

# YUKON ENERGY CORPORATION

## Board Order 2018-10 – Compliance Filing

### 2017/2018 General Rate Application

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## 1.0 OVERVIEW

On June 22, 2017, Yukon Energy filed with the Yukon Utilities Board (“the Board” or “YUB”) its General Rate Application (“the Application”) for 2017 and 2018. By Order 2017-04, the Board established a process for review of that Application, and following that process on December 27, 2018, the Board issued Order 2018-10, approving the 2017 and 2018 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 60 days in accordance with the directions set out in the Reasons for Decision (Appendix A attached to Order 2018-10).

This Compliance Filing sets out for approval of the Board the Yukon Energy revised filings as required by Order 2018-10, along with all related explanations<sup>1</sup>. 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 2018-10).

### 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 2018-10. Table 1.1 below provides a summary of the changes to the revenue requirement and revenues at existing rates in place at the start of 2017.

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<sup>1</sup> As required, the filing addresses only those directions of the Board in its Reasons for Decision pertaining to Yukon Energy’s 2017 and 2018 revenue requirements.

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

**Table 1.1:  
Summary of Changes to the Revenue Requirement and Revenues at Existing Rates**

	Original Filing		Compliance Filing		Difference		Notes
	2017	2018	2017	2018	2017	2018	
<b>Revenue Requirement</b>							
Fuel and Purchased Power	2,381	2,407	2,460	2,677	79	270	2017 actuals and 2018 updated load forecast
Non Fuel O&M -Labour	11,770	11,823	11,869	11,932	99	109	2017 Actuals and capital allocation change
Non Fuel O&M -Other	10,290	10,192	10,583	10,192	293	0	2017 Actuals
Depreciation and Amortization	10,814	11,094	10,848	11,141	34	48	See Appendix 1.1, Table 1.1-2
Return on Rate Base	13,289	14,348	13,442	13,850	153	-498	See Appendix 1.1, Table 1.1-2
<b>A Total Revenue Requirement</b>	<b>48,544</b>	<b>49,864</b>	<b>49,202</b>	<b>49,794</b>	<b>658</b>	<b>-71</b>	
<b>Revenues at Existing Rates</b>							
							2017 actuals
Residential	2,002	2,016	2,203	2,016	201	0	
Commercial	4,036	4,054	4,350	4,054	315	0	
Industrial	4,198	4,198	4,829	3,952	631	-247	2018 Minto load forecast update
Streetlight and Sentinel Light	61	58	92	58	30	0	
Wholesale	25,641	25,684	27,253	26,114	1,612	430	2018 Wholesale sales forecast update
Secondary Sales revenues	642	642	470	115	-172	-527	2018 Secondary sales forecast update
Rider J Revenues	6,363	6,373	6,952	6,469	589	96	2018 Impact of base rate revenue changes
Other Revenue	253	253	319	253	66	0	
<b>B Total revenues at existing rates</b>	<b>43,196</b>	<b>43,279</b>	<b>46,467</b>	<b>43,032</b>	<b>3,271</b>	<b>-247</b>	
<b>C=A-B Required GRA rate increase</b>	<b>5,348</b>	<b>6,585</b>	<b>2,734</b>	<b>6,762</b>	<b>-2,613</b>	<b>176</b>	

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 2018-10 (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** – Overall change of test year sales and revenues at existing rates of \$3.271 million increase in 2017 and \$0.247 million decrease in 2018 to address the Board directives related to YEC GRA forecasts. Major impacts are described below. (See Table 1.1 for full disclosure of adjustments.)
  - a. Wholesales: \$1.612 million increase in firm wholesales (excluding Rider J) in 2017 to address 19.4 GW.h of added sales for actual versus forecast in the Application, and \$0.430 million increase in 2018 (excluding Rider J) based on direction that sales be increased by 5.2 GW.h to reflect the 2017 AEY compliance filing.
  - b. Major Industrial: \$0.631 million increase in 2017 (excluding Rider J) to address 5.2 GW.h of added sales for actual versus forecast in the Application, and \$0.247 million decrease in 2018 (excluding Rider J) based on direction to reflect updated sales forecast for Minto with a sales reduction of approximately 6.0 GW.h from the Application forecast.
  - c. Retail Sales: \$0.546 million increase in 2017 (excluding Rider J) to address 2.2 GW.h of added sales for actual versus forecast in the Application; no change for 2018 from the Application forecast.
  - d. Secondary sales: \$0.172 million decrease in 2017 to address 3.1 GW.h of reduced sales for actual versus forecast in the Application, and \$0.527 million decrease in 2018 to address 9.4 GW.h lower sales in the updated forecast (Undertaking 36) compared with the Application.
2. **Generation and Forecast Thermal** – Firm YEC generation for 2017, based on actual as directed, is 26.1 GW.h higher (at 446.5 GW.h) than the Application forecast, reflecting increased sales (see above) and lower losses at 8.1% of sales (versus 8.8% in the Application). Firm YEC generation forecast for 2018 is 0.9 GW.h lower (at 420.3 GW.h) than the Application forecast, reflecting lower sales (see Appendix 1.1, Table 1.1-1).
  - a. 2017 Thermal Generation – 2017 thermal generation is 0.9 GW.h lower (at 13.3 GW.h) than the Application forecast, reflecting actual thermal generation rather than long-term average (LTA) generation in the Application and much lower grid load.
  - b. 2018 Thermal Generation - 2018 thermal generation is 1.9 GW.h higher (at 16.4 GW.h) than the Application forecast, reflecting LTA thermal generation based on the updated load forecast and the LTA hydro and thermal generation forecasts (see Appendix 2.2).
  - c. 2017 Thermal Fuel Expense – 2017 thermal fuel expense is \$0.069 million higher (at \$2.411 million) than the Application forecast, reflecting actual diesel and LNG generation (72.7% LNG and 27.3% diesel) and fuel prices as directed as well as actual maintenance fuel costs. (Table 1.1 shows increase of \$0.079 million for Fuel and Purchased Power, reflecting increase in Purchased Power of \$0.010 million. Fuel costs for capital projects and RFID are not included in Fuel and Purchased Power costs.)

- d. 2018 Thermal Fuel Expense – 2018 thermal fuel expense is \$0.270 million higher (at \$2.638 million) than the Application forecast, reflecting the higher thermal generation forecast caused by:
- Changes to LTA hydro and thermal generation forecasts, including the changes in load shape<sup>2</sup> [see Appendix 2.2];
  - Assumed 90/10 LNG/diesel fuel mix and the Application forecast; and
  - 2018 thermal fuel expense uses Application maintenance fuel, forecast fuel prices and efficiencies as approved in the Order.
3. **Non-Fuel O&M** – Overall increase in non-fuel O&M of \$0.392 million in 2017 and \$0.109 million in 2018, compared to the Application forecast, reflecting the following:
- a. Labour Expense – An increase of \$0.099 million in 2017 and \$0.109 million in 2018. The 2017 change reflects actual FTEs, labour costs, and the updated capital-to-maintenance ratio to reflect inclusion of 2017 actual ratio (as part of 4 year average) as directed; the change for 2018 reflects the updated capital-to-maintenance ratio (see Section 2.3.1 of this Compliance Filing for more details).
- b. Non-Fuel Other Expense – An increase of \$0.293 million in 2017 to reflect actual costs as directed. No change in the 2018 forecast costs.
4. **Return on Rate Base and Depreciation and Amortization Expense** – Order 2018-10 approved actual costs in 2017 and forecast costs in 2018 for capital and deferred projects as proposed in the Application, subject to specific disallowed capital and deferred project costs in each test year (see Appendix 1.1, Table 1.1-3 and Section 2.7 of this Compliance Filing for details). Depreciation and amortization expense was generally approved as proposed, subject to changes resulting from 2017 actuals and 2018 disallowed projects. Capital structure (60% debt and 40% equity) was approved as proposed, along with costs of debt (subject to actual costs for 2017 and 2018 adjustments resulting from disallowed projects). Return on equity was approved at 8.70%, a reduction of 0.12 percentage points from the Application (see Appendix 1.1, Table 1.1-2 for impact on revenue requirement). The impact to these components from YUB directions in 2018-10 is as follows:
- a. **Mid-year Net Rate Base:** Compared to the Application, mid-year Net Rate Base as approved is approximately \$1.5 million lower (at \$272.9 million) in 2017 and \$4.1 million lower (at \$287.5 million) in 2018.
- b. **Depreciation and Amortization Expense:** Final depreciation and amortization expense is higher than the Application by \$0.034 million in 2017 and by \$0.048 million in 2018.

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<sup>2</sup> The lower 2018 Minto load used for the Compliance Filing reflects a sharp decline in about mid-year for the balance of the year, versus the Application forecast which was reasonably flat throughout the year. As noted in Undertaking #36 Revised, this material change in annual load shape requires an update to the DCF (now LWRP) Table 3.4-1 in the Application. See Appendix 2.1, Attachment 2.1-2 for more detailed review of adjustments made for this change in load shape.

- c. **Return on Rate Base:** Final return on rate base in 2017 is \$0.153 million higher than the Application; return on rate base in 2018 is \$0.497 million lower than the Application. Cost of debt in 2017 is 0.22 percentage points higher than the Application; in 2018, cost of debt is 0.09 percentage points lower than the Application.

#### 5. Rates and Stabilization Measures

- a. **Secondary Sales Rate** – No changes were made to the Application's proposed secondary sales rate, other than adoption of actual rates for 2017.
- b. **Rider F** – The Board approved the Application's proposals for including LNG in the ongoing DFPVA and Rider F determinations, subject to a provision that any variances due to changes in the thermal fuel mixture (forecast versus actual) are not included in the DFPVA. Forecast fuel efficiencies and fuel prices are approved as proposed in the Application for 2018 (actual fuel prices are approved for 2017). The Rider F true-up determinations for this Compliance Filing as reviewed in Section 1.3 below continue to utilize actual thermal fuel mixture in each test year.
- c. **Diesel Contingency Fund (DCF)/Low Water Reserve Fund (LWRF)** – Order 2018-10 approved the core principles and requirements for the DCF deferral account, directed that it be renamed the Low Water Reserve Fund (LWRF), and that its operation be made less complex. The proposed LWRF Term Sheet is provided in Appendix 2.1, Attachment 2.1-1 of this Compliance Filing. The 2017-2018 LWRF Annual Report is included in Appendix 2.2.
- d. **Wholesale Rate Schedule 42 & ERA** – The Wholesale Rate Schedule 42 (including the ERA) remains as approved by Board Order 2018-05, Appendix B. That is, the rate schedule does not require amendment based on implementation of YUB Order 2018-10. No ERA is applicable in 2017 due to the use of actual sales and costs for the approved revenue requirement. The ERA determinations for 2018 in Appendix 2.2 comply with the Board's determinations in Order 2018-10 regarding both the LWRF and the ERA.

### 1.2 IMPACT OF CHANGES ON REQUIRED RATE INCREASE

Board Order 2018-10 approved the Yukon Energy 2017 and 2018 revenue requirements subject to the adjustments that are required by the Order and the attached Reasons. Table 1.2 below provides the 2017/2018 required revenues from rates with changes as directed by Order 2018-10. Table 1.3 provides the detailed required revenue increase calculation.

**Table 1.2:  
YEC 2017/2018 Compliance Filing Revenue Required from Rates (\$000s)**

	<u>2017</u>	<u>2018</u>
Revenue Requirement	\$49,202	\$49,794
Less: Other Revenues	\$319	\$253
Less: Secondary Sales	\$470	\$115
Revenue Required from Firm Rates	\$48,413	\$49,425
Less: Revenues from Firm Sales at Existing Rates (including "Fixed" component of industrial Rider F)	<u>\$45,679</u>	<u>\$42,663</u>
Firm Rate Increase Proposed	\$2,734	\$6,762

**Table 1.3:  
YEC 2017/2018 GRA Compliance Filing Required Revenue Increase Calculation**

Line #			Actual <sup>4</sup> 2017	Forecast 2018
1a	Consolidated Firm Retail Sales Revenues - Base Rates <sup>1</sup>	\$000	58,150	55,822
1b	Consolidated Firm Industrial Sales Revenues - Base Rates	\$000	4,829	3,952
2a	Consolidated Rider J Revenue at pre-GRA rates <sup>2</sup>	\$000	6,952	6,437
2b	AEY Rider R Revenues <sup>3</sup>	\$000	5,349	4,961
3=1+2	<b>Total Consolidated Firm Sales Revenues at existing rates</b>	<b>\$000</b>	<b>75,280</b>	<b>71,172</b>
4=Table 1	Retail Revenue increase required in 2017	\$000	2,734	
5a=4/3	Required Rate Increase on total Consolidated Revenues	%	3.63%	
5b=4/(1a+1b)	Rider J Increase Required	%	4.34%	
6=3+4	<b>Total Consolidated Firm Sales Revenues with 2017 Increase</b>	<b>\$000</b>	<b>78,015</b>	<b>73,767</b>
7=Table 1	Total Revenue increase required in 2018	\$000		6,762
8=6-3	To Be Recovered from 2017 Increase	\$000		2,595
9=7-8	Total net increase required in 2018	\$000		4,167
10a=9/6	Required Rate Increase on total Consolidated Revenues	%		5.65%
10b=9/(1a+1b)	Required J Increase in 2018	%		6.97%
11=9+6	<b>Total Consolidated Firm Sales Revenues with 2018 Increase</b>	<b>\$000</b>		<b>77,934</b>
12	Total Cumulative 2017 and 2018 Rate Increases (compounded)		3.63%	9.49%
	<b>Rider J Required</b>			
13a=5b	Rider J Increase Required	%	4.34%	
13b=10b	Rider J Increase Required	%		6.97%
14	Existing Rider J - non-industrial	%	11.01%	
15	Existing Rider J - industrial	%	7.36%	
16=13+14	Total Rider J with increases - non-industrial	%	15.35%	22.32%
17=13+15	Total Rider J with increases - industrial	%	11.70%	18.67%

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-GRA rates include YEC's Rider J at 11.01% for firm YEC and AEY retail sales and at 7.36% for firm industrial sales.
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.
4. 2017 YEC and AEY Revenues, including Rider J and Rider R revenues are based on actual results.

In summary, compared to the 2017/2018 GRA Application:

- **In 2017**, the total revenue requirement is increased \$0.658 million, total revenue at existing rates is increased \$3.271 million and the required GRA Rate increase reduced by \$2.613 million.
- **In 2018**, the total revenue requirement reduced \$0.071 million, total revenue at existing rates reduced \$0.247 million and the required GRA rate increase increased by \$0.176 million.

Excluding time-limited true-up rate increases, the annualized required Rider J rate increase resulting from Board Order 2018-10 for each test year is as follows (prior to consideration of interim rates and true up riders as required to address implementation of Order 2018-10):

- **For 2017** – Rider J rate increase of 4.34% for retail and industrial customers.
- **For 2018** – Rider J rate increase of 6.97% for retail and industrial customers.
- **Cumulative rate increase** over the test years of 11.31% increase in Rider J for retail and industrial customers (compared to 11.11% in the Application) – A 0.20% increase from the requested cumulative Rider J increase as set out in the Application.
- **Total Resulting Rider J** – The total resulting Rider J, including existing Rider J without the interim 5.5% rider, is 22.32% for retail customers and 18.67% for industrial customers.

Order 2017-06 approved an interim refundable Rider J increase of 5.5% effective September 1, 2017 for the last 4 months of 2017 for all retail and industrial customers. A true-up rider is required to address 2017 revenue shortfalls related to (1) the final Rider J percentage rate increase for 2017; and (2) eight months of unrecovered rate increase revenues for 2017 [January 1, 2017 to August 31, 2017].

A true up rider will be required to address 2018 revenue shortfalls to address amounts not collected over 2018. Detailed calculations supporting the calculation of the true up rider are provided in Appendix 1.1, Tables 1.1-4 to 1.1-7.

Assuming that May 1, 2019 is the earliest date for implementing any adjustment to Rider J and Rider R to reflect Order 2018-10, true-up adjustments are required for 2017, 2018 and 4 months of 2019. In order to implement the rate-related decisions from Board Order 2018-10 effective May 1, 2019, the following true-up adjustments are required as at that date:

1. **Ongoing Rider J Adjustment** – Interim Rider J must be made final and increased to a final total cumulative rate increase of 11.31% for retail and industrial customers, effective May 1, 2019 (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).
2. **Across the Board Time-limited Rider R Charge** – To collect rate revenue shortfalls in 2017, 2018 and the first four months of 2019. This rider increase is proposed to be applied over 24 months (time-limited Rider of 5.94% from May 1, 2019 to April 30, 2021). This true up rider is primarily required because, in summary and as reviewed below, interim rates approved in Order 2017-06 are lower than the required rate increases for 2017 and 2018 based on the revenue requirement as approved in Order 2018-10. (See in Appendix 1.1, Table 1.1-4 for details of the Rider R charge determination.)

- **True-up Adjustment for 2017** – The 2017 test year is to be finalized consistent with a \$2.734 million rate revenue increase (compared to \$5.348 million proposed in the General Rate Application). At GRA test year forecasts for the compliance filing (i.e., actual sales), interim Rider J collections for September-December 2017 equal \$0.931 million; accordingly, a one-time adjustment of \$1.804 million is required to collect the net revenue shortfall for 2017. Yukon Energy proposes to collect this amount over a 24 month period starting from May 1, 2019.
- **True-up Adjustment for 2018** – The 2018 test year is to be finalized at a level providing for \$6.762 million annualized rate revenue increase. The interim Rider J continued to apply throughout 2018, with forecast collections at test year forecast load per the compliance filing equal to \$3.288 million. Accordingly, a one-time adjustment of \$3.474 million is required to collect the net revenue shortfall for 2018 due to the interim Rider J being in place. Yukon Energy proposes to collect this amount over a 24-month period starting from May 1, 2019.
- **True-up Adjustment for 2019** - The interim Rider J continued to apply in 2019 prior to implementation of final rate changes assumed as at May 1, 2019. Assuming that the new ongoing Rider J increase of 11.31% for retail and industrial is effective as of May 1, 2019, a one-time adjustment of \$1.314 million is required to collect the net revenue shortfall for 2019 due to the interim Rider J being in place until April 30, 2019. Yukon Energy proposes to collect this amount over a 24-month period starting from May 1, 2019.
- **Rider F True Up Adjustment** – Pursuant to past practice, at each YEC 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 as the base, as well as approved Secondary Sales forecast rates. The 2017 and 2018 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 2017/2018 Compliance Filing fuel efficiency and fuel prices, as well as related variance between actual and 2017/18 Compliance Filing Secondary Sales forecast rates. These adjustments, which total \$1.340 million increase in true-up requirement (\$0.054 million in 2017, \$1.286 million in 2018). The amount for 2018 at \$1.286 million is based on actual fuel mix and volumes.<sup>3</sup>
- **Total Net True Up Adjustment** – Consequently, taking into account the above true-up amounts for 2017, 2018 and 2019 plus the Rider F true-up adjustment, there is a need to recover a total \$7.932 million from ratepayers related to under collection of amounts in 2017, 2018 and 2019. Yukon Energy proposes to collect this amount over a 24-month period starting from May 1, 2019. Based on a consolidated base rate revenue forecast for this 24-month period of \$133.576 million (\$118.488 million non-industrial and \$15.088

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<sup>3</sup> Paragraph 293 of Appendix A to Board Order 2018-10: Reasons for Decision directs YEC to ensure that any variances due to changes in the thermal fuel mixture (forecast versus actual) are not included in the DFPVA. If variance is not permitted from the LNG/diesel fuel mix adopted for the Compliance Filing 2018 forecast (90% LNG and 10% diesel), the Rider F fuel price adjustment for 2018 would be slightly higher (at \$1.346 million) than the Rider F fuel price adjustment for 2018 used for the Rider R true-up (at \$1.303 million) based on the actual fuel mix in 2018 (see Appendix 1.1, Table 1.1-6A; also see Section 2.5.1 of this Compliance Filing for YEC's response to paragraph 293 of Appendix A to Board Order 2018-10: Reasons for Decision).

million industrial, as provided in Appendix 1.1, Table 1.1-7), the resultant time-limited 24-month Rider R is 5.94% effective May 1, 2019.

### 1.3 REQUESTED APPROVALS

Yukon Energy requests the following final approvals:

1. Approval to set an ongoing Rider J at 22.32% for retail customers and 18.67% for industrial customers, effective May 1, 2019, applicable to all YEC and AEY firm retail and industrial rates, including fixed Rider F and fixed monthly payments for major industrial rates (all AEY recoveries from this rider would flow through to YEC).
2. Approval to set a time-limited Rider R of 5.94%, to be in effect from May 1, 2019 to April 30, 2021 [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 2017, 2018 and 2019 net revenue shortfall as well as required Rider F adjustments for 2017 and 2018. Effective May 1, 2021, Rider R would be set to zero.
3. Approval, effective January 1, 2017, of the Low Water Reserve Fund (LWRF) to replace the Diesel Contingency Fund as described in Section 2 of this Compliance Filing, and more specifically in Attachment 2.1-1 to Appendix 2.1 of this Compliance Filing.
4. Approval of the 2017 and 2018 LWRF Annual Reports and the 2017 and 2018 ERF Filing as provided in Appendix 2.2 of this Compliance Filing, subject to Yukon Energy providing for Board approval any adjustment required when 2018 preliminary financial numbers are made final.
5. Approval of the updated Rider E rate schedule as provided in Attachment 2 of Appendix 2.2, at 0.00 cents/kW.h, for implementation effective April 1, 2019 in recognition that the forecast LWRF balance at \$2.172 million is well below the \$8 million cap.
6. Approval of the ongoing DFPVA mechanism for Rider F with deferred LNG fuel price variances using actual fuel mix as recommended by Yukon Energy in Section 2.5.1 of this Compliance Filing.



**Appendix 1.1:  
Supporting Tables**



**Table 1.1-1: YEC 2017/18 GRA Compliance Filing: Diesel Generation and Fuel Expense Forecast**

	2017/18 GRA		Adjustments (YUB 2018-10)		Compliance Filing	
	2017	2018	2017	2018	2017	2018
<b>Firm Load Forecast - 2017/18 GRA Application, GW.h</b>	<b>420.4</b>	<b>421.2</b>				
<i>Minto Load forecast update (paragraph 46)</i>			5.2	-6.0		
<i>Wholesales (paragraph 38)</i>			19.4	5.2		
<i>Non-industrial retail</i>			2.2	0.0		
<i>Lower actual Line Losses in 2017</i>			-2.9			
<i>Line Losses for the adjustments</i>			2.2	-0.1		
<i>Total Load adjustments</i>			26.1	-0.9		
<b>Load Forecast - Compliance Filing, GW.h</b>					<b>446.5</b>	<b>420.3</b>
<hr/>						
	2017/18 GRA		Adjustments (YUB 2018-10)		Compliance Filing	
	2017	2018	2017	2018	2017	2018
<b>Thermal Generation Forecast - 2017/18 GRA Application, GW.h</b>	<b>14.1</b>	<b>14.5</b>				
<i>Updated 2017 actuals and Updated Load Forecast for 2018 including load shape update</i>			-0.9	1.9		
<i>Total Load adjustments</i>			-0.9	1.9		
<b>Thermal Generation Forecast - Compliance Filing, GW.h</b>					<b>13.3</b>	<b>16.4</b>
<hr/>						
<b>Thermal Fuel Expense - 2017/18 GRA Application, \$000</b>	<b>2,342</b>	<b>2,368</b>				
<i>Updated 2017 actuals and Updated Load Forecast for 2018</i>			69	270		
<i>Total Load adjustments</i>			69	270		
<b>Thermal Fuel Expense - Compliance Filing, \$000</b>					<b>2,411</b>	<b>2,638</b>
<hr/>						
<b>Power Purchase - 2017/18 GRA Application, \$000</b>	<b>39</b>	<b>39</b>				
<i>Updated 2017 actuals and Updated Load Forecast for 2018</i>			10	0		
<i>Total Load adjustments</i>			10	0		
<b>Power Purchase - Compliance Filing, \$000</b>					<b>49</b>	<b>39</b>
<b>Total Fuel and Power Purchase, \$000</b>	<b>2,381</b>	<b>2,407</b>	<b>79</b>	<b>270</b>	<b>2,460</b>	<b>2,677</b>

**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	2017/18 GRA Application		YUB 2018-10 Compliance Filing		Adjustments	
	2017	2018	2017	2018	2017	2018
<b>Calculation of Rate Base</b>						
<b>Property, Plant and Equipment</b>						
<b>Year-end balance</b>	<b>603,879</b>	<b>618,511</b>	<b>598,756</b>	<b>612,435</b>	<b>-5,123</b>	<b>-6,076</b>
Accumulated Amortization	156,806	169,223	155,162	167,191	-1,644	-2,032
Construction-in-progress	4,358	8,274	4,776	7,620	418	-654
Disallowed assets [reflects closed projects]	691	691	2,746	2,746	2,055	2,055
Miscellaneous reserves	4,119	4,069	3,719	3,669	-399	-399
<b>Total Deductions</b>	<b>165,974</b>	<b>182,257</b>	<b>166,403</b>	<b>181,227</b>	<b>429</b>	<b>-1,030</b>
Deferred study costs	29,346	44,917	29,038	41,695	-309	-3,222
Less: Studies in Progress	-16,167	-29,859	-14,964	-29,498	1,203	361
Accum. Disallowed depreciation	184	200	349	553	165	353
<b>Total Additions</b>	<b>13,363</b>	<b>15,258</b>	<b>14,423</b>	<b>12,751</b>	<b>1,060</b>	<b>-2,508</b>
Previous Year Ending Balance	424,009	451,268	424,009	446,776	0	-4,492
Current Year Ending Balance	451,268	451,511	446,776	443,958	-4,492	-7,553
<b>Mid-year Balance</b>	<b>437,638</b>	<b>451,390</b>	<b>435,392</b>	<b>445,367</b>	<b>-2,246</b>	<b>-6,023</b>
<b>Rate Case</b>	<b>2,447</b>	<b>2,208</b>	<b>3,034</b>	<b>3,879</b>	<b>587</b>	<b>1,671</b>
<b>Working Capital requirements</b>	<b>5,200</b>	<b>5,210</b>	<b>5,290</b>	<b>5,344</b>	<b>90</b>	<b>134</b>
<b>Gross Mid-year Net Rate Base</b>	<b>445,285</b>	<b>458,808</b>	<b>443,717</b>	<b>454,590</b>	<b>-1,569</b>	<b>-4,218</b>
Net Mid-year Contributions	170,826	167,181	170,785	167,112	-41	-70
<b>Net Mid-year Net Rate Base</b>	<b>274,459</b>	<b>291,627</b>	<b>272,931</b>	<b>287,478</b>	<b>-1,528</b>	<b>-4,148</b>
<b>Average Cost of Capital</b>	4.84%	4.92%	4.92%	4.82%	0.08%	-0.10%
Cost of debt	2.18%	2.32%	2.40%	2.23%	0.22%	-0.09%
ROE	8.82%	8.82%	8.70%	8.70%	-0.12%	-0.12%
<b>Return on rate base</b>	<b>13,289</b>	<b>14,348</b>	<b>13,442</b>	<b>13,850</b>	<b>153</b>	<b>-497</b>
Debt	3,578	4,058	3,917	3,844	339	-213
ROE	9,711	10,290	9,525	10,006	-186	-284
<b>Total Return on rate base change</b>					<b>153</b>	<b>-497</b>
Due to change of ROE and Debt cost					227	-293
Due to change in Rate base					-74	-204
<b>Net Amortization</b>	<b>10,814</b>	<b>11,094</b>	<b>10,848</b>	<b>11,141</b>	<b>34</b>	<b>48</b>
Fixed Asset Depreciation	12,217	12,419	12,323	12,196	106	-223
Customer contribution	-5,007	-4,938	-5,539	-5,652	-531	-714
Amortization of fire insurance recoveries	-262	-262	-262	-262	0	0
Disallowed Depreciation	-16	-16	-182	-204	-165	-188
Amortization of deferred charges	3,883	3,891	4,507	5,063	625	1,172
Rate Case					-84	-65
Feasibility and Relicensing					235	759
Dam safety					0	0
Vegetation Management					0	0
Intangibles [transfers from PP&E and Regulatory]					474	478
<b>Total Impact to Revenue Requirement</b>					<b>187</b>	<b>-450</b>

Note:

1. The table shows only capital related, including cost of capital, adjustments based on YUB 2018-10.
2. The table does not include impacts of O&M adjustments.
3. The increase in amortization for Feasibility and Relicensing is mostly due to amortization of SKTP Planning Project costs. This increase is fully offset by increase in amortization of customer contributions.

**Table 1.1-3: Adjustments to the Ratebase [Detailed]**

in \$000	2017/18 GRA Application		YUB 2018-10 Compliance Filing		Adjustments	
	2017	2018	2017	2018	2017	2018
<b>Calculation of Rate Base</b>						
<b>Property, Plant and Equipment</b>						
<b>Year-end balance</b>	<b>603,879</b>	<b>618,511</b>	<b>598,756</b>	<b>612,435</b>	<b>-5,123</b>	<b>-6,076</b>
<i>Transfers to RFID</i>					-170	-170
<i>Transfers to Deferred [Intangible assets as per auditor]</i>					-3,513	-3,513
<i>2017 Actuals Update</i>					-1,440	-1,440
<i>Disallowed Spending:</i>						
<i>Stewart-Minto local SCADA [§446]</i>						-165
<i>Callison voltage regulator automation [§442]</i>						-115
<i>Dawson P158 T1/T2 transformer [§435]</i>						-200
<i>Aishihik control structure refurbishment [§426]</i>						-325
<i>Removed - Faro diesel building ventilation [§428]</i>						-100
<i>Other adjustments</i>						-48
<i>Accumulated Amortization</i>	156,806	169,223	155,162	167,191	-1,644	-2,032
<i>Transfers to Deferred</i>					-1,431	-1,431
<i>2017 Actuals Update and Other Adjustments to PP&amp;E noted above</i>					-213	-601
<i>Construction-in-progress</i>	4,358	8,274	4,776	7,620	418	-654
<i>AH3 control system drawings update [§374]</i>						25
<i>Aishihik control structure refurbishment [§426]</i>						-325
<i>Updates for 2017 actuals; for example:</i>					418	-354
<i>AH3 Lifting Device [GRA forecast was to close in 2017]</i>					240	
<i>LNG Third Engine lower spending</i>						-365
<i>Disallowed assets [reflects closed projects]</i>	691	691	2,746	2,746	2,055	2,055
<i>Disallowed - Aishihik elevator shaft steel rehabilitation project [§369]</i>					200	200
<i>Disallowed - AH reactor cable replacement [§373] - the actual spending at \$37,989 [forecast spending was at \$75,000].</i>					38	38
<i>DSM (\$478-481) - reflects spending after 2015 and spending for programs not approved by the YUB</i>					1,595	1,595
<i>Gladstone [§497] - reflects cost after September 2014</i>					221	221
<i>Miscellaneous reserves</i>	4,119	4,069	3,719	3,669	-399	-399
<i>2017 Actuals Update for RFID [including transfer from PP&amp;E noted above]</i>					-399	-399
<b>Total Deductions</b>	<b>165,974</b>	<b>182,257</b>	<b>166,403</b>	<b>181,227</b>	<b>429</b>	<b>-1,030</b>
<i>Deferred study costs</i>	29,346	44,917	29,038	41,695	-309	-3,222
<i>Disallowed - Time-of-use rate structure and smart grid [§519]</i>					-100	-100
<i>Disallowed - Northern Diesel Plan Relocation Study [§525]</i>						-100
<i>Mayo and Aishihik Climate Change Study [§516]</i>					-160	-320
<i>Whitehorse Hydro Uprate [§527]</i>						-450
<i>Small Hydro [§529]</i>						-625
<i>DSM (Paragraphs 478-481) - please see below Rate Case costs</i>					-1,455	-1,921
<i>Transfers from PP&amp;E and Regulatory [Intangible assets as per auditor]</i>					1,859	1,470
<i>Hearing Reserve Updates - please see below Rate Case costs</i>					3	-660
<i>2017 Actual Updates</i>					-456	-456
<i>Less: Studies in Progress [reflect above changes]</i>	-16,167	-29,859	-14,964	-29,498	1,203	361
<i>Accum. Disallowed depreciation [reflect above changes]</i>	184	200	349	553	165	353
<b>Total Additions [reflect above changes]</b>	<b>13,363</b>	<b>15,258</b>	<b>14,423</b>	<b>12,751</b>	<b>1,060</b>	<b>-2,508</b>
<i>Previous Year Ending Balance [reflect above changes]</i>	424,009	451,268	424,009	446,776	0	-4,492
<i>Current Year Ending Balance [reflect above changes]</i>	451,268	451,511	446,776	443,958	-4,492	-7,553
<b>Mid-year Balance [reflect above changes]</b>	<b>437,638</b>	<b>451,390</b>	<b>435,392</b>	<b>445,367</b>	<b>-2,246</b>	<b>-6,023</b>
<b>Rate Case</b>	<b>2,447</b>	<b>2,208</b>	<b>3,034</b>	<b>3,879</b>	<b>587</b>	<b>1,671</b>
<i>Total Rate Case</i>						
<i>Opening balance</i>	3,711	4,110	3,711	3,832	0	-278
<i>Year-end balance</i>	4,110	4,257	3,832	3,845	-278	-412
<i>Transfers to Intangible [Intangible assets as per auditor]</i>					-251	-251
<i>2017 Actual Updates</i>					-27	-161
<i>Mid-year balance</i>	3,911	4,184	3,772	3,839	-139	-345
<i>Less: DSM [included in deferred costs above]</i>						
<i>Opening balance</i>	2,484	2,445	2,484	990	0	-1,455
<i>Year-end balance</i>	2,445	2,801	990	880	-1,455	-1,921
<i>DSM disallowed (Paragraphs 478-481)</i>					-1,455	-1,921
<i>Mid-year balance</i>	2,465	2,623	1,737	935	-728	-1,688
<i>Less: Hearing Reserve [included in deferred costs above]</i>						
<i>Opening balance</i>	-973	-1,029	-973	-1,026	0	3
<i>Year-end balance</i>	-1,029	-266	-1,026	-926	3	-660
<i>The forecast charge against reserve reduced in 2018 [GRA cost claim now expected in 2019]</i>					3	-660
<i>Mid-year balance</i>	-1,001	-647	-1,000	-976	1	-329
<b>Working Capital requirements [reflects changes in spending and revenues]</b>	<b>5,200</b>	<b>5,210</b>	<b>5,290</b>	<b>5,344</b>	<b>90</b>	<b>134</b>
<b>Gross Mid-year Net Rate Base</b>	<b>445,285</b>	<b>458,808</b>	<b>443,717</b>	<b>454,590</b>	<b>-1,569</b>	<b>-4,218</b>
<i>Net Mid-year Contributions</i>	170,826	167,181	170,785	167,112	-41	-70
<b>Net Mid-year Net Rate Base</b>	<b>274,459</b>	<b>291,627</b>	<b>272,931</b>	<b>287,478</b>	<b>-1,528</b>	<b>-4,148</b>

**Table 1.1-4: Determination of 2017 and 2018 Revenue Shortfall True-up Rider**

Line No.		Reference	\$000
<b>2017</b>			
1	2017 Compliance Filing Revenue Requirement	Table 1.1	49,201.6
2	2017 Revenues at pre-GRA rates	Table 1.1	46,467.3
3	Revenue Shortfall/(Surplus)	L1 - L2	2,734.4
<b>Interim Rider J collections</b>			
4	September-December 2017 Interim Rider J Collections		930.7
5	<b>Net 2017 Revenue Shortfall/(Surplus) True-up</b>	<b>L3 - L4</b>	<b>1,803.7</b>
<b>2018</b>			
6	2018 Compliance Filing Revenue Requirement	Table 1.1	49,793.6
7	2018 Revenues at pre-GRA rates	Table 1.1	43,031.7
8	Revenue Shortfall/(Surplus)	L6 - L7	6,761.9
<b>Interim Rider J collections</b>			
9	Jan-Dec 2018 Forecast Interim Rider J Collections at GRA forecast	Table 1.3, L1a+L1b * 5.5%	3,287.6
10	<b>Net 2018 Revenue Shortfall/(Surplus) True-up</b>	<b>L8 - L9</b>	<b>3,474.3</b>
11	<b>Jan - April 2019 Revenue Shortfall/(Surplus) True-up</b>	<b>Table 1.1-5</b>	<b>1,314.5</b>
12	<b>Transfer of Rider F Adjustments</b>	<b>Table 1.1-6</b>	<b>1,339.9</b>
13	<b>Total Net Revenue Shortfall/(Surplus) True-up</b>	<b>L5 + L10 + L11 + L12</b>	<b>7,932.4</b>
<b>Consolidated Revenues at Base Rates for May 1, 2019 to Apr 30, 2021 [24 months]</b>			
14	Consolidated Non-industrial	Table 1.1-7	118,487.8
15	Consolidated Industrial	Table 1.1-7	15,088.6
16	<b>Total Consolidated Revenues at Base Rates</b>	<b>L14 + L15</b>	<b>133,576.4</b>
17	<b>2017 and 2018 Revenue Shortfall True-up Rider effective May 1, 2019</b>	<b>L13 / L16</b>	<b>5.94%</b>

**Table 1.1-5: Yukon Energy Corporation 2017/18 Compliance Filing: True-up for Jan-April 2019**

	YEC Retail Revenues				YEC Industrial Revenues				AEY Retail Revenues				Total Difference
	at Base Rates	Calculated at 2018 GRA Rider J as per Table 1.3	Calculated Interim Rider J at 5.5%	Difference	at Base Rates	Calculated at 2018 GRA Rider J as per Table 1.3	Calculated Interim Rider J at 5.5%	Difference	AEY retail revenues at Base Rates	Calculated at 2018 GRA Rider J as per Table 1.3	Calculated Interim Rider J at 5.5%	Difference	
	\$000	\$000	\$000	\$000	\$000	\$000	\$000	\$000	\$000	\$000	\$000	\$000	\$000
<b>2019 Forecast</b>													
January	623.9	70.6	34.3	36.3	233.6	26.4	12.8	13.6	5,597.2	633.2	307.8	325.3	375.2
February	588.4	66.6	32.4	34.2	232.8	26.3	12.8	13.5	4,861.8	550.0	267.4	282.6	330.3
March	596.6	67.5	32.8	34.7	230.5	26.1	12.7	13.4	4,774.9	540.2	262.6	277.5	325.6
April	577.8	65.4	31.8	33.6	227.2	25.7	12.5	13.2	4,071.1	460.5	223.9	236.6	283.4
<b>Total Jan-April 2019</b>	<b>2,386.8</b>	<b>270.0</b>	<b>131.3</b>	<b>138.7</b>	<b>924.2</b>	<b>104.5</b>	<b>50.8</b>	<b>53.7</b>	<b>2,183.9</b>	<b>1,061.8</b>	<b>1,122.1</b>	<b>1,314.5</b>	

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

**Table 1.1-6: Yukon Energy Corporation 2017/18 GRA Compliance Filing Rider F Adjustments for True-up (\$) based in 2018 on Actual Fuel mix**

Line No.	Month	Fuel Price Variance - Diesel [Original] <sup>1</sup>	Fuel Price Variance - LNG	RS 32 SS Adjustment <sup>2</sup>	Rider F Surcharge - Industrial	Rider F Surcharge - CIS	Inter- company Transfer	Balance
		A	B	C	D	E	F	G
<b>Original Filing</b>								
1	DFPVA 2017 Opening Balance							2,000
2	Jan-17	36,518		-7,082	-22,767	-23,956	27,739	12,451
3	Feb-17	26,965		-18,322	-18,957	-20,531	18,138	-255
4	Mar-17	46,447		-1,005	-21,591	-20,316	13,657	16,938
5	Apr-17	871		-18,118	-16,417	-18,244	19,231	-15,740
6	May-17	4,595		-20,359	-21,121	-16,484	54,688	-14,421
7	Jun-17	7,463		-16,007	-18,346	-16,972	37,771	-20,511
8	Jul-17	6,386		-23,814	-18,722	-16,844	42,322	-31,183
9	Aug-17	8,986		-16,413	-381	-13,414	23,839	-28,567
10	Sep-17	3,981		-16,498	-373	-337	1,567	-40,228
11	Oct-17	2,473		-10,782	-440	-311	3,010	-46,277
12	Nov-17	17,138		-16,604	-430	-394	-8,710	-55,276
13	Dec-17	19,276		-9,369	-415	-529	-1,254	-47,567
14	Dec-17							-47,567
15	Jan-18	192,982		-80	-500	-401	10,850	155,285
16	Feb-18	-147,788		-4	-424	-440	985	7,614
17	Mar-18	9,385		0	-425	-434	1,055	17,194
18	Apr-18	5,161		0	-448	-416	1,067	22,558
19	May-18	959		0	-360	-332	825	23,649
20	Jun-18	2,905		-84	-302	-355	782	26,595
21	Jul-18	2,537		-124	-346	-338	803	29,127
22	Aug-18	-1,340		-1,006	-341	-356	796	26,880
23	Sep-18	51		-520	-334	-405	835	26,507
24	Oct-18	1,002		-29	-306	-364	758	27,568
25	Nov-18	-320		0	-160	-381	625	27,332
26	Dec-18	-692		0	-143	-419	643	26,721
27	<b>December 31, 2018 Balance</b>							26,721
<b>Compliance Filing</b>								
Line No.	Month	Fuel Price Variance - Thermal [Revised] <sup>3</sup>		RS 32 SS Adjustment <sup>4</sup>	Rider F Surcharge - Industrial	Rider F Surcharge - CIS	Inter- company Transfer	Balance
		A		B	C	D	E	F
28	DFPVA 2017 Opening Balance							2,000
29	Jan-17		0	0	-22,767	-23,956	27,739	-16,984
30	Feb-17		0	0	-18,957	-20,531	18,138	-38,334
31	Mar-17		0	0	-21,591	-20,316	13,657	-66,584
32	Apr-17		0	0	-16,417	-18,244	19,231	-82,014
33	May-17		0	0	-21,121	-16,484	54,688	-64,932
34	Jun-17		0	0	-18,346	-16,972	37,771	-62,478
35	Jul-17		0	0	-18,722	-16,844	42,322	-55,722
36	Aug-17		0	0	-381	-13,414	23,839	-45,678
37	Sep-17		0	0	-373	-337	1,567	-44,822
38	Oct-17		0	0	-440	-311	3,010	-42,563
39	Nov-17		0	0	-430	-394	-8,710	-52,096
40	Dec-17		0	0	-415	-529	-1,254	-54,294
41	<b>Total Adjustment for 2017</b>							-54,294
42	Dec-17 adjusted							0
43	Jan-18		-176,189	50	-500	-401	10,850	-166,190
44	Feb-18		-174,542	3	-424	-440	985	-340,608
45	Mar-18		-146,226	0	-425	-434	1,055	-486,639
46	Apr-18		-203,037	0	-448	-416	1,067	-689,472
47	May-18		-30,957	0	-360	-332	825	-720,298
48	Jun-18		-16,958	351	-302	-355	782	-736,780
49	Jul-18		-13,138	426	-346	-338	803	-749,373
50	Aug-18		-3,113	3,450	-341	-356	796	-748,937
51	Sep-18		-375	1,785	-334	-405	835	-747,431
52	Oct-18		-69,684	83	-306	-364	758	-816,945
53	Nov-18		-138,592	0	-160	-381	625	-955,453
54	Dec-18		-330,230	0	-143	-419	643	-1,285,603
55	Dec-18							-1,285,603
56	<b>Total Adjustment for 2018</b>							-1,285,603
57	<b>Adjusted December 31, 2018 Balance</b>							0
58	<b>Total 2017 and 2018 Adjustments</b>							-1,339,897

**Notes:**  
1. Based on 2012/13 GRA fuel prices and fuel efficiencies.  
2. Based on 2012/13 GRA approved secondary sale rate.  
3. Based on 2017/18 GRA fuel prices and fuel efficiencies [for 2018: see Table 1.1-6A, Column M]. There is no impact to 2017 as actuals were used.  
4. Based on 2017/18 GRA secondary sale rate.

**Table 1.1-6A: Yukon Energy Corporation 2017/18 Compliance Filing Rider F Adjustments for True-up (\$)**

Line No.	Month	Actual LNG Generation, kW.h	Actual Diesel Generation, kW.h	Total Actual Thermal Generation, kW.h	2017/18 GRA Efficiency, kW.h/litre		2017/18 GRA Fuel Price, \$/litre		Actual Fuel Price, \$/litre			Adjusted Thermal Generation for DFPVA purposes, kW.h [maximum 10% cumulative diesel - annual 90% LNG and 10% diesel]		Fuel Price Variance with max 10% Diesel (annual 90% LNG, 10% diesel), \$	Fuel Price Variance with actual fuel mix, \$	
					LNG	Diesel	LNG	Diesel	LNG - monthly	LNG - cumulative	Diesel - monthly	Diesel - cumulative	LNG - Cumulative J=C-K			Diesel - Cumulative K=MIN(B or C*10%)
		A	B	C=A+B	D	E	F	G	H	I	J	K	L	M		
Recalculation of DFPVA for 2018 based on maximum 10% diesel as per YUB 2018-10 direction																
1	Jan-18	3,963,500	1,581,352	5,544,852	2.57	3.58	0.3767	0.9414	0.4716	0.4716	1.009	1.009	4,990,367	554,485	-194,714	-176,189
2	Feb-18	3,957,500	3,130,596	7,088,096	2.57	3.58	0.3767	0.9414	0.4388	0.4552	1.031	1.024	11,369,653	1,263,295	-181,818	-174,542
3	Mar-18	5,463,700	866,153	6,329,853	2.57	3.58	0.3767	0.9414	0.4368	0.4477	1.017	1.023	17,066,521	1,896,280	-138,302	-146,226
4	Apr-18	5,230,200	464,691	5,694,891	2.57	3.58	0.3767	0.9414	0.4720	0.4545	1.012	1.022	22,191,923	2,465,769	-212,884	-203,037
5	May-18	1,066,900	65,045	1,131,945	2.57	3.58	0.3767	0.9414	0.4464	0.4541	1.052	1.022	23,210,673	2,578,964	-29,665	-30,957
6	Jun-18	0	413,318	413,318	2.57	3.58	0.3767	0.9414	0.0000	0.4541	1.088	1.027	23,582,660	2,620,296	-15,195	-16,958
7	Jul-18	0	342,025	342,025	2.57	3.58	0.3767	0.9414	0.0000	0.4541	1.079	1.029	23,890,482	2,654,498	-12,018	-13,138
8	Aug-18	59,200	37,113	96,313	2.57	3.58	0.3767	0.9414	0.4643	0.4541	1.047	1.029	23,977,164	2,664,129	-3,203	-3,113
9	Sep-18	0	9,837	9,837	2.57	3.58	0.3767	0.9414	0.0000	0.4541	1.078	1.029	23,986,017	2,665,113	-342	-375
10	Oct-18	1,867,400	64,282	1,931,682	2.57	3.58	0.3767	0.9414	0.4707	0.4556	1.018	1.029	25,724,531	2,858,281	-71,376	-69,684
11	Nov-18	2,600,400	196,790	2,797,190	2.57	3.58	0.3767	0.9414	0.5061	0.4610	1.080	1.031	28,242,002	3,138,000	-145,017	-138,592
12	Dec-18	5,921,200	17,546	5,938,746	2.57	3.58	0.3767	0.9414	0.5197	0.4725	1.083	1.031	33,586,873	3,731,875	-341,099	-330,230
13	<b>Total</b>	<b>30,130,000</b>	<b>7,188,748</b>	<b>37,318,748</b>									<b>33,586,873</b>	<b>3,731,875</b>	<b>-1,345,634</b>	<b>-1,303,044</b>

**Table 1.1-7: Yukon Energy Corporation 2017/18 Compliance Filing Consolidated Revenue for 2019 True-up**

	YEC Retail Non-Industrial Base Rate Revenue Forecast		YEC Industrial Base Rate Revenue Forecast				AEY Retail Revenues			Total Consolidated Revenues
	Retail Sales	Revenues at Base Rates	Minto Sales	VG Sales	Total Industrial Sales	Revenues at Base Rates	Wholesales to AEY	Monthly distribution	Estimated AEY retail revenues at Base Rates	
	MW.h	\$000	MW.h	MW.h	MW.h	\$000	MW.h	%	\$000	
<b>2019 Forecast</b>										
January	3,949.6	623.9	1,500.0	-	1,500.0	233.6	35,578.1	11%	5,597.2	6,454.8
February	3,713.9	588.4	1,500.0	-	1,500.0	232.8	30,903.6	9%	4,861.8	5,683.1
March	3,752.6	596.6	1,500.0	-	1,500.0	230.5	30,350.8	9%	4,774.9	5,602.0
April	3,613.1	577.8	1,500.0	-	1,500.0	227.2	25,877.5	8%	4,071.1	4,876.1
May	3,197.3	515.8	1,500.0	773.1	2,273.1	241.0	23,303.2	7%	3,666.1	4,422.8
June	3,382.9	548.5	1,500.0	988.2	2,488.2	265.7	21,084.0	6%	3,317.0	4,131.2
July	3,554.8	579.6	1,500.0	3,174.1	4,674.1	515.9	22,179.4	7%	3,489.3	4,584.8
August	3,510.0	572.9	1,500.0	4,189.3	5,689.3	623.8	21,660.0	7%	3,407.6	4,604.4
September	3,396.3	550.6	1,500.0	4,673.4	6,173.4	664.8	23,747.1	7%	3,736.0	4,951.4
October	3,342.6	539.0	1,500.0	4,686.7	6,186.7	666.3	27,385.2	8%	4,308.3	5,513.6
November	3,396.8	543.8	1,500.0	5,312.4	6,812.4	734.2	31,304.8	9%	4,924.9	6,202.9
December	3,842.3	610.9	1,500.0	2,294.0	3,794.0	403.3	37,149.7	11%	5,844.5	6,858.8
<b>Total 2019</b>	<b>42,652.3</b>	<b>6,847.9</b>	<b>18,000.0</b>	<b>26,091.3</b>	<b>44,091.3</b>	<b>5,039.2</b>	<b>330,523.4</b>		<b>51,998.8</b>	<b>63,885.9</b>
<b>2020 Forecast</b>										
January	4,006.6	632.8	1,500.0	2,223.7	3,723.7	396.1	26,243.2	11%	5,661.5	6,690.4
February	3,812.7	603.7	1,500.0	2,187.0	3,687.0	392.2	23,194.4	9%	4,917.7	5,913.5
March	3,831.7	608.6	1,500.0	6,116.0	7,616.0	825.7	21,890.2	9%	4,829.7	6,264.0
April	3,668.2	586.3	1,500.0	6,146.4	7,646.4	827.9	22,522.6	8%	4,117.9	5,532.1
May	3,255.5	524.9	1,500.0	6,222.4	7,722.4	836.7	21,758.9	7%	3,708.2	5,069.8
June	3,405.9	552.3	1,500.0	6,330.9	7,830.9	849.7	24,295.4	6%	3,355.1	4,757.1
July	3,541.7	577.6	1,500.0	6,363.5	7,863.5	854.2	27,459.9	7%	3,529.4	4,961.2
August	3,527.5	576.1	1,500.0	6,576.7	8,076.7	878.1	31,597.7	7%	3,446.7	4,901.0
September	3,362.9	545.2	1,500.0	6,668.0	8,168.0	888.9	37,659.2	7%	3,778.9	5,212.9
October	3,311.3	534.2	1,500.0	6,671.4	8,171.4	889.8	35,984.4	8%	4,357.8	5,781.8
November	3,371.3	540.0	1,500.0	6,710.2	8,210.2	893.9	31,093.5	9%	4,981.5	6,415.4
December	3,833.5	609.4	1,500.0	2,562.1	4,062.1	436.5	30,959.3	11%	5,911.6	6,957.6
<b>Total 2020</b>	<b>42,928.7</b>	<b>6,891.2</b>	<b>18,000.0</b>	<b>64,778.2</b>	<b>82,778.2</b>	<b>8,969.8</b>	<b>334,658.7</b>		<b>52,595.9</b>	<b>68,456.9</b>
<b>2021 Forecast</b>										
January	3,782.5	596.0	-	2,481.1	2,481.1	279.0	26,243.2	11%	5,661.5	6,536.5
February	3,676.7	580.3	-	2,402.5	2,402.5	270.0	23,194.5	9%	4,917.7	5,768.0
March	3,665.4	580.6	-	6,550.6	6,550.6	727.4	21,890.2	9%	4,829.7	6,137.7
April	3,526.6	562.2	-	6,550.6	6,550.6	727.4	22,522.6	8%	4,117.9	5,407.5
<b>Total Jan-Apr 2021</b>	<b>14,651.2</b>	<b>2,319.0</b>	<b>-</b>	<b>17,984.8</b>	<b>17,984.8</b>	<b>2,003.9</b>	<b>93,850.4</b>		<b>19,526.7</b>	<b>23,849.7</b>
<b>AEY 2020 Base Rate Revenue Forecast</b>										
<b>Total May 1, 2019 to Apr 30, 2021</b>		<b>13,671.4</b>				<b>15,088.6</b>			<b>104,816.4</b>	<b>133,576.4</b>

**Notes:**

- YEC retail and industrial revenues at base rates are based on forecast for 2019, 2020 and 2021.
- AEY retail revenue forecasts are estimated based on AEY's 2016/17 GRA Compliance Filing [average unit cost] and YEC's 2019, 2020 and 2021 wholesale forecasts.

## 2.0 SUMMARY OF YUKON ENERGY RESPONSES TO BOARD DIRECTIVES

Section 2 summarizes how Decision 2018-10 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, at least in part, where relevant. In a few instances, responses are also provided to Board directions in the Reasons for Decision that are not included in the Appendix A Summary of Directions.

### *General Reliance on 2017 Actual Results*

In paragraph 86 of its Decision the Board noted that for the determination of YEC’s 2017-18 revenue requirements it would rely on 2017 actual results as provided in Undertaking 35.

The Board Order noted in paragraph 87 that where the Board was able to glean enough information from Undertaking 35 to make an Order with respect to a line item or cost component of the revenue requirement it would do so, and where further information was required YEC would be required to provide such information in its Compliance Filing. The Board stated that this approach will apply equally to each line item or cost components of YEC revenue requirements including specific capital project considerations and customer, energy sales and revenue information, which likewise inform specific components of revenue requirement.

The Compliance Filing addresses these directives below as required for specific components of the 2017 revenue requirement.

## 2.1 SALES AND GENERATION

### 2.1.1 Wholesales

#### **Board Directive #1**

The Board is of the view that the information to be used in setting rates should reflect the best information available at the time of the hearing. While the Board understands that YEC determines the wholesale forecast after running its own regression analysis and management’s own growth expectations, the Board is of the view that AEY may have more up-to-date information that may more accurately reflect the expected actuals. As a result, the Board directs YEC to use the actual wholesale sales to AEY for 2017 in the amount of 328.4 GW.h. For the 2018 wholesale forecast, the Board observes the difference of 19.4 GW.h between the 2017 actuals and the 2018 forecast. No explanation was provided for this difference. Considering that wholesales were forecast at 309 for 2017 and 309.5 for 2018, the Board is concerned about the reasonableness of the forecast for 2018. Therefore, the Board directs YEC to use the 2018 AEY Compliance amount of 314.7 GW.h for the 2018 forecast. **(Paragraph 38).**

## **Board Directive #2**

Additionally, several interveners expressed concern regarding the communication between YEC and AEY. While YEC submitted that additional communication would not have resulted in better forecasts for 2017 and 2018, the Board has noted the differences in the forecasts of YEC and AEY. Therefore, the Board directs YEC to refine its methodology to ensure its forecasts align closely with AEY's forecasts in future GRA submissions. Consequently, YEC is directed in its compliance filing to this decision to reflect actual wholesale sales of 328.4 GW.h for 2017 and forecast wholesale sales of 314.7 GW.h. for 2018. **(Paragraph 39).**

The firm wholesale forecast has been adjusted as directed to reflect actual wholesale sales of 328.4 GW.h for 2017 and forecast wholesale sales of 314.7 GW.h. for 2018. See Section 3 of this Compliance Filing for the Tab 7 Revised Schedules; in particular see Schedule 9 of the Tab 7 Revised Schedules provided as Appendix 3.1 and Appendix 3.2 of the Compliance Filing.

In response to Directive #2, prior to the next GRA YEC will endeavour to consult with AEY on a fulsome basis with respect to sales forecast methodology. YEC believes that the use of different methodologies can provide a more robust approach to testing sales assumptions and ultimately will result in better forecasts. Regardless, YEC will review its methodology to align its forecasts where reasonable and feasible with AEY's forecasts (particularly where such forecasts in an AEY compliance filing have been approved by the Board). YEC notes that for the 2017 and 2018 test years actual wholesales have been considerably higher than GRA forecasts provided by both AEY and YEC.

### **2.1.2 Major Industrial Sales**

#### **Board Directive #3**

The Board is of the view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application. Accordingly, the Board directs YEC to update its major industrial sales forecast in its compliance filing to account for the 2017 actuals and the updated 2018 Minto sales forecasts indicated in the undertaking. **(Paragraph 46)**

YEC has adjusted the industrial forecast to reflect 2017 actuals and the updated 2018 Minto sales forecast indicated in Undertaking 36. See Section 3 of this Compliance Filing for the Tab 7 Revised Schedules; in particular, see Schedule 9 of the Tab 7 Revised Schedules provided as Appendix 3.1 and Appendix 3.2 of the Compliance Filing.

### **2.1.3 Firm Retail**

#### **Board Directive #4**

The Board is of the view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application. Accordingly, YEC is directed to update 2017 for the actual firm retail sales. For 2018, the Board accepts the explanations given by YEC and finds that YEC's firm retail sales forecast for 2018 is reasonable. **(Paragraph 51)**

YEC has adjusted the firm retail forecast to reflect 2017 actuals; the 2018 forecast remains unchanged from the Application. See Section 3 of this Compliance Filing for the Tab 7 Revised Schedules. In particular,

see Schedule 9 of the Tab 7 Revised Schedules provided as Appendix 3.1 and Appendix 3.2 of the Compliance Filing.

#### **2.1.4 Secondary Sales**

##### **Directive #5**

While YEC explained that it, and not ratepayers, will bear the total impact of these sales revenues being less than forecast, the Board is of the view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application. As a result, the Board directs YEC to update the secondary sales forecast in its compliance filing to reflect the 2017 actuals and updated 2018 forecast that YEC indicated it used in its updated revenue requirement in Undertaking 36. **(Paragraph 55)**

YEC has adjusted the secondary sales forecast to reflect 2017 actuals and the updated 2018 secondary sales forecast indicated in Undertaking 36. See Schedule 9 of the Tab 7 Revised Schedules provided as Appendix 3.1 and Appendix 3.2 to Section 3 of the Compliance Filing.

#### **2.1.5 Power Generation**

##### **Directive #6**

Based on its view that the most accurate and current information available at the time of the hearing should be used to make a decision on an application, the Board directs YEC to update the generation forecast in its compliance filing to reflect the 2017 actuals and updated 2018 forecast that YEC indicated it used in the updated revenue requirement in Undertaking 35 and 36. **(Paragraph 60)**

YEC has adjusted the generation forecast to reflect 2017 actuals and the updated 2018 generation forecast in Undertaking 35 and 36. See Appendix 1.1, Table 1.1-1 and Schedule 9 of the Tab 7 Revised Schedules provided as Appendix 3.1 and Appendix 3.2 to Section 3 of the Compliance Filing.

#### **2.1.6 Peak Demand Forecast**

At paragraph 66 the Board noted its view that peak loads are likely to grow in coming years, and encouraged YEC to communicate closely with all parties (for example, customers, developers, mining operations) to forecast as accurately as possible to meet increased peak loads and new mining energy requirements.

In response, Yukon Energy will continue to communicate with relevant stakeholders in order to ensure forecasts are as accurate as possible.

## **2.2 REVENUE REQUIREMENT: FUEL AND PURCHASED POWER**

##### **Directive #7**

Given the above-noted advantages and disadvantages of LTA and ST hydro generation forecasts, the Board finds that, for purposes of this proceeding, it will not use the ST forecast for forecasting levels of hydro electric generation and thermal generation nor direct its use for future GRAs. In

determining the revenue requirements for these and future test years, the Board is focusing on the reasonableness of the forecasts and forecasting accuracy. Further, the onus is on YEC to adequately explain any variance between actual results and its forecast amounts. For these reasons, the Board directs YEC in future GRA filings to show actual hydro and thermal generation results when comparing previous and forecast test years. **(Paragraph 77)**

In response, YEC in this GRA filing for 2018 and in future GRA filings (a) will not use ST hydro generation forecasts, and (b) will continue to use LTA hydro and thermal generation forecasts (plus separate forecasts for thermal maintenance costs). The 2018 LTA hydro and thermal generation forecasts reflect the LTA forecast used in Table 3.4-1 of the GRA Application adjusted as required to address the major change in forecast seasonal shape of the Minto industrial load, i.e., the adjusted Minto load forecast for 2018 falls sharply at about mid-year for the balance of the year (versus being reasonably flat throughout the year in the Application forecast). The LTA determinations for 2018 are reviewed in more detail in Appendix 2.2, of this Compliance Filing.

YEC will in future GRA filings show actual hydro and thermal generation results when comparing prior and forecast test years.

#### **Directive #8**

The Board finds that proceeding in this manner will afford parties with the opportunity to examine any variances between 2016 and 2017 actual results, as well as variances between 2017 actual and forecast results in the compliance filing while still maintaining the ability of the Board to rely on the best available information at the time it renders its decision. To that end, where the discussion contained in subsequent sections of this decision has observed measurable variances between 2016 and 2017 actual results, or variances between 2017 actual and forecast results, YEC is directed to provide the applicable variance explanations in its compliance filing to this decision. **(Paragraph 88)**

In response, applicable variance explanations are provided in subsequent responses where discussion in the Board's decision observed measurable variances between 2016 and 2017 actual results, or variances between 2017 actual and forecast results.

#### **Directive #9**

As earlier stated in paragraphs 87-89, the Board is relying on 2017 actual results for the 2017 test year. However, the 2017 thermal generation amounts must be based on actual thermal generation fuel costs, not modelled results. Thermal generation fuel costs will be based on actual thermal generation output for the year and the costs required to produce that output. It is unclear if the fuel costs in Table 3 above represent actual costs or modelled costs. Therefore, YEC is directed in its compliance filing to this decision to reflect actual fuel costs for 2017. For the 2018 test period, YEC is to use the fuel costs related to YEC's forecast for 2018. **(Paragraph 100)**

In paragraph 101, the Board also notes that it reviewed the thermal assumptions provided by YEC and determined them to be reasonable, and accepted the cost and efficiency parameters (thermal assumptions) as submitted by YEC. As a result, the Compliance Filing retains these thermal assumptions for the 2018 test year forecast.

In response to Directive #9 in paragraph 100, actual 2017 thermal generation volumes (rather than modeled LTA volumes) and maintenance volumes are reflected in the Compliance Filing along with actual 2017 fuel costs (rather than costs based on forecast fuel prices).

For 2018, the Compliance Filing reflects LTA thermal generation volumes as discussed above in response to Directive #7 (paragraph 77) along with maintenance volumes as forecast in the Application and forecast thermal cost and efficiency parameters from the Application as approved in paragraph 101.

### **Directive #10**

In terms of the fuel mix, several different fuel mixes have been presented to the Board for the 2018 forecast. Consequently, the Board directs YEC, in its compliance filing, to state which fuel mix it is using for its 2018 forecast. (**Paragraph 102**)

The Compliance Filing for the 2018 thermal generation forecast continues to use the 90:10 LNG: diesel fuel mix as assumed in the Application.

## **2.3 REVENUE REQUIREMENT: NON-FUEL O&M**

### **2.3.1 Labour**

#### **Directive #11**

With respect to FTEs, notwithstanding that the table above (Table 11) illustrates that there have been minimal FTE increases forecast between 2016 actual and 2017 forecast, the Board considers that it requires actual 2017 FTE information in order to make a final determination on FTEs. YEC is directed to provide this information by way of updating the information found in Table 8 [sic] for 2017 actual FTE results. (**Paragraph 129**)

#### **Directive #14**

Where the directions contained in this order result in measurable FTE variances between 2017 actual results and 2016 actual or 2017 forecast results, YEC is directed to provide the applicable variance explanations in its compliance filing to this decision. (**Paragraph 132**)

As directed, further line item detail for actual 2017 Labour costs is provided in Table 2-1. The Compliance Filing assumes actual FTEs for 2017 and the 2018 Application forecast FTEs for 2018.

Key 2017 variances from forecast FTEs are summarized below:

- **President** – 2017 Actuals 1.04 FTE lower than forecast as Administrative Assistant/Receptionist moved from Corporate Services to Engineering Services as an Administrative Assistant for that department.
- **Resource Planning and Environment** – Actuals in 2017 1 FTE lower compared to 2016 actuals as First Nation Coordinator Admin. Asst. moved from Resource Planning to Engineering Services.

- **Operations** – 2017 actuals 0.62 FTE higher than forecast as backfill maintenance mechanic position ended December 31, 2016; and new mechanic position forecast for 2017 was not created until 2018.
- **Engineering services** – Increase of two between 2017 Original GRA Filing and 2016 Actual due to First Nation Coordinator transfer from Resource Planning to Engineering and new position of Asset Manager created; increase of one position in 2017 Compliance Filing over 2017 Original GRA filing is due to transfer of Admin Assistant/Receptionist from President to Engineering Services.

**Table 2-1: 2017 Actual Employee Complement History (FTEs)**

	2016 Actual	2017 Forecast			2018 Forecast		
		Original GRA Filing	Compliance Filing	Diff	Original GRA Filing	Compliance Filing	Diff
President	5.09	5.16	4.12	(1.04)	4.16	4.16	-
Communications	1.00	1.00	1.00	-	1.00	1.00	-
Human Resources & Info. Mgmt.	5.2	5.25	5.21	(0.04)	5.25	5.25	-
Resource Planning and Environment	6.00	5.00	5.00	-	5.00	5.00	-
Finance, Cust. Acctg. & Purchasing	16.87	16.79	16.94	0.15	16.79	16.79	-
Operations	44.15	43.50	44.12	0.62	44.50	44.50	-
Engineering Services	13.00	15.00	16.00	1.00	15.00	15.00	-
Health, Safety & Environment	2.00	2.00	2.00	-	2.00	2.00	-
<b>Total</b>	<b>93.31</b>	<b>93.70</b>	<b>94.39</b>	<b>0.68</b>	<b>93.70</b>	<b>93.70</b>	<b>-</b>

Note:

1. The employee complement numbers are net of allocation to YDC.

### **Directive #12**

Further, the Board agrees in principle with YEC's proposed update to its capital-to-maintenance allocation to a ratio of 18:82 based on recent trends. However, the Board directs this ratio be determined based on the inclusion of 2017 actual capital-to-maintenance results and for YEC to provide the updated 2017 ratio and, further, to clarify whether, based on this updated ratio, a change from its proposed 18:82 capital-to-maintenance ratio is required for the year 2018 in its compliance filing to this Order. **(Paragraph 130)**

In response, the Compliance Filing for 2017 and 2018 uses the updated four year capital-to-maintenance ratio of 17:83 as reviewed in the table below. The adjustment in 2018 was deemed to be required given the change resulting for 2017, and the lower actual 2017 ratio (15:85).

**Table 2-2: YEC Capital-to-Maintenance Labour Allocation for 2014-2017**

	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2014 -2017</b>
	<b>Actual</b>	<b>Actual</b>	<b>Actual</b>	<b>Actual</b>	<b>Average</b>
Capital	17.3%	20.1%	16.1%	14.9%	17.1%
Maintenance	82.7%	79.9%	83.9%	85.1%	82.9%

**Directive #13**

With respect to the labour escalation per cents relied on for labour-cost forecasting purposes in the amounts of 2.0 per cent and 1.75 per cent for the years 2017 and 2018 respectively, the Board directs YEC to provide 2017 actual labour escalation amounts for information purposes in its compliance filing to this Order. **(Paragraph 131)**

In response to the Board's direction 2017 actual labour escalation was 2.0%.

**Directive #15**

Finally, concerning the CW's request for a more complete picture of YEC's total labour costs and FTE count, the Board agrees it would be helpful to have this supplementary labour information available in a central location from the outset of YEC's application. The Board directs YEC in its next GRA to complete the labour schedule identified by CW in its evidence in as much detail (for both cost and FTE) as is applicable to YEC and to submit the information as an additional schedule within YEC's existing Tab 7 format. **(Paragraph 133)**

In response, Yukon Energy will in its next GRA complete the labour schedule identified by CW in its evidence in as much detail as applicable to YEC and submit this as an additional schedule within Tab 7.

**2.3.2 Production**

**Directive #16**

Based on the evidence and variance explanations provided therein, the Board is prepared to accept both YEC's 2017 actual results and the 2018 forecast. However, in the compliance filing to this decision, YEC is directed to update the information found in Table 12 for 2017 actual production costs by cost category. **(Paragraph 140)**

As directed, further line item detail for actual 2017 production costs is provided in the table that follows. As directed, the Compliance Filing assumes 2017 actual results (with the updated 4-year capital-to-maintenance ratio) and the Application 2018 forecast for Production cost forecasts [adjusted to reflect the updated capital-to-maintenance ratio].

2017 actual varied compared to forecast as follows: labour costs varied due to delay in approval to spend on capital projects; this resulted in more time spent on O&M; diesel costs varied due to rental of mobile diesels; hydro varied due to repairs at Mayo dam as well as higher than expected crane repair costs.

**Table 2-3: 2017 Actual Production Costs by Category**

	2016 Actual	2017 Forecast			2018 Forecast		
		Original GRA Filing	Compliance Filing	Diff	Original GRA Filing	Compliance Filing	Diff
Labour	\$ 4,133	\$ 4,010	\$ 4,176	\$ 166	\$ 4,109	\$ 4,131	\$ 22
Diesel	548	436	693	257	425	425	0
LNG	224	155	181	26	196	196	0
Hydro	1,058	1,075	1,209	133	1,093	1,093	0
Wind	14	6	40	35	6	6	0
Operation Supervision	62	77	66	-11	79	79	0
Total Production	\$ 6,039	\$ 5,760	\$ 6,366	\$ 606	\$ 5,907	\$ 5,930	\$ 22

### 2.3.3 Transmission & Distribution

Paragraph 160 of the Reasons for Decision notes that the Board requires further line item detail with respect to actual 2017 transmission and distribution costs, including brushing cost information in order to make a final determination on costs or YEC's proposal to discontinue the deferral of brushing costs above 2011 levels and to amortize the balance in the vegetation management deferral account over a period of 10 years. The Board notes that this is in part due to a lack of clarity as to the cause of the increase in total transmission and distribution costs shown in Table 15 for 2017 actuals.

#### **Directive #17**

YEC is directed to provide this detail by way of updating the information found in tables 13, 14 and 15 for 2017 actual transmission and distribution results in its compliance filing to this decision and to explain any variances as directed by the Board in paragraph 89. YEC is also directed to provide in its compliance filing the Actual 2017 closing balance of its Deferred Vegetation Management account and to clarify whether YEC deferred any 2017 actual costs in excess of \$0.502 million.  
**(Paragraph 161)**

2017 actual transmission and distribution results are provided in the tables that follow, along with variance explanations. 2018 forecasts from the Application are also provided, with adjustment to Labour as required to reflect the updated capital-to-maintenance ratio. There is a small net savings variance in brushing costs in 2017 actual compared to forecast for transmission and distribution combined due to favourable results of a tender process that occurred after the GRA forecast was developed.

**Table 2-4: Transmission Costs (\$000)**

	2016 Actual	2017 Forecast			2018 Forecast		
		Original GRA Filing	Compliance Filing	Diff	Original GRA Filing	Compliance Filing	Diff
Labour	\$ 621	\$ 560	\$ 655	\$ 95	\$ 562	\$ 635	\$ 72
Brushing Cost	1,034	1,182	1,134	-49	1,161	1,161	0
Deferred Brushing	-550	0	0	0	0	0	0
Net Brushing Cost	484	1,182	1,134	-49	1,161	1,161	0
Other Non-Labour	225	235	315	80	258	258	0
Total Transmission	\$ 1,330	\$ 1,977	\$ 2,104	\$ 127	\$ 1,981	\$ 2,054	\$ 72

Note:

1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year, distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was \$0.502 million.

The savings variance in transmission brushing costs in 2017 actual compared to forecast was \$-49,000 (due to favourable results of a tender process that occurred after the GRA forecast was developed).

**Table 2-5: Distribution Costs (\$000)**

	2016 Actuals	2017 Forecast			2018 Forecast		
		Original GRA Filing	Compliance Filing	Diff	Original GRA Filing	Compliance Filing	Diff
Labour	\$ 837	\$ 845	\$ 861	\$ 15	\$ 847	\$ 856	\$ 8
Brushing Cost	39	304	320	16	331	331	0
Deferred Brushing	-21	0	0	0	0	0	0
Net Brushing Cost	18	304	320	16	331	331	0
Other Non-Labour	266	226	251	25	204	204	0
Total Distribution	\$ 1,121	\$ 1,375	\$ 1,431	\$ 56	\$ 1,382	\$ 1,391	\$ 8

Note:

1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was \$0.502 million.

The increase variance in distribution brushing costs in 2017 actual compared to forecast was \$16,000 (due to results of a tender process that occurred after the GRA forecast was developed).

**Table 2-6: Total Net Transmission and Distribution Brushing Costs (\$000)**

	2016 Actual	2017 Forecast			2018 Forecast		
		Original GRA Filing	Compliance Filing	Diff	Original GRA Filing	Compliance Filing	Diff
Transmission Brushing	1,034	1,182	1,134	- 49	1,161	1,161	-
Distribution Brushing	39	304	320	16	331	331	-
Total Brushing	1,073	1,487	1,454	- 33	1,492	1,492	-
Transmission Deferred	- 550	-	-	-	-	-	-
Distribution Deferred	- 21	-	1	1	-	1	1
Brushing Deferred	- 571	-	0	0	-	0	0
Net Transmission Brushing	484	1,182	1,134	- 49	1,161	1,161	-
Net Distribution Brushing	18	304	319	15	331	330	- 1
Net Brushing Expense	\$ 502	\$ 1,487	\$ 1,453	\$ (33)	\$ 1,492	\$ 1,491	\$ (1)

**Table 2-7: Deferred Vegetation Management Account Closing Balance**

	2017 Forecast			2018 Forecast		
	Original GRA Filing	Compliance Filing	Diff	Original GRA Filing	Compliance Filing	Diff
Opening Balance	\$2,215	\$2,215	\$0	\$1,994	\$1,994	\$0
Annual Deferred Costs	0	0	0	0	0	0
Annual Amortization	-222	-222	0	-222	-222	0
Closing Balance	\$1,994	\$1,994	\$0	\$1,772	\$1,772	\$0

### 2.3.4 General O&M

Paragraph 166 of Reasons for Decision notes that based on the information provided in Undertaking 35, the Board considers that it requires further line item detail with respect to actual 2017 general O&M costs in order to make a final determination on these costs.

#### **Directive #18**

YEC is directed to provide this detail by way of updating the information found in Table 17 for 2017 actual results in its compliance filing to this decision and to explain any variances.  
**(Paragraph 167)**

As directed, further line item detail for actual 2017 O&M costs is provided in the table that follows. The Compliance Filing assumes 2017 actual results. The 2017 variance for labour reflects the changes discussed above for Labour; the balance of other 2017 costs increased 5.4% over forecast, reflecting increased transportation and maintenance requirements net of lower than forecast SCADA communication requirements. The 2018 forecast retains the Application forecast (modified as discussed above for updated Labour capital-to-maintenance ratio).

**Table 2-8: 2017 Actual General O&M Costs by Category**

	2016 Actuals	2017 Forecast			2018 Forecast		
		Original GRA Filing	Compliance Filing	Diff	Original GRA Filing	Compliance Filing	Diff
Labour	\$ 366	\$ 394	\$ 466	\$ 72	\$ 394	\$ 395	\$ 1
Transportation	459	501	540	39	504	504	0
Maintenance of Company Owned Properties	501	535	593	58	508	508	0
SCADA Communication	197	202	173	-29	207	207	0
Total General O&M	\$ 1,522	\$ 1,633	\$ 1,772	\$ 139	\$ 1,614	\$ 1,615	\$ 1

### 2.3.5 Administration

#### **Directive #19**

Given the variance explanation provided by YEC and the minimal variance between 2016 and 2017 actuals, the Board is prepared to accept YEC's 2017 actual administration cost amounts. However, in the compliance filing to this decision, YEC is directed to update the information found in Table 18 for 2017 actual administration costs by cost category for information purposes. **(Paragraph 172)**

As directed, further line item detail for actual 2017 Administration costs is provided in the table that follows. The Compliance Filing assumes 2017 actual results (modified as discussed above for Labour). The 2018 forecast retains the Application forecast (modified as discussed above for updated Labour capital-to-maintenance ratio).

**Table 2-9: 2017 Actual Administrative Costs by Category**

	2016 Actual	2017 Forecast			2018 Forecast		
		Original GRA Filing	Compliance Filing	Diff	Original GRA Filing	Compliance Filing	Diff
Labour	\$ 5,783	\$ 5,961	\$ 5,711	\$ (250)	\$ 5,911	\$ 5,916	\$ 5
Resource Planning	14	48	15	-33	48	48	0
Communications	129	130	130	-0	130	130	0
Customer Accounting	208	224	203	-21	225	225	0
Environmental Mgmt	166	278	252	-26	238	238	0
General	613	705	661	-44	662	662	0
Information Systems	576	631	654	24	645	645	0
Fish Hatchery	157	168	183	15	168	168	0
Safety	172	171	170	-0	182	182	0
Training	143	175	140	-35	175	175	0
Recruitment	231	244	222	-22	229	229	0
Board of Directors	160	182	158	-25	182	182	0
Union	0	95	0	-95	20	20	0
Regulatory Affairs	99	33	29	-4	33	33	0
Material Management	41	38	32	-5	37	37	0
Contracting	14	12	14	2	12	12	0
Professional Development	3	15	0	-15	15	15	0
<b>Total Administration</b>	<b>\$ 8,509</b>	<b>\$ 9,110</b>	<b>\$ 8,575</b>	<b>\$ (535)</b>	<b>\$ 8,912</b>	<b>\$ 8,917</b>	<b>\$ 5</b>

### 2.3.6 Property Tax

The Board notes at paragraph 196 that based on the information provided in Undertaking 35, the Board is prepared to approve the 2017 actual and the 2018 forecast property taxes in the amount of \$0.693 million and \$0.708 million, respectively. The Compliance Filing includes 2017 actual and 2018 Application forecast property taxes.

### 2.3.7 Reserve for Injuries and Damages (RFID)

The Board notes at paragraph 188 that based on the 2017 actual information provided in Undertaking 35 closely matching the 2017-2018 forecast amounts, the Board is prepared to approve the 2017 actual and 2018 forecast insurance and RFID costs. This includes approval of both the amortization over five years of the negative 2016 RFID balance in the amount of \$1.059 million and the updated annual RFID appropriation to an amount of \$0.267 million. The Compliance Filing includes 2017 actual and 2018 Application forecast insurance and RFID costs.

## **2.4 REVENUE REQUIREMENT: RATE BASE, DEPRECIATION & AMORTIZATION**

### **Directive #20**

The Board is not persuaded by the UCG argument that a problem exists with respect to YEC's "depreciation rates." In response to an IR, YEC clarified that, with the exception of the two LNG assets discussed above, it has used only depreciation parameters and the implied depreciation rates that had been previously presented in a depreciation study, tested in a GRA, or specifically approved by the Board. The Board considers that YEC did not make a formal request for approval of its "depreciation rates" because it had not requested a change to any of the depreciation parameters that inform an implied depreciation rate. For these reasons, the UCG recommendation for denying a change in YEC's depreciation rates is moot. Nonetheless, the Board considers that, given it has been eight years since the time of YEC's last full depreciation study, it would be beneficial for a full depreciation study to be completed, so as to avoid the potential for large changes to depreciation expense that could be associated with incorporating material changes to asset service lives. YEC is directed to submit a full depreciation study at the time of its next GRA. **(Paragraph 212)**

As directed, Yukon Energy will submit a full depreciation study at the time of its next GRA.

### **Directive #21**

The Board, however, does agree with the UCG observation that detail with respect to YEC's depreciation expense calculations was not easily obtained. It was not until asked a second time to provide the detailed depreciation and amortization expense calculations that YEC responded with the requested information. The Board considers this information to be essential in facilitating a review of YEC's depreciation and amortization expense irrespective of whether or not a change in depreciation parameters has been requested. YEC is directed to provide detailed depreciation and amortization calculations in all future GRAs consistent with the attachments provided with its response to YUB-YEC-2-27. This information may be included as an additional schedule within YEC's existing Tab 7 format. **(Paragraph 213)**

As directed, Yukon Energy will provide detailed depreciation and amortization calculations in all future GRAs consistent with the attachments provided with its response to YUB-YEC-2-27.

### **Directive #22**

The Board approves YEC's actual 2017 and forecast 2018 depreciation and amortization expense amounts, subject to any findings made elsewhere in this decision with respect to capital additions or specific deferral or reserve accounts. The Board directs that any findings made elsewhere in this decision that will affect YEC's depreciation and amortization expense calculation to be incorporated in its compliance filing to this decision. **(Paragraph 214)**

In response, the Compliance Filing retains the depreciation and amortization expense amounts as provided in the Application for 2017 and 2018, subject to adjustments as required to reflect findings made in the Decision with respect to changes in capital additions or specific deferral or reserves accounts.

The Board in paragraph 219 also accepted YEC's rationale for its proposed changes to the hearing cost reserve account, and found it reasonable for YEC to amortize the credit balance in the account and to decrease the annual provision as described. The Compliance Filing accordingly retains the hearing cost reserve account changes as proposed in the Application.

### **Directive #23**

It is the Board's view that YEC's management and reporting of deferral and reserve accounts has led to unnecessary inefficiencies and confusion with respect to the processing of its application. For this reason, the Board directs YEC to re-establish its standard of disclosure to one that is transparent, consistent and provides cross-referencing among each of the interrelated rate base and revenue requirement items and the individual components comprising each item. This applies equally to the disclosure on YEC's Tab 7 schedules and any supplementary information within YEC's application. **(Paragraph 226)**

Yukon Energy will work to improve its standard of disclosure and reporting of deferral and reserve accounts in Tab 3 and Tab 7 of its next GRA as directed by the Board. As this will take time to implement, no changes have been made in Tab 7 for this Compliance Filing.

## **2.4.1 Capital Structure & Return**

### **2.4.1.1 Cost of Debt**

At paragraph 234 the Board notes that it does not accept actual debt costs for YEC for 2017, as reflected in Undertaking 35, as it is not clear that those debt costs were based on a Board-approved rate for that cost of debt. However, at paragraph 237 the Board also notes that there is no evidence on the record of the proceeding as to the rate for long-term Canada bonds, and no party disagreed with the submission of YEC that its Application provides a market-based lower cost option available at the time of the application. For the purpose of this Decision, the Board accepted the forecast market rate for YEC's cost of debt of 2.15 per cent for each of the 2017 and 2018 test years. The Compliance Filing accordingly retains the forecast market rate for YEC's cost of debt of 2.15 per cent for each of the test years.

### **Directive #24**

In Board Order 2013-01, the Board directed that a formulaic approach be used for forecasting future costs of debt. This direction was not followed. The Board reiterates the direction and expects this direction to be followed. In future GRAs, both Yukon utilities are to provide their cost-of-debt forecast based on the formulaic approach (long-term Canada bonds plus 120 basis points). If a utility chooses to employ a market-based approach, that utility must also provide a forecast based on the approved formulaic approach. **(Paragraph 238)**

Yukon Energy will provide a cost-of-debt forecast based on the formulaic approach (long-term Canada bonds plus 120 basis points) in its next GRA. YEC may provide other references for debt cost where there is an advantage to ratepayers. All references including the formulaic approach will be provided for consideration by the Board and intervenors.

#### **2.4.1.2 Return on Common Equity**

At paragraph 242 of Reasons for Decision the Board notes as follows:

- YEC's capital structure of 60 percent debt and 40 percent equity has been previously approved by the Board, most recently through Board Order 2013-01.
- That the UCG submission to set equity thicknesses based on standards established in Alberta was not supported by evidence.
- Nothing on the record of this proceeding supports a change to the applied for and previously approved capital structure for YEC. The Board accepts the YEC capital structure of 40 percent equity and 60 percent debt.

At paragraph 246 the Board also notes that it continues to approve the use of the BCUC benchmark utility as the base or starting point for determining the ROE for Yukon utilities.

#### **Directive #25**

Based on principles developed in Decision 2017-01 and in terms of risk premium relative to the BCUC benchmark utility (FEI), the Board awards YEC 25 basis points for its small size. Further, in recognition of YEC's risks for generation, isolated grid and customer diversity, the Board awards YEC an additional 20 basis points for a total risk premium of 45 basis points above the BCUC benchmark utility. **(Paragraph 283 [partial])**

Pursuant to the Board's directions as reviewed above, the Compliance Filing retains the Application capital structure for YEC of 40 percent equity and 60 per cent debt, and includes an ROE for 2017 and 2018 of 8.70% [BCUC benchmark ROE of 8.75%, plus 45% risk premium, minus 50% per OIC 1995/90].

## **2.5 STABILIZATION MECHANISMS**

### **2.5.1 Rider F**

The Board indicates at paragraph 292 of the Reasons for Decision that it considers it reasonable to defer LNG price variances to the DFPVA and to include deferred LNG price variances in the amounts collected (or refunded) to customers through Rider F as the addition of a different thermal fuel is not contrary to the purpose of this deferral account and is consistent with the reasons for establishing such a deferral account. The Board approved YEC's request to incorporate references to LNG pricing in the Rider F policy.

#### **Directive #26**

Lastly, YEC has stated it will assume all risk with respect to the thermal fuel mixture (LNG versus diesel). Therefore, the Board directs YEC to ensure that any variances due to changes in the thermal fuel mixture (forecast versus actual) are not included in the DFPVA. YEC is to indicate, in its compliance filing to this application, the steps it will take to prevent changes in the thermal fuel mixture from appearing in the DFPVA. **(Paragraph 293)**

In response to Directive #26, YEC has reviewed the DFPVA monthly adjustment mechanism to assess what options may exist to reflect forecast versus actual thermal fuel mixture for LNG and diesel fuel. This matter

was not addressed during the proceeding, and was not part of YEC's commitment (subject to what is feasible with the DCF/LWRF year end adjustment mechanism) to assume risks related to actual fuel mix at forecast fuel prices in the determination of final annual DCF (now LWRF) transfers.

The DFPVA addresses the variance each month between forecast and actual fuel price at forecast fuel efficiency, based on actual thermal generation. This deferral account ensures that any net variance in actual versus forecast fuel price related to actual thermal generation is solely to the cost or credit of ratepayers. In order to retain consistency with these principles, diesel and LNG fuel price variances would need to be applied separately to actual diesel and LNG thermal generation.

Directive #26 would require that all actual thermal generation be assumed at the thermal fuel mixture approved for the GRA, i.e., the 90/10 LNG/diesel mix assumed for 2018 in the Compliance Filing, and that DFPVA fuel price variance be determined for each month based on the forecast blended fuel price at this mix versus the actual fuel price at this mix. The result would create a new variance reflecting the impact of the fuel mix variance from forecast.

Table 2-10 provides a simplified annual example using the Directive #26 requirements for 2018 fuel price true-up based on the forecast 90/10 fuel mix versus retaining actual 2018 fuel mix of 80.7% LNG and 19.3% diesel fuel. In this example, using the forecast fuel mix results in a slight increase of \$43k in the cost risk to customers.<sup>4</sup> This outcome differs from the decrease in customer costs with use of the 90/10 forecast fuel mix and forecast fuel prices with the LWRF 2018 year-end assessment in Appendix 2.2. As described above, the ratepayer is protected from variances in fuel mix primarily through the rules approved for the LWRF.

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<sup>4</sup> Actual results of this type of assessment for any year will vary depending on the actual fuel mix and prices in any year.

**Table 2-10: Rider F True-Up 2018 Example – Forecast vs Actual Fuel Mix**

				<b>Rider F True-Up for Actual</b>	
				<b>Forecast Fuel Prices</b>	<b>Actual Fuel Prices</b>
<b>Fuel Price (\$/kW.h)</b>					
LNG	90%	0.1466		0.1839	
Diesel	10%	0.2633		0.2883	
GRA Blend Mix (90/10)		0.1582		0.1943	
<b>Actual Generation (MW.h/yr)</b>					
LNG	80.7%			30,130	
Diesel	19.3%			7,189	
Total				37,319	
<b>Thermal Fuel Price True-Up (Actual-Forecast) (\$000/yr)</b>					
		<b>90/10 mix</b>		<b>80.7/19.1 mix</b>	
LNG		1,254		1,125	
Diesel		93		180	
Total		1,347		1,304	
Difference (ratepayer cost)			43		

Unlike the LWRP annual determination, the DFPVA determinations must be made on a monthly basis. Appendix 1.1, Table 1.1-6A provides a comparison of fixed versus actual fuel mix assessment for 2018 with month-to-month calculations as required for Rider F assessments. This more detailed example highlights additional practical implementation issues for the fixed fuel mix assessment when confronted with months where there is no actual use or actual price for LNG. Using the 90/10 LNG/diesel fixed fuel mix requires adoption of a cumulative monthly assessment as shown in Table 1.1-6A over the full year in order to secure the \$1.346 million final result applicable for 2018 as shown above, i.e., separate DFPVA assessments by month without the ongoing cumulative assessment for months-to-date in the year do not yield this same overall annual result for 2018.

Based on the considerations noted above, YEC recommends that the DFPVA with LNG and diesel fuels be determined based on actual fuel mix rather than forecast fuel mix in order to retain consistency with current DFPVA principles and to avoid potential conflicts with the LWRP risk assignments as well as other complexities that may otherwise arise. In contrast to the annual LWRP determination, the DFPVA monthly determinations create added issues if variances in actual fuel mix are not retained.

## **2.5.2 Diesel Contingency Fund (DCF)/ Low Water Reserve Fund (LWRF)**

### **Directive #27**

For these reasons, the Board directs YEC to create a deferral account that records the variance between actual thermal generation fuel costs (based on volume only) and the GRA forecast thermal generation fuel costs (based on volume only) that are due to changes in water conditions. Factors such as equipment failure, force majeure, capital or planned maintenance events are not to be included in the calculations for this deferral account. YEC is directed, in its compliance filing to this decision, to propose trigger levels (+/-) that will initiate a rider proceeding to dispense with the balance in the deferral account. **(Paragraph 321)**

### **Directive #28**

The difference between the directed deferral account above and YEC's proposed DCF is that the deferral account will be adjusted for those variances between approved forecast and actual, not modelled, results. In other words, the deferral account will be adjusted for changes in hydro generation that are a result of changes in water availability. YEC is directed, in its compliance filing, to explain the method it will use to determine the variance in hydro generation due to water availability. The Board directs that the deferral account be named the Low Water Reserve Fund (LWRF) as it will incorporate a broader range of thermal generation. YEC will adjust the balance in the LWRF on an annual basis for the difference in forecast thermal generation from actual thermal generation based on forecast load and only adjusting for the changes in hydro generation that are a result of changes in water availability. **(Paragraph 322)**

### **Directive #29**

To draw from the LWRF due to low water levels, YEC will have to submit an application to the Board requesting a drawdown of the fund indicating that the application is due to changes in hydro generation because of changes in water levels from those contained in the last Board-approved forecast. YEC will take the forecast risk for incremental generation costs for incremental loads outside of the forecast period with the exception of incremental load covered by the ERA. YEC is directed to amend its DCF term sheet to comply with these directions. Conversely, when the fund requires replenishment, YEC can apply to the Board for rate rider to replenish the LWRF. YEC, in its compliance filing, may submit any potential ceiling for the LWRF rate rider. **(Paragraph 323)**

### **Directive #30**

YEC's DCF is currently at or around its cap of \$8,000,000. This balance in the DCF is to be transferred in its entirety to the LWRF. The Board is not persuaded by the submissions of parties that a change in the cap is required because to date it has not been used to refund customers, and customers would have to wait longer for such refunds if the cap was increased. This would not be a fair outcome. **(Paragraph 324)**

### **Directive #31**

YEC is directed, in its compliance filing to this decision, to provide further details on how this LWRF will operate. (**Paragraph 325**)

Appendix 2.1 of the Compliance Filing provides an amended DCF Term Sheet (now called the LWRF Term Sheet) that describes how the LWRF will operate to comply with the Board's directions in Order 2018-10, as well as the DCF/ LWRF 2017 and 2018 Annual Reports.

## **2.6 RATES**

### **2.6.1 Secondary Sales Rates**

In paragraph 336, the Board indicated that it accepted YEC's reasons for secondary sales rates being lower than firm customers and required no further action from YEC on this issue for this Application.

### **2.6.2 Wholesale Rates**

The Board provided the following directives related to wholesale rates and the Energy Reconciliation Adjustment (ERA).

### **Directive #32**

The Board accepts the submissions of YEC on wholesale rate matters. The UCG submissions ignore the requirements of OIC 1995/90 and is therefore rejected by the Board. The AEY position of paying YEC ERA amounts as it collects those amounts from customers lacks detail as to how such a process would be implemented and is also rejected by the Board. Given the Board's determinations with respect to the LWRF, YEC is directed to amend the ERA portion of Rate Schedule 42 to ensure it is in compliance with those directions. (**Paragraph 341**)

### **Directive #33**

To be clear, ERA billing or refund amounts will be based on a consistent definition of costs. In this decision, the Board has clarified that actual costs for both the LWRF and the ERA are those costs related to actual thermal generation and not forecast thermal generation. Further, if significant industrial load enters or leaves the Yukon Integrated System or there are material changes in generation assets where either or both of these factors change the baseload generation mix, YEC can propose changes as to how the LWRF and the ERA operate at that time. (**Paragraph 342**)

### **Directive #34**

YEC is directed to make the changes requested in this section in its compliance filing to this decision. (**Paragraph 343**)

Appendix 2.1 of the Compliance Filing provides the LWRF Term Sheet that describes how the LWRF will operate to comply with the Board's directions in Order 2018-10, including the direction in paragraph 342 to propose changes as to how the LWRF operates if significant industrial load enters or leaves the YIS or

there are material changes in generation assets where either or both of these factors change the baseload generation mix.

The ERA portion of Rate Schedule 42 as approved in Board Order 2018-05, Appendix B has general provisions that continue to apply with the LWRP Term Sheet. No ERA is applicable in 2017 as there is no variance between forecast and actual results as regards wholesales and thermal generation costs. The ERA determinations for 2018 are provided in Appendix 2.2 to comply with the Board's determinations in Order 2018-10 regarding both the LWRP and the ERA.

## **2.7 CAPITAL & DEFERRED PROJECTS**

The directives in Appendix A of Order 2018-10 on capital and deferred projects are reviewed below. Specific adjustments to rate base are set out in Appendix 1.1, Table 1.1-3.

### **2.7.1 Major Projects > \$ 1 Million**

#### **Directive #35**

The Board also notes that, in Undertaking 35, YEC noted that mid-year net rate base is within 0.2 per cent of the GRA forecast. However, YEC did not provide 2017 actuals for capital costs on a project-by-project basis. Accordingly, the Board directs YEC to update its costs for each project in the compliance filing to this decision. (**Paragraph 356**)

Pursuant to Directive #35, YEC has updated its costs to reflect 2017 actuals for each project in the compliance filing's rate base.

##### **2.7.1.1 Aishihik Third Turbine**

YEC is not applying for recovery of any costs related to this project in the test years.

The Board notes at paragraph 361 that "there is no need to direct YEC to demonstrate that the costs incurred in relation to this project are not included in the 2017 or 2018 requested revenue requirement as requested by YEC" and accordingly, the Board makes no determination on the prudence of the costs of this project at this time.

##### **2.7.1.2 Aishihik Elevator Shaft Structural Steel Rehabilitation**

At paragraph 368 the Board accepts that this project was driven by the requirements imposed by the OH&S and that it is a project to address safety concerns within the elevator shaft. The Board indicates at paragraph 370 that cost components for this project were prudent and reasonable outside of the specific component identified in paragraph 369 (Directive #36 below).

#### **Directive #36**

In the view of the Board, it was imprudent of YEC, as part of its 2011 project, to use clamps that do not meet modern standards for this use. Accordingly, the Board disallows \$200,000 of the costs for the Aishihik elevator shaft steel rehabilitation project. The Board directs YEC to reflect this direction in its compliance filing to this decision. (**Paragraph 369 [partial]**)

In response, the disallowed costs have been removed from rate base in the Compliance Filing.

### **2.7.1.3 Aishihik Electrical and Control Upgrades**

The Board makes a number of comments regarding specific cost components in paragraphs 373 to 380 of Order 2018-10, and three specific directives (#37 to #39). The Board provides specific comments regarding the following cost components and notes at paragraph 380 that it has reviewed the other components/projects included within the Aishihik electrical and control upgrades and finds that they are needed for the continued safe and reliable provision of utility service:

- **AH3 control system drawings update (Paragraph 374):** The Board states that costs related to this component are to be held in WIP, and the Board will consider the reasonableness and prudence of these costs when approval is sought to add the project to rate base.
  - In response to this directive, costs related to this component have been moved to WIP.
- **Aishihik HMI installation (Paragraph 376):** The Board accepts YEC's position that the Aishihik electrical and control upgrades resulted from the asset assessment by KGS and the plant inspections from 2015, and approves the costs associated with the Aishihik HMI installation as requested by YEC.
- **Aishihik RTU replacement (Paragraph 377):** The Board accepts the submission from YEC that the Aishihik electrical and control upgrades resulted from the asset assessment by KGS and the plant inspections from 2015 and approves the costs associated with the Aishihik RTU replacement as requested by YEC.
- **Aishihik blackstart modifications (Paragraph 379):** The Board accepts that this project is necessary to ensure that the newly installed blackstart generator can operate properly and to reduce wear on that generator.

#### **Directive #37**

The Board is of the view that YEC acted imprudently in its 2011 replacement of the reactor cable and that ratepayers should not be asked to pay the costs of fixing work that was improperly done only seven years ago. Accordingly, the Board disallows the \$0.075 million that YEC has proposed to include in its rate base for the AH reactor cable replacement and directs YEC to reflect this in its compliance filing. **(Paragraph 373 [partial])**

In response to Directive #37, the disallowed costs related to the 2011 replacement of the reactor cable were removed from rate base in the Compliance Filing.

#### **Directive #38**

The Board accepts that the estimated 15-hour reduction in the backup battery bank's ability to service station components is significant and warrants installation of a battery dedicated to the lube oil pump. Accordingly, the Board finds that the lube oil pump battery installation is needed and approves this component of the project. However, before approving the reasonableness of the costs, the Board directs YEC in its compliance filing to provide the 2017 actual costs for this component of the project. **(Paragraph 378 [partial])**

In response to Directive #38, Yukon Energy provides the following as regards the 2017 actual costs of the AH3 lube oil pump battery installation project:

- This component was not able to be completed in 2017 (actual 2017 cost = \$0); and
- It was deferred to 2018 and completed at a cost of \$50,806.

**Directive #39**

The Board directs YEC to update its 2017 costs for these projects to reflect 2017 actuals and to reflect the other findings in this section in its compliance filing. YEC, in the compliance filing, is also to indicate when it proposes to add these costs to rate base. **(Paragraph 381)**

In Response to the Board’s Directive, 2017 actual costs for each other cost element/ project within the Aishihik Electrical & Control Upgrades are provided below and reflected in the Compliance Filing.

**Table 2-11: Aishihik Electrical & Control Upgrades Actual Costs (2016 – 2017)**

	2016	2017	Total
AH2 Control System Replacement	\$ 110,938.30	\$ 507,543.36	\$ 618,481.66
AH1 Controls Upgrade	\$ 116,503.59	\$ 603,699.20	\$ 720,202.79
AH0 SS Circuit Breakers	\$ 3,526.68	\$ 83,563.63	\$ 87,090.31
S-167 Porcelain Insulator	\$ 28,255.35	\$ 44,137.52	\$ 72,392.87
Aishihik Reactor Cable Replacement		\$ 37,989.43	\$ 37,989.43
Aishihik Control - RTU Removal		\$ 11,529.30	\$ 11,529.30
AHC - AH3 Deficiencies		\$ 680.37	\$ 680.37
Added to Ratebase in 2017			\$ 1,548,366.73

**2.7.1.4 Communications Upgrades**

In paragraph 394 the Board notes that it accepts that communications upgrades are warranted but notes that each component of the project was examined to determine whether all of the components are needed.

**Directive #40**

Therefore, the Board finds that the satellite installations for SCADA, fibre communications upgrades and network access controls are necessary as part of YEC’s disaster recovery planning and approves these projects. The Board notes that, based on the response to YUB-YEC-1-67, there have been no cost changes since the estimates provided in the BBA assessment. Nonetheless, the Board directs YEC to include all actual costs for 2017 for all capital projects as part of its compliance filing to this decision. **(Paragraph 395 [partial])**

As specified in Directive #40, YEC has included in the Compliance Filing all actual costs for 2017 for all capital projects that are included in rate base (including all Communications Upgrade projects costs for 2017).

### **2.7.1.5 LNG Plant**

At paragraph 405 the Board accepts that the additional costs for the LNG Plant, as described by YEC, are the result of requirements of the YESAB and YOGA permitting; notes its view that these cost overruns are not a result of insufficient cost controls; and finds that a reduction in the costs for the LNG plant and an independent audit of this project are not necessary.

The Compliance Filing retains LNG Plant costs in rate base as filed in the Application, as approved by the Board.

### **2.7.1.6 LNG Third Engine**

At paragraph 412 the Board indicates that the cost per MW of the third LNG engine project is favourable when compared to alternative projects; finds that it is reasonable for YEC to continue with this project; and accepts YEC's submission with respect to the N-1 capacity reliability criterion in support of this project. The Board notes at paragraph 413 that YEC was not requesting that costs of the project be added to rate base for the test years; and as the project is not part of the rate base additions for this test period, any determination on the prudence of project costs is deferred until YEC applies for this project to be put into rate base.

Costs for this project remain in WIP for the test years.

### **2.7.1.7 Directives related to Other Major Capital Projects**

Directives related to approval of costs for the following projects are provided at paragraph 421 and 422 of the Decision: Hydro overhauls for WH4, MH2, T&D Breaker Replacements, T&D Line Replacements, Wareham Spillway Gate Hoist Replacement, Whistle Bend Supply/Takhini Upgrade.

#### **Directive #41**

The Board has reviewed each of these major capital projects and the supporting evidence on the record of this proceeding. The Board considers that each of these projects is necessary and the associated costs are prudently incurred by YEC. However, the Board notes that the Hydro unit #WH4 overhaul, T&D – breaker replacements include 2017 costs that must be updated for actuals. Accordingly, the Board directs YEC to update its 2017 costs to reflect 2017 actuals for those projects, in its compliance filing to this decision. **(Paragraph 421)**

#### **Directive #42**

The hydro unit #MH2 overhaul, T&D – line replacement, Wareham spillway gate hoist replacement and Whistle Bend Supply/Takhini Upgrade do not include costs for 2017. YEC is directed to reflect the 2018 forecast costs for these projects in its compliance filing. **(Paragraph 422)**

The Compliance Filing updates YEC's 2017 costs to reflect 2017 actuals for these other projects where applicable. Forecasts costs for 2018 are used where applicable.

## **2.7.2 Projects >\$100,000 and < \$1 million**

The following provides all directives, and confirms where relevant how any directed changes are addressed in the Compliance Filing. All projects included in 2017 rate base are updated to actual 2017 costs.

### **2.7.2.1 Aishihik Control Structure Refurbishment**

#### **Directive #43**

YEC provided no information on the specific activities that will be carried out as part of this assessment. Given that YEC has already observed that the deck timbers are worn and rotting and some of the support beams are crushed and “are in danger of failing completely,” the Board is of the view that the amount of \$325,000 simply to assess the structure is excessive and, in this case, is not necessary before taking action on the repairs or replacement. The Board is of the view that the funds would be better spent carrying out the repair or replacement. Therefore, the Board denies YEC’s proposed \$325,000 for the current test period and directs YEC to reflect this finding in its compliance filing. (**Paragraph 426**)

As directed, costs for this project have been removed from rate base for 2018.

### **2.7.2.2 Faro Building Diesel Ventilation**

#### **Directive #44**

YEC is directed to provide information in its compliance filing on the frequency of the overheating issue and whether the project could be deferred until 2021 when one of the two diesel units is to be replaced. Further, YEC is to state in its compliance filing if the 2021 unit replacement will require additional alterations to the Faro diesel building. (**Paragraph 428 [partial]**)

The project has been deferred and no costs have been incurred. Project costs will be held in WIP and no costs are included in the 2018 test year rate base.

The frequency of overheating is minimal, however this is due to the fact that this unit is not run outside of monthly runups (it serves as a backup to FD7). YEC has been hesitant to invest money in the plant as FD1 has been on the verge of retirement for some time. The ventilation work could likely be deferred until the unit is retired, however, Planning has determined this will likely be pushed back to 2022-23 instead of 2021.

### **2.7.2.3 Wareham Dam Blackstart Generator**

In paragraph 430, the Board notes that YEC has not provided information on the frequency of previous problems encountered due to the lack of a blackstart generator at this location or with respect to the likelihood of such problems arising in the future. The Board states that it considers the potential of the spill gates freezing shut to be a significant event and therefore accepts the costs for this project as submitted by YEC.

Costs for the project are included in Compliance Filing rate base, including actual 2017 costs.

#### **2.7.2.4 Whitehorse Wind 1 Decommission**

##### **Directive #45**

The Board accepts that these costs are reasonable and prudent. Accordingly, the Board approves this project and directs YEC to update the associated costs to include 2017 actuals in the compliance filing to this decision. **(Paragraph 432)**

Costs for the project are included in Compliance Filing rate base, including actual 2017 costs.

#### **2.7.2.5 Dawson P158 T1/T2 Transformer**

##### **Directive #46**

The Board notes that this project was included and approved in YEC's 2012-13 GRA, however, it now appears that this work was not completed by YEC, and YEC has not provided any explanation for not carrying out this project. Given that YEC has provided no evidence indicating that the transformer was improperly constructed in 2004, and given that this project was approved but not carried out in the subsequent six years since approval, the Board does not accept YEC's submission that this project is necessary to address safety concerns. As such, the prudence of the related costs has not been shown. Consequently, the Board denies the inclusion in rate base of YEC's proposed \$200,000 for this project and directs YEC to reflect this finding in its compliance filing. **(Paragraph 435)**

As directed, costs for this project have been removed from rate base for 2018 in the Compliance Filing.

#### **2.7.2.6 Substation Protection and Control Minor Upgrades**

##### **Directive #47**

The Board accepts that it is necessary for YEC to engage in ongoing work at its substations to ensure safe and reliable service and therefore approves this project as applied for by YEC. However, the Board directs YEC to update the costs for this project to include 2017 actuals in the compliance filing to this decision. **(Paragraph 437)**

##### **Directive #48**

However, in subsequent GRAs, when requesting approval of any such upgrades, the Board directs YEC to include a detailed description of the work that has been carried out or will be carried out at each substation and more detailed explanations of the need for the work at each substation. **(Paragraph 438)**

Costs for the project are included in Compliance Filing rate base, including actual 2017 costs. In subsequent GRAs, YEC will include detailed description of the work and the need for the work at each substation as directed by the Board.

### **2.7.2.7 Transmission System Protection Upgrades**

#### **Directive #49**

The Board considers that this project is necessary for the safe and reliable operation of the electrical system and that the costs are reasonable. Therefore, the Board approves this project and directs YEC to update the associated costs to include 2017 actuals in the compliance filing to this decision. **(Paragraph 440)**

Costs for the project are included in Compliance Filing rate base, including actual 2017 costs.

### **2.7.2.8 Callison Voltage Regulator Automation**

#### **Directive #50**

The Board notes that YEC has not provided information on the amount of time that would be saved during outages nor the subsequent operating cost savings resulting from eliminating the need for an operator to travel six kilometers to the substation. Therefore, the Board finds that YEC has not sufficiently demonstrated that this project is reasonable and prudent and, as such, that it would be reasonable to incur such costs. Accordingly, the Board denies YEC's proposed inclusion in rate base of the \$115,000 associated with this project and directs YEC to reflect this finding in its compliance filing. **(Paragraph 442)**

As directed, costs for this project have been removed from rate base for 2018.

### **2.7.2.9 Building Condition Report Response**

#### **Directive #51**

The Board agrees that it is reasonable for YEC to replace end-of-life components in its buildings and facilities. However, in order to approve the related costs, additional information is needed on which of the replacements are needed as a result of components being at end of life and which are being upgraded only to meet changes to codes. Accordingly, the Board directs YEC to file, as part of its compliance filing, a detailed itemized list of the work done or proposed to be done as part of this project, a description of each item, the costs for each item and the reasons why each item must be done. The reasoning for each item should include an explanation of whether it is an end-of-life replacement or if it is bringing the component up to current codes and, in the case of the latter, a reference to the relevant code and an explanation of why the component needs to be brought up to code at this time. **(Paragraph 444)**

Detail regarding the need and justification for building upgrades was provided during the 2017/18 GRA proceeding. Specifically, a copy of the Building Condition Report was provided in response to John Maissan-YEC-1-37(a). The response to UCG-YEC-1-29 provided a list of projects included in the forecast 2018 budget of \$299,000 along with related references within the Building Condition Report.

The following table summarizes forecast costs and provides a description of the work and the reason it is to be done (i.e., end of life or health and safety).

**Table 2-12: Summary of 2018 Capital Building Upgrades (\$000)**

<u>Work</u>	<u>Description</u>	<u>Cost</u>	<u>Reason</u>
Faro Fire Alarms	Replacement of fire alarm panel, smoke & heat detectors, horn strobes, and pull stations at two locations (Faro office and FD7 plant)	\$ 28.3	End of life
Whitehorse Fire Alarms	Replacement of fire alarm panel, smoke & heat detectors, horn strobes, and pull stations at three locations (Main office, IT trailer, Electrician/Drafting trailers)	\$ 72.0	End of life
Whitehorse Diesel Plant	Replacement of downspouts and front gate, investigation of structural and ventilation issues	\$ 31.7	End of life
WH4 water leaks	Investigation of water leaks at the WH4 hydro plant	\$ 5.0	End of life
Fish Ladder	Investigate roofing and structural issues and waterproof exterior load bearing walls at the Whitehorse fish ladder building	\$ 55.5	End of life
Staff Houses	Investigation of structural issues at two Dawson houses, freeze up concerns at the Aishihik House, and building envelope and water issues at a Mayo staff house	\$ 36.7	End of life
Mayo Fire Alarms	Replacement of fire alarm panel, smoke & heat detectors, horn strobes, and pull stations at the Mayo office building	\$ 12.1	End of life
Mayo Office	Investigation of HVAC, Roofing, and Structural issues at the Mayo office as well as concrete repairs and the installation of heat-tracing and gutters on the roof	\$ 53.5	End of life / Health & Safety
Kulan	Installation of heat tracing and gutters on the roof of the Kulan warehouse	\$ 4.4	Health & Safety
		<u>\$ 299.1</u>	

In summary, costs are required either due to “end of life” or due to “Health & Safety” reasons.

The Health and Safety issue related to installation of eavestroughs and heat trace relate to formation of ice dams above entrance areas which could represent a safety hazard. A common solution for this issue is to install heat traces along the eaves to melt the ice and to allow water to flow along the gutters and downspouts but this will not generally solve the source of the problem which is the roof surface heating up. Ultimately, a study is recommended to determine the definite cause and to provide a more permanent solution. An allowance is included in the Capital Reserve for both the study and potential repairs triggered by the study. Costs for repairs will rely solely on the results of the study. An immediate item will also be included to remove the ice dam above the back entrance door and to clean the gutters to avoid water dripping and minimize tripping hazards.

### **2.7.2.10 Stewart-Minto Local SCADA**

#### **Directive #52**

YEC did not provide information on whether cost reductions would be achieved by installing the data concentrator. In addition, YEC did not explain the benefits of adding remote diagnostic capability at the substations. Therefore, the Board finds that YEC has not shown the need for the installation of the data concentrator. The Board therefore finds that the related costs are not reasonable. Accordingly, the Board denies YEC’s proposal to include \$165,000 in its rate base related to the Stewart-Minto local SCADA project and directs YEC to reflect this finding in its compliance filing. **(Paragraph 446)**

As directed, costs for this project have been removed from rate base for 2018.

### **2.7.2.11 Other Capital Projects Between \$100,000 and \$1 Million**

#### **Directive #53**

YEC proposed a number of other capital projects between \$100,000 and \$1 million. The Board has reviewed YEC's proposals for the Aishihik generator fire protection, Aishihik tailrace road and slope, Canyon Lake control structure and dyke refurbishment to implement dam safety recommendations, Whitehorse diesel system grounding for generators, Whitehorse local HMI/historian upgrade, L170 line access, S-150 – Whitehorse main RTU upgrade, Whitehorse-Aishihik-Faro transmission upgrades, 25 kV distribution cut-out replacement, customer extensions, Aishihik emergency signage and lighting upgrade, critical spares – system requirement, Dawson derrick digger, fencing upgrades – various sites, Mayo B door installation for crane inspection, Mayo transient trailer unit, vehicle purchases, voice repeater site for Little Salmon Area, voice repeater site for Mendenhall/Champagne and WRGS hazardous materials containment projects. The Board is satisfied that these projects are needed to ensure safe and reliable electrical service and that the related costs appear to be reasonable. Accordingly, the Board approves these projects but notes that many of them include forecast costs for 2017 that must be updated to reflect 2017 actuals. Therefore, the Board directs YEC to update, in its compliance filing, 2017 costs to reflect 2017 actuals for all of the projects listed above that include forecast costs for 2017. (**Paragraph 447**)

In paragraph 448, the Board identifies projects listed above that do not include forecast costs for 2017: Whitehorse diesel system grounding for generators, 25 kV distribution cut-out replacement, Aishihik emergency signage and lighting upgrade, Mayo B door installation for crane inspection, Mayo transient unit, voice repeater site for Little Salmon area, voice repeater site for Mendenhall/Champagne and WRGS hazardous materials containment. The costs for these projects are approved by the Board for inclusion in rate base as applied for.

Costs for the other projects listed above are included in Compliance Filing rate base, including actual 2017 costs where applicable.

### **2.7.3 Major Deferred Projects > \$1 million**

The following provides all directives, and confirms where relevant how any directed changes are addressed in the Compliance Filing. All projects included in 2017 rate base are updated to actual 2017 costs. Many deferred projects included in the Application were forecast only to be in WIP during the test years.

#### **2.7.3.1 Aishihik Generating Station Licence Renewal Project**

This project was forecast to remain in WIP during the test years. In paragraph 456 of the Reasons for Decision, the Board finds that renewing the Aishihik water license is a necessity for continued operation of the Aishihik generating station. The Board states that costs for this project are to remain in WIP, and prudence will be assessed at the time YEC applies to include these costs into rate base.

Costs for this project remain in WIP for the test years.

### **2.7.3.2 Battery Energy Storage System Project**

#### **Directive #54**

The Board finds that, given the costs and unproven nature of the technology in a northern environment, the project is not viable...For these reasons, the Board finds that expenditures on such a project are not warranted. As a result, the Board denies the inclusion of costs associated with the battery energy storage project in the revenue requirement for the test years and directs YEC to reflect this finding in its compliance filing. **(Paragraph 463 [partial])**

This project was forecast in the Application to remain in WIP during the test years. No costs are included in the test year revenue requirements.

### **2.7.3.3 Thermal Plant**

The Board stated as follows in paragraph 470 of Reasons for Decision:

The Board is of the view that YEC has supported its case that adding capacity is needed to meet system reliability needs under the N-1 criterion and that a greenfield thermal generation plant is one of the preferred methods to add the needed capacity. However, YEC has not provided a business case in support of this project. YEC did not detail the costs and benefits associated with this project. The Board finds that it is not reasonable for YEC to proceed with the project without a detailed business case that considers the alternatives to the project. The Board notes that YEC forecast costs for 2019 and 2020 of \$38 million and \$20 million respectively. The magnitude of these costs alone is reason for proceeding cautiously. The Board is not persuaded that this project is the only way to address the predicted capacity shortfall and that the forecast costs are reasonable. The Board requires a detailed evaluation of alternatives to this project included in the business case. **(Paragraph 470)**

#### **Directive #55**

Given the above, the Board accepts Mr. Maissan's recommendation that YEC provide a detailed comparison of alternatives for this project, including the pros, cons, capital costs, operating costs and timeline to in-service and justification for its preferred option. Accordingly, before undertaking any further costs on this project, the Board directs YEC to provide this information in any future application for this project. Any costs incurred to date for this project are to be held in WIP until such time as a new application is brought before the Board and the Board makes a determination on that application and the prudence of the costs incurred. **(Paragraph 471)**

This project was forecast in the Application to remain in WIP during the test years. No costs are included in the test year revenue requirements. YEC will continue to prepare a proper business case for this project that includes a detailed evaluation and comparison of alternatives as directed by the Board.

#### **2.7.3.4 Demand Side Management (DSM)**

The Board stated as follows in paragraph 477 of Reasons for Decision:

In Board Order 2013-01, Appendix A: Reasons for Decision, the Board found that it was premature to approve or disallow DSM expenses until YEC and YECL jointly filed a DSM plan. Until that time, the Board directed YEC to hold all DSM-related costs in WIP. YEC and YECL later submitted a five-year DSM plan, which the Board addressed in Order 2014-06. In that Order, the Board approved three DSM projects proposed by YEC and YECL: LED lighting, automotive heater timing rebates and low-cost energy efficient products. The Board also stated that it was not approving the DSM program for the five-year term and that YEC was to make a formal application to the Board before expanding the DSM program elements beyond that approved or beyond 2015.

#### **Directive #56**

Despite the Board determination that DSM projects were only approved up to 2015, YEC has continued with program expenditures beyond that point and has forecast continued DSM expenses during the test period. YEC did not make an application to the Board before expanding DSM programs beyond 2015. Accordingly, the Board finds that any DSM program expenditures that occurred after 2015 were not prudently incurred and are disallowed for inclusion in YEC's rate base. **(Paragraph 478)**

#### **Directive #57**

YEC also incurred expenses on DSM projects that do not fall within the three projects approved by the Board in Order 2014-06, despite the Board's explicit statement that YEC must apply to the Board before expanding its DSM program beyond the elements approved in that order. Accordingly, the Board finds that YEC's DSM expenditures on programs not approved in Order 2014-06 (LED lighting, automotive heater timing rebates and low-cost energy efficient products) were not prudently incurred and are disallowed for inclusion in YEC's rate base. **(Paragraph 479)**

The Board in paragraph 480 of Reasons for Decision stated as follows on LED streetlight retrofits:

Specific to LED streetlight retrofits, in Board Order 2017-01 the Board stated the following:

With respect to LED streetlight installations that are not end-of-life conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction. **(Paragraph 480)**

#### **Directive #58**

Although the Board made the above-noted finding in relation to AEY, YEC should have taken note of this finding, because such a finding equally applies to YEC. As a result, the Board considers that retrofitting streetlights at end of life with LED lights were prudent expenditures. Any LED installations that are not end-of-life conversions must not be included in YEC's rate base. **(Paragraph 481)**

**Directive #59**

The Board is not persuaded that YEC should continue to operate DSM projects. YEC has indicated the benefits of expanding the program and submitted that its programs have met or exceeded key performance indicators. However, the Board notes that the Yukon government has DSM incentive programs in place, and the Board is of the view that it is better to leave DSM projects to government, rather than having ratepayers fund these projects. For these reasons, the Board is of the view that continuation of DSM programs by YEC is not necessary. Accordingly, the Board denies YEC's requests to continue with any DSM programs other than end-of-life streetlight conversions as discussed above. **(Paragraph 482)**

**Directive #60**

The Board directs YEC to reflect the Board's findings with respect to DSM programs, as detailed above, in its compliance filing. **(Paragraph 483)**

The Compliance filing has removed from test year rate base all DSM costs as directed by the Board, including all costs incurred after 2015 other than LED streetlight retrofits for end-of-life conversions (all YEC DSM costs for streetlight retrofits meet this test) and all costs incurred prior to the end of 2015 on programs not included in Order 2014-06.

**2.7.3.5 Resource Plan**

In paragraph 488 of Reasons for Decision, the Board agrees with YEC that any longer term risks posed by disruptive technology are not sufficiently defined to merit the exclusion of the costs for the 2016 Resource Plan from YEC's rate base. The Board finds that the evidence and submissions of CW were not of assistance to the Board on this issue.

**Directive #61**

The Board acknowledges that when the first resource plan was approved, the Board asked YEC to update it in five years. However, the Board also notes that the same was not requested when YEC updated the resource plan in 2016. The Board accepts that the 2016 update of the resource plan provided benefits in the form of long-term planning, risk assessment and stakeholder engagement. The Board therefore accepts that YEC's costs for the 2016 update were prudently incurred and approves YEC's proposal to amortize those costs over five years. However, the forecast costs must be updated to reflect 2017 actual costs, and the Board directs YEC to do so in its compliance filing to this decision. **(Paragraph 489)**

**Directive #62**

However, the Board is of the view that it is not prudent for YEC to continue with these significant expenses to update the resource plan every five years. Accordingly, the Board directs YEC to seek Board approval prior to any future updates of its resource plan. Any such application must be accompanied by a detailed proposal for both costs and scope of work, including a description of work to be carried out internally and by consultants. YEC must also include an explanation of why any work to be done by consultants cannot be carried out by internal staff. **(Paragraph 490)**

Costs for the Resource Plan are included in Compliance Filing rate base, including actual 2017 costs. YEC will consider the Board's concerns about the prudence of costs prior to undertaking significant expenses to update the 2016 Resource Plan.

### 2.7.3.6 Gladstone Diversion

The Board stated as follows regarding the Gladstone Diversion project in paragraphs 494 and 496 of Reasons for Decision:

The Board acknowledges that in Order 2013-01, it found the project to be potentially viable and directed YEC to hold its expenditures in WIP until the project was complete or otherwise ended. **(Paragraph 494)**

In this proceeding, the evidence established that by September 2014, the CAFN and KFN conclusively opposed the project and that, according to the YEC, their support was necessary for the project to proceed. No evidence was led to explain or justify why any expenditures on this project continued past September 2014. Therefore, it is the Board's view that the project was no longer viable as of September 2014. At that point, project expenditures should have stopped. For these reasons, the Board finds that any costs incurred after September 2014 were not prudently incurred and are not recoverable from ratepayers. **(Paragraph 496)**

### Directive #63

Accordingly, the Board directs YEC to include in its compliance filing a detailed breakdown of any costs incurred after September 2014 for the Gladstone diversion project and to reflect the removal of those costs from the amount that YEC proposes to amortize for the Gladstone diversion project. **(Paragraph 497)**

Costs for the project incurred after September 2014 are detailed below and are excluded as directed from costs included in Compliance Filing rate base for the Gladstone Diversion project.

**Table 2-13 – Gladstone Diversion Project Costs**

	2016	2015	Post Sept 2014	Total
Consulting	\$ 1,950.00	\$ -		\$ 1,950.00
AFUDC	\$ 90,191.73	\$ 92,218.70	\$ 36,968.55	\$ 219,378.98
	<b>\$ 92,141.73</b>	<b>\$ 92,218.70</b>	<b>\$ 36,968.55</b>	<b>\$ 221,328.98</b>

### 2.7.3.7 Marsh Lake

The Board stated as follows regarding the Marsh Lake project in paragraphs 506 and 507 of Reasons for Decision:

YEC stated that it will not proceed without obtaining support from First Nations for this project. A significant amount of time has elapsed on this project, and YEC has spent almost \$7 million up to the end of 2016, with another \$1.275 million forecast to be spent in 2016 and 2017. Despite this time and effort, YEC has not been able to obtain the firm support of First Nations or the local community and is planning to take this project back to its own board for a reassessment.

Furthermore, the Stagegate 3 project review, including a decision to proceed to the YESAB assessment phase which YEC stated was planned for the fourth quarter of 2017, had not yet happened at the time of the oral hearing in late June 2018. **(Paragraph 506)**

The costs to date for this project represent an increase of almost 50 per cent, with the project not yet nearing completion. While the Board is of the view that this project may still be viable, the Board is concerned with the amount of time and expenditures to date with little apparent progress. The Board reminds YEC that if it chooses to continue developing this project, the onus will be on YEC to demonstrate the prudence of all expenditures related to the project. **(Paragraph 507)**

This project was forecast in the Application to remain in WIP during the test years. No costs are included in rate base for the test years. YEC has noted the Board's reminder that if YEC chooses to continue developing the project, the onus will be on YEC to demonstrate the prudence of all related expenditures.

### **2.7.3.8 Mayo Lake**

#### **Directive #64<sup>5</sup>**

The Board approved the Mayo Lake storage enhancement in Order 2013-01. Given that sediment removal is necessary to realize any benefits from this project, the Board considers that it is prudent to expand the scope of work for this project accordingly. Therefore, the Board approves the Mayo Lake storage enhancement project as applied for. The costs for this project are to remain in WIP, and the prudence of the costs will be assessed at the time the project is complete and YEC applies to add the costs to rate base. **(Paragraph 513)**

This project was forecast to remain in WIP during the test years. No costs are included in rate base for the test years.

### **2.7.4 Deferred Projects >\$100,000 and <\$1 million**

The following provides all directives, and confirms where relevant how any directed changes are addressed in the Compliance Filing. All projects included in 2017 rate base are updated to actual 2017 costs.

#### **2.7.4.1 Mayo and Aishihik Climate Change Study**

#### **Directive #65**

In response to a UCG IR, YEC indicated that the 35 years of data inflows into YECSIM reflect what was recorded over the 35 years, including any climate change impacts relevant to those years. Given YEC's statement that its YECSIM model includes climate change impacts, the Board finds that YEC has not adequately demonstrated that it is necessary to engage in a separate study specifically on climate change impacts. Accordingly, the Board finds there is no justification for this project and directs YEC to remove these costs from its revenue requirement for each of 2017 and

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<sup>5</sup> The Summary of Directions in Appendix A to Board Order 2018-10 references paragraph 513 of Appendix A for Directive #64, but provides text for Directive #65 that follows [paragraph 516 Appendix A]. The same text is repeated for Directive #64 and Directive #65. It is assumed that the text at paragraph 513 was intended to be Directive #64.

2018 and not recover the 2016 costs. The Board directs YEC further to reflect this finding in its compliance filing. (**Paragraph 516**)

This project was forecast to remain in WIP during the test years. No costs are included in rate base for the test years in the Compliance Filing.

#### **2.7.4.2 Time of Use Rate Structure and Smart Grid**

##### **Directive #66**

The Board finds that YEC has not provided information that persuades the Board that a study on smart grid and time-of-use rates is useful or needed. Accordingly, the Board directs YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing to this decision. (**Paragraph 519**)

As directed, all costs for this study have been removed from rate base for the Compliance Filing.

#### **2.7.4.3 Mt Sumanik Wind**

The Board notes at paragraph 521 that YEC has not stated the endpoint of this project or what the potential benefits will be; and indicates that it is not prepared to accept these costs until YEC provides a business case and a full justification of these costs.

As directed, no costs for Mt Sumanik Wind project are included in test year rate base for the Compliance Filing. Costs for this project have been retained in WIP.

#### **2.7.4.4 Northern Diesel Plant Location Study**

##### **Directive #67**

Given that YEC has indicated that it will not be taking any action to move the two plants in the near future, the Board considers that YEC has not sufficiently demonstrated the need for the study at this time and that the associated costs are reasonable. Accordingly, the Board directs YEC to remove any forecast expenditures and cost recovery related to the northern diesel plant location study. (**Paragraph 525**)

As directed, all costs for this study have been removed from rate base for the Compliance Filing.

#### **2.7.4.5 Whitehorse Hydro Uprate**

##### **Directive #68**

The Board considers YEC has not adequately quantified the expected benefits and costs of uprating the Whitehorse hydro units in order to justify an expense of this magnitude for an investigation. Accordingly, the Board denies YEC's proposed Whitehorse hydro uprate project and directs YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing. (**Paragraph 527**)

This project was forecast to remain in WIP during the test years. No costs are included in rate base for the test years in the Compliance Filing.

#### **2.7.4.6 Small Hydro**

##### **Directive #69**

The Board finds that YEC has not adequately quantified the benefits and costs of a small hydro project in order to justify an expense of this magnitude on the prefeasibility stage assessment. The Board is of the view that small hydro is better left to other entities such as independent power producers. Accordingly, the Board denies YEC's proposed small hydro project and directs YEC to remove any forecast expenditures and cost recoveries related to this project in its compliance filing. **(Paragraph 529)**

This project was forecast to remain in WIP during the test years. No costs are included in rate base for the test years in the Compliance Filing.

#### **2.7.4.7 Other**

The Board stated as follows regarding other deferred projects in paragraph 530 of Reasons for Decision:

YEC also proposed a number of other deferred projects between \$100,000 and \$1 million. The Board has reviewed the detailed line inspection, development of asset management program, forecasting model integration, asset appraisal, general rate application - 2017-2018 and Aishihik remediation work projects and finds that these projects are reasonable and the associated costs prudent. Accordingly, the Board approves these deferred projects as filed. **(Paragraph 530)**

The Compliance Filing includes in rate base for the test years costs as approved for the other deferred projects as referenced in paragraph 530 of the Reasons for Decision, with actual costs for 2017 as applicable.

## **2.8 POLICIES**

### **2.8.1 Planning Cost Accounting Policy (PCAP)**

In paragraph 540 of Reasons for Decision, the Board approved the PCAP submitted by YEC in its Application as Appendix 5-1.

### **2.8.2 New Vegetation Management Policy**

In paragraph 560 of Reasons for Decision, the Board approved the Vegetation Management Policy included in YEC's Application as Appendix 3.1, and agreed with YEC's position that this policy reflects the brushing and vegetation practices of YEC that are relevant to the testing of the prudence of the associated costs.

In paragraphs 558 and 559 of Reasons for Decision, the Board stated as follows:

The Board is satisfied that YEC conducted sufficient research into other jurisdictions and best practices and agrees that changes in brushing techniques and methodologies do not evolve rapidly enough to render the policy obsolete. **(Paragraph 558)**

The Board considers that it is always incumbent upon YEC to review and update where and when necessary any policy it adheres to in providing service to its customers and this fact alone addresses any concerns expressed by parties. YEC's Vegetation Management policy is not an exception to this concept. The Board expects that any necessary revisions to any policy under which YEC operates would be put forward in a future GRA. (**Paragraph 559**)

### **2.8.3 DSM Accounting Policy**

In paragraph 566 of Reasons for Decision, the Board finds that the proposed DSM accounting policy, as submitted in its revised form in the Application, has addressed the comments of the Board in Order 2013-01, and the Board approved the DSM accounting policy submitted by YEC in its Application as Appendix 5-2.

**Appendix 2.1:**  
**Diesel Contingency Fund (DCF)/**  
**Low Water Reserve Fund (LWRF)**



## **APPENDIX 2.1 - DIESEL CONTINGENCY FUND (DCF)/ LOW WATER RESERVE FUND (LWRF)**

### ***Board Directions***

Sections 4.9.2 and 4.9.3 of Appendix A of Order 2018-10 provide the Board's views and directions on the Diesel Contingency Fund (DCF) stabilization mechanism for rates and revenues. The DCF stabilizes thermal (e.g., diesel and LNG thermal) generation cost impacts caused by fluctuation of hydro or wind generation due to changes in water or wind conditions that are beyond the utility's control.

The Board reaffirms in paragraphs 318-319 of the Reasons for Decision that the risk of low water conditions and events (with respect to added costs for thermal generation) have been and should be borne by the customers of the utility, and finds "that a DCF-type of mechanism is required" for YEC. The Board finds (paragraph 320) that the existing DCF is complex and that a simpler mechanism is needed for adjusting for variances between approved forecast hydro and thermal generation and actual (rather than modelled) hydro and thermal generation in a test year.

The Board directs (paragraphs 321-322) that YEC create a deferral account named the Low Water Reserve Fund (LWRF) that "records the variance between actual thermal generation fuel costs (based on volume only) and the GRA forecast thermal generation fuel costs (based on volume only) that are due to changes in water conditions". Factors such as equipment failure, force majeure, capital or planned maintenance events are not to be considered in the calculations for this deferral account. YEC is to adjust the balance in the LWRF on an annual basis for the variance between actual and forecast thermal generation that is only due to changes in hydro generation that are a result of changes in water availability. YEC is directed, in its Compliance Filing, to explain the method it will use to determine the variance in hydro generation due to water availability.

The Board directs (see below, paragraph 323) that YEC amend the DCF term sheet to comply with these directions, including a requirement for Board approval of any drawdown of the LWRF and for any rider to replenish the LWRF. Separately, in paragraph 342 (Directive #33 addressing the ERA), the Board states that YEC can propose changes as to how the LWRF and the ERA operate if significant industrial load enters or leaves the Yukon Integrated System or there are material changes in generation assets where either or both of these change the baseload generation mix.

YEC is directed (see below, paragraphs 324-325) to transfer the balance in the DCF in its entirety to the LWRF, and to provide in its Compliance Filing further details on how the LWRF is to operate. The Board did not approve any change to the DCF cap of \$8 million.

### ***Response***

Attachment 2.1-1 provides an amended DCF Term Sheet (now called the LWRF Term Sheet) to comply with the Board's directions in Order 2018-10.

Consistent with the Board's directions in paragraph 323, the amended LWRF Term Sheet retains the general structure of the earlier Term Sheet and Fund procedures, including the following elements:

1. Inclusion of AEY Fish Lake hydro generation and well as YEC hydro generation, and maintaining a reference to wind generation even though there is presently no wind generation now operating or forecast in 2019 on the Yukon Integrated System (YIS);
2. Exclusion of thermal generation costs related to RFID, capital or thermal maintenance requirements;
3. The current +/- \$8 million cap for the Fund;
4. The existing mechanisms for reporting on the Fund and for Board approval of any rate rider to refund or charge ratepayers regarding the Fund; and
5. The new mechanism proposed in the 2017-18 GRA to provide that costs for YEC thermal generation savings (excess) are calculated so that YEC's final fiscal year expense for the total expected thermal generation (i.e., YEC expense after all transfers) is 90% LNG and 10% diesel as assumed in the GRA forecast, subject to the constraint that the LNG share of any transfer into or out of the LWRF cannot exceed 100%.

The change in the amended LWRF is to simplify, as directed, the method used to determine the variance in hydro generation due to water availability.

At year end the LWRF is adjusted for the variance between actual thermal generation (after removal of generation for RFID, capital, and maintenance) and GRA approved forecast thermal generation (excluding generation for capital and maintenance) that is due to changes in water conditions from what was assumed for the GRA forecast hydro generation.

YEC's Fund procedures as implemented with the DCF identify the variance at year end between the relevant actual and forecast thermal generation, and no change is proposed for these determinations.

- The LWRF Term Sheet example in Table 2.1-1 (Attachment 2.1-1) at row 3 shows this variance at +20.04 GW.h for 2018 actual YEC thermal generation (36.40 GW.h) relative to GRA compliance filing forecast (16.36 GW.h).

The DCF's complexities occur in separating out the share of this variance between actual and forecast thermal generation that is due to variance in actual versus GRA assumed water conditions. A key requirement in this regard is to separate thermal generation changes due to overall YIS load changes from thermal generation changes due to water condition changes.

As reviewed below, the LWRF Term Sheet includes a Fixed Change Factor to simplify the determination of LTA forecast thermal generation at actual YIS load for any fiscal year:

- The LWRF Term Sheet example in Table 2.1-1 at row 6 shows the YIS load variance at +26.74 GW.h for 2018 actual YIS generation load (447.00 GW.h) relative to GRA compliance filing forecast (420.27 GW.h).
- The LWRF Term Sheet example in Table 2.1-1 at row 8 provides an estimate of LTA thermal generation at actual YIS load of 28.46 GW.h, using the simplified method, i.e., the adjusted LTA thermal generation equals GRA forecast LTA thermal generation (16.38 GW.h) plus a Fixed Change Factor (45.3%) times the YIS variance (26.74 GW.h). The Fixed Change Factor estimates the LTA

thermal generation share of any change in YIS load from the GRA forecast YIS load (see Attachment 2.1-2 for review of how the Fixed Change Factor is determined for the 2018 GRA).

- The LWRF Term Sheet example in Table 2.1-1 at row 9 indicates that 7.94 GW.h of the variance in thermal generation is due to adverse changes in water conditions, equal to actual thermal generation (36.40 GW.h) less LTA thermal generation at actual YIS load (28.46 GW.h). At row 10, the resulting \$1.256 million payment from the LWRF to YEC is estimated.

The LWRF Term Sheet specifies that YEC will provide the Board, for review and approval, an update to the Fixed Change Factor when required in future to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

### ***2017-2018 Year End Deferral Account Reports***

The DCF fund amount was last approved for December 31, 2016. All funds in the DCF as at January 1, 2017 are transferred to the LWRF as at that date, as per the LWRF Term Sheet. As noted in the LWRF Term Sheet, no payments into or out of the LWRF occurred in 2017 other than interest and Rider E rebates (due to the Board Order 2018-10 direction that 2017 test year revenue requirement reflect actual grid loads and grid generation)<sup>6</sup>.

Appendix 2.2 provides the LWRF 2017 and 2018 Annual Report and the 2018 ERA Final Report.

The ERA portion of Rate Schedule 42 as approved in Board Order 2018-05, Appendix B has general provisions that continue to apply with the LWRF Term Sheet. No ERA is applicable in 2017 as there is no variance between forecast and actual results as regards wholesales and thermal generation costs. The ERA determinations in Appendix 2.2 for 2018 comply with the Board's determinations in Order 2018-10 regarding both the LWRF and the ERA.

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<sup>6</sup> The response to UCG-YEC-2-39 Revised – Attachment 1 provided the April 13, 2018 letter with the 2017 DCF Annual Report and the 2017 ERA Final Report. These reports assumed YEC GRA forecasts rather than actual generation for 2017 as directed in Order 2018-10, and therefore are now no longer valid for 2017.



**Attachment 2.1-1:  
LWRF Term Sheet: YEC Grid and AEY Fish Lake**



## **ATTACHMENT 2.1-1: LWRF TERM SHEET: YEC GRID & AEY FISH LAKE**

The DCF Term Sheet as approved in Appendix A to Board Order 2015-01 is hereby updated and revised in compliance with Board Order 2018-10, which directed that the LWRF replace the then existing Diesel Contingency Fund ("DCF"). The DCF fund amount was last approved for December 31, 2016. All funds in the DCF as at January 1, 2017 are transferred to the LWRF as at that date. Aside from interest and Rider E rebates, no payments into or out of the LWRF occurred in 2017 (due to the Board Order 2018-10 direction that 2017 test year revenue requirement reflect actual grid loads and grid generation).

### **PURPOSE & FUNCTION:**

The Low Water Reserve Fund ("LWRF") operates to smooth customer rate changes from thermal (diesel, LNG and other thermal) generation cost impacts caused by fluctuation of hydro or wind generation due to changes in water conditions or changes in wind conditions.<sup>7</sup> Thermal generation costs not related to changes in water or wind conditions 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 (LTA) water and wind availability as determined in accordance with this Term Sheet.<sup>8</sup>

### **LONG-TERM AVERAGE (LTA):**

The annual expected LTA thermal generation requirements for the 2018 GRA test year are determined based on LTA hydro and wind generation conditions<sup>9</sup> [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) and Table 2.1-4 in Attachment 2.1-2.<sup>10</sup>

At actual YIS firm load, LTA thermal generation (i.e., thermal generation assuming the same water conditions for hydro generation as approved for the GRA thermal forecast) equals the GRA expected LTA thermal generation plus a Fixed Change

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<sup>7</sup> Appendix A to Board Order 2015-01, section 2.1.1.4, page 11.

<sup>8</sup> 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."

<sup>9</sup> LTA hydro generation under any set of assumed grid generation load and grid generation capacity and licence conditions is determined in the 2017/2018 GRA based on the then-current YEC SIM power benefit model calculations based on 35 years of water record for the interconnected grid and updated reservoir and generation station water flow requirement changes as noted in Appendix 3.4 of the Application. As load grows a portion of the load growth is currently served (on average) by increased hydro output and the remainder by increased average thermal generation (diesel or LNG).

<sup>10</sup> Unless otherwise noted, AEY Fish Lake generation based on long-term average as approved by the Board Order 2014-06 at 8.73 GW.h and the last approved YEC wind generation (wind generation ceased to be available in 2017). The Fish Lake long-term average generation for 2012 and 2013 was at 4.38 GW.h due to unavailability of Unit #1. YEC's 2017/2018 GRA compliance filing assumes Fish Lake hydro long term average generation of 8.39 GW.h for 2018, based on information provided by AEY, and no wind generation capability.

Factor of 45.3% share of the change in YIS firm load (actual minus approved GRA forecast).<sup>11</sup> YEC will provide the Board, for review and approval, an update to the Fixed Change Factor when required in future to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits 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<sup>12</sup> and LTA thermal generation at the actual YIS load.

Table 2.1-1 provides an example year-end LWRF determination based on 2018 GRA forecasts and actual results (excluding AEY hydro generation for simplicity and assuming average approved thermal generation cost of 15.83 cents per kW.h).

Starting with YEC fiscal year 2018, costs for YEC thermal generation savings (excess) are calculated so that YEC's final fiscal year expense for the total expected thermal generation (i.e., YEC expense after all transfers) is 90% LNG and 10% diesel, subject to the constraint that the LNG share of any transfer into or out of the LWRF cannot exceed 100%. 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.<sup>13</sup> The LWRF example in Table 2.1-3 reflects these requirements based on fuel prices in the 2017/18 GRA.

Non-fuel O&M costs related to YEC thermal generation are not included in the LWRF calculations at this time. YEC will review and report on this at its next GRA.

**DIESEL ON THE MARGIN:**

The Board in Order 2015-01 noted that it does not consider diesel being "on the margin" part of the criteria for invoking the then existing DCF. Based on current loads, expected load growth and LTA hydro generation, the Board determined that there is a reasonable expectation that under these conditions that diesel or "thermal" generation will form part of baseload generation thus making the question of diesel being either "on the margin" or "off the margin" moot.

**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

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<sup>11</sup> See Attachment 2.1-2. The 45.3% is the average LTA thermal generation share of a +/- 5 GWh/yr change in the YIS firm load from the 2018 GRA forecast, based on the model used to forecast the GRA thermal generation related to the forecast YIS firm load.

<sup>12</sup> 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.

<sup>13</sup> YEC's 2017/2018 GRA 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 15.058 cents per kW.h).

material (drought) changes in hydro availability. This cap is retained for the LWRF in YEC's 2017/18 GRA compliance filing.

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

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 the 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 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 fiscal year end will only be placeholders; only the year end determinations will in fact have ongoing relevance for accounting and rate riders.

Examples of LWRF calculations for 5 years are provided in Tables 2.1-2 and 2.1-3 below.

**Table 2.1-1: Example LWRF Determination – 2018 Year End (excludes AEY hydro)**

	<b>Year end LWRF Deferral Account</b>
	<b>2018 GW.h</b>
<b>1 GRA Forecast LTA Thermal Generation</b>	16.36
<b>2 Actual Thermal Generation*</b>	36.40
<b>3 Change in Thermal Generation (2-1)</b>	20.04
<b>4 Forecast Load</b>	420.27
<b>5 Actual Load</b>	447.00
<b>6 Load Variance (5-4)</b>	26.74
<b>7 Fixed Change Factor (LTA thermal generation share of load variance at row 6)</b>	45.3%
<b>8 LTA Thermal Generation at Actual Load (7x6+1)</b>	28.46
<b>9 Thermal Generation Change due to Water Changes (2-8)**</b>	7.94
	Million \$
<b>10 LWRF payment to YEC (charge to YEC) for costs due to water changes (9x0.1583)***</b>	1.25622

\* 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.

\*\*\* Assumed for example average thermal generation cost of \$0.1583/kW.h.

**Table 2.1-2: LWRF Operation Example for 5 Forecast Years**

Assumed DCF cap (+/- \$8 million) - Assumes Year 1 GRA forecast load 420 GWh, Forecast LTA Thermal Generation at 14 GWh, and Fixed Charge Factor at 45%

Line	Activity	Year 1	Year 2	Year 3	Year 4	Year 5
A	LWRF Opening Balance <sup>1</sup> (\$000s)	\$8,000	\$8,000	\$8,000	\$8,000	\$1,902
B	Yukon Grid Generation <sup>2</sup>	423,730	433,730	445,500	455,600	469,730
C	AEY Fish Lake <sup>2</sup>	8,730	8,730	8,900	7,000	8,730
	YEC Grid Generation <sup>2</sup>					
D	Assumed actual YEC Hydro (MW.h)	409,000	421,000	433,500	378,600	356,000
E	Assumed actual YEC Thermal [net of capital, insurance, maintenance] (MW.h)	6,000	4,000	3,100	70,000	105,000
F	Assumed actual actual Wind (MW.h)	0	0	0	0	0
G=D+E+F	Total YEC Generation (MW.h)	415,000	425,000	436,600	448,600	461,000
H	Expected YEC Thermal Generation in Rates <sup>3</sup> (MW.h)	11,750	16,250	21,470	28,267	32,450
I=E-H	YEC Thermal Generation to be Included in LWRF (MW.h)	(5,750)	(12,250)	(18,370)	41,733	72,550
J=I*Fuel cost	Incremental Thermal Generation Cost to Charge <sup>4</sup> (Refund) LWRF(\$000s)	(\$843)	(\$1,797)	(\$2,933)	\$6,121	\$10,642
K=J	Total LWRF operation for YEC YEC pays to LWRF Fund YEC withdraws from LWRF Fund	\$843	\$1,797	\$2,933	(\$6,121)	(\$10,642)
L=A+K	LWRF Ending Balance (\$000s)	\$8,843	\$9,797	\$10,933	\$1,879	(\$8,740)
M	Interest on LWRF Balance <sup>5</sup> (\$000s)	\$111	\$122	\$137	\$23	(\$109)
N=L+M	LWRF Ending Balance <sup>6</sup> after Interest charge (\$000s)	\$8,954	\$9,919	\$11,070	\$1,902	(\$8,849)
O	Required Collections/(Refund) <sup>7</sup> (\$000s)	\$954	\$1,919	\$3,070	\$0	(\$849)
P=N-O	LWRF Ending Balance <sup>8</sup> after Required Collections/(Refund) (\$000s)	\$8,000	\$8,000	\$8,000	\$1,902	(\$8,000)

Notes:

- LWRF opening balance for Year 1 is a hypothetical amount.
- Assumed actual generation. Please see detailed calculations in Table 2.1-3.
- Expected YEC thermal generation is calculated based on LWRF Term Sheet for 2018 GRA. Please see detailed calculations in Table 2.1-3.
- LNG generation cost assumed at 14.66 cents/ kW.h and diesel generation cost assumed at 26.33 cents/kW.h (based on 2017/18 GRA average fuel costs).
- Per the March 11, 1996 letter recording the settlements [provided as Exhibit B-16 in the 2008/2009 GRA] the DCF fund (and now the LWRF) 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. For this example used 1.25% based on Government of Canada Bond Yields for 3-year and 5-year issues.
- Positive balances represent amounts to the benefit of ratepayers; negative balances are amounts owing to YEC.
- In any year when the balance in the LWRF falls outside of the approved cap range at fiscal year end, YEC shall apply to the Board for approval of a rate rider to dispense with the balance that is outside of that range within 60 days of the fiscal year end.
- Notional ending balance for illustration purposes only. Any excess amount of approved +/- LWRF cap balance range at fiscal year end would be dispensed within the next 12 months [April through March of following year], unless YUB approves a different period for a charge to mitigate adverse rate impacts.

**Table 2.1-3: LWRF Operation Examples for 5 Load Forecast Cases**

Line No			Notes
L1a	Diesel Fuel Cost per kW.h	26.333 cents/kW.h	
L1b	LNG Fuel Cost per kW.h	14.668 cents/kW.h	GRA Application Average Fuel cost (2017/18 GRA Application)
L1c	GRA YIS firm Load forecast	420,000 MW.h	
L1d	GRA LTA Thermal Generation forecast	14,000 MW.h	
L1e	GRA Fixed Change Factor	45% LTA thermal generation share of firm YIS load change	

**Calculation of Thermal Cost to Charge (Refund) LWRF**

**Year 1 - Actual Wind and Fish Lake at Forecast; Actual Thermal Generation Below LTA Expected**

Assumptions			
L2	YEC Grid load	415,000 MW.h	assumed actual
L3	Fish Lake	8,730 MW.h	assumed actual
L4=L2+L3	Total Grid load	423,730 MW.h	
Assumed Actual Generation Sources			
L5	AEY Fish Lake	8,730 MW.h	assumed actual
L6	YEC Hydro	409,000 MW.h	assumed actual
L7	YEC Thermal (net of capital, insurance and maintenance)	6,000 MW.h	assumed actual
L7a	YEC Diesel (net of capital, insurance and maintenance)	3,000 MW.h	assumed actual
L7b	YEC LNG (net of capital, insurance and maintenance)	3,000 MW.h	assumed actual
L8	YEC Wind	- MW.h	assumed actual
L9	Total Grid load	423,730 MW.h	
LTA Expected Generation Sources			
L10	AEY Fish Lake (expected)	8,730 MW.h	AEY Fish Lake long term average hydro generation based on YUB Order 2014-06.
L11	YEC Wind (expected)	- MW.h	YEC 2017/18 GRA Compliance Filing
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	415,000 MW.h	
L13=L1d	LTA GRA Thermal Generation Forecast	14,000 MW.h	
L14=(L2-L1c)xL1e	LTA Thermal change due to YIS load change	- 2,250 MW.h	
L15=L13+L14	Total Expected YEC Thermal Generation	11,750 MW.h	
L16=L15	Expected YEC Thermal Generation in Rates	11,750 MW.h	
	Diesel	3,000 MW.h	Expected thermal less expected LNG.
	LNG	8,750 MW.h	90% of expected thermal, subject to not exceeding expected thermal less actual diesel.
L17=L7	Actual YEC Net Thermal Generation	6,000 MW.h	assumed net actual
	Diesel	3,000 MW.h	
	LNG	3,000 MW.h	
L18=L17-L16	YEC Thermal Generation to be included in LWRF	- 5,750 MW.h	
L18a	YEC Diesel Generation to be included in LWRF	- MW.h	
L18b	YEC LNG Generation to be included in LWRF	- 5,750 MW.h	
L19=L1axL18a+L1bxL18b	Incremental YEC Thermal Generation Cost to Charge (Refund) LWRF (\$000s)	(\$843)	

**Year 2 - Actual Wind and Fish Lake at Forecast; Actual Thermal Generation Below Expected**

Assumptions			
L2	YEC Grid load	425,000 MW.h	assumed actual
L3	Fish Lake	8,730 MW.h	assumed actual
L4=L2+L3	Total Grid load	433,730 MW.h	
Assumed Actual Generation Sources			
L5	AEY Fish Lake	8,730 MW.h	assumed actual
L6	YEC Hydro	421,000 MW.h	assumed actual
L7	YEC Thermal (net of capital, insurance and maintenance)	4,000 MW.h	assumed actual
L7a	YEC Diesel (net of capital, insurance and maintenance)	3,000 MW.h	assumed actual
L7b	YEC LNG (net of capital, insurance and maintenance)	1,000 MW.h	assumed actual
L8	YEC Wind	- MW.h	assumed actual
L9	Total Grid load	433,730 MW.h	
Expected Generation Sources			
L10	AEY Fish Lake (expected)	8,730 MW.h	AEY Fish Lake long term average hydro generation based on YUB Order 2014-06.
L11	YEC Wind (expected)	- MW.h	YEC 2017/18 GRA Compliance Filing
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	425,000 MW.h	
L13=L1d	LTA GRA Thermal Generation Forecast	14,000 MW.h	
L14=(L2-L1c)xL1e	LTA Thermal change due to YIS load change	- 2,250 MW.h	
L15=L13+L14	Total Expected YEC Thermal Generation	16,250 MW.h	
L16=L15	Expected YEC Thermal Generation in Rates	16,250 MW.h	100% of long-term average
	Diesel	3,000 MW.h	Expected thermal less expected LNG.
	LNG	13,250 MW.h	90% of expected thermal, subject to not exceeding expected thermal less actual diesel.
L17=L7	Actual YEC Net Thermal Generation	4,000 MW.h	assumed net actual
	Diesel	3,000 MW.h	
	LNG	1,000 MW.h	
L18=L17-L16	YEC Thermal Generation to be included in LWRF	- 12,250 MW.h	
L18a	YEC Diesel Generation to be included in LWRF	- MW.h	
L18b	YEC LNG Generation to be included in LWRF	- 12,250 MW.h	
L19=L1axL18a+L1bxL18b	Incremental YEC Thermal Generation Cost to Charge (Refund) LWRF (\$000s)	(\$1,797)	

**Table 2.1-3: LWRF Operation Examples for 5 Load Forecast Cases (cont.)**

**Year 3 - Actual Wind and Fish Lake Higher than Forecast; Actual Thermal Generation Below Expected**

<i>Assumptions</i>			
L2	YEC Grid load	436,600 MW.h	assumed actual
L3	Fish Lake	8,900 MW.h	assumed actual
L4=L2+L3	Total Grid load	445,500 MW.h	
<b>Assumed Actual Generation Sources</b>			
L5	AEY Fish Lake	8,900 MW.h	assumed actual
L6	YEC Hydro	433,500 MW.h	assumed actual
L7	YEC Thermal (net of capital, insurance and maintenance)	3,100 MW.h	assumed actual
L7a	YEC Diesel (net of capital, insurance and maintenance)	100 MW.h	assumed actual
L7b	YEC LNG (net of capital, insurance and maintenance)	3,000 MW.h	assumed actual
L8	YEC Wind	- MW.h	assumed actual
L9	Total Grid load	445,500 MW.h	
<b>Expected Generation Sources</b>			
L10	AEY Fish Lake (expected)	8,730 MW.h	AEY Fish Lake long term average hydro generation based on YUB Order 2014-06.
L11	YEC Wind (expected)	- MW.h	YEC 2017/18 GRA Compliance Filing
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	436,770 MW.h	
L13=L1d	LTA GRA Thermal Generation Forecast	14,000 MW.h	
L14=(L2-L1c)xL1e	LTA Thermal change due to YIS load change	7,470 MW.h	
L15=L13+L14	Total Expected YEC Thermal Generation	21,470 MW.h	
L16=L15	Expected YEC Thermal Generation in Rates	21,470 MW.h	100% of long-term average
	Diesel	2,147 MW.h	Expected thermal less expected LNG.
	LNG	19,323 MW.h	90% of expected thermal, subject to not exceeding expected thermal less actual diesel.
L17=L7	Actual YEC Net Thermal Generation	3,100 MW.h	assumed net actual
	Diesel	100 MW.h	
	LNG	3,000 MW.h	
L18=L17-L16	YEC Thermal Generation to be included in LWRF	- 18,370 MW.h	
L18a	YEC Diesel Generation to be included in LWRF	- 2,047 MW.h	
L18b	YEC LNG Generation to be included in LWRF	- 16,323 MW.h	
L19=L1axL18a+L1bxL18b	Incremental YEC Thermal Generation Cost to Charge (Refund) LWRF (\$000s)	(\$2,933)	

**Year 4 - Actual Wind and Fish Lake below Forecast; Actual Thermal Generation Above Expected**

<i>Assumptions</i>			
L2	YEC Grid load	448,600 MW.h	assumed actual
L3	Fish Lake	7,000 MW.h	assumed actual
L4=L2+L3	Total Grid load	455,600 MW.h	
<b>Assumed Actual Generation Sources</b>			
L5	AEY Fish Lake	7,000 MW.h	assumed actual
L6	YEC Hydro	378,600 MW.h	assumed actual
L7	YEC Thermal (net of capital, insurance and maintenance)	70,000 MW.h	assumed actual
L7a	YEC Diesel (net of capital, insurance and maintenance)	20,000 MW.h	assumed actual
L7b	YEC LNG (net of capital, insurance and maintenance)	50,000 MW.h	assumed actual
L8	YEC Wind	- MW.h	assumed actual
L9	Total Grid load	455,600 MW.h	
<b>Expected Generation Sources</b>			
L10	AEY Fish Lake (expected)	8,730 MW.h	AEY Fish Lake long term average hydro generation based on YUB Order 2014-06.
L11	YEC Wind (expected)	- MW.h	YEC 2017/18 GRA Compliance Filing
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	446,870 MW.h	
L13=L1d	LTA GRA Thermal Generation Forecast	27,126 MW.h	
L14=(L2-L1c)xL1e	LTA Thermal change due to YIS load change	1,141 MW.h	
L15=L13+L14	Total Expected YEC Thermal Generation	28,267 MW.h	
L16=L15	Expected YEC Thermal Generation in Rates	28,267 MW.h	100% of long-term average
	Diesel	20,000 MW.h	Expected thermal less expected LNG.
	LNG	8,267 MW.h	90% of expected thermal, subject to not exceeding expected thermal less actual diesel.
L17=L7	Actual YEC Net Thermal Generation	70,000 MW.h	assumed net actual
	Diesel	20,000 MW.h	
	LNG	50,000 MW.h	
L18=L17-L16	YEC Thermal Generation to be included in LWRF	41,733 MW.h	
L18a	YEC Diesel Generation to be included in LWRF	- MW.h	
L18b	YEC LNG Generation to be included in LWRF	41,733 MW.h	
L19=L1axL18a+L1bxL18b	Incremental YEC Thermal Generation Cost to Charge (Refund) LWRF (\$000s)	\$6,121	

**Table 2.1-3: LWRF Operation Examples for 5 Load Forecast Cases (cont.)**

**Year 5 - Actual Wind and Fish Lake at Forecast; Actual Thermal Generation Above Expected**

Assumptions			
L2	YEC Grid load	461,000 MW.h	assumed actual
L3	Fish Lake	8,730 MW.h	assumed actual
L4=L2+L3	Total Grid load	469,730 MW.h	
Assumed Actual Generation Sources			
L5	AEY Fish Lake	8,730 MW.h	assumed actual
L6	YEC Hydro	356,000 MW.h	assumed actual
L7	YEC Thermal (net of capital, insurance and maintenance)	105,000 MW.h	assumed actual
L7a	YEC Diesel (net of capital, insurance and maintenance)	40,000 MW.h	assumed actual
L7b	YEC LNG (net of capital, insurance and maintenance)	65,000 MW.h	assumed actual
L8	YEC Wind	- MW.h	assumed actual
L9	Total Grid load	469,730 MW.h	
Expected Generation Sources			
L10	AEY Fish Lake (expected)	8,730 MW.h	AEY Fish Lake long term average hydro generation based on YUB Order 2014-06.
L11	YEC Wind (expected)	- MW.h	YEC 2017/18 GRA Compliance Filing
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	461,000 MW.h	
L13=L1d	LTA GRA Thermal Generation Forecast	14,000 MW.h	
L14=(L2-L1c)xL1e	LTA Thermal change due to YIS load change	18,450 MW.h	
L15=L13+L14	Total Expected YEC Thermal Generation	32,450 MW.h	
L16=L15	Expected YEC Thermal Generation in Rates	32,450 MW.h	100% of long-term average
	Diesel	40,000 MW.h	Expected thermal less expected LNG.
	LNG	- 7,550 MW.h	90% of expected thermal, subject to not exceeding expected thermal less actual diesel.
L17=L7	Actual YEC Net Thermal Generation	105,000 MW.h	assumed net actual
	Diesel	40,000 MW.h	
	LNG	65,000 MW.h	
L18=L17-L16	YEC Thermal Generation to be included in LWRF	72,550 MW.h	
L18a	YEC Diesel Generation to be included in LWRF	- MW.h	
L18b	YEC LNG Generation to be included in LWRF	72,550 MW.h	
L19=L1axL18a+L1bxL18b	Incremental YEC Thermal Generation Cost to Charge (Refund) LWRF (\$000s)	\$10,642	

**Attachment 2.1-2:  
Determination of Fixed Change Factor for 2018 GRA**



## ATTACHMENT 2.1-2: DETERMINATION OF FIXED CHANGE FACTOR FOR 2018 GRA

The Board in Order 2018-10 has determined in Section 4.1 of Appendix A (paragraph 77) that it will not use for this proceeding the short-term (ST) forecast for forecasting levels of hydro-electric generation and thermal generation nor direct its use for future GRAs. In the current compliance filing, YEC has therefore continued to use the long-term average (LTA) forecast for forecasting levels of hydro-electric generation and thermal generation for 2018 (the Board directed use of actual generation for 2017). The LWRF must therefore determine the impact on thermal generation of changes in 2018 (and future year) water conditions from the LTA water conditions assumed in the 2018 test year.

A copy of Table 3.4-1 in the Application is attached. This table was used in the Application to determine LTA hydro and thermal generation at different annual firm YIS loads, including the 2018 GRA filing forecast thermal generation.

Footnote #3 in Undertaking #36 Revised noted as follows regarding the updated Minto load forecast requiring an update to the LTA forecast:

“LTA was assessed [for the update in the Undertaking] using the Exhibit B-1 Table 3.4-1, without re-running YECSIM to adjust this table to reflect the major change in annual load shape.<sup>14</sup>”

....

“In reality, the reduction in 2018 revenue requirement would likely be smaller than indicated in the attached table when the DCF table is updated as required for the material change in annual load shape<sup>15</sup>, i.e., the LTA thermal generation will be higher than assumed in Update 2018 due to the higher-than-GRA forecast loads in the early winter months (which months drive annual thermal LTA) and the much lower-than-GRA forecast loads for the last six months.”[Undertaking #36 Revised, July 23, 2018]

Table 2.1-4 as attached provides the Compliance Filing LTA hydro and thermal generation based on the same YECSIM water years and grid conditions as Table 3.4-1 in the Application, adjusted to reflect the major change in forecast seasonal shape of the Minto industrial load, i.e., the adjusted Minto load forecast for 2018 falls sharply at about mid-year for the balance of the year (versus being reasonably flat throughout the year in the Application forecast). The 2018 Compliance Filing forecast thermal generation based on Table 2.1-4 is 16.36 GW.h at the forecast firm load of 420.27 GW.h.<sup>16</sup>

Based on the LTA hydro generation conditions assumed for the GRA compliance filing forecast (e.g., LTA water conditions, YIS hydro and wind generation capability, and the overall seasonal shape of the YIS load), Table 2.1-4 also shows the change in forecast LTA thermal generation associated with 5 GW.h changes in annual YIS load from the 420.27 GW.h 2018 compliance filing forecast. In order to simplify the LWRF determinations of forecast LTA thermal generation at each year end based on actual YIS loads and

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<sup>14</sup> The DCF Term Sheet (Attachment 3.4-1 of Exhibit B-1) requires at page 3.4-14 that YEC will provide the Board, for review and approval, an update to Table 3.4-1 when required in future to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/ permits or other factors. The updated load forecast for 2018 materially changes the annual load shape from that assumed for Table 3.4-1, with higher industrial loads in the first few winter months and very low industrial loads for the last six months.

<sup>15</sup> That is, the significant reduction in load to serve Minto.

<sup>16</sup> No wind generation is forecast in the 2018 test year compliance filing.

GRA forecast water conditions, this table is used as follows to determine a Fixed Change Factor for LTA thermal generation specific to the 2018 GRA load forecast:

- A 5 GW.h increase in load to 425.27 GW.h results in LTA thermal generation of 18.73 GW.h based on this table, indicating a LTA thermal generation increase of 2.38 GW.h/year (or 47.6% of the change in load).
- A 5 GW.h decrease in load to 415.27 GW.h results in LTA thermal generation of 14.20 GW.h based on this table, indicating a LTA thermal generation decrease of 2.15 GW.h/year (or 43.0% of the change in load).
- Overall, the same absolute +/- change in load from the 420.27 GW.h forecast results in LTA thermal changes equal on average to 45.3% of the change in load (i.e., the average of the above 47.6% and 43.0% shares of the +5 and -5 GW.h changes in YIS load).
- This 45.3% average percentage LTA thermal share of firm load change is specific to the GRA forecast firm load, and is proposed as the **Fixed Change Factor** in the LWRF Term Sheet for the 2018 GRA.

**Table 3.4-1 from YEC 2017-18 GRA**

Line Number	YEC Grid Load Net of Wind (GWh)	YEC Hydro Generation (GWh)	YEC Thermal Generation (GWh)	Increase in		Thermal as % of Increased Load
				Load (GWh)	Thermal Generation (GWh)	
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	370.0	369.337	0.663			
2	375.0	373.626	1.374	5.0	0.710	14%
3	380.0	377.800	2.200	5.0	0.826	17%
4	385.0	381.845	3.155	5.0	0.955	19%
5	390.0	385.750	4.250	5.0	1.096	22%
6	395.0	389.503	5.497	5.0	1.246	25%
7	400.0	393.098	6.902	5.0	1.405	28%
8	405.0	396.528	8.472	5.0	1.570	31%
9	410.0	399.789	10.211	5.0	1.739	35%
10	415.0	402.877	12.123	5.0	1.911	38%
11	420.0	405.793	14.207	5.0	2.084	42%
12	425.0	408.537	16.463	5.0	2.256	45%
13	430.0	411.111	18.889	5.0	2.426	49%
14	435.0	413.521	21.479	5.0	2.590	52%
15	440.0	415.772	24.228	5.0	2.748	55%
16	445.0	417.874	27.126	5.0	2.898	58%
17	450.0	419.836	30.164	5.0	3.038	61%
18	455.0	421.669	33.331	5.0	3.167	63%
19	460.0	423.388	36.612	5.0	3.281	66%
20	465.0	425.007	39.993	5.0	3.380	68%
21	470.0	426.545	43.455	5.0	3.462	69%
22	475.0	428.019	46.981	5.0	3.525	71%
23	480.0	429.452	50.548	5.0	3.567	71%
24	485.0	430.865	54.135	5.0	3.587	72%

Notes:

- "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected Fish Lake hydro generation.
- The thermal generation and increase for the added load are based on a polynomial equation derived from "YEC SIM" - the simulation model developed for the Integrated Grid by KGS Group.
- 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 YEC SIM.
- 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.
- 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.
- This table assumes max load at 485 GW.h and minimum load at 370 GW.h. If the load exceeds these limits then the table needs to be updated.
- Numbers are subject to rounding.

**Example**

**Expected YEC Thermal Generation for the YEC generation at 417 GW.h (net of expected (GRA) Wind)**

- Step 1. Find the closest load from Column A that is less than 417 GW.h = 415 GW.h (Line 10).
- Step 2. Find the thermal generation from Column C = 12.123 GW.h (Line 10).
- Step 3. Find the difference between the given load (417 GW.h) and load from Step 1 (415 GW.h) = 2 GW.h
- Step 4. Apply the percentage from Column F (Line 11, 42%) to the difference from Step 3 (2 GW.h) = 0.840 GW.h
- Step 5. Add numbers from Step 2 (12.123 GW.h) and Step 4 (0.840 GW.h) = 12.963 GW.h

The expected thermal generation at 417 GW.h load is 12.963 GW.h.

Notes:

The load assumed the maximum load at 485 GW.h and the minimum load at 370 GW.h.

**Table 2.1-4: 2018 Expected LTA Generation with Minto Load Shape Change**

Line Number	YEC Grid Load Net of Wind (GWh)	YEC Hydro Generation (GWh)	YEC Thermal Generation (GWh)	Increase in		Thermal as % of Increased Load
				Load (GWh)	Thermal Generation (GWh)	
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	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:

- "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected Fish Lake hydro generation.
- The thermal generation and increase for the added load are based on a polynomial equation derived from "YEC SIM" - the simulation model developed for the Integrated Grid by KGS Group.
- 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 YEC SIM.
- 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.
- 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.
- 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.
- Numbers are subject to rounding.

**Example**

**Expected YEC Diesel Generation for the YEC generation at 417 GW.h (net of expected (GRA) Wind)**

- Step 1. Find the closest load from Column A that is less than 417 GW.h = 415 GW.h (Line 4).
- Step 2. Find the diesel generation from Column C = 14.091 GW.h (Line 4).
- Step 3. Find the difference between the given load (417 GW.h) and load from Step 1 (415 GW.h) = 2 GW.h
- Step 4. Apply the percentage from Column F (Line 5, 43%) to the difference from Step 3 (2 GW.h) = 0.860 GW.h
- Step 5. Add numbers from Step 2 (14.091 GW.h) and Step 4 (0.860 GW.h) = 14.951 GW.h

The expected diesel generation at 417 GW.h load is 14.951 GW.h.

**APPENDIX 2.2: LWRF 2017 AND 2018  
ANNUAL REPORTS & ERA 2017 AND 2018 FILING**



February 25, 2019

Mr. Robert Laking, Chair  
Yukon Utilities Board  
Box 31728  
Whitehorse, Yukon Y1A 6L3

Dear Mr. Laking:

**Re: Low Water Reserve Fund (“LWRF”) 2017 and 2018 Annual Reports, and 2017 and 2018 Energy Reconciliation Adjustment (“ERA”) Filing**

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Pursuant to Yukon Utilities Board (“YUB” or the “Board”) direction in Board Order 2018-10 and Yukon Energy’s 2017/18 General Rate Application (“GRA”) Compliance Filing, this correspondence is providing Yukon Energy Corporation’s (“Yukon Energy” or “YEC”) Annual Reports summarizing LWRF and ERA activities up to December 31, 2017 based on actual results, and up to December 31, 2018 based on preliminary actuals, and includes the following information:

- **Attachment 1** - LWRF Calculations for 2017 and 2018 and Balance Updates.
- **Attachment 2** - Updated Rider E Rate Schedule (at \$0.00c/kWh rebate effective April 1, 2019).
- **Attachment 3** - 2017 and 2018 ERA Filing.

Yukon Energy is not able to provide an update on Water Forecast Conditions for 2019 until later in March, after it reviews snowpack data that is received at the start of March. Yukon Energy will file this update with the Board as soon as it is available.

The Board in Order 2018-10 in relation to Yukon Energy’s 2017/18 GRA directed (Appendix A, paragraphs 321-322) that YEC create a deferral account, the Low Water Reserve Fund (LWRF), that “records the variance between actual thermal generation fuel costs (based on volume only) and the GRA forecast thermal generation fuel costs (based on volume only) that are due to changes in water conditions”. The Board also directed (paragraph 323) that YEC amend the Diesel Contingency Fund (“DCF”) term sheet to comply with the above directions, including a requirement for Board approval of any

drawdown of the LWRF and for any rider to replenish the LWRF; and to transfer the balance in the DCF in its entirety to the LWRF (paragraphs 324-325).

To comply with the Board Order 2018-10:

- YEC in its 2017/18 GRA Compliance Filing included an amended DCF term sheet [Appendix 2.1, Attachment 2.1-1 to the Compliance Filing], which is now called LWRF.
- The DCF fund amount was last approved for December 31, 2016. All funds in the DCF as of January 1, 2017 are transferred to the LWRF effective that date, as per the LWRF Term Sheet. The opening balance of LWRF for 2017 starts with 2016 DCF closing balance as reviewed in the tables below.
- Due to the Board Order 2018-10 direction that 2017 test year revenue requirement reflect actual grid loads, grid generation and fuel costs no payments into or out of the LWRF occurred in 2017 other than interest and Rider E rebates. Based on Board direction in order 2018-10, the 2017 DCF Annual Report and the 2017 ERA Final Report provided to the Board on April 13, 2018, as revised in response to UCG-YEC-2-39 Revised – Attachment 1, are now no longer valid for 2017.<sup>1</sup>

A summary of each of the above documents follows.

### **LWRF Calculations and Balance as of December 31, 2017 and preliminary results for December 31, 2018**

Attachment 1, Table 1 provides LWRF calculations and balance for 2017 actuals and 2018 preliminary actuals, and Table 2 provides a LWRF Continuity Schedule. Rider E is proposed to set to 0.00 cents/kW.h effective April 1, 2019 due to LWRF balance expected to be within +/- \$8 million, therefore no Rider E calculation is provided in this filing.

In summary, the tables in Attachment 1 indicate as follows regarding the annual LWRF calculations and balance for 2017 and preliminary results for 2018:

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<sup>1</sup> YEC notes that 2017 DCF Annual report provided on April 13, 2018 as revised in UCG-YEC-2-39 Revised Attachment 1 [YEC's 2017/18 GRA] erroneously showed 2017 opening balance at \$5.770 million. The accurate opening balance is \$9.485 million as provided in Table 2 of 2016 DCF Annual report [filed with the Board on April 5, 2017], which provided final balances for 2012, 2013 and 2014 consistent with the Board's approval of these balances in Section 2.4 of Appendix A to Board Order 2015-06.

- 2017 actuals:
  - Due to the Board Order 2018-10 direction that 2017 test year revenue requirement reflect actual grid loads, grid generation and fuel costs, no payments into or out of the LWRF occurred in 2017 other than interest and Rider E rebates.
- 2018 preliminary actuals:
  - Based on preliminary actual annual load for 2018 and the proposed LWRF Term Sheet in the 2017/18 GRA Compliance Filing, the "expected" thermal requirement for 2018 is 29.864 GW.h with 23.679 GW.h LNG (Table 1, L15)<sup>2</sup>.
  - Actual annual thermal generation requirement for 2018 (net of LNG and diesel charged to capital, RFID and maintenance) was 35.958 GW.h, including 6.186 GW.h diesel and 29.772 GW.h LNG.
  - The resulting overall gap between expected and actual thermal generation for 2018 equals 6.093 GW.h, all of which is assumed to be LNG generation per 2017/18 GRA determinations and the LWRF Term Sheet. The resulting payment required from LWRF to YEC for 2018 is \$0.894 million.<sup>3</sup>
- LWRF balances:
  - 2017
    - Based on YUB 2018-10 direction, the DCF balance at December 31 2016 is transferred to the LWRF [\$9.485 million as provided in Table 2 of 2016 DCF Annual report filed with the Board on April 5, 2017].
    - No incremental thermal generation charges into or out of the LWRF [revenue requirement for the 2017 test year is based on actuals].
    - Less Rider E rebates for 2017 at \$2.861 million.
    - Add interest charged to the balance at \$0.086 million.
    - Closing balance of \$6.710 million.
  - 2018

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<sup>2</sup> In this Compliance Filing, LNG is assumed to displace 90% of the 2018 expected long-term average thermal requirements, subject to not exceeding total expected thermal less actual net diesel generation (excluding RFID, capital and maintenance).

<sup>3</sup> Based on 2017/18 GRA average fuel costs at \$0.1467 per kW.h for LNG as approved by YUB in Order 2018-10.

- Opening balance of \$6.710 million.
- Incremental thermal generation charge at \$0.894 million [YEC withdraws from LWRF, as per Attachment 1 Table 1].
- Less Rider E rebates for 2018 at \$2.874 million.
- Add interest charged to the balance at \$0.076 million.
- Closing balance of \$3.019 million.
- Jan-April of 2019
  - The forecast Rider E rebates for January 1 through March 31 of 2019 at \$0.847 million resulting in forecast balance of \$2.172 million at April 1, 2019.

### **Updated Rider E**

In Order 2015-06, the Board directed that YEC refund DCF contributions in excess of the \$8.0 million cap through a rate rider applicable to all firm sales throughout the Yukon (Rider E). Based on the 2015 Annual filing, the Board's letter of April 6, 2016 reinstated the earlier DCF rebate at 0.68 cents/kWh on an interim basis, effective May 1, 2016. This refund rider continues to be in effect.

On April 13 2018, as part of the 2017 DCF Annual report, YEC requested that Rider E be set to \$0.00/kWh to reflect the forecast DCF balance being less than the \$8 million cap. The Board directed at that time to defer issues related to 2017 and the DCF pending resolution of YEC's 2017-18 GRA.

On January 28, 2019 sent a letter to the Board noting the DCF balance being below the \$8 million cap and cessation of the Rider E rebates was urgently required prior to finalization of the 2017-18 GRA compliance filing of YEC. YEC also noted that the current refund Rider E continues to reduce the Fund balance on average by approximately \$0.3 million each month, and respectfully requested direction to set the Rider E to \$0.00/kWh effective March 1, 2019.

Table 2 of Attachment 1 shows that LWRF balance forecast to be at \$2.172 million by April 1, 2019 which is well below the \$8.0 million cap. Based on this forecast, no Rider E rebate is appropriate and the Rider E refund to ratepayers is therefore proposed at 0.00 cents/kW.h for implementation effective April 1, 2019.

### **2017 and 2018 ERA Filing**

Attachment 3, Table 1 in this filing provides the 2017 actual and 2018 preliminary actual ERA Filing:

- 2017 actuals:
  - No ERA is applicable for 2017 due to Order 2018-10 direction that 2017 test year revenue requirement reflect actual grid loads, grid generation and fuel costs.
- 2018 preliminary actuals:
  - Based on preliminary actuals, 2018 wholesales over GRA forecast results in added YEC costs of \$1.169 million and added YEC revenues from increase in wholesale of \$1.844 million. As a result, the change in revenues exceeds the change in costs, and no ERA amount is payable to YEC.

If you have any questions regarding the above please contact the undersigned.

Yours truly,

A handwritten signature in black ink, appearing to read "Ed Mollard".

Ed Mollard, CPA, CGA  
Chief Financial Officer  
Yukon Energy Corporation

# ATTACHMENT 1: LWRP CALCULATIONS AND BALANCE UPDATES FOR 2017 AND 2018

## Table 1: LWRP Calculations for 2017 and 2018

Line No		2017	2018		Notes
L1a	Diesel Fuel Cost per kW.h	26.333	26.333	cents/kW.h	GRA Application Average Fuel cost (2017/18 GRA Application)
L1b	LNG Fuel Cost per kW.h	14.668	14.668	cents/kW.h	
L1c	GRA YIS firm Load forecast	446,458	420,265	MW.h	
L1d	GRA LTA Thermal Generation forecast	13,261	16,355	MW.h	
L1e	GRA Fixed Change Factor	45.3%	45.3%	LTA thermal generation share of firm YIS load change	
<b>Calculation of Thermal Cost to Charge (Refund) LWRP</b>					
<i>Assumptions</i>					
L2	YEC Grid load	446,458	450,086	MW.h	Actual
L3	Fish Lake	7,103	5,458	MW.h	Actual
L4=L2+L3	Total Grid load	453,561	455,544	MW.h	
<i>Assumed Actual Generation Sources</i>					
L5	YECL Fish Lake	7,103	5,458	MW.h	Actual
L6	YEC Hydro	431,951	412,768	MW.h	assumed actual (L2-L7-L8)
L7	YEC Thermal	14,474	37,319	MW.h	Actual
	Diesel	4,618	7,189	MW.h	Actual
	LNG	9,856	30,130	MW.h	Actual
L7a	YEC Diesel/LNG charged to capital, RFID and maintenance	1,213	1,361	MW.h	Actual
	Diesel	995	1,003	MW.h	Actual
	LNG	218	358	MW.h	Actual
L7b=L7-L7a	YEC Net Diesel/LNG	13,261	35,958	MW.h	Actual
	Diesel	3,623	6,186	MW.h	Actual
	LNG	9,638	29,772	MW.h	Actual
L8	YEC Wind	33	-	MW.h	Actual
L9	Total Grid load	453,561	455,544	MW.h	
<i>LTA Expected Generation Sources</i>					
L10	YECL Fish Lake (expected)	8,536	8,391	MW.h	Based on YEC forecast in 2017/18 GRA [2017 is based on AEY 2016/17 GRA Compliance Filing].
L11	YEC Wind (expected)	33	-	MW.h	Adjusted to reflect actual facility change
L12=L9-L10-L11	YEC Grid load net of expected Fish Lake and Wind	444,992	447,153	MW.h	
L13=L1d	LTA GRA Thermal Generation Forecast	13,261	16,355	MW.h	
L14=(L2-L1c)xL1e	LTA Thermal change due to YIS load change	-	13,509	MW.h	GRA Fixed Change Factor times change from forecast.
L15=L13+L14	Total Expected YEC Thermal Generation	13,261	29,864	MW.h	
L16=L15	Expected YEC Thermal Generation in Rates	13,261	29,864	MW.h	
	Diesel	3,623	6,186	MW.h	Expected thermal less expected LNG.
	LNG	9,639	23,679	MW.h	90% of expected thermal, subject to not exceeding expected thermal less actual diesel.
L17=L7	Actual YEC Net Thermal Generation	13,261	35,958	MW.h	Net of capital, RFIS and maintenance thermal (L7b)
	Diesel	3,623	6,186	MW.h	
	LNG	9,638	29,772	MW.h	
L18=L17-L16	YEC Thermal Generation to be included in LWRP	-	0	6,093	MW.h
	YEC Diesel Generation to be included in LWRP	-	-	-	MW.h
	YEC LNG Generation to be included in LWRP	-	0	6,093	MW.h
L19=L1axL.18a+L1bxL.18b	Incremental YEC Thermal Generation Cost to Charge (Refund) LWRP (\$000s)	(\$0)	\$894		

**Table 2: LWRF Continuity Schedule**

Line	Activity	2017 (\$000s)	2018 (\$000s)
A	Opening Balance <sup>1</sup>	\$9,485	\$6,710
B	Incremental Diesel Generation Cost to Charge/(Refund) <sup>2</sup> to LWRF	(\$0)	\$894
C=B	Total LWRF operation for YEC		
	YEC pays to LWRF	\$0	\$0
	YEC withdraws from LWRF	\$0	(\$894)
D=A+C	LWRF Balance after Annual Operation	\$9,485	\$5,816
E	Interest on LWRF Balance <sup>3</sup>	\$86	\$76
F=D+E	LWRF Balance after Interest charge	\$9,571	\$5,893
G	Rider E (Rebate)/Collections [January - December]	(\$2,861)	(\$2,874)
H=F+G	LWRF Ending Balance	\$6,710	\$3,019
I	LWRF (Rebate)/Collections January - March 31, 2019 (forecast)		(\$847)
J=H+I	Forecast LWRF Balance, After (Rebate)/Collections to March 31		\$2,172
K	LWRF Cap <sup>4</sup>		+/-8000
L=J-K	LWRF Rebate/(Collections) Required		\$0

Notes:

1. Opening Balance is based on 2016 DCF ending balance as provided in DCF 2016 Annual Filing.

2. Based on calculations in Table 1.

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 based on LWRF Term Sheet, YEC 2017-18 GRA Compliance Filing, Appendix 2.1, Attachment 2.1-1.

## ATTACHMENT 2: UPDATED RIDER E RATE SCHEDULE

Page 1 of 1

Effective: 2019 04 01  
Supercedes: 2016 05 01

### RIDER E

#### LOW WATER RESERVE FUND RIDER

- AVAILABLE:** To all retail and major industrial electric services throughout the Yukon Territory.
- APPLICABLE:** To all retail and major industrial classes of service [not applicable to secondary sales].
- RATE:** Service will be rendered at the applicable rates with the following surcharge/(refund):  
  
A rate of 0.00 ¢ per kW.h will be applied to all firm kWh consumed.
- NOTE:** Rider E will be applied to all firm kWh consumed for the period from April 1, 2019 to March 31, 2020.  
  
Rider E does not apply to Rate Schedule 32 Secondary Energy.

## ATTACHMENT 3: 2017 and 2018 ERA FILING

**Table 1: ERA Determination for 2017 and 2018**

	2017	2018	
			preliminary
<b>A Wholesales Variance for AEY (MW.h)</b>			
Actual wholesales	328,426	332,270	A1
GRA approved wholesales assuming Fish Lake LTA generation	328,426	314,700	A2 [See note 1]
Fish Lake generation adjustment (expected LTA less actual)	0	2,933	A3 [See note 2]
<b>Change in wholesales for ERA</b>	<b>0</b>	<b>14,637</b>	A4=A1-A2-A3
<b>B YEC Cost Impact per kW.h change in Wholesales</b>			
Losses (%)	8.06%	9.34%	B1 [Actuals]
Total YEC's actual generation net of secondary (MWh)	446,493	450,086	B2 [See note 2]
GRA approved firm load forecast (MWh)	446,493	420,265	B3 [See note 1]
YEC incremental generation relative to GRA approved (MW.h)	0	29,821	B4=B2-B3
YEC's actual LTA Thermal Generation (MWh)	13,261	35,958	B5 [See note 2]
GRA LTA Thermal Generation (MWh)	13,261	16,355	B6 [See note 1]
YEC Incremental thermal generation relative to GRA approved (MWh)	0	19,602	B7=B5-B6
Incremental thermal generation for incremental total generation (%)	45.30%	45.30%	B8 [See note 2]
Thermal Generation cost per GRA (\$/kW.h)	0.1818	0.1613	B9 [See note 2]
<b>YEC thermal cost change (\$/kWh wholesales)</b>	<b>0.0890</b>	<b>0.0799</b>	B10=B9*B8*(1+B1)
<b>C YEC Revenue Impact per kW.h change in Wholesales</b>			
<b>Rate Schedule 42 Energy Charge (\$/kW.h wholesales)</b>	<b>0.08298</b>	<b>0.08298</b>	C1
<b>Average YEC rider applicable to AEY retails (\$/kWh wholesales)</b>	<b>0.01975</b>	<b>0.02636</b>	C2 [See note 3]
<b>D Net thermal cost impact on YEC (\$000)</b>			
Wholesale Change: Cost Impact (YEC thermal generation costs)	0	1,169	D1=A4*B10
Wholesale Change: Revenue Impact (YEC revenues)	0	1,844	D2=A4*(C1+C2)+A3*C1
Cost change>revenue change ("Yes"=1, "No"=0)	1	0	D3=is D1>D2 (absolute)
<b>ERA Charge (rebate) to AEY [Net added cost (cost saving) for YEC]</b>	<b>0</b>	<b>0</b>	D4=D3*(D1-D2)

**Notes:**

- 2017 is based on actuals as per YUB Order 2018-10; 2018 forecast as directed by YUB in Order 2018-10 [both subject to 2017/18 GRA Compliance Filing approval].
- Please see LWRF calculations in Table 1 for actual thermal generation numbers and incremental thermal generation percentages.
- YEC Rider J revenues include actual Rider J [pre-2017/18 GRA] plus increase in Rider J based on YEC's 2017/18 GRA Compliance Filing. Average Rider is estimated total Rider J revenues [including 2017/18 GRA increase] from AEY retail customers divided by wholesales net of Fish Lake adjustments.



### **3.0 TAB 7 REVISED SCHEDULES**

The revised schedules from Tab 7 of the Application are attached with adjustments as required by Order 2018-10 and the attached Reasons for Decision. In addition the following supporting appendices are provided:

- Appendix 3.1 provides Tab 7 schedules with the explanation for adjustments to the 2017 test year; and
- Appendix 3.2 provides Tab 7 schedules the explanation for adjustments to the 2018 test year.

Explanations of the adjustments are provided in Section 1.1 and Section 2 of this Compliance Filing.



# Yukon Energy Corporation 2017/18 GRA Compliance Filing

February 25, 2019

## Schedule Index

1	Computation of Rate Base
2	Computation of Allowance for Working Capital
2A	Effect of GST on Working Capital
3	Continuity Schedule of Property, Plant and Equipment
4A	Cost of Capital Calculation - 2013 - 2015 Actuals
4B	Cost of Capital Calculation - 2016 Actual and 2017 Actual and Forecast
4C	Cost of Capital Calculation - 2018 Forecast
5	Utility Revenue Requirement
6	Statement of Earnings
7	Statement of Retained Earnings
8	Reconciliation of Utility Income to Net Earnings
9	Summary of Customers, Energy Sales and Revenues
10	Summary of Operating and Maintenance Expenses
11	Summary of Cost of Long - Term Debt



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Computation of Rate Base**  
**(\$000s)**

Schedule 1  
February 25, 2019

Line No.	Description	Cross Ref.	2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Proposed 2017	Forecast Proposed 2018
<b>1</b>	<b>Property, Plant and Equipment</b>								
2	Year end balance	S.3 L.5	520,651	520,406	555,552	577,888	589,387	598,756	612,435
	Deduct:								
3	Accumulated depreciation (note 1)	S.3 L.10	120,694	119,279	125,757	134,978	144,703	155,162	167,191
4	Construction-in-progress	S.3 L.11	19,798	24,137	53,893	13,362	18,467	4,776	7,620
5	Disallowed assets	S.3 L.12	691	691	691	691	691	2,746	2,746
6	Miscellaneous reserves	S.3 L.13	5,904	5,684	5,452	5,223	4,169	3,719	3,669
7	Total deductions		147,087	149,792	185,794	154,254	168,030	166,403	181,227
	Add:								
8	Deferred study costs (note 2)	S.3 L.15	27,891	24,106	24,615	21,957	27,212	29,038	41,695
9	Less: Studies in Progress	S.3 L.16	(14,742)	(13,618)	(16,773)	(19,070)	(24,728)	(14,964)	(29,498)
10	Other deferred costs	S.3 L.17	-	-	-	-	-	-	-
11	Accum. Disallowed depreciation	S.3 L.18	119	119	135	151	167	349	553
12	Total additions		13,267	10,607	7,977	3,038	2,651	14,423	12,751
	<b>Net plant in Service</b>								
13	Current year-end balance	S.3 L.20	386,831	381,221	377,735	426,672	424,009	446,776	443,958
14	Previous year-end balance		387,051	383,931	381,221	377,735	426,672	424,009	446,776
15	Total		773,882	765,152	758,956	804,407	850,681	870,784	890,734
16	Mid-year balance		386,941	382,576	379,478	402,204	425,340	435,392	445,367
18	Mid-year regulatory deferral		1,486	1,693	1,367	2,007	2,061	3,034	3,879
19	Working capital	S.2 L.8	4,280	4,520	4,495	4,791	4,928	5,290	5,344
20	<b>Gross Rate Base</b>		392,707	388,789	385,340	409,002	432,329	443,717	454,590
	Deduct:								
	<b>Contributions for extensions</b>								
21	Current year-end balance		191,243	180,582	181,163	200,167	200,500	200,832	201,232
22	Contributions in WIP		10,500	174	262	605	167	21	-
23	Current year-end balance in-service		180,743	180,408	180,901	199,561	200,332	200,811	201,232
24	Accumulated amortization of contributions		16,305	16,390	20,002	23,626	27,729	31,844	35,976
25	Net current year-end balance in-service		164,438	164,018	160,899	175,935	172,604	168,967	165,256
26	Previous year-end balance		167,607	167,445	164,018	160,899	175,935	172,604	168,967
27	Total		332,046	331,463	324,917	336,834	348,539	341,571	334,223
28	Mid-year balance		166,023	165,732	162,459	168,417	174,269	170,785	167,112
29	<b>Net Rate Base</b>	S.5 L.1	226,684	223,058	222,882	240,584	258,060	272,931	287,478

Note 1: Including Reserve for Future Removal and Site Restoration

Note 2: Planning and Study costs, Relicensing, Dam Safety costs and Vegetation Management. Net of contributions.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Computation of Allowance for Working Capital**  
(\$000s)

Schedule 2  
February 25, 2019

Line No.	Description	Cross Ref.	2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Proposed 2017	Forecast
									Proposed 2018
1	Operating and maintenance	S.5 L.5	20,844	22,786	21,052	21,723	21,812	23,836	23,715
2	Taxes other than income	S.5 L.6	326	331	331	473	686	693	708
3	Non-allowable expenses		(85)	(84)	(85)	(86)	(95)	(96)	(100)
4	Cash operating expenses		21,085	23,033	21,298	22,110	22,403	24,433	24,323
5	27/365		1,560	1,704	1,575	1,636	1,657	1,807	1,799
6	Inventory (three year average)		2,830	2,948	3,026	3,300	3,426	3,665	3,703
7	GST Impact on working capital	S.2A L.11	(110)	(131)	(106)	(145)	(155)	(182)	(158)
8	Working capital	S.1 L.19	4,280	4,520	4,495	4,791	4,928	5,290	5,344

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Effect of GST on Working Capital**  
**(\$000s)**

Schedule 2A  
 February 25, 2019

Line No.	Description	Cross Ref.							<u>Forecast</u>
			2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Proposed 2017	Proposed 2018
1	Expenses subject to GST		39,395	33,079	47,770	29,427	26,210	28,301	42,084
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		1,970	1,654	2,388	1,471	1,310	1,415	2,104
4	Day Factor		14	14	14	14	14	14	14
5	Recoverable portion of GST impact		76	63	92	56	50	54	81
6	Revenue subject to GST		42,263	40,492	41,245	41,855	42,686	49,202	49,794
7	GST blended rate (2009 GRA)		4.58%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
8	GST payable		1,935	2,025	2,062	2,093	2,134	2,460	2,490
9	Day factor		35	35	35	35	35	35	35
10	Payable portion of GST impact		186	194	198	201	205	236	239
11	Net impact of GST on working capital	S.2 L.7	(110)	(131)	(106)	(145)	(155)	(182)	(158)

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Continuity Schedule of Property, Plant and Equipment**  
**(\$000s)**

Schedule 3  
February 25, 2019

Line No.	Description	Cross Ref.							<u>Forecast</u>
			2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Proposed 2017	Proposed 2018
1	<b>Property, Plant and Equipment</b>								
2	Balance at beginning of year		496,938	495,795	520,406	555,552	577,888	589,387	598,756
3	Net Increases to PPE (Table 5.1)		23,713	25,717	37,583	22,728	12,314	9,798	13,678
4	Retirements, disposals and adjustments		-	(1,106)	(2,437)	(392)	(815)	(429)	-
5	Balance at end of year	S.1 L.2	520,651	520,406	555,552	577,888	589,387	598,756	612,435
6	<b>Accumulated depreciation (including Future Removal Reserve)</b>								
7	Balance at beginning of year		111,706	111,476	119,279	125,757	134,978	144,703	155,162
8	Depreciation expense	S.6 L.7	8,989	8,854	8,906	9,524	10,607	12,268	12,031
9	Retirements, disposals and adjustments		-	(1,051)	(2,428)	(303)	(882)	(1,808)	(2)
10	Balance at end of year		120,694	119,279	125,757	134,978	144,703	155,162	167,191
	Deduct:								
11	Construction-in-progress	S.1 L.4	19,798	24,137	53,893	13,362	18,467	4,776	7,620
12	Disallowed assets	S.1 L.5	691	691	691	691	691	2,746	2,746
13	Miscellaneous reserves (note 1)	S.1 L.6	5,904	5,684	5,452	5,223	4,169	3,719	3,669
14	Total		26,393	30,513	60,037	19,276	23,328	11,242	14,036
	Add:								
15	Deferred study costs (note 2)	S.1 L.8	27,891	24,106	24,615	21,957	27,212	29,038	41,695
16	Less: Studies in Progress	S.1 L.9	(14,742)	(13,618)	(16,773)	(19,070)	(24,728)	(14,964)	(29,498)
17	Other deferred costs	S.1 L.10	-	-	-	-	-	-	-
18	Accum. Disallowed depreciation	S.1 L.11	119	119	135	151	167	349	553
19	Total		13,267	10,607	7,977	3,038	2,651	14,423	12,751
20	Net Property, Plant and Equipment	S.1 L.13	386,831	381,221	377,735	426,672	424,009	446,776	443,958

Note 1: Includes Fire Insurance Reserve and the Reserve for Injuries and Damages

Note 2: Planning and Study costs, Relicensing, Dam Safety costs and Deferred Overhauls. Net of contributions.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Cost of Capital Calculation**  
**2013 Approved and 2013-2015 Actual**  
**(\$000s)**

Schedule 4A  
February 25, 2019

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
<b>2013 Approved</b>							
1	Long-Term debt	S.11 L.18	137,410	60.0%	136,010	3.58%	4,867
2	Common Stock	S.7 L. 8	91,607	40.0%	90,674	8.25%	7,481
3	Total	S.5 L.3	229,017	100.0%	226,684	5.45%	12,348
<b>2013 Actual</b>							
4	Long-Term debt	S.11 L.18	133,482	60.0%	133,925	3.38%	4,522
5	Common Stock	S.7 L. 8	88,837	40.0%	89,132	7.42%	6,617
6	Total	S.5 L.3	222,319	100.0%	223,058	4.99%	11,138
<b>2014 Actual</b>							
7	Long-Term debt	S.11 L.18	133,636	59.0%	131,486	3.22%	4,228
8	Common Stock	S.7 L. 8	92,891	41.0%	91,396	8.44%	7,710
9	Total	S.5 L.3	226,527	100.0%	222,882	5.36%	11,938
<b>2015 Actual</b>							
10	Long-Term debt	S.11 L.18	141,509	59.0%	141,951	2.00%	2,840
11	Common Stock	S.7 L. 8	98,327	41.0%	98,634	8.10%	7,989
12	Total	S.5 L.3	239,837	100.0%	240,584	4.50%	10,829

**Yukon Energy Corporation**  
**Cost of Capital Calculation**  
**2016 Actual and 2017 Actual and Forecast (Existing / GRA)**  
**(\$000s)**

Schedule 4B  
February 25, 2019

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
<b>2016 Actual</b>							
1	Long-Term debt	S.11 L.18	152,363	59.8%	154,412	2.10%	3,239
2	Common Stock	S.7 L. 8	102,272	40.2%	103,648	8.69%	9,002
3	Total	S.5 L.3	254,636	100.0%	258,060	4.74%	12,242
<b>Proposed 2017</b>							
4	Long-Term debt	S.11 L.18	163,803	59.9%	163,452	2.40%	3,917
5	Common Stock	S.7 L. 8	109,714	40.1%	109,479	8.70%	9,525
6	Total	S.5 L.3	273,517	100.0%	272,931	4.93%	13,442
<b>Proposed 2018</b>							
10	Long-Term debt	S.11 L.18	172,472	60.0%	172,485	2.23%	3,844
11	Common Stock	S.7 L. 8	114,985	40.0%	114,994	8.70%	10,006
12	Total	S.5 L.3	287,457	100.0%	287,478	4.82%	13,850

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Utility Revenue Requirement**  
(\$000s)

Schedule 5  
February 25, 2019

<b>Line No.</b>	<b>Description</b>	<b>Cross Ref.</b>	<b>2013 Approved</b>	<b>Actual 2013</b>	<b>Actual 2014</b>	<b>Actual 2015</b>	<b>Actual 2016</b>	<b>Proposed 2017</b>	<b>Forecast Proposed 2018</b>
1	Net rate base	S.1 L.30	226,684	223,058	222,882	240,584	258,060	272,931	287,478
2	Average Rate of return on rate base		5.45%	4.99%	5.36%	4.50%	4.74%	4.93%	4.82%
3	Utility income	S.8 L.1	12,348	11,138	11,938	10,829	12,242	13,442	13,850
4	Utility expenses								
5	Operating and maintenance (note 1)	S.6 L.3	20,844	22,786	21,052	21,723	21,812	23,836	23,715
6	Taxes other than income	S.6 L.4	326	331	331	473	686	693	708
7	Amortization of deferred costs	S.6 L.5	3,462	4,561	2,846	2,764	1,581	4,507	5,063
8	Reserve for Injuries and Damages	S.6 L.6	226	226	226	226	226	479	479
9	Depreciation	S.6 L.7	8,989	8,894	8,906	9,828	10,615	12,323	12,196
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(3,831)	(3,939)	(3,953)	(3,886)	(4,364)	(5,801)	(5,914)
11	Disallowed depreciation		(16)	(16)	(16)	(16)	(16)	(182)	(204)
12	Donations		(85)	(84)	(85)	(86)	(95)	(96)	(100)
13	Total utility expenses		<u>29,915</u>	<u>32,759</u>	<u>29,307</u>	<u>31,026</u>	<u>30,445</u>	<u>35,760</u>	<u>35,943</u>
14	Revenue Requirement	S.6 L.1	<u>42,263</u>	<u>43,897</u>	<u>41,245</u>	<u>41,855</u>	<u>42,686</u>	<u>49,202</u>	<u>49,794</u>

Note 1: Includes fuel expenses and purchased power.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Statement of Earnings**  
(\$000s)

Schedule 6  
February 25, 2019

Line No.	Description	Cross Ref.								<b>Forecast</b>
			2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Proposed 2017	Proposed 2018	
1	Revenues (note 1)	S.5 L.14	42,263	43,897	41,245	41,855	42,686	49,202	49,794	
2	<b>Operating expenses</b>									
3	Operating and maintenance	S.10 L.15	20,844	22,786	21,052	21,723	21,812	23,836	23,715	
4	Taxes other than income	S.5 L.6	326	331	331	473	686	693	708	
5	Amortize deferred costs	S.5 L.7	3,462	4,561	2,846	2,764	1,581	4,507	5,063	
6	Reserve for Injuries and Damages	S.5 L.8	226	226	226	226	226	479	479	
7	Depreciation	S.3 L.8	8,989	8,894	8,906	9,828	10,615	12,323	12,196	
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(3,831)	(3,939)	(3,953)	(3,886)	(4,364)	(5,801)	(5,914)	
9	Total		<u>30,016</u>	<u>32,859</u>	<u>29,408</u>	<u>31,129</u>	<u>30,556</u>	<u>36,037</u>	<u>36,247</u>	
10	<b>Operating income</b>		12,247	11,038	11,837	10,727	12,130	13,165	13,546	
11	<b>Other income</b>									
12	Allowed for Funds Used	S.8 L.2	500	927	1,188	714	819	466	542	
13	Miscellaneous (note 2)	S.8 L.3	(23)	(492)	(86)	(98)	(1,592)	(285)	(515)	
14	Total		<u>477</u>	<u>435</u>	<u>1,102</u>	<u>616</u>	<u>(772)</u>	<u>181</u>	<u>28</u>	
15	<b>Other expenses</b>									
16	Interest expense	S.8 L.4	4,917	4,128	5,225	3,662	3,356	3,880	4,431	
17	Total		<u>4,917</u>	<u>4,128</u>	<u>5,225</u>	<u>3,662</u>	<u>3,356</u>	<u>3,880</u>	<u>4,431</u>	
18	<b>Net earnings</b>	S.8 L.8	<u>7,807</u>	<u>7,345</u>	<u>7,713</u>	<u>7,681</u>	<u>8,001</u>	<u>9,466</u>	<u>9,142</u>	

Note 1: Includes revenues from sales and other revenues.

Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Statement of Retained Earnings**  
**(\$000s)**

Schedule 7  
February 25, 2019

<b>Line No.</b>	<b>Description</b>	<b>Cross Ref.</b>	<b>2013 Approved</b>	<b>Actual 2013</b>	<b>Actual 2014</b>	<b>Actual 2015</b>	<b>Actual 2016</b>	<b>Proposed 2017</b>	<b>Forecast Proposed 2018</b>
1	Balance at beginning of year		37,270	35,040	35,434	43,147	46,307	51,037	60,755
	Add:								
2	Net earnings	S.6 L.18	7,807	7,345	7,713	7,681	8,001	9,466	9,142
3	IFRS Comprehensive Income Adjustment		-	-	-	(4,521)	(430)	252	1,660
4	Balance at end of year before dividend		45,076	42,385	43,147	46,307	53,878	60,755	71,557
	Less:								
5	Common Dividends/(Injection) (note 1)		6,332	6,951	-	-	2,841	-	10,414
6	Balance at end of year		38,744	35,434	43,147	46,307	51,037	60,755	61,143
	<b>Shareholder's Equity</b>								
7	Common shares		53,600	53,600	53,600	53,600	53,600	54,036	54,036
8	Retained earnings		38,744	35,434	43,147	46,307	51,037	60,755	61,143
9	Total		92,344	89,034	96,747	99,907	104,637	114,791	115,179

Note:

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

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Reconciliation of Utility Income to Net Earnings**  
**(\$000s)**

Schedule 8  
February 25, 2019

<b>Line No.</b>	<b>Description</b>	<b>Cross Ref.</b>	<b>2013 Approved</b>	<b>Actual 2013</b>	<b>Actual 2014</b>	<b>Actual 2015</b>	<b>Actual 2016</b>	<b>Proposed 2017</b>	<b>Forecast Proposed 2018</b>
1	Utility Income (Return on Rate Base)	S.5 L.3	12,348	11,138	11,938	10,829	12,242	13,442	13,850
	Add:								
2	Allowance for funds used	S.6 L.12	500	927	1,188	714	819	466	542
3	Other income (expenses)	S.6 L.13	(23)	(492)	(86)	(98)	(1,592)	(285)	(515)
			<u>12,825</u>	<u>11,573</u>	<u>13,040</u>	<u>11,445</u>	<u>11,469</u>	<u>13,623</u>	<u>13,878</u>
	Less:								
4	Interest - long-term	S.6 L.17	4,917	4,128	5,225	3,662	3,356	3,880	4,431
5	Donations	S.5 L.12	85	84	85	86	95	96	100
6	Disallowed costs	S.5 L.13	-	-	-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	16	16	16	16	16	182	204
			<u>5,019</u>	<u>4,229</u>	<u>5,327</u>	<u>3,765</u>	<u>3,468</u>	<u>4,157</u>	<u>4,735</u>
8	Net earnings	S.6 L.18	7,807	7,344	7,713	7,681	8,002	9,466	9,143



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Summary of Customers, Energy Sales and Revenues**  
(\$000s)

Schedule 9  
February 25, 2019

Line No.	Description	2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Proposed 2017	Proposed 2018
1	<b>Residential</b>							
2	Customers	1,536	1,559	1,561	1,588	1,609	1,653	1,635
3	Sales in MWh	12,408	13,385	13,327	13,121	13,390	14,965	13,719
4	MWh sales per customer	8	8.6	8.5	8.3	8.3	9.1	8.4
5	Revenue (\$000s)	1,815	1,943	1,938	1,913	1,956	2,203	2,016
6	Cents per KWh	14.6	14.5	14.5	14.6	14.6	14.7	14.7
7	<b>General Service</b>							
8	Customers	467	470	475	480	488	499	489
9	Sales in MWh	22,620	22,283	23,616	24,551	24,994	26,132	25,436
10	MWh sales per customer	48	47.4	49.8	51.1	51.2	52.4	52.0
11	Revenue (\$000s)	3,735	3,621	3,894	4,048	4,180	4,350	4,054
12	Cents per KWh	16.5	16.3	16.5	16.5	16.7	16.6	15.9
13	<b>Industrial</b>							
14	Sales in MWh	40,592	40,513	36,302	37,186	41,169	43,419	32,193
15	Revenue (\$000s)	4,787	4,595	3,958	4,159	4,478	4,829	3,952
16	Cents per KWh	11.8	11.3	10.9	11.2	10.9	11.1	12.3
17	<b>Street lights</b>							
18	Sales in MWh	279	281	290	290	256	228	214
19	Revenue (\$000s)	88	89	92	92	88	88	56
20	Cents per KWh	31.6	31.6	31.6	31.6	34.5	38.6	26.0
21	<b>Space lights</b>							
22	Sales in MWh	15	14	14	14	14	12	12
23	Revenue (\$000s)	4	4	4	4	4	3	3
24	Cents per KWh	26.8	26.5	26.6	25.9	26.0	28.6	22.5
25	<b>Total Company - Firm Retail and Industrial</b>							
26	Customers	2,003	2,029	2,036	2,068	2,098	2,152	2,125
27	Sales in MWh	75,913	76,476	73,549	75,162	79,823	84,756	71,573
28	Revenue (\$000s)	10,429	10,252	9,886	10,214	10,705	11,474	10,081
29	Cents per KWh	13.7	13.4	13.4	13.6	13.4	13.5	14.1
30	<b>Wholesale sales</b>							
31	Sales in MWh	307,147	307,927	295,284	297,961	301,207	328,426	314,700
32	Revenue (\$000s)	25,487	25,546	24,503	24,725	24,994	27,253	26,114
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3	8.3	8.3
34	<b>Total Company - Firm</b>							
35	Sales in MWh	383,061	384,403	368,833	373,122	381,030	413,182	386,273
36	Revenue (\$000s)	35,916	35,798	34,388	34,939	35,700	38,727	36,194
37	Cents per KWh	9.4	9.3	9.3	9.4	9.4	9.4	9.4
38	<b>Secondary</b>							
39	Sales in MWh	0	3,959	5,415	7,030	4,835	8,385	2,059
40	Revenue (\$000s)	0	275	410	544	371	470	115
41	Cents per KWh		6.9	7.6	7.7	7.7	5.6	5.6
42	<b>Total Company</b>							
43	Sales in MWh	383,061	388,363	374,248	380,152	385,865	421,567	388,332
44	Revenue (\$000s)	35,916	36,073	34,798	35,483	36,071	39,196	36,310
45	Cents per KWh	9.4	9.3	9.3	9.3	9.3	9.3	9.4
46	Rider J		6,288	6,167	6,172	6,342	6,952	6,469
47	Post-GRA Reconcil Req'd							
48	GRA Increase Req'd	6,163					2,734	6,762
49	<b>Total Sales of Power</b>	<b>42,079</b>	<b>42,360</b>	<b>40,966</b>	<b>41,655</b>	<b>42,413</b>	<b>48,883</b>	<b>49,541</b>
50	Other Revenues	184	1,537	280	200	273	319	253
51	<b>Total Revenues</b>	<b>42,263</b>	<b>43,897</b>	<b>41,246</b>	<b>41,855</b>	<b>42,686</b>	<b>49,202</b>	<b>49,794</b>



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Summary of Operating and Maintenance Expenses**  
(\$000s)

Schedule 10  
February 25, 2019

Line No.	Description	Cross Ref.							<u>Forecast</u>
			2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Proposed 2017	Proposed 2018
1	<b>Utility operations</b>								
2	Production		4,494	5,310	5,588	5,472	6,039	6,366	5,930
3	Transmission and distribution		2,112	2,960	2,565	2,530	2,450	3,535	3,445
4	General		1,405	1,485	1,735	1,749	1,522	1,772	1,615
5	Administration and general		8,654	8,080	8,495	8,101	8,509	8,575	8,917
6	Insurance		895	990	1,017	1,030	1,037	1,032	1,031
7	Sub-total		<u>17,559</u>	<u>18,824</u>	<u>19,400</u>	<u>18,881</u>	<u>19,557</u>	<u>21,280</u>	<u>20,938</u>
8	Donations		85	84	85	86	95	96	100
9	Sub-total		<u>85</u>	<u>84</u>	<u>85</u>	<u>86</u>	<u>95</u>	<u>96</u>	<u>100</u>
10	O&M not including fuel and								
11	purchased power		<u>17,644</u>	<u>18,908</u>	<u>19,485</u>	<u>18,967</u>	<u>19,653</u>	<u>21,376</u>	<u>21,038</u>
12	Fuel		3,160	3,848	1,528	2,720	2,114	2,411	2,638
13	Purchased power		40	30	41	36	45	49	39
14	Sub-total		<u>3,200</u>	<u>3,878</u>	<u>1,569</u>	<u>2,756</u>	<u>2,159</u>	<u>2,460</u>	<u>2,677</u>
15	Total operating and maintenance	S.6 L.3	<u>20,844</u>	<u>22,786</u>	<u>21,054</u>	<u>21,723</u>	<u>21,812</u>	<u>23,836</u>	<u>23,715</u>
	<b>Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:</b>								
16	Reserve for Injuries and Damages		226	226	226	226	226	479	479
17	Property Taxes		326	331	331	473	686	693	708
18	less: Donations		<u>-85</u>	<u>-84</u>	<u>-85</u>	<u>-86</u>	<u>-95</u>	<u>-96</u>	<u>-100</u>
19	O&M per Table 3.3 (Tab 3)		<u>18,111</u>	<u>19,381</u>	<u>19,957</u>	<u>19,580</u>	<u>20,470</u>	<u>22,452</u>	<u>22,125</u>



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Summary of Cost of Long - Term Debt**  
**(\$000s)**

Schedule 11  
 February 25, 2019

Line No.	Description	Cross Ref.	2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Proposed 2017	Forecast Proposed 2018
<b>General Purpose Long-Term Debt Balance</b>									
1	TD Canada Trust (4.02%)		2,945	2,946	1,912	837	0	0	0
2	YDC \$81.9M Loan (4.25%)		72,891	72,891	69,891	0	0	0	0
3	YDC Mayo B Flexible Term Debt		21,226	21,226	20,889	20,552	20,215	19,878	19,542
4	TD Bank Swap (2.69%)		15,900	10,687	10,366	10,036	9,697	9,348	8,991
5	YDC \$17.1M Debt (3.69%)		17,780	15,727	15,044	0	0	0	0
6	YDC \$2.1M Debt (3.97%)			2,053	2,053	0	0	0	0
7	YDC \$5.5M Debt (4.27%)		7,774	5,471	5,471	0	0	0	0
8	Minto Decommissioning Reserve			2,553	2,586	2,613	2,636	2,660	2,684
9	YDC \$5.5M Debt (2.40%)				5,505	5,505	5,505	5,505	5,505
10	YDC \$92.5M Debt (2.40%)					88,775	85,091	81,407	77,723
11	YDC \$21.0M Debt (2.21%)					20,984	20,145	19,306	18,466
12	YDC \$12.1M Debt (2.10%)						12,136	12,136	12,136
13	New 2017 Debt (2.15%)							21,940	21,940
14	New 2018 Debt								5,776
15	Current year-end balance		138,516	133,555	133,717	149,302	155,425	172,181	172,763
16	Previous year-end balance		136,304	133,409	133,555	133,717	149,302	155,425	172,181
17	Mid Year		137,410	133,482	133,636	141,509	152,363	163,803	172,472
<b>Interest Costs</b>									
18	TD Canada Trust (4.02%)		140	140	99	57	14	0	0
19	YDC \$81.9M Loan (4.25%)		3,225	3,225	3,098	0	0	0	0
20	YDC Mayo B Flexible Term Debt		212	130	-112	128	167	770	334
21	TD Bank Swap (2.69%)		687	292	284	275	266	257	247
22	YDC \$17.1M Debt (3.69%)		653	606	580	0	0	0	0
23	YDC \$2.1M Debt (3.97%)			82	82	0	0	0	0
24	YDC \$5.5M Debt (4.27%)				234	0	0	0	0
25	Minto Decommissioning Reserve			31	33	26	23	24	24
26	YDC \$5.5M Debt (2.40%)					132	132	132	132
27	YDC \$92.5M Debt (2.40%)					2,213	2,131	2,042	1,954
28	YDC \$21.0M Debt (2.21%)						464	445	427
29	YDC \$12.1M Debt (2.10%)							255	255
30	New 2017 Debt (2.15%)								472
31	New 2018 Debt								
32	<b>Total Cost of Interest</b>		4,917	4,507	4,297	2,831	3,196	3,925	3,844
33	Mid-Year Cost of Debt		3.58%	3.38%	3.22%	2.00%	2.10%	2.40%	2.23%



**Appendix 3.1:**  
**Summary of Adjustments to Tab 7 Schedules for 2017**



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Computation of Rate Base**  
**(\$000s)**

Schedule 1  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017			Explanation
			Original Filing	Adjustment	Compliance Filing	
<b>1</b>	<b>Property, Plant and Equipment</b>					
2	Year end balance	S.3 L.5	603,879	(5,123)	598,756	2017 actuals update. Impact of disallowed assets [see Appendix 1.1, Tables 1.1-2 and 1.1-3].
	Deduct:					
3	Accumulated depreciation (note 1)	S.3 L.10	156,806	(1,644)	155,162	2017 actuals update.
4	Construction-in-progress	S.3 L.11	4,358	418	4,776	2017 actuals update.
5	Disallowed assets	S.3 L.12	691	2,055	2,746	Impact of disallowed assets [see Appendix 1.1, Tables 1.1-2 and 1.1-3].
6	Miscellaneous reserves	S.3 L.13	4,119	(399)	3,719	2017 actuals update.
7	Total deductions		<u>165,974</u>	<u>429</u>	<u>166,403</u>	
	Add:					
8	Deferred study costs (note 2)	S.3 L.15	29,346	(309)	29,038	2017 actuals update.
9	Less: Studies in Progress	S.3 L.16	(16,167)	1,203	(14,964)	2017 actuals update.
10	Other deferred costs	S.3 L.17	-	-	-	
11	Accum. Disallowed depreciation	S.3 L.18	184	165	349	2017 actuals update.
12	Total additions		<u>13,363</u>	<u>1,060</u>	<u>14,423</u>	
	<b>Net plant in Service</b>					
13	Current year-end balance	S.3 L.20	451,268	(4,492)	446,776	2017 actuals update.
14	Previous year-end balance		424,009	-	424,009	
15	Total		<u>875,276</u>	<u>(4,492)</u>	<u>870,784</u>	
16	Mid-year balance		437,638	(2,246)	435,392	2017 actuals update.
18	Mid-year rate case expense		2,447	587	3,034	2017 actuals update.
19	Working capital	S.2 L.8	5,200	90	5,290	2017 actuals update.
20	<b>Gross Rate Base</b>		445,285	(1,569)	443,717	2017 actuals update.
	Deduct:					
	<b>Contributions for extensions</b>					
21	Current year-end balance		200,900	(68)	200,832	2017 actuals update.
22	Contributions in WIP		-	21	21	2017 actuals update.
23	Current year-end balance in-service		200,900	(89)	200,811	
24	Accumulated amortization of contributions		31,851	(7)	31,844	2017 actuals update.
25	Net current year-end balance in-service		<u>169,049</u>	<u>(81)</u>	<u>168,967</u>	
26	Previous year-end balance		<u>172,604</u>	-	<u>172,604</u>	
27	Total		<u>341,652</u>	<u>(81)</u>	<u>341,571</u>	
28	Mid-year balance		<u>170,826</u>	<u>(41)</u>	<u>170,785</u>	
29	<b>Net Rate Base</b>	S.5 L.1	<u>274,459</u>	<u>(1,528)</u>	<u>272,931</u>	Impact of above changes.

Note 1: Including Reserve for Future Removal and Site Restoration

Note 2: Planning and Study costs, Relicensing, Dam Safety costs and Deferred Overhauls. Net of contributions.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Computation of Allowance for Working Capital**  
(\$000s)

Schedule 2  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Operating and maintenance	S.5 L.5	23,363	473	23,836	2017 actuals update.
2	Taxes other than income	S.5 L.6	696	(3)	693	2017 actuals update.
3	Non-allowable expenses		(96)	0	(96)	
4	Cash operating expenses		23,962	471	24,433	Impact of above changes.
5	27/365 in 2009 GRA		1,773	35	1,807	Impact of above changes.
6	Inventory (three year average)		3,603	62	3,665	2017 actuals update.
7	GST Impact on working capital	S.2A L.11	(176)	(6)	(182)	Impact of above changes.
8	Working capital	S.1 L.19	5,200	90	5,290	Impact of above changes.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Effect of GST on Working Capital**  
**(\$000s)**

Schedule 2A  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Expenses subject to GST		29,575	(1,273)	28,301	2017 actuals update.
2	GST Rate		5%	0%	5%	
3	GST Recoverable		1,479	(64)	1,415	Impact of above changes.
4	Day Factor		14	-	14	
5	Recoverable portion of GST impact		57	(3)	54	Impact of above changes.
6	Revenue subject to GST		48,544	658	49,202	2017 actuals update.
7	GST blended rate (2009 GRA)		5%	0%	5%	
8	GST payable		2,427	33	2,460	Impact of above changes.
9	Day factor		35	-	35	
10	Payable portion of GST impact		233	3	236	Impact of above changes.
11	Net impact of GST on working capital	S.2 L.7	(176)	(6)	(182)	Impact of above changes.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Continuity Schedule of Property, Plant and Equipment**  
(\$000s)

Schedule 3  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017		Compliance Filing	Explanation
			Original Filing	Adjustment		
1	<b>Property, Plant and Equipment</b>					
2	Balance at beginning of year		589,387	-	589,387	
3	Net Increases to PPE		14,492	(4,694)	9,798	2017 actuals update.
4	Retirements, disposals and adjustments (note 1)		-		(429)	2017 actuals update.
5	Balance at end of year	S.1 L.2	603,879	(5,123)	598,756	2017 actuals update. Impact of disallowed assets [see Appendix 1.1, Tables 1.1-2 and 1.1-3].
6	<b>Accumulated depreciation (including Future Removal Reserve)</b>					
7	Balance at beginning of year		144,703	-	144,703	
8	Depreciation expense	S.6 L.7	12,105	162	12,268	2017 actuals update.
9	Retirements, disposals and adjustments (note 1)		(2)		(1,808)	
10	Balance at end of year		156,806	(1,644)	155,162	
	Deduct:					
11	Construction-in-progress	S.1 L.4	4,358	418	4,776	2017 actuals update.
12	Disallowed assets	S.1 L.5	691	2,055	2,746	Impact of disallowed assets [see Appendix 1.1, Tables 1.1-2 and 1.1-3].
13	Miscellaneous reserves (note 2)	S.1 L.6	4,119	(399)	3,719	
14	Total		9,168		11,242	
	Add:					
15	Deferred study costs (note 3)	S.1 L.8	29,346	(309)	29,038	2017 actuals update.
16	Less: Studies in Progress	S.1 L.9	(16,167)	1,203	(14,964)	2017 actuals update.
17	Other deferred costs	S.1 L.10	-	-	-	
18	Accum. Disallowed depreciation	S.1 L.11	184	165	349	2017 actuals update.
19	Total		13,363	1,060	14,423	
20	Net Property, Plant and Equipment	S.1 L.13	451,268	(4,492)	446,776	Impact of above changes.

Note 1: Largely relate to retirements and disposals, as well as charges against the Reserve for Future Removal and Restoration.

Note 2: Includes Fire Insurance Reserve, Deferred Dewatering Revenues and the Reserve for Injuries and Damages.

Note 3: Planning and Study costs, Relicencing, Dam Safety costs and Deferred Overhauls. Net of contributions.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Cost of Capital Calculation**

Schedule 4  
February 25, 2019 Filing

(\$000s)

<b>Line No.</b>	<b>Description</b>	<b>Cross Ref.</b>	<b>Mid Year Balance</b>	<b>Ratio</b>	<b>Mid Year Rate Base</b>	<b>Mid Year Cost Rate</b>	<b>Return</b>
<b>2017 Original Filing</b>							
1	Long-Term debt	S.11 L.18	164,747	59.9%	164,369	2.18%	3,578
2	Common Stock	S.7 L. 8	<u>110,343</u>	<u>40.1%</u>	<u>110,090</u>	<u>8.82%</u>	<u>9,711</u>
3	Total	S.5 L.3	<u>275,090</u>	<u>100.0%</u>	<u>274,459</u>	<u>4.84%</u>	<u>13,289</u>
<b>Adjustment</b>							
4	Long-Term debt		-944	0.0%	-917	0.22%	339
5	Common Stock		<u>-629</u>	<u>0.0%</u>	<u>-611</u>	<u>-0.12%</u>	<u>-186</u>
6	Total		<u>-1,573</u>	<u>0.0%</u>	<u>-1,528</u>	<u>0.08%</u>	<u>153</u>
<b>2017 Compliance Filing</b>							
7	Long-Term debt	S.11 L.18	163,803	59.9%	163,452	2.40%	3,917
8	Common Stock	S.7 L. 8	<u>109,714</u>	<u>40.1%</u>	<u>109,479</u>	<u>8.70%</u>	<u>9,525</u>
9	Total	S.5 L.3	<u>273,517</u>	<u>100.0%</u>	<u>272,931</u>	<u>4.93%</u>	<u>13,442</u>

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Utility Revenue Requirement**  
(\$000s)

Schedule 5  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017		Compliance Filing	Explanation
			Original Filing	Adjustment		
1	Net rate base	S.1 L.20	274,459	(1,528)	272,931	2017 actuals update. Impact of disallowed assets.
2	Average Rate of return on rate base		4.84%	0.08%	4.93%	2017 actuals update for debt cost and ROE reduction from 8.82% to 8.70%.
3	Utility income	S.8 L.1	13,289	153	13,442	2017 actuals update.
4	Utility expenses					
5	Operating and maintenance (note 1)	S.6 L.3	23,363	473	23,836	2017 actuals update.
6	Taxes other than income	S.6 L.4	696	(3)	693	2017 actuals update.
7	Amortization of deferred costs	S.6 L.5	3,883	625	4,507	2017 actuals update.
8	Reserve for Injuries and Damages	S.6 L.6	479	-	479	2017 actuals update.
9	Depreciation	S.6 L.7	12,217	106	12,323	2017 actuals update.
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(5,269)	(531)	(5,801)	2017 actuals update.
11	Disallowed depreciation		(16)	(165)	(182)	2017 actuals update and impact of disallowed assets.
12	Donations		(96)	0	(96)	
13	Disallowed Expenses		-	-		
14	Total utility expenses		<u>35,255</u>	<u>505</u>	<u>35,760</u>	Impact of above changes.
15	Revenue Requirement	S.6 L.1	<u>48,544</u>	<u>658</u>	<u>49,202</u>	Impact of above changes.

Note 1: Includes fuel expenses and purchased power.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Statement of Earnings**  
(\$000s)

Schedule 6  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Revenues (note 1)	S.5 L.15	48,544	658	49,202	2017 actuals update.
2	<b>Operating expenses</b>					
3	Operating and maintenance	S.10 L.15	23,363	473	23,836	2017 actuals update.
4	Taxes other than income	S.5 L.6	696	(3)	693	2017 actuals update.
5	Amortize deferred costs	S.5 L.7	3,883	625	4,507	2017 actuals update.
6	Reserve for Injuries and Damages	S.5 L.8	479	-	479	2017 actuals update.
7	Depreciation	S.3 L.8	12,217	106	12,323	2017 actuals update.
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(5,269)	(531)	(5,801)	2017 actuals update.
9	Total		<u>35,367</u>	<u>670</u>	<u>36,037</u>	2017 actuals update.
10	<b>Operating income</b>		13,177	(12)	13,165	2017 actuals update.
11	<b>Other income</b>					
12	Allowed for Funds Used	S.8 L.2	863	(398)	466	2017 actuals update.
13	Miscellaneous (note 2)	S.8 L.3	<u>(32)</u>	<u>(253)</u>	<u>(285)</u>	2017 actuals update.
14	Total		<u>831</u>	<u>(650)</u>	<u>181</u>	
15	<b>Other expenses</b>					
16	Interest expense	S.8 L.4	<u>3,945</u>	<u>(65)</u>	<u>3,880</u>	2017 actuals update.
17	Total		<u>3,945</u>	<u>(65)</u>	<u>3,880</u>	
18	<b>Net earnings</b>	S.8 L.8	<u>10,063</u>	<u>- 598</u>	<u>9,466</u>	2017 actuals update.

Note 1: Includes revenues from sales, non-operating revenues and other revenues.

Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Statement of Retained Earnings**  
**(\$000s)**

Schedule 7  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Balance at beginning of year		51,037	-	51,037	2017 actuals update.
	Add:					
2	Net earnings	S.6 L.18	10,063	(598)	9,466	2017 actuals update.
3	IFRS Comprehensive Income Adjustment	S.6 L.18	-	252	252	2017 actuals update.
4	Balance at end of year before dividend		61,101	(346)	60,755	
	Less:					
5	Common Dividends/(Injection) (note 1)		-	-	-	
6	Balance at end of year		61,101	- 346	60,755	
	<b>Shareholder's Equity</b>					
7	Common shares		54,948	(912)	54,036	2017 actuals update.
8	Retained earnings		61,101	(346)	60,755	2017 actuals update.
9	Total		116,049	(1,258)	114,791	

Note:

1. YDC equity injection required in order to maintain 60/40 debt to equity ratio.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Reconciliation of Utility Income to Net Earnings**  
(\$000s)

Schedule 8  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Utility Income (Return on Rate Base)	S.5 L.3	13,289	153	13,442	2017 actuals update.
	Add:					
2	Allowance for funds used	S.6 L.13	863	(398)	466	2017 actuals update.
3	Other income (expenses)	S.6 L.14	(32)	(253)	(285)	2017 actuals update.
			<u>14,121</u>	<u>(498)</u>	<u>13,623</u>	
	Less:					
4	Interest - long-term	S.6 L.17	3,945	(65)	3,880	2017 actuals update.
5	Donations	S.5 L.12	96	(0)	96	
6	Disallowed costs	S.5 L.13	-	-	-	
7	Disallowed depreciation	S.5 L.11	16	165	182	2017 actuals update and impact of disallowed assets.
			<u>4,057</u>	<u>100</u>	<u>4,157</u>	
8	Net earnings	S.6 L.18	10,064	(598)	9,466	



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Summary of Customers, Energy Sales and Revenues**  
**(\$000s)**

Schedule 9  
February 25, 2019 Filing

Line No.	Description	2017			Explanation
		Original Filing	Adjustment	Compliance Filing	
1	<b>Residential</b>				
2	Customers	1,624	29	1,653	All changes are for 2017 actuals update
3	Sales in MWh	13,622	1,343	14,965	
4	MWh sales per customer	8	1	9	
5	Revenue (\$000s)	2,002	201	2,203	
6	Cents per KWh	14.70	0.02	14.72	
7	<b>General Service</b>				
8	Customers	490	9	499	
9	Sales in MWh	25,318	814	26,132	
10	MWh sales per customer	52	1	52	
11	Revenue (\$000s)	4,036	315	4,350	
12	Cents per KWh	15.94	0.71	16.65	
13	<b>Industrial</b>				
14	Sales in MWh	38,219	5,200	43,419	
15	Revenue (\$000s)	4,198	631	4,829	
16	Cents per KWh	10.98	0.14	11.12	
17	<b>Street lights</b>				
18	Sales in MWh	225	4	228	
19	Revenue (\$000s)	58	30	88	
20	Cents per KWh	26.01	12.63	38.64	
21	<b>Space lights</b>				
22	Sales in MWh	12	0	12	
23	Revenue (\$000s)	3	1	3	
24	Cents per KWh	22.46	6.11	28.56	
25	<b>Total Company - Firm Retail and Industrial</b>				
26	Customers	2,114	38	2,152	
27	Sales in MWh	77,395	7,361	84,756	
28	Revenue (\$000s)	10,297	1,177	11,474	
29	Cents per KWh	13.30	0.23	13.54	
30	<b>Wholesale sales</b>				
31	Sales in MWh	309,000	19,426	328,426	
32	Revenue (\$000s)	25,641	1,612	27,253	
33	Cents per KWh	8.30	0.00	8.30	
34	<b>Total Company - Firm</b>				
35	Sales in MWh	386,395	26,787	413,182	
36	Revenue (\$000s)	35,938	2,789	38,727	
37	Cents per KWh	9.30	0.07	9.37	
38	<b>Secondary</b>				
39	Sales in MWh	11,464	-3,079	8,385	
40	Revenue (\$000s)	642	-172	470	
41	Cents per KWh	5.60	0	5.60	
42	<b>Total Company</b>				
43	Sales in MWh	397,859	23,708	421,567	
44	Revenue (\$000s)	36,580	2,616	39,196	
45	Cents per KWh	9.19	0.10	9.30	
46	Rider J	6,363		6,952	
47	Post-GRA Reconcil Req'd	0		0	
48	GRA Increase Req'd	5,348	-2,613	2,734	
49	Total Sales of Power	<u>48,291</u>	<u>592</u>	<u>48,883</u>	
50	Other Revenues	253	66	319	
51	Total Revenues	48,544	658	49,202	



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Summary of Operating and Maintenance Expenses**  
(\$000s)

Schedule 10  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	<b>Utility operations</b>					
2	Production		5,760	606	6,366	2017 Actual update. O&M labour cost change [paragraph 130, changed to capital updated to use 2014-2017 average].
3	Transmission and distribution		3,352	183	3,535	
4	General		1,633	139	1,772	
5	Administration and general		9,110	-535	8,575	
6	Insurance		1,031	1	1,032	
7	Sub-total		<u>20,886</u>	<u>395</u>	<u>21,280</u>	
8	Donations		96	-0	96	
9	Sub-total		<u>96</u>	<u>0</u>	<u>96</u>	
10	O&M (not including fuel and					Impact of the above changes.
11	purchased power)		<u>20,982</u>	<u>394</u>	<u>21,376</u>	
12	Fuel		2,342	69	2,411	2017 actuals update.
13	Purchased power		39	10	49	2017 actuals update.
14	Sub-total		<u>2,381</u>	<u>79</u>	<u>2,460</u>	
15	Total operating and maintenance	S.6 L.3	<u>23,363</u>	<u>473</u>	<u>23,836</u>	Impact of the above changes.
<b>Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:</b>						
16	Reserve for Injuries and Damages		479	0	479	2017 actuals update.
17	Property Taxes		696	-3	693	2017 actuals update.
18	less: Donations		-96	0	-96	2017 actuals update.
19	O&M per Table 3.3 (Tab 3)		<u>22,060</u>	<u>392</u>	<u>22,452</u>	



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Summary of Cost of Long - Term Debt**  
**(\$000s)**

Schedule 11  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2017			Explanation
			Original Filing	Adjustment	Compliance Filing	
<b>General Purpose Long-Term Debt Balance</b>						
1	TD Canada Trust (4.02%)		0	0	0	
2	YDC \$81.9M Loan (4.25%)		0	0	0	
3	YDC Mayo B Flexible Term Debt		19,878	0	19,878	
4	TD Bank Swap (2.69%)		9,348	0	9,348	
5	YDC \$17.1M Debt (3.69%)		0	0	0	
6	YDC \$2.1M Debt (3.97%)		0	0	0	
7	YDC \$5.5M Debt (4.27%)		0	0	0	
8	Minto Decommissioning Reserve		2,660	0	2,660	
9	YDC \$5.5M Debt (2.40%)		5,505	0	5,505	
10	YDC \$92.5M Debt (2.40%)		81,407	0	81,407	
11	YDC \$21.0M Debt (2.21%)		19,306	0	19,306	
12	YDC \$12.1M Debt (2.10%)		12,136	0	12,136	
13	New 2017 Debt (2.15%)		23,828	-1,887	21,940	Update for actuals
14	New 2018 Debt		0	0	0	
15	Current year-end balance		174,068	-1,887	172,181	Impact of the above changes.
16	Previous year-end balance		155,425	0	155,425	
17	Mid Year		164,747	-944	163,803	Impact of the above changes.
<b>Interest Costs</b>						
18	TD Canada Trust (4.02%)		0	0	0	
19	YDC \$81.9M Loan (4.25%)		0	0	0	
20	YDC Mayo B Flexible Term Debt		432	339	770	Update for actuals
21	TD Bank Swap (2.69%)		257	0	257	
22	YDC \$17.1M Debt (3.69%)		0	0	0	
23	YDC \$2.1M Debt (3.97%)		0	0	0	
24	YDC \$5.5M Debt (4.27%)		0	0	0	
25	Minto Decommissioning Reserve		24	0	24	
26	YDC \$5.5M Debt (2.40%)		132	0	132	
27	YDC \$92.5M Debt (2.40%)		2,042	0	2,042	
28	YDC \$21.0M Debt (2.21%)		445	0	445	
29	YDC \$12.1M Debt (2.10%)		255	0	255	
30	New 2017 Debt (2.15%)		0	0	0	
31	New 2018 Debt		0	0	0	
32	<b>Total Cost of Interest</b>		3,586	339	3,925	Impact of the above changes.
33	Mid-Year Cost of Debt		2.18%	0.22%	2.40%	Impact of the above changes.



**Appendix 3.2:**  
**Summary of Adjustments to Tab 7 Schedules for 2018**



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Computation of Rate Base**  
(\$000s)

Schedule 1  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018			Explanation
			Original Filing	Adjustment	Compliance Filing	
<b>1</b>	<b>Property, Plant and Equipment</b>					
2	Year end balance	S.3 L.5	618,511	(6,076)	612,435	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
	Deduct:					
3	Accumulated depreciation (note 1)	S.3 L.10	169,223	(2,032)	167,191	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
4	Construction-in-progress	S.3 L.11	8,274	(654)	7,620	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
5	Disallowed assets	S.3 L.12	691	2,055	2,746	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
6	Miscellaneous reserves	S.3 L.13	4,069	(399)	3,669	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
7	Total deductions		<u>182,257</u>	<u>(1,030)</u>	<u>181,227</u>	
	Add:					
8	Deferred study costs (note 2)	S.3 L.15	44,917	(3,222)	41,695	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
9	Less: Studies in Progress	S.3 L.16	(29,859)	361	(29,498)	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
10	Other deferred costs	S.3 L.17	-	-	-	
11	Accum. Disallowed depreciation	S.3 L.18	200	353	553	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
12	Total additions		<u>15,258</u>	<u>(2,508)</u>	<u>12,751</u>	
	<b>Net plant in Service</b>					
13	Current year-end balance	S.3 L.20	451,511	(7,553)	443,958	Impact of above changes.
14	Previous year-end balance		451,268	(4,492)	446,776	Please see 2017 actuals.
15	Total		<u>902,779</u>	<u>(12,046)</u>	<u>890,734</u>	
16	Mid-year balance		451,390	(6,023)	445,367	Impact of above changes.
18	Mid-year rate case expense		2,208	1,671	3,879	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
19	Working capital	S.2 L.8	5,210	134	5,344	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
20	<b>Gross Rate Base</b>		458,808	(4,218)	454,590	Impact of above changes.
	Deduct:					
	<b>Contributions for extensions</b>					
21	Current year-end balance		201,300	(68)	201,232	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
22	Contributions in WIP		-	-	-	
23	Current year-end balance in-service		201,300	(68)	201,232	
24	Accumulated amortization of contributions		35,986	(10)	35,976	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
25	Net current year-end balance in-service		<u>165,314</u>	<u>(58)</u>	<u>165,256</u>	
26	Previous year-end balance		169,049	(81)	168,967	Please see 2017 actuals.
27	Total		<u>334,363</u>	<u>(140)</u>	<u>334,223</u>	
28	Mid-year balance		167,181	(70)	167,112	Impact of above changes.
29	<b>Net Rate Base</b>	S.5 L.1	<u>291,627</u>	<u>(4,148)</u>	<u>287,478</u>	Impact of above changes.

Note 1: Including Reserve for Future Removal and Site Restoration

Note 2: Planning and Study costs, Relicensing, Dam Safety costs and Deferred Overhauls. Net of contributions.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Computation of Allowance for Working Capital**  
(\$000s)

Schedule 2  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Operating and maintenance	S.5 L.5	23,336	379	23,715	Fuel expense and labour cost adjustment.
2	Taxes other than income	S.5 L.6	708	-	708	
3	Non-allowable expenses		(100)	-	(100)	
4	Cash operating expenses		23,944	379	24,323	
5	27/365 in 2009 GRA		1,771	28	1,799	Impact of the above changes.
6	Inventory (three year average)		3,598	105	3,703	Impact of 2017 actuals.
7	GST Impact on working capital	S.2A L.11	(159)	1	(158)	Impact of the above changes.
8	Working capital	S.1 L.19	5,210	134	5,344	Impact of the above changes.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Effect of GST on Working Capital**  
**(\$000s)**

Schedule 2A  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Expenses subject to GST		41,694	390	42,084	Impact of changes in expenses.
2	GST Rate		5%	0%	5%	
3	GST Recoverable		2,085	20	2,104	Impact of the above changes.
4	Day Factor		14	-	14	
5	Recoverable portion of GST impact		80	1	81	Impact of the above changes.
6	Revenue subject to GST		49,864	(71)	49,794	Please see Schedule 5, Line 15
7	GST blended rate (2009 GRA)		5%	0%	5%	
8	GST payable		2,493	(4)	2,490	Impact of the above changes.
9	Day factor		35	-	35	
10	Payable portion of GST impact		239	-	239	Impact of the above changes.
11	Net impact of GST on working capital	S.2 L.7	(159)	1	(158)	Impact of the above changes.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Continuity Schedule of Property, Plant and Equipment**  
**(\$000s)**

Schedule 3  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018		Explanation	
			Original Filing	Adjustment		Compliance Filing
<b>1</b>	<b>Property, Plant and Equipment</b>					
2	Balance at beginning of year		603,879	(5,123)	598,756	Please see 2017 actuals.
3	Net Increases to PPE (Table 5.1)		14,631	(953)	13,678	Please see Appendix 1.1 Tables 1.1-2 and 1.1-3 for details of the adjustments.
4	Retirements, disposals and adjustments (note 1)		-		-	
5	Balance at end of year	S.1 L.2	618,511	(6,076)	612,435	
<b>6</b>	<b>Accumulated depreciation (including Future Removal Reserve)</b>					
7	Balance at beginning of year		156,806	(1,644)	155,162	Please see 2017 actuals.
8	Depreciation expense	S.6 L.7	12,419	(387)	12,031	Please see Appendix 1.1 Tables 1.1-2 and 1.1-3 for details of the adjustments.
9	Retirements, disposals and adjustments (note 1)		(2)		(2)	
10	Balance at end of year		169,223	(2,032)	167,191	
	Deduct:					
11	Construction-in-progress	S.1 L.4	8,274	(654)	7,620	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
12	Disallowed assets	S.1 L.5	691	2,055	2,746	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
13	Miscellaneous reserves (note 2)	S.1 L.6	4,069	(399)	3,669	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
14	Total		13,034		14,036	
	Add:					
15	Deferred study costs (note 3)	S.1 L.8	44,917	(3,222)	41,695	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
16	Less: Studies in Progress	S.1 L.9	(29,859)	361	(29,498)	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
17	Other deferred costs	S.1 L.10	-	-	-	
18	Accum. Disallowed depreciation	S.1 L.11	200	353	553	Please see Appendix 1.1, Tables 1.1-2 and 1.1-3 for details of the adjustments.
19	Total		15,258	(2,508)	12,751	Impact of the above changes.
20	Net Property, Plant and Equipment	S.1 L.13	451,511	(7,553)	443,958	Impact of the above changes.

Note 1: Largely relate to retirements and disposals, as well as charges against the Reserve for Future Removal and Restoration.

Note 2: Includes Fire Insurance Reserve, Deferred Dewatering Revenues and the Reserve for Injuries and Damages.

Note 3: Planning and Study costs, Relicencing, Dam Safety costs and Deferred Overhauls. Net of contributions.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Cost of Capital Calculation**

Schedule 4  
 February 25, 2019 Filing

(\$000s)

<b>Line No.</b>	<b>Description</b>	<b>Cross Ref.</b>	<b>Mid Year Balance</b>	<b>Ratio</b>	<b>Mid Year Rate Base</b>	<b>Mid Year Cost Rate</b>	<b>Return</b>
<b>2018 Original Filing</b>							
1	Long-Term debt	S.11 L.18	174,973	60.0%	174,974	2.32%	4,058
2	Common Stock	S.7 L. 8	<u>116,653</u>	<u>40.0%</u>	<u>116,653</u>	<u>8.82%</u>	<u>10,290</u>
3	Total	S.5 L.3	<u>291,625</u>	<u>100.0%</u>	<u>291,627</u>	<u>4.92%</u>	<u>14,348</u>
<b>Adjustment</b>							
4	Long-Term debt		-2,501	0.0%	-2,489	-0.09%	-213
5	Common Stock		<u>-1,667</u>	<u>0.0%</u>	<u>-1,659</u>	<u>-0.12%</u>	<u>-284</u>
6	Total		<u>-4,168</u>	<u>0.0%</u>	<u>-4,148</u>	<u>-0.10%</u>	<u>-498</u>
<b>2018 Compliance Filing</b>							
7	Long-Term debt	S.11 L.18	172,472	60.0%	172,485	2.23%	3,844
8	Common Stock	S.7 L. 8	<u>114,985</u>	<u>40.0%</u>	<u>114,994</u>	<u>8.70%</u>	<u>10,006</u>
9	Total	S.5 L.3	<u>287,457</u>	<u>100.0%</u>	<u>287,478</u>	<u>4.82%</u>	<u>13,850</u>

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Utility Revenue Requirement**  
(\$000s)

Schedule 5  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Net rate base	S.1 L.20	291,627	(4,148)	287,478	Please see Schedule 1 Line 20
2	Average Rate of return on rate base		4.92%	-0.10%	4.82%	Please see Schedule 4A Line 6
3	Utility income	S.8 L.1	14,348	(498)	13,850	Please see Schedule 4A Line 6
4	Utility expenses					
5	Operating and maintenance (note 1)	S.6 L.3	23,336	379	23,715	Please see Schedule 2 Line 1
6	Taxes other than income	S.6 L.4	708	-	708	
7	Amortization of deferred costs	S.6 L.5	3,891	1,172	5,063	Please see Appendix 1.1, Table 1.1-2
8	Reserve for Injuries and Damages	S.6 L.6	479	-	479	
9	Depreciation	S.6 L.7	12,419	(223)	12,196	Please see Appendix 1.1, Table 1.1-2
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(5,200)	(714)	(5,914)	Please see Appendix 1.1, Table 1.1-2
11	Disallowed depreciation		(16)	(188)	(204)	Please see Appendix 1.1, Table 1.1-2
12	Donations		(100)	-	(100)	
13	Disallowed Expenses		-	-	-	
14	Total utility expenses		<u>35,516</u>	<u>427</u>	<u>35,943</u>	Impact of the above changes.
15	Revenue Requirement	S.6 L.1	<u>49,864</u>	<u>- 71</u>	<u>49,794</u>	Impact of the above changes.

Note 1: Includes fuel expenses and purchased power.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Statement of Earnings**  
(\$000s)

Schedule 6  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Revenues (note 1)	S.5 L.15	49,864	(71)	49,794	Please see Schedule 5 Line 15
2	<b>Operating expenses</b>					
3	Operating and maintenance	S.10 L.15	23,336	379	23,715	Please see Schedule 2 Line 1
4	Taxes other than income	S.5 L.6	708	-	708	
5	Amortize deferred costs	S.5 L.7	3,891	1,172	5,063	Please see Schedule 5 Line 7
6	Reserve for Injuries and Damages	S.5 L.8	479	-	479	
7	Depreciation	S.3 L.8	12,419	(223)	12,196	Please see Appendix 1.1, Table 1.1-2
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(5,200)	(714)	(5,914)	Please see Appendix 1.1, Table 1.1-2
9	Total		<u>35,633</u>	<u>614</u>	<u>36,247</u>	Impact of the above changes.
10	<b>Operating income</b>		14,231	(685)	13,546	Impact of the above changes.
11	<b>Other income</b>					
12	Allowed for Funds Used	S.8 L.2	719	(177)	542	Update to capital and 2017 actuals update.
13	Miscellaneous (note 2)	S.8 L.3	<u>(32)</u>	<u>(483)</u>	<u>(515)</u>	Impact of 2017 actual updates and regulatory losses.
14	Total		<u>688</u>	<u>(660)</u>	<u>28</u>	
15	<b>Other expenses</b>					
16	Interest expense	S.8 L.4	<u>4,201</u>	<u>230</u>	<u>4,431</u>	Please see Schedule 11 Line 35
17	Total		<u>4,201</u>	<u>230</u>	<u>4,431</u>	
18	<b>Net earnings</b>	S.8 L.8	<u>10,718</u>	<u>- 1,576</u>	<u>9,142</u>	Impact of the above changes.

Note 1: Includes revenues from sales, non-operating revenues and other revenues.

Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Statement of Retained Earnings**  
(\$000s)

Schedule 7  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Balance at beginning of year		61,101	(346)	60,755	Please see Schedule 7 Line 5 for 2017
	Add:					
2	Net earnings	S.6 L.18	10,718	(1,576)	9,142	Please see Schedule 6 Line 18
3	IFRS Comprehensive Income Adjustment	S.6 L.18	-	1,660	1,660	IFRS Adjustment [no impact to rates]
4	Balance at end of year before dividend		<u>71,819</u>	<u>(262)</u>	<u>71,557</u>	
	Less:					
5	Common Dividends/(Injection) (note 1)		<u>9,512</u>	<u>902</u>	<u>10,414</u>	Impact of the changes for 2018.
6	Balance at end of year		<u><u>62,307</u></u>	<u><u>- 1,164</u></u>	<u><u>61,143</u></u>	Impact of the above changes.
	<b>Shareholder's Equity</b>					
7	Common shares		54,948	(912)	54,036	Impact of the changes for 2018.
8	Retained earnings		<u>62,307</u>	<u>(1,164)</u>	<u>61,143</u>	Impact of the changes for 2018.
9	Total		<u><u>117,256</u></u>	<u><u>(2,076)</u></u>	<u><u>115,179</u></u>	

Note:

1. YDC equity injection required in order to maintain 60/40 debt to equity ratio.

**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Reconciliation of Utility Income to Net Earnings**  
(\$000s)

Schedule 8  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	Utility Income (Return on Rate Base)	S.5 L.3	14,348	(498)	13,850	Please see Schedule 5 Line 3
	Add:					
2	Allowance for funds used	S.6 L.13	719	(177)	542	Changes to capital and 2017 actuals update.
3	Other income (expenses)	S.6 L.14	(32)	(483)	(515)	Please see Schedule 6 Line 13
			<u>15,035</u>	<u>(1,158)</u>	<u>13,878</u>	Impact of the above changes.
	Less:					
4	Interest - long-term	S.6 L.17	4,201	230	4,431	Please see Schedule 11 Line 35
5	Donations	S.5 L.12	100	-	100	
6	Disallowed costs	S.5 L.13	-	-	-	
7	Disallowed depreciation	S.5 L.11	16	188	204	Please see Schedule 5 Line 11
			<u>4,317</u>	<u>418</u>	<u>4,735</u>	
8	Net earnings	S.6 L.18	10,718	(1,576)	9,143	Impact of the above changes.



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Summary of Customers, Energy Sales and Revenues**  
**(\$000s)**

Schedule 9  
February 25, 2019 Filing

Line No.	Description	2018			Explanation
		Original Filing	Adjustment	Compliance Filing	
1	<b>Residential</b>				
2	Customers	1,635	0	1,635	
3	Sales in MWh	13,719	0	13,719	
4	MWh sales per customer	8	0	8	
5	Revenue (\$000s)	2,016	0	2,016	
6	Cents per KWh	14.70	0.00	14.70	
7	<b>General Service</b>				
8	Customers	490	-1	489	
9	Sales in MWh	25,436	0	25,436	
10	MWh sales per customer	52	0	52	
11	Revenue (\$000s)	4,054	0	4,054	
12	Cents per KWh	15.94	0.00	15.94	
13	<b>Industrial</b>				
14	Sales in MWh	38,219	-6,027	32,193	Minto load reduction from 38.2 GW.h to 32.2 GW.h [Order 2018-10, paragraph 46].
15	Revenue (\$000s)	4,198	-247	3,952	Impact of the lower sales forecast.
16	Cents per KWh	10.98	1.29	12.27	
17	<b>Street lights</b>				
18	Sales in MWh	214	0	214	
19	Revenue (\$000s)	56	0	56	
20	Cents per KWh	26.01	0.00	26.01	
21	<b>Space lights</b>				
22	Sales in MWh	12	0	12	
23	Revenue (\$000s)	3	0	3	
24	Cents per KWh	22.46	0.00	22.46	
25	<b>Total Company - Firm Retail and Industrial</b>				
26	Customers	2,126	-1	2,125	
27	Sales in MWh	77,599	-6,027	71,573	Impact of the above changes.
28	Revenue (\$000s)	10,327	-247	10,081	Impact of the above changes.
29	Cents per KWh	13.31	0.78	14.08	
30	<b>Wholesale sales</b>				
31	Sales in MWh	309,519	5,181	314,700	As directed by YUB, Order 2018-10, paragraph 38.
32	Revenue (\$000s)	25,684	430	26,114	Impact of the increased wholesale forecast.
33	Cents per KWh	8.30	0.00	8.30	
34	<b>Total Company - Firm</b>				
35	Sales in MWh	387,118	-846	386,273	Impact of the above changes.
36	Revenue (\$000s)	36,011	183	36,194	Impact of the above changes.
37	Cents per KWh	9.30	0.07	9.37	
38	<b>Secondary</b>				
39	Sales in MWh	11,464	-9,405	2,059	Lower secondary sales forecast [Order 2018-10, paragraph 55].
40	Revenue (\$000s)	642	-527	115	Impact of the lower sales forecast.
41	Cents per KWh	5.60	0	5.60	
42	<b>Total Company</b>				
43	Sales in MWh	398,582	-10,250	388,332	Impact of the above changes.
44	Revenue (\$000s)	36,653	-343	36,310	Impact of the above changes.
45	Cents per KWh	9.20	0.15	9.35	
46	Rider J	6,373		6,469	
47	Post-GRA Reconcil Req'd	0		0	
48	GRA Increase Req'd	6,585	176	6,762	GRA required rate increase change
49	Total Sales of Power	<u>49,611</u>	<u>-71</u>	<u>49,541</u>	Impact of the above changes.
50	Other Revenues	253	0	253	
51	Total Revenues	49,864	-71	49,794	Impact of the above changes.



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Summary of Operating and Maintenance Expenses**  
(\$000s)

Schedule 10  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018			Explanation
			Original Filing	Adjustment	Compliance Filing	
1	<b>Utility operations</b>					
2	Production		5,907	22	5,930	
3	Transmission and distribution		3,364	81	3,445	
4	General		1,614	1	1,615	O&M labour cost increase [paragraph 130, capital allocation updated].
5	Administration and general		8,912	5	8,917	
6	Insurance		1,031	0	1,031	
7	Sub-total		<u>20,829</u>	<u>109</u>	<u>20,938</u>	
8	Donations		100	0	100	
9	Sub-total		<u>100</u>	<u>0</u>	<u>100</u>	
10	O&M (not including fuel and					
11	purchased power)		<u>20,929</u>	<u>109</u>	<u>21,038</u>	Impact of the above changes.
12	Fuel		2,368	270	2,638	
13	Purchased power		39	0	39	
14	Sub-total		<u>2,407</u>	<u>270</u>	<u>2,677</u>	
15	Total operating and maintenance	S.6 L.3	<u>23,336</u>	<u>379</u>	<u>23,715</u>	Impact of the above changes.
<b>Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:</b>						
16	Reserve for Injuries and Damages		479	0	479	
17	Property Taxes		708	0	708	
18	less: Donations		-100	0	-100	
19	O&M per Table 3.3 (Tab 3)		<u>22,016</u>	<u>109</u>	<u>22,125</u>	



**Yukon Energy Corporation 2017/18 GRA Compliance Filing**  
**Summary of Cost of Long - Term Debt**  
**(\$000s)**

Schedule 11  
February 25, 2019 Filing

Line No.	Description	Cross Ref.	2018			Explanation
			Original Filing	Adjustment	Compliance Filing	
<b>General Purpose Long-Term Debt Balance</b>						
1	TD Canada Trust (4.02%)		0	0	0	
2	YDC \$81.9M Loan (4.25%)		0	0	0	
3	YDC Mayo B Flexible Term Debt		19,542	0	19,542	
4	TD Bank Swap (2.69%)		8,991	0	8,991	
5	YDC \$17.1M Debt (3.69%)		0	0	0	
6	YDC \$2.1M Debt (3.97%)		0	0	0	
7	YDC \$5.5M Debt (4.27%)		0	0	0	
8	Minto Decommissioning Reserve		2,684	0	2,684	
9	YDC \$5.5M Debt (2.40%)		5,505	0	5,505	
10	YDC \$92.5M Debt (2.40%)		77,723	0	77,723	
11	YDC \$21.0M Debt (2.21%)		18,466	0	18,466	
12	YDC \$12.1M Debt (2.10%)		12,136	0	12,136	
13	New 2017 Debt (2.15%)		23,828	-1,887	21,940	Actuals
14	New 2018 Debt		7,004	-1,228	5,776	Reflect changes in rate base to maintain 60/40 ratio
15	Current year-end balance		175,878	-3,115	172,763	Impact of the above changes.
16	Previous year-end balance		174,068	-1,887	172,181	Please see Schedule 11 for 2017.
17	Mid Year		174,973	-2,501	172,472	Impact of the above changes.
<b>Interest Costs</b>						
18	TD Canada Trust (4.02%)		0	0	0	
19	YDC \$81.9M Loan (4.25%)		0	0	0	
20	YDC Mayo B Flexible Term Debt		507	-173	334	Due to lower forecast load
21	TD Bank Swap (2.69%)		247	0	247	
22	YDC \$17.1M Debt (3.69%)		0	0	0	
23	YDC \$2.1M Debt (3.97%)		0	0	0	
24	YDC \$5.5M Debt (4.27%)		0	0	0	
25	Minto Decommissioning Reserve		24	0	24	
26	YDC \$5.5M Debt (2.40%)		132	0	132	
27	YDC \$92.5M Debt (2.40%)		1,954	0	1,954	
28	YDC \$21.0M Debt (2.21%)		427	0	427	
29	YDC \$12.1M Debt (2.10%)		255	0	255	
30	New 2017 Debt (2.15%)		512	-41	472	2017 update
31	New 2018 Debt		0	0	0	
32	<b>Total Cost of Interest</b>		4,058	-213	3,844	Impact of the above changes.
33	Mid-Year Cost of Debt		2.32%	-0.09%	2.23%	Impact of the above changes.