YUKON ENERGY CORPORATION
2021 GENERAL RATE APPLICATION

Utilities Consumers' Group
Information Request No. 1

A. General Requests

i.) Identify all persons (in-house and consultants) who have worked on this application to date and cost for each person.

ii.) Explain what measures Yukon Energy took to simplify this rate application to lower the costs of regulation and lessen the reliance for outside lawyers and consultants to deliberate our future.

iii.) Give the updated estimated costs for this 2021GRA.

B. Revenue Requirement Requests

Reference: *YUB Rules of Practice October 17, 2012*

Response to information requests
14. (1) Subject to subsection (3) where an information request has been directed to a party and served on that party in accordance with the Board's directions, the party shall prepare a response that:
a) repeats each question in the information request,
b) provides full and adequate response to each question, and
c) identifies the individual or individuals who were responsible for preparing the response.

Request: Please be certain to identify each response with the individual/s who prepared it.

Reference: *Yukon Energy 2021 Rate Application*

Request:

1. Please provide details of all customer and stakeholder consultations conducted by Yukon Energy Corporation during development of this application prior to submitting it to the YUB.
2. Please provide specific details on how YEC's customers were informed of proposals being considered for inclusion in the application and how input from customers was used to develop details of the application.
3. Please provide all documentation related to issues discussed during these consultations and a list of all parties involved in the consultations.
4. Please identify how and when the leadership / Board of YEC approved the General Rate Application as provided to the YUB. Please identify the dates on which these approvals were provided.

Reference: *November 2020 Application page 1*

YEC states "Pursuant to the Order in Council (OIC) 1995/90 (as amended by 2018/220) direction, the Board must ensure until the end of 2018 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers. Consequently, for both 2017 and 2018, all proposed rate adjustments for retail customers and industrial customers apply equally, as percentages".

Reference: *Board Order 2010-13, Appendix A – Reasons for Decision*

"Therefore, the Board directs the Companies to file a joint COS study within six months of the expiry of OIC 2008/149. The Board further directs the Companies to incorporate all findings and directions of this Decision into the next COS study."

Request:

5. Since the OIC 2008/149 expired at the end of 2018, please confirm the above Board direction was accomplished. If not, why not?
6. Please explain what Yukon Energy plans to do about following Board directions and orders?

Reference: *November 2020 Application page 2*

YEC states:"This GRA addresses a difficult situation, Yukon Energy's actual ROE has continued to fall well short of the 2018 approved ROE, and a new GRA is required to address ongoing revenue shortfalls."

Request:

7. Please provide details of any measures since the last 2017/18 GRA that have been taken to manage Yukon Energy's ongoing welfare.
8. Did Yukon Energy attempt any debt re-negotiation with Yukon Development Corporation(YDC) or any Promissory Note's flexible debt re-financing provisions to help alleviate some pressure. If not, why not?
9. Did YDC make any contributions that reduced project costs to be recovered from ratepayers? If yes, explain what for and how much.
10. Are there any secondary sales revenues or other related revenues forecast for 2021? If not, what will YEC do with any revenues if these circumstances change?
11. Were there any adjusted thermal fuel costs recouped from the Diesel Contingency Fund operation or the implementation of the Whitehorse Diesel-Natural Gas Conversion Project (LNG Project or LNG Plant project).
12. Please provide specific details YEC realized to:
    a) reduce ongoing costs? ;
    b) reduce waste? ; and
    c) improve performance?
13. Please provide steps YEC has taken to date to study and consider a performance-based regulation mechanism, including earnings sharing.

Reference *November 2020 Application page 2*

YEC states: "Yukon Energy has developed an approach to enable a rate adjustment for the 2021 test year to address YEC's financial requirements without any material change in customer bills."

Reference: *November 2020 Application, page 4 YEC states:"In accordance with OIC 1995/90 direction, the Application proposes that Yukon Energy revenue shortfall for the test year be recovered through a Rider J increase of 15.01 percentage points in 2*021 applicable to all YEC and AEY retail firm customers and all major industrial firm rates. This Rider J increase results in an overall increase in existing rates (excluding existing Rider J1 true-up a*nd Rider F) of 11.54% for 2021.*

Request:

14. Please explain this second reference in simple laymans language as it is massively confusing. How can YEC exclude/deduct true-up and rider F from your requested revenue requirement increase? Why would they not simply come off our bills when paid off?
15. Please confirm the YEC is requesting a 15.01 per cent increase for the 2021 test year. Explain.
16. As YEC proclaims in the first reference that there will not be any material change in the customer bills, please explain how the expected reduction of the fuel Rider F will offset the requested increase for the proposed interim request, i.e. give the amount of Rider F reduction (as a percentage) expected and how this matches with the proposed interim rider of 10.08% increase requested?
17. Please give the amount of the true-up Rider as a percentage that YEC claims will offset the 15.01% increase slated for December 1, 2021 final rates.

18. Does YEC plan to reintroduce a Rider F charge after the first quarter of January, 2022 or when/if the price of diesel fluctuates from the rate hearing decision price? If yes how does the YEC propose this will keep bills from material changes?
19. Please provide detailed calculations of the total bill impacts for non-government residential customers (including customer charges, energy charges, all rate riders), similar to format as Table 4.2A-3 (1000kWh.) for 500, 750 , and 15000 kWh. per month comparing bills from Jan /2018 to Dec/2021.
20. Please provide detailed calculations of the total bill for non-government general service customers (including demand charges, energy charges, all rate riders)similar to Table 4.2A-4 (2000kWh.) for1500, 2500 and 3000 kWh. per month comparing bills from Jan 2018 to Dec/2021.

Reference: *November 2020 Application, page 2*
YEC states: "The 2021 GRA approach will also work to prevent rate and bill instability beyond 2021, and reduce rate increase requirements for subsequent GRA.''

Request:

21. Please explain exactly how the YEC proposes to accomplish this broad statement.
22. Please explain how the YEC will guarantee its' trust to ratepayers that YEC will follow through with this statement. Or does this mean that instead of 20% increase next application, you will only need 15 per cent yet again? Or is this just another statement like 'other rates will go down when we connect the mines'?

Reference: *November 2020 Application, page 4. Summary of Requests #1*
YEC states it requests "approval of a forecast revenue requirement of $75.135million for 2021.

Request:

23. Please confirm that the YUB approved revenue requirements were $48.544 million for 2017 and $49.864 million for 2018
24. Please explain, in layman's language, why an increase of $25 million or 50% since the last GRA (in three years) should be acceptable to your ratepayers.
25. Please provide a chart showing approved revenue requirement amounts for all GRA years since YEC took control of Management in 1998.

Reference *November 2020 Application Tab.1-7*

1.3 CHANGES IN FORECAST LOADS

The 2021 load forecast is about 28% higher than the 2018 approved forecast. As noted in Table 1-2, revenues from higher loads are largely offset by increases in fuel costs. Higher non-industrial loads also result in capacity shortfalls that must be addressed and that are driving both capital and O&M cost increases.

Test year forecasts for 2021 reflect the following:

- ***Wholesale Load** – Actual 2018 (332.3 GWh) 17.6 GWh higher than approved forecast (314.7 GWh); firm wholesales for 2021 are forecast at 343.5 GW.h.*
- ***Industrial Load** – Actual 2018 industrial load exceeded approved forecast (36.9 GWh vs 32.2 GWh). Forecast firm Yukon Energy sales to industrial customers for the 2021 test year is*

102.911 GW.h.

Reference November 2020 Application Tab1-7/8

*• **Thermal Generation requirements are growing due to higher firm grid loads** – The 24 2018 Compliance Filings approved a forecast of 16.4 GW.h for long-term average (LTA) thermal 25 generation requirements to supply the 2018 forecast grid load of 420 GWh. The 2021 LTA 3 Forecast total firm generation load for the 2021 test year is 538.7 GW.h, compared to the 2018 approved load of 420.3 GWh. thermal generation forecast is 1 84.3 GW.h for a forecast grid load 538.7 GW.h. The increased LTA 2 thermal generation accounts for $10.8 million of the 2021 GRA cost increases from the approved 3 2018 GRA (based on 2018 GRA approved fuel prices). These added LTA thermal generation costs 4 due to load growth are more than fully recovered by the increased revenues ($14.4 million) from 5 the load growth.*

Request;

26. If increase *revenues from higher loads are largely offset by increases in fuel costs ,* the reverse holds true in that fuel costs are largely offset by revenues from higher loads, why is Yukon Energy claiming a revenue shortfall of $2.1 million in this application for fuel costs?[1]
27. Please confirm Yukon Energy's policy approach through this application is to apply for forecast costs in fuel and purchased power; set the fuel rider in August to zero which basically offsets the requested interim rider (if the proposed fuel increase is accepted; and then rekindle Rider F at a latter date in 2022.
28. Please confirm that the wholesale load is <u>forecast</u> to increase by 3.34% in 2021 from the 2018 Actual load.
29. Please confirm that industrial load is <u>forecast</u> to increase by 179% in 2021 from the 2018 Actual load.
30. If this is indeed the case, why does Yukon Energy insist <u>"that higher non-industrial loads result in capacity shortfalls that must be addressed and that are driving both capital and O&M cost increases"</u>? Is it not the industrial loads that are mostly driving these proposed increases?
31. What does Yukon Energy propose to do in this application to offset this blatant discrimination demonstrated for firm wholesale ratepayers?

Reference Application November 2020, Page 3

*• **Energy & Peak Load Changes (8.4% of revenue shortfall):** Dependable capacity requirements caused by peak load growth for non-industrial sales drives diesel rental costs that account for $3.8 million (34.9%) of the 2021 GRA revenue shortfall. Higher overall loads provide increased revenues at existing rates ($14.4 million) that reduce the 2021 revenue shortfall by $2.9 million after considering load-related cost impacts of $10.8 million for increased long-term average thermal generation fuel cost requirements at 2018 GRA fuel prices (to address added energy generation) and $0.7 million for increased Mayo B Promissory Note interest due to higher loads.*

Request:

32. Does this above statement mean that if dependable capacity for peak load growth for non-industrial sales is needed (i.e. running of diesels or LNG)that the industrial loads will be temporarily discontinued during peak time frames? In other words are the mines on SCADA disconnect during peak loads requiring the usage of our rental diesels?
33. If not, why does Yukon Energy state that it is"dependable capacity requirements caused by peak load growth for <u>non- industrial sales</u>"

1 *Application November 2020, Page 3, Fuel Price Changes(19.4% of revenues shortfall)*

which drives this cost?

34. Please confirm the Mayo B Promissory Note is to Yukon Development Corporation.
35. Should it not be the government/YEC (through edicts and OICs and PPAs) that takes fiscal responsibility for increased mine loads driving such rate increases rather than recouping this from the firm ratepayers through this rate application?

Reference: Application November 2020
Section 6.1 of OIC 1995/90 requires the Board to ensure that rates charged to major industrial customers are sufficient to recover the cost of service to that customer class.

Reference: YEC 2003-04 Rate Hearing Transcripts p.649
Mr. Morrison: "Customers are customers, load is load. And we don't attribute specific diesel costs to to different customers.

Request:

36. Please reconcile the above underlined statements, if YEC cannot differentiate what the specific diesel costs are to serve each individual mine, how can YEC guarantee your regulator that you are adhering to the above OIC.

Reference Application November 2020, Tab 1-9
*• **Defined Benefit Pension Deferral Account:** In this Application Yukon Energy is requesting approval of defined benefit pension plan deferral account 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. A similar deferral account was approved for AEY by Board Order 2014-06.*

Request:

37. Please explain how this affects the revenue requirement for this application and if it does by how much in dollars and percentage?

Reference Application November 2020, Tab 1-8/9
*• **VGC Group and Alexco Fixed Charge:** Rate Schedule 39 as currently approved includes a Fixed Charge for VGC Group and for Alexco of $8,402/ month, subject to amendment from time to time, including provision for allocation of the Fixed Charge between VGC Group and Alexco in years when both customers are Major Industrial Customers of YEC.6 As reviewed in Appendix 4.3 of this Application, YEC expects to file with the Board in late November/ early December 2020 for approval of an amended Transmission Facilities Fixed Cost effective January 1, 2021 of $428,812, resulting in an 1 interim Fixed Charge (85% of the Transmission Facilities Fixed Cost) effective January 1, 2021 of $35,734 per month, with allocation of the interim Fixed Charge between VCG Group and Alexco [Table 4.3-2, Appendix 4.3 of this Application]. Aside from changes related to the 2021 GRA, a final Fixed Charge for 2021 would occur after 2021 year end as required to reflect final actual Transmission Facilities Fixed Cost and the actual MWh energy sales in 2021 that occurred to VGC Group and Alexco.*

Request:

38. Since Alexco came on line again in November 2020, and it is obvious that Yukon Energy had this amendment to the agreement already to go, why did YEC not include this Filing with this application to reduce the revenue requirement as well as regulatory costs for another process?

39. Will the firm ratepayer benefit from this Alexco agreement amendment in this 2021 rate applcation?
40. If yes, please show where and how in the application this adjustment is included.
41. If no, please explain why not?
42. Will Alexco be responsible for any of the transmission line and sub-station contribution costs to lower the rate base cost?
43. If not, why not.

Reference Application November 2020 Tab ***Table 3.3:***

Labour $ 11,932 $ 12,083 $ 11,863 $ 12,727 $ 13,310 $ 13,310
Production 1,799 3,300 3,935 4,876 5,978 5,978
Transmission 1,419 1,058 1,304 1,403 1,394 1,394
Distribution 535 449 293 536 491 491
General O&M 1,219 1,395 1,530 1,352 1,391 1,391
Administration 3,001 3,016 3,365 3,491 3,858 3,858
Insurance and Reserve for
Injuries/Damages 1,510 1,525 1,596 1,778 1,902 2,259
Property Taxes 708 671 673 739 750 750
Total OM&A (Tab 7, Schedule 10) $ 22,125 $ 23,497 $ 24,559 $ 26,903 $ 29,074 $ 29,430

Forecast

5 Non-labour costs are forecast to increase by $5.928 million in 2021 over 2018 approved costs. The
6 average annual compound increase in non-labour expenses is approximately 16.51% (2021 expenses
7 over 2018 approved) primarily due to $3.834 million costs for diesel rentals required to meet the N-1
8 single contingency capacity planning criteria (no diesel rental costs were included in the 2018 aprpoved
9 costs).
10 An increase in labour expense makes up $1.378 million, or 19%, of the total $7.306 million increase in
11 operating and maintenance expense forecast for 2021 over 2018 approved costs. The average annual
12 compound increase in labour expenses is approximately 3.71% (2021 expenses over 2018 approved).
13 ***3.3.1 Labour***
14 Total labour expenditure is made up of labour expense for maintenance and administration and
15 capitalized labour. Capitalized labour is charged to capital projects and becomes part of revenue
16 requirement through annual deprectiation charges incurred after in service. Maintenance and
17 administarion labour expense is charged directly to revenue requirement. Total maintenance and
18 administration labour expense is forecast to be $13.310 million in 2021 as compared to 2018 approved
19 costs of $11.932 million, reflecting an increase of $1.378 million.

Request:

44. Please breakdown expenditure amounts and reason for all non-labour forecast costs of $5.928 minus the $3.834 million diesel rentals; i.e $2.094 million amount.
45. According to Table 3.3 and line 10 above, Labour costs are forecast to increase by $1.378 million or 11.5% since last GRA approval. Please breakdown all labour expenditures for maintenance and explain the need for each increase.
46. Please breakdown all labour expenses for administration and explain the need for each increase.
47. According to Table 3.3 above, Administration costs are forecast to increase by (*Administration 3,001 3,016 3,365 3,491 3,858 3,858)* $0.857 million or 28.6% since last GRA approval. Please give breakdown of all Administration costs and reason for increase in each partitioning.

48. According to Table 3.3 above, According to Table 3.3 above, *(Insurance and Reserve for Injuries/Damages 1,510 1,525 1,596 1,778 1,902 2,259)* costs are forecast to increase by $0.749 million or 50% since last GRA approval. Please give details on why this reserve has increased this great amount since the last GRA approval.

Reference November 2020 Application Tab2-3

21 • Actual hydro generation in 2020 is forecast at 86.0% of grid generation, reflecting annual water
22 availability at about LTA. Current forecast hydro generation for 2021 is 94.0% of grid generation,
23 reflecting forecast water availability above LTA.

Request:

49. What does this exactly mean, i.e. do you have the actual hydro generation for 2020 or is it forecast?
50. If not, please rephrase this to make it understandable.

Reference November 2020 Application Tab2-12

18 As indicated in Table 2.2, the peak demand for the integrated system is forecast to be 112.7 MW in 2021.
19 The actual peak demand was 93.0 MW in 2018, 90.0 MW in 2019 and 103.8 MW in 2020.

Request:

51. Does this 112.7MWforecast peak demand for 2021 include the three mines now on line? If not, please provide this mining peak load.
52. If this does include the mines, please breakdown the peak demand for firm ratepayers and for industrial ratepayers.

Reference November 2020 Application Tab2-13

11To address the severity of a potential
12 outage, Yukon Energy incorporated a second test – the N-1 standard which determines system
13 capacity assuming the loss of the system's single largest generating or transmission-related
14 generation resource. This standard does not include industrial loads as part of the assessment. It
15 ensures there is sufficient grid generation installed to meet firm residential and commercial
16 customers' loads when a failure occurs to the single largest system component.

Request:

53. Does this mean that the industrial loads are temporarily taken off the system until the reason for a potential outage is fixed and normal hydro power is restored, i.e. only firm customers are accommodated with the N-1 back-up supply?
54. If not, why not?

Reference November 2020 Application Tab2-15

5 In summary, under N-1, there is surplus of dependable capacity of approximately 1.25
6 MW in 2021. Without rented diesel units, the N-1 capacity shortfall would be 25.75 MW
567 in 2021.

Request:

55. How much above the standard rental costs for the diesels, when they are being used (i.e is there a usage fee added to the stand-by rental? And how much?)
56. Please chart the operating-owned YEC diesels with capacity for each in Whitehorse, Faro, Mayo, Dawson. Ross River,

Teslin, Carmacks, Carcross, Haines Junction, and any others.

57. Please chart the operating ATCO diesels in all their operating area on the grid with each capacity.
58. Would we today require diesels on the integrated grid if the mines were not operating (answer without peak load and with peak load)?

Reference November 2020 Application Tab2-17

TAB 2 - SALES AND GENERATION Table 2.2:
Summary of Energy Balance, Losses, and Peak
Forecast Line No. Description 2018 Approved 2018Actual 2019 Actual 2020 Forecast 2021
Sales and Losses
1 Total Energy Sales 388,332 412,470 403,492 465,788 495,151
2 Losses - MWh 34,173 37,898 37,185 42,193 43,575
3 Losses - % 8.8% 9.2% 9.2% 9.1% 8.8%
4 Total Generation 422,506 450,368 440,676 507,980 538,726
5 Secondary Sales Related Generation 2,241 282 0 0 0
6 Firm Load Generation 420,265 450,086 440,676 507,980 538,726

Request:

59. Give reason for the continual increase in loss of MWh on the grid through the four year period listed?
60. From above 118,461MWh increase of firm load generation from forecast 2021 to 2018 approved, or 28% (divided by 4 years equals a 7% increase per year) when you state earlier that the yearly firm load is increasing at 3.5% ????which is it?

Reference November 2020 Application Tab2-17

Peak – MW2 Integrated System *92.9 93.0 90.0 103.8 112.7*

Request:

61. Please explain the major difference of 19.8MW from 2018 approved to 2021 forecast for integrated peak.

Reference November 2020 Application Tab2.1-1

APPENDIX 2.1: LONG-TERM AVERAGE THERMAL GENERATION CALCULATIONS
As per previous Board directives, Yukon Energy's GRA revenue requirement annual thermal generation costs for test years are based on long-term average (LTA) hydro generation (rather than forecasts of actual hydro generation resulting from actual water conditions). Accordingly, for the purpose of the 2021 GRA to test year, hydro and thermal generation forecasts are based on LTA water supply for hydro generation as updated with the latest information.
The determination of LTA annual hydro availability is adjusted as required in each GRA to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.
The forecast 2021 LTA thermal generation for the Application is 84.3 GW.h, based on the Table 2.1-1 developed to determine annual expected YEC thermal generation based on long-term average YEC hydro generation at YEC 2021 forecast grid loads (net of expected IPPs and expected Fish Lake generation) ranging from 475 to 585 GW.h/year. The forecast for the test year is based on the following proposed updates to the determination of LTA annual hydro availability for the current GRA:
a) Yukon Energy now has more water year records compared to 2017/18 GRA [38 water years, from 1981 to 2018, compared to 35 water years, 1981 to 2015, used in 2017/18 GRA]. This added

information has tended to increase LTA hydro estimates.

Request:

62. Does YEC have any management command/influence on the hydro system capability and usage? Explain.
63. Why is not the 2019 year included in your forecast model?
64. Do we now have more than average water conditions in our systems available for generation? Provide latest Update on Forecast Water Conditions for 2020 qualifying answer.
65. If yes, will this increased hydro use not result in a windfall for the utility if this particular forecasting model is accepted
66. Please explain how the LWRF is functioning under these positive conditions.

Reference *November 2020 Application Tab3-3*

The forecast Return on Rate Base increases by 20% ($2.832 million) from 2018 approved to 2021 forecast as proposed in the Application. The increase primarily reflects about 12% increase in mid-year rate base in 2021 over 2018 approved. Yukon Energy's capital structure continues to be financed with 60% long-term debt and 40% equity. The forecast 2021 average cost of long-term debt at 2.81% is 58 basis points [or 26%] higher than the 2018 approved cost at 2.23%, primarily reflecting Mayo B related debt's higher interest with higher loads. The forecast 2021 return on equity at 8.70% remains unchanged from the 2018 approved cost.

Yukon Energy's forecast for new long-term debt interest rate for the 2021 test year is based on long-term Canada bonds plus 120 basis points as directed by the Board. Please see Tab 3, Section 3.5.1. The interest rate adopted for new debt forecast in the test year is 2.19%, determined using a formulaic approach based on the long-term Canada Bonds rate plus 120 basis points (Government of Canada Long-Term Bond Benchmark at 0.99% as of June 30, 2020).

Request:

67. Why is long term debt rates proposed to increase by 26% since last approved GRA while the Bank of Canada rate trending downward, now at 0.25 per cent?
68. Is the add-on of 120 basis points non- negotiable for a new application? If not, why not?
69. Why are ratepayers paying, the holder of the Mayo B debt, prime rates when it is to our publicly-owned shareholder who owns the debt?
70. Does not this term note higher load reflect the mines of that area?
71. Does Yukon Energy make increased revenues from selling to the mines?
72. Why are firm ratepayers paying a premium for this term note when it is through a government decision via Yukon Energy to sell to the mines at a pre-determined contract price?

Reference *November 2020 Application 3-6*

Purchased power costs also include forecast purchases in 2021 under the Yukon government Independent Power Production (IPP) Policy of 1.983 GW.h1 as provided in Table 2.2. The purchase cost for the IPPs in 2021 is assumed at $0.1583/kW.h based on the latest approved thermal fuel cost for YEC in its 2017/18 GRA.2 Total IPP purchase cost is forecast at $0.314 million for 2021.

Request:

73. What is the YEC protocol to purchase from IPP?
74. Please give a cost /benefit analysis of this 2021 forecast IPP purchase cost of $0.134million?
75. Please provide purchase agreement with this IPP or any IPP?

Reference November 2020 Application 3-8

TAB 3 - REVENUE REQUIREMENT

1 Labour expense is generally a function of the following factors:
*2 • **Labour Rates** – This includes factors such as base pay, benefit cost, annual increments*
3 (performance increments, cost of living adjustments), etc.

Request:

76. Please explain how performance increments are assessed and valued.

*9 • **Head Count** – This relates to the number of full time equivalent positions. The Yukon Energy*
10 employee complement is shown in Table 3.4.
11 Of the total labour expense increase from 2018 approved, approximately $0.882 million relates to
12 additional headcount and $0.740 million relates to labour rate increases. The balance is made up of other
13 factors impacting labour costs such as changes in overtime, vacancies and capital allocation.

Request:

77. Since labour head count costs are proposed to increase more than $1.6 million, explain.

*14 **Table 3.4:***
*15 **Employee Complement History 2018Approved Actual2018 Actual2019 Forecast2020 Proposed2021***

President	*4.16*	*5 .14*	*4.82*	*4.01*	*4.16*
First Nation Relations - - - -				*1.00*	
Communications, Cust. Acctg. 1.00		*1 .00*	*1.00*	*3.10*	*4.60*
Human Resources & Info. Mgmt. 5.25		*5 .27*	*5.34*	*5.32*	*5.25*
Resource Planning and Environment 5.00		*5 .00*	*5.75*	*5.51*	*7.05*
Finance, Cust. Acctg. & Purchasing 16.79		*1 6.89*	*17.24*	*13.54*	*14.79*
Operations	*44.50*	*4 6.58*	*47.12*	*48.75*	*49.25*
Engineering Services	*15.00*	*1 3.03*	*15.16 1*	*5.63*	*15.50*
Health, Safety & Environment	*2.00*	*2 .00*	*2.00*	*2.00*	*2.00*
Total	*93.70*	*94.91*	*98.44*	*9 7.86*	*103.60*

Note:
1. The employee complement numbers are net of allocation to YDC.
17 2. Customer Accounting was transferred from Finance to Communications in 2020.
18 Table 3.4 shows that the total position count is forecast to increase by 9.90 positions since 2018
19 approved to 2021 test year.

Request:

78. Why are Approved 2018 compliments different from Actual 2018?
79. Explain what positions make up the four employee complement with job description in the presidents office.
80. Explain why the vice president cannot do the job of FN relations?
81. What exactly is the VP job description?
82. Explain the 3.6 positions added in communications, customer Acctg.
83. Explain the 2 positions added in resource planning and environment.

84. Explain why environment is in two locations in this above chart.
85. Provide a chart giving each of the YEC positions (management and non-management) pay grade/scale and performance bonus.
86. Explain how each of these compare with other utilities in Canada.

Reference *November 2020 Application*

SUPPORTING DOCUMENTS PAGE 3-9
TAB 3 - REVENUE REQUIREMENT

At the historic staff level, 1 employees were finding it difficult to keep pace with increased demands, more 2 so as additional assets are added and increasing burden for planning and executing capital works.

Request:

87. Please identify any/each consultant/contract hiring and cost amounts for planning and executing capital works.

6 There are a number of corporate factors that directly affect employee complement:
7 • Increasing assets;
8 • Strategic importance of improving First Nation and public engagement, realtionships and 9 communications;
10 • Steady growth in customer accounts;
11 • Increased planning requriements for projects recommended through the 2020 Ten Year 12 Renewable Electricity Plan; and
13 • Continuing high capital demands to maintain existing aging assets.
14 To combat the above issues, YEC is forecasting an increased employee complement. The increase in 15 employee complement has resulted in a significant decrease in forecast overtime costs for 2021. Also, the 16 increased employee complement in 2019 through 2021 is due to an effort, where possible, to do more 17 work internally as opposed to hiring outside consultants and contractors. YEC has made a conscience 18 effort to limit increases to only those areas where required as reviewed below.

Request:

88. Please identify the decrease in actual and forecast overtime costs for each of the years since 2018.
89. Please identify all cost savings for doing work internally as opposed to hiring outside consultants and contractors.

Reference *November 2020 Application Tab 3*

6 ***3.3.6 Administration***
7 As shown in Table 3.9, Administration expense is forecast to increase $1.640 million (18%) in 2021 over 8 2018 approved primarily due to increase in labour costs by $0.783 million (13%) in 2021 over 2018 9 approved reflecting labour cost changes as well as functional changes noted in section 3.3.1. Non-labour 10 costs are forecast to increase $0.856 million (29%) in 2021 over 2018 approved.
11 ***Table 3.9:****12* ***Administration ($000) 2018Approved Actual2018 Actual2019 Forecast2020 Existing2021 Proposed2021***

Labour	*$ 5,916*	*$ 5,949*	*$ 5,835*	*$ 6,113*	*$ 6,699*	*$ 6,699*
Resource Planning	*48*	*48*	*29*	*174*	*84*	*84*
Communications	*130*	*126*	*129*	*125*	*155*	*155*
Customer Accounting	*225*	*208*	*244*	*206*	*240*	*240*
Environmental Mgmt	*238*	*184*	*197*	*259*	*535*	*535*
General	*662*	*688*	*742*	*620*	*790*	*790*
Information Systems	*645*	*555*	*771*	*803*	*741*	*741*
Fish Hatchery	*168*	*158*	*169*	*200*	*210*	*210*
Safety	*182*	*210*	*168*	*168*	*226*	*226*
Training	*175*	*173*	*131*	*124*	*200*	*200*

Recruitment 229 245 379 323 255 255
Board of Directors 182 246 280 274 252 252
Union 20 119 60 148 90 90
Regulatory Affairs 33 26 11 15 20 20
Material Management 37 9 31 32 32 32
Contracting 12 5 7 12 12 12
Professional Development 15 15 17 7 15 15
Total Administration $ 8,917 $ 8,966 $ 9,201 $ 9,603 $ 10,557 $ 10,557

• The increase in Administration costs 1 reflect ongoing cost pressusre related to recruitment, 2 training, safety and other cost categories, including: Environmental Management expenses are 3 forecast to increase by $0.297 million (124%) in 2021 over 2018 approved due to increased 4 environmental monitoring activities associated with the new 3 year water license of the Aishihik 5 Generating Station.
6 • General administration expenses are forecast to increase by $0.129 million (19%) in 2021 over 7 2018 approved primarily due to new licenses required for the new asset management software.
8 • Information Systems expenses are forecast to increase by $0.096 million (15%) in 2021 over 9 2018 approved due to increased costs for data circuits.
10 • Union expenses are forecast to increase by $0.070 million (350%) in 2021 over 2018 approved 11 but is $0.029 less than 2018 actual. Fluctuations in Union expenses are due to cyclical 12 renegotiation of the Collective Bargaining Agreement, which expired December 31, 2019.
13 • Board of Directors expenses are forecast to increase by $0.069 million (38%) in 2021 over 2018 14 approved due to additional training and increased meeting costs, as reflected in 2018 actuals.

Request:

90. Please explain what is meant by administration labour costs and breakdown the cost for each of these admin labour costs.
91. Was/were outside consultants hired for resource planning. If so, please name the contractor/s and provide costs?
92. Was/were outside consultants hired for environmental management. If so, please name the contractor/s and provide costs.
93. Breakdown general administration expenses with costs.
94. Provide each new license required and final costs for the new asset management software.
95. Explain what function the communications have and how they are cost/accounted.
96. Explain what material management is and how it is cost/accounted.
97. Explain how you know you will need new data circuits until need?
98. If you do not have to purchase any/some of new circuit boards how will this discrepancy be accounted?

Reference November 2020 Application, Table 3.13:

5 ***Mid-Year Net Rate Base****6* ***($000)***

	Approved2018	***Actual2018***	***Actual2019***	***Forecast2020***	***Existing2021***	***Proposed2021***
Year-End:						
Net plant in service1	*$ 278,702*	*$ 287,713*	*$ 293,199*	*$ 303,158*	*$ 323,642*	*$ 322,649*
Mid-Year:						
Net plant in service						
Before contributions	*$ 445,367*	*$ 449,441*	*$ 458,678*	*$ 475,781*	*$ 498,719*	*$ 498,223*
Less contributions	*167,112*	*166,677*	*168,222*	*177,603*	*185,319*	*185,319*

Net plant in service 278,255 282,764 290,456 298,178 313,400 312,904
Mid-year regulatory deferral2 3,879 3,805 3,009 2,484 2,732 2,732
Working capital 5,344 5,617 5,935 6,592 6,985 7,141
Net Rate Base $ 287,478 $ 292,186 $ 299,399 $ 307,255 $ 323,117 $ 322,777
Notes:
2 This reflects the regulatory deferred costs, excluding DSM and the balance of the hearing reserve account.
1 Net plant in service at year end is gross property, plant and equipment plus deferred study and relicensing costs, less work in progress, depreciation, amortization, customer contributions, reserve for future removal and site restoration, deferred fire gain, and disallowed assets.

Forecast

8 Yukon Energy's 2021 mid-year forecast rate base in this Application is $322.777 million (an increase of
9 $35.3 million or 12% from 2018 approved mid-year rate base of $287.5 million).

Request:

99. Is this proposed $35.3 million increase in rate base since the last GRA only for plants that are now providing a service?
100. If no, identify cost amounts separating plants now providing a service from other costs not providing a service.
101. Explain what mid-year regulatory deferral means.
102. Please provide a chart identifying the approved rate base for each GRA year since 1998.
103. Identify and explain each separate contribution donor and amount for all years in chart.
104. Explain why 2018 actual rate base is different from 2018 approved?
105. Explain why difference between existing 2021 and proposed 2021?
106. Since $11.861M 2019 increase, $7.856 M 2020 increase, $35.3M increase in rate base since 2018 approved, identify amounts for each year already approved. Identify where and when these were approved.

Reference November 2020 Application, Appendix 3.1 2017-19 KPI Report:

Generation Source

Hydro 441,048 413,052 370,819
% of Total 96.8% 91.7% 84.1%
Diesel 4,618 7,186 3,793
% of Total 1.0% 1.6% 0.9%
LNG 9,856 30,130 66,065
% of Total 2.2% 6.7% 15.0%
Wind 32.582 0 0
% of Total 0.0% 0.0% 0.0%

Request:

107. Is the LNG still classed as back-up with this amount of usage? Explain.
108. How much is wind expected to replace diesel and LNG in 2021?

109. Identify how each SAIDI,SAIFI and CADI compare to Fortis BC (Electric) in 2019.

Reference November 2020 Application, Return on Common Equity Tab 3-27

*16 • **Risk Premium Adder for YEC:** Order 2018-10 established a 45 basis point risk premium for*
17 YEC over the BCUC benchmark ROE. A 45 basis point risk premium for YEC was considered to be
18 fair and reasonable based on: (1) recognition of small size and principles established for AEY in
19 Order 2017-01;7 and (2) recognition of YEC risk related to generation, isolated grid, and
20 customer diversity.8 As noted in Tab 8, there are no new issues or material changes in
21 circumstance at this time that would alter the basis for approving a risk premium of 45 basis
22 points for Yukon Energy.

Request:

110. Does Fortis BC (Electric) borrow the majority of its' money/debt from a government mother corporation?
111. Does Fortis BC (Electric) receive federal and provincial contributions for various programs? Explain.
112. Does Fortis BC (Electric) have a rider or mechanism for Fuel price changes, a Low Water Reserve Fund/ similar mechanism, or any other mechanism for stabilizing rates?
113. Identify the gross margin for YEC in 2019 and 2020.
114. Identify the earnings before interest, taxes and amortization for YEC in 2019 and 2020.
115. Compare the numbers in 113 and 114 for the YEC to those of Fortis BC (Electric).

C. Capital Projects

Reference November 2020 Application,p. 5-1

21 Total spending on PP&E projects in the 2021 test year as shown in Table 5.1 totals $61.767 million, with
22 91% of this spending in major projects over $1 million ($56.266 million) and 48% ($29.801 million, Table
23 5.2-1) included in 2021 rate base. Total PP&E spending was $21.300 million in 2018, $31.154 million in
24 2019, and is forecast at $36.171 million in 2020. Overall, PP&E transfers to rate base since the end of
25 2018 approximate $92 million. Contributions transferred to rate base to offset some of these
26 expenditures since the end of 2018 approximate $37 million (Table 5.1).
27 Deferred cost capital spending (including Work in Progress [WIP] and after contributions) was $4.3
28 million in 2018 (Table 5.3), $3.7 million in 2019 (Table 5.4), and is forecast at $5.4 million in 2020 (Table
29 5.5) and $10.5 million in 2021 (Table 5.6). The current GRA results in approximately $7.4 million of
1 Deferred costs being brought into rate base in the current GRA (including relevant test year spending and
2 before transfers to the Hearing Reserve Account), with approximately $1.5 million for 2019, $4.0 million
3 for 2020, and $1.9 million for 2021.
4 Actual and forecast intangible asset spending (including WIP) over 2018 to 2021 is $6.062 million, all of
5 which is forecast to be brought into rate base by 2021, as illustrated in Table 5.7.

Request:

1. Are PP&E spending for 2018, 2019 and 2020 assumed approved or will they have to wait the outcome of this hearing?
2. Do the PP&E requested transfers to rate base since the end of 2018 approximate $92 million include the 2021 test year? Explain.
3. Are total deferred capital costs for 2018, 2019 and 2020

assumed approved or will they have to wait the outcome of this hearing?

4. If only $7.4 million of deferred capital costs requested into rate base, would the remaining $7.5 million go into WIP? Explain.
5. Provide a table identifying (PP&E, deferred and intangible) approved capital costs that were placed into rate base for each GRA year since 1990, including requested 2021 amounts.

Reference November 2020 Application,5-1 Capital Projects

2 Capital project investments in rate base are generally grouped in one of three categories: capital works
3 on property, plant and equipment; deferred cost studies (including new supply and other feasibility
4 studies, studies required by regulation or relicensing and dam safety works); and intangible assets.

Request:

6. Provide all related stages a capital project undergoes from concept planning to a plant in use. Include all regulatory stages as well.
7. Identify how each stage cost is accounted for.
8. Provide a table/chart demonstrating stages for each capital project greater than $1 million applied for in this application rate base [2] since 2017/18 approved. On this chart for each stage, identify all consultant firm/s name and cost, all contract firm name and cost, all in-house costs with reason, a total of each stage cost. Provide and identify all contributions amounts (government, mining, others) for each stage.
9. Identify any cost overruns and amounts for each stage of each project in #8 above.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

*21 ○ **LNG Third Engine/ Critical Spares** – actual cost of approximately $8.261 million,*
22 completed and in service in 2018, but not included in rate base approved in 2017/18
23 GRA.

Reference: *June 22, 2017 Application, page 5-26*

LNG Third Engine ($6.2 million)

Request:

10. Is $8.261million actual cost or approximate cost?
11. Exactly what was the projected cost for this project from the 2017/18 GRA.
12. If different from the above $8.261 million, explain cost overruns.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

*1 **5.2.1.2 N-1 Capacity Shortage Thermal Rental Site Infrastructure***
*2 **N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure6 ($0.227 million in***
*3 **WIP at end of 2018 and $1.070 million in 2019)***

2 Capital Projects ^ $1 million to include: LNG 3rd.Turbine; N-1 Capacity Shortage Whitehorse site; N-1 Capacity Shortage Faro site; Mayo to McQuesten Transmission Line; McQeusten Sub-Station; Transmission Line Refurbishment; Transmission Line 178 Refurbishment; Breaker Replacement Program; Replace P125 Headgate; WH2 Uprate; WH4Upr

4 The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under
5 its single contingency (N-1) capacity reliability criterion that approximated 6 MW in 2017, increasing to
6 10-11 MW by 2019. Yukon Energy is required to provide sufficient dependable winter capacity to meet
7 the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given
8 the need to maintain reliable service and to address an ongoing and growing dependable capacity
9 shortfall.
10 The project involved the design of infrastructure to accommodate temporary rented thermal generators
11 at Whitehorse substation to address the capacity shortfall projected under the N-1 for 2018/19 and
12 2019/20 winters.
13 In winter 2018/19 six temporarily rented 1.8 MW units were installed in the proximity of S150 Whitehorse
14 Rapids Substation. The 2019 project included installation of two additional temporarily rented 1.8 MW
15 units in the area between P126 Whitehorse Diesel and S150 Whitehorse Substation. The project scope
16 included planning support, limited engineering design assistance, protection settings and installation
17 support temporary seasonal diesel power generators to meet seasonal N-1 load requirements and assist
18 with meeting winter system peaks. Total project cost was approximately $1.298 million.
19 ***N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure7 ($2.037 million forecast in***
20 ***2020)***
21 The project involves the design and installation of temporary rental site electrical infrastructure at Faro
22 (870S) to ensure Yukon Energy can continue to meet its N-1 capacity planning requirements.
23 The project scope includes engineering and design, procurement of materials, installation and
24 construction and other internal and project management costs. Specifically, the major scopes of work
25 include:
26 • Preliminary design and feasibility studies (system impact study and grounding studies); and
6 Table 5.2-1 references this project as "N-1 Capacity Shortage Mobile Genset."
7 Table 5.2-1 references this project as "N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure".
• Faro 870S 1 temporary diesel generator infrastructure – design, procurement, construction and
2 commissioning, including: civil/ structural work; 138 kV line tap and substation work; 4160V
3 collection system; fuel system; stations service power; protection, control, communication and
4 SCADA integration.
5 The project is expected to be completed in 2020 at an estimated budget of $2.037 million. The project is
6 on track for a mid-November 2020 in service date.

Reference: YUB's Order 2009-8 directions to YEC

" In future GRA applications, YEC to include business cases for major capital projects that included the following information: • descriptions of the project • economic analysis including preliminary engineering estimates • discussion of alternatives and how the chosen option was determined • discussion of the risks of proceeding with the chosen alternative • discussion of risks of not proceeding with the chosen alternative; and • discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs. "

Request:

13. Chart all YEC diesels with capacity amounts available in Whitehorse, Faro, Mayo, Dawson, and other towns. Identify for each unit when last retrofitted and at what cost. Identify for each unit when end of life.
14. Chart all ATCO Electric Yukon diesels with capacity amounts, on the grid.
15. Chart natural gas units with each unit capacity.
16. Since these two project are jointly concerned and YEC is now requesting to place costs of over $3 million onto the rate base for 2021 test year, with the very limited information for each of these projects, provide the businesses case for each following the above Board directives.
14. In which year did YEC first rent gensets? How many?
15. Explain when and why YEC chose to move 7 generators to Faro.
16. Explain precisely why so much was expended to

accommodate these rentals.

Reference: Mayo to Keno Transmission Line and McQuesten Sub- Station

Request:

17. Identify forecast 2021 kWhr. usage for all non-government and government residential and commercial ratepayers on grid from Mayo to Keno (do not include Mayo).
18. Identify forecast 2021 kWhr. usage for each of the two mines, VCG and Alexco.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5-11

11 Table 5.2.1-2: Project Cost and Contributions

	Actual2018	***Actual2019***	***Forecast2020***	***Forecast2021***
MMTL Upgrade ($000)	*0*	*501*	*20,000*	*11,200*
MMTL Contribution ($000)	*0*	*274*	*15,000*	*8,400*
Net Expense	***0***	***227***	***5,000***	***2,800***

12 The total spending of $20.501 million for 2019 and 2020 is offset by $15.274 million in contributions [net
13 $5.227 million] and is forecast to be closed and included in rate base in December 2020; the spending of
14 $11.200 million in 2021 is offset by $8.400 million in contributions [net $2.800 million] and is forecast to
15 be closed and included in rate base in December 2021.

Request:

19. Identify contribution amount and contributor for each year and explain precisely what used for. (Not adequately explained in business profile).
20. If none of these contributions were from Alexco please explain why not?

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5-12

22 ***5.2.1.4 McQuesten Substation (including Asset Contribution) – ($0.123 million in 2018 and***

23 ***$11.496 million in 2019; with $10.688 million contribution)***

Request:

21. Identify contribution amount and contributor for each year and explain precisely what each was used for. (Not adequately explained in business profile).
22. If none of these contributions were from Alexco please explain why not?

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.2.1.5 Transmission Line Refurbishment - L70, L171 and L172 in 2018 and 2019 ($4.272
15 ***million in 2019)***

16 Yukon Energy's 138 kV Whitehorse-Aishihik-Faro (WAF) transmission system was constructed in the late
17 1960's and early 1970's, and plays a critical role linking key hydro generation sources to load centres in
18 Whitehorse and on the northern grid. Recent studies as well as a detailed line assessment in 2017
19 indicated that key components of the WAF system were at end of life, in poor condition, and required
20 replacement.
21 This project was initiated to address replacement of key components of the following YEC transmission
22 lines which are approaching the end of their economic life.
25 At the time future Step Down transformer costs were estimated at $1.34 million.

Request:

23. Who made and why was the decision made to expense this money all at once rather than stepping-up the yearly maintenance program utilizing in-house personnel?
24. Does this $4.272 million cost in 2019 include the $1.34 costs for Step Down transformers.
25. If yes, demonstrate that this work was done.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.2.1.6 Transmission Line Refurbishment – L178 (forecast $1.3 million in 2021)

12 The final phase of the Transmission Line Refurbishment Project will commence in 2021 for the Carmacks
13 to Faro Transmission Line (L178), as refurbishment has been completed for L170, L171 and L172 (see
14 Section 5.2.1.5).
15 Outages on the L178 currently trip at S164 (Takhini Substation) and can result in an outage on the
16 Takhini-Carmacks L170 transmission line. Failure to complete this element of the refurbishment project
17 would increase the risk of component failure on L178 resulting in a split in the North-South grid and
18 significant thermal generation costs in the northern gird to maintain supply to all customers.

Request:

26. Has outages of the L178 line ever caused a failure on the grid?
27. If so, how often and when?
28. Has utilizing the yearly maintenance in-house team considered as a viable alternative. If not, why not?

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.2.1.8 Replacement of P125 Head Gate ($0.093 million in 2019, $2.300 million forecast in
8 ***2020, and $3.500 million forecast in 2021)***

Request:

29. If an adequate response charting breakdown is met in UCG-IR Capital 8 and 9 includes this project, then UCG has no further questions for now.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

13 **5.2.1.10 WH4 Uprate - Servomotor Replacement ($0.052 million in 2018; $0.079 million in**
14 **2019; $0.400 million forecast in 2020; and $1.000 million forecast in 2021)**

The total project budget is $1.531 1 million and includes work from 2018 through to project completion
2 (expected in Q3 2021).

Request:

30. Provide all <u>prior</u> work done on WH4, years work completed, along with each cost for the WH4 Uprate program, that have been already been approved and placed in rate base.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.3.1 Major Projects >$1 Million – Rate Base Additions

12 o ***Aishihik Relicensing (Three Year Licence Renewal)*** *- ($1.004 million net increase*
13 in rate base by the end of 2021, excluding reductions due to amortization).

5.3.1.1 Aishihik Generating Station Three Year Licence Renewal – ($0.805 million to end of
23 ***2019; and $0.200 million in 2020)***

16 Costs for the 3-year AGS licence renewal were incurred from January 2019 through to end of February
17 2020 (when the 3-year licence renewal was obtained). Costs over this period include regulatory costs for
18 the Designated Office review; costs related to the preparation of the Yukon Water Board Application for
19 the 3-year renewal and for the 60-day renewal and for the related review processes; and costs related to
20 preparation of an application to extend the DFO Fisheries Act Authorization and related review processes;
21 and costs related to negotiations with CAFN and for negotiation of compensation with claimants pursuant
22 to the Waters Act .
29 The DFO evaluation concluded in August 2019 with the issuance of an Evaluation Report. Decision Documents were issued in September 2019.
30 Issued December 24, 2019.
31 A 60-day renewal was issued in December 2019 extending the licence to February 29, 2020, and a 3-Year renewal was issued on February 19, 2020.

Request:

31. Provide all costs allocated for AGS YESAB review (each consultant name, work done and cost for each. Provide all in-house costs with work done.
32. Provide all costs allocated for AGS Water Board review (any and all consultant costs and in-house costs).
33. Were both these licenses granted?
34. How much did it cost for FN negotiations and compensation and how was this accounted for?

Reference: June 22, YEC 2017 Application, page 5-31 and Table 5.3, page 5-56Aishihik Relicensing ($2.899 million) $2.899 million cost identified at page 5-31 and $8.9 million cost identified on Table 5.3 at page 5-56.

Request:

35. Identify which amount was approved as a WIP for 2017/2018 GRA.
36. What portion of these costs allocated from WIP to rate base?
37. Identify how these costs were different from the ones now requested to place into rate base.
38. Identify any and all consultant firms, work performed and each cost for this phase of the relicensing.
39. Please confirm that costs related to the Aishihik Relicensing will not be recovered in rates until approved by the YUB this general rates application process.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

17 o ***Demand Side Management (DSM)*** *– ($1.737 million net increase in rate base by the*
18 end of 2021, excluding reductions due to amortization).
5.3.1.2 Demand Side** 1 **Management – ($0.833 million to the end of 2019; $0.375 million
2 ***forecast in 2020 and $0.894 million forecast in 2021, with contributions of $0.365***
3 ***million).***
The Board made the following DSM related determination in Board Order 2018-10
6 (paragraph 482):
7 "The Board is not persuaded that YEC should continue to operate DSM projects. YEC has
8 indicated the benefits of expanding the program and submitted that its programs have
9 met or exceeded key performance indicators. However, the Board notes that the Yukon
10 government has DSM incentive programs in place, and the Board is of the view that it is
11 better to leave DSM projects to government, rather than having ratepayers fund these
12 projects. For these reasons, the Board is of the view that continuation of DSM programs
13 by YEC is not necessary."

22 ***DSM Program Development***
A Capacity DSM Feasibility Study and an updated CPR model,35 to design 1 a suite of new DSM
2 programs to complement the existing inCharge program. This work was completed in early 2019. Minimal costs to provide brand and education continuity have also been incurred since early
5 2019 to maintain the inCharge program in the local market. Project expenditures to be included in rate
6 base of $1.279 million ($0.385 in 2019 and $0.894 million in 2021) are amortized over 10 years.

Reference: Board Order 2013-01 Appendix A determined: "that it was not approving the DSM program for the five-year term and that YEC was to make a formal application to the Board before expanding the DSM program elements beyond that approved or beyond 2015."

Request:

40. Has there been a court determination on the YEC request to Review and Vary Board Decision 2018-10?
41. If the courts have not rendered a favourable decision on this matter, why is YEC still proceeding with DSM expenditures?
42. Did YEC get prior authorization from the Board to proceed with new DSM programming as directed by the Board to undergo these studies and models with costs of $1.279 million?
43. What are the programs complementing the inCharge that have been implemented?
44. Confirm that YEC requires acceptance from the YUB before rates can be set which recover any expenditures for energy efficiency or conservation (DSM measures) .

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5
17 o **Demand Side Management (DSM)** – ($1.737 million net increase in rate base by the
18 end of 2021, excluding reductions due to amortization).

7 ***DSM Residential Demand Response Pilot***
20 Yukon Energy has pursued a pilot program testing internet connected, wifi enabled
21 demand response technology designed to control residential baseboard and hot water heating during
22 winter peak periods to help reduce system peak and reduce reliance on thermal generation such as diesel
23 or natural gas.
34 Yukon Energy also noted plans to undertake a Capacity DSM Feasibility Study to quantify the potential cost and achievable uptake
of capacity-focused DSM programs such as demand response, behaviour change and other demand-focused measures.
35 At the time Yukon Energy also noted plans to update the Conservation Potential Review (CPR) model used to inform DSM program design, to better match the inputs needed for resource planning; and to develop in house capacity to use the CPR model
to extract data for resource planning and program design purposes.
The objective of the program is to: 1 evaluate the technical feasibility of the demand response technology;
2 model and test the peak shifting effect of the pilot; test the reliability of the peak shifting effects of the
3 pilot; and evaluate customer acceptance of the demand response events.
4 The project is managed by Yukon Energy with funding support from Atco Electric Yukon (AEY), Yukon
5 Development Corporation (YDC) and Natural Resources Canada (NRCan). Project expenditures of $0.809
6 million ($0.434 million in 2019 and $0.375 million in 2020) are to be included in rate base, offset by
7 contributions of $0.365 million in 2019, are amortized over 10 years.

Reference: https://www.yukon-news.com/news/smart-grid-pilot-project- announced/
"It's worth $1.3 million, with the federal government chipping in $650,000 and the Yukon government contributing $250,000. ATCO and Yukon Energy cover the rest — $300,000 and $100,000, respectfully."

Request:

45. Explain precisely what the $0.809 million costs are for?
46. How much exactly is YEC requesting to rate base?

47. Why is YEC costing any of this to the ratepayer rate base when all of the costs were to be recovered from contributions (see above)?
48. Confirm that YEC requires acceptance from the YUB before rates can be set which recover any expenditures on this demand response program.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

8 ***LED Streetlight Retrofit Program***
The 2017/18 GRA outlined the basis for
13 the LED Streetlight Replacement program noting that Yukon Energy decided to move forward with the
14 retrofit of streetlight assets with LEDs.37 Streetlights in downtown Dawson and Mayo were retrofit in 2016
15 with plans to retrofit the remaining streetlights in Faro, Mendenhall and Champagne in 2018. As
16 illustrated in Table 5.3, $0.273 million was added to rate base in 2018.

Reference: Appendix A to Board Order 2018-10 Reasons, p.91 #480 and 481

Board determined as a result of above: "The Board considers that retrofitting streetlights at end of life with LED lights were prudent expenditures. Any LED installations that are not end-of-life conversions are not to be included in rate base."

Request:

49. Did YEC receive prior authorization from the Board to spend the $0.273 million demonstrating end-of-life conversions?
50. Confirm that YEC requires acceptance from the YUB before rates can be set which recover any expenditures on this streetlight conversion.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.4-1: FEASIBILITY STUDIES – POTENTIAL RENEWABLE GENERATION OPTIONS
IPP Standing Offer Program Implementation
2018WIP 2019 Addition 2020Addition 2021Addition
$48,127 $183,912
Yukon Energy and ATCO Electric Yukon (AEY) are responsible for implementing the Yukon Government's Independent Power Producers (IPP) Policy. The Standing Offer Program (SOP) was developed based on the model used in British Columbia
The utilities were directed to implement the policy by the Yukon Government and are required to execute the policy. OIC 2019-25 requires that utility costs be recovered in rates. With total expenditures of $232,039 to be amortized over five years.

Request:

51. If the YEC model was based on one produced in British Columbia, explain why a quarter million dollars in cost be needed to re-invent the template?
52. Identify the section of OIC 2019-25 that states precisely that the utilities costs be recovered from rates for <u>developing</u> an IPP standing offer program..
53. Why could not the Yukon Energy staff implement this policy in-house?

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab

FACTORS DRIVING THE 2021 RATE INCREASE REQUIREMENT
16 • ***Other Cost Changes ($0.7 million impact, 6.0% of shortfall):*** *Other cost changes*
17 affecting the 2021 GRA revenue shortfall include depreciation rate changes ($0.6 million
18 increase), Reserve for Injuries and Damages (RFID) updates ($0.4 million increase), <u>and new</u>

19 Independent Power Production (IPP) costs ($0.3 million).

Request:

53. Explain the difference in the business case cost of $232,039million for IPP and the impact to rates of $0.3 million for new IPP costs.
54. Which is relevant and how is this reflected in application costs?

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab

Mt Sumanik Wind Feasibility Studies

2018WIP 2019Addition 2020Addition 2021Addition

$694,427 $31,155 $50,000

Mt Sumanik was identified as a particular site of interest for wind development given the advantages of its proximity to Whitehorse. From 2014 to 2015, work on this project focused on the siting, engineering, environmental assessment, permitting and installation of wind monitoring equipment at Mt Sumanik. This included completion of applicable studies such as a grid impact study and wind integration study. A Lidar unit and power supply system was installed on Mt Sumanik to track wind data.

From 2016 to 2017, the project work consisted mostly of data collection and management, as well as evaluating upgrades to the power system for the monitoring equipment which experienced difficulties. In 2018 work was conducted to repair the laser of the Lidar unit as the equipment was malfunctioning. Yukon Energy's 2016 Resource Plan identified a potential energy gap under the High Industrial Activity scenario. The Action Plan identified one wind supply option under this scenario. Accordingly, as wind was still a resource of interest, Yukon Energy considered whether further data monitoring should be conducted given missing data from the malfunctioning equipment.

The need for Yukon Energy to directly conduct resource wind monitoring and site assessments has since been eliminated due to the high likelihood that future wind resources will be developed by Independent Power Producers. As such, the project was decommissioned in 2020 with total expenditures of $775,581 to be amortized over five years.

Request:

55. Breakdown all costs associated, including consultant firms and costs for each; i.e. for siting, engineering, environmental assessment, permitting and installation of wind monitoring equipment on Mt. Sumanik.
56. In what year was IPP policy presented by YTG to Yukon Energy for implementation?
57. In what year was YEC first made aware that Northern Energy was planning a wind farm in the Whitehorse area?

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

WH2 Uprate Engineering1

2018WIP 2019Addition 2020Addition 2021Addition

$207,944 $44,448 $6,679

In 2016, Hatch assessed the uprate options at the WRGS. Uprate of the WH2 was considered the most economically attractive option. The WH2 Uprate project would include completion of the WH2 unit's rehabilitation, replacement of the turbine runner and stator rewind and rotor refurbishment. The WH2 uprate engineering study was the first stage of a multi-year, phased project. The initial stage involved selection of an Owners Engineer to conduct preliminary design work (commenced in 2018 and completed in 2020).An external engineer was required to undertake this work as uprate studies are a specialized skillset that YEC does not employ internally. By end of 2021 WH2 Uprate Engineering costs will be transferred to Property, Plant and Equipment and added to WH2 Uprate total cost [amortized over 72 years starting in 2022]. However, this requires replacement of the existing stator winding and refurbishment of the rotor field poles and windings. before the end of 2021. The project is to be closed in 2021 with total expenditures of $259,072 to be amortized over 72

years.

Request:

58. Was the total cost of $250K for work given to Hatch?
59. If not, which engineering firm did study and at what cost?
60. If not, were there additional costs?
61. Confirm that existing WH2 stator has been replaced, winding and refurbishment of rotor field poles and windings complete.
62. At what cost?

Reference: ***5.2.1.9 WH2 Uprate ($3.044 million in 2019, $1.693 million forecast in 2020, and $7.300 million forecast in 2021)***

In 2017, Hatch completed an economic assessment of various uprate options at the Whitehorse Rapids Generating Station (WRGS).
The project is planned to be implemented over a three year period (2019-21).
The WH2 uprate scope 1 of work will include unit rehabilitation, runner replacement, generator stator and rotor re-winding, governor replacement, exciter replacement and upgrading of the control and condition monitoring systems.
Yukon Energy contracted Litostroj Power to undertake the runner fabrication with the following concurrent activities planned for 2020: governor fabrication, balance of plant civil construction; balance of plant P&C design completion, relace of balance of plant request for proposal, and delivery of materials to Whitehorse. The balance of plant civil scope work included rehabilitation of the tailrace crane superstructure and concrete piers. Due to significant new damage to the WH1 and WH2 penstocks discovered in 2020, the planned penstock work was cancelled and will be completed as part of the penstock repairs.
The WH2 uprate project is currently expected to be delivered on time with total project cost of $12.038 million.28

Request:

63. Further to reference above giving WH2 business plan, is the first reference engineering costs of $259,039 included in this business plan?
64. If not, why not?
65. WH2 scope of work include *unit rehabilitation, runner replacement, rotor re-winding, governor replacement, exciter replacement and upgrading of the control and condition monitoring systems.* Did Listostroj Power do all the work in scope above and at what cost.
66. If Listostroj Power did not do all the work outlined above to the cost of $12,038 million, identify which firm/s was/were hired, what work done and at what cost.
67. Identify work done in-house and at what cost.
68. Identify any costs above associated with the balance of work identified above including rehab of tail race crane and concrete piers.
69. Identify all costs and for what work completed to WH2 for 2018 and any prior years.
70. Confirm that $12.038 million is the total amount for overhaul of WH2.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.2.1.10 WH4 Uprate - Servomotor Replacement ($0.052 million in 2018; $0.079 million in

14 ***2019; $0.400 million forecast in 2020; and $1.000 million forecast in 2021)***
15 The project involves detailed design, procurement and installation of two new Servomotors for
16 Whitehorse Hydro Unit 4 (WH4) wicket gate operation.
19 Contracts with Andritz (OEM), L&S Electric (to review documentation and develop a governor
20 commissioning plan) and Hatch (owners engineer) have been finalized. Procurement has not yet been
21 undertaken for testing services and installation of a lifting device.
22 Yukon Energy entered into a contract with ANDRITZ Hydro for the design and supply of two new servo
23 motors. Final design is nearing completion and manufacturing is expected to commence in Q3 2020.
24 Other work is proceeding in parallel including planning for changes to the governor, signature testing and
25 characteristic testing with assistance from Hatch and L&S Electric. Delivery of the Servos is expected by
26 January 2021. Contractor mobilization and installation, testing and commissioning is expected to occur in
27 June 2021. The project is expected to be in service in June 2021.

Request:

71. Detail which contracts and work performed with costs to Andritz(OEM), L&S Electric, and Hatch.
72. Identify any other contracts with work performed and costs.
73. Identify all work performed and costs for in-house.
74. Identify all costs and for what work completed to WH4 for 2018 and prior years.
75. Give total cost of WH4 overhaul to date.

Reference : ***APPENDIX 5.2: CAPITAL PROJECTS*** TO RATE BASE

5.2-1: GENERATION PROJECTS

Dam Safety Review
Dam Safety Program
2019Actual 2020Forecast 2021Forecast
$300,000

A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA).
A DSR was completed in 2020 and included an extensive inspection of all water control facilities, underwater inspection of structural elements by divers, geotechnical investigation of the Whitehorse power canal, and research into historical records of YEC assets. The 2020 DSR resulted in a detailed report that prioritized recommendations for work to be completed in future years. Spending in 2021 is required to address 2020 DSR outcomes and priorities identified for 2021. Some of the high priority items that will be addressed include:
• Wareham dam spillway design
• Warning and danger signage around the six dams
• Public safety around Marsh Lake

Dam Safety Recommendations 2017/18
2019Actual 2020Forecast 2021Forecast
$272,000 $300,000
The 2015 DSR resulted in a detailed report that outlined a list of observed deficiencies and corresponding recommended actions to address identified deficiencies and eliminate hazardous conditions which could adversely affect the safety of the public and YEC staff. 2019 spending included required maintenance around the Marsh Lake control structure, and replacement of Whitehorse piezometers; while planned 2020 activities include replacement of the Mayo Lake Dam wood planking, Wareham Dam seismic upgrades, and the implementation of a public safety plan at the Marsh Lake control structure.

Request:

76. Confirm all projects listed in Appendix 5.2 need to undergo a prudence test and approval from the Board before any/all can be entered into rate base.
77. Confirm the last DSR was done in 2015.
78. Confirm each project must be confirmed to be 'used and

useful' before it can be entered into rate base.

79. Why were the 2015 recommendation of DSR not done until 2019 and forecast 2020, if they are so hazardous?
80. Are not some of the forecast work for 2021 the same as the 2021 safety recommendations?

P126 LNG Boil-Off Gas Heat Exchanger
2019Actual 2020Forecast 2021Forecast
$194,000

Prior to decommissioning of the Mirrlees diesel generators, LNG boil off gas was piped to P126 and burned in the P126 plant boiler and/or dissipated through the WD1 jacket water heat exchanger. With retirement and removal of the three Mirrlees gensets at the Whitehorse Diesel Plant (P126) there was a requirement to replace this heat dissipation function and to design, supply and install a new heat exchanger at the plant to dissipate extra heat from the combustion of LNG boil off gas. Work related to the installation of the heat exchanger included hiring an owners engineer to prepare design, drawings and specifications for the new heat exchanger, piping, a new pump with VFD, and a temperature sensing device, and provide mechanical and electrical drawings and technical specifications for equipment and piping installation for tendering the construction work.

Request:

81. Confirm this work has been completed and operational.
82. Why is this extra heat not utilized to heat buildings or some other cross purpose?

Wareham Gate Heater
2019Actual 2020Forecast 2021Forecast
$574,000 $100,000

The Wareham Gate Heating project replaced an old and ineffective heating system on both Wareham Spillway Gates. The new system is designed to keep both spillway gates operational through the winter. Passing flows during outages and times of high inflows is a critical function of the spillway.

Request:

83. Confirm this work has been completed and operational.

Wareham Gate Refurbishment
2019Actual 2020Forecast 2021Forecast
$250,000

The Wareham Dam impounds Wareham Lake and is classified as an extreme hazard Dam.1 The Wareham Spillway Gates have been in service since 1953 and are critical infrastructure for the Wareham Dam. The spillway gates at Wareham Dam have had significant leakage problems over a number of years, primarily due to age-related wear and corrosion. Recent observations, including an external engineering assessment, indicated that the gates were deteriorating in several ways. Specifically, the skinplates were experiencing pitting corrosion2 and needed to be repaired by sandblasting, adding additional plates and plug welding and seal welding the plates in an array to add strength. During testing of the hoist following repairs in 2019, extremely high friction forces were also observed acting on the gate; the wheel bushing was worn; and there was evidence of fretting wear on the wheel paths. Side seals were also leaking at a high rate at times; and copper staunching rod links and retaining clips required refurbishment with new self lubricated bushings to allow them to seal smoothly. Spending in 2020 was focused on undertaking work as identified above to address each of these issues.

Request:

84. Confirm this work has been completed and operational.

Whitehorse Diesel System Grounding for Generators
2019Actual 2020Forecast 2021Forecast
$218,000 $10,000

This project prepared grounding calculations and installed acceptable grounding equipment for all Whitehorse diesel generators in order to address the following issues: (1) WD4 and WD5 generators were ungrounded and in the case of a ground fault there was risk of significant damage to this equipment; and (2) the grounding for WD6 and WD7 generators was not identical, and this was an inadequate configuration when several generators were running in parallel.

Request:

85. Confirm this work has been completed and operational.

86. Why would Yukon Energy have any facility that is not properly grounded?

WH1 and WH2 Design and Install Dewatering System
2019Actual 2020Forecast 2021Forecast
$137,000

A suitable system was not in place to automatically control the water levels in the WH1 and WH2 draft tube during dewatering activities. This project installed a redundant and automatic dewatering system integrated with the station PLC to provide visibility and status alarms to increase safety and reduce the risk of a flood in the P125 plant. Prior to implementation of the project, the existing system was oversized, and required large volumes of makeup water to be

Request:

87. Confirm this work has been completed and operational.
88. Why would the existing system be oversized in the first place?

WH4 Ventilation
2019Actual 2020Forecast 2021Forecast
$750,000

The WH4 plant is overheating during the summer. Given that YEC is adding additional capacity to the WH4 hydro unit with new servo motors in 2021, removing the restriction placed on output by the overheating issue will enable the extra capacity to be used reliably throughout the year.

Request:

89. Why is this program not included in the WH4 overhaul?
90. Confirm this work has been completed and operational.

5.2-2: TRANSMISSION PROJECTS
Alexco Mobile Substation Connection
2019 Actual 2020Forecas 2021Forecast
$178,000
($178,000contribution)

Alexco plans to use a 3 MVA, 69 kV/4.16 kV mobile self-contained substation to feed their Birmingham site at Keno. The substation must be connected to the McQuesten-Keno 69 kV line. The project includes supply, installation and commissioning of the new line tap including connection to existing 69 KV line, engineering and commissioning support for the new mobile substation. YEC has engaged Chimax to complete a 69 kV line tap design to connect the Alexco mobile substation to the McQuesten-Keno 69 kV line. The actual project costs will be fully recovered from the customer.

Request:

91. Is this to be included in the rate base account and how is this accommodated?

Line 177 Re Route
2019Actual 2020Forecast 2021Forecast
$105,000 $250,000

Some areas of L177 are on the border, or within, the highway right of way (ROW). The Yukon Highways Department is undertaking road construction upgrades; and the design will have cuts for a new ditch starting where some YEC poles are currently located. Three poles fall within a highway cut and at least one will be within 2 m of a highway cut. As a condition of our permit with YG, YEC is required to move the affected poles, and poles adjacent, in order to meet Yukon Government's construction requirements.

Request:

92. Why would Yukon Energy not be liable for this error?
93. Should not Yukon Energy or their contractor absorb this cost?
94. Confirm this work completed and operational.

Minto Mine Substation – Neutral Ground Resistor
2019 Actual 2020Forecast 2021Forecast
$105,000
($184,000 contribution3)

The Minto mine requires that the following equipment be installed at the S254 Minto mine substation to be in

compliance with regulatory direction: 25 kV recloser c/w bypass switch, instrument transformers, protection and controls; and 5 kV NGR c/w instrument transformers, protection and control. As this equipment is being installed at the customer's request, the full cost of the work will be recovered from the customer.

Request:

94. Is this to be included in the rate base account and how is this accommodated?

Line 177 Re Route
Protection and Control Program
2019 Actual 2020Forecast 2021Forecast
$300,000

The protection and control program is a capital replacement program under development as part of the Asset Management Framework. YEC has engaged SNC to conduct an asset condition assessment for all protection and control equipment in all generating plants and substations throughout the YEC system. The protection and control review will develop a 20-year capital plan to prioritize the replacement of aging protection and control assets throughout the YEC grid. The program is being undertaken to improve system reliability, protect generating and transmission assets, and reduce outage frequency.

Request:

95. Since the YEC has spent millions on a Asset Management Program, explain why Yukon Energy would need to hire an outside consultant to do this work?

Line 177 Re Route Transmission Line Access

2019 Actual 2020Forecast 2021Forecast
$324,000 $300,000

YEC requires access to transmission lines for maintenance, inspection, and brushing activities. A number of temporary access points lacked the necessary permitting and were potentially not constructed to an acceptable standard. The Yukon government authority has indicated this situation is no longer acceptable and must be rectified.
3The project included the completion of a management plan for transmission access points including current condition, work and permits required, and estimated costs, specifically for accesses required to complete the Transmission Line Refurbishment project (see Section 5.2.1.5). It also included construction of new accesses and upgrades to existing accesses. Completion is expected to result in faster response times for emergency line work, avoidance of potential YG penalties and reliable access to key YEC assets.

Request:

96. Is this not included in another area of capital works?
97. Since the YEC has spent millions on a Asset Management Program, explain why Yukon Energy would need to hire an outside consultant to do this work?

Van Gorda Substation

2019Actual 2020Forecast 2021Forecast
$54,000 $199,000
($188,000 contribution)

Crown Indigenous Relations and Northern Affairs Canada (CIRNAC) is responsible for the Faro Mine Site; they are working to design, supply, install and commission a substation at the Van Gorda mine which is part of the Faro mine complex. CIRNAC has also expressed interest in transferring ownership of an existing stepdown transformer (138kV: 4.16 kV / 12 MVA) at the Faro substation which is currently out of service. CIRNAC has requested that Yukon Energy support their project. Yukon Energy's role in the project would be to support CIRNAC and its technical consultants with respect to technical and operational matters, support transfer of ownership of the T1 Transformer, supply YEC approved meters, complete SCADA works for YEC monitoring, and monitor commissioning activities. YEC will witness all commissioning and start up activities.

Request:

98. Why is this not fully recovered from CIRNAC?
99. Is this to be included in the rate base account and how is this accommodated

WAF Transmission Upgrades

2019Actual 2020Forecast 2021Forecast
$793,000
The WAF transmission system allows low cost hydro generation supplied from Aishihik, Whitehorse, or Faro to be transmitted to other locations on the grid. Failure of a transmission line structure would interrupt this supply, potentially resulting in a wider grid collapse. The structures on this transmission line were built in the 1960s through 1970s and were in various stages of deterioration. 2019 project work focused on L178 (Carmacks to Faro). The remainder of the WAF line was addressed as part of the Transmission Line Refurbishment (TLR) project (see Tab 5, Section 5.2.1.5); and the remainder of the deficient L178 structures will be replaced as part of the L178 portion of the TLR project (see Tab 5, Section 5.2.1.6).

Request:

100. Appears to be a duplicate of the L178 capital request? Explain.

5.2-3: DISTRIBUTION PROJECTS
Customer Extensions
2019Actual 2020Forecast 2021Forecast
$626,000
($698,000 contribution)
$600,000
($426,000 contribution)
$600,000
($400,000 contribution)
Yukon Energy is required to provide service to new customers connecting to the grid system. Customer extensions are forecast and budgeted as capital items without identifying specific projects. Most costs of customer extensions are covered by customer contributions pursuant to the Terms and Conditions of Service.

Request:

101. Explain how you forecast extensions and contribution?

L355 Voltage Regulator
2019Actual 2020Forecast 2021Forecast
$144,000 $35,000
Atco Electric Yukon (AEY) has reported low voltage levels (below CSA standards) at the AEY Haines Junction substation, which is supplied from Aishihik via distribution line L355. The project identified the voltage profile of L355, determined the appropriate location and settings of voltage regulators, and completed all installation and commissioning work.

Request:

102. Were these new voltage regulators and are they now in use?
103. What is the forecast work for 2020? And why to rate base?

System Improvements for Eagle Gold Mine
2019 Actual 2020Forecast 2021Forecast
$487,000
($487,000
Contribution)
The VGC Group PPA provides for development on the Yukon grid of the McQuesten Substation plus the Initial YEC Facilities Improvements, as described in Schedule C of the VGC Group PPA, prior to Commencement of Delivery to the Eagle Gold Mine. These Yukon grid enhancements and facilities are required to connect the Mine to the existing transmission grid, to maintain acceptable system voltages while supplying this new load, and to address potential contingent operating conditions such as loss of generation at Mayo or loss of the transmission connection between Mayo and Whitehorse. The VGC Group PPA provides in Section 6.1 for YEC to recover from the mine the reasonably incurred capital costs for the Initial YEC System Improvements as set out in Schedule C of the PPA.

Request:

104. How is this accounted for in the rate base?

5.2-4: GENERAL PLANT AND EQUIPMENT PROJECTS
Communications Upgrades
2019Actual 2020Forecast 2021Forecast

$801,000

The project completed a number of recommendations that resulted from a Communications Needs Assessment undertaken by an independent consultant that were required to achieve necessary improvements in security, integration, performance and redundancy. The project was reviewed in detail in the 2017/18 GRA.4 YEC noted at the time that the project was planned to be executed over multiple years –"The 2017/18 review noted that satellite installations for SCADA and fibre communications upgrades were required to create redundancy for disaster planning; network access controls were needed due to changes resulting from the satellite installations, and that the SCADA communications upgrades would facilitate satellite communication at YEC's various sites. Key projects completed in 2019 included: fibre communication upgrades; SCADA upgrades, the Takhini Redundant Datacentre; Satellite installations for SCADA.

Request:

105. Identify the independent consultant for the Communications Needs Assessment , work completed and cost.
106. Identify the contractor/s who did the upgrades, work completed and costs.
107. Are all these upgrades now operating efficiently?

Building Upgrades

2019Actual 2020Forecast 2021Forecast

$370,000 $275,000

In 2016, an external consultant was hired to perform an asset assessment on YEC-owned buildings and facilities, mainly consisting of staff houses and administration buildings.

2019 work included: exterior works,7 HVAC retrofits,8 flooring replacement,9 electrical panel replacements,10 and equipment replacement. 2020 costs relate to replacement of the WH4 hydro plant (P127 roof). During 2019 the roof membrane failed, and an interim patch was installed to address a leak. If the roof was not repaired additional leaks would develop and need to be addressed at a much higher cost.

Request:

108. Identify the external consultant hired to perform asset assessment and costs associated.
109. Is all the work now completed?
110. Does Yukon Energy have a maintenance person for its buildings?

Compact Digger Truck

2019Actual 2020Forecast 2021Forecast

$185,000

The purchase of a 4 to 5 ton chassis compact digger truck for use in Dawson...

Request:

111. Is this digger truck now purchased and operating in Dawson?

Crane Inspection

2019Actual 2020Forecast 2021Forecast

$165,000 $400,000

During an annual crane inspection, three YEC cranes (Aishihik service building, P127 powerhouse, & P127 stop log hoist) were identified as needing significant structural, electrical, and mechanical repairs in order remain in acceptable working condition. 2020 spending will provide for a detailed assessment of each crane to determine an engineered plan for replacement or refurbishment as required. Actual construction activities are planned for 2021.

Request:

112. Has this inspection and construction been completed and now operating?

Mayo Earthworks

2019Actual 2020Forecast 2021Forecast

$300,000

A number of issues at and around the Mayo Hydro facilities have been identified. These include slope instability and erosion issues near access roads (Mayo A, Mayo B, and Wareham dam), both powerhouse buildings, surge tank, and both substations. During 2019 a complete site inventory of civil issues was undertaken to identify and prioritize embankments. 2020 spending developed a detailed work plan for identified issues including a geotechnical assessment, topographic survey, detailed engineering design (including drawings and specifications), construction

methodology, and project scope, schedule & budget development.

Request:

113. Is this earthworks all completed or was this just for the assessment work?

114. Identify contractor, work completed and cost for each job.

New Mobile Office Unit – IT

2019Actual 2020Forecast 2021Forecast

$230,000

The existing IT trailer houses five offices and a closed storage space. It is aging and requires additional O&M support each year. The project involves replacement of the aging, undersized IT trailer with a larger unit able to accommodate eight office spaces and storage. Additional office spacing would allow for staff expansion as a less costly solution than building onto the main building.

Request:

115. Has this IT trailer been bought, set up and operational ?

Vehicle Purchases

2019Actual 2020Forecast 2021Forecast

$258,000 $476,000 $580,000

Fleet vehicles...

Request:

116. Identify which vehicles have been purchased and are operational?

Water Improvement Upgrades

2019Actual 2020Forecast 2021Forecast

$150,000

The cooling water and potable water systems in the YEC main corporate office have experienced pre-mature piping failure and select cooling coil leaks for at least the past 10 years. An external engineering firm was engaged to assess the current systems and provide recommendations to address the issues. The project will implement those recommendations including the installation of a particulate filter, a VFD drive for the existing pump, a heat exchanger, new cooling water piping and valves, and fan coil drip pans with leak detection.

Request:

117. Which firm did assessment, and at what cost?

118. Are the necessary changes made and operational?

5.2-5: OVERHAULS & RESERVE FOR SITE RESTORATION PROJECTS

FD7 Overhaul

2019Actual 2020Forecast 2021Forecast

$580,000

Faro Diesel #7 (FD7) is located at the Faro Diesel Plant and uses as 12-cylinder Caterpillar Model 3612 diesel engine as its prime mover (vintage 1992).

Request:

119. Is FD7 overhauled and now operational?

Decommissioning on WD3

2019Actual 2020Forecast 2021Forecast

$999,000

After removing the third Mirrlees engines from service, all three units were fully decommissioned. Decommissioning included disassembly and removal of all ancillary equipment and piping, asbestos abatement as required, separation and hoisting of major engine components, and backfill and compaction of the engine pits. All decommissioned equipment was removed from site and appropriately disposed of.

Request:

120. Is this work complete or is it forecast?

121. Identify contractor and cost for each project.

Site Restoration Transmission Lines

2019Actual 2020Forecast 2021Forecast

$174,000

The Utility maintains a regulatory provision for future removal and site restoration related to property, plant and

equipment. Costs of dismantling capital assets, including site remediation, are applied to this account. In 2019, YEC spent $0.174 million on site remediation relating to the L178 and L355 Transmission Lines.

Request:

122. Identify contractor/s work completed and costs.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.3-1: SPENDING ON SUSTAINING CAPITAL

1. Aishihik Generating Station (AGS) Long Term Year Water Use Licence Renewal

2018 WIP 2019Additions 2020Additions 2021Additions

$4,957,199 $512,755 $1,488,000 $960,000

The planned long term AGS Water Use Licence renewal project and related costs were initially reviewed as part of the 2017/18 GRA. At that time, it was noted that the total forecast budget for the project was $3.569 million spread over five years (2015-2019). Project expenditures to support the long term licence renewal were reviewed in detail in the 2017/18 GRA (See Section 5.3.1.2 and response to YUB-YEC-1-77 in that GRA). Total deferred costs to the end of 2018 were forecast at $2.899 million.

In 2018, Yukon Energy prepared a long-term Project Proposal application for filing with YESAA Designated Office in December 2018, prior to Yukon Energy's decision in early 2019 to secure a three-year licence renewal.1 The longterm Project Proposal document was updated over Q1 and Q2 2020 and filed with the Haines Junction Designated Office in July 2020. It is expected that the Designated Office review process will be completed in Q2 2021. Yukon Energy expects to prepare and file its long term water use licence renewal application with the Yukon Water Board in early 2021, and that a hearing regarding the licence renewal would occur sometime in 2022.

The deferred costs forecast in the Application include spending in WIP increasing from $4.957 million at the end of 2018 to $7.918 million by the end of 2021. The project is forecast to be complete by the end of 2022.

A three-year licence renewal was secured in February 2020, extending the licence to December 31, 2022.

Request:

123. Outline project related work completed, costs and contracts awarded, as prepared for 2017/18 GRA.
124. Were these approved? If so, give relevant Board decision.
125. If forecast cost to end of 2018 were forecast at $2.899 million, why is the 2018 WIP listed at $4.957,199 million
126. Identify firms hired, contract amount and work completed for the $512,755, 2019 additions.
127. Identify in-house work completed and costs for 2019 additions.
128. Identify firms hired, contract amount and work completed for the $1.488 million 2020 additions.
129. Identify in-house work completed and costs for 2020 additions.
130. Identify firms hired, contract amount and work completed for the $0.966 million 2021 additions.
131. Identify in-house work completed and costs for 2021 additions.

2. Whitehorse Generating Station Water Use Licence Renewal

2018 WIP 2019Additions 2020Additions 2021Additions

$260,000

The existing water use licence for the Whitehorse Rapids Generating Station (WRGS) expires at end of 2025 and must be renewed in order to ensure ongoing, lawful operation of the WRGS hydro facilities. This is a multi-year project to renew the existing long-term project authorizations for the WRGS Hydro Plants and associated infrastructure. Project activities include conducting required baseline studies (e.g., environmental, socio-economic, engineering), and undertaking environmental and socio-economic effects assessment, First Nation engagement and consultation, other stakeholder engagement as required to submit a YESAA project proposal to the Whitehorse Designated Office. Project activities will also include completing the YESAA review process, the water use renewal

process with the Yukon Water Board, and Fisheries Act Authorization (DFO) regulatory process.

Request:

132. Identify firms hired, contract amount and work completed for the $0.260 million 2021 additions.
133. Identify in-house work completed and costs for 2021 additions.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.3-2: SPENDING TO ADDRESS CAPACITY PLANNING REQUIREMENTS
Diesel Retirement Replacement (12.5 MW)

2018 WIP	2019Additions	2020Additions	2021Additions
$41,007	$554,224	$800,000	$5,000,000

it was determined that considering the results of the technical, environmental and socio-economic research, as well as public feedback, YEC would focus potential options to add or replace capacity at existing generation facilities on an incremental basis as diesel engines are retired.
This includes consideration of the following near term activities:
• Installation of 5 MW of thermal capacity at the Whitehorse Diesel 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, Yukon Energy will continue to rent diesel generators each winter to ensure an adequate supply of back-up power in case of an emergency.

Request:

134. Identify all diesels with capacity now retired.
135. Identify all consultant firms hired, work performed and each cost for 2018WIP, 2019 and 2020 years totaling $1,395.231 million.
136. Identify all in house work performed and cost for these years.
137. Is the $5 million for 2021 for a new diesel generator? Explain.

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.2-3: SPENDING TO MAXIMIZE RENEWABLE GENERATION FROM EXISTING FACILITIES
4. Southern Lakes Enhanced Storage (Marsh Lake Storage Project)

2018 WIP	2019Addition	2020Additions	2021Additions
$7,319,000	$374,899	$485,000	$1,200,000

Forecast MLSEP project costs and actual expenditures were reviewed in detail in the 2012/13 and the 2017/18 GRAs. The 2012/13 GRA, identified the project as a relatively small project, with earliest in-service assumed in 2014 (first full year 2015) at a capital cost (2010$) of $10.5 million, with mitigation design (shoreline erosion and surface water) expected to comprise about one-half of this total cost (actual costs for mitigation were stated in the 2012/13 GRA as an item that at that time could not be known with any certainty). In the 2017/18 GRA, forecast total project costs increased to $15.377 million ($9.795 million forecast for effects assessment; $0.300 million forecast for YESAA assessment and permitting; and $7.127 million forecast for mitigation implementation).3
Annual incremental hydro generation was estimated at 6.4 GW.h on average, focused in winter months at the current Whitehorse plant. Annual operating cost (2010$) was estimated at $8/MW.h. Full Utilization LCOE (2010$) was estimated at 8.5 cents/ kW.h. Marsh Lake Storage was also assumed in the 2012/13 GRA

Project Update

During the 2017/18 GRA, Yukon Energy indicated that the next major milestone was obtaining First Nation support for the project in order to progress to the YESAB assessments stage.

The deferred costs forecast in the Application assumes that the project continues, with spending in WIP increasing from $7.319 million at the end of 2018 to $9.379 million by the end of 2021. Potential in service for the Project is 2023.

Request:

138. Does Yukon Energy now have all involved First Nations and Southern Lakes property owners on board with this project. Provide documents demonstrating this.
139. Identify all consultant firms hired, work performed and each cost for 2018WIP, 2019, 2020 and 2021 years totaling $9.319 million.
140. Identify all in-house work performed and cost for these years.
141. What is the new estimated cost to do the construction and mitigation for this project?
142. What would be the updated LCOE?

Reference: ***5. Mayo Lake Storage Enhancement Project – including Mayo Lake Outlet Dredging***

2018 WIP 2019Additions 2020Additions 2021Additions

$3,373,374 $262,379 $460,000 $525,000

E (2010$) of 6.3 centres/kWh

[6] Section 5.3.1.4 of the 2012/13 GRA Application reviewed the project concept, work completed to date (including environmental and socio-economic fieldwork activities, analysis and assessment, project proposal preparation, engineering support, and public consultation), and project risks, costs and benefits. The project was included in the 2012/13 GRA under Relicensing rather than Feasibility Study deferred cost projects, reflecting the central objective to modify the current water licence affecting water storage at Mayo Lake.

[7] Section 5.3.1.9 of the 2017/18 GRA provided an update on the project progress, costs, and potential in service. Further detail was provided in response to YUB-YEC-1-85 in the 2017/18 GRA. In Order 2018-10, the Board noted that it had approved the Mayo Lake storage enhancement in Order 2013-01, and that given that sediment removal was necessary to realize any benefits from this project it was prudent to expand the scope of work for this project accordingly

Project Update

In 2018, Northwest Hydraulic Consultants (NHC) was retained to provide a technical assessment regarding whether sediment remediation steps in the Mayo Outlet Channel were feasible and cost effective.

The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from $3.373 million at the end of 2018 to $4.621 million by the end of 2021.

Request:

143. Confirm the N'acho Nyak Dun has been in favour of this proposal from the start and continuing until this day. Provide documents demonstrating this.
144. What is the estimated total cost to complete this project?
145. What is the updated LCOE?

Reference : GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

Building Condition Reports 2020-2024

2018WIP 20192020Addition 2021Addition

$175,000

Building condition reports are required to formally document the structure and fabric of a property, describe the construction of the building and its current condition, and outline work required, timing and costs for completion.

An external engineering firm will undertake site visits for all owned YEC properties and provide an assessment of the condition of each site that outlines requirements for immediate maintenance and repairs; maintenance and repairs required over the next five years; code violations; and cost estimates for required work. The building condition report will be used to forecast O&M projects building condition assessment capital works over 2020-2024.
The project is to be closed in 2021 with total expenditures of $175,000 to be amortized over five years.

Request:

146. Why does Yukon Energy not simply get a building inspector from the YTG or Whitehorse to building inspections as that is what they do, instead of hiring an expensive engineer, most of who are even not qualified to do all the necessary tasks.
147. Identify which engineering firm received contract.

Business Continuity Plan

2018WIP 2019Addition 2020Addition 2021Addition
80,000 $75,000

A gap analysis was undertaken by a third party consultant regarding Yukon Energy's current Business Continuity Plan (BCP). This identified substantial work required to address the identified gaps in order to meet current industry standards. This includes development of technical recovery procedures, based on identified Recovery Time Objectives (RTO) for the various business processes related to IT applications and infrastructure components; developing a defined methodology for evaluating the criticality of vendors, establishing vendor Business Continuity/Disaster Recovery (BC/DR) requirements, and monitoring vendor BC/DR compliance; and developing a formal BC/DRP/Emergency Response Planning training program or exercise and testing program. If the current BC/DR program deficiencies are not addressed, YEC will face a number of risks in the event of an actual emergency. This includes delays in poorly defined Incident Command System, unclear priorities for returning critical support systems to service, lack of adequate employee training or potential communication breakdowns.
The project is to be closed in 2020 and 2021 with total expenditures of $155,000 to be amortized over five years.

Request:

148. How did Yukon Energy identify this was a problem
149. Identify which consultant firm/s got contracts for what work and what cost.

Mayo and Aishihik Hydro Climate Change

2018WIP 2019Addition 2020Addition 2021Addition
$474,313 $124,249 $40,000

A partnership was developed in 2016 between Yukon College and INRS, a university institution which developed a successful joint ARD/CRD proposal to leverage funding from NSERC. The project is to be closed in 2020 with total expenditures of $638,562 to be amortized over five years.

Request:

150. Does Yukon Energy have engineers in their personnel?
151. Does Yukon Energy have a hydrologist in their personnel?
152. If Yukon Energy aligned with Yukon College and INRS why would YEC need an expensive independent consultant?
153. Identify which consultant firm/s received contracts for this study and at what cost.

PMF Flood Study

2018WIP 2019Addition 2020Addition 2021Addition
$150,000

A Probable Maximum Flood (PMF) study is required for Aishihik Lake and Canyon Lake.
The project is to be closed in 2021 with total expenditures of $150,000 to be amortized over five years.

Request:

154. Does Yukon Energy have a hydrologist on staff?

155. Why would this project not be included in the Aishihik Water License costs?
156. Which consultant firm/s did this project work and at what cost?
157. Provide latest Hydrology Report.

Transmission Access Road Program Study

2018WIP 2019Addition 2020Addition 2021Addition
$132,787 $200,000

Yukon Energy does not have a proper inventory of all the road accesses for transmission line access; and does not know the status of all the accesses that are required to maintain approximately 1,110 km of transmission line. The objective of the study is to engage an external consultant to provide a GIS database outlining access locations; the current status of accesses; and to prepare a GIS data base and report that includes a gap analysis of what needs to be addressed to complete the GIS database.
The project is to be closed in 2020 and 2021 with total expenditures of $332,787 to be amortized over five years.

Request:

158. Does Yukon Energy personnel not routinely inspect and work on all transmission line locations?
159. Why would these staff workers not be able to inventory locations, need and GPS these locations?
160. Which consultant firm/s did this expensive work and at what cost?

Whitehorse Diesel Rental Substation Improvements

2018WIP 2019Addition 2020Addition 2021Addition
$100,000

The temporary substation behind the diesel plant is the grid connection point for the rental diesel fleet, was built using repurposed/ savaged equipment, and has temporary fencing. The cables for the temporary substation were reused from the WD1 and WD2 units and are aged.
Cabling from this substation to S150 is a direct connection, and a cable fault will result in the shutdown of S150, which is the primary generating and distribution station on the grid. In order to prevent risk of such a failure, the cables, breakers, and enclosures must be replaced and a permanent fence must be installed. The natural gas pipe and regulator must also be relocated and cable protection at S150 must be installed. Spending in 2021 relates to developing an engineered solution, including a budget and risk analysis.
The project is to be closed in 2021 with total expenditures of $100,000 to be amortized over 45 years.

Request:

161. From Yukon Energy preamble above it appears as if YEC knew all of the relevant problems existed from their own staff and engineers. As such, explain why an independent study was necessary?
162. Which firm received this study contract?

10 Year Renewable Energy Plan

2018WIP 2019Addition 2020Addition 2021Addition
$310,842 $402,125

A desktop update of the 2016 Resource Plan
was completed with additional renewable energy project considerations. The update consisted of a new long term load forecast, expansion of existing hydro inventory, update of financial resource attributes, portfolio analysis and an action plan charting the path for resource development and implementation over the next 10 years. The outcome of this project and its acceptance will allow YEC to establish and follow a plan to ensure that reliability criteria are met.
The project is to be closed in 2020 with total expenditures of $712,967 to be amortized over five years.

The Tab 5 test year forecasts include capital costs for the Ten Year Renewable Energy Plan which addresses resource planning updates as required for current YEC resource planning. This includes consideration of impacts on future peak load growth and energy generation requirements as a result of Yukon's strategy for climate change, energy and a green economy, particularly as regards IPP policy resource project development impacts on energy and capacity resource balances, and policy impacts on future peak loads related to ongoing initiatives for electrification, electric vehicles, and heat pumps.

Reference: ***Directive #62 (paragraph 490) – Resource Plan Update***

• However, the Board is of the view that it is not prudent for YEC to continue with these significant expenses to update the resource plan every five years. Accordingly, the Board directs YEC to seek Board approval prior to any future updates of its resource plan. Any such application must be accompanied by a detailed proposal for both costs and scope of work, including a description of work to be carried out internally and by consultants. YEC must also include an explanation of why any work to be done by consultants cannot be carried out by internal staff.

Request:

163. Did Yukon Energy seek prior approval of the Board and was this approval given? Identify Board decision.
164. If no, as this was almost three quarters of million dollars update, should not Yukon Energy have followed Board directions?
165. Identify which consultant firm/s received contracts, for what work to be done and at what cost.

Atlin Hydro EPA Preparation

2018WIP 2019Addition 2020Addition 2021Addition

$200,000

The Atlin (Pine Creek) Hydro Expansion project was selected as a key project in the 10 Year Renewable Electricity Plan, given its relatively advanced stage of development as a brown-field expansion project, when compared to other potential greenfield hydro developments. The project also has a lower Levelized Cost of Energy (LCOE) than the Drury Lake project. In 2020, YEC engaged in discussions with Xeitl Limited Partnership (Xeitl LP) (Taku River Tlingit development corporation) regarding the Atlin project being planned by Xeitl LP, and key principles and terms for an Agreement-in-Principle (AIP), as well as potential IPP contract provisions. An AIP has been signed, and discussions towards an EPA are underway. The project is to be closed in 2020 with total expenditures of $200,000 to be amortized over five years.

Request:

166. Explain exactly what study is needed here?
167. Identify which consultant firm/s performed tasks, what work done and costs.

Dam Safety Review

2018WIP 2019Addition 2020Addition 2021Addition

$315,000

A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA). Reporting on outcomes of this review is also required by each Yukon Energy generating facility water use licence. The DSR includes a comprehensive review of all of Yukon Energy's dam structures, and includes consideration of all civil, structural, geotechnical, electrical, mechanical and safety issues that may affect YEC personnel and the general public. The review identifies hazards and potential problems of high risk that require immediate attention (within one year) as well as lower risk items that can be performed over time. The project is to be closed in 2020 with total expenditures of $315,000 to be amortized over five years.

Request:

168. Identify which firm/s performed these reviews, work performed and what cost.

Reference: ***5.4 INTANGIBLE ASSETS***

Intangible assets are reviewed in Table 5.7 and include financial software, customer service costs and

13 costs related to development of an asset management framework (i.e., Enterprise Asset Management
14 Purchase and Implementation).

5.4.1.1 Enterprise Asset Management (EAM) System Purchase** 1 **and Implementation –
2 ***($0.809 million in 2019, $3.854 million forecast in 2020, and $0.275 million forecast in 2021)38***

4 The 2017/18 GRA included feasibility costs for development of an Asset Management Program that would
5 document plans to systematically assess major asset groups (hydro, substations and transmission and
6 distribution) and manage the planning of investments to meet overall corporate goals.39
16 The existing Computerized Maintenance Management System (CMMS) does not meet Yukon Energy's
17 current or future asset management needs. An EAM system is an enterprise level software application
18 that enables an organization – particularly an asset intensive organization – to manage and optimize its
19 assets throughout the entire asset lifecycle including asset needs identification, asset investment planning
20 and prioritization, advanced asset maintenance management and asset performance tracking.
21 EAM project activities since 2018 relate to the selection, purchase, planning and implementation of an
22 EAM system. A procurement process to evaluate and select a replacement system was initiated in 2018;
23 and selection of a replacement EAM system was completed in 2019. The tool will be integrated with the
24 Microsoft Dynamics GP, YEC's financial management solution, and other legacy applications to provide an
25 integrated solution that ties to YEC's financial and inventory management systems.
26 The following project activities have been completed:

38 $0.276 million was spent in 2018 under PP&E and transferred to Intangibles in 2019. The 2019 spending was $0.533 million to total 2019 cost to rate base at $0.809 million.
39 2017/18 GRA, Appendix 5.4, page 5.4-2 provides a summary of this project, with forecast spending of $0.200 million in 2017 and$0.150 million in 2018. In Order 2018-10, the Board found the project reasonable and the associated costs prudent and approved the deferred costs as filed.
40The ISO 55000 standard is an international standard covering management of assets of any kind.

• ***Procurement of Project** 1 **Management Services:** In 2019, YEC issued a Request for*
2 Proposals (RFP) for project management of the EAM implementation, and KPMG was selected as
3 the proponent for this work. The KPMG team is well qualified and experienced and its team
4 members successfully implemented a similar EAM system at NTPC (demonstrating knowledge and
5 competence to deal with issues faced by small, northern Crown utilities).
6 • ***Procurement of Software Solution:** A multi-stage competitive procurement was administered*
7 in 2018. A total of 27 potential suppliers were invited to participate in a request for information
8 process. From this, 8 vendors were invited to a full request for proposal (RFP) process. As a final
9 step, three vendors were invited to participate in vendor presentations and site visits and full cost
10 work up. Based on this extensive process, YEC awarded a time and materials contract to Infor
11 ERP Software.
12 Over 2020, YEC has worked towards implementation of the software solution provided by Infor. This has
13 included the following:
14 • ***Inception (completed in 2020):** Undertaking activities related to project kickoff; training*
15 workshops by vendor (Infor) with YEC team members; workshops conducted by Infor to define
16 as-is process models, technical strategy and architecture and KPIs as a basis for the EAM
17 solution; workshop conducted by KPMG (OCM lead) to gather YEC executive input on expected
18 organizational challenges and ensure alignment project objectives; and prioritization
19 requirements for next phase.
20 • ***Elaboration (commenced in 2020 and ongoing):** Involves detailed scoping and finalization*
21 of business requirements and integration design, advanced training for core team members,
22 development of a testing strategy, scope and defining data structures and plan integration
23 strategy and requirements.
• ***Construction (commenced in Q2 2020 and Completed in Q4 2020):** Development of user*
25 acceptance testing plan, initial testing and final data conversion preparation by vendor. This
26 includes development of training curriculum and methodology and approach; assessment of
27 impact of EAM project on YEC; test all modules of AEM solution, going through business
28 processes and verifying functionality; determine if designed and configured solution meets YEC's
29 requirements and specifications; build EAM integrations with YEC legacy systems; local testing of
30 integrations developed; and end to end system testing of AEM system and integrations.
• **Transition (commenced in Q4 2020 and ongoing):** Finalization 1 of EAM solution and
2 preparation to launch into production; including preparing for training for broader YEC users;
3 outline and convert data from non-EAM systems to EAM systems and checking redundancies
4 involved while going live; change impact assessment based on enhanced understanding of
5 project; assessment of readiness for launch and finalize EAM for users and convert to production
6 'live' environment.
7 • **Optimize (commence late Q4 2020 and complete early 2021):** After launch into

8 production review of project successes and lessons learned, including limited support work from
9 vendor as required.
10 Total costs to complete the project are currently estimated at $4.938 million. The project is expected to
11 be fully implemented in early 2021.

Request:

169. Identify which firm did the feasibility plan and at what cost.
170. Identify where Yukon Energy received approval to add 2019 costs of $0.809 million to rate base.
171. Reconcile the difference in the approved 2017/18 deferred costs of $0.350 million and the $0.276 million 2018 spending and transfer to intangibles.
172. Provide breakdown of 2019 spending of $0.533 million, i.e. job description, consultant/s firms hired and cost for each.
173. Identify which firm/consultant received contract for project management services and at what cost.
174. Provide cost for actual Enterprise Asset Management System and related software.
175. Provide breakdown of costs for Inception project kickoff, various training workshops, etc.
176. Provide costs for Elaboration finalization, integration, advanced training, etc.
177. Provide a breakdown of all costs with reasons for Construction, Transition and Optimize phases of program.
178. Provide any in-house costs for all of this project phases.
179. Is this new model of EAM now fully implemented and operational?
180. If some of total cost of $4.938million for EAM already on approved rate base?
181. If yes, identify amount and Board reference decision.

Reference: ***APPENDIX 5.5: DEFERRED STUDIES***

Deferred cost projects with total spending since 2018 greater than $100,000 million and less than $1 million that remain in WIP in 2021, excluding General Rate Application costs in WIP, have total expenditures of $0.400 million and

EV Infrastructure Project

2018WIP 2019Addition 2020Addition 2021Addition

$200,000

Strategy development will assess the potential impact of electric vehicles on the Yukon electrical system and identify a path forward for YEC to meet these challenges.

Request:

182. Has this assessment been completed?
183. If this cost is for strategy development why is this not done in-house with the many personnel on staff?
184. Identify which firm/s performed tasks concerning this assessment, what work was done and at what cost?

P125 Trashrack Study
2018WIP 2019Addition 2020Addition 2021Addition

$200,000

The P125 intake is becoming blocked with debris and frazil ice. These blockages are currently being removed

manually by divers and plant operators. This results in multiple outages each year to address blockages. Not addressing this issue will mean continued outages and requirement for divers to address the issue manually. A track rack must be installed that can permanently address the variety of debris encountered at the intake. The study will confirm the deck structural capacity and other details such as power supply and trash rack geometry.

Request:

185. Confirm that this cost and work is not identified in another area of work to be performed.
186. Has this work been completed and finalized?

Reference: ***APPENDIX 5.6: INTANGIBLE ASSETS >$100,000 AND<$1 MILLION ADDED TO RATE BASE***
ERP System Upgrades
2019Actual 2020Forecast 2021Forecast
$200,000
Given Yukon Energy's role as the primary generator of electricity for an isolated grid, it is critical to maintain a modern and robust Enterprise Resource Planning (ERP) system. ERP system refers to a type of software that organizations use to manage day-to-day business activities such as accounting, procurement, project management, maintenance management and supply chain operations. Best practice is to update systems regularly to ensure that the systems are up to date. The project involves upgrades to the ERP system components to the recommended latest stable versions. System experts are contracted to help with individual components as these are critical systems and Yukon Energy has no inhouse expertise.

Request:

187. Given the cost of this program upgrade, will Yukon Energy now use this in-house capability instead of hiring your consultant?

Reference: ***Feasibility Study***
Table 5.4 2017-18
Total Feasibility Study WIP *8,589,838 1,090,716 (132,667) 9,547,887*
Table 5.6 2021
Total Feasibility Study WIP *9,833,270 7,370,000 (979,072) 16,224,199*

Request:

188. Confirm increase in WIP Feasibility Studies from 2017-18 to 2021 is $6,676,312.
189. Confirm increase in Total WIP from 201-18 GRA to 2021 is $11,394,258.

Reference: ***APPENDIX 5.3: DEFERRED PROJECTS >$1 MILLION NOT ADDED TO RATEBASE***
Deferred expenditure test year spending on major projects (i.e., expenditures over $1 million) retained in WIP is focused on projects required to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance), investments to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other potential future generation and transmission requirements.
Approximately $28.573 million of deferred costs are forecast to be incurred in WIP for major projects by the end of 2021. Details on actual and forecast expenditures by year are reviewed in Tables 5.2 to 5.6.
*• **Spending on Sustaining Capital:** Net deferred costs in WIP by end of 2021 of approximately $8.178 million:*
*1. **Aishihik Generating Station Water Use 25 Year Licence Renewal** – (forecast WIP cost of approximately $7.918 million by end of 2021 - project planned for completion in 2022).*
*2.**Whitehorse Rapids Generating Station Water Use Licence Renewal -** (forecast• **Spending to address Capacity Planning Requirements:** Net deferred costs in WIP by end of 2021 of approximately $6.395 million:*

*3. **Diesel Retirement Replacement (12.5 MW)** – (forecast WIP cost of approximately $6.395 million by end of 2021 planning, engineering, permitting, long-lead equipment procurement – total project planned for completion by 2024, with certain portions completed and in service starting in 2022).*

*• **Spending on planning to maximize renewable energy generation from existing facilities**: Net deferred costs in WIP by end of 2018 of approximately $14.000 million:*

*4. **Southern Lakes Storage (Marsh Lake Storage Enhancement Project)** – (forecast WIP cost of approximately $9.379 million by end of 2021 - project subject to ongoing review, potential in-service by 2023).*

*5. **Mayo Lake Storage Enhancement Project (including Mayo Lake Outlet Channel)** – (forecast WIP cost of approximately $4.621 million*

Request:

190. Although it appears Yukon Energy will not place these projects onto the rate base for the test year, is Yukon Energy now using this process to get regulatory approval for all of these projects lining up for $28.573 million in the WIP? Explain.
191. As Aishihik relicencing is lining up for almost $8 million in the WIP, explain how Yukon Energy justifies this cost?
192. Identify which firm/s managed/is managing this Aishihik license renewal from the beginning until now, what work was performed and at what cost.
193. Identify which firm/s managed/is managing the Whitehorse Station license renewal from the beginning until now, what work was performed and at what cost.
194. Does the Diesel Retirement Replacement cost of $6.395 million include the purchasing of any new generators? Explain.
195. Justify the costs for Southern Lakes Storage and Mayo Lake Enhancement, <u>for each,</u> including discussion of risks of not proceeding with these projects as well as discussion of assumptions included in the business case for escalation factors, loading, financial measures, term of project and associated ancillary costs, as per Board Order 2009-8.

Reference: ***APPENDIX 5.1: CAPITAL PROJECTS > $1 MILLION NOT IMPACTING RATE BASE***

Appendix 5.1 provides project summaries for capital projects with spending over the period from 2019 to 2021 exceeding $1 million that remain in WIP at the end of 2021 (and therefore do not affect the 2021 GRA revenue requirement). <u>Total forecast spending on these projects is forecast to grow from $1.129 million in 2019, to $2.860 million in 2020 to $31.966 in 2021.</u> The forecast material increase in 2021 spending relates largely to the Battery Energy Storage System project which has $25 million forecast spending in 2021. However, it is noted that spending for this project will be offset by a $16.5 million contribution. Further details on annual spending are summarized in Table 5.2-2.

As outlined below, spending for these projects is largely focused on: (1) capital works to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance); (2) investments to ensure sufficient dependable capacity for the integrated grid; and other projects.

• Capital Works to Address Sustaining Capital Requirements:

1. Dawson Voltage Conversion
2. MH0 (Mayo A) Generating Station Slope Stability
3. Replacement of Mayo A Surge Chamber
4. Stop Log Crane WH Main Spillway
5. Asset Management Framework

*• **Investments to Ensure Dependable Capacity**:*
6. Battery Energy Storage System (transfer from Feasibility)
7. Pumped Storage
8. Southern Lakes Transmission Line
9. Whitehorse Interconnection
*• **Other:***
10. Aishihik Contract DisputeWIP cost of approximately $0.260 million by end of 2021 - project planned for completion in 2025)

Request:

196. Is the total spending requested to go in WIP $31.966 million, or is this just forecast 2021?
197. Although it appears Yukon Energy will not place these projects onto the rate base for the test year, is Yukon Energy planning to use this process to get regulatory approval for all of these projects lining up for at least $31.966 million in the WIP? Explain.
198. Does Yukon Energy consider this a complete final capital review for each of these these above projects, to then transfer into rate base next rate hearing?

Reference: Sole-Sourced Contracts

Request:

199. Since 2018, including the 2017-18 regulatory proceedings before the Yukon Utilities Board, identify all expenditures related to work completed by InterGroup Consultants Ltd. on behalf of Yukon Energy Corporation.
200. Identify any of the above contracts given through a request for proposal or tender/bidding process.
201. Since 2018, including the 2017-18 regulatory proceedings before the Yukon Utilities Board, identify all expenditures related to work completed by John Landry LLB /DLAPiper on behalf of Yukon Energy Corporation.
202. Identify any of the above contracts given through a request for proposal or tender/bidding process.

Reference: YUB Order 2009-8, Appendix A, page 37

"*Further, in future GRA applications, the Board directs YEC to include business cases for major capital items, including electronic models. Business cases will include:*

- *descriptions of the project*
- *economic analysis including preliminary engineering estimates*
- *discussion of alternatives and how the chosen option was determined*
- *discussion of the risks of proceeding with the chosen alternative*
- *discussion of risks of not proceeding with the chosen alternative; and*
- *discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.*