YUKON ENERGY CORPORATION

Board Order 2022-03 – Compliance Filing

2021 General Rate Application

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1.0 OVERVIEW

On November 20, 2020, Yukon Energy filed with the Yukon Utilities Board ("the Board" or "YUB") its General Rate Application ("the Application") for 2021. By Order 2020-04, the Board established a process for review of that Application, and following that process on March 16, 2022, the Board issued Order 2022-03, approving the 2021 revenue requirements for Yukon Energy with the changes directed in the Reasons for Decision, and directing Yukon Energy to provide a compliance filing to the Board within 30 days in accordance with the directions set out in the Reasons for Decision (Appendix A attached to Order 2022-03).

This Compliance Filing sets out for approval of the Board the Yukon Energy revised filings as required by Order 2022-03, along with all related explanations[1]. References to particular directions reference the paragraph number provided in the Reasons for Decision.

This filing includes the following sections:

- **Section 1** – Overview of key changes to the Application based on the Board's directives, summary impact on proposed rate increase, and requested approvals.
- **Section 2** – Summary of Yukon Energy Response to Board Directives addressed in the Compliance Filing.
- **Section 3** – Tab 7 Revised Schedules (revised Tab 7 schedules from the Application with adjustments as required by Order 2022-03).

1.1 OVERVIEW OF KEY CHANGES BASED ON BOARD'S DIRECTIVES

Section 1.1 provides an overview of changes to the Application that result from Order 2022-03. Table 1.1 below provides a summary of the changes to the revenue requirement and revenues at pre-2021 GRA rates with VGC Group and Alexco Fixed Charges as outlined in Table 1.1-4a.

[1] As required, the filing addresses only those directions of the Board in its Reasons for Decision pertaining to Yukon Energy's 2021 revenue requirements.

Table 1.1:
Summary of Changes to the Revenue Requirement and Revenues at Existing Rates ($000)

		Original Filing	Compliance Filing	Change	Notes and Reference to YUB Order 2022-03
	Revenue Requirement				
	Fuel and Purchased Power	15,897	15,882	-15	*Please see Table 1.1-1 [§66]*
	Non Fuel O&M -Labour	13,310	13,016	-294	*Removal cost for three vacant positions [§90]*
	Non Fuel O&M -Other	16,120	15,559	-562	
	Costs for two spare diesel units			*-342*	*[§114]*
	Reserve for Injuries/Damages			*-220*	*[§134 and §135]*
	Depreciation and Amortization	13,125	12,766	-360	*Please see Table 1.1-2*
	Return on Rate Base	16,682	15,656	-1,027	*Please see Table 1.1-2*
A	**Total Revenue Requirement**	**75,135**	**72,878**	**-2,257**	
	Revenues at Existing Rates				
	Residential	2,384	2,384	0	
	Commercial	5,388	5,388	0	
	Industrial	11,535	11,481	-55	*Please see Table 1.1-4a*
				-119	*Lower fixed charges collected*
				64	*Additional fixed charges to be collected for 2021*
	Streetlight and Sentinel Light	84	84	0	
	Wholesale	28,507	28,507	0	
	Secondary Sales revenues	0	0	0	
	Rider J Revenues	15,897	15,887	-10	*Impact of reduced RS 39 fixed charge*
	Other Revenue	369	369	0	
B	**Total revenues at existing rates**	**64,164**	**64,100**	**-65**	
C=A-B	**Required GRA rate increase**	**10,971**	**8,779**	**-2,192**	

The following provides an overview of the key changes to the Application based on the Board's directions provided in the Reason's for Decision to Order 2022-03 (see Section 2 of this Compliance Filing for review of the related specific directives in the Order for each major element below):

1. **Sales Forecast** – There is no change in the sales forecast GWh in the Compliance Filing. The reduction of $0.055 million in Industrial revenues and related $0.010 million in Rider J revenues shown in Table 1.1 reflects adjustment to the VGC Group and Alexco Fixed Charges.[2]

2. **Generation and Forecast Thermal** – There is a small change in generation related to a 2 GWh reduction in forecast IPP generation updated as directed in paragraph 66 of Order 2022-03, offset by a resulting 1.6 GWh increase in LTA thermal generation [see Table 1.1-1]. This results in a $0.015 million reduction in fuel and purchase power expense.

3. **Non-Fuel O&M** – Overall decrease in non-fuel O&M of $0.856 million in 2021, compared to the Application forecast, reflecting the following:

    a. **Labour Expense** – Removal of costs for three vacant positions as directed in paragraph 90 of Order 2022-03 results in a $0.294 million reduction in labour expense.

    b. **Non-Fuel Other Expense** – Overall reduction in non-fuel other expense of $0.562 million. This includes reduction in production expense related to removal of costs for two spare diesel rental units ($0.342 million as per YUB-YEC-2-1 (c)) as directed in paragraph 114 of Order 2022-03; and reduction in Reserve for Injury and Damages expense of $0.220 million related to disallowance of COVID-19 expense and amortization of RFID balance over 10 years instead of 5 years as directed in paragraphs 134 and 135 of Order 2022-03.

4. **Return on Rate Base and Depreciation and Amortization Expense** – Order 2022-03 approved costs in 2021 for capital and deferred projects, subject to specific disallowed costs and other directed changes to depreciation and amortization expense (see Appendix 1.1, Tables 1.1-2 and 1.1-3 of this Compliance Filing for details). The capital structure was approved as proposed (60% debt and 40% equity), along with the cost of new debt. The return on equity was reduced from 8.7% to 8.2% (a reduction of 50 basis points from the Application) (see Table 1.1-2 for the impact on revenue requirement). The impact to these components from YUB directions in Board Order 2022-03 is as follows:

    a. **Mid-year Net Rate Base**: Compared to the Application, mid-year Net Rate Base as approved is approximately $12.192 million lower (at $310.585 million) in 2021 [see Table 1.1-2 and 1.1-3 for details].

    b. **Depreciation and Amortization Expense**: Final depreciation and amortization expense is lower than the Application by $0.360 million in 2021 [see Table 1.1, Table 1.1-2 and Table 1.1-3a for details].

[2] Table 1.1-4(a) shows actual VGC Group and Alexco 2021 fixed charges (column D) $118,698 below the forecast in the GRA Application (column A); however, column D in this table shows that with Order 2022-03 a $64,006 increase in fixed charges is required in 2021 above what was paid. Table 1.1 shows a net $0.055 million adjustment to the GRA Application forecast industrial revenues. The resulting "revenues at existing rates" of $64.1 million is the existing revenue available to fund the revenue requirement after taking into account final VGC Group and Alexco fixed charges required for 2021 as per Order 2022-03.

c. **Return on Rate Base**: Final return on rate base in 2021 is $1.027 million lower than the Application. [see Table 1.1].

5. **Rates and Stabilization Measures**

a. **Secondary Sales Rate** – No changes were directed regarding proposed secondary sales rate.

b. **Rider F –** Forecast fuel efficiencies and fuel prices are approved as proposed in the Application for 2021. The Rider F true-up determinations for the Compliance Filing are reviewed in Section 1.3.

c. **Low Water Reserve Fund (LWRF) –** Order 2022-03 approved the Low Water Reserve Fund (LWRF) term sheet which is provided in Appendix 2 of this Compliance Filing.

1.2 IMPACT OF CHANGES ON REQUIRED RATE INCREASE

Board Order 2022-03 approved the Yukon Energy 2021 revenue requirements subject to the adjustments that are required by the Order and the attached Reasons. Table 1.2 below provides the 2021 required revenues from rates with changes as directed by Order 2022-03. Table 1.3 provides the detailed required revenue increase calculation.

Table 1.2:
YEC 2021 Compliance Filing Revenue Required from Rates ($000s)

	2021
Revenue Requirement (from Table 1.1)	$72,878
Less: Other Revenues	$369
Less: Secondary Sales	$0
Revenue Required from Firm Rates	$72,510
Less: Revenues from Firm Sales at Existing Rates (including "Fixed" component of industrial Rider F)	$63,731
Firm Rate Increase Proposed	$8,779

Table 1.3:
YEC 2021 GRA Compliance Filing Required Revenue Increase Calculation

Line #			2021
1a	Consolidated Firm Retail Sales Revenues - Base Rates[1]	$000	61,574
1b	Consolidated Firm Industrial Sales Revenues - Base Rates	$000	11,481
2a	Consolidated Rider J Revenue at pre-GRA rates[2]	$000	15,887
2b	AEY Rider R Revenues[3]	$000	6,068
3=1+2	**Total Consolidated Firm Sales Revenues at existing rates**	$000	95,009
4=Table 1	Retail Revenue increase required in 2021	$000	8,779
5a=4/3	Required Rate Increase on total Consolidated Revenues	%	9.24%
5b=4/(1a+1b)	Rider J Increase Required	%	12.02%
6=3+4	**Total Consolidated Firm Sales Revenues with 2021 Increase**	$000	103,788
7	Total Cumulative 2021 Rate Increase		9.24%
	Rider J Required		
8=5b	Rider J Increase Required	%	12.02%
9	Existing Rider J - non-industrial	%	22.32%
10	Existing Rider J - industrial	%	18.67%
11=8+9	Total Rider J with increases - non-industrial	%	34.34%
12=8+10	Total Rider J with increases - industrial	%	30.69%

Notes:
1. Total Consolidated Retail Revenues at existing Base Rates include revenues from YEC and AEY's residential, general service and streetlight sales.

2. Consolidated Rider J revenues at pre-2021 GRA rates include YEC's Rider J at 22.32% for firm YEC and AEY retail sales and at 18.67% for firm industrial sales based on YUB 2019-08 Order.

3. AEY Rider R Revenues at existing rates include AEY's Rider R at 8.30% for firm retail and industrial base rate sales of YEC and AEY.

Compared to the 2021 GRA Application, Total Revenues at Existing Rates decreased by $0.065 million; while the total Revenue Requirement decreased by $2.257 million. This results in a net decrease in required GRA revenues of $2.192 million (required GRA rate increase of $8.779 million in the Compliance Filing compared to $10.971 million in the Application). These results are detailed in Tables 1.1 and 1.2.

The required Rider J rate increase resulting from Board Order 2022-03 for the 2021 test year (prior to consideration of interim rates and true up riders as required to address implementation of Order 2022-03) is 12.02% (see rows 5b and 8 in Table 1.3).

Order 2021-08 approved an interim refundable rate rider increase of 10.08% (Rider J) for retail firm rates and industrial firm rates for all electrical consumption on or after July 1, 2021. Order 2021-14 also approved an additional interim refundable Rider J of 9.25% (Rider J) (total interim refundable Rider J of 19.33 percentage points) for retail firm rates and industrial firm rates for all electrical consumption on or after December 1, 2021. A true-up rider is required to address the extent to which the interim refundable Rider J collected the compliance filing 2021 revenue requirement prior to the final Rider J approved for 2021 is implemented effective June 1, 2022. Detailed calculations supporting the calculation of the true up rider are provided in Appendix 1.1, Tables 1.1-4 to 1.1-7 and summarized below.

In order to implement the rate-related decisions from Board Order 2022-03 effective June 1, 2022, the following true-up adjustments are required as at that date:

- **Ongoing Rider J Adjustment** – Interim Rider J must be made final and decreased to final total cumulative rate increase of 9.24% for retail and industrial customers[3], effective June 1, 2022 (until the next General Rate Application or until such time as otherwise adjusted by the Board, e.g., at such time as Phase II matters are addressed and all riders are included in base rates). Rider J is accordingly adjusted to 34.34% for non-industrial customers and 30.69% for industrial customers.
- **Across the Board Time-limited Rider J1 Charge** – For recovery of revenue shortfall during 2021 and the first five months of 2022 a shortfall true up rider of 2.56% is required effective June 1, 2022. This rider is proposed to be applied for 24 months (timeline limited rider of 2.56% from June 1, 2022 to May 31, 2024) to recover a $3.835 million shortfall. This true up is required to address net shortfall in rate revenues for 2021 and the first five months of 2022 (see Appendix 1.1, Table 1.1-4 for details of the Rider J1 charge determination).
    - **True Up Adjustment for 2021** – The 2021 test year is to be finalized consistent with a reduction of $2.192 million in the required rate revenue increase ($8.779 million required rate increase in the Compliance Filing compared to $10.971 million as requested in the GRA Application). Interim Rider J collections over July to December 2021 were $3.852 million resulting in a shortfall of $4.927 million for 2021 compared to the $8.779 million compliance filing revenue shortfall.
    - **True Up Adjustment for 2022** – For January to May 2022 the forecast revenue surplus of $2.419 million reflects the difference between the final Rider J in this Compliance Filing and interim Rider J approved by the Board in Orders 2021-08 and 2021-14.
    - **Rider F Adjustment** – Pursuant to past practice, at each GRA the Rider F account relating to YEC is reset to zero for the Compliance Filing. All future calculations relating to Rider F will utilize the Board approved fuel prices and fuel efficiency for the 2021 test year as the base. The 2021 Rider F Adjustments (see Appendix 1.1, Table 1.1-6) equal the difference in fuel price forecast from actual fuel prices calculated by using the 2021 compliance filing fuel efficiency and fuel prices, as well as related variance between actual.[4] These adjustments provide for a $1.327 million increase true up requirement.

1.3 REQUESTED APPROVALS

Yukon Energy requests the following final approvals:

1. Approval to set an ongoing Rider J at 34.34% for retail customers and 30.69% for industrial customers, effective June 1, 2022, applicable to all YEC and AEY firm retail and industrial rates, including fixed Rider F and fixed charge payments for major industrial rates (all AEY recoveries from this rider would flow through to YEC).

[3] See Table 1.3. a 12.02 percentage point Rider J increase is required over the existing Rider J in effect prior to the 2021 GRA interim refundable rates, i.e., existing Rider J of 22.32% for retail customers and 18.67% for industrial customers.
[4] No secondary sales forecast in the 2021 GRA, therefore no secondary sales rate related adjustments are included.

2. Approval to set a time-limited Rider J1 of 2.56%, to be in effect from June 1, 2022 to May 31, 2024 [over 24-month period], applicable to all YEC and AEY firm retail and industrial rates (all AEY recoveries from this rider would flow through to YEC), to collect the remaining 2021 and 2022 net revenue shortfall as well as required Rider F adjustments for 2021. Effective May 31, 2024, Rider J1 would be set to zero.
3. Approval to collect RS39 Fixed Charge true-up of $200,810.5 required for 2021 and the first four months of 2022 from specific industrial customers, Alexco and Victoria Gold, as set out in Table 1.1-4a with recovery of $157,976.5 from VGC Group and $42,834.0 from Alexco. This true-up will be recovered on or before December 31, 2022 based on a payment schedule to be arranged with each customer. This true up charge will not be subject to Rider J or Rider J1 charges.

Appendix 1.1:
Supporting Tables

Table 1.1-1: 2021 GRA Fuel Cost Calculation ($000)

	2021 GRA Original Filing	2021 GRA Compliance Filing	Change
Gross YEC Load (MW.h)	538,726	538,726	0
IPPs (MW.h)	1,983	2	-1,981
YEC Load net of IPPs (MW.h)	536,743	538,724	1,981
LTA Thermal Generation (MW.h)	84,306	85,930	1,624
LNG	*75,875*	*77,337*	*1,462*
Diesel	*8,431*	*8,593*	*162*
Fuel Prices, $/kW.h			
LNG Price	$0.1814	$0.1814	$0.0000
Weighted Average Diesel price	$0.2051	$0.2051	$0.0000
LTA Fuel Cost, $000	**$15,490**	**$15,788**	**$298**
Maintennace run-ups (MW.h)			
Diesel Run-Ups	198	198	-
LNG Run-Ups	-	-	-
Total Maintenance, $000	**$41**	**$41**	**$0**
Total Fuel Cost, $000	**$15,530**	**$15,829**	**$298**
Purchased Power Cost, $000			
Wholesale	$52.9	$52.9	$0.0
IPPs	$314.0	$0.4	-$313.6
	$366.9	**$53.3**	**-$313.6**
Total Fuel and Purchased Power Cost, $000	**$15,897**	**$15,882**	**-$15**

Note:

1. The revised long-term average thermal generation for the Compliance Filing was calculated based on Table 2.1-1 in Appendix 2.1 of the Application reflecting updated 2021 generation net of IPPs at 538,724 MWh compared to 536,743 MWh in the Original Application illustrated in Table 1.1-1. The resulting LTA thermal generation for 2021 is 85,930 MWh compared to 84,306 MWh in the Original Application or increase of 1,624 MWh.

Table 1.1-2: Adjustments to the Ratebase, Return on Ratebase and Amortization Expense [see Table 1.1-3 for details of changes]

in $000	2021 GRA Application	YUB 2022-03 Compliance Filing	Adjustments
Calculation of Rate Base			
Property, Plant and Equipment			
2020 Year-end balance	**677,309**	**672,467**	**-4,842**
2021 Year-end balance	**738,663**	**728,282**	**-10,381**
Accumulated Amortization	198,970	198,339	-631
Construction-in-progress	37,389	40,572	3,183
Disallowed assets [reflects closed projects]	1,582	12,152	10,571
Miscellaneous reserves	5,012	7,647	2,635
Total Deductions	**242,953**	**258,711**	**15,758**
Deferred study costs	44,400	42,022	-2,379
Less: Studies in Progress	*-29,972*	*-30,489*	*-517*
Total Additions	***14,428***	***11,532***	***-2,896***
Previous Year Ending Balance	*486,307*	*484,894*	*-1,414*
Current Year Ending Balance	*510,138*	*481,103*	*-29,035*
Mid-year Balance	***498,223***	***482,999***	***-15,224***
Rate Case	***2,732***	***3,046***	***314***
Working Capital requirements	***7,141***	***7,092***	***-49***
Gross Mid-year Net Rate Base	**508,096**	**493,137**	**-14,959**
Net Mid-year Contributions	*185,319*	*182,552*	*-2,767*
Net Mid-year Net Rate Base	**322,777**	**310,585**	**-12,192**
Average Cost of Capital	*5.17%*	*5.04%*	*-0.13%*
Cost of debt	*2.81%*	*2.93%*	*0.12%*
ROE	*8.70%*	*8.20%*	*-0.50%*
Return on rate base	**16,682**	**15,656**	**-1,026**
Debt	*5,447*	*5,469*	*22*
ROE	*11,235*	*10,187*	*-1,048*
Total Return on rate base change			**-1,027**
Due to change of ROE and Debt cost			*-397*
Due to change in Rate base			-630
Net Amortization	**13,125**	**12,766**	**-360**
Fixed Asset Depreciation	*13,581*	*13,372*	*-209*
Customer contribution	*-4,461*	*-4,416*	*45*
Amortization of fire insurance recoveries	*-262*	*-262*	*0*
Disallowed Depreciation	*-204*	*-238*	*-34*
Amortization of deferred charges	*4,471*	*4,310*	*-161*
Rate Case	*767*	*683*	*-84*
Feasibility and Relicensing	*2,640*	*2,612*	*-28*
Dam safety	*93*	*64*	*-28*
Vegetation Management	*222*	*222*	*0*
Intangibles	*749*	*729*	*-20*
Total Impact to Revenue Requirement			**-1,386**

Table 1.1-3: Adjustments to the Ratebase [detailed]

in $000	2021 GRA Application	YUB 2022-03 Compliance Filing	Adjustments
Calculation of Rate Base			
Property, Plant and Equipment			
2020 Year-end balance	**677,309**	**672,467**	**-4,842**
Mayo to McQuesten Transmission Line Upgrade [§258] - cost update			*-3,014*
Replace P125 WH2 Head Gate [§270] - cost update			*-342*
N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure [§250] - Faro cost update			*409*
WH2 Uprate [§277, §278] - cost update, please also see Disallowed Costs			*-827*
WH4 Uprate - Servomotor [§280, §282] - cost update, please also see Disallowed Costs			*-146*
Dam Safety Recommendations 2017-18 [§285, §289] - cost update			*-176*
Wareham Gate Refurbishment [§285, §289] - cost update			*-104*
L177 Re Route [§285, §289] - cost update			*-1*
Transmission Line Access [§285, §289] - cost update			*-297*
Mayo Earthworks [§285, §289] - cost update			*-262*
Vehicle Purchases [§285, §289] - cost update			*52*
Water Improvement Upgrades [§285, §289] - cost update			*-94*
Building Upgrades [§285, §289] - cost update			*-39*
2021 Year-end balance	**738,663**	**728,282**	**-10,381**
2020 adjustments			*-4,842*
Mayo to McQuesten Transmission Line Upgrade [§258] - cost update			*932*
Replace P125 WH2 Head Gate [§270] - cost update			*-3,479*
WAF L178 [§265] - cost update, please also see WIP			*-1,000*
WH2 Uprate [§277, §278] - cost update, please also see Disallowed Costs			*1,057*
WH4 Uprate - Servomotor [§280, §282] - cost update, please also see Disallowed Costs			*15*
L177 Re Route [§285, §289] - cost update			*-175*
Protection and Control Program [§285, §289] - cost update			*-175*
Mayo Earthworks [§285, §289] - cost update			*50*
New Mobile Office Unit - IT [§285, §289] - cost update			*-230*
Vehicle Purchases [§285, §289] - cost update			*-98*
Water Improvement Upgrades [§285, §289] - cost update			*7*
WH4 Ventilation [§285, §287] - please also see WIP - cost update			*-600*
FD7 Overhaul [§285, §289] - cost update			*-580*
Compact Digger Truck [§285, §289] - cost update			*-185*
WH2 Uprate Engineering study [moved from defferred - please see deffered costs below]			*259*
Disposals [assets replaced by Mayo to McQuesten Transmission Line Upgrade]			*-1,337*
Accumulated Amortization	**198,970**	**198,339**	**-631**
Disposals [assets replaced by Mayo to McQuesten Transmission Line Upgrade]			*-417*
Other adjustments			*-5*
Capital additions update and Life parameters update - Please see Table 1.1.- 3 a			*-209*
Construction-in-progress	**37,389**	**40,572**	**3,183**
Vehicle Purchases [§289] - moved to WIP			*482*
Replace P125 WH2 Head Gate [§270]- moved to WIP			*2,072*
L177 Re Route [§289]- moved to WIP			*179*
WAF L178 [§265]- moved to WIP			*300*
WH4 Ventilation [§285, §287]- moved to WIP			*150*
Disallowed assets [net book value]	**1,582**	**12,152**	**10,571**
Due to loss of DSM Appeal, $1.593 million DSM disallowed costs in the 2017/18 GRA have been written off [UCG-YEC-2-16-2 (a)]. The cost at $1.593 million and amortization impact at $0.319 million to net change of $1.274 million.			*-1,274*
WH2 Uprate [§278]			*6,531*
WH4 Uprate - Servomotor [§282]			*851*
Enterprise Asset Management [§333]			*4,657*
Enterprise Asset Management amortization			*-194*
Miscellaneous reserves	**5,012**	**7,647**	**2,635**
Added LWRF [§368]			*2,782*
RFID balance change [§134 and §135]			*-146*
Total Deductions	**242,953**	**258,711**	**15,758**

Table 1.1-3: Adjustments to the Ratebase [detailed] [cont'd]

Deferred Study Costs and Intangibles	**44,400**	**42,022**	**-2,379**
2020 and 2021 Cost Updates [§316, §323]:			
Aishihik Relicensing – Three-Year Licence Renewal - cost update			*-88*
Mayo and Aishihik Hydro Climate Change Study - cost update			*28*
Transmission Access Road Program Study - cost update			*-245*
IPP Standing Offer Program Implementation - cost update			*98*
Mt. Sumanik Wind Feasibility Study - cost update			*-25*
Dam Safety Review - cost update			*-61*
Building Condition Reports 2021-2024 - cost update			*-175*
Whitehorse Diesel Rental Substation Improvements - cost update			*-100*
ERP System Upgrades Project [§335] - cost update			*-42*
WH2 Uprate Eng. Study [moved to PP&E - page 5.4-3, footnote 1 of the Application]			*-259*
DSM adjustments [§310, §311]			*-1,549*
DSM 2021			*-774*
DSM 2020			*-283*
DSM cost write-off [$0.399 million 2019 costs and $0.093 million 2018 costs]			*-492*
Enterprise Asset Management [§331] - cost update			*-281*
Increase in Hearing Reserve [YUB Order 2020-02]			*124*
Amortization impact of 2020 and 2021 changes			*197*
Less: Studies in Progress [also includes Rate Case]	*-29,972*	*-30,489*	*-517*
Atlin Hydro EPA Preparation [§316, §322]			*-517*
Total Additions [reflect above changes]	***14,428***	***11,532***	***-2,896***
Previous Year Ending Balance [reflect above changes]	*486,307*	*484,894*	*-1,414*
Current Year Ending Balance [reflect above changes]	*510,138*	*481,103*	*-29,035*
Mid-year Balance [reflect above changes]	***498,223***	***482,999***	***-15,224***
Rate Case	***2,732***	***3,046***	***315***
Atlin Hydro EPA Preparation Cost [§316, §323] - cost update, please see Studies in Progress			*315*
Working Capital requirements [reflects changes in spending and revenues]	***7,141***	***7,092***	***-49***
Gross Mid-year Net Rate Base	**508,096**	**493,137**	**-14,959**
Net Mid-year Contributions	*185,319*	*182,552*	*-2,767*
2020 ending balance [please see below]	*183,149*	*180,255*	*-2,895*
Mayo to McQuesten Transmission Line Upgrade [§258]			*-2,895*
2021 ending balance	*187,488*	*184,849*	*-2,639*
Mayo to McQuesten Transmission Line Upgrade - 2020			*-2,895*
Mayo to McQuesten Transmission Line Upgrade - 2021			*211*
Amortization impact			*45*
Net Mid-year Net Rate Base	**322,777**	**310,585**	**-12,192**

Table 1.1 -3a): Adjustments to the Fixed Asset Depreciation Expense [detailed]

in $000	2021 GRA Application	YUB 2022-03 Compliance Filing	Adjustments	Note
Fixed Asset Depreciation	**13,581**	**13,372**	**-209**	
Hydro Plant				
Structures and Improvements	*523*	*488*	*-35*	*Capital additions update*
Reservoirs, Dams, and Waterways	*1,685*	*1,683*	*-2*	*Capital additions update*
Waterwheels,Turbines & Generation	*439*	*310*	*-129*	*Life change from 60 to 85*
Diesel Production				
Accessory Electric Equipment	*200*	*209*	*9*	*Capital additions update*
Main Transmission Facilities				
Poles and Fixtures	*1,720*	*1,277*	*-443*	*Life change from 50 to 65; Capital additions update*
Survey Costs	*199*	*149*	*-50*	*Capital additions update*
Substation Equipment	*1,578*	*1,314*	*-264*	*Life change from 45 to 54*
Substation VGC Group - Gold Mine	*238*	*891*	*653*	*Life change from 45 to 12*
Depreciation Study Differences	*-80*	*35*	*114*	*Depreciation variance for VG Substation [§195]*
Sub Transmission Lines				
Poles and Fixtures	*90*	*67*	*-23*	*Life change from 50 to 65; Capital additions update*
Substation Equipment	*178*	*148*	*-30*	*Life change from 45 to 54*
Distribution System	*530*	*526*	*-4*	*Capital additions update*
Building and Other Equipment				
Building and Improvements	*213*	*191*	*-22*	*Life change from 50 to 55; Capital additions update*
Other	*559*	*549*	*-10*	*Capital additions update*
Transportation	*431*	*455*	*24*	*Capital additions update*

Table 1.1 -3b): VG Substation Depreciation True-up Calculation [§195]

in $000	Total Cost	2019-2020 Depreciation [Assets 54 Years; Contributions 12 Years]	2019-2020 Depreciation [Assets and Contributions 12 Years]	2019-2020 Depreciation Variance	Remaining Life	Depreciation Variance Annual True-up
	A	**B**	**C**	**D=C-B**	**E**	**F=D/E**
Capital Assets [net of $930,563 YEC cost]	10,688.6	326.5	1,469.1	1,142.6	10.0	114.3
Contributions	10,688.6	1,469.1	1,469.1	0.0	10.0	0.0
Net Cost	0.0	-1,142.6	0.0	1,142.6		114.3

Table 1.1-3 c): LWRF Calculations for 2021 [based on actuals]

Line No		2019	2020	2021		Notes
L1a	Diesel Fuel Cost per kW.h	26.333	26.333	20.507	cents/kW.h	GRA Average Fuel cost
L1b	LNG Fuel Cost per kW.h	14.668	14.668	18.136	cents/kW.h	
L1c	GRA YIS firm Load forecast	420,265	420,265	538,724	MW.h	
L1d	GRA LTA Thermal Generation forecast	16,355	16,355	84,306	MW.h	
Calculation of Thermal Cost to Charge (Refund) LWRF						
	Assumptions					
L2	YEC Grid load	440,676	504,793	527,351	MW.h	Actual
L3	Fish Lake	4,964	5,034	9,843	MW.h	Actual
L4=L2+L3	Total Grid load	445,639	509,827	537,194	MW.h	
	Assumed Actual Generation Sources					
L5	YECL Fish Lake	4,964	5,034	9,843	MW.h	Actual
L6	YEC Hydro	370,818	435,356	488,132	MW.h	assumed actual (L2-L7-L8)
L7	YEC Thermal	69,858	69,437	39,216	MW.h	Actual
	Diesel	3,793	21,723	17,671	MW.h	Actual
	LNG	66,065	47,714	21,545	MW.h	Actual
L7a	*YEC Diesel/LNG charged to capital, RFID and maintenance*	1,653	71	527	MW.h	Actual
L7a1	*Diesel*	1,482	71	466	MW.h	Actual
L7a2	*LNG*	171	-	61	MW.h	Actual
L7b=L7-L7a	*YEC Net Diesel/LNG*	68,205	69,366	38,689	MW.h	Actual
L7b1	*Diesel*	2,311	21,652	17,204	MW.h	Actual
L7b2	*LNG*	65,894	47,714	21,485	MW.h	Actual
L7b3=L7b1/L7b	*Diesel % of total net thermal*	*3%*	*31%*	*44%*		
L8	IPPs	0	0	2	MW.h	Actual
L9	Total Grid load	445,639	509,827	537,194	MW.h	
	LTA Expected Generation Sources					
L10	AEY Fish Lake (expected)	8,391	8,391	8,730	MW.h	Note 1
L11	IPPs (expected)	0	0	2	MW.h	Note 2
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	437,248	501,436	528,462	MW.h	
L13=L12-L1c+L11	Load Variance	16,984	81,171	-10,260	MW.h	
L14	LTA Thermal Generation at Actual Load	25,300	67,443	77,599	MW.h	Estimated based on LWRF Term Sheet
L15=L7b/L14	Actual Thermal Generation as % of LTA Thermal Generation	270%	103%	50%		
L16=L14	Expected YEC Thermal Generation in Rates	25,300	67,443	77,599	MW.h	Estimated based on LWRF Term Sheet
L16a	Diesel	*2,530*	*21,052*	*17,204*	MW.h	Total thermal less LNG below.
L16b	LNG	*22,770*	*46,391*	*60,395*	MW.h	90% of total thermal, subject to not exceeding total thermal less estimated diesel (when L15>100%) or actual diesel (when L15<100%).
L17=L7b	YEC Net Thermal Generation	68,205	69,366	38,689	MW.h	
L17a=L7b1	Diesel	*2,311*	*21,652*	*17,204*	MW.h	
L17b=L7b2	LNG	*65,894*	*47,714*	*21,485*	MW.h	
L18=L17-L15	YEC Thermal Generation to be included in LWRF	42,905	1,923 -	38,910	MW.h	
L18a=L17a-L16a	YEC Diesel Generation to be included in LWRF	-219	600	-	MW.h	
L18b=L15b-L16b	YEC LNG Generation to be included in LWRF	43,124	1,323 -	38,910	MW.h	
L19=L1axL18a+L1bxL18b	Incremental YEC Thermal Generation Cost to Charge (Refund) LWRF ($000s)	$6,268	$352	($7,057)		

Notes:

1. YEC's 2021 GRA assumed Fish Lake generation at 3.628 GWh for 2021 based on information provided by AEY at the time of preparation of the GRA application. This forecast assumed that only one unit would be available in 2021. However, in 2021 actual year both units were in service. Therefore, Fish Lake expected generation for 2021 is based on long-average generation as approved by YUB Order 2014-06.
2. IPP generation as updated for YEC's 2021 GRA Compliance Filing for YUB Order 2022-03.

Table 1.1-3 c) i): LWRF Continuity Schedule

Line	Activity	2017 ($000s)	2018 ($000s)	2019 ($000s)	2020 ($000s)	2021 ($000s)
A	**Opening Balance[1]**	**$9,485**	**$6,709**	**$3,379**	**($3,900)**	**($4,272)**
B	Incremental Diesel Generation Cost to Charge/(Refund)[2] to LWRF	$0	$534	$6,268	$352	($7,057)
C=B	Total LWRF operation for YEC					
	YEC pays to LWRF	$0	$0	$0	$0	$7,057
	YEC withdraws from LWRF	$0	($534)	($6,268)	($352)	$0
D=A+C	**LWRF Balance after Annual Operation**	**$9,485**	**$6,176**	**($2,889)**	**($4,252)**	**$2,784**
E	**Interest on LWRF Balance[3]**	**$86**	**$76**	**($7)**	**($20)**	**($3)**
F=D+E	**LWRF Balance after Interest charge**	**$9,570**	**$6,252**	**($2,896)**	**($4,272)**	**$2,782**
G	**Rider E (Rebate)/Collections [January - December]**	**($2,861)**	**($2,874)**	**($1,004)**	**$0**	**$0**
H=F+G	**LWRF Ending Balance**	**$6,709**	**$3,379**	**($3,900)**	**($4,272)**	**$2,782**
I	**LWRF Cap [4]**		**`+/-8000**	**`+/-8000**	**`+/-8000**	**`+/-16000**
J	**LWRF Rebate/(Collections) Required**		**$0**	**$0**	**$0**	**$0**

Notes:

1. Opening Balance is based on 2016 DCF ending balance as provided in DCF 2016 Annual Filing.
2. 2021 is based on calculations in Table 1.1-3 c) using GRA Compliance Filing forecasts.
3. Per the March 11, 1996 letter recording the settlements [provided as Exhibit B-16 in the 2008/2009 GRA] the DCF fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit.
4. LWRF cap was increased to +/- $16 million as per YUB Order 2022-03.

Table 1.1-4: Determination of 2021 Revenue Shortfall True-up Rider

Line No.		Reference	June 1, 2022 Rate Implementation $000
	2021		
1	2021 GRA Compliance Filing Revenue Requirement	Table 1.1	72,878.3
2	2021 Revenues at pre-GRA rates	Table 1.1	64,099.5
3	Revenue Shortfall/(Surplus)	L1 - L2	8,778.7
	Interim Rider J collections		
4	July 1, 2021 - December 31, 2021 Interim Rider J Collections		3,851.9
5	**Net 2021 Revenue Shortfall/(Surplus) True-up**	**L3 - L4**	**4,926.8**
6	**Jan - May 2022 Revenue Shortfall/(Surplus) True-up**	**Table 1.1-5**	**-2,419.0**
7	**Transfer of Rider F Adjustments**	**Table 1.1-6**	**1,326.8**
8	**Total Net Revenue Shortfall/(Surplus) True-up**	**L5 + L6 + L7**	**3,834.6**
	Consolidated Revenues at Base Rates for June 1, 2022 to May 31, 2024 [24 months]		
9	Consolidated Non-industrial	Table 1.1-7	125,612.4
10	Consolidated Industrial	Table 1.1-7	24,339.8
11	**Total Consolidated Revenues at Base Rates**	**L9 + L10**	**149,952.2**
12	**2021 and Jan-May 2022 Revenue Shortfall True-up Rider J1 effective June 1, 2022**	**L8 / L11**	**2.56%**

Table 1.1-4a): Yukon Energy Corporation 2021 GRA Compliance Filing: VCG Group and Alexco Fixed Charges

	Included in the Original Application	Calculated based on YUB 2022-03 and in-service dates for new assets	Variance for Compliance Filing	Billed Fixed Charges [Apr-Dec interim]	Required True-up
	A	B	C=B-A	D	E=B-D
2021					
January	$35,734.4	$9,440.2	-$26,294.2	$8,402.0	$1,038.2
February	$35,734.4	$9,440.2	-$26,294.2	$8,402.0	$1,038.2
March	$35,734.4	$9,440.2	-$26,294.2	$8,402.0	$1,038.2
April	$35,734.4	$29,569.0	-$6,165.4	$31,656.5	-$2,087.5
May	$35,734.4	$29,569.0	-$6,165.4	$31,656.5	-$2,087.5
June	$35,734.4	$29,569.0	-$6,165.4	$31,656.5	-$2,087.5
July	$35,734.4	$29,569.0	-$6,165.4	$31,656.5	-$2,087.5
August	$35,734.4	$29,569.0	-$6,165.4	$31,656.5	-$2,087.5
September	$35,734.4	$29,569.0	-$6,165.4	$31,656.5	-$2,087.5
October	$35,734.4	$29,569.0	-$6,165.4	$31,656.5	-$2,087.5
November	$35,734.4	$69,408.6	$33,674.2	$31,656.5	$37,752.1
December	$35,734.4	$69,408.6	$33,674.2	$31,656.5	$37,752.1
Total	**$428,812.8**	**$374,120.4**	**-$54,692.4**	**$310,114.5**	**$64,005.9**
2022					
January		$65,857.6		$31,656.5	$34,201.1
February		$65,857.6		$31,656.5	$34,201.1
March		$65,857.6		$31,656.5	$34,201.1
April		$65,857.6		$31,656.5	$34,201.1
Total Jan-May 2022					**$136,804.6**
Total true-up					**$200,810.5**

2021 Actual Sales	MWh	% share	Share of true-up
Victoria Gold	36,976	78.7%	$157,976.5
Alexco	10,026	21.3%	$42,834.0
Total	47,001		$200,810.5

Notes:

1. The fixed charges included in the Application are from page 1-8 of the Application and Table 4.3-2 in Appendix 4.3.

2. Calculated fixed charges in the Compliance Filing reflect the following:

* full year impact of McQuesten substation net cost
* March 15, 2021 completion date for the new transmission line
* October 28, 2021 completion date for Statcom

3. The fixed charges for Jan-April 2022 are based on YEC's Limited Scope Application filed on April 8, 2022.

Table 1.1-4a) i): YEC Transmission Facilities Fixed Costs in Rate Base

		2020	2021
	Existing Transmission net costs		
1	Year End Net Cost*	2,244,721	1,155,849
2	Annual Depreciation*	37,222	18,069
3	Accumulated Depreciation*	646,100	288,640
4=1-3	Year End Net Book Value	1,598,621	867,209
5	Rate Base [3 months of 2020 + 9 months of 2021]		**1,050,062**
	Total New Transmission Facilities Fixed Costs		
	YEC's McQuesten Substation Costs**		
6	Year End Net Cost [net of contributions]	930,563	930,563
7	Annual Depreciation	17,233	17,233
8	Accumulated Depreciation	28,422	45,655
9=6-8	Year End Net Book Value	902,141	884,908
10	Mid-Year Rate Base		**893,525**
	Transmission Facilities Development***		
11	Year End Cost	0	15,719,005
12	Year End Contributions	0	-11,441,795
13=11+12	Year End Net Cost	0	4,277,211
14	Depreciation [Apr - Dec]	0	53,446
15	Accumulated Depreciation	0	53,446
16=13-15	Year End Net Book Value	0	4,223,765
17	Rate Base [9 months]		**3,167,824**
	SVC/Statcom Costs***		
18	Year End Cost	0	13,219,598
19	Year End Contributions	0	-9,622,487
20=18+19	Year End Net Cost	0	3,597,111
21	Depreciation [Nov - Dec]	0	64,058
22	Accumulated Depreciation	0	64,058
23=20-22	Year End Net Book Value	0	3,533,053
24	Rate Base [2 months]		**588,842**
	Total New Transmission Facilities Fixed Costs		
25=10+17+24	**Rate Base**		**4,650,190**
26=7+14+21	**Depreciation**		**134,737**

Notes:

* 2021 cost and depreciation for the existing assets reflect retirement of portion of the transmission line as new transmission line replaced about 32 km of 52 km of existing line.

** VGC Group PPA Section 7.7 (b) notes Fixed Charge will include YEC's McQuesten Substation Costs. As per section 6 (d) YEC's McQuesten Substation Costs after VGC Group contributions at $930,563.

*** Transmission Facilities completed on March 15, 2021; SVC/Statcom on October 28, 2021.

Table 1.1-4a) ii): Adjusted Transmission Facilities Fixed Charge Calculation for Jan-March 2021

	2021	
Existing Transmission Facilities		
Rate Base	$1,050,062	Table 1, Line 5
Average Cost of Capital (2021 GRA Compliance Filing)	5.04%	
Return on Rate Base	$52,931	
Depreciation	$18,069	Table 1, Line 2
Subtotal existing facilities	**$71,000**	
YEC's McQuesten Substation Costs [net of contributions]		
Rate Base	$893,525	Table 1, Line 10
Average Cost of Capital (2021 GRA Compliance Filing)	5.04%	
Return on Rate Base	**$45,040**	
Depreciation	$17,233	Table 1, Line 7
Subtotal new facilities	**$62,273**	
Total Transmission Facilities Fixed Cost	**$133,273**	
Fixed Charge at 85% of annual costs	$113,282	
Fixed Charge per month	$9,440.2	

Major Industrial Use of Transmission Facilities	Sales, MW.h
Victoria Gold	43,147
Alexco	9,794

Monthly Fixed Charges, $/month	**Jan-March 2021**
Victoria Gold	$7,693.84
Alexco	$1,746.37
Total	$9,440.21

Table 1.1-4a) iii): Adjusted Transmission Facilities Fixed Charge Calculation for Apr-Oct 2021

	2021	
Existing Transmission Facilities		
Rate Base	$1,050,062	Table 1, Line 5
Rate Base adjusted for 7 months	$612,536	
Average Cost of Capital (2021 GRA Compliance Filing)	5.04%	
Return on Rate Base	$30,876	
Annual Depreciation	$18,069	Table 1, Line 2
Depreciation adjusted for 7 months	$10,541	
Subtotal existing facilities	**$41,417**	
New Transmission Facilities [net of contributions] - Excluding Statcom		
Rate Base	$4,061,348	Table 1, Line 10 + Line 17
Rate Base adjusted for 7 months	$2,985,086	
Average Cost of Capital (2021 GRA Compliance Filing)	5.04%	
Return on Rate Base	**$150,471**	
Annual Depreciation	$70,679	Table 1, Line 7 + Line 14
Depreciation adjusted for 7 months	$51,621	
Subtotal new facilities	**$202,092**	
Total Transmission Facilities Fixed Cost	**$243,509**	
Fixed Charge at 85% of annual costs	$206,983	
Fixed Charge per month	$29,569.0	
Major Industrial Use of Transmission Facilities	Sales, MW.h	
Victoria Gold	43,147	
Alexco	9,794	
Monthly Fixed Charges, $/month	**April-Oct 2021**	
Victoria Gold	$24,098.93	
Alexco	$5,470.03	
Total	$29,568.96	

Table 1.1-4a) iv): Adjusted Transmission Facilities Fixed Charge Calculation for Nov-Dec 2021

	2021	
Existing Transmission Facilities		
Rate Base	$1,050,062	Table 1, Line 5
Rate Base adjusted for 2 months	$175,010	
Average Cost of Capital (2021 GRA Compliance Filing)	5.04%	
Return on Rate Base	$8,822	
Annual Depreciation	$18,069	Table 1, Line 2
Depreciation adjusted for 2 months	$3,012	
Subtotal existing facilities	**$11,833**	
New Transmission Facilities [net of contributions]		
Rate Base	$4,650,190	Table 1, Line 25
Rate Base adjusted for 2 months	$1,441,724	
Average Cost of Capital (2021 GRA Compliance Filing)	5.04%	
Return on Rate Base	**$72,674**	
Annual Depreciation	$134,737	Table 1, Line 26
Depreciation adjusted for 2 months	$78,807	
Subtotal new facilities	**$151,481**	
Total Transmission Facilities Fixed Cost	**$163,314**	
Fixed Charge at 85% of annual costs	$138,817	
Fixed Charge per month	$69,408.6	
Major Industrial Use of Transmission Facilities	Sales, MW.h	
Victoria Gold	43,147	
Alexco	9,794	
Monthly Fixed Charges, $/month	**Nov-Dec 2021**	
Victoria Gold	$56,568.50	
Alexco	$12,840.05	
Total	$69,408.55	

Table 1.1-5: Yukon Energy Corporation 2021 GRA Compliance Filing: True-up calculation for Jan - May 2022

	YEC Retail Revenues				YEC Industrial Revenues				AEY Retail Revenues				
	at Base Rates	Required Rider J Increase as per Table 1.3	Calculated Interim Rider J with 19.33%	Difference	at Base Rates	Required Rider J Increase as per Table 1.3	Calculated Interim Rider J with 19.33%	Difference	AEY retail revenues at Base Rates	Required Rider J Increase as per Table 1.3	Calculated Interim Rider J with 19.33%	Difference	Total Difference
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	
2022 Forecast													
January	824.5	99.1	159.4	- 60.3	1,023.8	123.0	197.9	- 74.9	5,812.0	698.4	1,123.5	- 425.1	- 560.2
February	797.1	95.8	154.1	- 58.3	904.0	108.6	174.7	- 66.1	5,125.1	615.9	990.7	- 374.8	- 499.2
March	769.2	92.4	148.7	- 56.3	1,075.8	129.3	207.9	- 78.7	5,082.6	610.8	982.5	- 371.7	- 506.6
April	652.2	78.4	126.1	- 47.7	1,023.9	123.0	197.9	- 74.9	4,417.5	530.8	853.9	- 323.1	- 445.6
May	579.3	69.6	112.0	- 42.4	989.7	118.9	191.3	- 72.4	4,000.0	480.7	773.2	- 292.5	- 407.3
Total Jan-May 2022	**3,622.4**	**435.3**	**700.2**	**- 264.9**	**5,017.2**	**602.9**	**969.8**	**- 366.9**		**2,936.5**	**4,723.7**	**- 1,787.2**	**- 2,419.0**

Notes:
1. Please see Table 1.1-7 for details.

Table 1.1-6: Yukon Energy Corporation 2021 GRA Compliance Filing
Rider F Adjustments for True-up ($)

Line No.	Month	Fuel Price Variance [Original][1]	Fuel Price Variance [Revised][2]	RS 32 SS Adjustment[3]	Rider F Surcharge - Industrial	Rider F Surcharge - CIS	Inter-company Transfer	Balance
		A	B	C	D	E	F	G
Based on 2017/18 GRA inputs								
1	FPVA 2021 Opening Balance							-2,276,392
2	Jan-21	-155,407		0	85,202	84,362	349,743	-1,912,493
3	Feb-21	-254,051		0	85,293	56,605	326,044	-1,698,602
4	Mar-21	-5,406		0	99,170	63,596	268,831	-1,272,410
5	Apr-21	-7,206		0	104,724	58,382	271,281	-845,229
6	May-21	-29,148		0	94,311	43,025	149,712	-587,328
7	Jun-21	303		0	111,875	44,575	106,736	-323,840
8	Jul-21	385		0	0	38,085	64,742	-220,627
9	Aug-21	-8,955		0	0	484	-334	-229,432
10	Sep-21	14,203		0	0	-5	104	-215,130
11	Oct-21	-51,828		0	0	-4	-40	-267,002
12	Nov-21	-328,916		0	0	44	-19	-595,893
13	Dec-21	-647,485		0	0	-2	-21	-1,243,400
14	**December 31, 2021 Balance**							-1,243,400

Line No.	Month	Fuel Price Variance [Original][1]	Fuel Price Variance [Revised][2]	RS 32 SS Adjustment[3]	Rider F Surcharge - Industrial	Rider F Surcharge - CIS	Inter-company Transfer	Balance
		A	B	C	D	E	F	G
Based on 2021 GRA inputs								
15	FPVA 2021 Opening Balance							-2,276,392
16	Jan-21		-90,230	0	85,202	84,362	349,743	-1,847,316
17	Feb-21		-326,252	0	85,293	56,605	326,044	-1,705,626
18	Mar-21		-23,378	0	99,170	63,596	268,831	-1,297,407
19	Apr-21		-44,098	0	104,724	58,382	271,281	-907,118
20	May-21		-7,664	0	94,311	43,025	149,712	-627,733
21	Jun-21		-979	0	111,875	44,575	106,736	-365,527
22	Jul-21		-7,568	0	0	38,085	64,742	-270,268
23	Aug-21		-33,407	0	0	484	-334	-303,524
24	Sep-21		21,535	0	0	-5	104	-281,891
25	Oct-21		-58,382	0	0	-4	-40	-340,317
26	Nov-21		-267,790	0	0	44	-19	-608,082
27	Dec-21		-718,651	0	0	-2	-21	-1,326,755
28	**Total Adjustment**							-1,326,755

Notes:
1. Based on 2017/18 GRA fuel prices and fuel efficiencies.
2. Based on 2021 GRA fuel prices and fuel efficiencies.
3. No secondary sale rate impact as no sales forecast for 2021 in the GRA.

Table 1.1-7: Yukon Energy Corporation 2021 GRA Compliance Filing: Consolidated Revenues for True-up[5]

	YEC Retail Non-Industrial Base Rate Revenue Forecast		YEC Industrial Base Rate Revenue Forecast					AEY retail revenues at Base Rates	Total Consolidated Base Rate Revenues
	Retail Sales	Revenues at Base Rates	Minto Sales	VG Sales	Alexco Sales	Total Industrial Sales	Revenues at Base Rates		
	MW.h	$000	MW.h	MW.h	MW.h	MW.h	$000	$000	$000
2022 Forecast									
January	5,195.9	824.5	4,174.8	2,739.1	1,099.3	8,013.2	1,023.8	5,812.0	7,660.4
February	5,028.9	797.1	3,763.2	1,767.9	1,029.4	6,560.5	904.0	5,125.1	6,826.2
March	4,793.4	769.2	4,326.0	3,062.4	1,243.8	8,632.2	1,075.8	5,082.6	6,927.6
April	4,083.0	652.2	3,946.8	3,680.2	820.1	8,447.1	1,023.9	4,417.5	6,093.7
May	3,593.3	579.3	3,741.6	3,698.2	720.7	8,160.5	989.7	4,000.0	5,568.9
June	3,617.2	587.3	3,918.3	3,932.2	832.9	8,683.3	1,033.9	3,717.4	5,338.5
July	3,327.6	540.1	3,908.6	3,950.2	856.2	8,715.0	1,035.1	3,654.2	5,229.3
August	3,061.4	497.2	3,559.2	3,968.2	884.2	8,411.6	1,001.4	3,752.2	5,250.8
September	3,514.4	571.4	3,610.9	3,986.2	764.4	8,361.5	1,007.5	4,056.7	5,635.6
October	3,239.5	521.7	4,007.0	4,004.2	1,011.1	9,022.2	1,069.4	4,528.2	6,119.3
November	3,738.0	597.8	3,959.7	4,022.2	1,011.1	8,993.0	1,067.0	5,101.5	6,766.3
December	3,614.7	573.1	4,007.0	2,424.1	1,011.1	7,442.2	938.4	5,689.3	7,200.8
Total 2022	**46,807.4**	**7,511.1**	**46,923.2**	**41,234.8**	**11,284.3**	**99,442.2**	**12,169.9**	**54,936.6**	**74,617.6**
2023 Forecast									
January	4,530.7	716.6	4,174.8	2,739.1	1,099.3	8,013.2	1,023.8	5,823.2	7,563.6
February	4,260.7	669.5	3,763.2	1,767.9	1,029.4	6,560.5	904.0	5,209.0	6,782.5
March	4,271.1	675.2	4,326.0	3,062.4	1,243.8	8,632.2	1,075.8	5,119.3	6,870.3
April	4,273.2	682.7	3,946.8	3,680.2	820.1	8,447.1	1,023.9	4,480.2	6,186.9
May	3,540.6	569.6	3,741.6	3,698.2	720.7	8,160.5	989.7	4,065.0	5,624.3
June	3,110.1	502.1	3,918.3	3,932.2	832.9	8,683.3	1,033.9	3,788.8	5,324.7
July	3,974.9	647.4	3,908.6	3,950.2	856.2	8,715.0	1,035.1	3,706.4	5,388.8
August	3,854.8	628.9	3,559.2	3,968.2	884.2	8,411.6	1,001.4	3,803.6	5,433.9
September	3,974.3	647.4	3,610.9	3,986.2	764.4	8,361.5	1,007.5	4,126.9	5,781.9
October	3,471.4	559.6	4,007.0	4,004.2	1,011.1	9,022.2	1,069.4	4,591.2	6,220.2
November	3,772.4	602.4	3,959.7	4,022.2	1,011.1	8,993.0	1,067.0	5,186.0	6,855.5
December	3,991.6	634.7	4,007.0	2,424.1	1,011.1	7,442.2	938.4	5,776.3	7,349.4
Total 2023	**47,025.8**	**7,536.1**	**46,923.2**	**41,234.8**	**11,284.3**	**99,442.2**	**12,169.9**	**55,676.0**	**75,382.0**
2024 Forecast									
January	3,950.7	622.7	4,174.8	2,739.1	1,099.3	8,013.2	1,023.8	5,834.4	7,481.0
February	3,609.8	562.3	3,763.2	1,767.9	1,029.4	6,560.5	904.0	5,294.3	6,760.6
March	3,805.7	592.7	4,326.0	3,062.4	1,243.8	8,632.2	1,075.8	5,156.3	6,824.7
April	4,472.3	714.6	3,946.8	3,680.2	820.1	8,447.1	1,023.9	4,543.8	6,282.4
May	3,488.6	560.1	3,741.6	3,698.2	720.7	8,160.5	989.7	4,131.0	5,680.9
Total June 1, 2022 to May 31, 2024		**14,477.1**					**24,339.8**	**111,135.3**	**149,952.2**

[5] Jan-March 2022 YEC sales are based on preliminary actuals. April-December 2022 sales are based on forecasts prepared for 2022 Business Plan. The forecast industrial sales for 2023 and Jan-May 2023 are assumed at 2022 forecast level [based on information available for YEC at the time of this filing]. AEY revenues are based on information provided by AEY for 2022 and 2023.

2.0 SUMMARY OF YUKON ENERGY RESPONSES TO BOARD DIRECTIVES

Section 2 summarizes how Decision 2022-03 was applied by Yukon Energy in this Compliance Filing to derive the adjusted schedules, as well as to address other matters. Section 2 is arranged by section and number in the Appendix A "Summary of Directions" in the Reasons for Decision. Directions are quoted, in part, where relevant or otherwise summarized. As there was no specific list enumerated Board directions in Order 2022-03, the specific paragraph number references have been provided.

2.1 SALES AND GENERATION

2.1.1 Sales

The Board approved the Yukon Energy 2021 sales forecast as filed in the 2021 General Rate Application, including the Wholesales Sales Forecast (paragraph 38); Industrial Sales Forecast (paragraph 42); Retail Sales Forecast (paragraph 47); and the Secondary Sales Forecast (paragraph 55). The Compliance Filing reflects these approvals.

2.1.2 Power Generation

The Board approved the Yukon Energy 2021 generation forecast, including hydro generation, diesel generation, LNG generation and forecast line losses (see paragraphs 66 to 68), as filed in the 2021 General Rate Application. The Board also accepted the peak demand forecast included in the 2021 GRA. The Compliance Filing reflects these approvals.

Forecast IPP Generation

The Board accepted YEC's explanation regarding IPP timing uncertainty and directs YEC to update the generation forecast for 2021 in its compliance filing for any change in forecast IPP generation (see paragraph 66). The Compliance Filing includes updated hydro/thermal forecast generation to reflect the change in forecast IPP generation and long-term average (LTA) thermal generation. This results in a 2 GWh decrease in IPP generation, a 1.6 GWh increase in LTA thermal generation, and a $0.015 million net decrease in fuel and purchase power costs. See Appendix 1.1, Appendix 1, Table 1.1-1 for details.

2.2 REVENUE REQUIREMENT: FUEL AND PURCHASED POWER

The Board accepted the rationale and 2021 forecasts for YEC in terms of the thermal fuel mix, forecast LNG delivered price of $0.4824 per litre, the forecast average efficiency for LNG generation of 2.66 kW.h/litre and the resulting forecast LNG cost of $0.1814/kW.h (paragraph 76). The Board also accepted the forecast diesel delivered prices for 2021 of $0.7243 per litre for Whitehorse, $0.7615 per litre for Faro, $0.7898 per litre for Dawson and $0.7696 per litre for Mayo; and the 2021 forecast diesel efficiencies for diesel fuel of 3.60 kW.h/litre in Whitehorse, 3.62 kW.h/litre in Faro, 3.71 kW.h/litre in Dawson and 4.01 kW.h/litre in Mayo. The resulting approved weighted average cost of diesel is $0.2051/kWh.

The Board noted that the above determinations were "subject to Board Findings in other parts of this Board Order regarding quantities of diesel units and related diesel fuel volumes" (paragraph 76). It is noted that there is no impact on fuel and purchased power costs related to the disallowance of diesel rental spare costs. Fuel and purchase power costs are updated related to the change in generation related to the update in forecast IPP generation (as required by paragraph 66 of Order 2022-03). The change in forecast IPP generation results in a $0.015 million decrease in fuel and purchase power costs (see Table 1.1 and Appendix 1, Table 1.1-1).

2.3 REVENUE REQUIREMENT: NON-FUEL O&M

2.3.1 Labour Expense

With regard to labour expense the Board approved the requested labour escalation of 2% (comprising 1.75 percent specific to base pay and 0.25 percent related to other employee benefits) (see paragraph 91).

The Board disallowed labour costs for three FTEs that remained vacant positions at the time of the oral hearing and directed YEC to remove all capital labour and O&M labour costs associated with the three forecast FTEs (paragraphs 88-90). In response to the Board's direction Yukon Energy has reduced labour expense related to the following vacant FTEs: Senior Communications advisor; Senior Project Manager; Maintenance Mechanic. This results in a $0.294 million decrease in revenue requirement.

2.3.2 Production Expense

The Board determined that two spare diesel rental units were redundant and directed YEC to remove the costs for two of the rented diesel units from its production expense in the Compliance Filing (paragraph 114). This change was implemented – see Table 1.1 for summary of impact on production expense (the change results in a $0.342 million decrease in production expense).

2.3.3 Reserve for Injuries and Damages (RFID)

The Board directed the following changes to the RFID account:

1. The Board did not accept YEC's inclusion of $0.073 million in COVID-related costs as recoverable under the RFID account (paragraph 133).

2. The Board also directed that to the extent that YEC has included similar COVID-19 costs in its 2021 forecast RFID transactions "that YEC similarly remove these costs from its RFID annual costs in its compliance filing to Order 2022-03" (paragraph 134).

3. The Board directed YEC to amortize the resultant balance over a period of 10 years in its Compliance Filing, "consistent with the period of amortization the Board has afforded to YEC's Deferred Vegetation Management Account" (paragraph 135).

4. YEC was directed to also revise and re-submit Tables 9 and 10 in the Board Order (Sections 5.2.2.4.1 and 5.2.2.4.2, respectively) as documented support for the dollar impact of the Board directions found in this section (paragraph 136).

The above changes were implemented in the compliance filing as directed, resulting in a $0.220 million decrease in RFID expense (See Table 1.1, and revised Tables 9 and 10 from Board Order 2022-03 as provided below per the direction in Board Order 2022-03).

Table 9. Insurance costs and Reserve for Injuries and Damages ($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
Insurance	$ 1,031	$ 1,046	$ 1,117	$ 1,299	$ 1,423
Reserve Appropriation (RFID)	479	479	479	479	616
Total	$ 1,510	$ 1,525	$ 1,596	$ 1,778	$ 2,039

Note:

1. As per Board Order 2018-10, the Existing RFID amount reflects annual appropriation of $0.267 million plus amortization of the 2016 balance over a five year period [$0.212 million/year] to total $0.479 million.

2. The Proposed 2021 RFID amount reflects annual appropriation of $0.411 million (the ten-year average) plus amortization of the 2020 balance over a ten-year period [$0.205 million/year] to total $0.616 million.

Table 10. Reserve for Injuries and Damages (RFID) Continuity Schedule ($000)

Original Filing

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
Opening Balance	-$906	-$1,247	-$1,419	-$1,002	-$2,121
Annual Appropriation	479	479	479	479	835
Annual Costs	-267	-651	-62	-1,598	-411
Closing Balance	-$694	-$1,419	-$1,002	-$2,121	-$1,697

Compliance Filing

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
Opening Balance	-$906	-$1,247	-$1,419	-$1,002	-$2,048
Annual Appropriation	479	479	479	479	616
Annual Costs	-267	-651	-62	-1,525	-411
Closing Balance	-$694	-$1,419	-$1,002	-$2,048	-$1,843

Change

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
Opening Balance	$0	$0	$0	$0	$73
Annual Appropriation	0	0	0	0	-220
Annual Costs	0	0	0	73	0
Closing Balance	$0	$0	$0	$73	-$146

Note: The Compliance Filing reflects removal of COVID-19 costs in the amount of $0.073 million [paragraph 134] and amortizing the resultant balance over a period of 10 years [paragraph 135].

2.4 REVENUE REQUIREMENT: RATE BASE, DEPRECIATION & AMORTIZATION

2.4.1 Depreciation Study

The Board provided specific directions for six accounts and directed YEC to update its forecast 2021 depreciation expense calculations including its amortization of reserve differences true-up calculation, to reflect these findings in its compliance filing to this Board Order (paragraph 148).

The six accounts specifically highlighted by the Board in Order 2022-03 are outlined below along with how the specific directions are addressed in the Compliance Filing.

Account 1615-506 – Hydro Plant - Water Wheels, Turbines, and Generators

> 152. … neither the retirement data, which is limited, nor the comments of YEC personnel that they have replaced some assets prior to reaching 60 years reasonably support the significant 25-year reduction to service life. … The Board directs YEC to maintain an 85-R3 life-curve for this account in its compliance filing to this Board Order.

This was implemented in the Compliance Filing as directed. See Table 1.1-3a which notes a $0.129 million decrease in depreciation expense in the compliance filing due to this adjustment.

Account 1625-610 – Distribution System – Meters and Account 1625-620 – Distribution System – Meter Equipment

> 155. The Board agrees with Mr. Watson's rationale for decreasing the service life of YEC Account 1625-610 and Account 1625-620 to a 16-SQ life-curve in order to align with the maximum expected life of YEC's digital meters and metering equipment assets.

The Compliance Filing did not require any adjustment from the 2021 GRA Application.

Account 1635-300 – Main Transmission Facilities – Poles and Fixtures and Account 1640-300 – Sub-Transmission Lines – Poles and Fixtures

> 163. The Board is not persuaded that the transmission line refurbishment program, which purports to remove poles at approximately 50 years, should be the primary reason for a corresponding change in service life. This is particularly relevant given that there appears to be an established "Test and Treat" process that serves to preserve if not extend the average service life of YEC's poles.
>
> 164. YEC is directed to continue to rely on the currently approved 60-R3 for Account 1635-300……due to the similarity of the assets in accounts 1635-300 and 1640-300, the Board accepts YEC's proposal to align the service lives between these two accounts….the Board directs YEC to incorporate a 60-R3 life-curve for Account 1640-300 in its compliance filing to this Board Order. [Note: highlighted is a typo and should be the existing 65-R3]
>
> 165. … the Board is concerned with comments from YEC's operations personnel contained in YEC's IR responses, which appear to indicate that YEC is replacing 50-year-old transmission poles without retiring the original pole.

> 166. The Board directs YEC to provide its rationale for not retiring assets that have been replaced and to further explain how this rationale aligns with group depreciation practices in its compliance filing to this Board Order. This information is required not only for accounts 1635-300 and 1640-300 but for any other of YEC's depreciation study accounts which would be similarly affected by any YEC practice of not retiring assets that no longer provide utility service, such as appears to be the case for YEC's transmission poles.

The above direction was implemented in the Compliance Filing. See Table 1.1-3a which notes the following adjustments to depreciation expense in the Compliance Filing compared with the 2021 GRA Application:

- $0.443 million decrease in Main Transmission Facilities Poles and Fixtures expense related to life change from 50 to 65 years [including impact of updated capital costs].
- $0.023 million decrease in Sub-transmission Line Poles and Figures expense related to life change from 50 to 65 years [including impact of updated capital costs].

It is noted that Order 2022-03 appears to have a typographical error in paragraph 164 – as the paragraph references "the currently approved 60-R3 for Account 1635-300" which is incorrect. The correct reference is 65-R3 (which corresponds to the reference in Appendix 1 of Board Order 2022-03). Yukon Energy has applied 65-R3 to Account 1635-300 and 1640-300 (consistent with Appendix 1).

YEC's practice is to retire assets that have been replaced. YEC's process is that the project manager is to indicate what assets have been replaced when a new asset is constructed. However, in this case the project manager did not indicate any assets to be retired, which was not accurate. Upon further review, YEC has assessed the line and written off assets in the amount of $1.337 million [with $0.417 million accumulated amortization to net book value at $0.920 million]. The Compliance Filing reflects this write-off [please see Table 1.1-3].

Account 1635-710 – Main Transmission Facilities – Substation Equipment and Account 1640-710 – Sub-Transmission Lines – Substation Equipment

> 173. The Board finds that neither the limited retirement data, nor the comments of YEC personnel, provide sufficient justification to persuade the Board that a five-year reduction to service life for Account 1635-710 is reasonable. YEC's proposed reduction to service life for Account 1635-710 is denied and YEC is directed to continue to rely on the currently approved 54-S0 life-curve for this account in its compliance filing to this Board Order.
>
> 174. However, due to the similarity of the assets in accounts 1635-710 and 1640-710, the Board accepts YEC's proposal to align the service lives between these two accounts.

This was implemented in the Compliance Filing as directed. See Table 1.1-3a which notes:

- Main Transmission facilities substation equipment depreciation expense decrease of $0.264 million related to life change from 45 to 54 years.
- Sub-transmission substation equipment depreciation expense decrease of $0.030 million related to life change from 45 to 54 years.

Account 1645-201 – Buildings & Other Equipment – Building & Improvement

> 178. In the absence of an actuarial analysis, the Board does not consider that the comments of YEC personnel have provided sufficient support for the proposed life-curve changes for Account 1645-201 from 55-R1 to 50-R2. Without confirmation from YEC that these shorter lived assets are of sufficient quantum such that they will significantly influence the service life of the account as a whole, the Board is unable to approve the change requested.
>
> 179. YEC is directed to continue to rely on the currently approved 55-R1 life-curve for Account 1635-300 in its compliance filing to this Board Order. [Note: highlighted is a typo and should be 1645-201]

This was implemented in the Compliance Filing as directed. See Table 1.1-3a which notes decrease in depreciation expense for Building and Improvements of $0.022 million related to life change from 50 to 55 years.

It is noted that Order 2022-03 appears to have a typographical error in paragraph 179 – the paragraph references Account 1635-300, however, the correct reference should be 1645-201.

Account 1665-403 – LNG Plant – Fuel Holders

> 182. The Board accepts the supplementary information provided by YEC in its IR response. Accordingly, a 60-R2 life-curve is approved for Account 1665-403.

The Compliance Filing did not require any adjustment from the 2021 GRA Application.

2.4.2 Victoria Gold Group Assets

The Board made the following directions with regard to the VGC assets:

> 195. YEC is directed to create a separate sub-transmission asset account designated as Substation "VGC Group – gold mine" for those assets to which the $10.688 million contribution relates and to amortize these substation costs over a period of 12 years consistent with a 12-SQ. For any difference between the depreciation rate associated with the use of a service life of 54 years since the year 2019, YEC is also directed to update its amortization of reserve differences mechanism to effect a true-up of this amount in its compliance filing ….
>
> 196. … the Board finds that all assets constructed for the purpose of servicing the VGC Group mine, regardless of whether there was a related contribution, should similarly be amortized over a period of 12 years. For clarity, YEC is directed to create a separate sub-transmission asset account designated as Substation "VGC Group – gold mine" for each asset category constructed for the purpose of servicing the VGC Group mine and to amortize the related asset costs over a period of 12 years consistent with a 12-SQ. For each asset category (account) affected, YEC is further directed to update its amortization of the reserve differences mechanism to effect a true-up of this amount in its compliance filing…

This was implemented in the Compliance Filing as directed. See Table 1.1-3b for details regarding the VG substation depreciation true-up calculation. This notes a $0.114 million depreciation variance annual true up related to depreciation of the net cost for capital assets and contributions over 12 years (instead of

depreciation assets over 54 years and contributions over 12 years as outlined in the Application) as illustrated in Table 1.1.3b.

2.4.3 Defined Benefits Pension Account (DPVA)

The Board directed as follows regarding the DPVA:

> 205. The Board approves YEC's request for a defined benefit pension deferral account.
>
> 207. …. the Board considers it necessary to incorporate a downward adjustment to YEC's risk premium and return on equity.

The defined benefit pension deferral account will be implemented as directed.

2.4.4 Hearing Cost Reserve Account

The Board directed as follows regarding the Hearing Cost Reserve Account:

> 218. The Board denies YEC's DSM appeal costs charged to the hearing reserve account between January 1, 2019, and September 30, 2021. The Board directs YEC to remove those costs from its hearing costs reserve account in its Compliance Filing to this Board Order.

Costs related to the DSM Appeal have been removed from the hearing cost reserve. See Appendix 1, Table 1.1-2 which notes a $0.084 million decrease in rate case amortization.

2.5 CAPITAL STRUCTURE & RETURN

2.5.1 Return on Common Equity (ROE)

The Board directed as follows regarding the risk premium used by YEC to determine ROE:

> 233. … Although YEC disagreed that a reduction to the risk premium is necessary to reflect the shifting of these risks, for the reasons above, the Board does not agree. The OIC reduces YEC's risks in providing utility service and the Board determines that a reduction of 50 basis points is warranted in YEC's risk premium. Therefore, in the compliance filing to this Board Order, YEC shall reflect the Board-approved ROE of 8.20 percent for 2021.

The risk premium applied to determine YEC's ROE has been adjusted to 8.20% as directed. See Appendix 1, Table 1.1-2 for details. This shows a reduction in expense related to the reduction in allowed ROE of $1.048 million, reflecting the reduced ROE percentage and the reduced rate base.

2.6 CAPITAL & DEFERRED PROJECTS

The directives in Appendix A of Order 2022-03 on capital and deferred projects are reviewed below. Specific adjustments to rate base are set out in Appendix 1.1, Table 1.1-2 and 1.1-3.

2.6.1 Major Projects > $ 1 Million

In paragraph 237 the Board denied YEC's request to consider cost updates only for major projects, noting:

> … Absent compelling reasons to the contrary, the Board maintains its past practice which is to consider the most up-to-date information provided on the record for capital projects for a test year or years. Accordingly, because the Board finds that YEC has not fully substantiated its rationale for including some updates and for excluding updates for capital projects between $100,000 and $1 million to be persuasive in setting YEC's capital forecasts for 2021, YEC's request is denied.

2.6.1.1 LNG Third Engine

> 247. The Board finds the $8.261 million of actual cost incurred for this project is prudent and directs YEC to add this amount to the 2021 rate base.

This was included in rate base as directed.

2.6.1.2 Whitehorse and Faro Diesel Infrastructure

> 250. The Board finds that the $1.298 million associated with the N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure Project is reasonable and directs YEC to add this amount to the 2021 rate base. The Board also accepts the $2.446 million associated with the N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure Project and directs YEC to add this amount to the 2021 rate base.

This was included in rate base as directed. Table 1.1-3 shows cost update impact for the Faro project.

2.6.1.3 Mayo-McQuesten Transmission Line and Substation

> 258. The Board is prepared to accept the $8.628 million actual and forecast costs for the Mayo to McQuesten Transmission Project …and directs YEC to include the actual capital spending amounts for this project in the 2021 rate base … the Board accepts the $0.931 million after-contribution amount for the McQuesten Substation Project as reasonable and directs YEC to add this amount to the 2021 rate base.
>
> 259. …all assets associated with the mine are amortized over 12 years, which includes the STATCOM device… costs of the STATCOM device will be paid for over the lifetime of the mine, thereby limiting the exposure of costs to non-industrial ratepayers even if the life of the STATCOM device exceeds the life of the mine.

This was included in rate base as directed – see Table 1.1-3 which shows the adjustment to rate base for the project, and Table 1.1-3b which shows the VG Substation Depreciation True-Up Calculation.

2.6.1.4 Transmission line Refurbishment Projects

> 265. … the Board finds the $4.272 million incurred for the first phase to be prudent and directs YEC to include this amount in the 2021 rate base. The Board also accepts the $0.3 million for the second phase to be reasonable and approves the actual capital spending amount incurred by YEC to date. However, the $0.3 million will not be added to the 2021 rate base, as the project is not complete. Costs for the second phase will only be added to the rate base once the second phase is complete and YEC provides the actual capital spending amount incurred in the next GRA.

This was included in ratebase as directed – see Table 1.1-3.

2.6.1.5 Breaker Replacement Project

> 267. The Board finds there is a necessity for the Breaker Replacement Project given the age of the components and the reliability issues identified by YEC. Thus, the Board finds that the $2.260 million in actual costs associated with this project appears to be prudent and directs YEC to add the costs to the 2021 rate base.

This was included in ratebase as directed.

2.6.1.6 P125 Headgate

> 270. The Board finds there is a necessity for this project, given the age of the headgates and based on the results of tests and assessments conducted by SNC Lavalin. The Board also finds YEC acted reasonably in updating its costs for this project since headgate work for units WH1 and WH3 was delayed to 2022 and 2023, respectively. … the Board finds the actual capital spend of $2.072 million for this project reasonable. However, this $2.072 million will not be added to the 2021 rate base, as the project is not complete. Costs for this project will only be added to rate base once the project is complete and YEC provides the actual capital spending amount incurred in the next GRA.

Project cost impacts on ratebase were adjusted as directed – see Table 1.1-3 which shows the adjustment to rate base for the project, both for the cost update and for keeping the costs in WIP.

2.6.1.7 WH2 Uprate

> 277. … the Board finds there is value in addressing the existing capacity shortfall and offsetting thermal generation but is not persuaded that the applied-for costs for this project are reasonable. YEC's costs for this project were $12.267 million even though Hatch's cost estimates for uprating the WH1 unit, which would be similar to the cost estimates for uprating the WH2 unit, were approximately $1.99 million with the same original turbine flow and $4.78 million with an increase in turbine flow. … YEC never discussed the reasons for these cost differences in its business case or why the WH2 Uprate Project exceeded the Hatch estimates.
>
> 278. .. the Board finds YEC's business plan for this project did not adequately justify the costs and benefits of this project, nor did it adequately explain the reasons the project was the preferred alternative. Given the Board's concerns with the reasonableness of the costs, the recommendations in the Hatch report and the deficiencies in the business case, the Board finds it appropriate to approve costs of $4.78 million, which was the Hatch cost estimate for uprating a unit with increased turbine flow, plus 20 percent for cost overruns. The Board directs YEC to include this cost in its compliance filing.

This was included in ratebase as directed – see Table 1.1-3 which shows the adjustment to rate base for the project; and notes the net book value of disallowed costs for the project. The Board's ruling identifies a question that the Board found was not addressed in the business case evidence for this project to increase renewable energy output and provide sustaining capital benefits. YEC has applied to the Board for a review and variance of that aspect of the decision. However, if the decision is not varied to include the full cost of

this project in ratebase, YEC will request that this project be fully included in ratebase in the next GRA at which time YEC will address the question raised in Order 2022-03. Until the decision is varied or the next application is filed, YEC will keep the additional cost in disallowed assets for accounting purposes.

2.6.1.8 WH4 Uprate Servomotor Replacement Project

> 281. The Board finds there is a value for the WH4 Uprate Servomotor Replacement Project in 2021 but is not persuaded that the applied-for costs are reasonable. YEC, as part of its responses to the Board's second round of information requests, provided the Hatch report's recommendation to replace the existing servomotors. In that report, Hatch provided a cost estimate of $457,000 for replacing the servomotors. During the proceeding, YEC did not explain why the costs for this project increased from the original Hatch cost estimate.
>
> 282. Accordingly, given the Board's concerns with the reasonableness of the costs and a lack of a business case for the project to support the magnitude of costs compared to the expected benefits for the project, the Board finds it appropriate to approve costs of $457,000 based on the Hatch cost estimate, plus 20 percent for cost overruns, which amounts to $548,400. The Board directs YEC to include these updated costs in its compliance filing.

This was included in ratebase as directed – see Table 1.1-3 which shows the adjustment to rate base for the project; and notes the net book value of disallowed costs for the project. The Board's ruling identifies a question that the Board found was not addressed in the business case evidence for this project to increase renewable energy output and provide sustaining capital benefits. YEC has applied to the Board for a review and variance of that aspect of the decision. However, if the decision is not varied to include the full cost of this project in ratebase, YEC will request that this project be fully included in ratebase in the next GRA at which time YEC will address the question raised in Order 2022-03. Until the decision is varied or the next application is filed, YEC will keep the additional cost in disallowed assets for accounting purposes.

2.6.2 Projects between $100,000 and $1 million

With regard to projects between $100,000 and $1 million – the Board directed as follows:

> 287. The Board is not prepared to approve the costs for the WH4 Ventilation Project…it is unclear whether temperatures during the summer caused the unit to exceed operational limits in a manner that would impact the unit. Additionally, the original 2021 forecast of this project was $750,000, which was then reduced to $150,000 because YEC delayed the project and needed to conduct additional studies to determine greater cost certainty.
>
> 288. The Board has reviewed the rationale provided and costs for the remaining projects in this category and finds that the actual and forecast costs for these projects appear to be reasonable.
>
> 289. The Board directs that YEC include the updated costs, excluding the WH4 Ventilation Project, for any projects that have been completed prior to or during the 2021 test year period. Costs for these projects will only be added to rate base once YEC provides the actual capital spending amount in the next GRA and demonstrates that the costs were prudently incurred.

These costs were included in ratebase as directed – see Table 1.1-3 which shows the adjustment to rate base for the WH4 Ventilation Project for both the revised costs and for retaining in WIP.

2.6.3 Deferred Cost Projects >$1million

2.6.3.1 Aishihik Re-licencing – Three Year Licence Renewal

294. The Board finds the costs incurred for the Aishihik Relicensing Project were necessary, given that there is a need for YEC to renew its water use licences associated with the AGS facility, and that the applied-for costs are reasonable. As such, the Board directs YEC to include the updated cost of $916,872 in the 2021 rate base.

This was included in ratebase as directed – see Table 1.1-3 which shows the adjustment to rate base for the project.

2.6.3.2 DSM

311. The Board has reviewed the evidence on the record of the proceeding and accepts YEC's explanation for the adjusted DSM costs of $279,852 for 2019, 2020 and 2021. The Board finds that the YEC actual and forecast for Residential Demand Response Pilot at $186,266 ($68,307 in 2019, $82,969 in 2020 and $35,000 in 2021) and DSM Program Design of future DSM programs forecast at $85,000 in 2021 are reasonable for the following reasons.

314. Similarly, the DSM program design of future DSM programs at a forecast cost of $85,000 in 2021 was also supported and is approved as filed.

This was included in rate base as directed – see Table 1.1-3 which shows the adjustment to rate base for the project.

2.6.4 Deferred Cost Projects between $100,000 and $1 Million

322. The Board is not prepared to approve the costs for the Atlin Hydro EPA Preparation project because YEC currently has an application for review of the Atlin EPA before the Board. The Board finds it necessary to complete the regulatory process for the Atlin EPA before it can assess the prudence of costs for preparation work.

323. For all other costs in this category, the Board has reviewed the business cases and costs for projects in this category and finds the actual capital spending for these projects prudent. … To ensure that actual capital spending to the end of 2021 is accurately reflected in rate base, the Board directs YEC include the updated costs for any projects that have been completed prior to or during the 2021 test year period. Costs for these projects will only be added to rate base once YEC provides the actual capital spending amount in the next GRA.

These costs were included in ratebase as directed – see Table 1.1-3 which shows the adjustment to costs for the Atlin Hydro EPA Preparation Project and that it is being retained in WIP for 2021.

2.6.5 Intangible Assets

2.6.5.1 Enterprise Asset Management System Purchase and Implementation Project

> 332. The Board accepts that there is a requirement to keep asset management practices aligned with industry standards such as ISO 55000. However, the Board is concerned with the EAM project as proposed in this Application. YEC … cited non-YEC-specific case studies to determine the reductions in long-term asset costs. None of this evidence was prepared based on project-specific information, which … limits the evidence's persuasiveness.
>
> 333. … YEC stated that it explored other software alternatives but did not provide any details on these alternatives and why they were ruled out …. Regarding the chosen vendor for the software solution, YEC stated it scored higher on technical merits compared to the lowest bidder…YEC did not provide any details on these technical merits. …the Board does not have sufficient evidence to assure itself that the EAM project was a reasonable alternative for YEC to pursue with regard to asset management. … the Board finds the costs associated with this project are not reasonable and denies inclusion of the costs for this project in the 2021 rate base.

As directed – this cost is not included in rate base at this time. See Appendix 1, Table 1.1-3 for details.

Yukon Energy acknowledges the Board's concerns regarding the specific justification for this project expenditure (i.e., YEC-specific case studies, details on alternative approaches that were ruled out, etc) and will provide more specific support to justify these costs at its next Generation Rate Application, as the project is used and useful and providing benefits to ratepayers.

2.6.5.2 Projects between $100,000 and $1 Million

> 335. The Board has reviewed the business case and costs for the project in this category. Based on the information provided by YEC, the Board finds there is a need for this project. The Board directs YEC include the actual capital spending amount for the ERP System Upgrades Project in the 2021 rate base.

This has been implemented in the Compliance Filing as directed. See Appendix 1, Table 1.1-3 for details.

2.7 ADDITIONAL MATTERS RELATED TO THE GRA

2.7.1.1 Rate Schedule 39 Fixed Charge

> 340. The Board directs YEC to reflect the changes in the depreciation parameters for calculating the fixed charges that are directed in this Board Order in its future application to finalize Rate Schedule 39 fixed charges. These charges are to be effective January 1, 2021

On April 8, 2022, Yukon Energy provided a Fixed Charge Adjustment – Limited Scope Application to the Board. The document requests approval of an interim Rate Schedule 39 Fixed Charge rate as at May 1 2022. The limited scope application takes into account where feasible the following Board 2022-03 directions in addressing the added costs for SVC Statcom, on the understanding that final adjustments and true-ups of the Fixed Charge will be addressed in YEC's compliance filing:

1. YEC is directed (paragraph 340) to reflect the changes in depreciation parameters for calculating the fixed charges as directed in this Board Order in its future application to finalize Rate Schedule 39 fixed charges. These charges are to be effective January 1, 2021.

2. YEC is directed (paragraph 195) to create a separate sub-transmission asset account as Substation "VGC Group – gold mine" for those assets to which the $10.688 million contribution relates and to amortize these substation costs over a period of 12 years consistent with a 12-SQ. The Board further directed (paragraph 196) that all assets constructed for the purpose of servicing the VGC Group mine, regardless of whether there was a related contribution, should similarly be amortized over 12 years. For each asset category (account) affected, YEC is further directed (paragraph 196) to update its amortization of the reserve differences mechanism to effect a true-up of this amount in its compliance filing to this Board Order.

3. The Board further directed (paragraph 259) that "all assets associated with the mine are amortized over 12 years, which includes the Statcom device. This means that the costs of the STATCOM device will be paid for over the lifetime of the mine, thereby limiting the exposure of costs to non-industrial ratepayers even if the life of the STATCOM device exceeds the life of the mine."

4. The 12 year period specified in the Board's directions is to align amortization of contributions and costs over the period that the assets are expected to serve the VGC Group mine customer (paragraphs 193 and 194).

The Limited Scope Application notes YEC transmission facilities costs in rate base (net costs after contributions and related depreciation) for 2021 and 2022 updated to include the costs for SVC/Statcom as well as updates required to reflect YEC's 2021 GRA approvals related to weighted average cost of capital

and deprecation rates. The table includes the costs related to:

- **Existing Transmission Costs** - these costs for the assets that were already in place prior of development of the new transmission facilities. These costs are updated to reflect retirement of the portion of the existing transmission line that is replaced by new transmission line.

- **YEC's McQuesten Substation Costs -** these are defined in the VGC Group PPA as the costs that VCG Group recovered from YEC, related to YEC substation upgrades to accommodate 138 kV transmission if developed in the future which was completed in 2019 [net cost of $0.931 million].

- **Transmission Facilities Development Costs** - YEC net costs after federal government contributions [75% of eligible costs] for the new transmission between Mayo and McQuesten Substation that was completed in March 2021; and

- **SVC/Statcom Costs** - YEC net costs after federal government contributions [75% of eligible costs] for the SVC/Statcom that was completed in late October of 2021. These costs are amortized over remaining life of the mine (10 years) consistent with the direction in the Board Order 2022-03, paragraph 259 where the Board noted "the costs of the STATCOM device will be paid for over the lifetime of the mine, thereby limiting the exposure of costs to non-industrial ratepayers even if the life of the STATCOM device exceeds the life of the mine."

The 2022 cost related to existing and new Mayo-Keno transmission facilities (including the SVC/Statcom) are $929,755 based on the weighted average cost of capital (WACC) at 5.04% for the 2021 GRA (Board Order 2022-03 Compliance Filing), resulting in a revised Fixed Charge (85% of the Transmission Facilities Fixed Cost) of $65,857.64 per month. The Fixed Charge is allocated between VCG Group and Alexco based on forecast sales for 2022 and will be adjusted annually based on actual sales as indicated in Rate Schedule 39.

2.7.1.2 Low Water Reserve Fund

Annual Reports

> 347. A revised term sheet could not be filed until after OIC 2021/16 was in force and the Board is satisfied that the term sheet complies with the OIC. …On a go-forward basis, the Board directs YEC to submit its annual LWRF report to the Board on within 60 days of the close of the year. YEC shall reflect this direction in its revised LWRF term sheet to be filed in the compliance filing...

The LWRF Term Sheet is provided as Appendix 2 to this compliance filing. The above noted change is reflected in the LWRF term sheet. An annual report will be provided as soon as possible in 2021 now that Order 2022-03 direction has been provided approving the LWRF Term Sheet.

Rate Payer Risk

> 354. The Board is concerned that customers are bearing additional risk that is properly be YEC's responsibility in developing its forecast for generation load. While the Board considers that asymmetrical risk sharing regarding incremental generation load recovered in rates ultimately harms ratepayers (as reflected in Board Orders 2018-10 and 2019-04) OIC 2021/16 has changed the law in that regard. That OIC directs that risks and costs for incremental generation loads be borne by customers, as reflected in the amended subsections 9(4) and 9(7) of the Rate Policy Directive (1995). Consequently, the Board now has less discretion to determine who should properly bear forecast risk of low generation, YEC or ratepayers.
>
> 355. … the Board found that YEC risks with respect to the LWRF have decreased and directed that YEC's risk premium be adjusted downward to reflect this reduced risk of the utility.

The reduction in ROE is reflected in the Compliance Filing – see Table 1.1 and Appendix 1, Table 1.1-2.

Maximum / Minimum Balance

> 360. The Board accepts the submissions of YEC that the change to the LWRF cap to +/- $16 million will satisfy the directions as provided in Sections 9(6) and 9(8) of OIC 2021/16 and directs YEC to reflect this in the revised LWRF Term Sheet. YEC shall include an updated LWRF term sheet as part of its compliance filing to this Board Order.

This is reflected in the Term Sheet provided as Appendix 2 to the Compliance Filing.

Offset to Rate base

> 368. … YEC expects the LWRF to maintain a positive balance (i.e., collecting funds for future low water events) and that a positive balance is expected to exist in most years. … OIC 2021/16 states that the LWRF must be operated to minimize the effect on rates for retail customers and major industrial customers that would be caused by variation in actual renewable source availability. Given at least one past Board Order directing the treatment of low water reserve funds as an offset to rate base, the Board directs YEC, on a go-forward basis, to treat the balance in the LWRF as an offset to rate base. The Board directs YEC to reflect this change in its compliance filing.

This change is reflected in the Compliance Filing – see Appendix 1, Table 1.1-3 which indicates under Miscellaneous Reserves – a $2.782 million adjustment for 2021 year end rate base deduction related to the added LWRF; in addition, the 2020 year end rate base has been increased by the $4.272 million LWRF deficit at that year end (overall mid-year 2021 rate base impact from the LWRF adjustments is a rate base increase of $0.745 million). Detailed LWRF calculations for 2020 and 2021 are provided in Table 1.1-3 c) and Table 1.1-3 c) i). The calculations included in these tables are based on the best available information at this time. Yukon Energy plans to file the LWRF Annual report separately after the compliance filing has been completed.

Appendix 2.1:
Low Water Reserve Fund (LWRF) Term Sheet

APPENDIX 2.1 - LOW WATER RESERVE FUND (LWRF) TERM SHEET

PURPOSE & FUNCTION:

The Low Water Reserve Fund ("LWRF", or the "Fund") is a deferral account that operates to smooth customer rate changes from thermal (diesel, LNG and other thermal) generation cost impacts caused by fluctuation of renewable generation due to changes from long-term average annual renewable source availability.[6] Thermal generation costs not related to changes in renewable source availability are not included in LWRF determinations, including thermal generation costs due to equipment failure, force majeure, capital projects, or planned maintenance events.

Yukon Energy Corporation (YEC) manages the LWRF as a ratepayer "trust fund". The Fund is only to be used for variations from long-term average annual renewable source availability as determined in accordance with this Term Sheet.[7]

LONG-TERM AVERAGE (LTA):

Annual thermal generation requirements for each GRA test year are determined for the LWRF based on long-term average ("LTA") annual renewable source availability[8] [including LTA in ATCO Electric Yukon's (AEY's) Fish Lake hydro generation] at the test year forecast firm load on the Yukon Integrated System (YIS). The LWRF determination after the end of each YEC financial year will utilize the LTA annual hydro generation table and the LTA annual generation for other renewable sources for the last approved GRA test year, subject to changes as approved by the Board.

Table 1 provides an example for 2019 LWRF update where YEC continues to use the final approved 2018 GRA expected LTA hydro and thermal generation.

a. Table 1 LTA generation was adopted for 2018 load and generation conditions to determine annual expected YEC thermal generation based on long-term average YEC hydro generation at YEC grid loads (net of expected Fish Lake generation) ranging from 400 to 450

[6] Terms as defined in OIC 2021/16: "Long-term average annual renewable source availability" is defined in section 9(1) as "the annual amount of renewable generation that would be available to contribute to meeting forecast or actual customer requirements, based on average annual renewable source availability over the life of a renewable generation facility, as determined using available historical water records respecting long-term average annual hydro generation and available information respecting other renewable generation." "Renewable generation" is defined in section 1 as "generation of electricity from renewable sources, including hydro, wind, solar, geothermal and biomass sources."

[7] Appendix A to Board Order 2015-01, section 2.1.1.4, page 14. The Board directed as follows: "Any application to utilize the fund in some other fashion will require the closing of the fund, the refunding of any balances to customers, and the direction for YEC to use short-term forecasts for its hydro generation in future GRAs."

[8] LTA source availability for YEC hydro generation under any set of assumed grid generation load and grid generation capacity and licence conditions is determined in each GRA based on the then-current YECSIM power benefit model calculations based on available years of water record generation, e.g., see Appendix 2.1 of the 2021 GRA Application. As load grows a portion of the load growth is currently served (on average) by increased YEC hydro output (after use of available IPP and wind generation as well as AEY's Fish Lake hydro generation) and the remainder by increased average thermal generation (diesel or LNG). LTA source availability for Independent Power Production (IPP), YEC wind generation (when applicable) and AEY Fish Lake hydro generation are determined based on available information.

GW.h/year, assuming the mine loads connected as forecast in the GRA approved final Compliance Filing for 2018.

b. An example is provided below the table, using this approved LTA generation table for 2018, of the LWRF determination of YEC thermal generation at the actual 2019 grid load of 437.248 GW.h (net of expected Fish Lake generation).

In preparing an annual LWRF determination after the end of a YEC financial year, YEC will provide the Board, for review and approval, an update to the LTA hydro generation table for the last approved YEC GRA test year when required to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits, Independent Power Production (IPP) connections, or other factors.

LWRF THERMAL SAVINGS (COSTS):

YEC thermal generation savings (excess) are calculated on an annual basis for the LWRF based on the variance between actual thermal generation[9] and LTA thermal generation at the actual YIS load. The actual YIS load for this assessment is net of long-term average annual (i.e., expected) availability for all renewable sources other than YEC hydro generation, including Fish Lake hydro, and IPP renewable generation.

Table 2 provides an example year-end LWRF determination for 2019 based on the last approved LTA hydro generation (as per Table 1.1-1) and actual 2019 results.

Table 2 shows that costs for YEC thermal generation savings (excess) are calculated so that YEC's final fiscal year expense for the total expected thermal generation (i.e., YEC expense after all transfers) equals the last GRA approved LTA fuel mix (i.e., for the 2017/18 GRA this approved fuel mix was 90% LNG and 10% diesel), subject to the constraints (when setting LWRF based on actual load) noted in Table 2.[10] Fuel costs for this calculation are based on the last approved average cost of LNG and diesel fuel for YEC per kWh based on the most recent YEC GRA.[11] The LWRF example in Table 2 reflects these requirements based on fuel prices in the 2017/18 GRA.[12]

[9] Actual thermal generation excludes thermal generation charged to capital projects, RFID, or maintenance. Costs for actual thermal generation are charged separately for diesel and LNG generation based on the last approved average cost of fuel for YEC per kW.h based on the most recent YEC GRA.

[10] The constraints are: (a) when actual thermal > LTA thermal, LNG not exceeding total LTA thermal less estimated diesel (LTA thermal times actual diesel percent of actual thermal); and (b) when actual thermal < LTA thermal, LNG not exceeding total LTA thermal less actual diesel. These constraints reduce LNG share of YEC's final LTA thermal to less than 90% when actual diesel share exceeds 10% (if actual thermal > LTA thermal) or when actual diesel generation exceeds 10% of LTA thermal (if actual thermal < LTA thermal).

[11] YEC's 2017/2018 GRA as approved is applicable for the 2019 example, and includes average LNG fuel cost at 14.668 cents per kW.h and average diesel fuel cost at 26.333 cents/kW.h, and assumes that 90% of LTA thermal is supplied by LNG and 10% by diesel (average blended price of 15.834 cents per kW.h).

[12] Actual diesel as a share of the estimated actual thermal generation for the forecast load is assumed to be the greater of 10% (as per the GRA forecast) and the actual diesel generation percentage of actual year-end YEC firm generation.

Non-fuel O&M costs related to YEC thermal generation are not included in the LWRF calculations.

QUANTUM & CAP:

The Board in Order 2015-01 approved a "cap" for the DCF of +/- $8 million as an acceptable balance between frequency of rider applications and ability to handle material (drought) changes in hydro availability. This cap was retained in YEC's 20217-18 GRA Compliance Filing. Effective 2021, this cap for the LWRF is increased to +/- $16 million per Order 2022-03, Appendix A, paragraph 360.

In any year when the balance in the LWRF falls outside of the approved LWRF cap range at fiscal year end, YEC shall apply forthwith to the Board, and in any event within 60 days of the financial year end, for approval of a rate rider to dispense with the balance that is outside of that range.

The refund (when LWRF balance exceeds the approved maximum cap level) or collection (when LWRF balance is below the approved minimum cap level) is to be made by way of a rate-rider to customers over next 12 month period. YEC may apply and the Board may approve a longer/shorter refund/collections period depending of the amount of refund/collections required. The rider is applicable for all retail and industrial firm sales in Yukon for both YEC and AEY.

INTEREST:

The Fund is to attract interest based upon the short/intermediate term bond rates in which YEC may invest the Fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to YEC through a line of credit.

QUARTERLY & ANNUAL REPORTING:

An annual report is required to be filed with the Board for approval of the Board within 60 days of the close of the year (Order 2022-03, Appendix A, paragraph 347) detailing additions and deletions to the Fund and a forecast of water conditions for the next year. The annual report to the Board is also to include a proposed rate rider to refund/collect any amount that exceeds the approved cap. The Board will direct YEC on the additions and deletions to the Fund, and on any proposed rate rider.

Quarterly reports regarding the LWRF calculations and LWRF balance updates will be provided to the Board based on interim determinations prior to a fiscal year end. The quarterly LWRF calculations will be based on forecast loads for the year at the time of calculation as the LWRF table calculates the expected diesel amount based on annual load, not quarterly.

Any interim determinations prior to a financial year end will only be placeholders; only the year end determinations will in fact have ongoing relevance for accounting and rate riders.

Table 1: 2018 Expected LTA Generation as Approved

Line Number	YEC Grid Load Net of Wind (GWh)	YEC Hydro Generation (GWh)	YEC Thermal Generation (GWh)	Increase in Load (GWh)	Increase in Thermal Generation (GWh)	Thermal as % of Increased Load
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	400.0	391.135	8.865			
2	405.0	394.564	10.436	5.0	1.572	31%
3	410.0	397.834	12.166	5.0	1.730	35%
4	415.0	400.909	14.091	5.0	1.924	38%
5	420.0	403.769	16.231	5.0	2.140	43%
6	425.0	406.404	18.596	5.0	2.365	47%
7	430.0	408.818	21.182	5.0	2.587	52%
8	435.0	411.027	23.973	5.0	2.791	56%
9	440.0	413.062	26.938	5.0	2.965	59%
10	445.0	414.965	30.035	5.0	3.096	62%
11	450.0	416.794	33.206	5.0	3.171	63%

Notes:
1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected renewable other than YEC hydro generation, e.g., Fish Lake hydro, YEC wind, IPP renewables.
2. The thermal generation and increase for the added load are based on a polynomial equation derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.

3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 35 "water years" on record (1981-2015) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.

4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake) and restricted Mayo GS winter flows.
5. The simulation model results are based on the 2018 forecast load distributions, and requires modifications when new mines or industrial loads are connected [or disconnected from] to the grid.
6. This table assumes max load at 450 GW.h and minimum load at 400 GW.h. If the load exceeds these limits then the table needs to be updated.
7. Numbers are subject to rounding.

2019 Update Example
Expected YEC Thermal Generation for YEC generation at 437,248.5 MWh (net of expected renewable other than YEC hydro)

Step 1. Find the closest load from Column A that is less than 437 GW.h = 435 GW.h (Line 8).

Step 2. Find the thermal generation from Column C = 23.973 GW.h (Line 8).

Step 3. Find the difference between the given load (437.2485 GW.h) and load from Step 1 (435 GW.h) = 2.2485 GW.h

Step 4. Apply the percentage from Column F (Line 9, 59%) to the difference from Step 3 (2.2485 GW.h) = 1.327 GW.h

Step 5. Add numbers from Step 2 (23.973 GW.h) and Step 4 (1.327 GW.h) = 25.300 GW.h

The expected thermal generation at 437.2485 GW.h load is 25.300 GW.h.

Table 2: LWRF Analysis – 2019 Year End Example

		Year end LWRF Deferral Account
		2019
	Actual Outcomes	GW.h
1	**Actual Thermal Generation**	68.205
1a	**Actual Diesel Generation**	2.311
1b	**Actual LNG Generation**	65.894
1c	**Actual Diesel Generation as percentage of total Actual Thermal Generation (1a/1)**	*3.39%*
2	**LTA Thermal Generation at Actual Load (see Table 1)**	25.300
2a	**LTA Diesel Generation (2-2b)**	2.530
2b	**LTA LNG Generation*** **	22.770
3	**YEC Thermal Generation to be included in LWRF (1-2)****	42.905
3a	**YEC Diesel Generation to be included in LWRF(1a-2a)**	(0.219)
3b	**YEC LNG Generation to be included in LWRF (1b-2b)**	43.124
4	**Incremental YEC Thermal Generation Cost to Charge (Refund) LWRF ($000s) (diesel at $0.26333/kWh x row 3a + LNG at $0.14668/kWh*row 3b)**	**$6,268**

* Actual Thermal for Generation excludes RFID, capital and maintenance thermal.

** Negative is charge to YEC for water>LTA; positive is credit to YEC for water<LTA.

*** 90% of LTA thermal (row 2), subject to not exceeding total LTA thermal less estimated LTA diesel (row 1c*row2) when actual thermal> LTA thermal and not exceeding total LTA thermal less actual diesel (row 1a) when actual thermal< LTA thermal.

3.0 TAB 7 REVISED SCHEDULES

The revised schedules from Tab 7 of the Application are attached with adjustments as required by Order 2022-03 and the attached Reasons for Decision.

Appendix 3.1:
Tab 7 Schedules

Yukon Energy Corporation 2021 GRA Compliance Filing

April 14, 2022

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2 Computation of Allowance for Working Capital
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Yukon Energy Corporation
Computation of Rate Base
($000s)

Schedule 1
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	**Property, Plant and Equipment**						
2	Year end balance	S.3 L.4	612,436	615,387	642,738	672,467	728,282
	Deduct:						
3	Accumulated depreciation (note 1)	S.3 L.8	163,053	160,541	172,426	185,384	198,339
4	Construction-in-progress	S.3 L.12	7,620	4,491	8,088	11,873	40,572
5	Disallowed assets	S.3 L.11	2,193	2,193	1,989	351	12,152
6	Miscellaneous reserves	S.3 L.16	7,808	7,249	6,231	650	7,647
7	Total deductions		180,674	174,474	188,735	198,259	258,711
	Add:						
8	Deferred study costs and Intangible assets (note 2)	S.3 L.59	41,695	29,962	32,019	36,071	42,022
9	Less: Studies and Intangible Assets in Progress	S.3 L.60	29,498	18,930	20,881	25,386	30,489
10	Total additions		12,198	11,032	11,138	10,686	11,532
	Net plant in Service						
11	Current year-end balance	S.3 L.62	443,960	451,945	465,141	484,894	481,103
12	Previous year-end balance		446,777	446,795	451,945	465,141	484,894
13	Mid-year balance		445,368	449,370	458,543	475,017	482,999
14	Mid-year regulatory deferral		3,879	3,876	3,144	2,632	3,046
15	Working capital	S.2 L.8	5,344	5,617	5,935	6,582	7,092
16	**Gross Rate Base**		454,592	458,863	467,621	484,231	493,137
	Deduct:						
	Contributions for extensions (PP&E)						
17	Current year-end balance		201,232	199,527	211,719	225,337	254,348
18	Contributions in WIP		-	603	385	776	20,776
19	Current year-end balance in-service		201,232	198,924	211,333	224,560	233,571
20	Accumulated amortization of contributions		35,976	34,536	39,276	44,306	48,722
21	Net current year-end balance in-service		165,256	164,387	172,057	180,255	184,849
22	Previous year-end balance		168,967	168,967	164,387	172,057	180,255
23	Mid-year balance		167,112	166,677	168,222	176,156	182,552
24	**Net Rate Base**	S.5 L.1	287,480	292,186	299,399	308,076	310,585

Note 1: Including Reserve for Future Removal and Site Restoration
Note 2: Planning and Study costs, Relicencing, Dam Safety costs, Vegetation Management and Intangible Assets. Net of contributions.

Yukon Energy Corporation
Computation of Allowance for Working Capital
($000s)

Schedule 2
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	Operating and maintenance	S.5 L.5	23,715	27,794	29,784	37,676	43,211
2	Taxes other than income	S.5 L.6	708	671	673	739	750
3	Non-allowable expenses		(100)	(99)	(166)	(95)	(120)
4	Cash operating expenses		24,323	28,366	30,290	38,320	43,841
5	27/365		1,799	2,098	2,241	2,835	3,243
6	Inventory (three year average)		3,703	3,697	3,837	3,913	4,014
7	GST Impact on working capital	S.2A L.11	(158)	(178)	(143)	(166)	(165)
8	Working capital	S.1 L.19	5,344	5,617	5,935	6,582	7,092

Yukon Energy Corporation
Effect of GST on Working Capital
($000s)

Schedule 2A
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	Expenses subject to GST		42,084	37,733	53,916	63,064	96,063
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		2,104	1,887	2,696	3,153	4,803
4	Day Factor		14	14	14	14	14
5	Recoverable portion of GST impact		81	72	103	121	184
6	Revenue subject to GST		49,794	52,059	51,302	59,947	72,825
7	GST blended rate (2009 GRA)		5.00%	5.00%	5.00%	5.00%	5.00%
8	GST payable		2,490	2,603	2,565	2,997	3,641
9	Day factor		35	35	35	35	35
10	Payable portion of GST impact		239	250	246	287	349
11	Net impact of GST on working capital	S.2 L.7	(158)	(178)	(143)	(166)	(165)

Yukon Energy Corporation
Continuity Schedule of Property, Plant and Equipment, Deferred Costs and Intangible Assets
($000s)

Schedule 3
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
	Property, Plant and Equipment						
1	Balance at beginning of year		598,756	598,756	615,387	642,738	672,467
2	Net Increases to PPE (Table 5.1)		13,680	20,189	29,259	29,729	57,152
3	Retirements, disposals and adjustments		-	(3,559)	(1,908)	-	(1,337)
4	Balance at end of year	S.1 L.2	612,436	615,387	642,738	672,467	728,282
	Accumulated depreciation						
5	Balance at beginning of year		150,857	150,857	160,541	172,426	185,384
6	Depreciation expense	S.6 L.7	12,196	12,185	12,677	12,963	13,372
7	Retirements, disposals and adjustments		-	(2,501)	(791)	(5)	(417)
8	Balance at end of year	S.1 L.3	163,053	160,541	172,426	185,384	198,339
	Deductions from PP&E:						
9	Disallowed assets		2,746	2,746	2,746	1,152	13,192
10	Accum. Disallowed depreciation		(553)	(553)	(757)	(801)	(1,039)
11	Net Disallowed	S.1 L.5	2,193	2,193	1,989	351	12,152
12	Construction-in-progress	S.1 L.4	7,620	4,491	8,088	11,873	40,572
	Miscellaneous Reserves						
13	Fire Insurance Reserve		4,704	4,704	4,442	4,180	3,918
14	LWRF					(4,272)	2,782
15	Reserve for Injuries and Damages		(1,035)	(1,419)	(1,002)	(2,048)	(1,843)
16	Reserve for Future Removal and Site Restoration		4,139	3,963	2,790	2,790	2,790
17	Total Miscellaneous Reserves	S.1 L.6	7,808	7,249	6,231	650	7,647
18	Total Deductions		17,621	13,933	16,308	12,874	60,371
19	Net Property, Plant and Equipment for Rate Base		431,762	440,913	454,003	474,208	469,571
	Add:						
20	Deferred study costs and Intangible assets (net of contributions)						
21	Feasibility Studies						
22	Opening balance		18,499	18,499	17,798	16,841	16,798
23	Additions		14,127	1,091	866	1,826	6,686
24	Amortization		(1,838)	(1,791)	(1,824)	(1,869)	(2,274)
25	Year-end balance		30,788	17,798	16,841	16,798	21,210
26	Relicensing						
27	Opening balance		6,604	6,604	8,447	10,123	11,882
28	Additions		1,544	2,359	2,102	2,060	1,745
29	Amortization		(515)	(515)	(427)	(301)	(339)
30	Year-end balance		7,633	8,447	10,123	11,882	13,288
31	Dam Safety						
32	Opening balance		118	118	89	59	203
33	Additions		-	-	-	174	80
34	Amortization		(30)	(30)	(30)	(30)	(64)
35	Year-end balance		89	89	59	203	219
36	Vegetation Management						
37	Opening balance		1,994	1,994	1,772	1,551	1,329
38	Additions		-	-	-	-	-
39	Amortization		(222)	(222)	(222)	(222)	(222)
40	Year-end balance		1,772	1,772	1,551	1,329	1,108
41	Intangibles						
42	Opening balance		1,859	1,859	1,684	2,339	5,076
43	Additions		79	308	1,215	3,315	1,095
44	Amortization		(478)	(482)	(560)	(578)	(729)
45	Year-end balance		1,460	1,684	2,339	5,076	5,442
46	DSM						
47	Opening balance		990	1,009	1,097	1,205	720
48	Additions		-	182	210	(400)	120
49	Amortization		(110)	(93)	(103)	(85)	(93)
50	Year-end balance		880	1,097	1,205	720	747
51	Hearing Reserve						
52	Opening balance		(1,026)	(1,026)	(926)	(99)	63
53	Additions		155	155	883	217	-
54	Amortization		(55)	(55)	(55)	(55)	(55)
55	Year-end balance		(926)	(926)	(99)	63	8
56	Total Deferred Costs and Intangible Assets						
57	Opening balance		29,038	29,056	29,962	32,019	36,071
58	Additions		15,906	4,094	5,276	7,192	9,726
59	Amortization		(3,248)	(3,188)	(3,219)	(3,139)	(3,776)
60	Year-end balance	S.1 L.8	41,695	29,962	32,019	36,071	42,022
61	Less: Deferred Studies and Intangible Assets in Progress	S.1 L.9	29,498	18,930	20,881	25,386	30,489
62	Total Net Deferred Costs and Intangible Assets for Rate Base		12,198	11,032	11,138	10,686	11,532
63	Total Net PP&E, Deferred Costs and Intangible Assets for Rate Base	S.1 L.11	443,960	451,945	465,141	484,894	481,103
64	Other Regulatory						
65	Opening balance		3,868	3,850	3,902	2,386	2,878
66	Additions		318	309	(1,209)	836	815
67	Amortization		(295)	(257)	(307)	(345)	(479)
68	Year-end balance		3,891	3,902	2,386	2,878	3,214
69	Total Net PP&E, Deferred Costs and Intangible Assets		447,850	455,847	467,527	487,771	484,317

Yukon Energy Corporation
Calculation of Depreciation Expense for 2021
$000

Schedule 3A
April 14, 2022

Description	Cost at 2020 Year End	2021 Additions	2021 Disposals/ Adjustments	Cost at 2021 Year End	Proposed Depreciation Rate (Years)	2021 GRA Compliance
Land						
Hydraulic Production	444.9	0.0		444.9	0	0.0
Diesel Production	27.7	0.0		27.7	0	0.0
Main Transmission Facilities	576.9	0.0		576.9	0	0.0
Distribution System	17.8	0.0		17.8	0	0.0
General Plant	548.0	0.0		548.0	0	0.0
Rights	128.8	0.0		128.8	50	1.6
Depreciation Study Differences						0.0
Total Land	**1,744.0**	**0.0**	**0.0**	**1,744.0**		**1.6**
Hydro Plant						
Structures and Improvements	35,100.6	13,926.1		49,026.7	72	488.2
Buildings and Improvements	10,278.7	0.0		10,278.7	40	257.0
Reservoirs, Dams, and Waterways	173,385.2	300.0		173,685.2	103	1,683.5
Overhaul	6,712.1	0.0		6,712.1	10	671.2
Waterwheels,Turbines & Generation	26,904.6	0.0		26,904.6	85	309.9
Accessory Electric Equipment	27,364.1	0.0		27,364.1	40	684.8
Accessory Digital Equipment	837.9	0.0		837.9	20	41.9
Misc Power Plant Equipment	11,791.4	25.0		11,816.4	30	393.0
Fencing	107.1	0.0		107.1	30	2.7
Depreciation Study Differences						-140.5
Total Hydro Plant	**292,481.9**	**14,251.1**	**0.0**	**306,732.9**		**4,391.7**
Diesel Production						
Structures and Improvements	1,562.4	0.0		1,562.4	72	21.7
Buildings and Improvements	466.1	0.0		466.1	55	8.5
Fuel Holders, Products, and ACC	1,688.5	0.0		1,688.5	40	26.0
Generating Equipment and Prime	14,192.9	0.0		14,192.9	40	635.2
Overhaul	2,962.8	0.0		2,962.8	5	592.6
Minto Generating Equipment	243.5	0.0		243.5	12	26.1
Accessory Electric Equipment	9,427.5	0.0		9,427.5	45	208.7
Misc Power Plant Equipment	1,837.7	0.0		1,837.7	30	59.2
Depreciation Study Differences						-70.2
Total Diesel Production	**32,381.3**	**0.0**	**0.0**	**32,381.3**		**1,507.7**
Wind Turbine						
Wind Turbine	0.0	0.0		0.0	0	0.0
Total Wind Turbine	**0.0**	**0.0**	**0.0**	**0.0**		**0.0**
Main Transmission Facilities						
Poles and Fixtures	83,423.8	12,132.0	978.1	94,577.6	65	1,276.9
Brushing	14,082.3	0.0		14,082.3	60	234.7
Survey Costs	4,083.4	0.0		4,083.4	60	149.3
Overhead Conductors / Poles	20,561.3	0.0	358.4	20,202.9	60	342.7
Overhead Conductors / Towers	278.0	0.0		278.0	60	4.6
Substation Equipment	70,642.9	125.0		70,767.9	54	1,314.0
Substation VGC Group - Gold Mine	10,688.6			10,688.6	12	890.7
Substation Buildings	1,536.2	0.0		1,536.2	55	27.9
Substation Fences	274.5	0.0		274.5	30	8.9
Depreciation Study Differences						34.7
Total Main Transmission Facilities	**205,570.9**	**12,257.0**	**1,336.5**	**216,491.4**		**4,284.4**
Sub Transmission Lines						
Poles and Fixtures	4,659.6	0.0		4,659.6	65	67.0
25Kv Minto Spur- Structure	2,646.1	0.0		2,646.1	12	0.0
Brushing	41.6	0.0		41.6	60	0.7
Brushing Minto	432.5	0.0		432.5	12	0.0
Survey costs	0.0	0.0		0.0	60	0.0
Survey costs Minto	95.1	0.0		95.1	12	0.0
Overhead Conductors	1,840.4	0.0		1,840.4	60	30.5
Underground Conductors / Conduit	83.9	0.0		83.9	45	1.9
Overhead Conductors Minto	920.7	0.0		920.7	12	0.0
Substation Equipment	8,013.6	0.0		8,013.6	54	148.4
Substation Equipment Minto	7,111.2	0.0		7,111.2	12	74.6
Depreciation Study Differences						-45.8
Total Sub Transmission Lines	**25,844.8**	**0.0**	**0.0**	**25,844.8**		**277.2**
Distribution System						
Poles and Fixtures	9,709.1	648.0		10,357.1	40	242.4
Brushing	44.8	0.0		44.8	50	0.9
Survey costs	619.4	0.0		619.4	50	17.7

Yukon Energy Corporation Schedule 3A
Calculation of Depreciation Expense for 2021 April 14, 2022
$000

Description	Cost at 2020 Year End	2021 Additions	2021 Disposals/ Adjustments	Cost at 2021 Year End	Proposed Depreciation Rate (Years)	2021 GRA Compliance
Overhead conductors - Poles	268.2	0.0		268.2	50	4.3
Overhead Costs	2,117.4	0.0		2,117.4	40	52.9
Underground Services	385.2	0.0		385.2	40	9.6
Underground Conduit	40.5	0.0		40.5	40	1.0
Wind Monitoring Equipment	0.0	0.0		0.0	0	0.0
Meters	312.6	0.0		312.6	16	16.1
Meter Equipment	288.4	0.0		288.4	16	17.2
Substation Equipment	1,287.2	0.0		1,287.2	40	30.3
Substation Buildings	64.8	0.0		64.8	55	1.2
Substation Fences	100.3	0.0		100.3	30	3.3
Street Lights	591.6	0.0		591.6	40	13.8
Line Transformers	4,051.1	0.0		4,051.1	35	113.0
Sentinel Lights	36.4	0.0		36.4	30	1.2
Depreciation Study Differences						1.3
Total Distribution System	**19,916.9**	**648.0**	**0.0**	**20,564.9**		**526.3**
Building and Other Equipment						
Survey Costs Land	4.3	0.0		4.3	50	0.1
Structures and Improvements (Hydro)	2,529.5	50.0		2,579.5	50	49.9
Building and Improvements	10,549.7	131.8		10,681.5	55	190.9
Office Furniture and Equipment	1,877.4	25.0		1,902.4	20	47.2
Communication Site Towers	19.3	0.0		19.3	40	0.5
Communication Site Fences	64.1	25.0		89.1	30	2.1
Computer Hardware	2,063.4	230.0		2,293.4	7	130.2
Computer Software	0.0	0.0		0.0	5	0.0
Tool and Instruments	2,157.5	490.0		2,647.5	20	84.4
Wind Monitoring Equipment	14.3	0.0		14.3	15	1.0
Communication Equipment	5,615.6	100.0		5,715.6	20	234.1
Company Owned Houses / Land	59.0	0.0		59.0	40	1.3
Company Owned Houses	2,132.4	0.0		2,132.4	40	17.1
Depreciation Study Differences						-19.0
Total Building and Other Equipment	**27,086.6**	**1,051.8**	**0.0**	**28,138.4**		**739.6**
Transportation						
Utility Vehicles	371.6	30.0		401.6	8	25.6
Sedans and Stationwagons	137.8	0.0		137.8	11	6.0
Trucks & Pole Trailer	11.0	0.0		11.0	25	0.4
Pole Trailers > 10,000 Lbs	53.7	0.0		53.7	25	1.7
Trucks 3/4 to 2 Ton	3,430.1	0.0		3,430.1	9	293.8
Trucks > 3 Ton	1,459.8	0.0		1,459.8	20	58.4
Foremost	1,003.9	0.0		1,003.9	20	50.2
Depreciation Study Differences						19.3
Total Transportation	**6,467.8**	**30.0**	**0.0**	**6,497.8**		**455.4**
Critical Spares						
Critical Spares	1,193.6	0.0		1,193.6	0	0.0
Total Critical Spares	**1,193.6**	**0.0**	**0.0**	**1,193.6**		**0.0**
LNG Production						
Structures and Improvements	6,184.7	0.0		6,184.7	72	85.9
Fuel Holders	13,200.7	0.0		13,200.7	60	220.0
Generator	20,891.0	0.0		20,891.0	40	522.3
Overhaul	343.3	180.0		523.3	2	171.4
Accessory Electric Equipment	3,655.9	0.0		3,655.9	45	81.2
Misc Power Plant Equipment	2,850.6	35.0		2,885.6	30	95.0
Fence	779.7	0.0		779.7	30	26.0
Depreciation Study Differences						-14.0
Total LNG Prodution	**47,905.9**	**215.0**	**0.0**	**48,120.9**		**1,187.9**
Total	**660,593.6**	**28,452.9**	**1,336.5**	**687,709.9**		**13,371.9**

Yukon Energy Corporation
Cost of Capital Calculation
($000s)

Schedule 4
April 14, 2022

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio		Mid Year Rate Base	Mid Year Cost Rate	Return
	2018 GRA Compliance							
1	Long-Term debt	S.11 L.18	172,472	60.0%		172,473	2.23%	3,844
2	Common Stock	S.7 L. 8	115,005	40.0%		115,007	8.70%	10,006
3	Total	S.5 L.3	287,477	100.0%		287,480	4.82%	13,850
	2018 Actual							
7	Long-Term debt	S.11 L.18	159,363	57.4%		167,814	2.58%	4,336
8	Common Stock	S.7 L. 8	118,109	42.6%		124,372	6.25%	7,773
9	Total	S.5 L.3	277,472	100.0%		292,186	4.14%	12,110
	2019 Actual							
10	Long-Term debt	S.11 L.18	170,377	58.6%		175,532	2.71%	4,757
11	Common Stock	S.7 L. 8	120,229	41.4%		123,867	3.81%	4,723
12	Total	S.5 L.3	290,606	100.0%		299,399	3.17%	9,480
	Forecast 2020				**Deemed Ratio**			
13	Long-Term debt	S.11 L.18	180,367	59.8%	60.0%	182,952	2.91%	5,322
14	Common Stock	S.7 L. 8	121,488	40.2%	40.0%	125,125	3.72%	4,659
15	Total	S.5 L.3	301,855	100.0%	100.0%	308,076	3.23%	9,981
	2021 GRA Compliance				**Deemed Ratio**			
19	Long-Term debt	S.11 L.18	186,198	60.4%	60.0%	186,351	2.93%	5,469
20	Common Stock	S.7 L. 8	122,262	39.6%	40.0%	124,234	8.20%	10,187
21	Total	S.5 L.3	308,460	100.0%	100.0%	310,585	5.04%	15,656

Yukon Energy Corporation
Utility Revenue Requirement
($000s)

Schedule 5
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	Net rate base	S.1 L.24	287,480	292,186	299,399	308,076	310,585
2	Average Rate of return on rate base		4.82%	4.14%	3.17%	3.24%	5.04%
3	Utility income	S.8 L.1	13,850	12,110	9,480	9,981	15,656
4	Utility expenses						
5	Operating and maintenance (note 1)	S.6 L.3	23,715	27,794	29,784	37,676	43,211
6	Taxes other than income	S.6 L.4	708	671	673	739	750
7	Amortization of deferred costs	S.6 L.5	3,543	3,500	3,582	3,540	4,310
8	Reserve for Injuries and Damages	S.6 L.6	479	479	479	479	616
9	Depreciation	S.6 L.7	12,196	12,185	12,677	12,963	13,372
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(4,394)	(4,377)	(5,002)	(5,291)	(4,678)
11	Disallowed depreciation		(204)	(204)	(204)	(44)	(238)
12	Donations		(100)	(99)	(166)	(95)	(120)
13	Total utility expenses		35,943	39,949	41,822	49,966	57,222
14	Revenue Requirement	S.6 L.1	49,794	52,059	51,302	59,947	72,878

Note 1: Includes fuel expenses and purchased power.

Yukon Energy Corporation
Statement of Earnings
($000s)

Schedule 6
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	Revenues (note 1)	S.5 L.14	49,794	52,059	51,302	59,947	72,878
2	**Operating expenses**						
3	Operating and maintenance	S.10 L.15	23,715	27,794	29,784	37,676	43,211
4	Taxes other than income	S.5 L.6	708	671	673	739	750
5	Amortize deferred costs		3,543	3,500	3,582	3,540	4,310
6	Reserve for Injuries and Damages	S.5 L.8	479	479	479	479	616
7	Depreciation	S.3 L.8	12,196	12,185	12,677	12,963	13,372
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(4,394)	(4,377)	(5,002)	(5,291)	(4,678)
9	Total		36,247	40,252	42,192	50,105	57,581
10	**Operating income**		13,546	11,807	9,110	9,842	15,298
11	**Other income**						
12	Allowed for Funds Used	S.8 L.2	542	539	648	829	1,194
13	Miscellaneous (note 2)	S.8 L.3	(515)	(824)	(951)	(473)	(139)
14	Total		28	(284)	(304)	356	1,056
15	**Other expenses**						
16	Interest expense	S.8 L.4	4,431	5,583	6,124	9,663	5,666
17	Total		4,431	5,583	6,124	9,663	5,666
18	**Net earnings**	S.8 L.8	9,142	5,939	2,683	534	10,688

Note 1: Includes revenues from sales and other revenues.
Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

Yukon Energy Corporation
Statement of Retained Earnings
($000s)

Schedule 7
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	Balance at beginning of year		60,775	61,366	67,653	65,606	66,993
	Add:						
2	Net earnings	S.6 L.18	9,142	5,939	2,683	534	10,688
3	IFRS Comprehensive Income Adjustment		1,660	348	(1,859)	853	-
4	Balance at end of year before dividend		71,577	67,653	68,477	66,993	77,681
	Less:						
5	Common Dividends (note 1)		10,414	-	2,871	-	13,703
6	Balance at end of year		61,163	67,653	65,606	66,993	63,977
	Shareholder's Equity						
7	Common shares		54,036	53,600	53,600	56,777	56,777
8	Retained earnings		61,163	67,653	65,606	66,993	63,977
9	Total		115,200	121,253	119,206	123,770	120,754

Note:
1. YDC equity injection/dividend estimates required in order to maintain 60/40 debt to equity ratio.

Yukon Energy Corporation
Reconciliation of Utility Income to Net Earnings
($000s)

Schedule 8
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	Utility Income (Return on Rate Base)	S.5 L.3	13,850	12,110	9,480	9,981	15,656
	Add:						
2	Allowance for funds used	S.6 L.12	542	539	648	829	1,194
3	Other income (expenses)	S.6 L.13	(515)	(824)	(951)	(473)	(139)
			13,878	11,825	9,176	10,337	16,712
	Less:						
4	Interest - long-term	S.6 L.17	4,431	5,583	6,124	9,663	5,666
5	Donations	S.5 L.12	100	99	166	95	120
6	Disallowed costs	S.5 L.13	-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	204	204	204	44	238
			4,735	5,886	6,494	9,803	6,024
8	Net earnings	S.6 L.18	9,142	5,939	2,683	534	10,688

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues
($000s)

Schedule 9
April 14, 2022

Line No.	Description	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	**Residential**					
2	Customers	1,635	1,689	1,730	1,756	1,780
3	Sales in MWh	13,719	15,626	15,384	16,730	16,210
4	MWh sales per customer	8.4	9.3	8.9	9.5	9.1
5	Revenue ($000s)	2,016	2,262	2,262	2,413	2,384
6	Cents per KWh	14.7	14.5	14.7	14.4	14.7
7	**General Service**					
8	Customers	489	506	517	516	514
9	Sales in MWh	25,436	27,171	29,148	32,250	32,323
10	MWh sales per customer	52.0	53.7	56.4	62.5	62.9
11	Revenue ($000s)	4,054	4,490	4,833	5,351	5,388
12	Cents per KWh	15.9	16.5	16.6	16.6	16.7
13	**Industrial**					
14	Sales in MWh	32,193	36,910	27,286	64,856	102,904
15	Revenue ($000s)	3,952	4,378	3,673	7,260	11,481
16	Cents per KWh	12.3	11.9	13.5	11.2	11.2
17	**Street lights**					
18	Sales in MWh	214	224	168	168	168
19	Revenue ($000s)	56	87	82	82	82
20	Cents per KWh	26.0	39.1	48.8	48.8	48.8
21	**Space lights**					
22	Sales in MWh	12	11	10	10	10
23	Revenue ($000s)	3	3	3	3	3
24	Cents per KWh	22.5	29.2	26.7	28.1	26.6
25	**Total Company - Firm Retail and Industrial**					
26	Customers	2,125	2,195	2,247	2,272	2,293
27	Sales in MWh	71,573	79,941	71,997	114,013	151,614
28	Revenue ($000s)	10,081	11,221	10,853	15,108	19,337
29	Cents per KWh	14.1	14.0	15.1	13.3	12.8
30	**Wholesale sales**					
31	Sales in MWh	314,700	332,270	331,495	351,775	343,537
32	Revenue ($000s)	26,114	27,572	27,507	29,190	28,507
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3
34	**Total Company - Firm**					
35	Sales in MWh	386,273	412,212	403,491	465,788	495,151
36	Revenue ($000s)	36,194	38,792	38,360	44,298	47,844
37	Cents per KWh	9.4	9.4	9.5	9.5	9.7
38	**Secondary**					
39	Sales in MWh	2,059	258	0	0	0
40	Revenue ($000s)	115	20	0	0	0
41	Cents per KWh	5.6	7.6	7.6	0.0	0.0
42	**Total Company**					
43	Sales in MWh	388,332	412,470	403,492	465,788	495,151
44	Revenue ($000s)	36,310	38,812	38,360	44,298	47,844
45	Cents per KWh	9.4	9.4	9.5	9.5	9.7
46	Rider J	13,231	13,329	13,842	15,289	15,887
47	Post-GRA Reconcil Req'd					
48	GRA Increase Req'd				0	8,779
49	Total Sales of Power	49,541	52,141	52,203	59,588	72,510
50	Other Revenues	253	-82	-901	359	369
51	Total Revenues	49,794	52,059	51,302	59,947	72,878

Yukon Energy Corporation
Summary of Operating and Maintenance Expenses
($000s)

Schedule 10
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	**Utility operations**						
2	Production		5,930	7,755	8,402	9,871	10,438
3	Transmission and distribution		3,445	2,835	2,767	3,215	3,188
4	General		1,615	1,746	1,921	1,695	1,763
5	Administration and general		8,917	8,966	9,201	9,603	10,397
6	Insurance		1,031	1,046	1,117	1,299	1,423
7	Sub-total		20,938	22,347	23,407	25,684	27,209
8	Donations		100	99	166	95	120
9	Sub-total		100	99	166	95	120
10	O&M not including fuel and						
11	purchased power		21,038	22,447	23,574	25,779	27,329
12	Fuel		2,638	5,295	6,153	11,836	15,829
13	Purchased power		39	53	57	60	53
14	Sub-total		2,677	5,348	6,211	11,896	15,882
15	Total operating and maintenance	S.6 L.3	23,715	27,794	29,784	37,676	43,211
	Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the f						
16	*Reserve for Injuries and Damages*		*479*	*479*	*479*	*479*	*616*
17	*Property Taxes*		*708*	*671*	*673*	*739*	*750*
18	*less: Donations*		*-100*	*-99*	*-166*	*-95*	*-120*
19	*O&M per Table 3.3 (Tab 3)*		*22,125*	*23,497*	*24,559*	*26,903*	*28,575*

Yukon Energy Corporation
Summary of Labour Costs
($000s)

Schedule 10A
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
1	**Total FTEs**	Tab 3, Table 3.4	93.7	94.9	98.4	97.9	100.6
2	**Total Labour Costs**		14,394	14,173	14,131	15,420	15,719
3	O&M Labour Costs	Sum Lines 5-9	11,932	12,083	11,863	12,727	13,016
4	Labour Costs to Capital		2,461	2,090	2,268	2,694	2,703
	Labour Costs						
5	Production		4,131	4,455	4,467	4,995	4,802
6	Transmission		635	526	545	659	674
7	Distribution		856	801	625	617	629
8	General		395	351	391	343	372
9	Administration		5,916	5,949	5,835	6,113	6,539
10	Total Labour		11,932	12,083	11,863	12,727	13,016

Yukon Energy Corporation
Summary of Cost of Long - Term Debt
($000s)

Schedule 11
April 14, 2022

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	2021 GRA Compliance
	General Purpose Long-Term Debt Balance						
1	YDC Mayo B Flexible Term Debt		19,542	19,542	19,205	18,868	18,531
2	TD Bank Swap (2.69%)		8,991	8,991	8,623	8,245	7,858
3	Minto Decommissioning Reserve		2,684	2,710	2,769	2,800	2,816
4	YDC $5.5M Debt (2.40%)		5,505	5,505	5,505	5,505	5,505
5	YDC $92.5M Debt (2.40%/2.83%)		77,723	77,723	74,039	70,356	66,672
6	YDC $21.0M Debt (2.21%)		18,466	18,466	17,627	16,788	15,948
7	YDC $12.1M Debt (2.10%)		12,136	12,136	12,136	12,136	12,136
8	TD Bank Swap (3.665%)		21,940	23,406	22,811	22,194	21,554
9	New 2018 Debt-2018 True Up (2.15%)		5,776	0	0	0	0
10	TD Bank Swap (2.899%)		0	0	6,688	6,498	6,303
11	YDC $2.9M Debt (2.899%)		0	0	2,871	2,871	2,871
12	New 2020 Debt-2019 True Up (2.19%)		0	0	0	8,760	8,760
13	New 2020 Debt-2020 True Up (2.19%)		0	0	0	13,439	13,439
14	New 2021 Debt-2021 True Up (2.19%)		0	0	0	0	1,544
15	Current year-end balance		172,763	168,479	172,274	188,460	183,937
16	Previous year-end balance		172,181	150,246	168,479	172,274	188,460
17	Mid Year		172,472	159,363	170,377	180,367	186,198
	Interest Costs						
18	YDC Mayo B Flexible Term Debt		334	771	690	1,049	1,030
19	TD Bank Swap (2.69%)		247	247	237	227	217
20	Minto Decommissioning Reserve		24	45	59	31	16
21	YDC $5.5M Debt (2.40%)		132	132	132	132	132
22	YDC $92.5M Debt (2.40%/2.83%)		1,954	1,954	1,865	1,984	1,886
23	YDC $21.0M Debt (2.21%)		427	427	408	390	371
24	YDC $12.1M Debt (2.10%)		255	255	255	255	255
25	TD Bank Swap (3.665%)		472	287	848	826	803
26	New 2018 Debt-2018 True Up (2.15%)		0	0	0	0	0
27	TD Bank Swap (2.899%)		0	0	81	191	186
28	YDC $2.9M Debt (2.899%)		0	0	42	83	83
29	New 2020 Debt-2019 True Up (2.19%)		0	0	0	35	192
30	New 2020 Debt-2020 True Up (2.19%)		0	0	0	44	294
31	New 2021 Debt-2021 True Up (2.19%)		0	0	0	0	0
32	**Total Cost of Interest**		3,844	4,118	4,618	5,247	5,464
33	Mid-Year Cost of Debt		2.23%	2.58%	2.71%	2.91%	2.93%