=13-14	Total Additions to PP&E for Working Capital Purposes	16,091	26,704	33,739	60,086	60,086	
	Operating and Maintenance Costs						
16	Fuel	5,348	6,211	11,874	13,153	15,897	Schedule 10, Line 14
17	LWRF Transfer [estimate]	-534	-4,398	-375	0	0	Note 3
18=16-17	Total Fuel	5,882	10,609	12,248	13,153	15,897	
19	Non-fuel O&M net of Labour Cost	10,264	11,544	12,958	14,535	14,535	Schedule 10, Line 7 less Labour Cost per Tab 3, Table 3.3
20=18+19	Total for Working Capital Purposes	37,733	53,916	69,534	99,535	102,279	Schedule 2A, Line 1

Notes:

- Amortization expense for deferred costs are added back to calculate annual change in deferred cost balances before amortization. The amortization expense is before impact of contributions. During the review of calculations YEC noticed that amortization expense of Intangibles was not added back. However, the impact is insignificant [the revenue requirement is underestimated by less than \$100].
- AFUDC is removed for GST impact calculations.
- LWRF transfers are estimated at the time of filing of the Application.

REFERENCE: Application, Summary item 1(c), page 5; Table 3.14, page 3-22

ISSUE: Depreciation Expense

QUOTE: “Depreciation and Amortization Expenses: Approval of depreciation and amortization expenses forecast of \$13.125 million for 2021, including approval of the following:

i. Updated Depreciation Rates: Approval of updated depreciation rates as set out in Tab 7, with an overall increase to 2021 depreciation expense of approximately \$0.636 million; and ...

c. **Depreciation and Amortization Expenses:** Approval of depreciation and amortization expenses forecast of \$13.125 million for 2021, including approval of the following:

i. **Updated Depreciation Rates:** Approval of updated depreciation rates as set out in Tab 7, with an overall increase to 2021 depreciation expense of approximately \$0.636 million; and

**Table 3.14:
Depreciation and Amortization
(\$000)**

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast 2021	
					Existing 2021	Proposed 2021
Fixed Asset Depreciation	\$ 12,196	\$ 12,185	\$ 12,677	\$ 12,963	\$ 12,945	\$ 13,581
Less: Customer contribution	-5,652	-5,635	-6,237	-6,482	-5,911	-5,911
Less: Amortization of fire insurance recoveries	-262	-262	-262	-262	-262	-262
Less: Disallowed Depreciation	-204	-204	-204	-204	-204	-204
Plus: Amortization of deferred charges	5,063	5,020	5,079	4,992	5,921	5,921
Total Depreciation & Amortization	\$ 11,141	\$ 11,104	\$ 11,053	\$ 11,007	\$ 12,489	\$ 13,125

Notes:

1. Disallowed depreciation reflects fixed asset depreciation amounts for disallowed assets per YUB Orders: \$0.004 million (YUB 1992-1), \$0.012 million (YUB 2013-01) and \$0.188 million (YUB 2018-10).

QUESTION:

- a) Please clarify that the difference between Forecast 2020 (\$12,963 thousand) and Forecast Existing 2021 (\$12,945 thousand) fixed asset depreciation amounts represent a decrease in depreciation expense of \$18 thousand that is due to decreases in fixed asset amounts subject to depreciation expense. If not confirmed, please fully explain all reasons for the \$18 thousand decrease in fixed asset depreciation expense. Please include in the response the total amount of depreciable assets used in each of the Forecast 2020 fixed asset depreciation (\$12,963 thousand) and Forecast Existing/Proposed 2021 fixed asset depreciation

1 calculations (\$12,945/\$13,581 thousand) and a complete reference to where those
2 amounts can be confirmed in YEC's supporting Tabs.

3
4 b) Please clarify that the difference between Forecast Proposed 2021 (\$13,581
5 thousand) and Forecast Existing 2021 (\$12,945 thousand) fixed asset depreciation
6 amounts represents an increase in depreciation expense of \$636 thousand that is
7 due to changes in proposed depreciation parameters of average service life and
8 Iowa curve dispersion and mode. If not confirmed, please explain the reason for
9 the \$636 thousand increase in fixed asset depreciation expense.

10
11 c) Please provide a breakdown of the \$636 thousand increase in fixed asset
12 depreciation expense, referenced in part (b) above, between changes in average
13 service life and changes in Iowa Curve dispersion and mode.

14
15 d) Please provide detailed calculations by asset class ID and description that support
16 YEC's amortization of customer contributions in the amounts of Forecast 2020
17 (\$6,482 thousand) and Forecast Existing 2021 / Forecast Proposed 2021 (\$5,911
18 thousand). Please ensure that both asset class ID, description and working
19 formulae are included in the requested worksheet. Alternatively, if the calculations
20 are available elsewhere in YEC's Application, please provide a complete reference
21 to any Tab 3, Tab 5, Tab 7 or other schedule that can be used for the same purpose
22 of clearly arriving at the referenced amounts.

23
24 e) Please explain how YEC determines its amortization rates for contributions and its
25 process for retiring contributions.

26
27 f) For Forecast 2020 (\$4,992 thousand) and Forecast Existing 2021 / Forecast
28 Proposed 2021 (\$5,921 thousand) amortization of deferred charges amounts,
29 please provide a list identifying each deferred charge that comprises the amounts
30 noted and the basis of the amortization period for each deferred charge. If each
31 constituent calculation is available elsewhere in YEC's Application, please provide
32 a complete cross reference to any Tab 3, Tab 5, Tab 7 or other schedule that can
33 be used for the same purpose of clearly arriving at the referenced amounts.

34
35 g) The Board has summarized YEC's reporting in Tab 3 and Tab 7 of the amortization
36 of contributions, fire insurance recoveries and deferred charges in the following
37 table. Please reconcile the "Variance between reporting schedule" column by

1 identifying the nature of the cost that constitutes the variance and by providing an
2 explanation for why the costs are not being reported consistently by YEC between
3 Tab 3 and Tab 7 schedules:

	Tab 3, Schedule 3.14	Tab 7, Schedule 5	Variance between reporting schedule
	(\$ thousands)		
Amortization of customer contributions	(6,482)	(5,291)*	(1,453)
Amortization of fire insurance recoveries	(262)		
Amortization of deferred charges/costs	4,992	\$3,540	1,452
Total Forecast 2020	(1,752)	(1,751)	
Amortization of customer contributions	(5,911)	(4,723)*	(1,450)
Amortization of fire insurance recoveries	(262)		
Amortization of deferred charges/costs	5,921	4,471	1,450
Total Forecast (Existing and Proposed) 2021	(252)	(252)	

4 Source: Tab 3, Schedule 3.14 and Tab 7, Schedule 5 (where * is described as "amortization of contributions and
5 fire insurance recoveries").
6

7 h) Please explain how the lack of complete references between schedules (as noted
8 in part (f) above) and the variance between reporting schedules for what has
9 effectively been described as the same cost (as noted in part (g) above) has been
10 responsive or helpful to the Board with respect to Directive #23 which addressed
11 the Board's concerns about YEC's standard of disclosure with respect to its
12 deferral and reserve accounts.

13

14 **ANSWER:**

15

16 **(a)**

17

18 The difference between Forecast 2020 (\$12,963 thousand) and Forecast Existing 2021
19 (\$12,945 thousand) fixed asset depreciation amounts represent a decrease in
20 depreciation expense of \$18 thousand that is due to decreases in fixed asset amounts
21 subject to depreciation expense.

1 The total amount of depreciable assets used in each of the Forecast 2020 fixed asset
2 depreciation (\$12,963 thousand) and Forecast Existing/Proposed 2021 fixed asset
3 depreciation calculations (\$12,945/\$13,581 thousand) are in the top section of Tab 7,
4 Schedule 3. Specifically, these depreciation amounts can be found on Line 6 of this
5 schedule.

6
7 **(b)**

8
9 Confirmed.

10
11 **(c)**

12
13 A breakdown of the \$636 thousand increase in fixed asset depreciation expense is found
14 in Tab 7, Schedule 3A. In this schedule, the columns labelled '2021 Existing Forecast
15 Depreciation' and '2021 Forecast Proposed Forecast Depreciation' breakdown the
16 differences by each asset category.

17
18 **(d)**

19
20 A summary of YEC's amortization of customer contributions in the amounts of Forecast
21 2020 (\$6,482 thousand) and Forecast Existing 2021 / Forecast Proposed 2021 (\$5,911
22 thousand) by asset class ID is below. These amounts were system generated so no
23 additional excel calculations were done (or available to report). Amortization is based on
24 historical cost at the appropriate amortization rate (see response to part (e)).

	(\$000's)
Property, Plant & Equipment Contributions	
Residential Customer Contributions	136.33
General Service Customer Contributions	68.32
Industrial Customer Contributions	20.96
Street & Sentinel Light Customer Contributions	0.96
Other Contributions	2.70
Minto Contribution 138Kv Line	189.91
Minto Spur Contribution 25 Kv Line	825.08
Victoria Gold McQuestent Contribution	961.38
Yukon Development Corporation Contributions	1,604.26
Yukon Government Contributions	228.73
Government of Canada Contributions	990.71
	5,029.35
Feasibility Contributions	1,333.82
Regulatory Contributions	118.65
	6,481.82

(e)

YEC determines its amortization rates for contributions by applying International Financial Reporting Standards (IFRS) and as reviewed by YEC's external auditor, the Auditor General of Canada. Typically, the amortization period of the contribution matches the asset to which the contribution relates to. An exception to this is the Victoria Gold McQuesten contribution as much of the assets are being amortized over their life (45 years) but IFRS and the Auditor General of Canada required the contribution to be amortized over the expected life of the Victoria Gold mine (12 years).

YEC's process for retiring contributions is to remove the contribution from its records when it is fully amortized, or whenever the asset to which it relates to is disposed of, whichever is earlier.

(f) to (h)

Please see YUB-YEC-1-108 Attachment 1 that provides reconciliation of the referenced amortization numbers in the questions with detailed cross-references to the Application tabs, tables and schedules.

As illustrated in YUB-YEC-1-108 Attachment 1, the forecast amortization of deferred costs for 2020 at \$4.992 million and forecast for 2021 test year at \$5.921 million are before contributions.

As indicated in response to part d), the total amortization of contributions of \$6.482 million for 2020 forecast [Table 3.14] includes amount of deferred cost related contributions of \$1.452 million. The amortization of contributions for deferred costs for 2021 test year is \$1.450 million out of total amortization of contributions at \$5.911 million [Table 3.14].

The following Table 1 shows revised version of Table 3.14 where amortization of contributions for fixed assets and amortization of contributions for deferred costs are shown separately. A row was also added to the end of the table to show how the referenced numbers of \$5.291 million for 2020 and \$4.723 million for 2021 are derived.

Table 1: Depreciation and Amortization for 2020 Forecast and 2021 Test Year

		Forecast 2020	Proposed 2021
1	Fixed Asset Depreciation	\$ 12,963	\$ 13,581
2	Less: Customer contribution [fixed assets]	-5,029	-4,461
3	Less: Amortization of fire insurance recoveries	-262	-262
4	Less: Disallowed Depreciation	-204	-204
5	Plus: Amortization of deferred charges	4,992	5,921
6	Less: Customer contribution [deferred charges]	-1,452	-1,450
7=Sum(1:6)	Total Depreciation & Amortization	<u>\$ 11,007</u>	<u>\$ 13,125</u>
8=2+3	Amortization of customer contributions and fire insurance recoveries	-5,291	-4,723

**Amortization of Deferred Study Costs and Intangible Assets
(\$000s)**

Line No.	Description	2020 Forecast	2021 Test Year	Cross Ref.
	Deferred study costs and Intangible assets (net of contributions)			
	Feasibility Studies			
1	Amortization of Costs	3,202	3,568	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
2	Amortization of Contributions	(1,334)	(1,295)	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
3=1+2	Net Amortization	1,869	2,272	Tab 7, Schedule 3, Line 23
	Relicensing			
4	Amortization of Costs	301	368	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
5	Amortization of Contributions	-	-	
6=4+5	Net Amortization	301	368	Tab 7, Schedule 3, Line 28
	Dam Safety			
7	Amortization of Costs	30	93	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
8	Amortization of Contributions	-	-	
9=7+8	Net Amortization	30	93	Tab 7, Schedule 3, Line 33
	Regulatory [DSM, Other regulatory]			
10	Amortization of Costs	604	867	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
11	Amortization of Contributions	(119)	(155)	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
12=10+11	Net Amortization	485	712	Tab 7, Schedule 3, Sum of Lines 48, 66
	Intangibles			
13	Amortization of Costs	578	749	Tab 5, Table 5.7
14	Amortization of Contributions	-	-	
15=13+14	Net Amortization	578	749	Tab 7, Schedule 3, Line 43
	Vegetation Management			
16	Amortization of Costs	222	222	Tab 3, Table 3.14.2
17	Amortization of Contributions	-	-	
18=16+17	Net Amortization	222	222	Tab 7, Schedule 3, Line 38
	Hearing Reserve Amortization			
19	Amortization	55	55	Tab 7, Schedule 3, Line 53
20	Amortization of Contributions	-	-	
21=19+20	Net Amortization	55	55	
22=1+4+7+10+13+16+19	Total before contributions	4,992	5,921	Tab 3, Table 3.14
23=2+5+8+11+14+17+20	Amortization of contributions	(1,452)	(1,450)	
24=22+23	Total after contributions	3,540	4,471	Tab 7, Schedule 6, Line 5; Tab 7, Schedule 5, Line 7

REFERENCE: Application, Section 6.12, Directives (from Board Order 2018-10) related to revenue requirement: YEC response to Directive #21 – Depreciation and amortization expense details, page 6-5; YEC response to Directive #23 – Improved disclosures on deferral & reserve accounts, page 6-5; Tab 9 Depreciation Study, pages 9-6, 9-98 and 9-99; Tab 7, Schedule 3A, page 7-6

ISSUE: Responses to Board Directives #21 and #23

QUOTE: “Basis of Depreciation Estimates
The straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual functional depreciation rates are shown in Appendix A.”

PREAMBLE: In response to Directive #21 of Board Order 2018-10, YEC prepared “Tab 7, Schedules 3A and 3B” which it stated provided the Board-directed detailed depreciation and amortization calculations.

With respect to YEC’s response to Direction #21, the Board observes that Tab 7 contains Schedule 3A only and not Schedules 3A and 3B as referenced by YEC.

Further, the Board observes that Tab 7, Schedule 3A does not consistently include working formulae that would otherwise provide confirmation of the depreciation expense calculations therein.

1 In response to Directive #23 of Board Order 2018-10, YEC prepared
2 "Tab 7, Schedules 1 and 3" which it stated implemented changes to the
3 structure of those schedules in order to improve disclosure and
4 reporting of deferral and reserve accounts as directed by the Board.
5

6 **QUESTION:**
7

- 8 a) Please revise Tab 7, Schedule 3A to include the "Asset Class ID" for each account
9 and corresponding working formulae supporting the depreciation expense
10 calculations under each of the "2021 Existing Forecast Depreciation" and "2021
11 Proposed Forecast Depreciation" columns. Please provide references that would
12 build to the \$666,498 thousand "cost at 2020 year end" using individual line items
13 from Tab 7, Schedule 3 or any other Tab 7 schedule.
14
- 15 b) Please explain why Tab 7, Schedule 3A does not appear to use a mid-year
16 approach for the purposes of calculating depreciation expense. Please explain this
17 observation fully and clarify whether this is a change from previously approved
18 YEC depreciation expense calculation methodology.
19
- 20 c) Please explain why Tab 7, Schedule 3A appears to generally rely on the use of a
21 depreciation rate based on "years" alone and does not appear to use a
22 depreciation rate that includes consideration of the proposed Iowa Curve (including
23 the associated mode and dispersion). Please explain this observation fully and
24 clarify whether this is a change from previously approved YEC depreciation
25 expense methodology.
26
- 27 d) Referring to the responses to parts (a) to (c) above, please explain any difference
28 between the depreciation expense methodology described in those responses and
29 the basis of the annual depreciation estimates as described in the Tab 9
30 Depreciation Study on page 9-6 and quoted above.
31
- 32 e) Please provide the calculations (including working formulae) supporting the
33 amount of "depreciation study differences" by asset class grouping shown on Tab
34 7, Schedule 3A, given that the amounts do not appear to reflect the same amounts
35 provided in the Tab 9 Depreciation Study, Appendix A at pages 9-98 and 9-99.
36 Please also explain fully why the "depreciation study differences" on Tab 7,

1 Schedule 3A should not reflect the same “depreciation true-up annual provision for
2 true-up” amounts in Appendix A on pages 9-98 and 9-99.

3

4 f) Notwithstanding the differences in dollar amounts noted in part (e) above, please
5 explain fully whether YEC’s implied method to collect or refund any required
6 “depreciation study differences” as a set dollar amount (as indicated on Tab 7,
7 Schedule 3A) is a change from previously approved YEC depreciation expense
8 methodology.

9

10 g) Please clarify whether any of the information from Tab 9, Depreciation Study,
11 Appendix A is used to inform the Tab 7, Schedule 3A depreciation expense
12 calculations. If confirmed, please clearly cross reference the specific information
13 originating from Tab 9, Depreciation Study, Appendix A and where it is relied on,
14 or input, in Tab 7, Schedule 3A.

15

16 h) Referring to Tab 9, Depreciation Study, Appendix A on pages 9-98 and 9-99,
17 please revise Appendix A to include working formulae supporting the depreciation
18 expense calculations therein.

19

20 i) Referring to Tab 9, Depreciation Study, Appendix A on pages 9-98 and 9-99,
21 please clarify why the columns identified as “Accumulated Depreciation,” “AD
22 difference” and “Accumulated depreciation of A/D Difference” must be added
23 together to collectively determine the December 31, 2018 accumulated
24 depreciation balance. Please also explain why, in the alternative, YEC did not
25 simply provide the December 31, 2018 actual book accumulated depreciation
26 balances.

27

28 j) Referring to the quote in the preamble, if Schedule 3B was omitted by YEC in error,
29 please provide the schedule and ensure that it includes an “Asset Class ID” and
30 description for each account and working formulae for any calculations contained
31 therein.

ANSWER:

(a)

In Schedule 3A the “Asset Class ID” for each account is listed under the column labelled ‘Description’. The ‘2021 Existing Forecast Depreciation’ is system generated. The YEC fixed asset database consists of thousands of assets and excel is not used in this part of the forecast; therefore, a revised file with working formulae support is not available with excel. The system takes the cost of each of the individual assets and amortizes them individually over their respective amortization period. The depreciation system is audited by YEC’s external auditor, the Auditor General of Canada.

Regarding the ‘2021 Proposed Forecast Depreciation’ column, the formula was included in the excel file submitted with the Application. The formula can be interpreted in the following words:

Step 1:	Calculate average rate on existing Class ID	$\frac{\text{Cost at 2021 Year End}}{\text{2021 Existing Forecast Depreciation}}$
Step 2:	Calculate existing rate to proposed rate ratio	$\frac{\text{Existing Depreciation Rate}}{\text{Proposed Depreciation Rate}}$
Step 3:	Calculate average proposed rate	$\frac{\text{Average rate on existing Class ID (Step 1)}}{\text{Existing rate to proposed rate ratio (Step 2)}}$
Step 4:	Calculate 2021 Proposed Forecast Depreciation	$\frac{\text{Cost at 2021 Year End}}{\text{Average proposed rate (Step 3)}}$

The \$666,498 thousand “cost at 2020 year end” is built up from all categories and Class ID’s listed on Schedule 3A. It can be reconciled to Tab 7, Schedule 3 as follows:

<u>Forecast 2020</u>		<u>(\$M)</u>
Schedule 3, Line 4	Property, Plant and Equipment, balance at end of year	\$ 677.3
Schedule 3, Line 12	Construction-in-progress	10.8
		<u>\$ 666.5</u>

1 **(b)**

2
3 There is no basis to calculate depreciation on a mid-year basis. YEC calculates
4 depreciation in accordance with International Financial Reporting Standards. Each asset
5 is depreciated monthly based on its cost. For forecast depreciation, the methodology is
6 the same as it provides the most accurate forecast. As stated in part (a), this forecast is
7 system generated. Our understanding is this is not a change from previously approved
8 YEC depreciation expense calculation methodology.
9

10 **(c)**

11
12 YEC depreciates assets on a straight-line basis using 'Years' in accordance with
13 International Financial Reporting Standards. As YEC uses straight-line depreciation, use
14 of 'Years' or 'Rates' does not result in any differences in calculations. Years are the
15 inverse of Rates. This is not a change from previously approved YEC depreciation
16 expense methodology.
17

18 **(d)**

19
20 The depreciation expense methodology described in parts (a), (b) and (c) are consistent
21 with the basis of the annual depreciation estimates as described in the Tab 9 Depreciation
22 Study on page 9-6.
23

24 **(e)**

25
26 A comparison to Depreciation Study Differences as per the Depreciation Study compared
27 to Schedule 3A is provided below:

	Per Depreciation Study	Per Schedule 3A	Variance
Land	-13	-13	0
Hydro Plant	-140,298	-140,465	167
Diesel Production	-88,166	-70,208	-17,958
Main Transmission Facilities	-79,597	-79,597	0
Sub Transmission Lines	-46,022	-45,813	-209
Distribution System	49,971	1,329	48,642
Building and Other Equipment	-67,334	-18,982	-48,352
Transportation	19,268	19,267	1
LNG Production	-13,981	-13,981	0
	(366,172)	(348,463)	(17,709)

The differences above result due to a timing difference between when the Depreciation Study was performed and the current asset base. There is a variance in the Diesel Production class as Schedule 3A was updated for the retirement of the Mirlees diesel engines which were previously included in the Diesel Production Depreciation Differences calculation. As a result, International Financial Reporting Standards and the Auditor General of Canada required the 2019 Diesel Depreciation differences from a previous amount of \$101,236 per year to \$80,615 per year (a reduction of 20.4%). Therefore, the adjusted amount of \$80,615 is the 2021 Existing Forecast Depreciation amount found in Tab 7, Schedule 3A. YEC needed to adjust the 2021 Proposed Forecast Depreciation for this change in its actual existing depreciation study difference amount. The calculation to obtain this is as follows:

	Per Depreciation Study	Adjustment for Mirlees Retirement (%)	Adjustment for Mirlees Retirement (\$)	Per Schedule 3A
Diesel Production	\$ (88,166)	20.4%	\$ 17,959	\$ (70,208)

The other variance in depreciation differences between the Depreciation Study and Schedule 3A is a reclassification of assets, and therefore, depreciation differences between the classes of Distribution System (\$48,642) and Building and Other Equipment (\$-48,352) leaving an insignificant variance of \$290. The amounts in Schedule 3A should be used for regulatory purposes as those amounts will be used for accounting purposes according to International Accounting Reporting Standards.

1 **(f)**

2
3 There is not a change from previously approved YEC depreciation expense methodology.
4

5 **(g)**

6
7 As discussed in part (e), the depreciation study Appendix A is being used as the basis for
8 the calculation of depreciation study differences, subject to the adjustments also noted in
9 part (e).
10

11 **(h)**

12
13 Appendix A is being provided in native format. Since the computations have links to other
14 tabs in the workpaper the complete workpaper is being provided as Attachment 1 to this
15 response.
16

17 **(i)**

18 Certain true-ups in the depreciation reserve are used to comply with prior Board actions.
19 The format of presentation is the same as in the Company's last depreciation study.
20

21 **(j)**

22
23 The Application referenced Schedule 3B in error. There is no Schedule 3B.

YUKON ENERGY
COMPUTATION OF PROPOSED DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2018

Asset Class ID	Asset Class ID Description	Plant	Accumulated Depreciation	AD Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accumulated Depreciation	Accumulated Depreciation Variance	Proposed Depreciation Rate	Proposed Depreciation Amount	Remaining Life	Depreciation True-Up Annual Provision for True Up
Land												
1610-003	Land Hydro Production	444,912	0			444,912						
1610-004	Land Diesel Production	27,680	0			27,680						
1610-006	Land Main Trx Facilities	576,862	0	699	(199)	577,363						
1610-008	Land Distribution System	17,775	0			17,775						
1610-009	Land General Plant	547,992	0			547,992						
1610-106	Land Rights	128,780	(25,910)			102,870	(25,391)	(519)	2.00%	2,576	40.14	(13)
		1,744,002	(25,910)	699	(199)	1,718,592	(25,391)	(519)		2,576		(13)
Hydro Plant												
1615-200	Hydro-Strctrs & Imprvmts	34,163,123	(6,803,403)	(977,149)	63,766	26,446,337	(7,308,246)	(408,540)	1.39%	474,488	56.60	(7,218)
1615-201	Hydro-Building & Imprvmt	10,278,688	(427,340)			9,851,348	(362,324)	(65,016)	2.50%	256,967	38.59	(1,685)
1615-205 & 1615-206	Hydro-Rsrsvoirs Dams & Wtrways	172,919,206	(52,689,116)	(18,131,142)	1,386,390	103,485,339	(49,449,636)	(19,984,232)	0.97%	1,678,827	73.55	(271,727)
1615-506	Hydro-Wtrwhls, Trbines & Gen's	26,339,447	(3,747,076)	(269,433)	44,824	22,367,762	(6,351,635)	2,379,950	1.67%	438,991	45.53	52,271
1615-600	Hydro-Accessory Electric Equip	26,598,355	(5,186,340)	65,942	(23,197)	21,454,761	(7,445,689)	2,302,095	2.50%	664,959	28.80	79,926
1615-601	Hydro Accessory Digital Equip	837,945	(63,362)			774,582	(62,846)	(517)	5.00%	41,897	18.50	(28)
1615-700	Hydro-Misc Power Plant Equip	11,490,781	(3,087,765)	83,244	(46,809)	8,439,452	(3,223,878)	172,549	3.33%	383,026	21.58	7,995
1615-730	Hydro- Fences	107,086	(25,967)			81,119	(29,641)	3,674	3.33%	3,570	21.70	169
	Hydro Plant Total	282,734,632	(72,030,369)	(19,228,538)	1,424,975	192,900,700	(74,233,895)	(15,600,037)		3,942,725		(140,298)
Diesel Plant												
1620-200	Diesel-Strctrs & Imprvmts	1,562,352	(781,875)	(432,852)	106,295	453,920	(634,175)	(474,257)	1.39%	21,699	42.77	(11,087)
1620-201	Diesel-Building & Imprvmt	466,054	(99,651)	(20,501)	3,345	349,246	(62,300)	(54,507)	1.82%	8,474	47.65	(1,144)
1620-403	Diesel-Fuel Hldrs,Prdcts&Accss	1,688,501	(954,217)	(122,114)	114,775	726,946	(589,294)	(372,262)	2.50%	42,213	26.04	(14,296)
1620-500	Diesel-Gnrtnng Equip & Prime	13,841,607	(8,510,645)	(732,079)	1,052,443	5,651,327	(7,105,089)	(1,085,191)	2.50%	346,040	19.47	(55,744)
1620-501	Diesel-Gnrtnng Equip & Prime Retire :	1,970,549	(974,499)			996,050	(1,522,697)	548,198	NA	332,017	0.00	0
1620-508	Diesel-Minto Gnrtnng Equip	243,548	(176,888)			66,660	(192,809)	15,921	8.33%	20,296	2.50	6,368
1620-600	Diesel-Acc Electric Equip	5,416,976	(1,583,903)	(478,962)	171,809	3,525,920	(1,850,307)	(40,749)	2.22%	120,377	29.63	(1,375)
1620-700	Diesel-Misc Power Plant Equip	1,867,523	(825,077)	(371,646)	240,340	911,140	(763,247)	(193,136)	3.33%	62,251	17.74	(10,888)
	Diesel Plant Total	27,057,109	(13,906,754)	(2,158,154)	1,689,007	12,681,208	(12,719,918)	(1,655,983)		953,366		(88,166)
Distribution System												
1625-300	Dist System - Poles & Fxtrs	7,969,883	(1,905,688)	(14,629)	6,125	6,055,691	(1,614,735)	(299,457)	2.50%	199,247	31.90	(9,389)
1625-304	Dist System - Brushing	44,763	(17,835)	(3,235)	996	24,689	(26,238)	6,164	2.00%	895	20.69	298
1625-305	Dist System - Survey Costs	600,378	(168,274)	297		432,401	(112,698)	(55,279)	2.00%	12,008	40.61	(1,361)
1625-401	Dist System - O/H Cndctrs	74,570	(31,009)			43,561	(19,120)	(11,889)	2.00%	1,491	37.18	(320)
1625-410	Dist System - O/H Services	2,117,381	(847,311)	(78,539)	30,910	1,222,442	(931,877)	36,937	2.50%	52,935	22.40	1,649
1625-501	Underground Conduit	385,155	(26,519)			358,636	(22,631)	(3,888)	2.50%	9,629	37.65	(103)
1625-510	Dist System - Undgrnd Cnduit	40,460	(7,467)	(454)	171	32,710	(6,862)	(888)	2.50%	1,012	33.22	(27)
1625-610	Dist System - Meters	312,633	(185,181)	(33,787)	18,820	112,484	(266,434)	66,286	6.25%	19,540	2.36	28,035
1625-620	Dist System - Meter Equip	288,392	(148,993)	3,308	(968)	141,739	(237,596)	90,943	6.25%	18,025	2.82	32,270
1625-710	Dist System - Sbstdn EEquip	1,287,180	(512,564)	(50,938)	22,068	745,746	(473,237)	(68,197)	2.50%	32,180	25.29	(2,696)
1625-720	Dist System - Sbstdn Buildings	64,798	(35,020)	(19,520)	7,988	18,246	(31,214)	(15,339)	1.82%	1,178	28.51	(538)
1625-730	Dist System - Substation Fences	100,328	(15,200)			85,128	(11,684)	(3,517)	3.33%	3,344	26.51	(133)
1625-815	Dist System - Street Lights	588,493	(206,165)	(99,674)	39,803	322,456	(181,113)	(84,924)	2.50%	14,712	27.69	(3,067)
1625-905	Dist System - Line Trxfomers	4,000,082	(1,959,650)	(564,652)	249,975	1,725,756	(2,362,021)	87,694	2.86%	114,288	14.33	6,118
1625-961	Dist System - Sentinel Lights	36,443	(25,911)	(12,948)	9,589	7,173	(16,992)	(12,278)	3.33%	1,215	16.01	(767)
	Distribution System Total	17,910,940	(6,092,787)	(874,771)	385,478	11,328,860	(6,314,451)	(267,629)		481,697		49,971
Main Transmission Facilities												
1635-300	Main Trx - Poles & Fxtrs	60,444,290	(11,208,130)	(1,367,921)	441,757	48,309,996	(12,407,344)	273,051	2.00%	1,208,886	39.74	6,872
1635-304	Main Trx - Brushing	14,082,336	(3,234,991)	48,456	(13,702)	10,882,098	(2,588,715)	(611,522)	1.67%	234,706	48.97	(12,488)
1635-305	Main Trx - Survey Costs	3,541,446	(866,916)	(61,687)	17,348	2,630,191	(759,406)	(151,849)	1.67%	59,024	47.13	(3,222)
1635-402	Main Trx - O/H Cndctrs/Poles	20,561,275	(5,081,116)	(45,903)	11,990	15,446,247	(4,166,859)	(948,169)	1.67%	342,688	47.84	(19,819)
1635-404	Main Trx - O/H Cndctrs/Towers	277,975	(110,991)	(7,067)	2,070	161,987	(136,749)	20,761	1.67%	4,633	30.48	681
1635-710	Main Trx - Sbstdn Equip	66,600,655	(14,772,921)	(633,579)	246,252	51,440,407	(13,394,976)	(1,765,271)	2.22%	1,480,015	35.95	(49,104)
1635-720	Main Trx - Sbstdn Buildings	1,536,213	(216,619)	(2,223)	480	1,317,851	(156,704)	(61,659)	1.82%	27,931	49.39	(1,248)
1635-730	Main Trx - Sbstdn Fences	274,477	(92,674)	769	(605)	181,968	(63,234)	(29,275)	3.33%	9,149	23.09	(1,268)
	Main Transmission Facilities Total	167,318,667	(35,584,356)	(2,069,155)	705,591	130,370,747	(33,673,988)	(3,273,933)		3,367,031	322.59	(79,597)

YUKON ENERGY
COMPUTATION OF PROPOSED DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2018

Asset Class ID	Asset Class ID Description	Plant	Accumulated Depreciation	AD Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accumulated Depreciation	Accumulated Depreciation Variance	Proposed Depreciation Rate	Proposed Depreciation Amount	Remaining Life	Depreciation True-Up Annual Provision for True Up
Sub Transmission Lines												
1640-300	Sub Trx - Poles & Fxtrs	4,092,701	(2,281,354)	(780,721)	281,918	1,312,545	(2,059,673)	(720,483)	2.00%	81,854	24.84	(29,008)
1640-301	Sub Trx - Poles & Fxtrs Mnt Mn	2,646,132	(2,223,467)			422,665	(2,205,110)	(18,357)	8.33%	220,511	2.00	(9,179)
1640-304	Sub Trx - Brushing	41,597	(834)			40,763	(1,023)	189	1.67%	693	58.52	3
1640-306	Sub Trx - Brushing Mnt Mn	432,533	(363,453)			69,080	(360,444)	(3,009)	8.33%	36,044	2.00	(1,504)
1640-307	Sub Trx - Survey Costs Mnt Mn	95,136	(79,940)			15,196	(79,280)	(660)	8.33%	7,928	2.00	(330)
1640-401	Sub Trx - O/H Cndctrs	1,840,369	(564,991)	(112,184)	41,214	1,204,408	(490,758)	(145,203)	1.67%	30,673	44.00	(3,300)
1640-405	Sub Trx - Undrgrnd Cndctrs/Cnd	83,873	(47,669)	(194)	121	36,130	(57,555)	9,813	2.22%	1,864	14.12	695
1640-407	Sub Trx - O/H Cndctrs Mnt Mn	920,693	(773,631)			147,062	(767,244)	(6,387)	8.33%	76,724	2.00	(3,194)
1640-710	Sub Trx - Sbstrn EEquip	8,013,609	(756,527)			7,257,082	(557,208)	(199,319)	2.22%	178,080	41.87	(4,760)
1640-711	Sub Trx - Sbstrn Equip Mnt Mn	6,948,253	(5,781,101)			1,167,153	(5,790,211)	9,111	8.33%	579,021	2.00	4,555
	Sub Transmission Lines Total	25,114,895	(12,872,966)	(893,099)	323,253	11,672,083	(12,368,507)	(1,074,306)		1,213,393		(46,022)
Buildings & Other Equipment												
1645-110	Bldg&Otr - Survey Costs Land	4,321	(1,950)	(601)	193	1,963	(2,837)	479	2.00%	86	17.18	28
1645-200	Bldg&Otr-Strctrs/Imprvmnt Hyd	2,243,942	(333,448)	(3,049)	1,122	1,908,567	(251,936)	(83,440)	2.00%	44,879	44.39	(1,880)
1645-201	Bldg&Otr - Building & Imprvmnt	10,102,549	(3,653,478)	(946,961)	232,163	5,734,274	(3,535,922)	(832,354)	2.00%	202,051	32.50	(25,611)
1645-202	Bldg&Otr-Office Frmt & Equip	1,736,569	(1,267,513)	(130,011)	120,096	459,141	(1,272,514)	(4,914)	5.00%	86,828	5.34	(919)
1645-210	Bldg&Otr - Comm Site Towers	19,297	(11,471)	(1,115)	557	7,268	(7,109)	(4,920)	2.50%	482	25.26	(195)
1645-220	Bldg&Otr - Comm Site Fences	64,126	(30,756)	326	(241)	33,456	(19,994)	(10,676)	3.33%	2,138	20.65	(517)
1645-320	Bldg&Otr - Computer Hardware	1,715,886	(1,022,714)	70,421	(70,023)	693,569	(982,253)	(40,064)	14.29%	245,127	2.99	(13,386)
1645-330	Bldg&Otr - Computer Software	304,004	(132,784)	(7,872)	7,872	171,220	(148,885)	16,101	20.00%	60,801	2.55	6,311
1645-505	Bldg&Otr - Tools & Instruments	1,654,638	(904,640)	(168,321)	140,874	722,551	(889,892)	(42,195)	5.00%	82,732	9.24	(4,565)
1645-507	Bldg&Otr - Wind Mntng Equip	14,283	(11,022)		1,332	4,592	(12,854)	3,164	6.67%	952	1.50	2,109
1645-605	Bldg&Otr - Comm Equip	4,583,047	(2,453,712)	(53,911)	52,353	2,127,778	(2,365,191)	(90,078)	5.00%	229,152	9.68	(9,307)
1645-810	Bldg&Otr - Houses/Land	59,031	(22,410)	7,862	(4,433)	40,050	(14,986)	(3,996)	2.50%	1,476	29.85	(134)
1645-820	Bldg&Otr - Houses/Buildings	2,051,769	(1,430,615)	365,433	(190,775)	795,812	(777,167)	(478,790)	2.50%	51,294	24.85	(19,268)
	Total Building	24,553,463	(11,276,513)	(867,799)	291,091	12,700,242	(10,281,540)	(1,571,682)		1,007,998		(67,334)
Transportation												
1650-411	Trxptn - Utility Vehicles	344,073	(193,559)	12,716	(12,716)	150,514	(173,164)	(20,395)	12.50%	43,009	3.97	(5,132)
1650-412	Trxptn - Sedans & Stn Wagons	137,764	(90,423)	6,160	(6,160)	47,340	(78,421)	(12,003)	9.09%	12,524	4.74	(2,533)
1650-420	Trxptn - Trucks & Pole Trailer	11,000	(2,686)			8,314	(2,724)	37	4.00%	440	18.81	2
1650-430	Trxptn - Pole Trailer>10,000lbs	53,711	(18,374)	(748)	445	35,033	(17,243)	(1,434)	4.00%	2,148	16.97	(84)
1650-440	Trxptn - Trucks 3/4 to 2 Ton	2,644,537	(1,015,122)	(17,178)	17,178	1,629,415	(1,106,240)	91,118	11.11%	293,837	5.24	17,405
1650-470	Trxptn - Trucks > 3Tons	1,459,849	(401,649)	(12,391)	9,860	1,055,670	(453,561)	49,382	5.00%	72,992	13.79	3,582
1650-490	Trxptn - Foremost	1,003,858	(352,963)			650,895	(422,764)	69,801	5.00%	50,193	11.58	6,029
	Total Transportation	5,654,791	(2,074,777)	(11,441)	8,608	3,577,181	(2,254,117)	176,507		475,144		19,268
Critical Spares												
1655-750	Critical Spares	1,170,184	0			1,170,184						
LNG Plant												
1665-200	Structures and Improvements	6,184,735	(301,000)			5,883,735	(270,787)	(30,213)	1.39%	85,899	68.85	(439)
1665-403	Fuel Holders	13,200,669	(1,445,518)			11,755,151	(692,600)	(752,919)	1.67%	220,011	56.85	(13,243)
1665-500	LNG Generator	20,880,293	(1,157,153)			19,723,140	(1,233,591)	76,437	2.50%	522,007	37.64	2,031
1665-600	Accessory Electric Equipment	3,655,939	(282,214)			3,373,725	(253,176)	(29,038)	2.22%	81,243	41.88	(693)
1665-700	Miscellaneous Power Plant Equi	2,828,210	(321,574)			2,506,636	(287,467)	(34,106)	3.33%	94,274	26.95	(1,266)
1665-730	LNG Fence	779,651	(91,066)			688,585	(81,109)	(9,957)	3.33%	25,988	26.88	(370)
	Total LNG	47,529,497	(3,598,525)	0	0	43,930,972	(2,818,729)	(779,796)		1,029,423		(13,981)
	Total Yukon	600,788,180	(157,462,958)	(26,102,258)	4,827,804	422,050,768	(154,690,534)	(24,047,378)		12,473,354		(366,170)

Note: The following accounts were excluded from the depreciation study:
1615-504
1620-504
Asset 7060 removed from asset group 1615-506
Asset 8856 transferred from asset group 1645-200 to 1615-201

REFERENCE: Application, Section 1.2, Table 1-2, footnote 1, page 1-6; Section 3.4, page 3-22

ISSUE: Depreciation Expense

QUOTE: From footnote 1, Table 1-2:
“1. Excludes depreciation rate changes & impact of accelerated amortization of VGC Group contributions.”

From Section 3.4:

New contributions since 2018 include \$11.5 million from VGC Group to fund McQuesten Substation and system improvement capital costs, which contributions are being amortized over the expected 12 year life of the Eagle Gold mine.”

“Accelerated amortization of VGC Group contributions related to McQuesten Substation and system improvement costs result in these assets reducing total depreciation and amortization costs by \$0.665 million in the 2021 test year.”

PREAMBLE: Referring to Table 1-2, YEC states that “depreciation (fixed asset increases)” increases by the amount of \$1.154 million when comparing “2021 GRA over 2018 Approved” revenue. Further, YEC provides footnote 1 which states that the \$1.154 million increase “excludes depreciation rate changes & impacts of accelerated amortization of VGC Group contributions.”

QUESTION:

- a) Please provide further information detailing the how the contribution amount was determined and any agreement between parties (if required) with respect to the \$11.5 million contribution from VGC Group to fund McQuesten Substation and system improvement capital costs.
- b) Please provide the calculation of the \$1.154 million increase noted in the preamble and include a complete reference to where the information used in the requested calculation can be found in YEC’s supporting Tabs.

1 c) Please provide the calculation of the \$0.665 million decrease as quoted and
2 include a complete reference to where all information used in the requested
3 calculation can be found in YEC's supporting Tabs.

4
5 d) Please provide further detail with respect to the contributions being amortized on
6 an "accelerated" basis as compared to the amortization periods and rates YEC
7 uses for other contribution amounts. Please also explain whether the contribution
8 assets at issue are collectively the "McQuesten Substation and system
9 improvement costs" of [sic] some portion thereof.

10
11 e) Please clarify whether YEC had previous Board approval for the 12-year
12 amortization period being used and, in the absence of previous Board approval of
13 a 12-year amortization period, what the expected average service is for the
14 contribution assets at issue.

15
16 **ANSWER:**

17
18 **(a)**

19
20 Under the VGC Power Purchase Agreement (PPA), VGC Group is responsible for funding
21 the construction of the McQuesten Substation and certain identified system improvement
22 capital costs. More specifically, the contribution was determined as follows:

23

24	McQuesten Substation contribution	\$10.688
25	System Improvement contribution	<u>\$0.840</u>
26		<u>\$11.528</u>

27

- 28
- 29 • McQuesten Substation responsibilities and costs are set out in Schedule B to the
30 PPA. Except as otherwise specified in the PPA, VGC Group was responsible for
31 developing and funding all of the costs of the McQuesten Substation (including
32 actual final YEC Owner's Costs) prior to turning the facility over to YEC for
33 ownership and commercial operation. The only McQuesten Substation costs
34 funded by YEC related to the costs specifically required for the facility to be able
35 to be operated at 138 kV voltage if so required at some future time. YEC provisions
36 for payments to VGC Group are set out in Section 6.1 (c) and (d) of the PPA. The
McQuesten Substation is required to connect the VCG Group's Mine Facilities to

1 YEC's Transmission Facilities. YEC's Transmission Facilities also supply
2 electricity to other customers in the Keno region, including Alexco Resources.

- 3
- 4 • Initial system improvement costs of YEC to be funded by VGC Group are set out
5 in Schedule C to the PPA, with an estimate of \$1,677,883. Payment provisions are
6 detailed in Section 6.1(b) of the PPA. These system improvements are required to
7 enable YEC to provide electricity service to the VGC Group's Mine Facilities.
 - 8
 - 9 • The PPA provisions for VGC Group contributions were intended to result in VGC
10 Group fully funding the costs as noted so as to ensure that other ratepayers would
11 not be subject to any future cost risks related to these amounts.

12
13 **(b)**
14

15 The \$1.154 million increase is the increase in depreciation costs for fixed assets prior to
16 any changes in depreciation rates and prior to the impact of accelerated amortization of
17 VGC Group contributions. This amount is calculated as follows (subject to rounding):

- 18
- 19 1. The increase (after customer contributions) of \$0.490 million for 2021 Fixed Asset
20 Depreciation under Existing (\$7.034 million) versus 2018 Approved Fixed Asset
21 Depreciation (\$6.544 million) as provided in Table 3.14 of the Application; plus
22
 - 23 2. The added customer contribution amount for 2021 of \$0.665 million due to the
24 accelerated amortization of VGC Group contributions (see response to "c" below).

25
26 **(c)**
27

28 The \$0.665 million decrease in net depreciation in 2021 represents the impact of the
29 addition of McQuesten Substation and system improvement capital costs net of
30 contributions. The total is determined as follows:

Capital Costs - \$11.5 million

Depreciation (54 years)	\$0.214
Return on rate base	<u>\$0.572</u>

Contribution - \$10.688 million

Depreciation (12 years)	(\$0.961)
Return on rate base	<u>(\$0.489)</u>

Net Increase in Depreciation \$0.665

Return on rate base calculation is based on average 5.166% per Table 3.15 average cost of debt and equity. Additional explanation as follows:

1. Total contributions for McQuesten Substation (\$10.688 million contribution – see Section 5.2.1.4 of Application) and system improvements (\$0.840 million – the balance of the \$11.528 million VGC contributions related to these YEC assets. These assets were in YEC rate base in 2020. The attributed value for McQuesten Substation costs as funded by VGC Group has been included in YEC's costs included in rate base and subject to depreciation.
2. Costs funded by VGC Group for these facility contributions are amortized over an approximate 54 year average asset life (see Appendix 4.3, Table 4.3-1 for confirmation of approximate 54 year amortization of YEC's net McQuesten Substation Costs), resulting in annual depreciation of \$0.214 million for the \$11.5 million referenced amount; 2021 return on this portion of the rate base cost approximates \$0.572 million, resulting in a total annual 2021 cost in the proposed revenue requirement at \$0.785 million.
3. However, the related contributions are amortized over an approximate 12 year life of the Eagle Gold mine, resulting in annual amortization of \$0.961 million; 2021 return reduced on this portion of the rate base cost approximates \$0.489 million, resulting in a total annual 2021 contribution impact on reducing revenue requirement at \$1.450 million.
4. The difference between contribution amortization over approximately 12 years (step 3 above) versus over the approximate 54 year asset life (step 2 above) is \$0.665 million for 2021, with a variance in annual amortization of \$0.747 million being partly offset by a decrease in rate base return of \$0.083 million.

1 **(d) and (e)**

2
3 The referenced VGC Group contributions are all being amortized over the approximate
4 expected 12 year life of the mine as required by YEC's auditors (the Auditor General of
5 Canada) in accordance with International Financial Reporting Standards (IFRS) for
6 customer contributions. YEC has not had any prior Board approval for the 12-year
7 amortization of these contributions, nor any direction from the Board not to follow IFRS
8 with regard to these contributions, although this treatment aligns with the approach
9 directed by auditors with respect to the contributions to transmission system received from
10 the Minto Mine customer. The expected life of the related assets is as shown for the
11 amortization of the costs, i.e., approximately 54 years.

1 **REFERENCE:** **Application, Tab 9, Depreciation Study, pages 9-6 and 9-16**

2
3 **ISSUE:** **Depreciation Expense**

4
5 **QUOTE:** **“Basis of Depreciation Estimates**

6 The straight-line, broad (average) life group, remaining-life depreciation
7 system was employed to calculate annual and accrued depreciation in
8 this study. In this system, the annual depreciation expense for each
9 group is computed by dividing the original cost of the asset less
10 allocated depreciation reserve less estimated net salvage by its
11 respective average life group remaining life. The resulting annual
12 accrual amounts of all depreciable property within a function were
13 accumulated, and the total was divided by the original cost of all
14 functional depreciable property to determine the depreciation rate. The
15 calculated remaining lives and annual depreciation accrual rates were
16 based on attained ages of plant in service and the estimated service
17 life and salvage characteristics of each depreciable group. The
18 computations of the annual functional depreciation rates are shown in
19 Appendix A.”

20
21 **“Depreciation True Up Calculation**

22 Annual depreciation expense amounts for the depreciable accounts of
23 Yukon Energy were calculated by the straight-line method, average life
24 group procedure, and remaining-life technique. With this approach,
25 remaining lives were calculated according to standard ALG expectancy
26 techniques, using the Iowa Survivor Curves noted in the calculation.
27 For each plant account, the difference between the book depreciation
28 reserve and theoretical depreciation reserve, was divided by the
29 average remaining life to yield the annual depreciation true up. These
30 calculations are shown in Appendix A.

31
32 **Depreciation Rate Calculation Process**

33 Annual depreciation expense amounts for accounts all accounts were
34 calculated by the straight-line, average life group procedure, whole-life
35 technique.

36 These calculations are shown in Appendix A. The calculations of the
37 theoretical depreciation reserve values and the corresponding

1 remaining life calculations are shown in workpapers. Book depreciation
2 reserves were based on Company individual accounts and the
3 theoretical reserve computation was used to compute a composite
4 remaining life for each account.”
5

6 **PREAMBLE:** The above quotes refer to the use of a remaining-life depreciation
7 system; remaining-life technique and whole-life technique.
8

9 **QUESTION:**
10

- 11 a) Please fully explain the difference between each of the remaining-life depreciation
12 system, remaining-life technique and whole-life technique references. Please also
13 include an explanation of how each are incorporated and used within YEC’s
14 depreciation expense calculations.
15
- 16 b) Please provide a copy of the interview notes (as between YEC and Alliance
17 Consulting Group) prepared during the course of YEC’s depreciation study.
18
- 19 c) Please clarify that all data relied on during the preparation of YEC’s depreciation
20 study was actuarial-based and did not contain any simulated data.
21
- 22 d) YEC indicates in many instances “there was insufficient transactional data for an
23 actuarial life analysis” notwithstanding that this statement was accompanied by
24 other operational observations which implied the existence of actuarial data.
25 Please provide a retirement rate analysis (observed life table) for each
26 depreciation study account including the plotted actual data points and proposed
27 survivor curve.
28
- 29 e) Please provide a calculated annual accrual and accrued depreciation for each
30 depreciation study account.
31
- 32 f) Please clarify if YEC uses amortization accounting for all depreciation study
33 accounts that have been assigned the use of a square curve (SQ). If not confirmed,
34 please explain fully how YEC accounts for asset retirements for depreciation study
35 accounts using an SQ.

1 g) Please explain the basis for YEC's asset classes and groupings. If YEC has relied
2 on information respecting asset classes and groupings from other jurisdictions,
3 please provide a copy of that information including a description of the assets that
4 should be recorded into each separate asset class and grouping.
5

6 **ANSWER:**

7
8 **(a)**
9

10 The calculation of depreciation rates for YEC used the whole-life technique. The difference
11 between the actual and calculated accumulated provision for depreciation for each group
12 was allocated to future periods using the average remaining life for each group. Effectively,
13 this translates into the remaining life technique. Please see the attached excerpt from
14 Depreciation Systems for an explanation of the differences between the whole-life and
15 remaining life techniques.
16

17 **(b)**
18

19 Please see Attachment 1 to this response (interview notes).
20

21 **(c)**
22

23 All data relied upon was actuarial.
24

25 **(d)**
26

27 Please see Attachment 2 to this response.
28

29 **(e)**
30

31 Please see response to YUB-YEC-1-109 for the requested information.
32

33 **(f)**
34

35 Alliance Consulting Group is interpreting the question in being vintage group amortization
36 as set for the USA FERC accounting release 15.

1 [https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/vintage-year-](https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/vintage-year-accounting-general-plant-accounts)
2 [accounting-general-plant-accounts](https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/vintage-year-accounting-general-plant-accounts)

3
4 YEC does not use amortization accounting. Asset retirements are made by YEC based
5 on when assets are taken out of service. The SQ curve assigned in a few accounts in the
6 depreciation study are assigned due to the lack of sufficient historical transactional data
7 in which to determine a specific retirement dispersion. Therefore, those accounts were
8 assigned a SQ dispersion.

9
10 **(g)**

11
12 YEC has developed a fixed asset catalog which details its system of accounts and the
13 components within each account. Please see attachment 1 to this response.

Yukon Energy Interviews 5-6-19

IT – creating an integrated IT/communication asset management plan.

Communications towers – the current life is 30 years. They are there for satellite and microwave. They design for a 30-year life. The towers would likely have a longer life than 30 years.

Communication equipment (confirm that network equipment is in this account) – split network equipment (maybe 10-year life) from other communication equipment life satellite (possibly 30 years) and microwave (possibly 30 years) and phones (maybe 10 year life). Split network and set 10 year life, Other comm equip 25 year life.

Comm fencing should last longer than 20 years – maybe 30 years.

Computer hardware – servers, pcs, printers, etc. 70 percent of workstations are 4 years old or older. They don't have a solid refresh cycle or plan yet. Servers would have a longer life. The 7 year life seen is reasonable for now. They expect the life to decrease as they implement a management plan.

Computer software – they will give list of software with in-service dates and expected lives. Then we will look at buckets to separate software.

One wind monitoring site – will likely be out of this process within a year. It might be 10 years old now. At least move down to 15 years.

Operations

Transmission poles - Transmission Line Refurbishment (TLR) – Test and treat inspection and detailed line inspections. Results came back with prioritization to replace. The assets being replaced are around 50 years old. They would expect the same 50-year life for the remaining assets (with the caveat that there are no retirements). They are now using steel cross arms. Transmission poles in majority are capitalized when replaced but the original pole is not retired. New lines are capitalized.

Distribution – 25kv and less. Permafrost will put more stress on poles. ROW is narrower, closer to vehicles, shorter and lower-class poles. They would expect a shorter life than transmission – maybe 40 years. Replacements are charged to O&M. Only new lines are capitalized. They mostly use penta treatment.

Sub-transmission – 34.5kV – They have no 34.5kv lines. What is in this account? Life should follow what type. Teslin line? Built but another party operates.

Transmission – above 34.5kV. They are doing Distribution test and treat (no formal program though).

Over the last 3 years, they started using the “restoration fund” for removal cost.

What is Mnt Mn???

Brushing – capital clearing of ROW for new lines. There is a 10-year cycle for clearing brush on ROW – which is O&M. Setting the life to the life of the poles (or possibly ROW) is reasonable.

Transmission conductor – They would expect a longer life for conductor. They will replace poles without replacing conductor. Not a corrosive environment. Fire retardant will coat insulators and can cause replacements. Glass insulators are the norm. On some structures where it is anticipated that the line will be replaced within the next 20 years, they will use polymer insulators. They would expect maybe a 60-year life for transmission conductor.

Distribution conductor – Load growth would be a primary driver for replacement of conductor. There are a few extra reasons for replacing distribution conductor as compared to transmission conductor. They would expect a slightly shorter life for distribution conductor. A 50-year life is reasonable.

Distribution Services – most services are overhead. The capacity requirement for customers keep increasing (affecting both services and transformers). Many of the communities have older infrastructure. Commercial services would have a shorter life than residential services. Leaving the life at 40 years is reasonable.

Distribution UG – only substantially in 2 locations (Dawson and Farrow primarily) – They will often run a spare conduit with laying UG. Cable staying at a 40-year life is reasonable. Moving out to 50 years for conduit is reasonable.

Substation Equipment Transmission – 54 (versus 40 for distr) – transmission stations and distribution stations are in the same footprint. Differences between transmission sub equipment and distribution is primarily the voltage level – basically the same equipment in both. Distribution equipment would have a shorter life due in part to the faults that would reach distribution but not transmission, the number of operations on distribution would be higher, higher relative currents (and therefore more heat) in distribution, and the degree of attention that is focused on transmission brushing. Transformers – 40-50 year life, breakers 35 years from OCB and 50 from SF6. 7 HV breakers will be replaced in 2019 and 5 LV replaced in 2018. The 54-year life is too long considering the higher level of electronics and the move to SF6. Suggest making transmission 40 years and distribution 35 years.

Substation fencing – the 30-year life is reasonable.

Meters – 100% digital (or close). Current life is 30 years. Move to 16 years. Industry Canada Have to pull at 8 years, and if tested good, get another 5 years, and if sample is good, another 3 years. Then done. 16 years is the maximum life.

Line transformers- 40 years is a little long. Line transformers are subject to higher loading due to growth. Voltage fluctuations will also tend to shorten the life. This will shorten the life of the transformers. Suggest moving to 35 years.

Street lighting – 100% LED. There were a large number of failures at original installation. Replacement of heads would be O&M. Leaving at 40 years is reasonable.

Generation

Diesel plant – In White horse - 7 units in building (2 retired, one about to be – all three of same design - Mirrelees units) They lost vendor support for the Mirreless. 4 units remaining. 4 reciprocating diesels.

Most diesels are Caterpillar engines across the system. They retire based on hrs of use. Diesels are back-up/peaking (100K until retirement) – they run very seldom. Gas is 60k hrs until engine replacement. 5-year capital plan is starting to look at retiring one unit every 5 years. Major overhauls (\$350k) are capital. Gas overhauls (6k hr) are capitalized. Time between overhauls is based on use. The 5-year overhaul period is short – suggest moving to 10 years. Minto is the controls for a plant that wasn't purchased and is being amortized – continue the amortization at current. The structures and building lives are reasonable. Fuel holder life of 25 years is low. They will provide in service dates for tanks. 40 years is more reasonable. For the generators/prime movers, the block will last 40 years or more but some components will have a shorter life. Staying at the 40-year life is reasonable.

Hydro

Every 10 years, tear down and inspected. Upgrading one unit in 2020. 2 run of the river and 1 multi-year storage plants. Mayo – discussions are in play to retire one of the Mayo units (not the dam – just the units) but not firm enough to use in the study.

Life of dams, overhauls, digital electrical, misc and fences as approved are reasonable. Accessory electrical should move to 40 is reasonable. Runners/generators should move to 60 years – they have already replaced runners at under 60 years and rewound generators at under 60 years. Other units are being looked at for efficiency improvements as well.

LNG Plant – 3 units, 4 day full run capacity. In-service 2 in 2015 and 1 in 2018. These are first run units. Over 7500 hours since 2015 (2018 unit has over 3k hours). They think around 4k hrs per year for each unit. Structures, accessory electrical, misc and fencing lives are reasonable. Fuel holder life of 32 years is short. They are nickel, double walled tanks with no moisture ingress. With reasonable maintenance, a 60 year life is reasonable. Their projection is that the generators will need to be replaced at 15 years (which would be 60k hours at the current projected rate). The vaporization process (NEED TO FIND OUT WHERE THIS IS BOOKED) will have a shorter life (maybe 30 years).

Transportation

IF a vehicle is 8 years or older and has 160k KM and incurred greater 15% maintenance cost in one year. They are behind on their schedule.

Utility vehicles – currently at a 7 year life. Line crews use for 7 years (that is held to well). Occasionally, a quad or snow mobile will move to a plant and have a longer life (probably around 80% do not).

Moving the average out to 8 years to reflect the 20% that stay longer.

Sedans/Station wagons – currently a 7 year life. They are lasting longer – between 10-12 years years (landing on 11 with a steep dispersion is reasonable).

Pole trailers – the 25 year approved is reasonable.

Trucks – ¾ to 2 ton – 10 years is approved. Electrician(\$90k)/operations (\$70) vehicles would only drive at a level that 10 years is reasonable. Linemen (\$115k) would hit the maximum mileage in 3-4 years but other factors would let you keep them longer. They will be replaced by 8 years. There are equal numbers of each. Moving to a 9 year life for the average is reasonable.

Trucks greater than 3 ton – the approved 20 years is reasonable. They just spent \$40k to overhaul a 10 year old vehicle.

Trucks – Foremost – tracked vehicle (\$534k) and 2011 auger equipped Kenworth truck. The live should match the life of the greater than 3 ton trucks of 20 years.

Facilities Sean Munro Manager, Property & Projects

Furniture/Equipment – approved life is 20 years. When furniture is removed from a location, it is either transferred or disposed of. It is generally no reused. Michael can address the life.

Structures Hydro – hydro structures are on the water so they would have a little shorter life for various components. However, 40 years is shorter than expected. The newer buildings are more technology driven and have a little less longevity than the older built structures. Moving both hydro and non-hydro structures to 50 years is reasonable.

Some components of structures have a shorter life than the building itself. For example, Electrical panels (25 years), furnaces (15-20 years), fire alarm panels (20 years), flooring replacement (25 years), exterior (25-30 years),

Housing – currently 30 years is approved. The newest house is from 2005 and oldest is from pre-1980. 30 years is to low. Moving the life out to 40-year life is reasonable.

Fire protection systems – there is a large focus on fire protection and there is short life for the equipment (try to achieve 20 years maximum).

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-22**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1615-201 Hydro Buildings and Improvements 40 R2.5

6
7 This account is a newly created group. In 2019, an asset previously
8 booked in account 1645-200, Buildings- Structures and Improvements.
9 The asset is an elevator at Aishihik Hydro plant. The plant balance in
10 this account will be \$10.3 million. The approved life and curve for this
11 account is 40 R2.5. Based on information provided by Company
12 personnel and judgment, this study recommends retaining the existing
13 40 R2.5 for this account."
14

15 **QUESTION:**

16
17 a) Please provide further rationale for the proposed 40-R2.5 life and curve for
18 Account 1615-201, which is a "newly created group" of assets that were previously
19 within Account 1645-200 and for which YEC is now proposing a 50-R2 life and
20 curve.
21

22 b) Please clarify the specific information provided by Company personnel that
23 supports a 40-R2.5 life and curve for this account.
24

25 **ANSWER:**

26
27 **(a)**

28
29 The elevator that YEC moved to this new account is dissimilar (both in characteristics and
30 life) to other building assets in the originating account such as berms, roads, boilers, etc.
31 Mr. Dane Watson, Managing Partner of Alliance Consulting Group is a Professional
32 Engineer in the State of Texas and Certified Depreciation Professional. In Mr. Watson's
33 professional opinion, the majority of elevator components would have a shorter life than
34 the 50 years in its original account. Mr. Watson inspected those facilities on a site visit in
35 2019. Using his professional judgment, Mr. Watson estimated a decrease in life of 10
36 years as compared to its originating account and increased the amplitude of the Iowa
37 Curve from an R2 to an R2.5 to reflect slightly more homogeneous asset characteristics.

1 **(b)**

2

3 Other than the inspection, information on the transfer and description of the asset, no other
4 information was received by Alliance Consulting Group.

1 **REFERENCE:** Application, Tab 9, Depreciation Study, page 9-24

2
3 **ISSUE:** Depreciation Expense

4
5 **QUOTE:** "Account 1615-506 Hydro Water Wheels, Turbines, and Generators 60
6 R3

7
8 This account consists of water wheels, turbines, and other related
9 assets used in hydro production including runners, gates, regulator
10 systems, generator cooling systems, and generators. The plant
11 balance in this account at December 31, 2018 is \$26.3 million. The
12 approved life and curve for this account is 85 R3. Operational personnel
13 stated the approved life is too long, and that they have already replaced
14 runners and rewind generators prior to reaching 60 years. There was
15 insufficient transactional data for an actuarial life analysis. Based on
16 information provided by Company personnel, this study recommends
17 decreasing the life to 60 years and retaining the R3 curve for this
18 account."

19
20 **PREAMBLE:** YEC is proposing a significant reduction (of 25 years) in average
21 service life for this account.

22
23 **QUESTION:**

- 24
25 a) Please provide the dollar amount of retirements by transaction year and vintage
26 for the years 1998-2018.

27
28 **ANSWER:**

29
30 **(a)**

31
32 YEC is not able to provide the detailed information requested given the considerable
33 time and effort it would take to collect and summarize this information and its limited
34 relevance to the current review process.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-25**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1615-600 Hydro Accessory Electrical Equipment 40 R2.5
6 This account consists of generator controls, bus equipment, and other
7 related assets used in hydro production including auxiliary generators,
8 switching equipment, excitation systems, and station control systems.
9 The plant balance in this account at December 31, 2018 is \$26.6
10 million. The approved life and curve for this account is 45 R3. Based on
11 information provided by Company personnel and the indications from
12 the actuarial analysis, this study recommends decreasing the life to 40
13 years and moving to an R2.5 curve for this account."
14

15 **QUESTION:**

- 16
17 a) Please clarify the specific information provided by Company personnel that
18 supports a reduction (of five years) in average service life for this account.
19

20 **ANSWER:**

21
22 **(a)**

23
24 Documented information is shown below.
25

26 YEC's fixed asset catalog provides the following description of various assets in this
27 account.
28

29 This account shall include the installation costs of auxiliary generating apparatus,
30 conversion equipment and equipment used primarily in connection with the control
31 and switching of electric energy produced by hydraulic power and the protection
32 of electric circuits and equipment, except electric motors used to drive equipment
33 included in other accounts, such motors being included in the account in which the
34 equipment with which they are associated is included.

1 **Note A:** do not include in this account transformers and other equipment
2 used for changing the voltage or frequency of electricity for the purpose of
3 transmission or distribution.

4
5 **Note B:** when any item of equipment listed herein is used wholly to furnish
6 power to equipment, it shall be included in such equipment accounts.

7
8 Components of cost:

- 9
- 10 1. Auxiliary generators, including boards, compartments, switching
11 equipment, control equipment and connections to auxiliary power bus.
 - 12 2. Excitation system, including motor, turbine and dual-drive exciter sets
13 and rheostats, storage batteries and charging equipment, circuit
14 breakers, panels and accessories, knife switches and accessories,
15 surge arrestors, instrument shunts, conductors and conduit, special
16 supports for conduit generator field and exciter switch panels, exciter
17 bus tie panels, generator and exciter rheostats, special housings,
18 protective screens, etc.
 - 19
20 3. Generator main connections, including oil circuit breakers and
21 accessories, disconnecting switches and accessories, operating
22 mechanisms and interlocks current transformers, potential
23 transformers conductors and conduit special support for generator
24 main leads, grounding switch, special housings, protective screens,
25 etc. station buses, including main auxiliary, transfer, synchronizing and
26 fault ground buses, including oil circuit breakers and accessories,
27 disconnecting switches and accessories, operating mechanisms and
28 interlocks, reactors and accessories voltage regulators and
29 accessories, compensators, resistors, starting transformers, current
30 transformers potential transformers, protective relays, storage batteries
31 and charging equipment; isolated panels and equipment, conductors
32 and conduit, special supports, special fire extinguishing equipment and
33 test equipment.
 - 34
35 4. Station control system including station switchboards with panel wiring
36 panels with instruments and control equipment only, panels with
37 switching equipment mounted or mechanically connected, truck-type

1 switchboards complete, cubicles, station supervisory control devices,
2 frequency control equipment, master clocks, watt-hour meter, station
3 totalizing watt meter, storage batteries panels and charging sets,
4 instrument and transformers for supervisory metering, conductors and
5 conduit, special supports for conduit, switchboards, batteries, special
6 housing for batteries, protective screens, etc.

7
8 During informal discussions in the interview process and site visits, Company SMEs
9 related that they are seeing operational lives decreasing for many of the components
10 (especially electronic) in this account. They concurred with the limited actuarial analysis
11 indications that the overall operational life for assets in this account were decreasing
12 slightly. The formal interview notes document that Company personnel indicated that
13 given the components in this account, a slight reduction in the life of this account was
14 appropriate.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-32**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1620-403 Diesel Fuel Holders, Producers, and Accessories
6 40 R2

7 This account consists of pumps, storage tanks, natural gas/fuel oil
8 piping and other related assets at the diesel production plants. The
9 plant balance in this account at December 31, 2018 is \$1.7 million. The
10 approved life and curve for this account is 25 R2. Discussions with
11 operational personnel stated the existing life seems short, that many of
12 the existing assets are approximately 15 to 20 years old, are still
13 reliable, and not currently in need of replacement. There was
14 insufficient transactional data for an actuarial life analysis. Based on
15 type of assets, information provided by Company personnel and
16 judgment, this study recommends increasing to a 40 year life and
17 retaining the existing R2 curve for this account."
18

19 **QUESTION:**

- 20
21 a) Please clarify that the observations made by Company personnel supporting an
22 increase (of 15 years) in average service life are generally applicable to all assets
23 in this account.
24

25 **ANSWER:**

26
27 **(a)**

28
29 The statements above was not necessarily intended to apply to every component in this
30 account. Below is an extract from the Company's capital assets accounting manual.
31

32 This account shall include the installation costs of fuel handling and storage equipment
33 used between the point of fuel delivery to the station and the intake pipe through which
34 fuel is directly drawn to the engine and the cost of gas producers and accessories devoted
35 to the production of gas for use in prime movers driving main electric generators.

1 Components of cost:

- 2
- 3 1. Coils;
- 4
- 5 2. Heating piping and valves;
- 6
- 7 3. Pumps;
- 8
- 9 4. Fuel scrubbing equipment; and
- 10
- 11 5. Tanks and fuel oil storage.
- 12

13 With input from the SMEs that many of the assets are nearing the current average service
14 life, there were no concerns with reliability and no plans in place to begin replacement, an
15 extension in life was appropriate and found reasonable by Company SMEs. Based on
16 SME input that some items would likely last 60 years (i.e., Nickel, double walled tanks with
17 no moisture ingress) and Mr. Watson's experience with similar accounts over 35 years,
18 using judgement, a 15-year increase was recommended. With group accounting for utility
19 property, the goal is to establish an average service life for the entire group given the mix
20 of assets and lives within the group.

1 **REFERENCE:** Application, Tab 9, Depreciation Study, page 9-37

2
3 **ISSUE:** Depreciation expense

4
5 **QUOTE:** "Account 1625-300 Dist. System - Poles and Fixtures 40 R2

6
7 This account consists of the installation costs of poles and fixtures used
8 for supporting overhead distribution conductors and service wire. The
9 plant balance in this account at December 31, 2018 is \$8 million. The
10 approved life and curve for this account is 35 R2. Discussions with
11 operational personnel stated that right of ways are narrower for
12 distribution, putting the poles closer to vehicles and making them more
13 susceptible to being damaged. Additionally, permafrost puts more
14 stress on the shorter, lower class poles. Overall, operations estimates
15 the life of distribution poles to be 10 years less than transmission poles,
16 which use a life of 50 years. There was insufficient transactional data
17 for an actuarial life analysis. Based on type of assets, information
18 provided by Company personnel and judgment, this study recommends
19 moving to a 40 R2 for this account.
20

21 **PREAMBLE:** Statements in the above quote appear to conflict with YEC's proposed
22 increase (of 5 years) in average service life for this account.
23

24 **QUESTION:**

- 25
26 a) Please clarify how the increased susceptibility to damage from narrow rights-of-
27 way and permafrost to YEC's distribution system poles and fixtures is consistent
28 with a proposed increase (of five years) in average service life for this account.
29

30 **ANSWER:**

31
32 **(a)**

33
34 The discussion above is contrasting the life of distribution poles with those of transmission
35 poles. The current (and proposed) life of transmission poles is 50 years. The discussion
36 notes the reasons that distribution poles would have a shorter life than transmission poles.
37 A 35-year life for distribution poles is low compared to industry experience based on

1 Alliance Consulting Group's work across North America. A slight increase in life was
2 discussed with operations personnel. Based on the noted discussion, a 10-year spread
3 between transmission and distribution pole life was thought appropriate both to the
4 Company SMEs and Alliance. The 5-year increase was to move the distribution pole life
5 to 40 years as compared to the 50-year life of transmission poles.

1 **REFERENCE:** Application, Tab 9, Depreciation Study, pages 9-38 and 9-40

2
3 **ISSUE:** Depreciation Expense

4
5 **QUOTE:** "Account 1625-304 Dist. System - Brushing 50 R2
6 This account consists of costs associated with the brushing of the
7 distribution system. The plant balance in this account at December 31,
8 2018 is \$45 thousand. The approved life and curve for this account is
9 50 R2. The Company capitalizes the brush clearing of ROWs when
10 installing new lines. Operations stated the existing life is reasonable
11 and matches the life of O/H Conductor, which have a 50 year life."

12
13 "Account 1625-401 Dist. System – O/H Conductors 50 R2
14 This account consists of overhead conductors and other facilities
15 associated with the distribution system. The plant balance in this
16 account at December 31, 2018 is \$75 thousand. The approved life and
17 curve for this account is 35 R2. Discussions with operational personnel
18 stated they would expect the life of distribution conductor to be shorter
19 than transmission conductor. There was insufficient transactional data
20 for an actuarial life analysis. Based on type of assets, information
21 provided by Company personnel and judgment, this study recommends
22 increasing the life to 50 years while retaining the R2 curve for this
23 account."

24
25 **QUESTION:**

- 26
27 a) Notwithstanding YEC's operational personnel statement that distribution system
28 O/H conductors should have a shorter life than transmission system O/H
29 conductors, what other factors and rationale support a 50-R2 life and curve for this
30 account?

31
32 **ANSWER:**

33
34 **(a)**

35
36 Factors contributing to the selection of a 50-year life include Alliance's experience in
37 analyzing the life of conductor for numerous companies and the similarity between

1 transmission and distribution conductor adjusted for the higher level of exposure for
2 distribution conductor to failure from third-party damage or trees. Typically, the
3 characteristic of overhead conductor would suggest that the conductor would have a
4 slightly longer life than the poles the conductor is strung on and also a slightly longer life
5 than services. These factors, along with the input of Company SMEs all suggest that a 50-
6 year life is reasonable for distribution conductor.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-39**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1625-305 Dist. System – Survey Costs 50 R2
6 This account consists of costs association with land surveys and
7 assessments related to distribution easements. The plant balance in
8 this account at December 31, 2018 is \$600 thousand. The approved
9 life and curve for this account is 50 R3. There was insufficient
10 transactional data for an actuarial life analysis. Based on type of assets,
11 information provided by Company personnel and judgment, this study
12 recommends retention of the existing 50 year life with a slight change
13 in the curve to an R2 for this account."
14

15 **QUESTION:**

- 16
17 a) On what basis is YEC able to propose a change to a 50-R2 life and curve from the
18 approved 50-R3 life and curve without the benefit of an actuarial life analysis?
19
20 b) Please provide the directional impact of the change proposed in terms of an
21 increase or decrease to depreciation expense for this account for the year 2021.
22
23 c) Please clarify if the proposed life and curve for this account is intended to match
24 that of Account 1625-304 Dist. System – Brushing and Account 1625-401 Dist.
25 System – O/H Conductors.
26

27 **ANSWER:**

28
29 **(a)**

30
31 The proposal to change the dispersion curve is based on Alliance Consulting Group's
32 judgment and experience. We have performed more than 270 depreciation studies across
33 North America and have had many opportunities to see the various retirement patterns of
34 utility assets. Given the characteristics of these assets and the dispersion of the other
35 related assets, moving to a slightly flatter dispersion would better reflect the retirement
36 characteristics.

1 **(b)**

2

3 There is no change to depreciation as the life has not changed and YEC uses straight-line
4 amortization.

5

6 **(c)**

7

8 Yes, in part. It is reasonable for the retirement pattern for survey costs to match the other
9 asset groups mentioned in the question and the pattern matches the expectations for this
10 type of asset.

REFERENCE: Application, Tab 9, Depreciation Study, pages 9-41 and Comparison of Life Parameters, page 9-104

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QUOTE: “Account 1625-401 Dist. System – O/H Services 40 R2
This account consists of installation costs associated with overhead services such as transmission line installation and upgrades. The plant balance in this account at December 31, 2018 is \$2.1 million. The approved life and curve for this account is 40 R2. Discussions with Company personnel indicated the majority of services are overhead. The Company is experiencing an increased number of new services and need to update aging infrastructure. Operations stated commercial services would have a shorter life than residential services. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the 40 R2 life and curve for this account.”

QUESTION:

- a) Please confirm whether Tab 9, Depreciation Study, page 9-41 contains a typographical error in referencing “Account 1625-401 Dist. System – O/H Services 40 R2” and should correctly state “Account 1625-410 Dist. System – O/H Services 40 R2” as indicated on page 9-104. If not confirmed, please explain.
- b) Please describe at a high level the proportion of O/H service installations that are commercial versus residential for the years 1998-2018 and explain how this information does or does not influence retention of the 40-R2 life and curve for this account.

ANSWER:

(a)

The information life of the account 1625-401 is stated incorrectly on page 9-41. The information on page 9-104 is correct. The current life of this account is 35 R2. The

1 proposed life for this account is 50 years with a R2 dispersion. The graph depicted on
2 page 41 is not correct for this account.

3
4 **(b)**

5
6 The proposed 40-year life referenced in the question is not correct as indicated in part (a).
7 Alliance Consulting Group did not consider the commercial versus residential load
8 specifically. There is no evidence that the life characteristics would be materially different
9 between the two types of services. The interview notes with Company personnel stated:

10
11 Distribution conductor – Load growth would be a primary driver for replacement of
12 conductor. There are a few extra reasons for replacing distribution conductor as
13 compared to transmission conductor. They would expect a slightly shorter life for
14 distribution conductor. A 50-year life is reasonable.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-44**

2
3 **ISSUE: Depreciation Expense**

4
5 **PREAMBLE:** For each of Account 1625-610 Dist. System – Meters and Account 1625
6 620 Dist. System – Meter Equipment, YEC has proposed a change to
7 a 16-SQ life and curve from the approved 30-R2 life and curve in part
8 because it “pulls meters for testing at eight years and based on test
9 results may use the meter up to 16 years.”

10
11 **QUESTION:**

- 12
13 a) Please clarify whether the decision to pull meters for testing at eight years is a
14 change in policy from any policy that was in place when a 30-R2 life and curve was
15 approved for this account.
16
17 b) Referring to the response to part (a) above, was the change in policy based on
18 internal or external factors? Please explain fully.
19
20 c) Please provide observed life tables and the plotted actual data points with the
21 approved 30 R2 survivor curve for each of the two accounts referenced in the
22 preamble.
23

24 **ANSWER:**

25
26 **(a)**

27
28 The decision to pull meters for testing at eight years was an operational decision based
29 on experience of the Electrical department with use of these meters and was not based
30 on any policy.
31

32 **(b)**

33
34 YEC has installed AMI meters in these accounts. The changes in meter life expectancy
35 have occurred because the new meters are different in operation than electro-mechanical
36 meters of the past. In Alliance Consulting Group’s experience, no AMI meters across North

1 America have a life as long as the existing 30-year life. At the time of Mr. Watson's site
2 visit in 2019, Company experts made the following observations:

3
4 Meters – 100% digital (or close). Current life is 30 years. Move to 16 years. Industry
5 Canada Have to pull at 8 years, and if tested good, get another 5 years, and if
6 sample is good, another 3 years. Then done. 16 years is the maximum life.

7
8 **(c)**

9
10 In the case of assets where technology or regulation has changed, historical experience
11 does not predict the future of the Company's existing assets. Notwithstanding the above,
12 the requested information is provided in the following attachment:

- 13
14 • Attachment 1 - Acct 1625-620'; and
15
16 • Attachment 2 - Acct 1625-610'.

Observed Life Table

Scenario: Yukon Energy @ 2018

Account: 1625-620

Placement Band: 2000 - 2018

Observation Band: 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	228,641.93	0.00	0.00000	1.00000	100.00
0.5	228,641.93	0.00	0.00000	1.00000	100.00
1.5	228,641.93	0.00	0.00000	1.00000	100.00
2.5	228,641.93	0.00	0.00000	1.00000	100.00
3.5	228,641.93	0.00	0.00000	1.00000	100.00
4.5	228,641.93	0.00	0.00000	1.00000	100.00
5.5	228,641.93	0.00	0.00000	1.00000	100.00
6.5	228,641.93	0.00	0.00000	1.00000	100.00
7.5	228,641.93	14,302.44	0.06255	0.93745	100.00
8.5	214,339.49	0.00	0.00000	1.00000	93.75
9.5	164,175.29	0.00	0.00000	1.00000	93.75
10.5	135,357.34	0.00	0.00000	1.00000	93.75
11.5	135,357.34	11,441.25	0.08453	0.91547	93.75
12.5	105,530.44	0.00	0.00000	1.00000	85.82
13.5	0.00	0.00	0.00000	0.00000	85.82

Observed Life Table

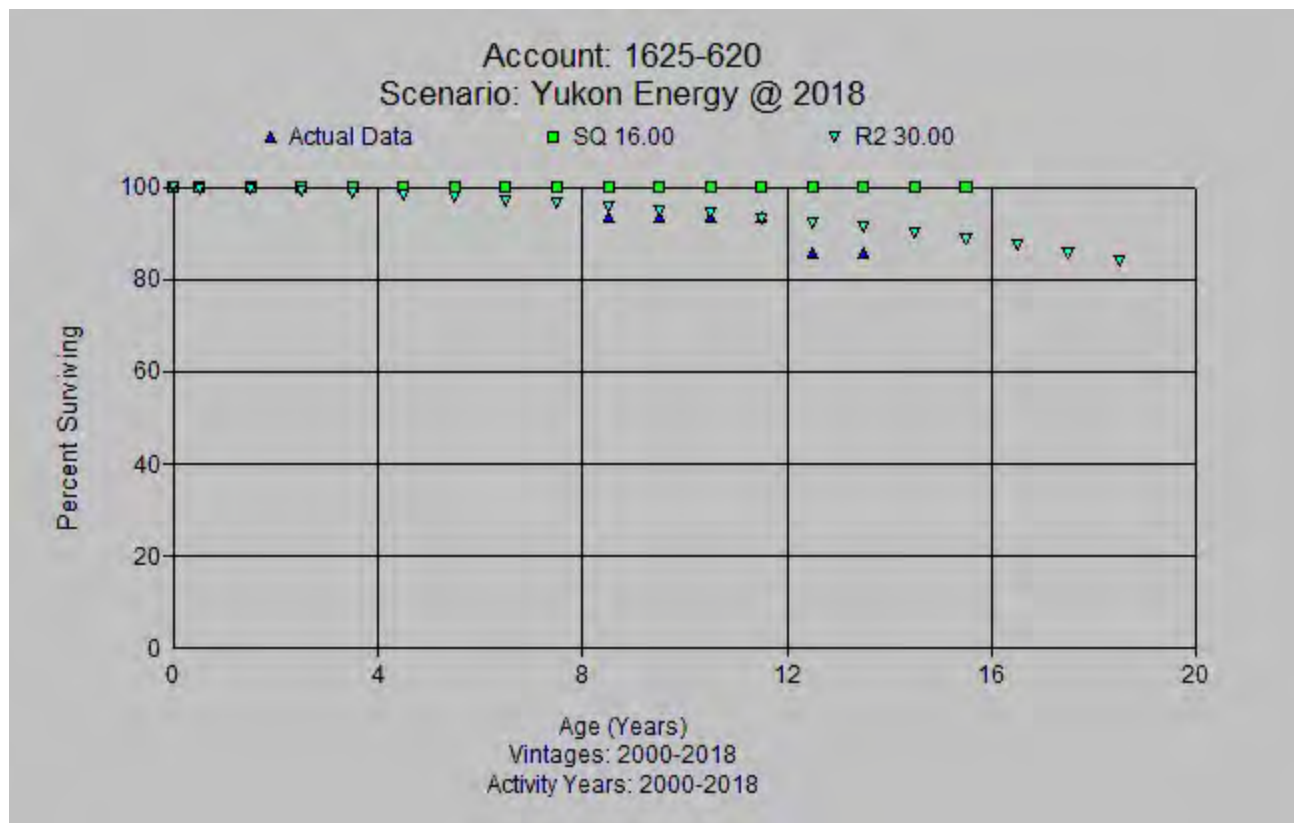
Scenario: Yukon Energy @ 2018

Account: 1625-620

Placement Band: 2000 - 2018

Observation Band: 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	228,641.93	0.00	0.00000	1.00000	100.00
0.5	228,641.93	0.00	0.00000	1.00000	100.00
1.5	228,641.93	0.00	0.00000	1.00000	100.00
2.5	228,641.93	0.00	0.00000	1.00000	100.00
3.5	228,641.93	0.00	0.00000	1.00000	100.00
4.5	228,641.93	0.00	0.00000	1.00000	100.00
5.5	228,641.93	0.00	0.00000	1.00000	100.00
6.5	228,641.93	0.00	0.00000	1.00000	100.00
7.5	228,641.93	14,302.44	0.06255	0.93745	100.00
8.5	214,339.49	0.00	0.00000	1.00000	93.75
9.5	164,175.29	0.00	0.00000	1.00000	93.75
10.5	135,357.34	0.00	0.00000	1.00000	93.75
11.5	135,357.34	11,441.25	0.08453	0.91547	93.75
12.5	105,530.44	0.00	0.00000	1.00000	85.82
13.5	0.00	0.00	0.00000	0.00000	85.82



Observed Life Table

Scenario: Yukon Energy @ 2018

Account: 1625-610

Placement Band: 1987 - 2018

Observation Band: 1987 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	312,632.61	0.00	0.00000	1.00000	100.00
0.5	312,632.61	0.00	0.00000	1.00000	100.00
1.5	312,632.61	0.00	0.00000	1.00000	100.00
2.5	312,632.61	0.00	0.00000	1.00000	100.00
3.5	312,632.61	0.00	0.00000	1.00000	100.00
4.5	312,632.61	0.00	0.00000	1.00000	100.00
5.5	281,350.96	0.00	0.00000	1.00000	100.00
6.5	281,350.96	0.00	0.00000	1.00000	100.00
7.5	281,300.96	0.00	0.00000	1.00000	100.00
8.5	281,250.96	0.00	0.00000	1.00000	100.00
9.5	281,250.96	0.00	0.00000	1.00000	100.00
10.5	227,195.23	0.00	0.00000	1.00000	100.00
11.5	226,166.46	0.00	0.00000	1.00000	100.00
12.5	208,619.72	0.00	0.00000	1.00000	100.00
13.5	208,619.72	0.00	0.00000	1.00000	100.00
14.5	177,574.18	0.00	0.00000	1.00000	100.00
15.5	177,574.18	0.00	0.00000	1.00000	100.00
16.5	177,574.18	0.00	0.00000	1.00000	100.00
17.5	177,574.18	0.00	0.00000	1.00000	100.00
18.5	171,268.41	0.00	0.00000	1.00000	100.00
19.5	133,719.08	0.00	0.00000	1.00000	100.00
20.5	0.00	0.00	0.00000	1.00000	100.00

Observed Life Table

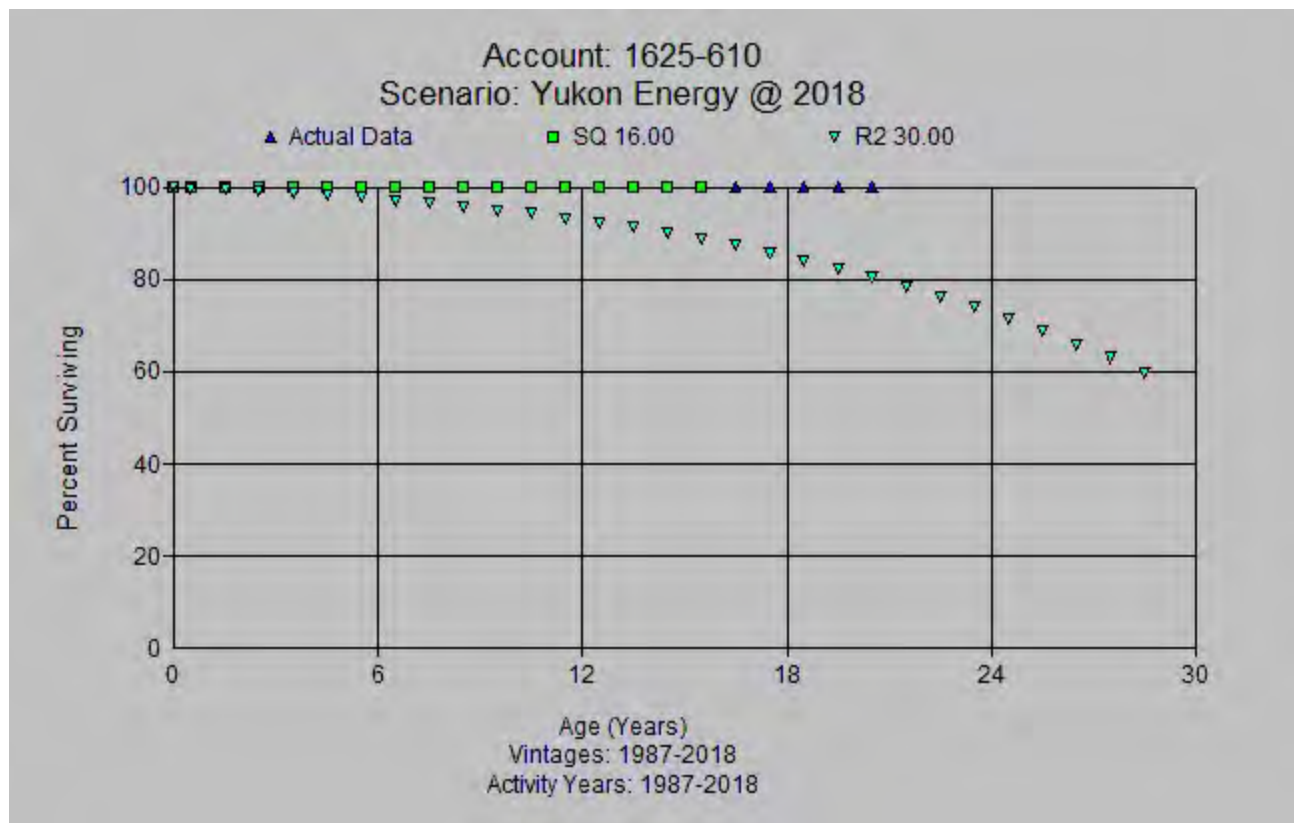
Scenario: Yukon Energy @ 2018

Account: 1625-610

Placement Band: 1987 - 2018

Observation Band: 1987 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	312,632.61	0.00	0.00000	1.00000	100.00
0.5	312,632.61	0.00	0.00000	1.00000	100.00
1.5	312,632.61	0.00	0.00000	1.00000	100.00
2.5	312,632.61	0.00	0.00000	1.00000	100.00
3.5	312,632.61	0.00	0.00000	1.00000	100.00
4.5	312,632.61	0.00	0.00000	1.00000	100.00
5.5	281,350.96	0.00	0.00000	1.00000	100.00
6.5	281,350.96	0.00	0.00000	1.00000	100.00
7.5	281,300.96	0.00	0.00000	1.00000	100.00
8.5	281,250.96	0.00	0.00000	1.00000	100.00
9.5	281,250.96	0.00	0.00000	1.00000	100.00
10.5	227,195.23	0.00	0.00000	1.00000	100.00
11.5	226,166.46	0.00	0.00000	1.00000	100.00
12.5	208,619.72	0.00	0.00000	1.00000	100.00
13.5	208,619.72	0.00	0.00000	1.00000	100.00
14.5	177,574.18	0.00	0.00000	1.00000	100.00
15.5	177,574.18	0.00	0.00000	1.00000	100.00
16.5	177,574.18	0.00	0.00000	1.00000	100.00
17.5	177,574.18	0.00	0.00000	1.00000	100.00
18.5	171,268.41	0.00	0.00000	1.00000	100.00
19.5	133,719.08	0.00	0.00000	1.00000	100.00
20.5	0.00	0.00	0.00000	1.00000	100.00



1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-45**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1625-710 Dist. System – Substation Equipment 40 S0
6 This account includes all distribution substation equipment such as bus
7 compartments, control equipment, ground rods, foundations, and
8 conversion equipment, switching equipment, and switchboards. The
9 plant balance in this account at December 31, 2018 is \$1.3 million. The
10 approved life and curve for this account is 40 R2. Discussions with
11 operations indicated the Company is experiencing a shorter life due to
12 an increased number of faults, more short-lived electronic equipment,
13 and the move to SF6 all decreasing the lives of existing assets. There
14 was insufficient transactional data for an actuarial life analysis. Based
15 on type of assets, information provided by Company personnel and
16 judgment, this study recommends a 40 S0 life and curve for this
17 account."
18

19 **QUESTION:**

- 20
21 a) On what basis is YEC able to propose a change to a 40-S0 life and curve from the
22 approved 40-R2 life and curve without the benefit of an actuarial life analysis?
23
24 b) Please explain why YEC did not propose to decrease the average service life from
25 40 years as opposed to changing the curve (from R2 to S0) given the statement
26 that YEC is experiencing a shorter life for these assets.
27
28 c) Please provide the directional impact of the change proposed in terms of an
29 increase or decrease to depreciation expense for this account for the year 2021.
30

31 **ANSWER:**

32
33 **(a)**

34
35 The proposal to change the dispersion curve is based on Alliance Consulting Group's
36 judgment and experience. We have performed more than 270 depreciation studies across
37 North America and have had many opportunities to see the various retirement patterns of

1 utility assets. Given the increasingly wide range of lives for assets within this account, the
2 investment mix is believed to be better modeled by a symmetrical and flatter dispersion.
3 This allows a reflection of the additional short-lived electronic components in substations.

4
5 **(b)**
6

7 The statements above should be clarified to say the shorter life referred to above is
8 difference between transmission substations in account 1635-710 and distribution
9 substations. Distribution equipment would have a shorter life due in part to the faults that
10 would reach distribution but not transmission, the number of operations on distribution
11 would be higher, higher relative currents (and therefore more heat) in distribution, and the
12 degree of attention that is focused on transmission brushing. Given the different types of
13 equipment between the functions and differences in voltage, Alliance Consulting Group's
14 proposal is similar to that of other North American utilities in our experience.

15
16 **(c)**
17

18 There is no change to depreciation as the life has not changed and YEC uses straight-line
19 amortization.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-47**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1625-730 Dist. System – Substation Fences 30 R4
6 This account includes the costs of fences located at distribution
7 substations. The plant balance in this account at December 31, 2018 is
8 \$100 thousand. The existing life for this account is 20 R4. The approved
9 life for this account is 20 years. There was insufficient transactional data
10 for an actuarial life analysis. Based on type of assets, information
11 provided by Company personnel and judgment, this study recommends
12 moving to a 30 R4 life and curve for this account."
13

14 **QUESTION:**

- 15
16 a) Please clarify the specific information provided by Company personnel that
17 supports an increase (of 10 years) in average service life for this account.
18
19 b) Please confirm whether Tab 9, Depreciation Study, page 9-104 contains a
20 typographical error in referencing an existing SQ Iowa Curve for this account. If
21 not confirmed, please explain.
22

23 **ANSWER:**

24
25 **(a)**

26
27 The statements made in Mr. Watson's interviews were opinions of experienced Company
28 operations employees and engineers. No further documentation was provided other than
29 the professional judgment of those individuals and the experience of Alliance.
30

31 **(b)**

32
33 Page 104 of Tab 9 shows the current life of this account to be 20 R4. Alliance Consulting
34 Group does not see a reference to the SQ curve for this account.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-49**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1625-905 Dist. System – Line Transformers 35 R2.5
6 This account includes all line transformers, capacitors, lightning
7 arrestors, and related equipment. The plant balance in this account at
8 December 31, 2018 is \$4 million. The approved life and curve for this
9 account is 40 R2.5. Discussions with operations stated the
10 transformers are subject to higher loading due to growth and expect the
11 life of these assets to decrease as a result. There was insufficient
12 transactional data for an actuarial life analysis. Based on type of assets,
13 information provided by Company personnel and judgment, this study
14 recommends moving to a 35 R2.5 life and curve for this account."
15

16 **QUESTION:**

- 17
18 a) Please clarify whether the higher loading due to growth in the system has led to
19 increased asset retirements.
20
21 b) Please clarify whether the higher loading due to growth in the system has resulted
22 in exceeding the maximum load recommended for YEC's distribution line
23 transformers.
24
25 c) Please provide the dollar amount of retirements by transaction year and vintage
26 for the years 1998-2018.
27

28 **ANSWER:**

29
30 **(a)**

31
32 There has not been an increase in asset retirements to date. YEC monitors the power flow
33 and demand on the larger system transformers feeding the communities, not distribution
34 transformers. The large transformers are recording increased peak demands, and
35 therefore, YEC assumes a portion of the distribution transformers are also at or above
36 capacity.

1 **(b)**

2
3 YEC does not monitor real-time small distribution transformer loading. There are
4 circumstances where distribution transformer failures can be attributed to overload. On
5 new customer connects YEC is now installing 25 kva transformers, where in the past 10
6 kva transformers would have been installed. AEY is also doing similar up rates on
7 transformers for new connects.

8
9 **(c)**

10
11 YEC is not able to provide the detailed information requested given the considerable time
12 and effort it would take to collect and summarize this information and its limited relevance
13 to the current review process.

1 **REFERENCE: Application, Tab 9, Depreciation Study, pages 9-51 and 9-59**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1635-300 Main Trx - Poles and Fixtures 50 R3
6 This account consists of poles and fixtures used for transmission
7 purposes. The plant balance in this account at December 31, 2018 is
8 \$60 million. The approved life and curve for this account is 65 R3.
9 Discussions with Company personnel indicated the Company has a
10 Transmission Line Refurbishment program in place and has started
11 replacing 50 year old poles. Yukon expects this to continue in the future
12 to address its aging infrastructure. Periodically poles are replaced
13 without having to replace the conductor. There was insufficient
14 transactional data for an actuarial life analysis. Based on type of assets,
15 information provided by Company personnel and judgment, this study
16 recommends moving to a 50 R3 for this account."

17
18 "Account 1640-300 Sub Trx – Poles & Fixtures 50 R3
19 This account consists of poles, fixtures, and other related assets used
20 in transmission operations, including anchors, brackets, cross arms,
21 braces, and foundations. The plant balance in this account at
22 December 31, 2018 is \$4.1 million. The approved life and curve for this
23 account is 45 R3. Discussions with Company personnel indicated the
24 Company has a Transmission Line Refurbishment program in place
25 and has started replacing 50 year old poles. Yukon expects this
26 program to continue in the future to address its aging infrastructure.
27 Periodically poles are replaced without having to replace the conductor.
28 There was insufficient transactional data for an actuarial life analysis.
29 Based on type of assets, information provided by Company personnel
30 and judgment, this study recommends moving to a 50 R3 for this
31 account."

32
33 **QUESTION:**

- 34
35 a) Please clarify whether YEC applies any treatment to its wooden poles as part of a
36 capital maintenance program that would serve to lengthen the expected average

1 service life. If so, please identify the program under which this capital work is
2 conducted.

3

4 b) Please fully explain whether it is the replacement of 50-year-old transmission poles
5 that is the main rationale for the proposed change to a 50-R3 life and curve from
6 the approved 65-R3 life and curve or some other factor.

7

8 c) Please provide the expected average service life of the new poles that are
9 replacing the 50 year-old poles being retired due to the refurbishment program.

10

11 d) Please provide the dollar amount of retirements by transaction year and vintage
12 for the years 1998-2018.

13

14 e) Given that it appears that YEC maintains O/H conductor accounts for each of the
15 poles and towers, please clarify whether YEC is installing any towers as the pole
16 replacement assets and, if so, identify in which account these transmission tower
17 assets are being recorded.

18

19 f) Given that it appears that YEC maintains O/H conductor accounts for each of the
20 poles and towers, please clarify whether YEC is installing any towers as part of a
21 new transmission line, and identify in which account these transmission tower
22 assets are being recorded.

23

24 g) Referring to the responses to part (e) and (f) above, please provide the expected
25 average service life of YEC's transmission tower assets.

26

27 h) Please clarify whether there is any difference in the general type of assets in
28 Account 1635 300 Main Trx – Poles and Fixtures 50-R3 and Account 1640-300
29 Sub Trx – Poles & Fixtures 50-R3. In the response, please address both poles and
30 towers.

1 **ANSWER:**

2
3 **(a)**

4
5 YEC established the first Test and Treat in 2009. Test and treat is a process that
6 determines the pole shell thickness above and below grade, treats cavities and eliminates
7 insect infestations.

8
9 Remedial test and treat programs consist of the following:

- 10
11 • Test pole for shell thickness, presence of rot/pests/defects.
12
13 • Internally treat with preservative.
14
15 • Externally treat below ground ground-line with Pole-Wrap Cu Nap bandage.
16
17 • Treat exposed heartwood or cavities with Cu Nap.
18
19 • Treat and destroy existing insect infestations.
20
21 • Determine if any poles require replacement or close monitoring.

22
23 **(b)**

24
25 The replacement of poles at 50 years would be a factor in setting the 50-year life. The
26 Company tests poles and routinely performs inspections. After detailed line inspections,
27 YEC prioritizes which assets to replace factoring in those results. Expectations of
28 Company SMEs and Alliance, as well as Alliance's experience across North America,
29 would also be factors in setting the 50-year life.

30
31 **(c)**

32
33 Although there may be cases where the poles being replaced are possibly stronger old-
34 growth trees and the replacement poles are from new-growth trees, Alliance's assumption
35 is that new poles would generally have the same life as the poles being replaced.

1 **(d)**

2
3 YEC is not able to provide the detailed information requested given the considerable time
4 and effort it would take to collect and summarize this information and its limited relevance
5 to the current review process.

6
7 **(e)**

8
9 YEC has no plans to “replace” wooden structures with towers.

10
11 **(f)**

12
13 There is the potential to install a new tower structure for a future river crossing in
14 Whitehorse Rapids to S171 Riverside substation. It's too early in the project to confirm
15 this.

16
17 **(g)**

18
19 As per the Depreciation Study, the expected life of Towers is 60 years.

20
21 **(h)**

22
23 Generally speaking, there is no significant difference in the general type of assets in
24 account 1635-300 and 1640-300 other than one is connected to Main Transmission
25 Facilities and the latter is connected to Sub Transmission Lines.

1 **REFERENCE:** Application, Tab 9, Depreciation Study, pages 9-52 to 9-55

2
3 **ISSUE:** Depreciation Expense

4
5 **PREAMBLE:** For each of Account 1635-402 Main Trx – O/H Conductors/Poles and
6 Account 1635-404 Main Trx – O/H Conductors/Towers, YEC has
7 proposed a 60-R3 life and curve from the approved 50-R3 life curve
8 based on: “Discussions with operational personnel estimate the life of
9 transmission conductor to be about 10 years longer than distribution
10 conductor, which is moving to a 50 year life.” Further, life and curves
11 for Account 1635-304 Main Trx – Brushing and Account 1635-305 Main
12 Trx – Survey Costs are proposed to “mirror the life of overhead
13 conductor, which uses a 60 year life.”

14
15 **QUESTION:**

- 16
17 a) Notwithstanding YEC’s operational personnel statement that transmission system
18 O/H conductors should have a longer life (by ten years) than distribution system
19 O/H conductors, what other rationale supports a 60-R3 life and curve for these four
20 transmission accounts?

21
22 **ANSWER:**

23
24 **(a)**

25
26 In addition to observations from Operations SMEs, Alliance also relied on its experience
27 analyzing similar assets across the utility industry and the characteristics seen in those
28 analyses.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-56**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1635-710 Main Trx – Substation Equipment 45 S0
6 This account consists of bus compartments, batteries, control
7 equipment, transformers, breakers, and other related station equipment
8 used in transmission operations. The plant balance in this account at
9 December 31, 2018 is \$66.6 million. The approved life and curve for
10 this account is 54 S0. Discussions with Company personnel indicated
11 they are experiencing a shorter life for the assets in this account due to
12 the increasing amount of short lived electronic assets at the stations.
13 Operations also stated that transformers typically last between 40 to 50
14 years; breakers have a 35 year life for OCB and 50 years for SF6.
15 Several breakers have already been replaced in 2018 and 2019. There
16 was insufficient transactional data for an actuarial life analysis. Based
17 on type of assets, information provided by Company personnel and
18 judgment, this study recommends moving to a 45 S0 for this account."
19

20 **QUESTION:**

- 21
22 a) Please explain why substation equipment should not reflect a similar average
23 service life between distribution and transmission function assets. For example,
24 Account 1625-710 Dist. System – Substation Equipment (proposed 40-S0 life and
25 curve) and Account 1635-710 Main Trx – Substation Equipment (proposed 45-S0
26 life and curve).
27

28 **ANSWER:**

29
30 **(a)**

31
32 From an engineering and operations perspective, transmission and distribution assets
33 have materially different forces of retirement and life characteristics. Transmission assets
34 generally have more system protection and designed with higher tolerances. Distribution
35 assets are more subject to faults and voltage variations. Alliance Consulting Group does
36 not normally see the same life between the two asset categories for other utilities. The

- 1 general pattern is for transmission substation accounts to have a slightly longer life than
- 2 distribution substation asset accounts.

1 **REFERENCE:** Application, Tab 9, Depreciation Study, pages 9-59 to 9-67 and 9-
2 105

3
4 **ISSUE:** Depreciation Expense

5
6 **PREAMBLE:** The Board requires further detail with respect to YEC's sub
7 transmission accounts at the referenced pages.

8
9 **QUESTION:**

- 10
11 a) Please provide detail and rationale respecting the segregation of YEC's
12 transmission assets into a further sub transmission category, which is further
13 segregated into accounts designated as (Minto Mine) "Mnt Mn".
14
15 b) Please clarify that, with the exception of those accounts designated by "Mnt Mn"
16 (1640-301, 1640-306, 1640-307, 1640-407 and 1640-711), the depreciation life
17 and curve proposed for YEC's sub transmission asset accounts (1640-300, 1640-
18 304, 1640-401, 1640-405 and 1640 710) are intended to mirror the equivalent main
19 transmission assets under the "1635" series of transmission asset accounts
20 because they generally include the same types of assets subject to the same types
21 of operating conditions. If not confirmed, please explain further.
22
23 c) Referring to the sub transmission asset accounts designated by "Mnt Mn" (1640-
24 301, 1640 306, 1640-307, 1640-407 and 1640-711), please explain the rationale
25 for these accounts being amortized on the basis of a 12-SQ life and curve. Please
26 also provide the dates upon which the Minto Mine assets were installed and
27 commenced amortization and why a 12-SQ life and curve remains applicable.
28

29 **ANSWER:**

30
31 **(a)**

32
33 Sub-transmission lines have lines designations separate from the main transmission lines.
34 This segregation provides improved and more comprehensive asset management of the
35 lines. Sub-transmission systems are those circuits that supply distribution substations to
36 communities or commercial customers. Common sub-transmission voltages include 34.5,
37 69, 115, and 138 kV. Further segregation of the Minto Mine was required as those assets

1 have a different life (life of the mine) in accordance with International Financial Reporting
2 Standards.

3
4 **(b)**

5
6 Confirmed.

7
8 **(c)**

9
10 In accordance with International Financial Standards and to obtain a clean audit opinion
11 from the Auditor General of Canada, it was determined that these assets were required to
12 have a life equal to the life of the mine.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-69**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1645-200 Bldg & Otr – Structures and Improvements Hydro
6 50 R2

7 This account includes the cost associated with the structures and
8 improvements associated with a hydro facility including berms,
9 signage, roads, boilers, and other related assets used to support
10 general operations. The plant balance in this account will be \$2.2
11 million, which reflects a transfer of \$10.3 million from this account into
12 account 1615-201. The approved life and curve for this account is 40
13 R2.5. There is no historical activity to analyze. Discussions with
14 Company personnel indicated these structures are on the water so they
15 would have a little shorter life for various components. However, the
16 existing 40 years is shorter than what would be expected. The newer
17 buildings are more technology driven and have a little less longevity
18 than the older built structures. There was insufficient transactional data
19 for an actuarial life analysis. Based on the type and use of assets and
20 judgment, this study proposes moving to 50 R2 at this time."

21
22 **QUESTION:**

- 23
24 a) Please clarify if the transfer of \$10.3 million into Account 1615-201 was the main
25 factor for the proposed increase (of 10 years) to a 50-R2 life and curve from the
26 approved 40-R2.5 life and curve for this account.
27
28 b) If part (a) above is not confirmed, please provide further rationale for the increase
29 in average service life given Company personnel statements that "these structures
30 are on the water so they would have a little shorter life for various components"
31 and that "the existing 40 years is shorter than what would be expected" and that
32 "newer buildings are more technology driven and have a little less longevity than
33 the older built structures".

1 **ANSWER:**

2

3 **(a) and (b)**

4

5 Yes, that was a material factor. The segregation of smaller, shorter-lived components into
6 account 1645-201 would change the mix of assets in 1645-200 and would make the lives
7 of the assets in the account more homogeneous. Increasing the life was to reflect the more
8 homogeneous life in the account after the transfer. Input from Company SMEs and
9 Alliance's experience also supported the move to a 50-year life.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-70**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1645-201 Bldg & Otr – Building and Improvements 50 R2
6 This account includes the cost associated with buildings and
7 improvements that includes staff housing, warehouses, offices, fencing,
8 building envelopes, fish hatchery, yard work, guard rails. The plant
9 balance in this account at December 31, 2018 is \$10.1 million. The
10 approved life and curve for this account is 55 R1. There is very limited
11 historical activity to analyze. Discussions with Company personnel
12 indicated many of the assets in this account have shorter lives than the
13 building. Based on the limited indications from the actuarial analysis,
14 mix and type of assets, and judgment, this study proposes moving to
15 50 R2 at this time."

16
17 **QUESTION:**

- 18
19 a) Please clarify the types of assets that Company personnel indicated "have shorter
20 lives than the building" and the approximate per cent proportion of these assets
21 compared to all assets in the account.
22
23 b) Please provide the dollar amount of retirements by transaction year and vintage
24 for the years 1998-2018 and indicate the proportion of assets being retired that
25 have been identified as those having shorter lives than the building in part (a)
26 above.

27
28 **ANSWER:**

29
30 **(a)**

31
32 The types of assets that might retire earlier than a large building might be facilities signage,
33 fish hatchery upgrades, security systems, guard rail extensions, car plug-ins for electric
34 vehicles, alternate road access, paving, and or water storage closets.

1 **(b)**

2

3 YEC is not able to provide the detailed information requested given the considerable time
4 and effort it would take to collect and summarize this information and its limited relevance
5 to the current review process.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-77**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1645-507 Bldg & Otr – Wind Monitoring Equipment 15 SQ
6 This account includes costs associated with wind monitoring
7 equipment. This includes tall towers and ultrasonic anemometers. The
8 plant balance in this account at December 31, 2018 is \$14 thousand.
9 The approved life and curve for this account is 20 SQ. There is no
10 historical data to analyze. Discussions with Company personnel
11 indicated there is one wind monitoring site, which will likely be out of
12 this process within a year. Company believes it might be 10 years old
13 now. Based on the type of assets, existing life, Company input, and
14 judgment, this study proposes moving to 15 SQ at this time."

15
16 **QUESTION:**

- 17
18 a) Please clarify if the reference to "one wind monitoring site, which will likely be out
19 of this process within a year" is an indication that this asset will no longer be used
20 and useful at the end of 2021.
21
22 b) If confirmed, please explain why YEC is proposing to continue to amortize the
23 assets over 15 years rather than simply retire them and recover any remaining net
24 book value at the end of 2021.
25

26 **ANSWER:**

27
28 **(a)**

29
30 All wind monitoring equipment has been disposed of, leaving no assets on record.
31

32 **(b)**

33
34 As disclosed in Tab 7, Schedule 3A, there is no forecast depreciation of Wind assets or
35 Wind Monitoring Equipment as there are no assets on record. However, this does not
36 mean YEC should not have a policy in the case it did have assets (as it did at the time of
37 the Depreciation Study).

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-78**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1645-605 Bldg & Otr – Communication Equipment 20 L4
6 This account includes the installation costs of telephone, fibre optic and
7 wireless equipment for general use in connection with utility operations
8 and includes antennae, booths, cable, handsets, insulators, poles and
9 fixtures, remote control equipment and line, storage batteries,
10 switchboards, underground conduit and cable for telephone or fibre
11 optics and other related equipment. The plant balance in this account
12 at December 31, 2018 is \$4.6 million. The approved life and curve for
13 this account is 20 L4. Discussions with Company personnel indicated
14 there is a variety of equipment types and varying lives. The life analysis
15 indicates a life between 20-25 years. Based on the type and use of the
16 equipment, Company input, life analysis indications, and judgment, this
17 study proposes retention of 20 L4 at this time. A graph of the observed
18 life table versus the recommended curve type is shown below."

19
20 **QUESTION:**

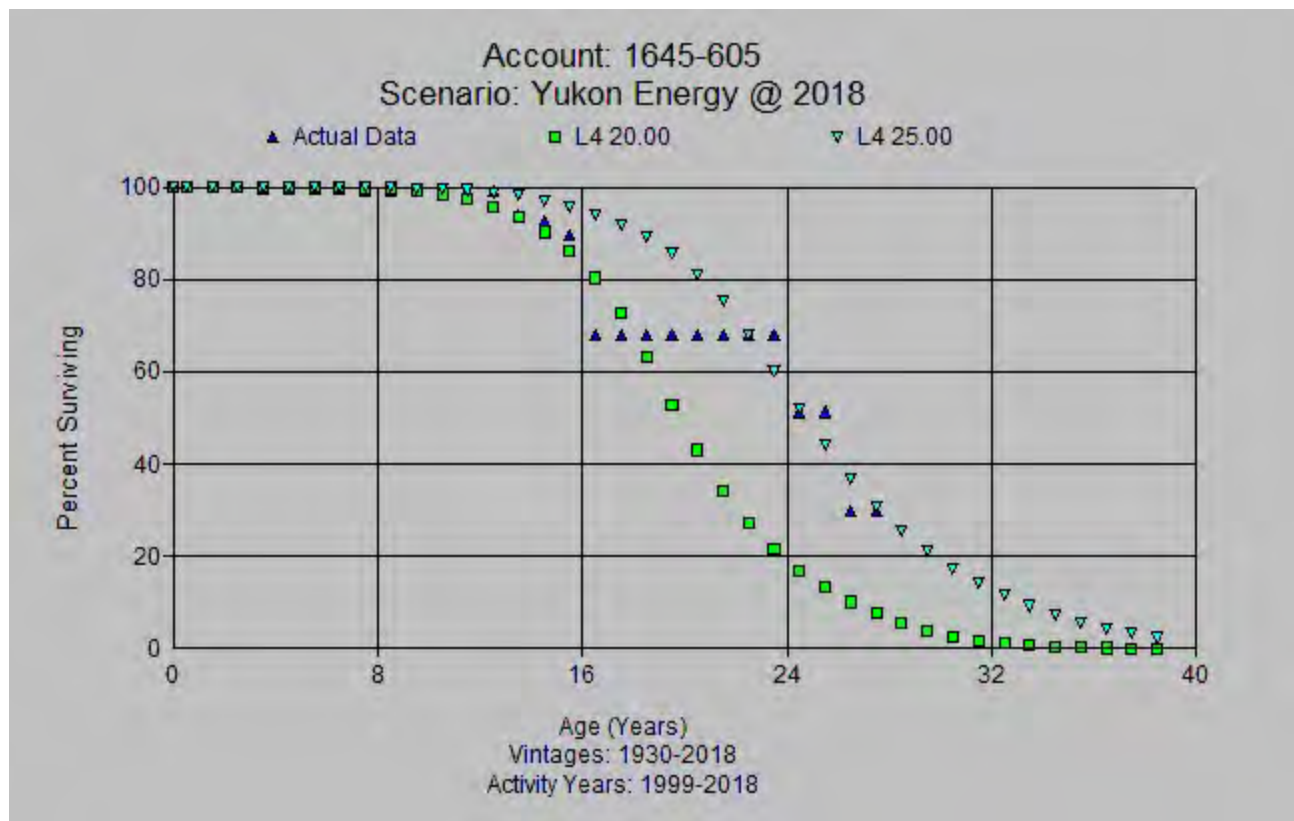
- 21
22 a) Please provide an observed life table and the plotted actual data points showing
23 both a 20-L4 and 25-L4 survivor curve for this account.

24
25 **ANSWER:**

26
27 **(a)**

28
29 The requested information is provided in the following attachments:

- 30
31 • Attachment 1- Acct 164-602 L4 20 & L25.bmp shows the requested graphs.
32
33 • Attachment 2 - Acct 1645-602 P30-18 E99-18.pdf is an Adobe file showing the
34 actual data points.
35
36 • Attachment 3 - Comparison of Life Table L4 20 and L4 25.pdf shows the actual
37 data compared to the survivor curves propounded in the question.



Observed Life Table

Scenario: Yukon Energy @ 2018

Account: 1645-605

Placement Band: 1930 - 2018

Observation Band: 1999 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	3,848,426.21	0.00	0.00000	1.00000	100.00
0.5	4,717,546.19	0.00	0.00000	1.00000	100.00
1.5	4,677,287.38	0.00	0.00000	1.00000	100.00
2.5	4,582,689.91	3,149.00	0.00069	0.99931	100.00
3.5	4,335,952.71	3,229.60	0.00074	0.99926	99.93
4.5	4,060,289.35	7,364.10	0.00181	0.99819	99.86
5.5	4,026,289.86	2,381.56	0.00059	0.99941	99.68
6.5	3,800,851.95	6,522.65	0.00172	0.99828	99.62
7.5	3,784,197.32	0.00	0.00000	1.00000	99.45
8.5	3,396,128.88	0.00	0.00000	1.00000	99.45
9.5	2,650,634.83	0.00	0.00000	1.00000	99.45
10.5	2,202,785.06	0.00	0.00000	1.00000	99.45
11.5	2,029,372.95	0.00	0.00000	1.00000	99.45
12.5	1,864,915.14	102,494.00	0.05496	0.94504	99.45
13.5	1,709,698.12	21,905.83	0.01281	0.98719	93.98
14.5	1,567,990.28	48,996.15	0.03125	0.96875	92.78
15.5	1,448,457.10	353,323.86	0.24393	0.75607	89.88
16.5	938,847.40	0.00	0.00000	1.00000	67.95
17.5	930,535.03	0.00	0.00000	1.00000	67.95
18.5	857,643.86	0.00	0.00000	1.00000	67.95
19.5	854,502.26	0.00	0.00000	1.00000	67.95
20.5	26,332.22	0.00	0.00000	1.00000	67.95
21.5	26,332.22	0.00	0.00000	1.00000	67.95
22.5	26,332.22	0.00	0.00000	1.00000	67.95
23.5	26,332.22	6,446.48	0.24481	0.75519	67.95
24.5	19,885.74	0.00	0.00000	1.00000	51.32
25.5	19,885.74	8,270.87	0.41592	0.58408	51.32
26.5	11,614.87	0.00	0.00000	1.00000	29.97
27.5	11,614.87	11,614.87	1.00000	0.00000	29.97
28.5	0.00	0.00	0.00000	1.00000	0.00

Surviving Percent Report

Scenario: Yukon Energy @ 2018

Account: 1645-605

Placement Band: 1930 - 2018

Observation Band: 1999 - 2018

Age	Actual	L4 20.00	L4 25.00
0.0	100.00	100.00	100.00
0.5	100.00	100.00	100.00
1.5	100.00	100.00	100.00
2.5	100.00	100.00	100.00
3.5	99.93	100.00	100.00
4.5	99.86	100.00	100.00
5.5	99.68	100.00	100.00
6.5	99.62	99.99	100.00
7.5	99.45	99.92	99.99
8.5	99.45	99.72	99.97
9.5	99.45	99.29	99.89
10.5	99.45	98.52	99.72
11.5	99.45	97.32	99.40
12.5	99.45	95.57	98.88
13.5	93.98	93.20	98.10
14.5	92.78	90.02	97.01
15.5	89.88	85.70	95.57
16.5	67.95	79.75	93.73
17.5	67.95	71.83	91.40
18.5	67.95	62.21	88.46
19.5	67.95	51.92	84.66
20.5	67.95	42.13	79.75
21.5	67.95	33.59	73.57
22.5	67.95	26.58	66.21
23.5	67.95	20.99	58.10
24.5	51.32	16.51	49.89
25.5	51.32	12.84	42.13
26.5	29.97	9.81	35.18
27.5	29.97	7.31	29.20
28.5	0	5.29	24.19

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-79**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1645-810 Bldg & Otr – Company Owned Houses/Land 40 R3
6 This account includes the costs of upgrades and maintenance
7 associated with the land of houses owned by the company. The plant
8 balance in this account at December 31, 2018 is \$59 thousand. The
9 approved life and curve for this account is 30 R3. Discussions with
10 Company personnel indicated the newest house is from 2005 and the
11 oldest is pre-1980. Company believes the existing life is too low. There
12 is not enough historical experience for analysis. Based on the type of
13 assets, Company input, and judgment this study proposes moving to
14 40 R3 for this account."

15
16 **QUESTION:**

- 17
18 a) Please clarify why "costs of upgrades and maintenance associated with the land
19 of houses owned by the company" should be capitalized into rate base as opposed
20 to expensed annually as an operating and maintenance cost.

21
22 **ANSWER:**

23
24 **(a)**

25
26 Consistent with YEC's capitalization policy previously provided to the YUB, and consistent
27 with International Financial Reporting Standards as audited by the Auditor General of
28 Canada, YEC capitalizes costs in excess of \$1,000 that have a life longer than one year.

1 **REFERENCE:** Application, Tab 9, Depreciation Study, page 9-82

2
3 **ISSUE:** Depreciation Expense

4
5 **QUOTE:** "Account 1650-411 Trxptn – Utility Vehicles 8 L2
6 This account includes the cost of utility trailers, cargo trailers, ATVs,
7 snowmobiles, and boats. The plant balance in this account at
8 December 31, 2018 is \$344 thousand. The approved life and curve for
9 this account is 7 L2. Discussions with Company personnel indicated the
10 line crews use these types of vehicles for seven years before it is
11 retired. Company indicated that occasionally, a quad or snow mobile
12 will move to a plant and have a longer life, but an estimated 80% of
13 these types of assets do not. However, the life analysis indicates a
14 longer life than existing and longer than what the Company expects,
15 which ranges from 10 to 15 years. Giving consideration to the type and
16 use of assets, Company input and expectations, we propose moving
17 the average out to eight years to reflect the 20% of assets that remain
18 longer. This study proposes 8 L2 for this account."

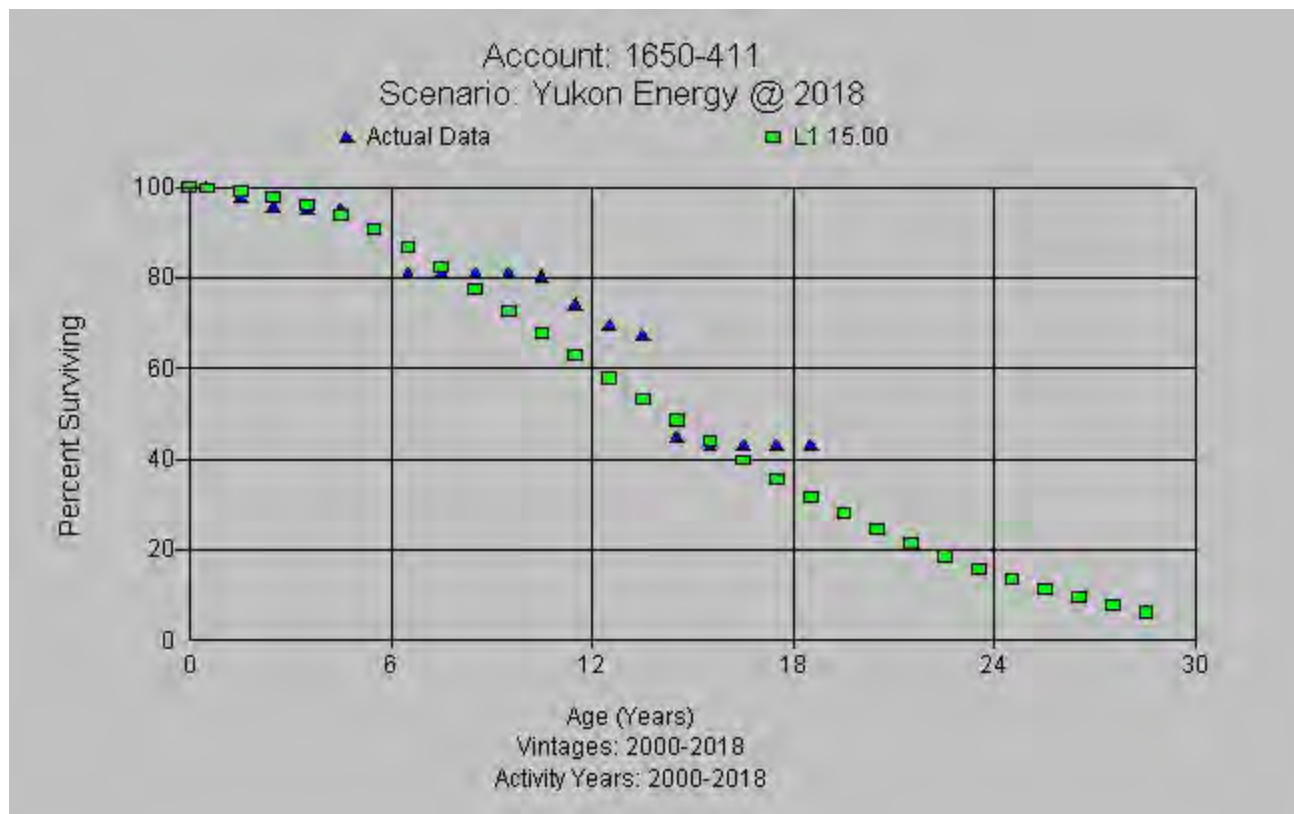
19
20 **QUESTION:**

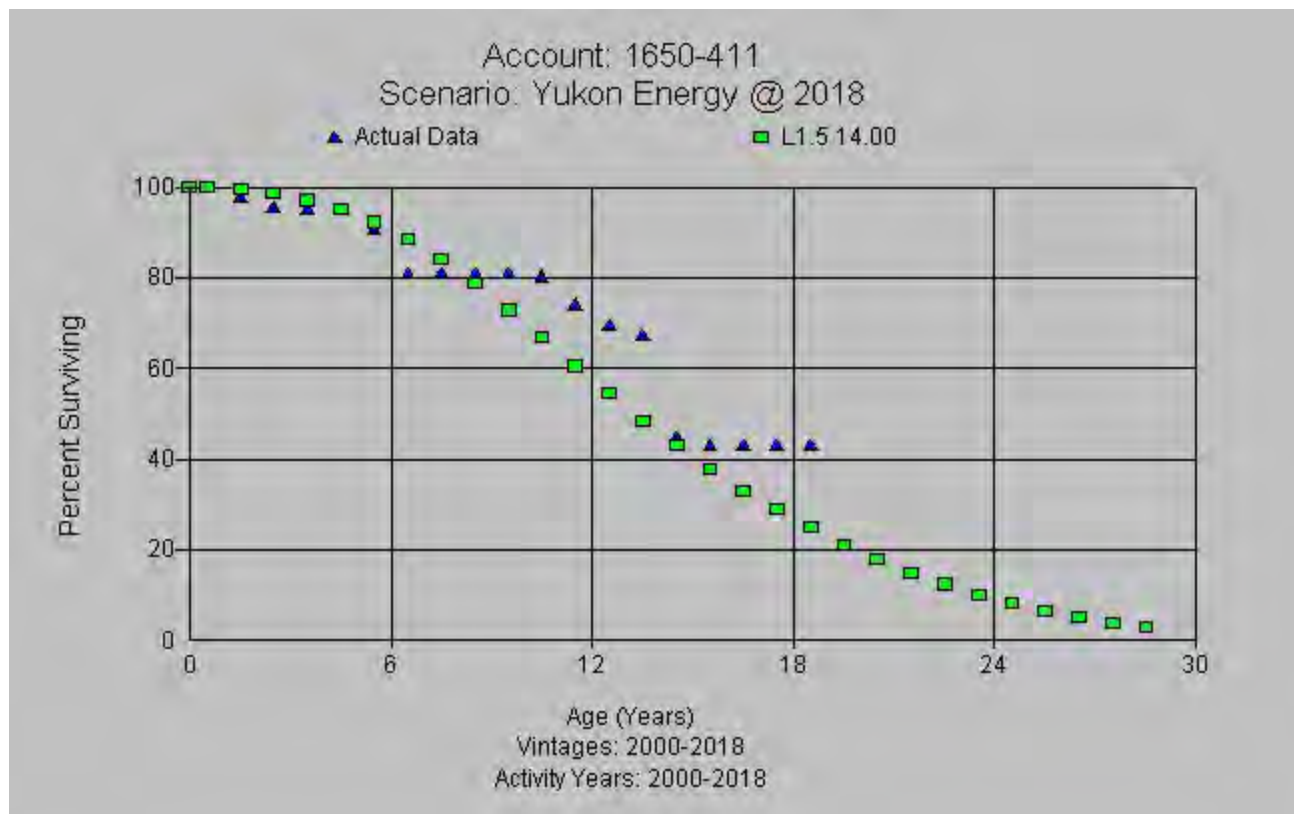
- 21
22 a) Please provide the "life analysis indicat[ing] a longer life than existing and longer
23 than what the Company expects, which ranges from 10 to 15 years".

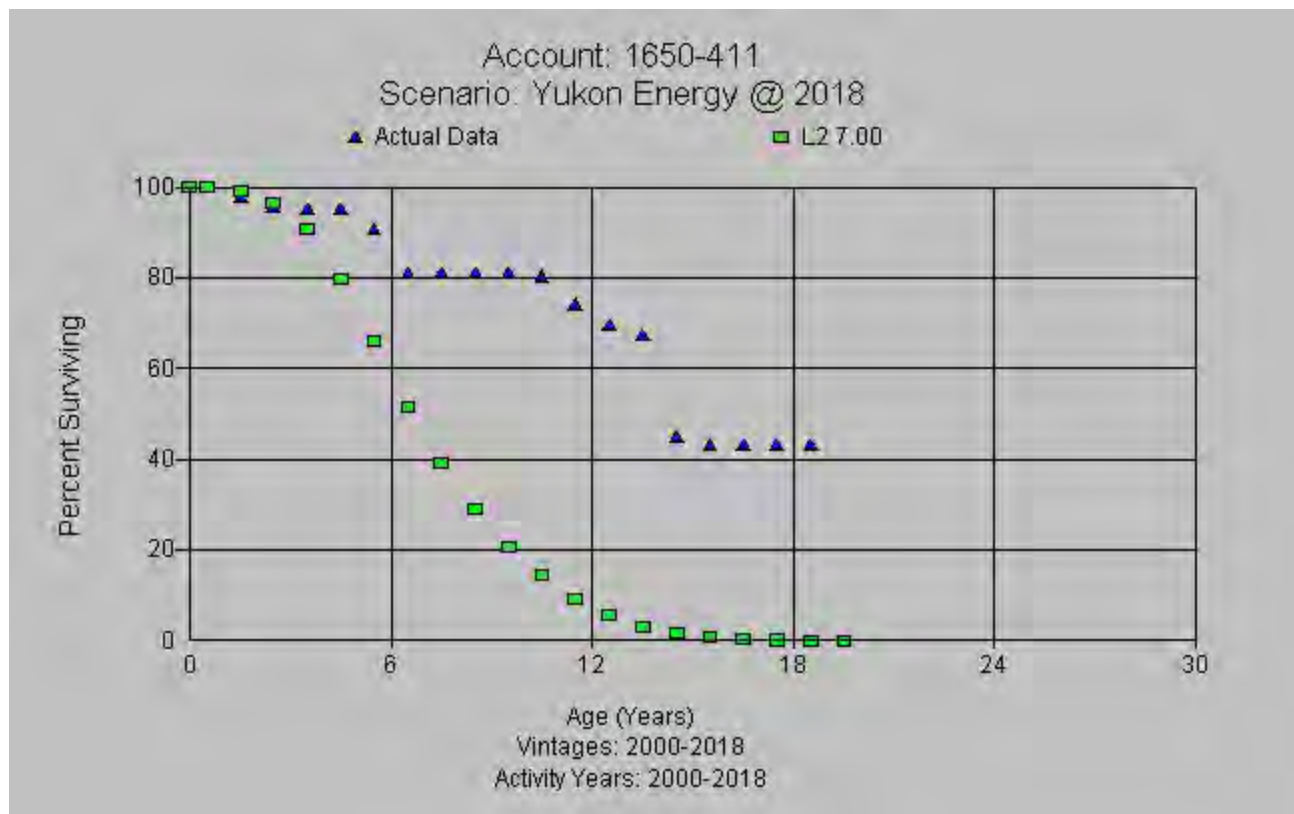
24
25 **ANSWER:**

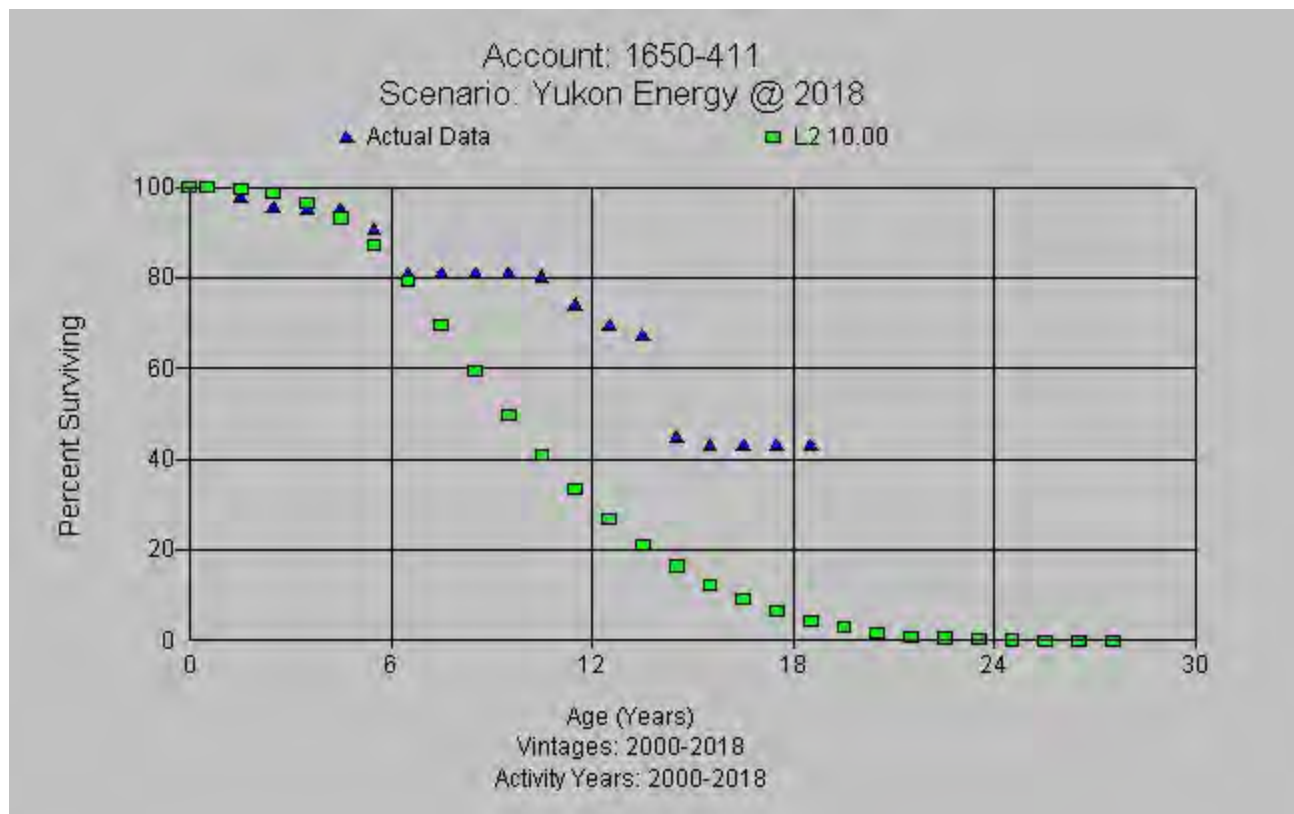
26
27 **(a)**

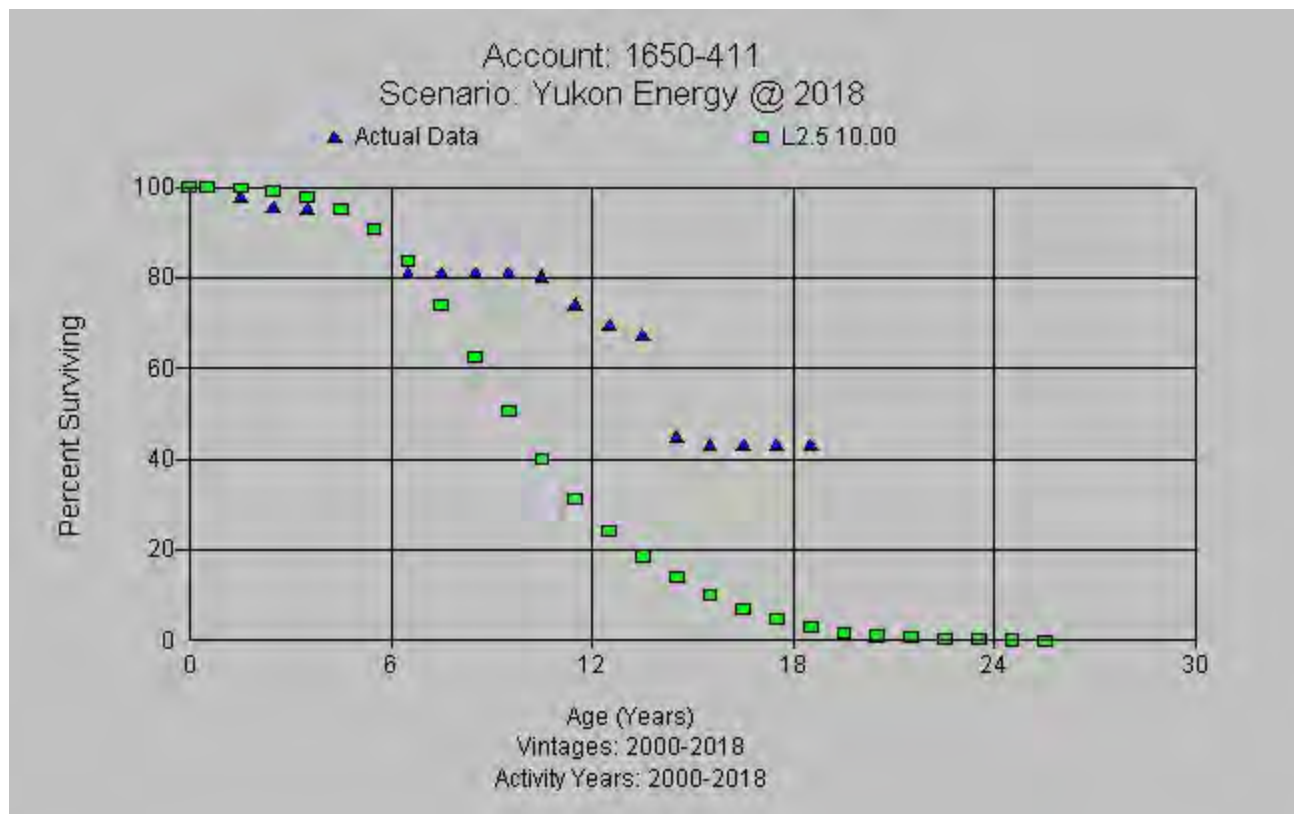
28
29 The requested information is provided as Attachment 1 to this response.











Observed Life Table

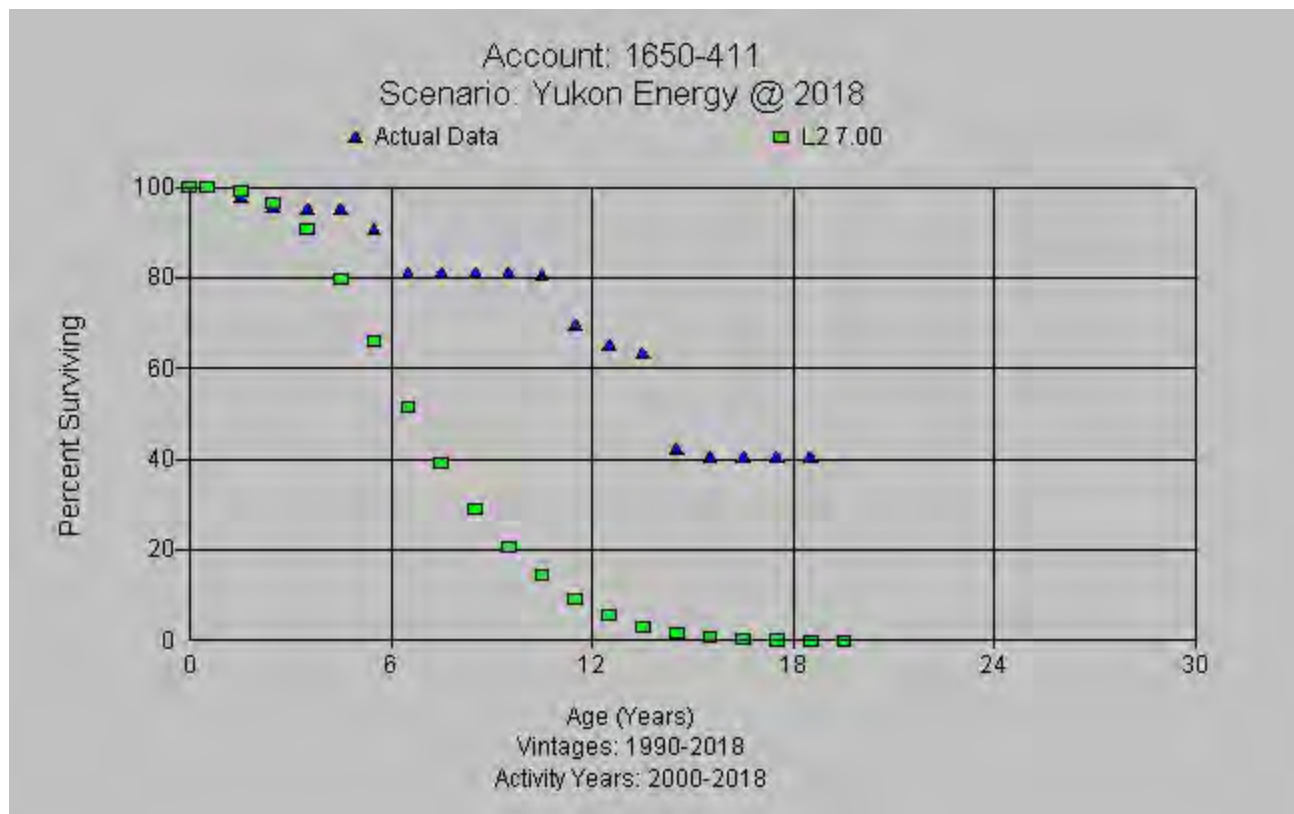
Scenario: Yukon Energy @ 2018

Account: 1650-411

Placement Band: 2000 - 2018

Observation Band: 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	448,042.18	0.00	0.00000	1.00000	100.00
0.5	405,592.18	8,463.00	0.02087	0.97913	100.00
1.5	397,129.18	8,400.00	0.02115	0.97885	97.91
2.5	358,967.13	2,465.00	0.00687	0.99313	95.84
3.5	327,841.44	0.00	0.00000	1.00000	95.18
4.5	230,470.67	11,068.60	0.04803	0.95197	95.18
5.5	181,452.27	18,938.70	0.10437	0.89563	90.61
6.5	162,513.57	0.00	0.00000	1.00000	81.16
7.5	162,513.57	0.00	0.00000	1.00000	81.16
8.5	162,513.57	0.00	0.00000	1.00000	81.16
9.5	162,513.57	1,460.77	0.00899	0.99101	81.16
10.5	129,871.48	9,951.37	0.07662	0.92338	80.43
11.5	108,550.11	6,849.00	0.06310	0.93690	74.26
12.5	96,125.17	2,800.00	0.02913	0.97087	69.58
13.5	93,325.17	31,328.73	0.33569	0.66431	67.55
14.5	61,996.44	2,244.25	0.03620	0.96380	44.87
15.5	59,752.19	0.00	0.00000	1.00000	43.25
16.5	31,356.70	0.00	0.00000	1.00000	43.25
17.5	26,192.29	0.00	0.00000	1.00000	43.25
18.5	0.00	0.00	0.00000	0.00000	43.25

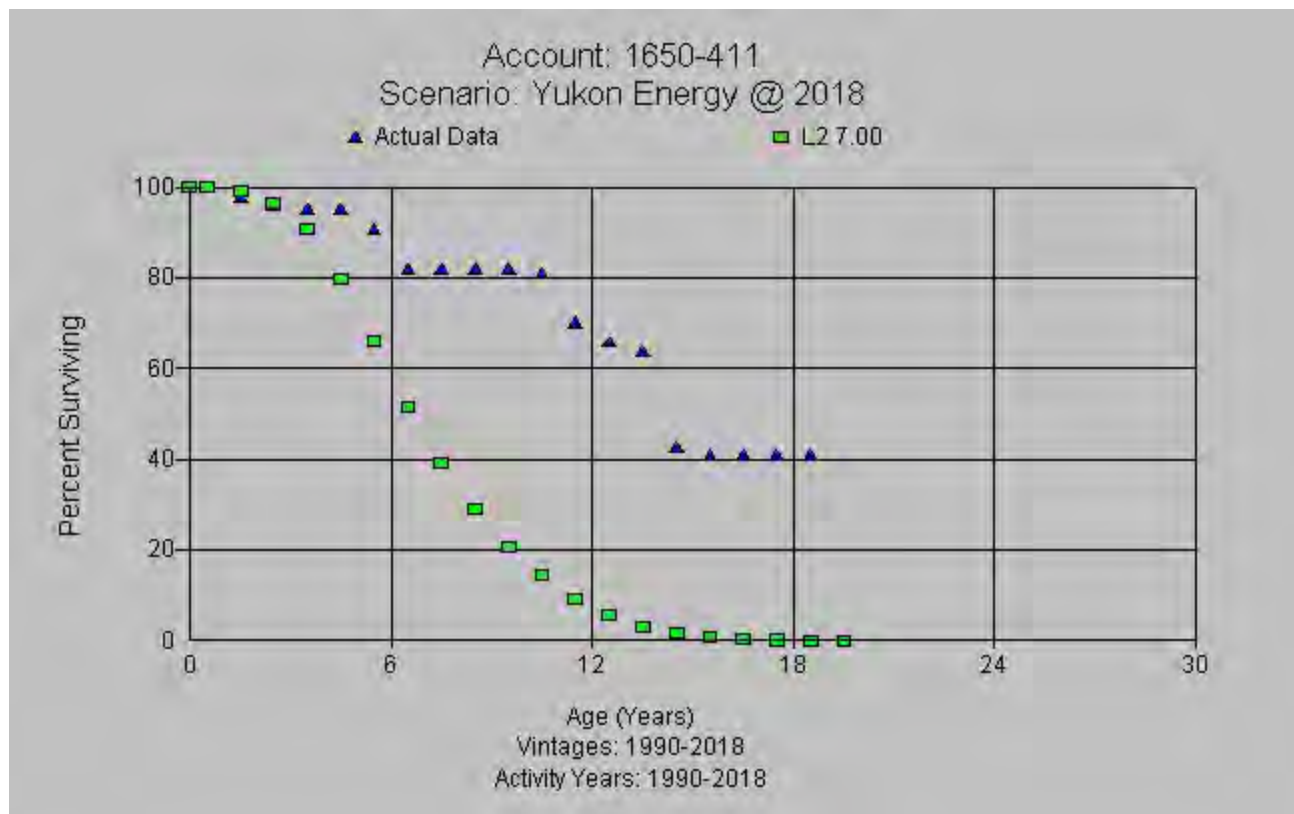


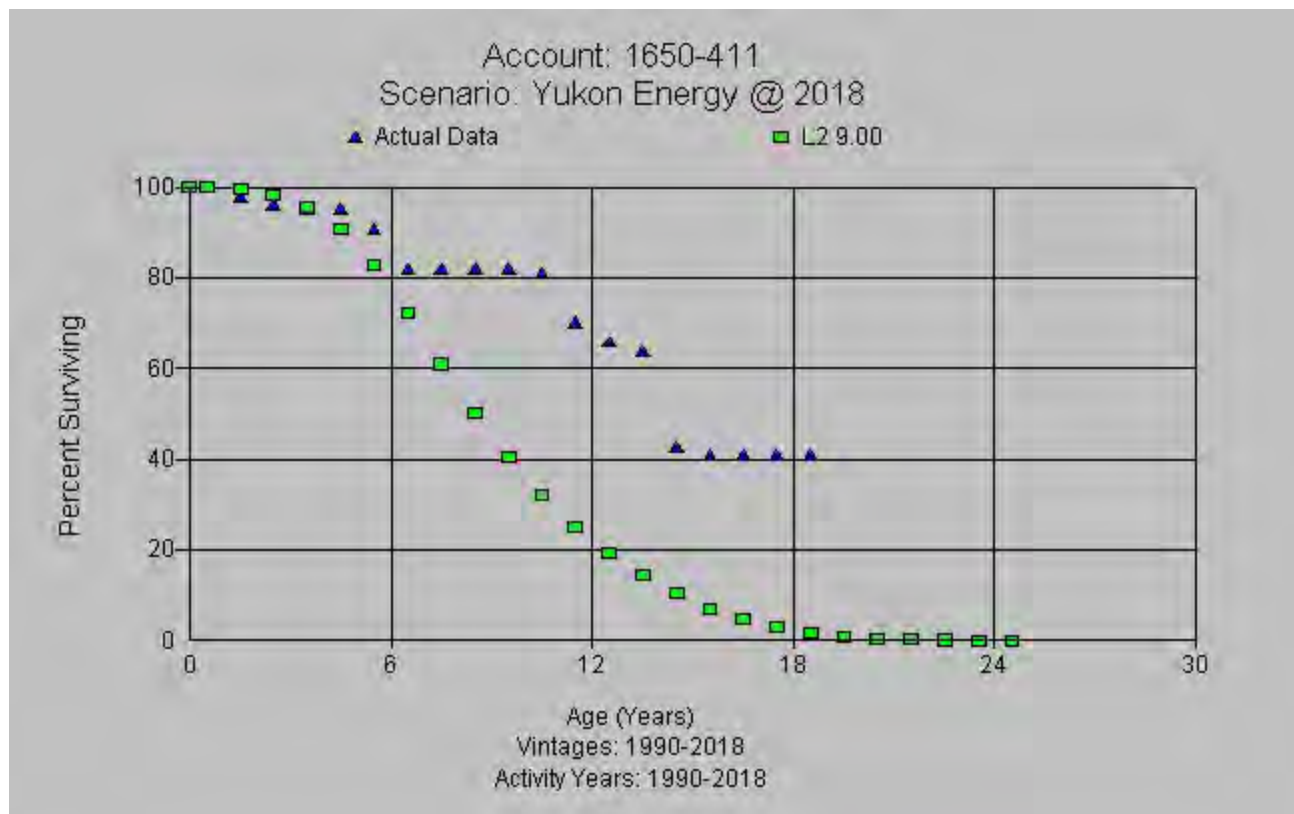
Observed Life Table

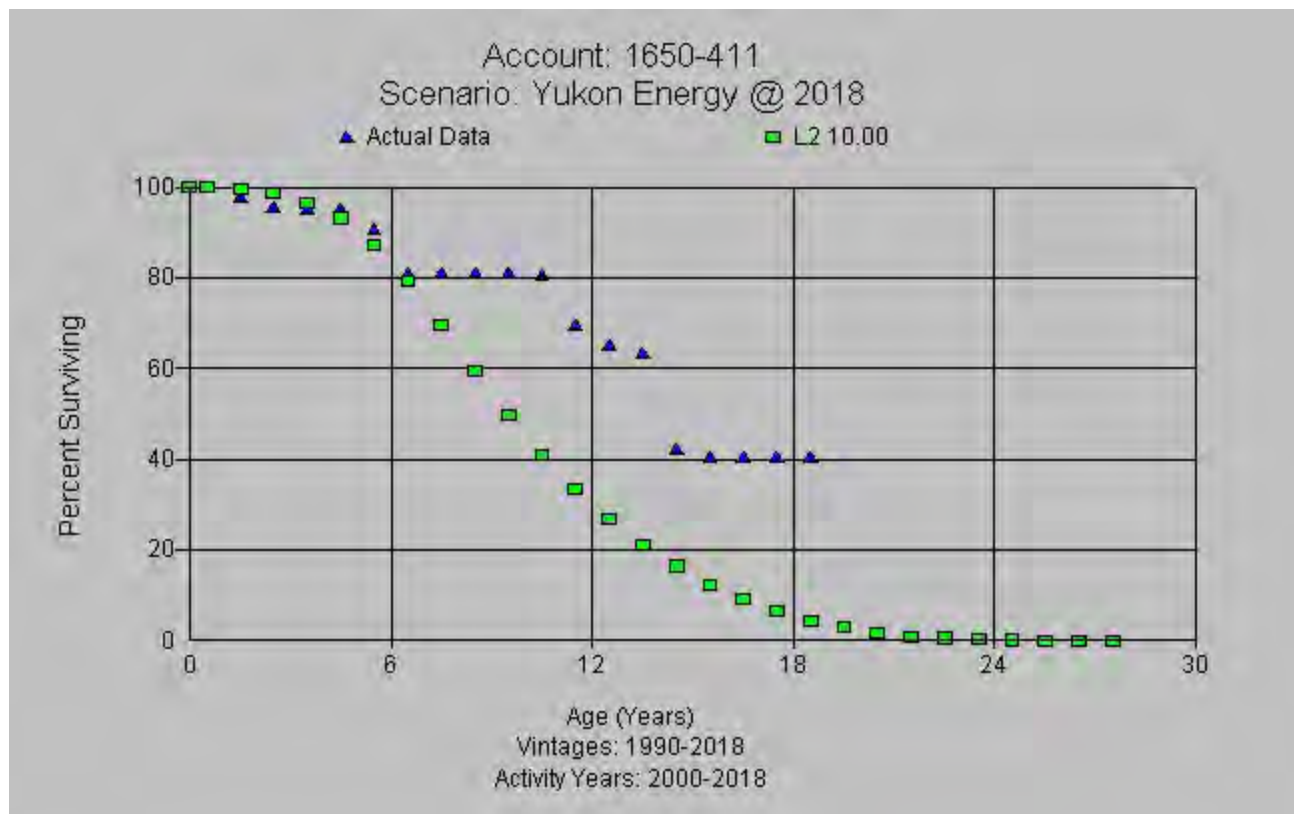
Scenario: Yukon Energy @ 2018
Account: 1650-411
Placement Band: 1990 - 2018

Observation Band: 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	448,042.18	0.00	0.00000	1.00000	100.00
0.5	405,592.18	8,463.00	0.02087	0.97913	100.00
1.5	397,129.18	8,400.00	0.02115	0.97885	97.91
2.5	358,967.13	2,465.00	0.00687	0.99313	95.84
3.5	327,841.44	0.00	0.00000	1.00000	95.18
4.5	230,470.67	11,068.60	0.04803	0.95197	95.18
5.5	181,452.27	18,938.70	0.10437	0.89563	90.61
6.5	162,513.57	0.00	0.00000	1.00000	81.16
7.5	162,513.57	0.00	0.00000	1.00000	81.16
8.5	162,513.57	0.00	0.00000	1.00000	81.16
9.5	171,063.57	1,460.77	0.00854	0.99146	81.16
10.5	138,421.48	18,501.37	0.13366	0.86634	80.46
11.5	108,550.11	6,849.00	0.06310	0.93690	69.71
12.5	96,125.17	2,800.00	0.02913	0.97087	65.31
13.5	93,325.17	31,328.73	0.33569	0.66431	63.41
14.5	61,996.44	2,244.25	0.03620	0.96380	42.12
15.5	59,752.19	0.00	0.00000	1.00000	40.60
16.5	31,356.70	0.00	0.00000	1.00000	40.60
17.5	26,192.29	0.00	0.00000	1.00000	40.60
18.5	0.00	0.00	0.00000	1.00000	40.60







Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-411
Placement Band: 1990 - 2018

Observation Band: 1990 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	456,592.18	0.00	0.00000	1.00000	100.00
0.5	414,142.18	8,463.00	0.02044	0.97956	100.00
1.5	405,679.18	8,400.00	0.02071	0.97929	97.96
2.5	367,517.13	2,465.00	0.00671	0.99329	95.93
3.5	336,391.44	0.00	0.00000	1.00000	95.28
4.5	239,020.67	11,068.60	0.04631	0.95369	95.28
5.5	190,002.27	18,938.70	0.09968	0.90032	90.87
6.5	171,063.57	0.00	0.00000	1.00000	81.81
7.5	171,063.57	0.00	0.00000	1.00000	81.81
8.5	171,063.57	0.00	0.00000	1.00000	81.81
9.5	171,063.57	1,460.77	0.00854	0.99146	81.81
10.5	138,421.48	18,501.37	0.13366	0.86634	81.11
11.5	108,550.11	6,849.00	0.06310	0.93690	70.27
12.5	96,125.17	2,800.00	0.02913	0.97087	65.84
13.5	93,325.17	31,328.73	0.33569	0.66431	63.92
14.5	61,996.44	2,244.25	0.03620	0.96380	42.46
15.5	59,752.19	0.00	0.00000	1.00000	40.92
16.5	31,356.70	0.00	0.00000	1.00000	40.92
17.5	26,192.29	0.00	0.00000	1.00000	40.92
18.5	0.00	0.00	0.00000	1.00000	40.92

Actuarial Life Analysis

Account: 1650-411
Scenario: Yukon Energy @ 2018
Placement Band: 1990 - 1994
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	<u>Censoring</u>		Error Sum of Squares	<u>Best Fit</u>	
	Age	Percent		Disp	ASL
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999		1.00			
1996 -2000		1.00			
1997 -2001	8.5	0.00	0.27976196	R4	7.15
1998 -2002	9.5	0.00	0.26840527	R4	7.25
1999 -2003	10.5	0.00	0.02795968	SQ	7.61
2000 -2004	11.5	0.00	0.02444965	SQ	7.64
2001 -2005	12.5	0.00	0.25298458	R4	7.20
2002 -2006	13.5	92.01	0.01360181	R0.5	40.28
2003 -2007	14.5	80.47	0.05407438	R0.5	20.27
2004 -2008	15.5	78.43	0.08433457	R0.5	19.44
2005 -2009	16.5	72.06	0.21165142	R0.5	15.96
2006 -2010	17.5	85.14	0.03720481	R0.5	33.76
2007 -2011	18.5	83.04	0.05522118	R0.5	31.01
2008 -2012		1.00			
2009 -2013	20.5	41.67	0.35368213	L0	13.95
2010 -2014	21.5	32.32	0.11686053	L1	14.90
2011 -2015	22.5	31.95	0.12452472	L0.5	15.45
2012 -2016	23.5	32.93	0.14060641	L0.5	15.61
2013 -2017	24.5	28.02	0.18447275	L0	14.70
2014 -2018	25.5	55.13	0.19831800	L1	25.45

Actuarial Life Analysis

Account: 1650-411
Scenario: Yukon Energy @ 2018
Placement Band: 1990 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	<u>Censoring</u>		Error Sum of Squares	<u>Best Fit</u>	
	Age	Percent		Disp	ASL
1990 -2018	28.5	40.93	0.19953081	L0	20.08
1995 -2018	28.5	40.88	0.19939398	L0	20.06
2000 -2018	28.5	40.60	0.20002144	L0	19.88
2005 -2018	28.5	43.66	0.18949751	L0	21.26
2010 -2018	28.5	38.56	0.25206453	L0	18.81
2015 -2018	28.5	76.36	0.10315800	L0	50.69

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-83**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1650-412 Trxptn – Sedans and Station Wagons 11 S4
6 This account includes the cost of vans, cars and smaller vehicles. The
7 plant balance in this account at December 31, 2018 is \$138 thousand.
8 The approved life and curve for this account is 7 L2. Discussions with
9 Company personnel indicated these vehicles are lasting longer than the
10 existing seven years. Company policy is if a vehicle is 8 years or older,
11 has 160,000 km, and has incurred maintenance costs greater than 15%
12 in one year, they would retire. However, they have fallen behind on this
13 schedule. The life analysis supports Company discussion that these
14 vehicles are lasting longer and the slippage in the schedule, with a life
15 indication of at least 12 years or more with a steeper dispersion pattern.
16 Giving consideration to the Company policy, recent experience,
17 expectations and judgment, this study proposes moving from 7 L2 to
18 11 S4 at this time."

19
20 **QUESTION:**

- 21
22 a) Please provide the "life analysis support[ing] Company discussion that these
23 vehicles are lasting longer and the slippage in the schedule, with a life indication
24 of at least 12 years or more with a steeper dispersion pattern".
25
26 b) If the life analysis discussed in part (a) above was not based on actuarial data,
27 please clarify how YEC is able to propose a change to an 11-S4 life and curve
28 from the approved 7-L2 life and curve without the benefit of an actuarial life
29 analysis.
30
31 c) Please provide the directional impact of the change proposed in terms of an
32 increase or decrease to depreciation expense for this account for the year 2021.

1 **ANSWER:**

2
3 **(a) and (b)**

4
5 The life analysis is provided as Attachment 1 to this response.

6
7 **(c)**

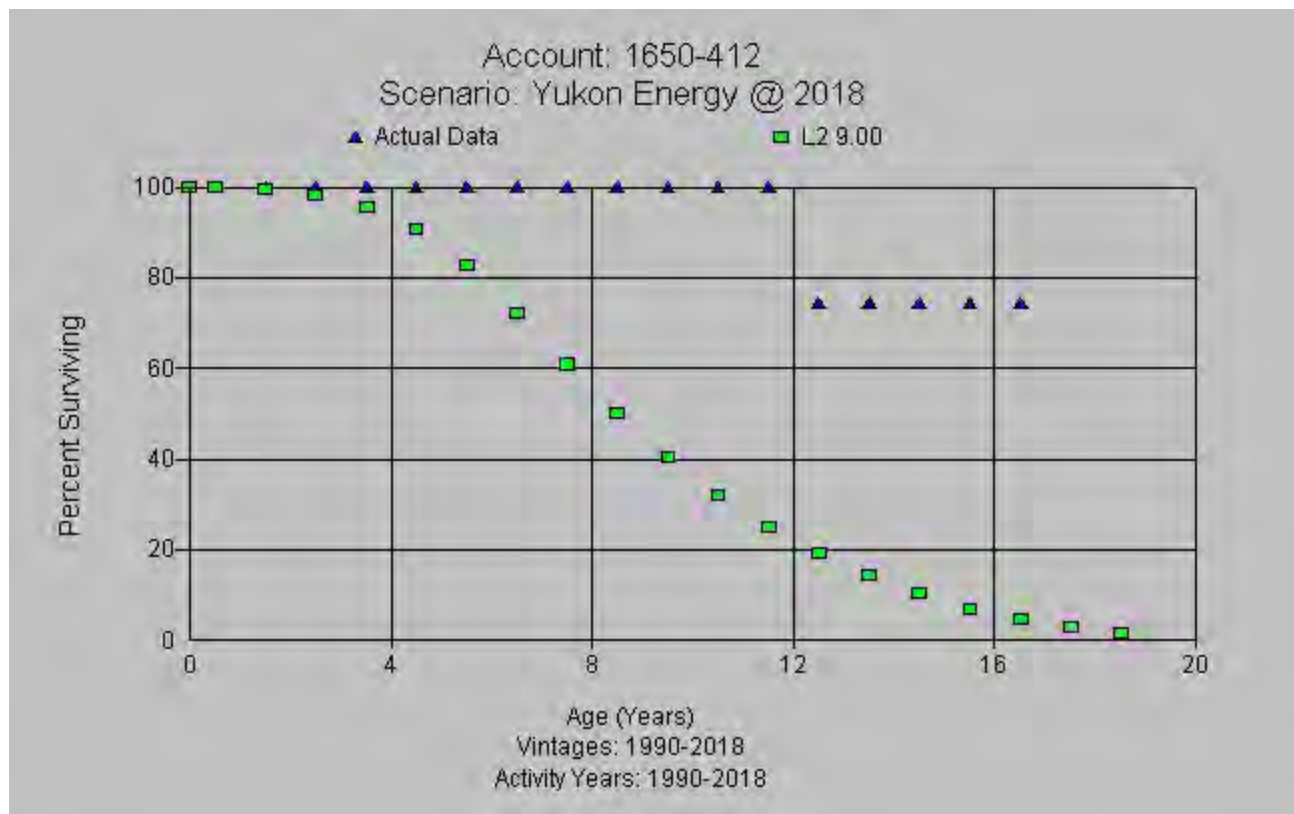
8
9 As the Depreciation Study proposes to increase the life of asset class from 7 years to 11
10 years, the directional impact on 2021 depreciation expense is a decrease.

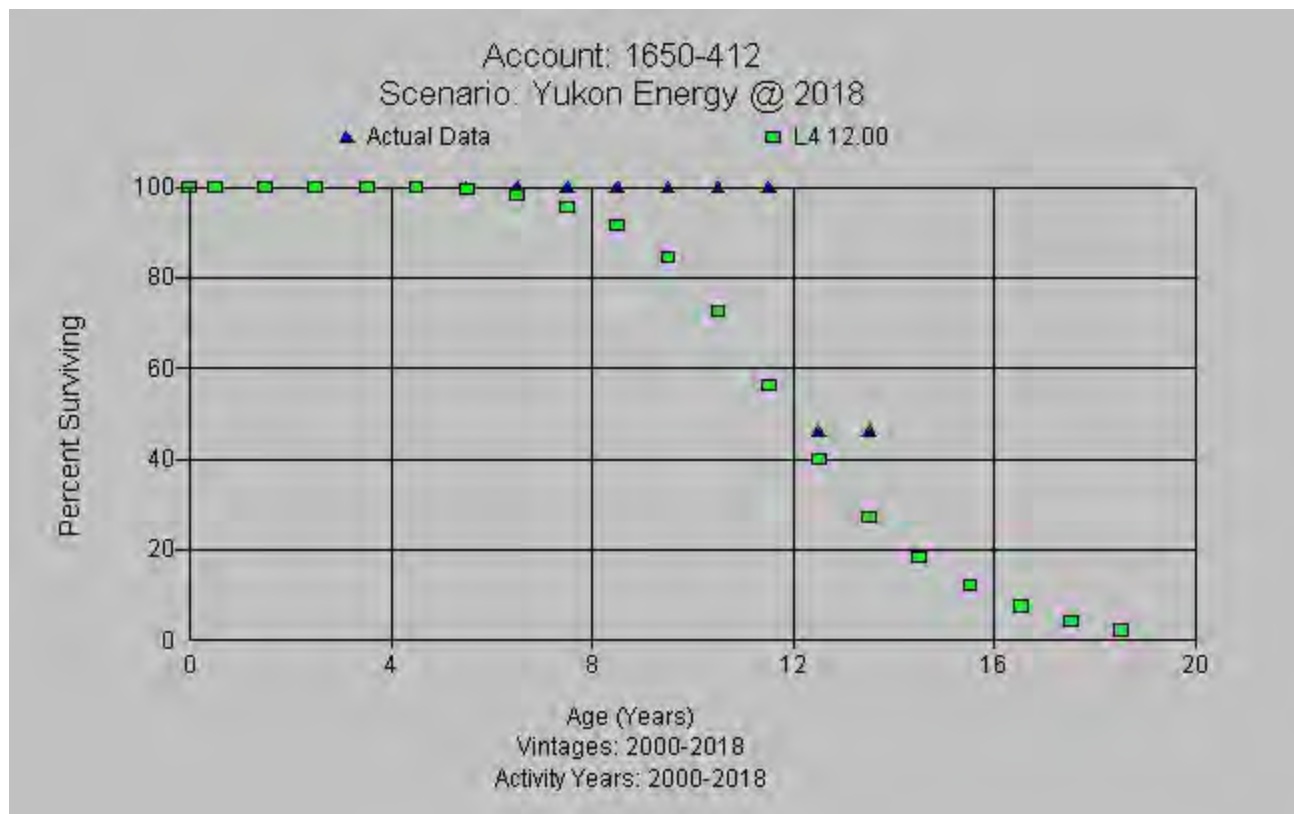
Observed Life Table

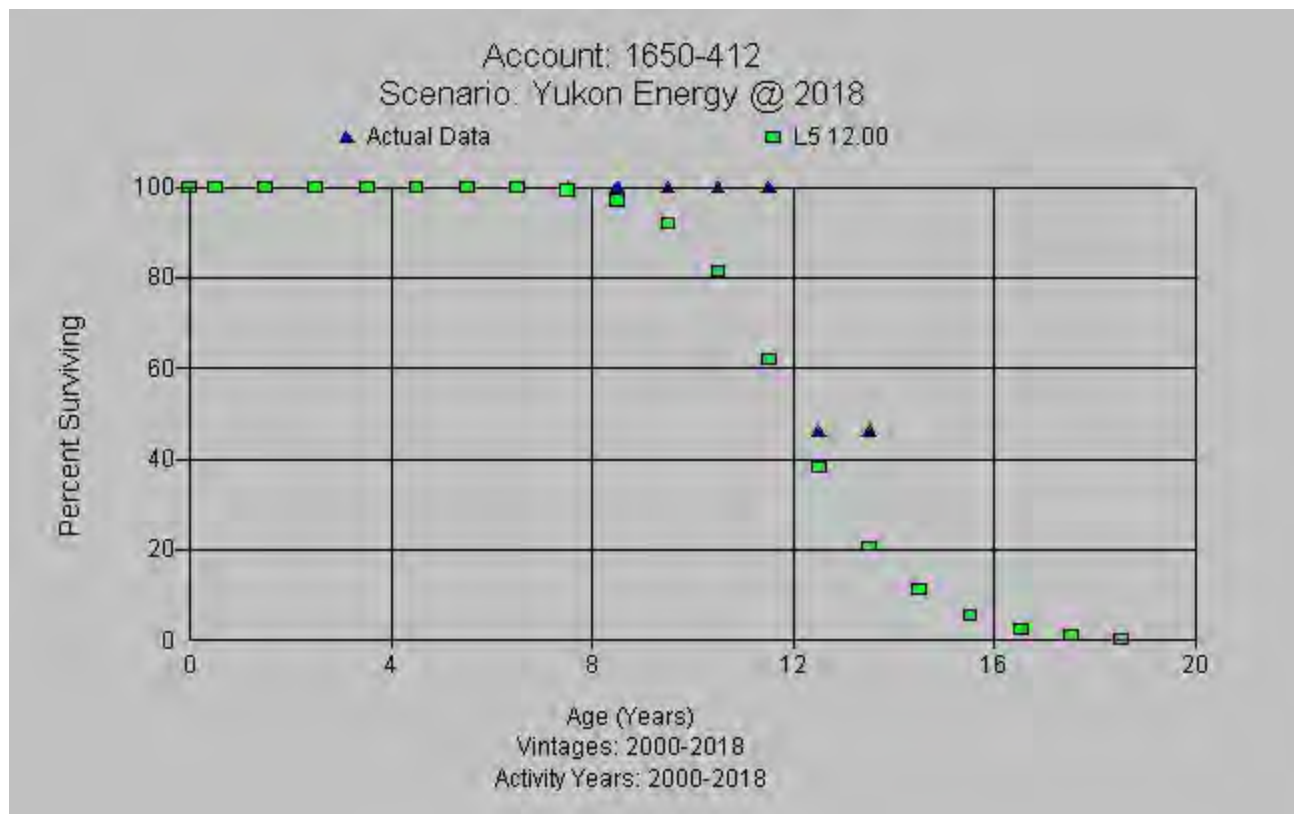
Scenario: Yukon Energy @ 2018
Account: 1650-412
Placement Band: 2000 - 2018

Observation Band: 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	168,107.25	0.00	0.00000	1.00000	100.00
0.5	168,107.25	0.00	0.00000	1.00000	100.00
1.5	168,107.25	0.00	0.00000	1.00000	100.00
2.5	168,107.25	0.00	0.00000	1.00000	100.00
3.5	168,107.25	0.00	0.00000	1.00000	100.00
4.5	83,295.55	0.00	0.00000	1.00000	100.00
5.5	83,295.55	0.00	0.00000	1.00000	100.00
6.5	83,295.55	0.00	0.00000	1.00000	100.00
7.5	83,295.55	0.00	0.00000	1.00000	100.00
8.5	56,355.66	0.00	0.00000	1.00000	100.00
9.5	56,355.66	0.00	0.00000	1.00000	100.00
10.5	56,355.66	0.00	0.00000	1.00000	100.00
11.5	56,355.66	30,343.66	0.53843	0.46157	100.00
12.5	26,012.00	0.00	0.00000	1.00000	46.16
13.5	0.00	0.00	0.00000	1.00000	46.16





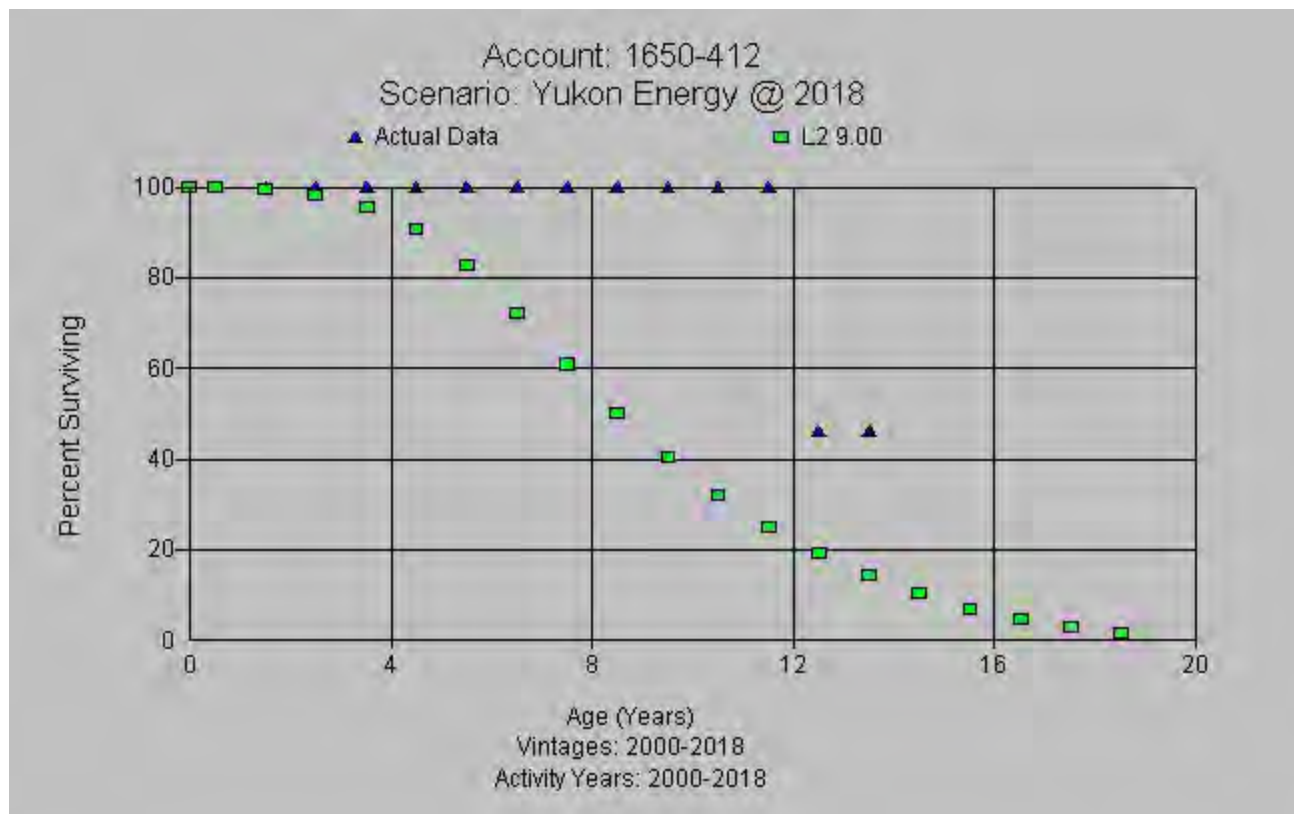


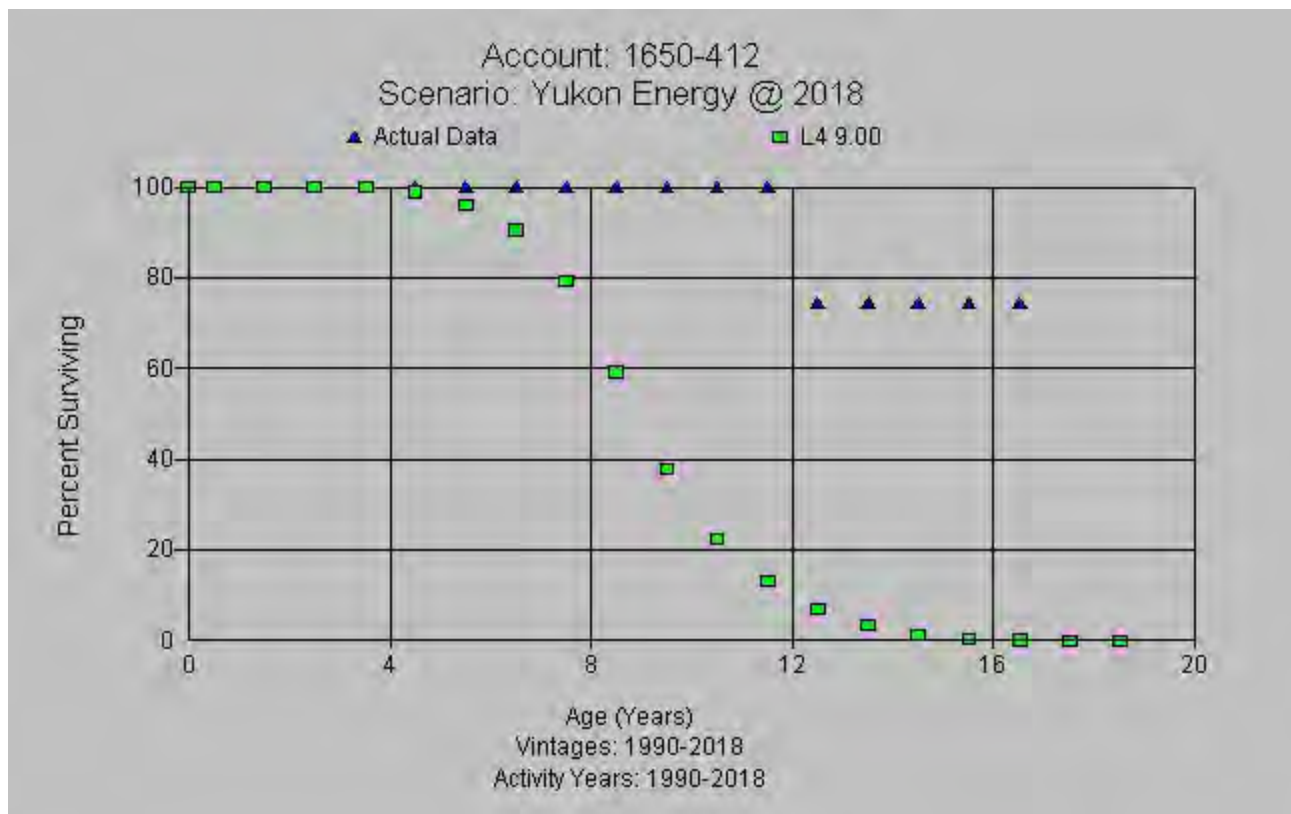
Observed Life Table

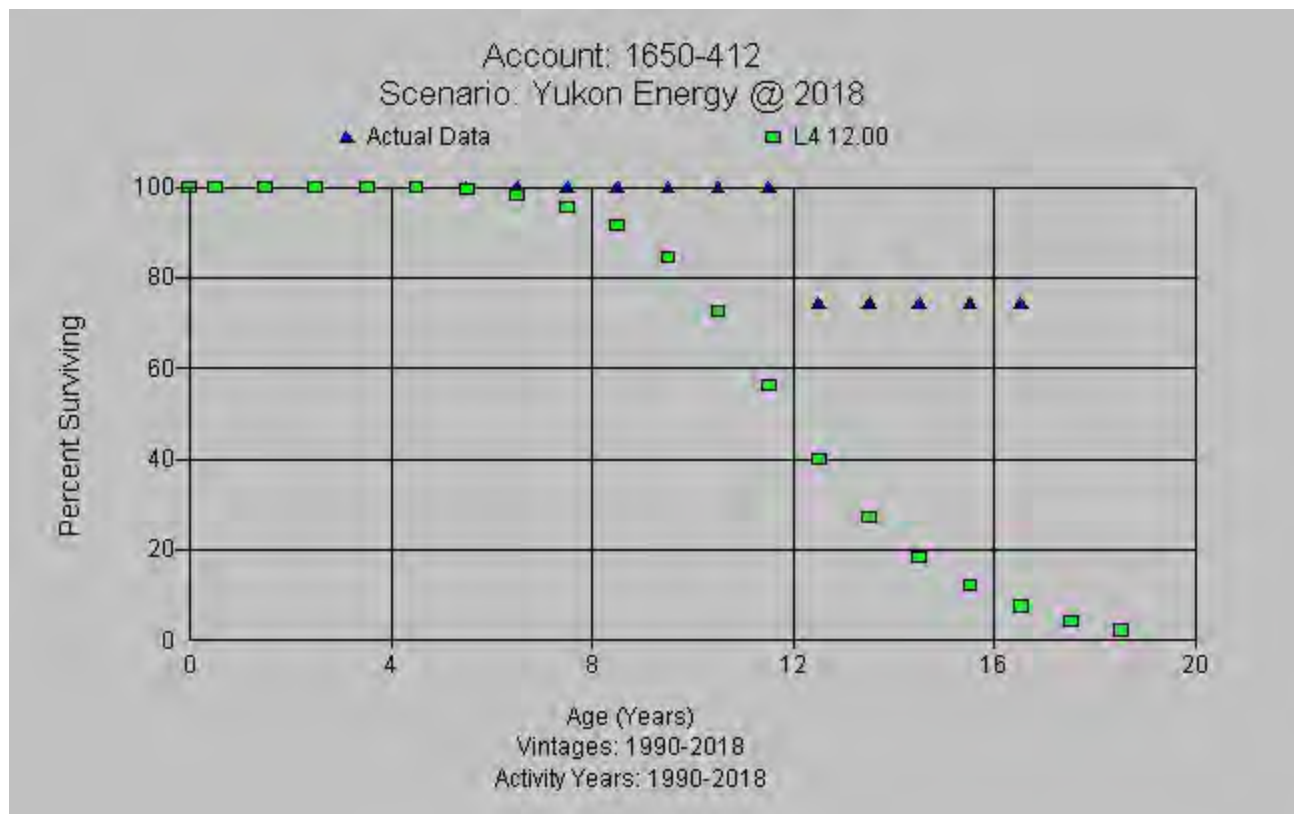
Scenario: Yukon Energy @ 2018
Account: 1650-412
Placement Band: 1990 - 2018

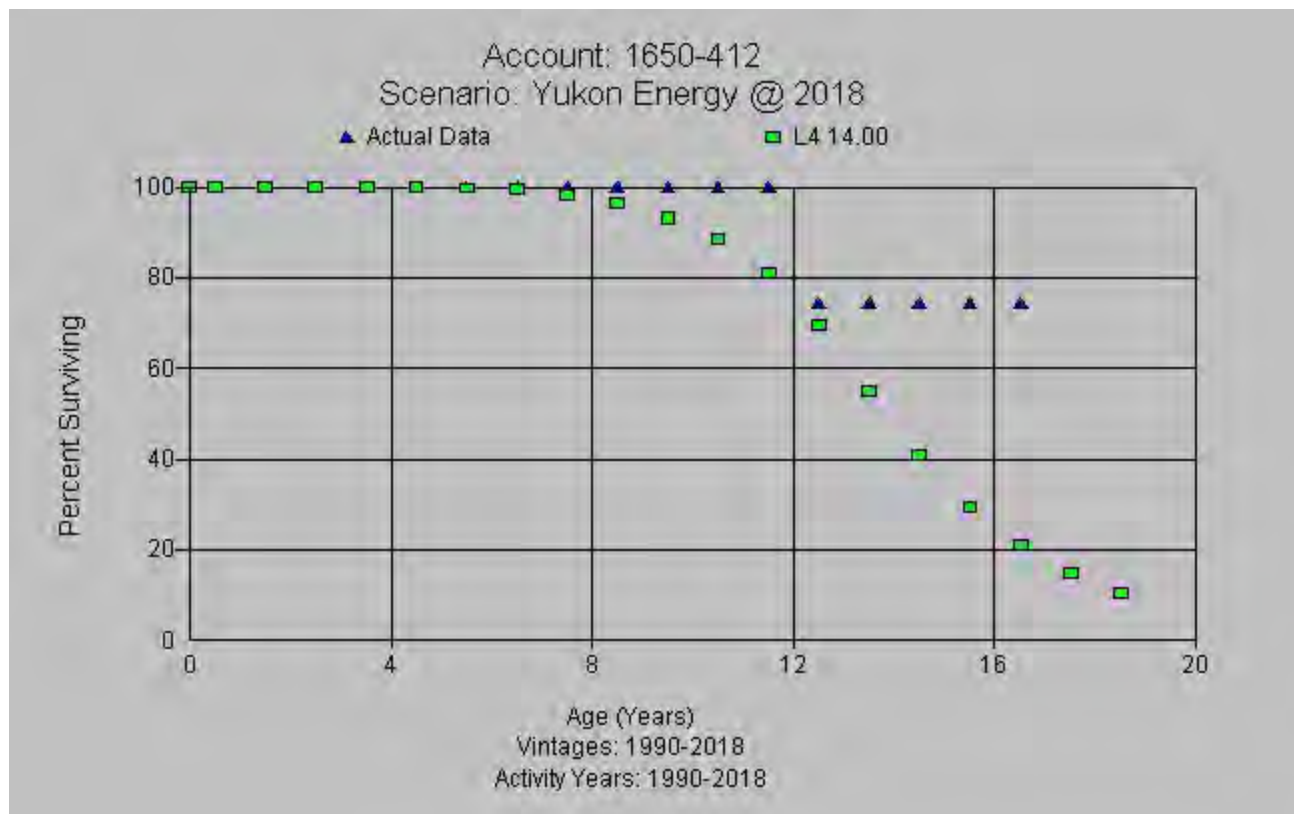
Observation Band: 1990 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	230,388.76	0.00	0.00000	1.00000	100.00
0.5	230,388.76	0.00	0.00000	1.00000	100.00
1.5	230,388.76	0.00	0.00000	1.00000	100.00
2.5	230,388.76	0.00	0.00000	1.00000	100.00
3.5	230,388.76	0.00	0.00000	1.00000	100.00
4.5	145,577.06	0.00	0.00000	1.00000	100.00
5.5	145,577.06	0.00	0.00000	1.00000	100.00
6.5	145,577.06	0.00	0.00000	1.00000	100.00
7.5	145,577.06	0.00	0.00000	1.00000	100.00
8.5	118,637.17	0.00	0.00000	1.00000	100.00
9.5	118,637.17	0.00	0.00000	1.00000	100.00
10.5	118,637.17	0.00	0.00000	1.00000	100.00
11.5	118,637.17	30,343.66	0.25577	0.74423	100.00
12.5	88,293.51	0.00	0.00000	1.00000	74.42
13.5	62,281.51	0.00	0.00000	1.00000	74.42
14.5	62,281.51	0.00	0.00000	1.00000	74.42
15.5	62,281.51	0.00	0.00000	1.00000	74.42
16.5	62,281.51	62,281.51	1.00000	0.00000	74.42
17.5	0.00	0.00	0.00000	1.00000	0.00









Placement Band	Observation Band	<u>Censoring</u>		Error Sum of Squares	<u>Best Fit</u>	
		Age	Percent		Disp	ASL
1980 -1984	1980 -1984		1.00			
1980 -1985	1981 -1985		1.00			
1980 -1986	1982 -1986		1.00			
1980 -1987	1983 -1987		1.00			
1980 -1988	1984 -1988		1.00			
1980 -1989	1985 -1989		1.00			
1980 -1990	1986 -1990		1.00			
1980 -1991	1987 -1991		1.00			
1980 -1992	1988 -1992		1.00			
1980 -1993	1989 -1993		1.00			
1980 -1994	1990 -1994		1.00			
1980 -1995	1991 -1995		1.00			
1980 -1996	1992 -1996		1.00			
1980 -1997	1993 -1997		1.00			
1980 -1998	1994 -1998		1.00			
1980 -1999	1995 -1999		1.00			
1980 -2000	1996 -2000		1.00			
1980 -2001	1997 -2001		1.00			
1980 -2002	1998 -2002		1.00			
1980 -2003	1999 -2003		1.00			
1980 -2004	2000 -2004	10.5	61.76	0.00205090	SQ	10.46
1980 -2005	2001 -2005	11.5	55.06	0.02917074	S5	11.43
1980 -2006	2002 -2006	12.5	55.06	0.05681257	S4	12.18
1980 -2007	2003 -2007	13.5	55.06	0.08222736	S3	13.12
1980 -2008	2004 -2008	14.5	55.06	0.10643770	L3	14.45
1980 -2009	2005 -2009	15.5	0.00	0.04708900	SQ	14.61
1980 -2010	2006 -2010	16.5	0.00	0.00000000	SQ	15.20
1980 -2011	2007 -2011	17.5	0.00	0.00000000	SQ	15.20
1980 -2012	2008 -2012	18.5	0.00	0.00000000	SQ	15.20
1980 -2013	2009 -2013	19.5	0.00	0.00000000	SQ	15.20
1980 -2014	2010 -2014		1.00			

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Placement Band	Observation Band	<u>Censoring</u>		Error Sum of Squares	<u>Best Fit</u>	
		Age	Percent		Disp	ASL
1980 -2015	2011 -2015	21.5	0.00	0.00000000	SQ	16.20
1980 -2016	2012 -2016	22.5	0.00	0.00000000	SQ	12.20
1980 -2017	2013 -2017	23.5	0.00	0.18016947	S4	13.90
1980 -2018	2014 -2018	24.5	0.00	0.18016947	S4	13.90

Actuarial Life Analysis

Account: 1650-412
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	<u>Censoring</u>		Error Sum of Squares	<u>Best Fit</u>	
	Age	Percent		Disp	ASL
1980 -2018	38.5	0.00	0.18800405	L3	20.06
1985 -2018	38.5	0.00	0.18800405	L3	20.06
1990 -2018	38.5	0.00	0.18800405	L3	20.06
1995 -2018	38.5	0.00	0.17621727	L3	19.26
2000 -2018	38.5	0.00	0.24650638	R5	15.77
2005 -2018	38.5	0.00	0.24650638	R5	15.77
2010 -2018	38.5	0.00	0.24650638	R5	15.77
2015 -2018		0.00			

1 **REFERENCE:** **Application, Tab 9, Depreciation Study, pages 9-84 and 9-105**

2
3 **ISSUE:** **Depreciation expense**

4
5 **QUOTE:** “Account 1650-420 Trxptn – Trucks and Pole Trailers 25 R1.5
6 This account includes the cost of large trucks and pole trailers that carry
7 less than 10,000 lbs. The plant balance in this account at December
8 31, 2018 is \$11 thousand. The approved life and curve for this account
9 is 25 R1.5. Discussions with Company personnel indicated the existing
10 25 year life is reasonable for the assets. There is no historical
11 experience to analyze. Giving consideration to the type of assets,
12 existing life, Company expectations, and judgment, this study proposes
13 retention of the 25 R1.5 at this time.”

14
15 **QUESTION:**

- 16
17 a) Given that page 9-105 indicates an existing 31-R1.5 life and curve, please clarify
18 which is the correct approved depreciation parameters and confirm that YEC
19 continues to propose a 25-R1.5 life and curve for this account.

20
21 **ANSWER:**

22
23 **(a)**

24
25 The current approved life for this account is 25 years with a R1.5 dispersion. The
26 information on page 105 should be corrected to 25 R1.5. YEC is proposing to retain that
27 curve and life for this account.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-86**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1650-440 Trxptn – Trucks $\frac{3}{4}$ to 2 Tons 9 L2
6 This account includes the cost of trucks that are $\frac{3}{4}$ to 2 Tons used by
7 employees to perform day to day duties. The plant balance in this
8 account at December 31, 2018 is \$2.6 million. The approved life and
9 curve for this account is 10 R2. Discussions with Company personnel
10 indicated that electricians would drive 90,000 and operations 70,000 in
11 approximately 10 years. Linemen would drive 115,000 and would hit
12 the maximum mileage in 3-4 years but there are other factors that
13 cause the Company to retain these vehicles longer. There are equal
14 numbers of each type of vehicle. Company expects they will be
15 replaced by 8 years. However, the life analysis indicates a life between
16 10 to 11 years. Giving consideration to Company policy, recent
17 experience, expectations and judgment, this study proposes moving
18 from 10 R2 to 9 L2 at this time."

19
20 **QUESTION:**

- 21
- 22 a) Please provide the "life analysis indicat[ing] a life between 10 to 11 years".
- 23
- 24 b) If the life analysis discussed in part (a) above was not based on actuarial data,
25 please clarify how YEC is able to propose a change to a 9-L2 life and curve from
26 the approved 10-R2 life and curve without the benefit of an actuarial life analysis.
- 27
- 28 c) Please provide the directional impact of the change proposed in terms of an
29 increase or decrease to depreciation expense for this account for the year 2021.
- 30
- 31 d) Please provide an observed life table and the plotted actual data points showing
32 both a 9-L2 and 10-R2 survivor curve for this account.

1 **ANSWER:**

2
3 **(a) and (b)**

4
5 The actuarial analysis for this account is provided as Attachment 1 to this response.

6
7 **(c)**

8
9 As the Depreciation Study proposes to decrease the life of asset class from 10 years to 9
10 years, the directional impact on 2021 depreciation expense is an increase.

11
12 **(d)**

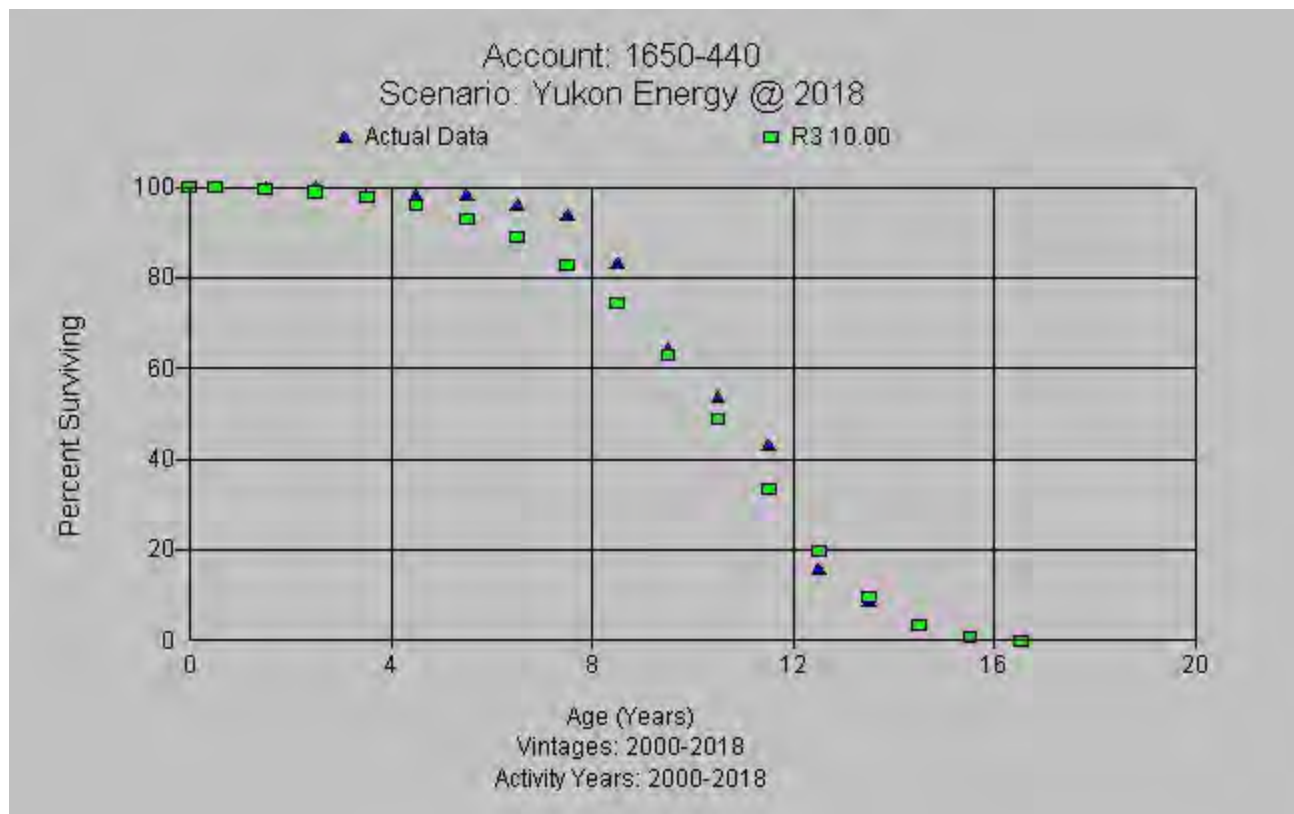
13
14 The data provided as YUB-YEC-1-136(a) Attachment 1 give the requested plot as well as
15 the Iowa curves propounded in the question. It should be noted that the movement to a 9
16 L2 was based on operational feedback from company SMEs related to recent operations
17 and would not necessarily be fully reflected in the long-term (20-year) historical actuarial
18 analysis.

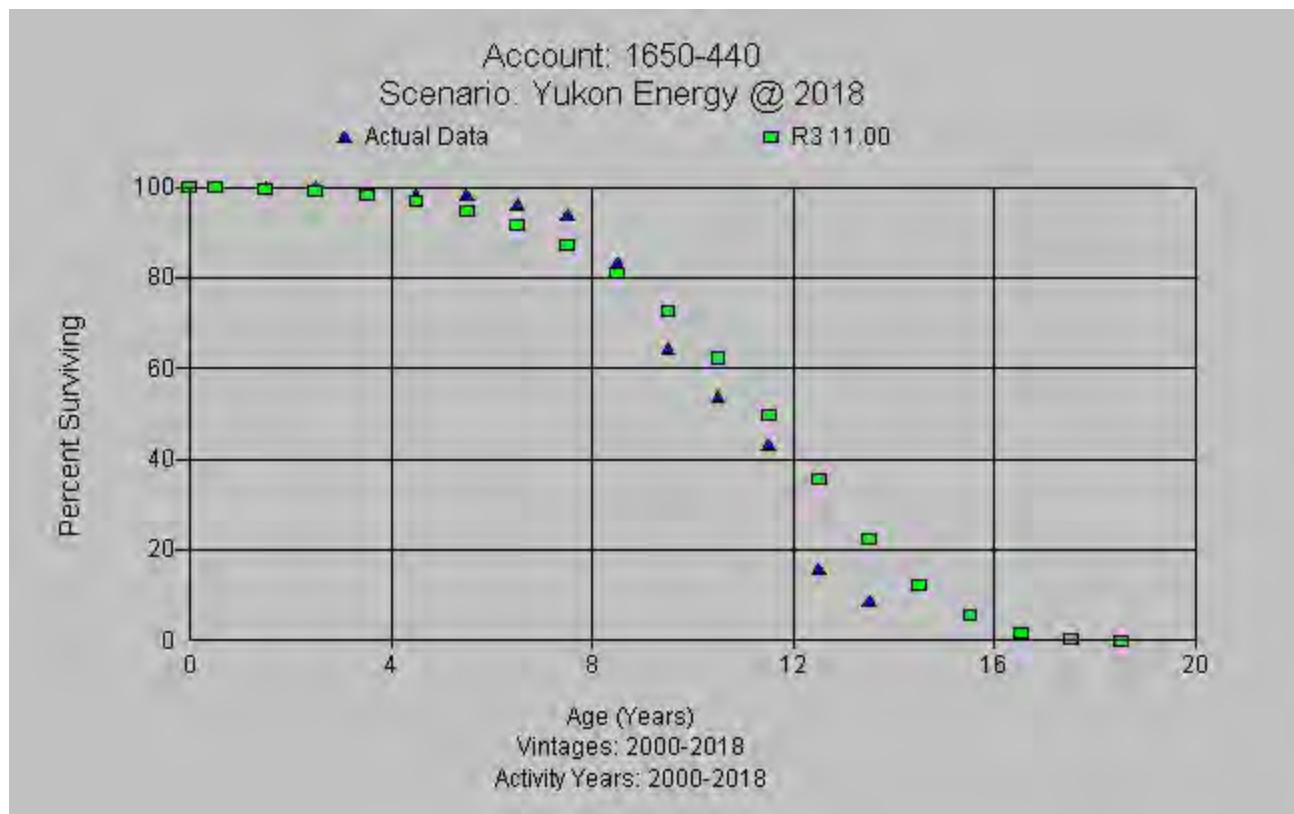
Observed Life Table

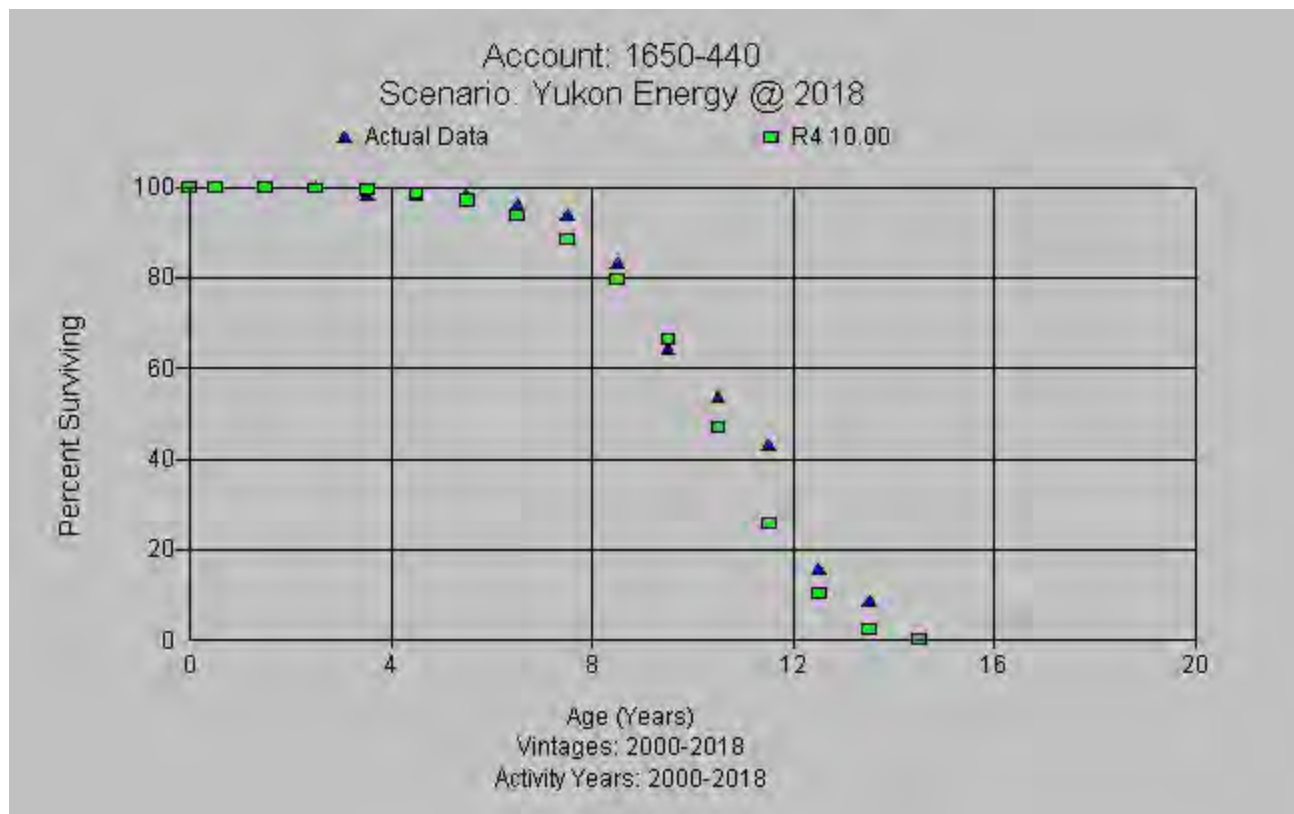
Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 2000 - 2018

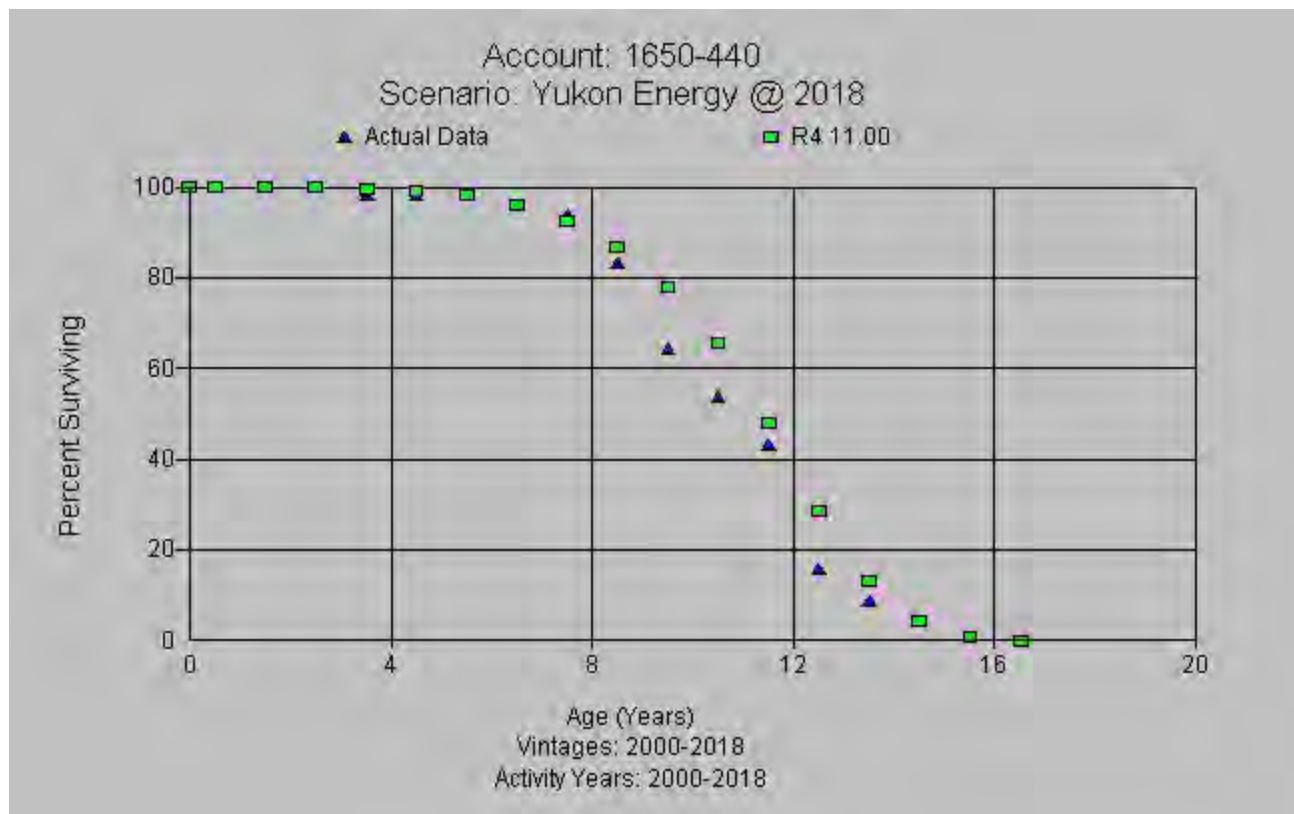
Observation Band: 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,271,334.92	0.00	0.00000	1.00000	100.00
0.5	4,062,392.91	0.00	0.00000	1.00000	100.00
1.5	3,870,565.79	0.00	0.00000	1.00000	100.00
2.5	3,467,190.96	58,633.84	0.01691	0.98309	100.00
3.5	3,078,687.98	1,679.77	0.00055	0.99945	98.31
4.5	2,910,388.95	0.00	0.00000	1.00000	98.26
5.5	2,618,780.95	61,456.44	0.02347	0.97653	98.26
6.5	2,420,767.51	49,192.00	0.02032	0.97968	95.95
7.5	2,106,627.22	238,926.04	0.11342	0.88658	94.00
8.5	1,492,087.54	340,973.61	0.22852	0.77148	83.34
9.5	1,151,113.93	188,671.58	0.16390	0.83610	64.29
10.5	759,094.23	152,182.98	0.20048	0.79952	53.76
11.5	535,081.39	337,715.98	0.63115	0.36885	42.98
12.5	197,365.41	89,067.71	0.45128	0.54872	15.85
13.5	108,297.70	108,297.70	1.00000	0.00000	8.70
14.5	0.00	0.00	0.00000	1.00000	0.00







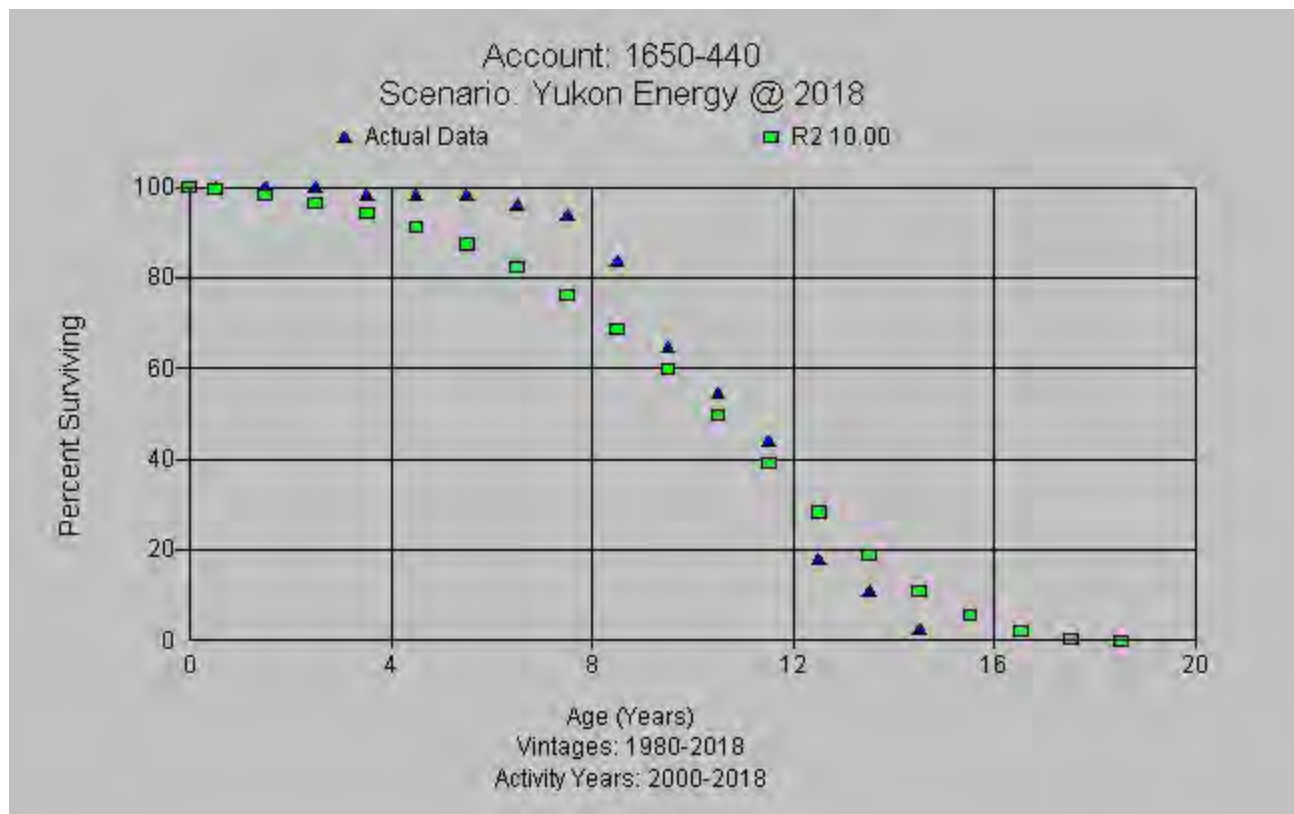


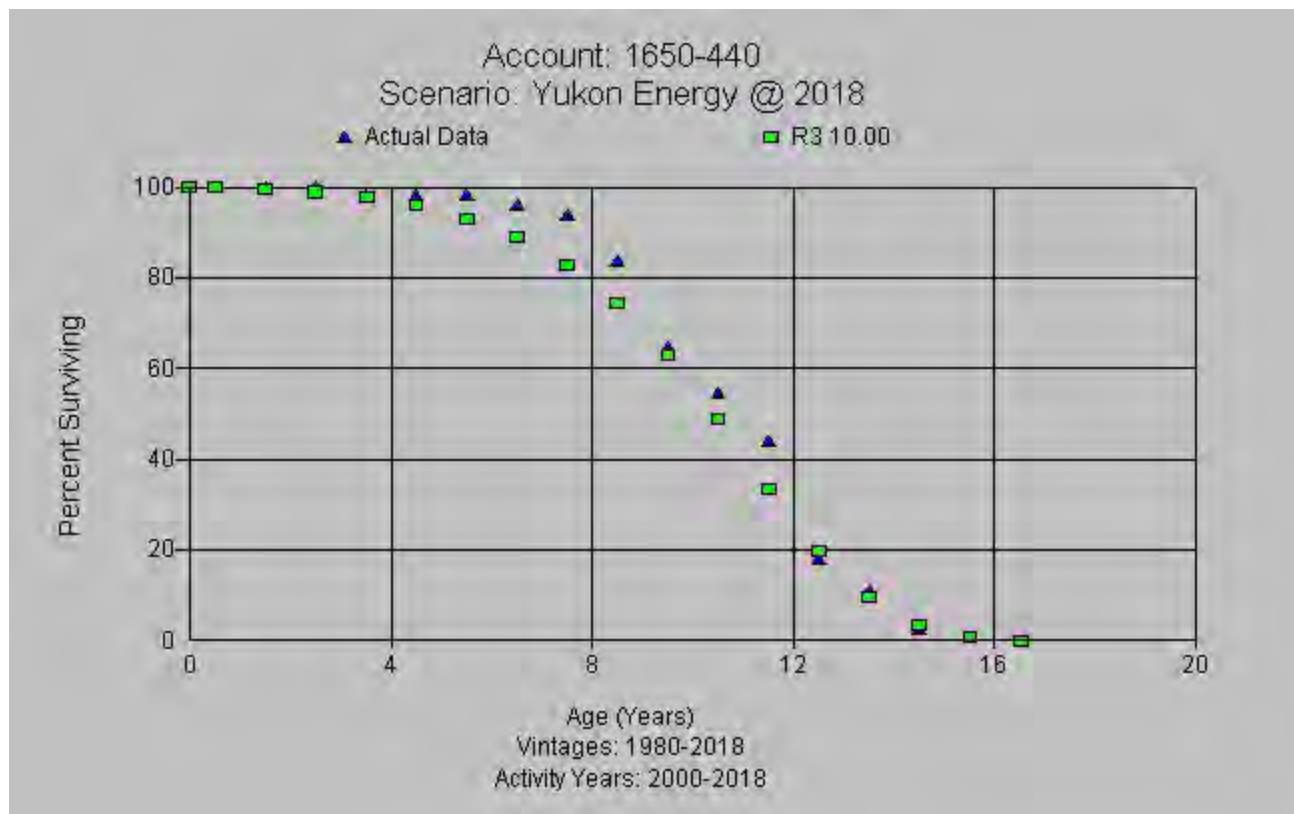
Observed Life Table

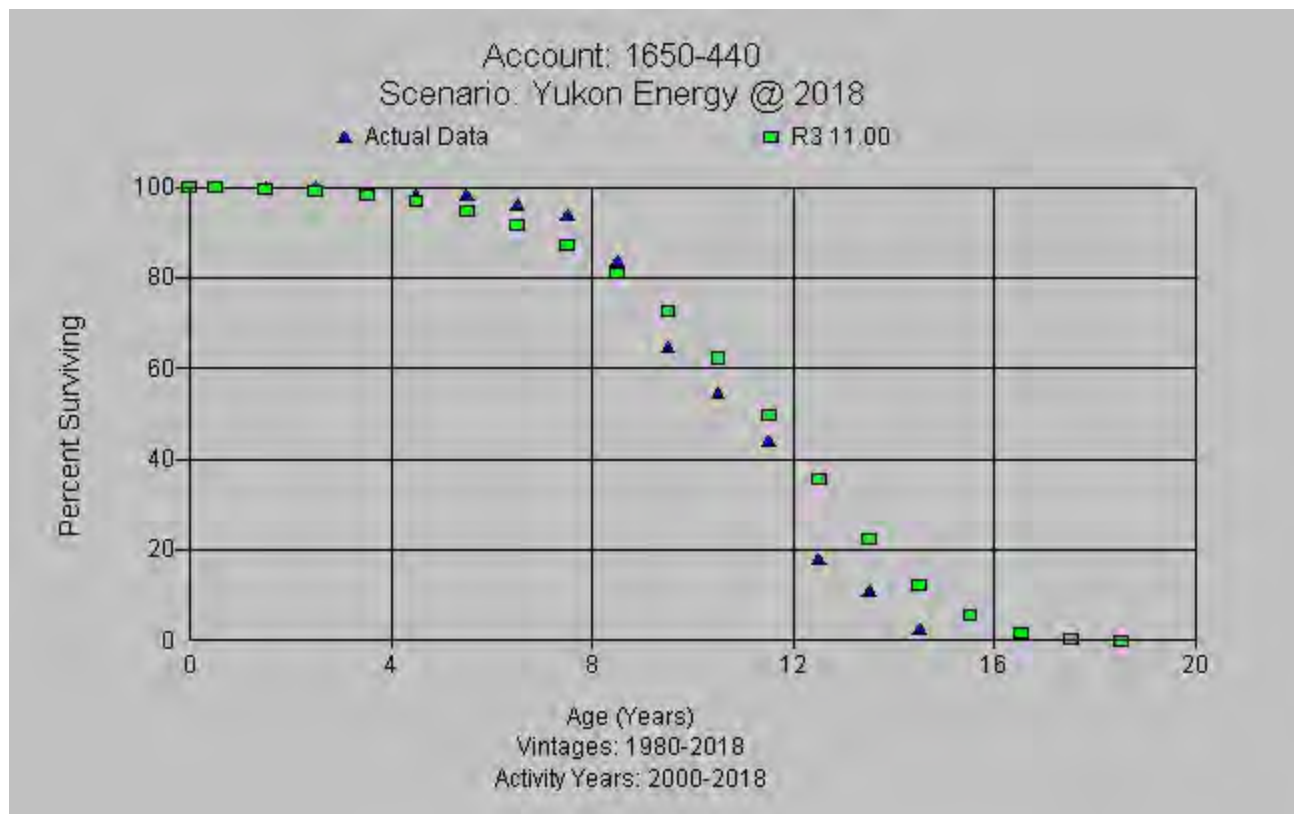
Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 1980 - 2018

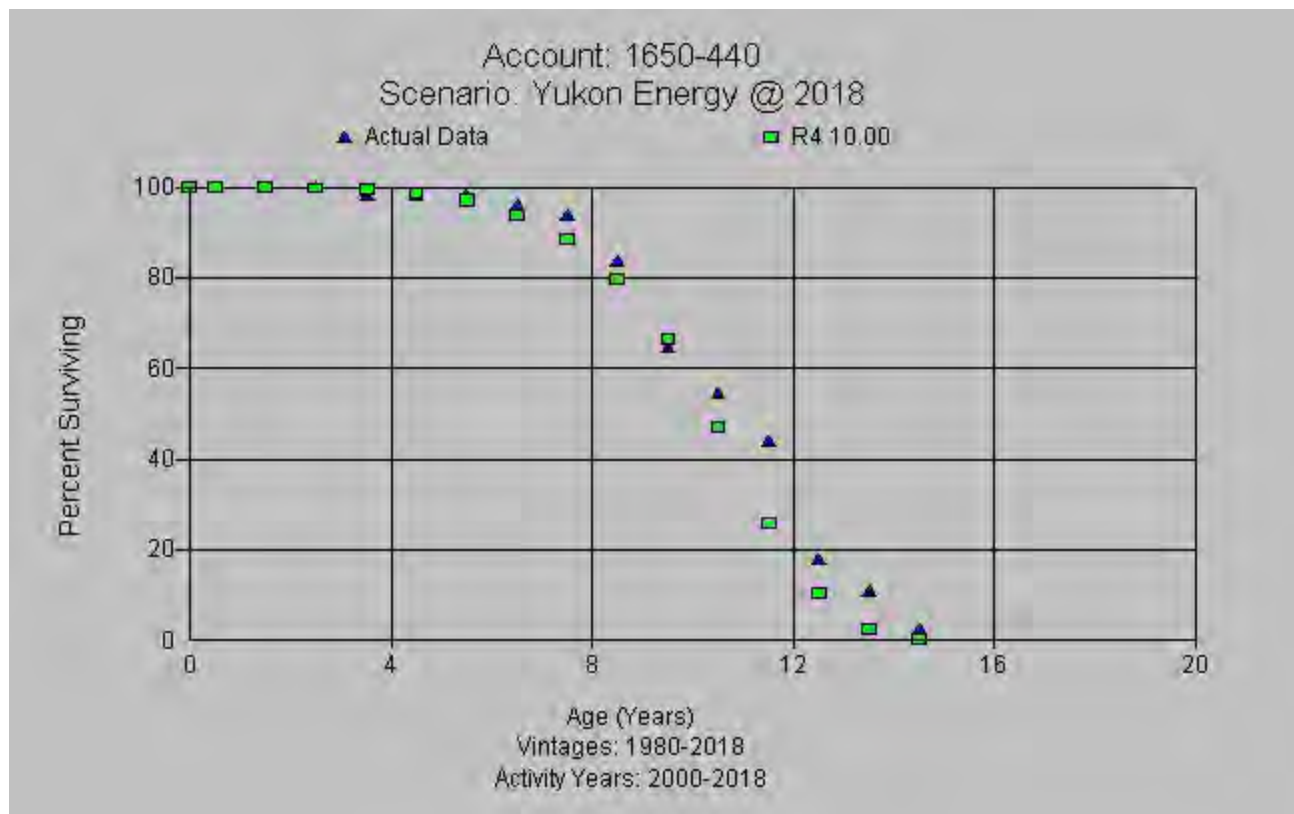
Observation Band: 2000 - 2018

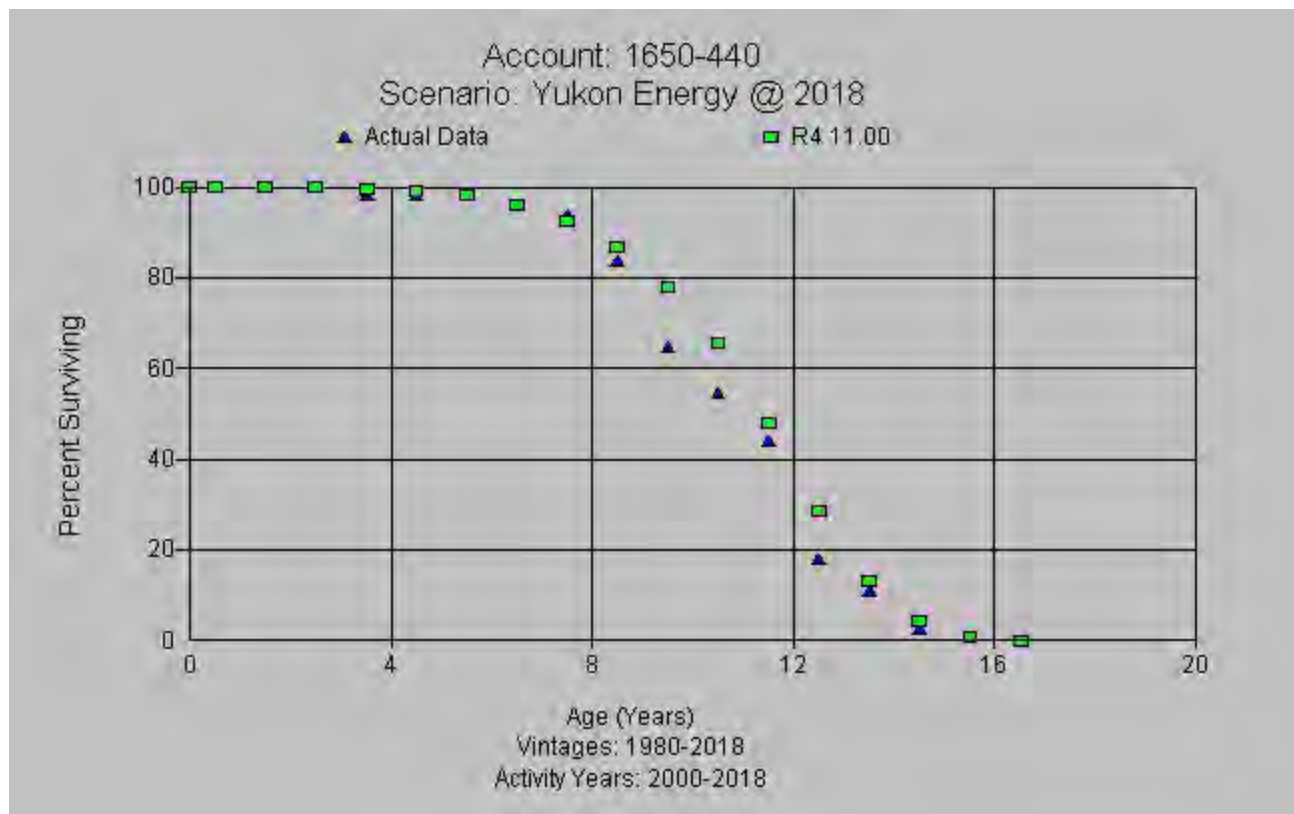
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,271,334.92	0.00	0.00000	1.00000	100.00
0.5	4,062,392.91	0.00	0.00000	1.00000	100.00
1.5	3,904,185.71	0.00	0.00000	1.00000	100.00
2.5	3,500,810.88	58,633.84	0.01675	0.98325	100.00
3.5	3,112,307.90	1,679.77	0.00054	0.99946	98.33
4.5	2,944,008.87	0.00	0.00000	1.00000	98.27
5.5	2,652,400.87	61,456.44	0.02317	0.97683	98.27
6.5	2,454,387.43	49,192.00	0.02004	0.97996	96.00
7.5	2,140,247.14	238,926.04	0.11163	0.88837	94.07
8.5	1,526,410.46	340,973.61	0.22338	0.77662	83.57
9.5	1,189,235.85	189,374.58	0.15924	0.84076	64.90
10.5	796,513.15	152,182.98	0.19106	0.80894	54.57
11.5	572,500.31	341,514.98	0.59653	0.40347	44.14
12.5	230,985.33	89,067.71	0.38560	0.61440	17.81
13.5	141,917.62	108,297.70	0.76310	0.23690	10.94
14.5	33,619.92	33,619.92	1.00000	0.00000	2.59
15.5	0.00	0.00	0.00000	1.00000	0.00
16.5	0.00	0.00	0.00000	1.00000	
17.5	0.00	0.00	0.00000	1.00000	
18.5	0.00	0.00	0.00000	1.00000	
19.5	171,495.34	0.00	0.00000	1.00000	
20.5	171,495.34	0.00	0.00000	1.00000	
21.5	171,495.34	0.00	0.00000	1.00000	
22.5	171,495.34	39,180.95	0.22847	0.77153	
23.5	132,314.39	0.00	0.00000	1.00000	
24.5	132,314.39	132,314.39	1.00000	0.00000	
25.5	0.00	0.00	0.00000	1.00000	









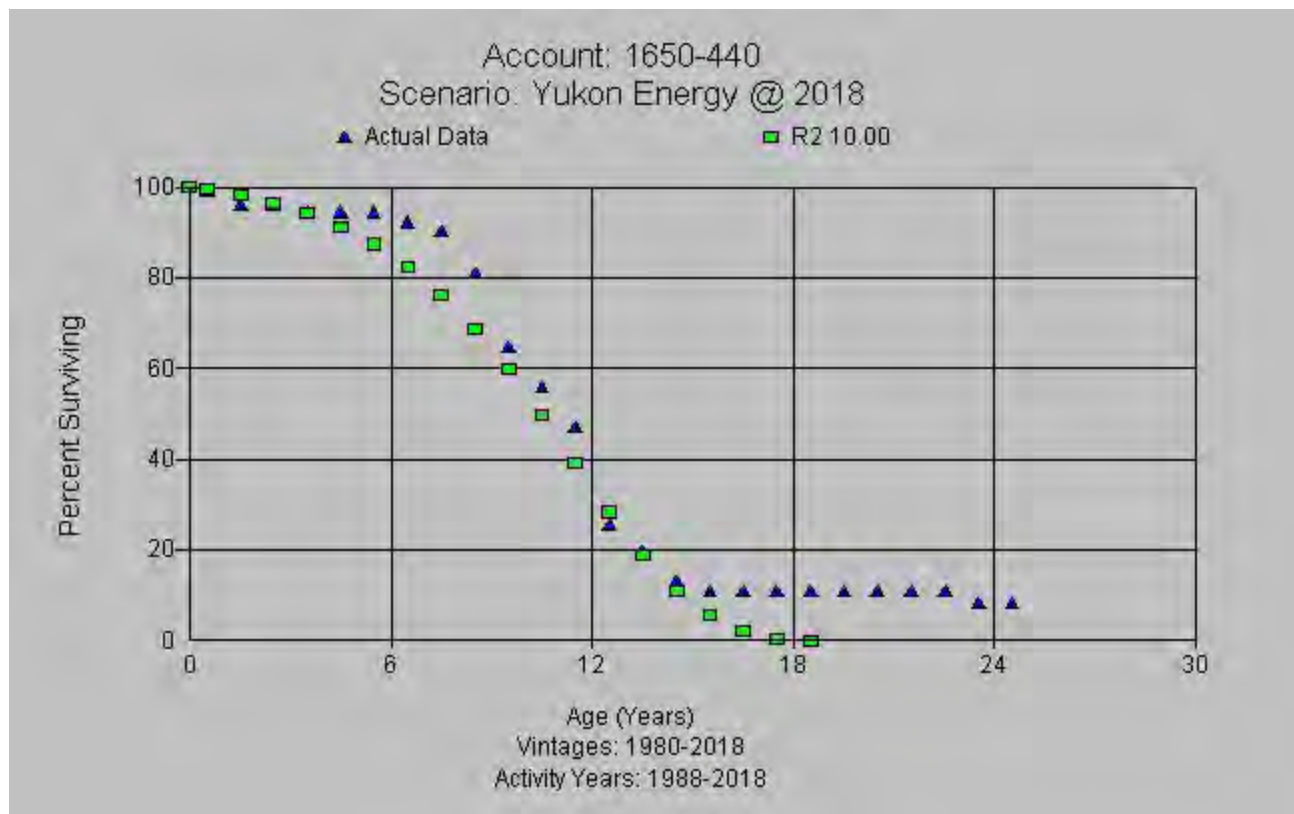


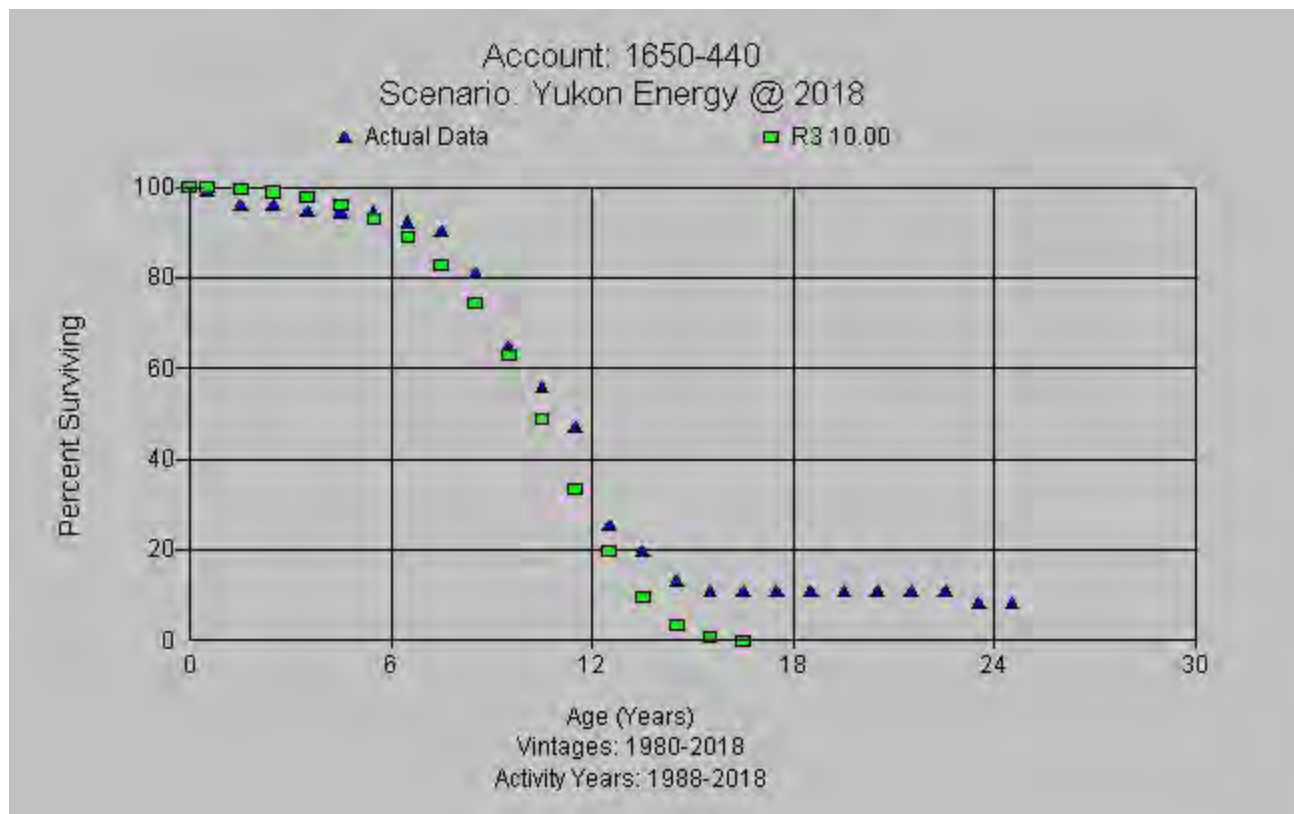
Observed Life Table

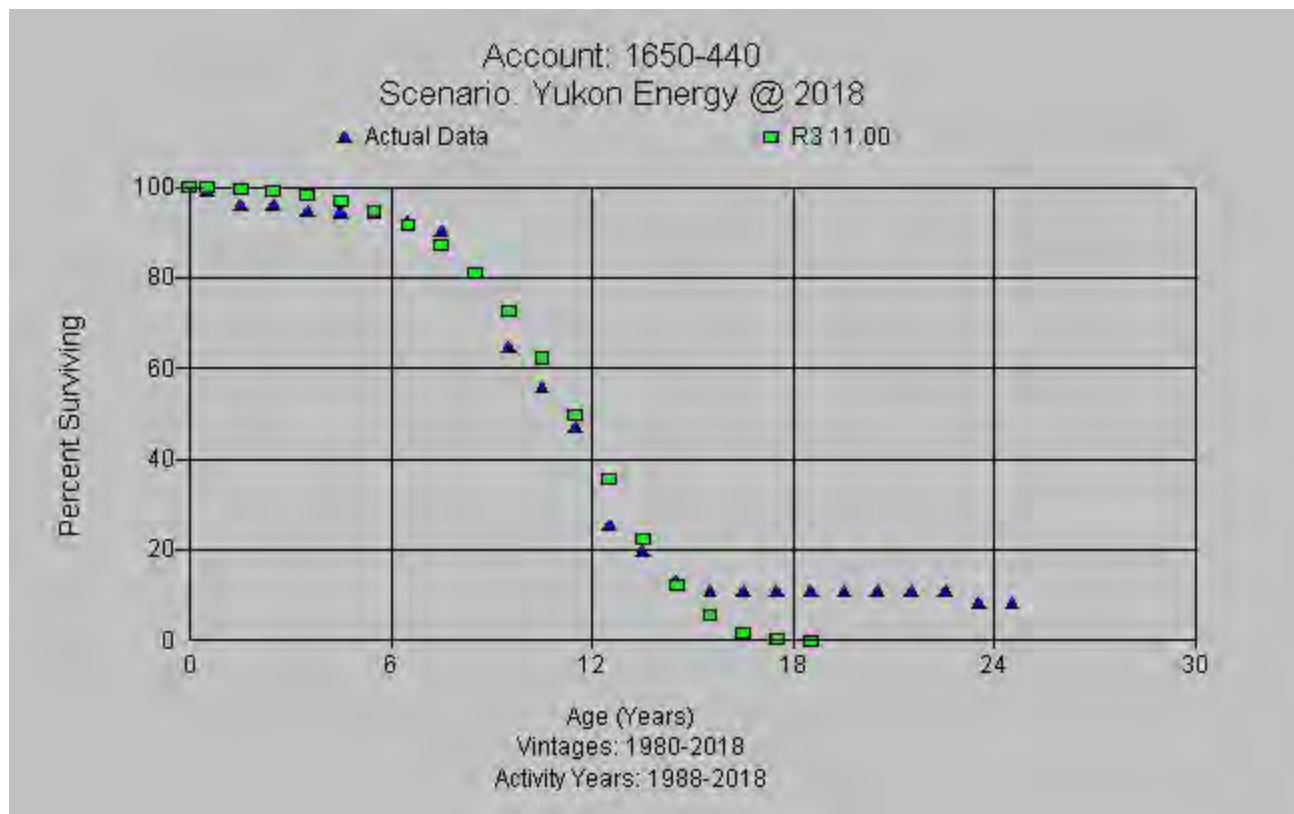
Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 1980 - 2018

Observation Band: 1988 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,472,283.84	39,576.00	0.00885	0.99115	100.00
0.5	4,223,765.83	123,251.00	0.02918	0.97082	99.12
1.5	3,908,687.71	0.00	0.00000	1.00000	96.22
2.5	3,505,312.88	58,633.84	0.01673	0.98327	96.22
3.5	3,116,809.90	1,679.77	0.00054	0.99946	94.61
4.5	2,948,510.87	0.00	0.00000	1.00000	94.56
5.5	2,656,902.87	61,456.44	0.02313	0.97687	94.56
6.5	2,458,889.43	49,192.00	0.02001	0.97999	92.38
7.5	2,316,244.48	238,926.04	0.10315	0.89685	90.53
8.5	1,701,704.80	340,973.61	0.20037	0.79963	81.19
9.5	1,360,731.19	189,374.58	0.13917	0.86083	64.92
10.5	968,008.49	152,182.98	0.15721	0.84279	55.89
11.5	743,995.65	341,514.98	0.45903	0.54097	47.10
12.5	402,480.67	89,067.71	0.22130	0.77870	25.48
13.5	313,412.96	108,297.70	0.34554	0.65446	19.84
14.5	205,115.26	33,619.92	0.16391	0.83609	12.99
15.5	171,495.34	0.00	0.00000	1.00000	10.86
16.5	171,495.34	0.00	0.00000	1.00000	10.86
17.5	171,495.34	0.00	0.00000	1.00000	10.86
18.5	171,495.34	0.00	0.00000	1.00000	10.86
19.5	171,495.34	0.00	0.00000	1.00000	10.86
20.5	171,495.34	0.00	0.00000	1.00000	10.86
21.5	171,495.34	0.00	0.00000	1.00000	10.86
22.5	171,495.34	39,180.95	0.22847	0.77153	10.86
23.5	132,314.39	0.00	0.00000	1.00000	8.38
24.5	132,314.39	132,314.39	1.00000	0.00000	8.38
25.5	0.00	0.00	0.00000	1.00000	0.00







Observed Life Table

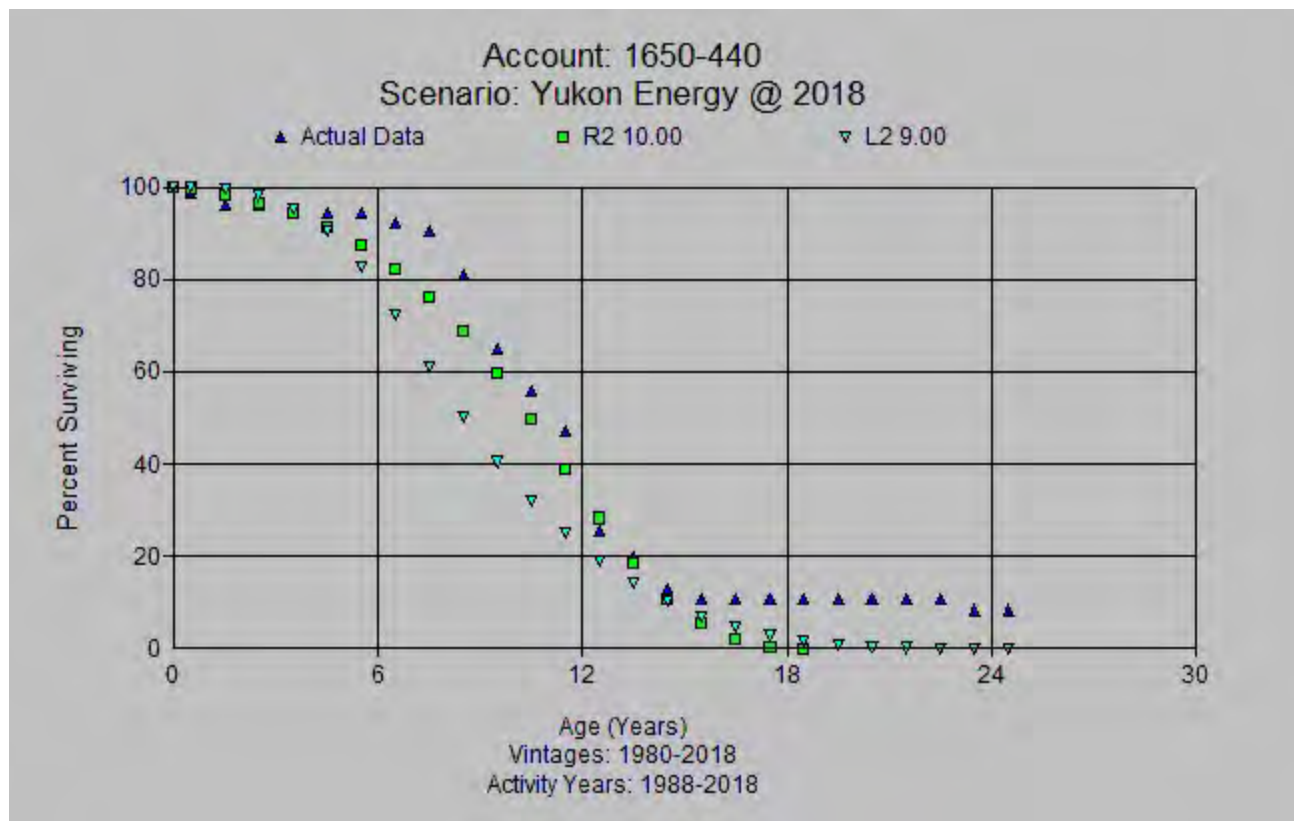
Scenario: Yukon Energy @ 2018

Account: 1650-440

Placement Band: 1980 - 2018

Observation Band: 1988 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,472,283.84	39,576.00	0.00885	0.99115	100.00
0.5	4,223,765.83	123,251.00	0.02918	0.97082	99.12
1.5	3,908,687.71	0.00	0.00000	1.00000	96.22
2.5	3,505,312.88	58,633.84	0.01673	0.98327	96.22
3.5	3,116,809.90	1,679.77	0.00054	0.99946	94.61
4.5	2,948,510.87	0.00	0.00000	1.00000	94.56
5.5	2,656,902.87	61,456.44	0.02313	0.97687	94.56
6.5	2,458,889.43	49,192.00	0.02001	0.97999	92.38
7.5	2,316,244.48	238,926.04	0.10315	0.89685	90.53
8.5	1,701,704.80	340,973.61	0.20037	0.79963	81.19
9.5	1,360,731.19	189,374.58	0.13917	0.86083	64.92
10.5	968,008.49	152,182.98	0.15721	0.84279	55.89
11.5	743,995.65	341,514.98	0.45903	0.54097	47.10
12.5	402,480.67	89,067.71	0.22130	0.77870	25.48
13.5	313,412.96	108,297.70	0.34554	0.65446	19.84
14.5	205,115.26	33,619.92	0.16391	0.83609	12.99
15.5	171,495.34	0.00	0.00000	1.00000	10.86
16.5	171,495.34	0.00	0.00000	1.00000	10.86
17.5	171,495.34	0.00	0.00000	1.00000	10.86
18.5	171,495.34	0.00	0.00000	1.00000	10.86
19.5	171,495.34	0.00	0.00000	1.00000	10.86
20.5	171,495.34	0.00	0.00000	1.00000	10.86
21.5	171,495.34	0.00	0.00000	1.00000	10.86
22.5	171,495.34	39,180.95	0.22847	0.77153	10.86
23.5	132,314.39	0.00	0.00000	1.00000	8.38
24.5	132,314.39	132,314.39	1.00000	0.00000	8.38
25.5	0.00	0.00	0.00000	1.00000	0.00



Actuarial Life Analysis

Account: 1650-440
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1992
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	<u>Censoring</u>		Error Sum of Squares	<u>Best Fit</u>	
	Age	Percent		Disp	ASL
1988 -1992	10.5	10.21	0.68975718	L0	1.35
1989 -1993		1.00			
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999	15.5	21.43	1.15483505	L0	4.25
1996 -2000	16.5	21.43	1.20337491	L0	4.37
1997 -2001	17.5	65.85	0.27806821	R0.5	14.72
1998 -2002	18.5	0.00	0.29725330	R3	8.41
1999 -2003	19.5	0.00	0.29725330	R3	8.41
2000 -2004	20.5	0.00	0.15361943	SQ	9.45
2001 -2005	21.5	0.00	0.03698002	SQ	7.62
2002 -2006	22.5	0.00	0.04150302	SQ	9.51
2003 -2007	23.5	0.00	0.38836051	R5	19.30
2004 -2008	24.5	0.00	0.78600263	R4	18.78
2005 -2009	25.5	0.00	0.00000000	SQ	21.20
2006 -2010		1.00			
2007 -2011		1.00			
2008 -2012	28.5	39.78	0.51553728	L0.5	20.07
2009 -2013	29.5	0.00	0.02862725	R4	11.52
2010 -2014	30.5	0.00	0.02702481	R4	10.95
2011 -2015	31.5	0.00	0.05330391	L4	9.64
2012 -2016	32.5	0.00	0.03623875	L4	9.72
2013 -2017	33.5	0.00	0.00486246	L5	9.42
2014 -2018	34.5	0.00	0.01958660	S4	9.97

Actuarial Life Analysis

Account: 1650-440
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	<u>Censoring</u>		Error Sum of Squares	<u>Best Fit</u>	
	Age	Percent		Disp	ASL
1988 -2018	38.5	0.00	0.08881781	L3	11.74
1993 -2018	38.5	0.00	0.07852830	L3	11.20
1998 -2018	38.5	0.00	0.02058427	R3	10.40
2003 -2018	38.5	0.00	0.01535568	R4	10.68
2008 -2018	38.5	0.00	0.01783253	R4	10.74
2013 -2018	38.5	0.00	0.01871452	S4	9.78
2018 -2018		1.00			

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-88**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1650-490 Trxptn – Foremost 20 R3
6 This account includes the cost of large specialty vehicles which are
7 usually tracked not wheeled vehicles. The plant balance in this account
8 at December 31, 2018 is \$1.0 million. The approved life for this account
9 is 25 years. Discussions with Company personnel indicated that there
10 is one tracked vehicle and a 2011 Kenworth truck equipped with an
11 auger. Company personnel believe the life should match the life of the
12 greater than 3 ton trucks of 20 years. There is no historical experience
13 to analyze. Giving consideration to type of assets, Company input and
14 expectations and judgment, this study proposes moving to 20 R3 at this
15 time."
16

17 **QUESTION:**

- 18
19 a) Please explain why the life of the tracked vehicle should match that of the Kenworth
20 truck.
21
22 b) Please clarify whether there have been any overhauls to either vehicle that would
23 be expected to increase average service life at the time they were carried out.
24 Please explain fully.
25
26 c) Please clarify whether there had been an Iowa Curve previously approved for this
27 account and, if so, please provide that value.
28

29 **ANSWER:**

30
31 **(a)**

32
33 There have been no retirements in this account, so it was not possible to perform any
34 actuarial life analysis. In the opinion of Company personnel, that asset was a reasonable
35 proxy for items in this account.

1 **(b)**

2
3 There has been no overhaul to the tracked vehicle. However, a complete service on this
4 unit was performed in 2017. Other than that, it has just received regular servicing as
5 considered necessary.

6
7 The 2011 Kenworth had its 10-year overhaul in 2019. This consisted of overhaul service
8 on the boom and outriggers. Other than that, it has just received regular servicing as
9 considered necessary.

10
11 **(c)**

12
13 In the last depreciation study, no Iowa curve was specified.

1 **REFERENCE:** Application, Tab 9, Depreciation Study, page 9-92

2
3 **ISSUE:** Depreciation Expense

4
5 **QUOTE:** "Account 1665-403 LNG Plant – Fuel Holders 60 R2
6 This account includes the installed cost of fuel handling and storage
7 equipment used between the point of fuel delivery to the station and the
8 intake pipe including boilers, pumps, produces, regenerators, tanks,
9 and vaporizers. The plant balance in this account at December 31,
10 2018 is \$13.2 million. The approved life for this account is 32 years.
11 The assets are new so there is limited historical data. Discussions with
12 Company personnel indicated the tanks are nickel, double walled with
13 no moisture ingress. The existing fuel holder life of 32 years is
14 considered to be low and with reasonable maintenance, a 60 year life
15 is expected. Considering the type of assets, information provided by
16 Company personnel and judgment, this study recommends moving the
17 life to 60 years with the R2 for this account."
18

19 **PREAMBLE:** YEC is proposing a significant increase (of 28 years) in average service
20 life for this account.
21

22 **QUESTION:**

- 23
24 a) Please provide any objective evidence such as manufacturers' information
25 available to YEC that further supports the increase (of 28 years) in average service
26 life for this account.
27

28 **ANSWER:**

29
30 **(a)**

31
32 The designer of the LNG skid has stated:

- 33
34 • 10+ years ago we moved large high pressure ASME vessels (non-cryogenic) built
35 in the 1960's for the race to the moon to the NASA Marshall Space Center that are
36 still in service (50 years).

1 • I recall seeing ASME cryogenic vessels built in the 1980's still in service but could
2 not recall where. (40 years).

3

4 • The first LNG tank install I was involved with was 1999 and it is still in-service w/o
5 any issues. (22 years).

6

7 From an engineering perspective, LNG is noncorrosive to stainless steel, so as long as
8 the tank is maintained properly, it should last 60 years.

1 **REFERENCE: Application, Tab 9, Depreciation Study, page 9-93**

2
3 **ISSUE: Depreciation Expense**

4
5 **QUOTE:** "Account 1665-500 LNG Plant – Generators 40 SQ
6 This account includes the installed cost of other prime movers including
7 engines, piping, air-filtering system, towers, pumps, hoists,
8 compressors, tanks, waste heat boilers, antiluctuators and other
9 related equipment. The plant balance in this account at December 31,
10 2018 is \$20.9 million. The approved life for this account is 40 years.
11 The assets are new so there is limited historical data. Discussions with
12 Company personnel indicated the current life is still applicable for this
13 account. Considering the type of assets, information provided by
14 Company personnel and judgment, this study retaining the life of 40
15 years and using a SQ dispersion for this account."
16

17 **QUESTION:**

- 18
19 a) Given that no other LNG asset class (within the 1665 series) has incorporated the
20 use of a SQ curve, please explain why, for Account 1665-500 LNG Plant –
21 Generators, it is appropriate to maintain an SQ curve as opposed to the R2 curve
22 used for all other LNG accounts.
23

24 **ANSWER:**

25
26 **(a)**

27
28 No historical analytical information existed to determine a specific retirement dispersion
29 for LNG generators and an SQ dispersion was assigned. In retrospect, modeling this
30 account in the same way as Account 1620-500 – Diesel Generators and Prime Movers
31 (40 R2) would also have been a reasonable approach. Using the R2 dispersion would
32 have slightly increased the depreciation expense for the 1665-500 account.

REFERENCE: Application, Tab 9, Depreciation Study, pages 9-22, 9-24, 9-69 and 9-102; Tab 7, Schedule 3A, Calculation of depreciation expense for Hydro overhauls and Diesel production overhauls, page 7-6

ISSUE: Depreciation Expense

Note: The following accounts were excluded from the depreciation study:

1615-504 Hydro Assets Overhaul

1620-504 Diesel Assets Overhaul

1620-504 Diesel Assets Overhaul

Asset 7060 removed from asset group 1615-506

Asset 8856 transferred from asset group 1645-200 to 1615-201

QUOTE: Note: The following accounts were excluded from the depreciation study:
1615-504 Hydro Assets Overhaul
1620-504 Diesel Assets Overhaul
1620-504 Diesel Assets Overhaul
Asset 7060 removed from asset group 1615-506
Asset 8856 transferred from asset group 1645-200 to 1615-201

PREAMBLE: Tab 7, Schedule 3A indicates that amortization periods for Hydro overhauls, Diesel production overhauls and LNG production overhauls are 10, five, and two years respectively.

QUESTION:

- a) Please confirm that the amortization periods for Hydro overhauls, Diesel production overhauls and LNG production overhauls of 10, five and two years respectively, as shown on Tab 7, Schedule 3A, remain valid.
- b) Referring to part (a) above, please explain how each of the amortization periods was determined and what specifically is proposed to be overhauled under each Hydro, Diesel and LNG category.
- c) Please identify Asset 7060, its historical cost, and why it is necessary to remove it from asset group 1615-506 (Hydro-Wtrwhls, Trbines & Gen's) on Tab 7, Schedule 3A given that there is no indication on page 9-24 (Hydro-Wtrwhls, Trbines & Gen's) of YEC's Tab 9, Depreciation Study that any asset was excluded from consideration in the depreciation study for Account 1615-506.

1 i. Please clarify if Asset 7060 is depreciable and, if so, provide a complete
2 reference to where the basis for its depreciation and related depreciation
3 expense amount for 2021 can be confirmed within YEC's supporting Tabs;
4 and

5
6 ii. If part (b)(i) above confirms that Asset 7060 is not depreciable, please
7 confirm that Asset 7060 is not included in the \$26,904.6 thousand cost at
8 2021 year end as shown on Tab 7, Schedule 3A for the Waterwheels,
9 Turbines & Generation account and clarify whether or not Asset 7060 forms
10 a component of rate base that is subject to a return calculation.

11
12 d) Please identify Asset 8856 and confirm that it is the elevator at Aishihik Hydro plant
13 discussed on pages 9-22 (Hydro Buildings and Improvements) and 9-69 (Bldg &
14 ltr – Structures and Improvements Hydro) of YEC's Tab 9, Depreciation Study.

15
16 **ANSWER:**

17
18 **(a)**

19
20 Confirmed.

21
22 **(b)**

23
24 Hydro and Diesel overhauls were approved in previous GRA's and YEC has no basis for
25 requesting a change to these amortization periods.

26
27 LNG overhauls were rounded to 2 years based on an analysis of expected LNG run-time
28 and scheduled overhauls. LNG generation is relatively new to YEC and run-time is
29 weather dependent so it may be appropriate to perform additional analysis in the future.

30
31 **(c)**

32
33 Asset 7060 is Whitehorse WH4 Overhaul performed in 2007. Rather than a Hydro-
34 Wtrwhls, Trbines & Gen's category, it is more appropriately classified as an Overhaul and
35 subject to the hydro overhaul amortization period. This Overhaul is fully amortized, so the
36 net book value is \$0. There is no amortization forecast in 2021.

1 **(d)**

2

3 Asset 8856 is the Aishihik Elevator Shaft Structural Steel Rehabilitation as discussed on
4 pages 9-22 (Hydro Buildings and Improvements) and 9-69 (Bldg & Itr – Structures and
5 Improvements Hydro) of YEC's Tab 9, Depreciation Study.

1 **REFERENCE:** Application, Section 3.4, Table 3.14.3, page 3-24; and Appendix
2 5.2, Section 5.2-5, Overhauls & reserve for site restoration
3 projects, page 5.2-11
4

5 **ISSUE:** Reserve for Site Restoration Continuity Schedule
6

7 **QUESTION:**
8

9 a) Please clarify whether the FD7 overhaul is related to YEC's reserve for site
10 restoration projects and, if so, explain why the \$580,000 forecast for 2021 was not
11 included in Table 3.14.3.
12

13 b) If part (a) above is not confirmed, please fully explain how YEC proposes to treat
14 the \$580,000 expenditure for regulatory purposes in the year 2021.
15

16 **ANSWER:**
17

18 **(a)**
19

20 The FD7 Overhaul is not related to YEC's reserve for site restoration projects. It is
21 categorized in the Application as an Overhaul.
22

23 **(b)**
24

25 YEC proposes to treat the FD7 Overhaul consistently with other overhauls in this
26 Application (LNG) and other overhauls in previous Applications. The FD7 Overhaul is
27 treated similar to other additions of Property, Plant and Equipment, and is specifically
28 identified as being added to Rate Base in the Application in Table 5.2-1 on page 5-33.

1 **REFERENCE: Application, Tab 2, Section 2.2.2, page 2-6**

2
3 **ISSUE: Industrial Demand**

4
5 **QUESTION:**

- 6
7 a) Please explain how other ratepayers are protected from the effects of significant
8 large industrial loads and potential swings in demand if those industrial loads come
9 on and off line.
10
11 b) What are the requirements in the power purchase agreements, or other industrial
12 electricity purchase agreements, to manage peak demand?
13
14 c) Please confirm how many times the mine load supply was curtailed due to
15 generation issues.
16
17 d) Please provide the monthly demand for VGC since the beginning of the operation.
18
19 e) Are the requirements to manage peak demand the same for all industrial
20 customers? Please explain.
21

22 **ANSWER:**

23
24 **(a)**

25
26 Other ratepayers can experience rate effects from significant large industrial loads, and
27 the potential swings in demand if those large industrial loads come on and off line, only
28 through new GRA filings to adjust existing rates. Prior to a new GRA response to such
29 events, the revenue requirement related impacts from changes in large industrial loads
30 are all borne by the utility.
31

32 Yukoners experienced such effects in the 1990s when the Faro mine, accounting for about
33 40% of overall Yukon loads, shut down its operations in 1993, then reopened its operations
34 in 1995, and then closed permanently in early 1998. As directed by the Board, YEC
35 addressed these significant changes through timely new GRA applications. In 1995, when
36 the Faro mine reopened, the Board issued Order 1995-01 declaring that all YEC and
37 YECL rates are made as interim refundable and retroactively adjustable effective July 1,

1 1995 other than RS 39 which continued to be interim refundable and retroactively
2 adjustable.

3
4 As documented in the 1990s, restoration of Faro mine loads reduced rates significantly
5 for other ratepayers; as a result, loss of the large Faro mine industrial load led to a need
6 to increase rates significantly to other ratepayers. Restoration of much smaller industrial
7 loads since the 1990s has tended to reduce rates for other ratepayers – but the magnitude
8 of potential rate swings related to such loads coming on and off line are currently much
9 smaller than the impacts associated with Faro mine load swings in the 1990s.

10
11 **(b)**

12
13 Power purchase agreements with industrial customers set maximum load limits and power
14 quality requirements for each customer, absent agreement with the utility to accommodate
15 higher peak loads, and also require each customer to provide forecast of load
16 requirements. Otherwise, these agreements do not provide for management of the
17 customer peak demand.

18
19 RS 39 includes provision for agreement with an industrial customer for a Winter Contract
20 Load that enables a Peak Shaving Credit to be arranged. No industrial customer has
21 elected to pursue this option. The VGC Group PPA specifies that this mine's operations
22 are forecast to have a much lower peak load during the key winter period.

23
24 The N-1 dependable capacity planning criterion for Yukon Energy excludes consideration
25 of major industrial customer peak demands. These industrial customers have on-site
26 diesel generation capability sufficient to address emergency electricity requirements in the
27 event that utility electricity supply is curtailed. In the event of a grid N-1 loss of generation,
28 electricity deliveries to major industrial customers are expected to be curtailed.

29
30 **(c)**

31
32 Grid splits occur from lightning or failed equipment. There is insufficient generation in the
33 north for the mine loading. During system restorations the mines are curtailed until system
34 security is re-established. High load or events that involve Aishihik can also limit YEC's
35 ability to feed the mines.

36
37 Total events in 2019 and 2020 was 19.

	Date	Event	Duration
1			
2	April 22, 2019	Major Outage	2 hr
3	June 8, 2019	Lightning	3 hr
4	June 12, 2019	Lightning	2 hr
5	June 25, 2019	L250 fault	30 mins
6	July 1, 2019	L180 fault	8 hr
7	July 10, 2019	L180 fault	4 hr
8	July 22, 2019	Lightning	1 hr
9	Sep 10, 2019	L180 fault	1 hr
10	Dec 2, 2019	L180 fault	4 hr
11	~Jan 14 2020	Very High Load	not sure on duration/dates.
12	Feb 7, 2020	WH4 Trip	10 hrs Minto 2 hr Eagle
13	Feb 13, 2020	WH4 Trip	2 hr
14	July 5, 2020	L178 outage	1 hr
15	July 11, 2020	Lightning	1 hr
16	Oct 26, 2020	Grid Split	10 hrs
17	Nov 14, 2020	P130 issues	1 hr
18	Dec 2, 2020	Grid Split	10 hrs
19	Dec 4, 2020	Grid Split	1 hr
20	Dec 26, 2020	Grid Split	120 hrs

21

22 **(d)**

23

24 Monthly demand for VGC since the beginning of operation is as follows:

		KVA
2019	MAY	840
	JUN	748
	JUL	3,360
	AUG	4,200
	SEP	4,480
	OCT	5,180
	NOV	5,180
	DEC	5,460
2020	JAN	5,740
	FEB	5,880
	MAR	5,880
	APR	6,440
	MAY	5,880
	JUN	5,040
	JUL	5,320
	AUG	6,160
	SEP	6,720
	OCT	7,560
	NOV	7,140
	DEC	6,440

1
2 (e)

3
4 There is no requirement to manage peak demand for industrial customers. Each mine's
5 power purchase agreement includes terms that define the Maximum Electrical Demand
6 allowed under the agreement.